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High-efficiency cogeneration in the Netherlands

Analysis of the potential for high-efficiency cogeneration and overview of barriers and recent developments

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Abstract
This report analyses the economic potential for cogeneration towards 2020 in the Netherlands. Important elements in the background of this study include the Dutch policy plans as laid down in the Clean and Efficient working programme. These policy plans are to realise the Dutch ambitions with regard to GHG-emissions and energy: 30% reduction of GHG emissions in 2020 relative to 1990, 2% annual energy saving and 20% renewable energy in 2020. The working programme is likely to give an important stimulation to many energy saving technologies, including cogeneration. At the same time the resulting dynamics create great uncertainty about the exact impact on various technologies. This uncertainty also holds for the 2020 position of cogeneration. For this reason, the current analysis explores the impact on cogeneration of a wider range of developments with regard to policies such as CO_2 prices and energy standards, energy prices and with regard to the role of competing technologies on both the heat market and the electricity market. Uncertainties in the results are large. In the industry, cogeneration is likely to contribute considerably to the Dutch government target, due to the relatively small role of alternative heat supply technologies in the short term. However, in the other sectors, alternative heat technologies may benefit more from ambitious targets and strong incentives than cogeneration.

Contents

List of tables

List of figures

Summary

Article 6 of the European directive 2004/8/EG of 11 February 2004 (CHP-directive) obliges member states to establish an analysis of the national potential for the application of high-efficiency cogeneration, including high-efficiency micro-cogeneration. Further, it obliges member states to evaluate progress towards increasing the share of high-efficiency cogeneration. This report describes this analysis and evaluation for the Netherlands, exploring the technical and economic potentials for high-efficiency cogeneration in the Netherlands.

Policy background unto 2020
Potentials for cogeneration are not stationary and unchangeable, but dynamic. They depend on developments in both the electricity markets and the demand and supply of heat. The Dutch and European policies required to realise the 2020 energy and emissions targets of the Dutch government, as formulated in the Clean and Efficient action programme, will result in large shifts in the demand and production of electricity and heat alike. This will create an important opportunity for many energy savings technologies, but at the same time creates uncertainties with regard to the roles of the individual technologies. Uncertainty is further increased as current policy plans have not yet reached their final shape, nor have European policies. For these reasons, it is not possible to provide specific estimates of cogeneration potential towards 2020.

To provide insights that also retain their validity outside the narrower context of the current Dutch policy targets, the analysis explores higher and lower CO_2 prices as well. Interactions between cogeneration and other developments that night be induced by the Clean and Efficient package are dealt with in a qualitative way.

Recent cogeneration developments
After some years of stagnating cogeneration capacity, recent years have seen an increase of installed capacity again. This is almost entirely due to the increase of gas engines in horticulture, which are well equipped to operate on volatile electricity markets.

Barriers
The Netherlands have a high share of cogeneration in electricity production. While this does not imply that there are no barriers for cogeneration at all, it does put the barriers in perspective. Overall, barriers do not appear to have a profound influence on the development of cogeneration in the Netherlands. Recent developments with regard to cogeneration can be largely explained by market developments.

Electricity market
For all practical purposes, the limitations on the electricity market appear to be less stringent than those on the heat market. In all but the most extreme situations, the electricity market can probably accommodate the additional cogeneration induced by the Clean and Efficient policies, along with other additional capacity such as renewable electricity and new coal plants. However, a likely side-effect is that the current net electricity imports will turn into net electricity exports.

Higher CO_2 prices, application of CCS, and the increase of intermittent renewable electricity will profoundly affect the electricity prices. While the average price will rise, the extent of this price rise is very uncertain, as is the expected difference between peak and off-peak prices. Currently, flexible cogeneration is more competitive than cogeneration in must-run situations. In the future, this is not likely to change.

Industry
Industry is the most important sector with regard to cogeneration. The technical potential for heat production by cogeneration in the industry is estimated to rise from a current 290 PJ towards 320 in 2020. However, around 100 PJ of this concerns the demand for direct heat. Application of cogeneration for direct heat usually requires far-reaching integration of cogeneration into the heart of the respective industrial processes. Industrial producers have strong reservations about cogeneration in such cases, because of the increased risk on process failures.

In the industry, the Clean and Efficient policies are not likely to have a profound impact on alternative technologies for heat supply and demand before 2020. A possible exception is the increased use of residual heat from processes. The estimated economic potential for 2020 energy savings as defined by the CHP-directive is between 50 PJ in the baseline and 90 PJ in case of CO_2 prices of 100 €/tonne.

Agriculture
In the Netherlands, greenhouse horticulture is the second most important sector for cogeneration. The application of heat buffers offers great flexibility on the electricity market, allowing horticulturalists to benefit from higher peak prices without creating a must-run situation during off-peak periods. In addition, part of the electricity is consumed by the companies themselves for assimilation lighting. Technical potential for cogeneration is estimated to be some 80 PJ of heat.

However, agriculture has relatively many possibilities for reduction of heat demand and alternative heat generation. The Clean and Efficient plans aim at greenhouse concepts that store excess heat summer heat for use during the winter season. Application of geothermal heat and residual heat from nearby industries are alternatives that offer the possibility for deeper CO_2 reduction than possible with cogeneration. As a result, rising CO_2 prices or other generic incentives are likely to result in an uncertain future for cogeneration in horticulture. While cogeneration as such becomes more attractive, other technologies are likely to benefit even more from the higher CO_2 prices. The estimated economic potentials for energy savings are around 20 PJ in 2020, with only minor variations with differing CO_2 prices. However, uncertainties are very high: many of the competing technologies still require further development and cost decreases. Disappointing developments with regard to these alternatives may give cogeneration a much stronger position in the greenhouse horticulture.

Services
The potentials in the services sectors are very uncertain, as there are important alternatives for cogeneration. In newly constructed office buildings for example, the application of heat pumps combined with heat and cold storage in aquifers is more or less becoming a standard technology. Such technologies offer possibilities for deeper CO_2 reduction than possible with cogeneration. As such, higher incentives or more stringent standard are likely to elicit more application of alternative technologies rather than cogeneration. For existing buildings, cogeneration may play an important role and in smaller buildings in the services sector, micro-CHP may play a role.

Households: micro-CHP
Micro-cogeneration is a very new technology, and uncertainties with regard to potentials and costs are large. Further, there are important alternative heat supply technologies such as heat pumps and solar heat boilers. Finally, the cost-effectiveness of micro-CHP and its competitors depends strongly on the amount of heat required in a house. As the Clean and Efficient programme aims at increasing the application of thermal isolation in existing houses, and aims at energy neutrality in newly constructed houses by 2020, average heat demand per location is expected to decrease dramatically during the next fifteen years, resulting in a worse position of micro-CHP.

The overall outcome of many important but uncertain developments is that the economic potential of micro-CHP is very uncertain. Depending on the success of the market introduction during the next four years, the maximum number of micro-CHP's present in 2020 is estimated at some 1 million. However, because of the aforementioned uncertainties, the actual 2020 number may be anything between zero and one million. There are too many uncertainties to translate this range to the resulting energy savings.

District heating
In both services and households, cogeneration based district heating is an alternative to on site cogeneration. In the Netherlands, application of district heating is not widespread. Most existing district heating system in the Netherlands already receive their heat from cogeneration or residual heat. For additional district heating systems, in case of new residential areas and offices the costs are relatively low, but here, the heat demand per building is decreasing rapidly, deteriorating the cost-effectiveness of district heating. On the other hand in existing buildings, heat demand is much higher, but the implementation of new district heating system in existing areas is very expensive. As with other cogeneration in the built environment, alternative technologies may benefit more in case of higher targets.

Overall
Overall, the major part of the cogeneration contribution to the extra savings of Clean and Efficient will come from industrial cogeneration. Here, the competition from alternative technologies for heat production is probably not important enough to prevent a larger role for cogeneration. In the agriculture and services the situation is different. Here more ambitious targets and stronger policies increase the probability that alternative technologies become important, perhaps at the cost of cogeneration. The alternatives offer possibilities for deeper reductions than possible with cogeneration. However, uncertainties are large, both with regard to actual technological developments and the situation on the electricity market.

1. Introduction

1.1 Background

Article 6 of the European directive 2004/8/EG of 11 February 2004 (CHP-directive) obliges member states to establish an analysis of the national potential for the application of high-efficiency cogeneration, including high-efficiency micro-cogeneration. Further, it obliges member states to evaluate progress towards increasing the share of high-efficiency cogeneration. This report describes this analysis and evaluation for the Netherlands.

1.2 CHP-directive

The CHP-directive gives the following prescriptions on the contents of the analysis and on the way the analysis is to be performed. Article 6.2 states that the analysis shall:

- Be based on well-documented scientific data and comply with the criteria listed in Annex IV.
- Identify all potential for useful heating and cooling demands, suitable for application of high-efficiency cogeneration, as well as the availability of fuels and other energy resources to be utilised in cogeneration.
- Include a separate analysis of barriers, which may prevent the realisation of the national potential for high-efficiency cogeneration. In particular, this analysis shall consider barriers relating to the prices and costs of and access to fuels, barriers in relation to grid system issues, barriers in relation to administrative procedures, and barriers relating to the lack of internalisation of the external costs in energy prices.

Annex IV specifies the criteria for analysis of national potentials for high-efficiency cogeneration:

(a) The analysis of national potentials referred to in Article 6 shall consider:
  - The type of fuels that are likely to be used to realise the cogeneration potentials, including specific considerations on the potential for increasing the use of renewable energy sources in the national heat markets via cogeneration.
  - The type of cogeneration technologies as listed in Annex I that are likely to be used to realise the national potential.
  - The type of separate production of heat and electricity or, where feasible, mechanical energy that high-efficiency cogeneration is likely to substitute.
  - A division of the potential into modernisation of existing capacity and construction of new capacity.

(b) The analysis shall include appropriate mechanisms to assess the cost effectiveness - in terms of primary energy savings - of increasing the share of high-efficiency cogeneration in the national energy mix. The analysis of cost effectiveness shall also take into account national commitments accepted in the context of the climate change commitments accepted by the Community pursuant to the Kyoto Protocol to the United Nations Framework Convention on Climate Change.

(c) The analysis of the national cogeneration potential shall specify the potentials in relation to the time frames 2010, 2015 and 2020 and include, where feasible, appropriate cost estimates for each of the time frames.

The directive further prescribes the way electricity from cogeneration is to be calculated (Annex II), the methodology for determining the efficiency of cogeneration and the definition of high-efficiency cogeneration (Annex III), and the efficiency reference values for separate production of heat production and electricity. Appendix A of this report shows the efficiency reference values, as applied in the current analysis. The approach according to the directive differs in some import ways from the approach applied in the Netherlands. Appendix B gives a detailed description of the relevant differences and their consequences. To allow for comparison with the numbers circulating in national documents, the report will specify savings and other results both according to the directive and according to the national approach.

1.3 Approach

CHP in the Netherlands is mature and represents over 30% of the power production. Stimulating policies in the past have taken CHP to cover large parts of its economic potential. Additional potentials are therefore not mere technological opportunities but depend on competition with other efficient technologies, market and policy developments. Therefore the character of this study is more like an analysis than an inventory.

New policies
The most recent analyses have been carried out to estimate the effects of the new policy package, Clean and Efficient. This policy package aims at ambitious targets with regard to GHG-emission reduction, energy efficiency, and renewable energy. Because of the uncertainties with regard to the definitive shape of many policies, and due to the uncertainties with regard to important European developments such as the ETS and energy relevant directives, these latest analyses have resulted in a mere estimate of bandwidths of possible policy effects, based on partial analyses. Yet, the Clean and Efficient policy package is likely to be one of the dominant forces in the years to come for the development of cogeneration and other options for attaining the targets.

The dominant role of Clean and Efficient combined with the availability of mere bandwidths, and partial analyses have important consequences for the way the analysis on cogeneration potential can be performed. The Dutch targets on GHG-emissions, energy savings and renewable energy are ambitious, and the required policies, both national and European, will probably move the Dutch energy system towards unfamiliar territory. This will not only affect CHP, but other technologies as well. It is very difficult to predict the new balance of power between various technologies in such a strongly different energy system. For this reason, the current analysis is limited to partial analyses that explore the effects of important factors such as CO_2 prices and electricity prices, and the development of competing technologies, both on the heat market and the electricity market.

Starting points
Starting points of the analysis on cogeneration potentials are the high oil price variant of the Global economy scenario, GEHP (Farla et al, 2006; CPB/MNP/RPB, 2006), and the analyses performed for the evaluation of Clean and Efficient (Menkveld et al, 2007 a,b). The analyses further uses information and insights on alternatives for cogeneration from (Daniëls and Farla, 2006 a, b; Daniëls et al, 2006; Daniëls et al, 2007; Seebregts, 2007)

Sensitivity analysis
The CHP-directive demands an analysis on the technical and economic potentials in 2010, 2015 and 2020. The economic potentials shown will be based on various sets of energy prices and CO_2 prices. The analysis will qualitatively evaluate the effects of other options that are likely to penetrate given the same set of policies and prices, and that will affect the economic and technical potential for CHP. These options include savings on heat demand, alternative heat supply technologies, alternative electricity generation technologies and technologies that compete with CHP for the available energy resources. For the industry, agriculture and energy sector, important policies include the ETS and to a lesser extent the stimulation of renewable electricity. For the services and households, the policies directed on energy savings, generally energy performance standards, are important. Because of the great sensitivity of the economic performance of

cogeneration for relatively minor changes in prices and policies, there will be a qualitative analysis on variations in the assumed prices and policies.

Data sources and models

The analysis will use the models and data sources applied in the Netherlands for energy outlooks and policy analysis, and results available from previous analyses. The heat demand in the model is calibrated to statistics, but the part of heat demand to be considered technical cogeneration potential is based on expert judgements on the level of separate energy functions[1].

The last general update of the input data of the models has taken place in 2004. There has been no opportunity to collect new data in a systematic way. However, if possible the results have been adapted to reflect new developments, and otherwise the text addresses the possible effects of such developments.

Currently, several projects are carried out that collect data on actual developments with regard to cogeneration. The results of these projects are expected by the end of 2007. The current analysis incorporates actual information where available.

1.4 Guide to the report

After this introductory chapter, Chapter 2 evaluates the progress of CHP in the Netherlands, as requested in Article 6.3 of the directive, while Chapter 3 contains a separate analysis of barriers for CHP in the Netherlands, as requested in Article 6.2. Chapter 4 sketches an overview of the assumptions on prices and policies applied in the current analysis. Chapter 5 describes possible developments on the electricity market, both with regard to the room for cogeneration and the factors that influence electricity prices and price response to rising CO_2 prices. Chapter 6 deals with large-scale and small-scale CHP and Chapter 7 with micro-CHP. Chapter 8 discusses the results and presents some important conclusions.

Appendix A shows the reference values for separate generation of electricity and heat in the Netherlands, as calculated in accordance with the directive (EC, 2004). Appendix B compares the methodology of the directive with the methodologies generally applied in the Netherlands. Appendix C gives background information on the most important data sources and models applied for this analysis. Appendix D gives detailed results of the calculations carried out.

[1] E.g.: CO_2 fertilisation, heating in the greenhouse horticulture, naphtha cracking in the petrochemical industry.

2. Main CHP-developments 1998-2006

This chapter discusses developments in the capacity and electricity production of Combined Heat and Power (CHP) installations in the Netherlands. An estimate is given for the energy savings due to cogeneration.

2.1 Total capacity and electricity production

In 2006 the total electrical capacity of CHP installations in the Netherlands was 9,538 MW_e[2]. Compared to 2005 (8,796 MW_e) the total capacity increased by 8.4%. This increase is mainly due to new installations in the agriculture and waste incineration sectors. The development of CHP capacity over the period from 1998 to 2006 is shown in Figure 2.1. The substantial increase in 2004 is caused by the opening of the Intergen plant in Rijnmond (825 MW_e) and the E.On Lyondell unit on the Maasvlakte. The figures shown include cogeneration units that do not meet the European criteria for high-efficiency cogeneration. This includes both older units with low efficiencies and new units that have not (yet) attained sufficiently high heat sales. However, fuel input and electricity and heat production numbers are not publicly available. Therefore, it is not possible to filter out units that do not meet the high efficiency criteria.

The figures exclude coal-based CHP capacity. In the Netherlands, three coal-fueled steam-turbine installations produce electricity as well as useful heat. There are two plants in Geertruidenberg (Amer 8 and Amer 9) and one in Nijmegen (Gelderlandcentrale). The corresponding coal cogeneration capacity is 1944 MW_e. On average, the coal based cogeneration has a relatively low heat-to-power ratio (11.5% in 2006).

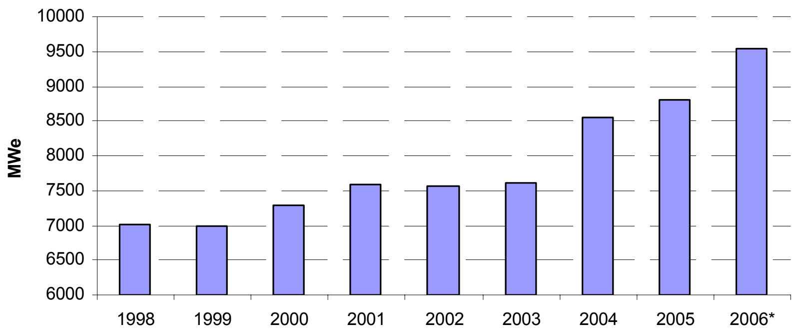

Figure 2.1 *Development of the total electrical CHP capacity (excluding coal-fueled CHP) from 1998 to 2006*
Source: CBS.

2 All data from CBS for 2006 are preliminary.

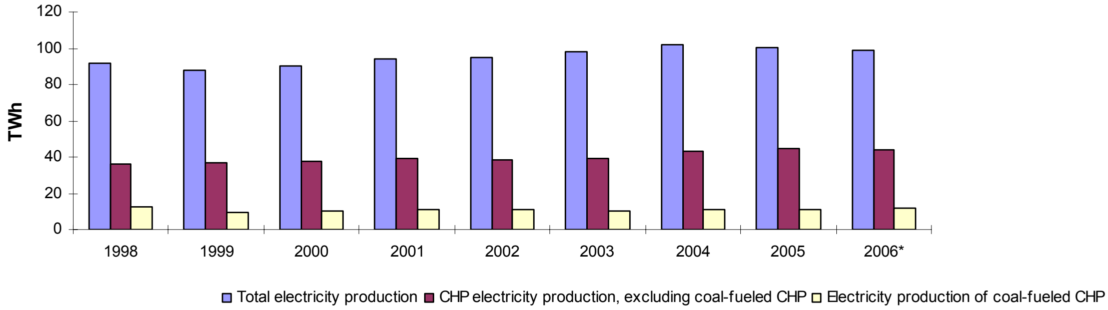

Figure 2.2 *Development of the electricity production (total, CHP and coal-fueled CHP) from 1998 to 2006*
Source: CBS.

The total production of electricity in 2006 amounted to 98.8 TWh. With production of CHP installations (excluding coal-CHP) equal to 44.1 TWh, the share of CHP in the total electricity production was 44.6%. In 1998 this share stood at 39.4%. This is relatively high when compared with other European countries (Eurostat, 2007).

In the following, central and decentralised CHP units are distinguished. According to CBS (Statline, 2007), central generation includes the centrally coordinated generation of electricity and heat by units connected to the high voltage grid of the TSO TenneT. Decentralised cogeneration includes all cogeneration of electricity and heat that is not centrally coordinated, by installations situated at companies of which the primary objective is not production of electricity or heat. Besides the aforementioned central coal-fuelled installations there are 15 Combined Cycle Gas Turbines (CCGT) with a total capacity of 3250 MW_e and four gas turbines with a total capacity of 171 MW_e (data for 2006). No changes occurred in these capacities between 2005 and 2006.

2.2 Cogeneration in the industry

In the decentralised CHP installations, we distinguish installations in the industry and in other sectors. In 2006 the total capacity of CHP in the industry was 3220 MW_e. With a share of 55%, the majority of this capacity is situated in the chemical industry. Figure 2.3 shows the development of industrial CHP capacity over the period 1998-2006. This capacity is quite stable. Most notable is a sharp increase in 2001, which can be ascribed to the chemical industry. There were only minor changes in 2006.

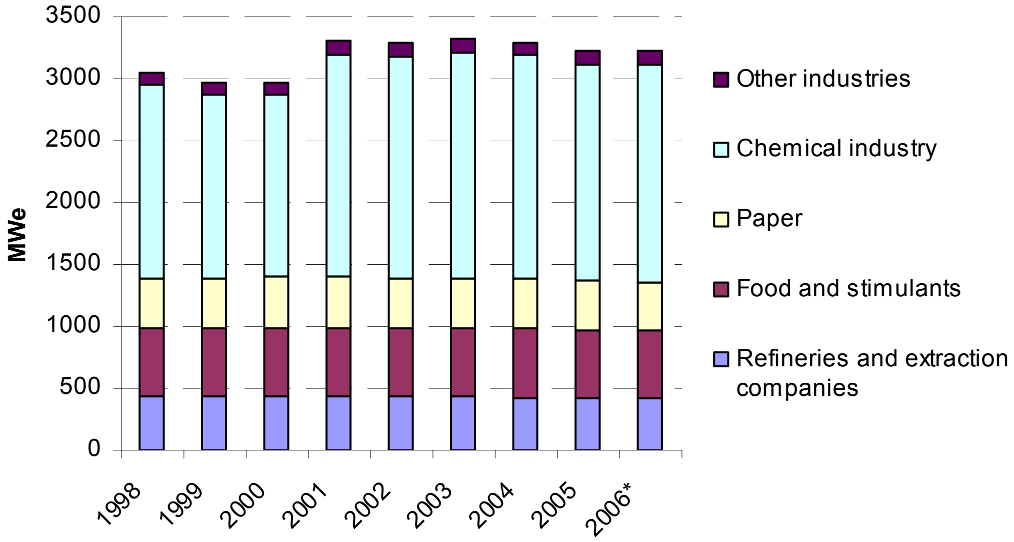

Figure 2.3 *Development of CHP capacity in the industry*
Source: CBS.

Table 2.1 gives an overview of characteristics of cogeneration in the industry for the year 2006. The share of the chemical industry in the total electricity production of industrial CHP was 59%. The installations in the chemical industry have the largest average electrical capacity. In the 'Food and stimulants' and 'Other industries' sectors, installations are generally much smaller.

Table 2.1 *Overview of characteristics of CHP in the industry for 2006*

Sector	Total input [TJ]	Production of electricity [TJ]	Production of steam/heat [TJ]	Electrical capacity [MW_e]	Number of installations
Refineries and extraction companies	48126	9624	29956	425	30
Food and stimulants	33033	8206	17971	544	86
Paper	27727	8042	13881	391	27
Chemical industry	143628	39055	74412	1760	47
Other industries	5581	959	3965	100	61
Total	258095	65886	140185	3220	251

Source: CBS.

As can be seen from Figure 2.4, CCGT and gas turbines are the most important types of CHP installations in the industry, accounting for respectively 63% and 24% of the total capacity in 2006. Brief descriptions of the installation types are presented in Table E.1 in Appendix E.

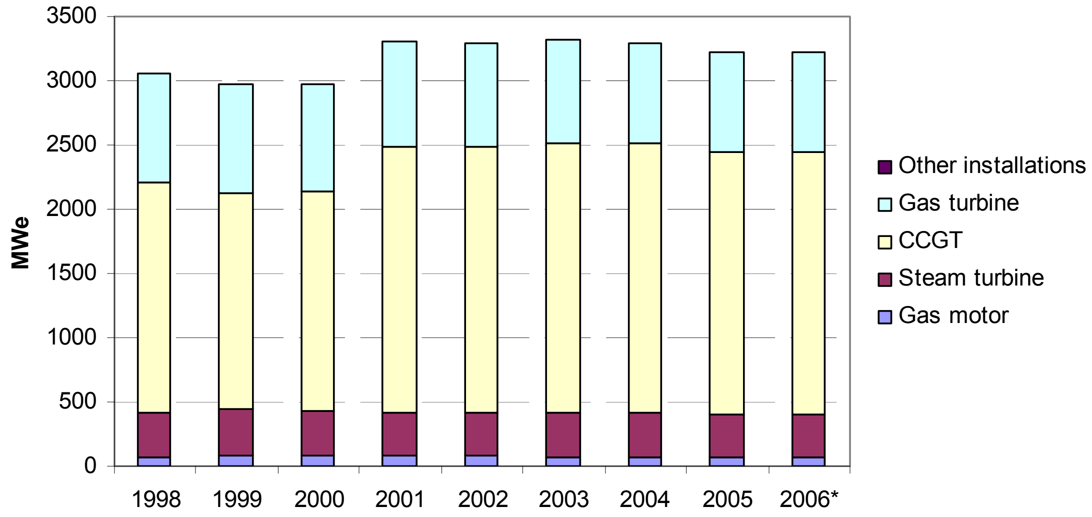

Figure 2.4 *Development of CHP capacity in the industry, for each technology (1998-2006)*
Source: CBS.

2.3 Cogeneration in non-industrial sectors

The category Other Sectors comprises:
- Agriculture
- Distribution companies
- Health care
- Waste incineration
- Other producers.

Health care and part of the other producers belong to the services sector. Cogeneration for the residential sector is often operated by the distribution companies. Large district heating systems are not included here.

In 2006, the total CHP capacity in these sectors was 2897 MW_e, a sharp increase of 34% compared to 2005, when the capacity was only 2158 MW_e. There was a surge of capacity in the sectors Agriculture and Waste Incineration (see Figure 2.5). In agriculture, the capacity increased from 1240 MW_e to 1841 MW_e (+48%). In waste incineration, the capacity doubled from 137 MW_e to 277 MW_e (+102%). The capacity added in 2004 can be ascribed to these two sectors as well. The electrical capacities in other sectors were practically stable.

Figure 2.5 *Development of CHP capacity in the Other Sectors for the subsectors (1998-2006)*
Source: CBS.

The overview of the characteristics of CHP in the Other Sectors for 2006 in Table 2.2 shows that the majority of installations is situated in the Agriculture sector.

Table 2.2 *Overview of characteristics of CHP in the Other sectors for 2006*

Sector	Total input [TJ]	Production of electricity [TJ]	Production of steam/heat [TJ]	Electrical capacity [MW_e]	Number of installations
Agriculture	44490	15574	22590	1841	2422
Distribution companies	8000	2866	2257	315	79
Health care	7849	2569	4068	172	458
Waste incineration	31894	6260	2702	277	27
Other producers	10782	3504	5655	292	805
Total	103015	30773	37272	2897	3791

Source: CBS.

As can be seen from Figure 2.6, the gas motor is the most used type of CHP installation in the non-industrial sectors. With 80% of the capacity in 2006 it clearly dominates over the other technologies. In 2006, there was a strong increase in capacity of gas motors from 1711 MW_e to 2315 MW_e. The capacity of steam turbines also increased rapidly from 26 MW_e in 2004 to 267 MW_e in 2006.

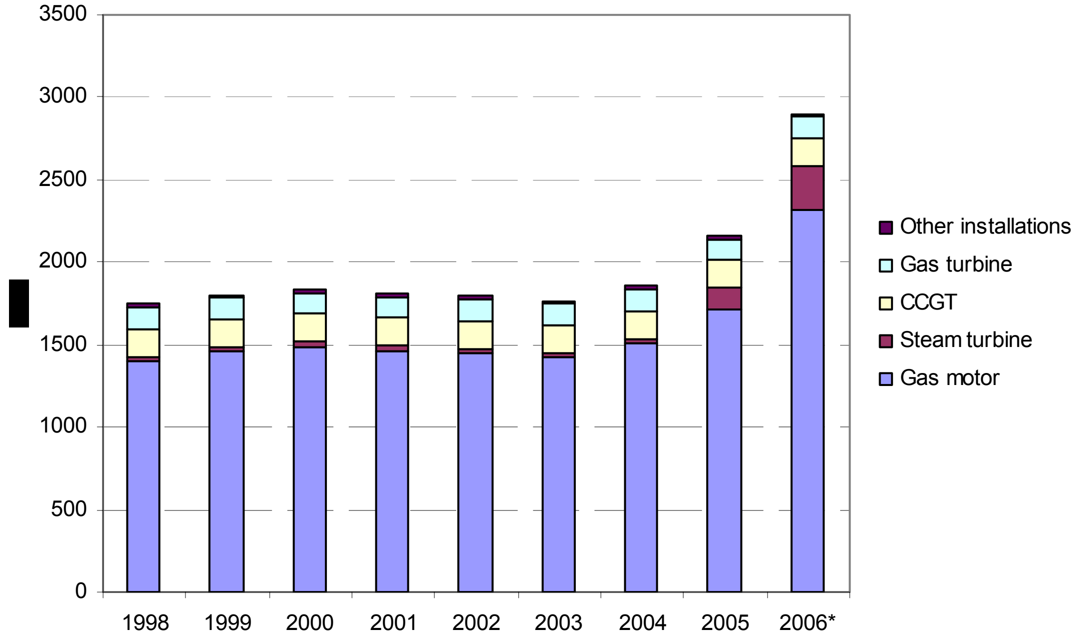

Figure 2.6 *Development of CHP capacity in the Other sectors for installation types (1998-2006)*
Source: CBS.

CHP in greenhouse horticulture
One of the most important developments is the growth of CHP capacity in greenhouse horticulture. Farmers usually produce electricity to use for greenhouse assimilation lighting and export their excess electricity to the grid. In addition, there are also cogeneration units that only export to the grid. With the current electricity prices this is economically attractive and this development fits into the trend of intensification of greenhouse farming. From Table 2.3 it can be seen that the electricity production in the agriculture sector increased by 31% in 2006 compared to 2005.

Table 2.3 *Electricity production and capacity of CHP in Agriculture*

		1998	1999	2000	2001	2002	2003	2004	2005	2006*
Electricity production	[GWh]	3060	3254	3149	3094	3043	2986	3037	3300	4326
Capacity	[MW_e]	919	966	995	969	956	960	1042	1240	1841

Source: CBS.

2.4 Heat distribution

District heating systems supply heat to residential areas and companies. In the appendix the distribution of the capacity for district heating over the provinces is given for 2005. In recent years, there have been only few developments in projects for heat distribution.

2.5 Bio-energy small-scale cogeneration

CHP installations can also use biomass as fuel. At the end of 2006 there were about 56 small-scale bio-energy CHP installations. There were two gasifiers, 14 combustion installations and 40 fermentation installations. In these figures, installations that use gas from waste dumps, biogas from sewage works and biogas in the industry are not included. In 2006 four new combustion installations and 14 new fermentation installations were taken into operation (mainly on farms). In 2006 the cumulative capacity amounted to about 56 MW_e, an increase of 10 MW_e compared to the previous year. Table 2.4 summarized the avoided use of fossil fuels due to bio-CHP. (Source: Statusdocument Bio-energie 2006, SenterNovem).

Table 2.4 *Avoided use of fossil fuels due to bio-CHP as estimated by SenterNovem*

	Prevented use of fossil energy [TJ]				
	2002	2003	2004	2005	2006
Bio-CHP combustion	2050	2050	2290[a]	2560[a]	2700
Bio-CHP from biodegradable waste and manure fermentation	140	170	210	280	380

[a] Excluding the CDEM installation in Duiven.
Source: Statusdocument bio-energie, 2006.

2.6 Energy savings due to cogeneration

Application of cogeneration saves energy compared to separate generation of electricity and steam/heat. The energy savings shown are based on CBS statistics for fuel input, electricity production and steam/heat production of CHP installations. The reference efficiencies for separate generation are derived from the EU directive, which depend on fuel type and year of installation. As the precise age is not known for all installations, the calculation assumes average reference efficiencies for the previous 15 years. Transport losses for centrally produced electricity are assumed to be 5%. This allows for calculation of the reference energy input of separate generation, and the energy savings of cogeneration. Table 2.5 gives an overview of energy savings for 2006, and Appendix B gives details for the period 1998-2006.

Table 2.5 *Calculated energy savings per technology for central/decentralised placement (2006)*

	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
Steam turbine, central	104.3	42.0	4.8	2.0	2
CCGT, central	130.9	59.1	29.8	21.4	14
Gas turbine, central	12.3	2.9	7.8	2.2	15
Gas engine, decentral	65.6	22.5	33.5	18.1	22
Steam turbine, decentral	70.9	10.1	32.4	-4.7	-7
CCGT, decentral	133.9	44.7	56.4	22.8	15
Gas turbine, decentral	90.1	19.1	54.9	13.3	13
Central (total)	247.5	104.0	42.5	25.7	9
Decentral (total)	360.5	96.4	177.2	49.6	12
Total	608.0	200.5	219.7	75.2	11

The total energy savings due to cogeneration for 2006 were 75.2 PJ. Central installations contributed 25.7 PJ and decentral installations 49.6 PJ[3]. It can be seen that steam turbines add only little to energy savings from CHP. Use of Combined Cycle Gas Turbines is most important for the savings from central CHP. Gas motors, CCGT and gas turbines all contribute significantly to the energy savings for decentrally located installations.

3 According to the calculation method of the Dutch Protocol Monitoring (PME), the same decentral cogeneration units realised approximately twice as much energy savings. The differences between the PME and the savings according to the CHP directive are explained in Appendix B

3. Barriers for CHP

3.1 Introduction

Article 6.2 of Directive 2004/8/EG (EC, 2004) sums up the following potential barriers for the realisation of the national potential for high-efficiency cogeneration, which have to be evaluated: 'In particular, this analysis shall consider barriers relating to the prices and costs of and access to fuels, barriers in relation to grid system issues, barriers in relation to administrative procedures, and barriers relating to the lack of internalisation of the external costs in energy prices'.

Therefore this chapter deals subsequently with the following barriers in separate sections:

- Prices and costs of and access to fuels.
- Grid system issues.
- Barriers related to administrative procedures.
- Internalisation of external costs.

While barriers as such are relevant in the Netherlands, and while they may inhibit the realisation of individual cogeneration units, the Dutch situation as such proves that the barriers present have not prevented the realisation of a large amount of cogeneration potential. In addition, from an economic point of view, the deterioration of the economic position of cogeneration on the electricity markets after 2000 cannot be mainly attributed to barriers, unless obvious market failures can be demonstrated.

3.2 Prices and costs of and access to fuels

Prices of electricity and heat in a liberalised energy market have to cover the production costs of CHP units. For CHP generated electricity, capital costs, fuel costs as well as related input costs like national and regional network tariffs, flexibility remuneration and energy levies have to be taken into account.

In the Netherlands CHP is generally gas-fired, so that fuel costs usually correspond to the costs of natural gas. In general, gas-fired facilities for electricity production have relatively low cost of capital and relatively high cost of fuel. Accordingly, the cost structure of CHP electricity production is dominated by fuel costs.

Therefore, the difference between electricity prices and the costs of gas needed to generate electricity, known as the spark spread, is a key driver for the profitability of gas-fired CHP. From this point of view, two factors may have an important impact on CHP. First, wider spark spread fluctuations influence the need for flexible power production; and second, the CHP subsidy scheme in the Netherlands is faced with regulatory uncertainty due to, although not exclusively, changes in fuel cost. These reasons are subsequently treated below. In addition, the access to the markets for electricity (output) and fuels (main input) will be dealt with. Finally, this paragraph will deal with the often-mentioned supposed distortion of electricity prices by German subsidies on indigenous coal mining.

Higher need for flexibility due to more price-variability in current market environment influences CHP

In the past the spark spread was more or less stable due to the regulation of the energy market. However, along with the liberalisation of the electricity production market electricity and gas prices are now determined on market places and as a consequence prices and the spark spread are fluctuating more widely. This has implications for existing as well as new CHP facilities.

Existing CHP units
Price variability is based on production cost differences, which are highly influenced by the marginal technology (the technology which the marginal unit deployed uses). During peak hours, gas-fired facilities are price setting and as CHP is relatively cost effective compared to such facilities, CHP can produce electricity fairly competitive during the peak. During off-peak hours however coal-fired facilities set the price of electricity and such facilities can produce at much lower marginal cost. CHP facilities that have a must-run character, i.e. facilities that have to be dispatched for reasons other than power demand, therefore may be forced to sell their power at prices lower than needed to cover the operational costs.[4] These notions are reflected in the spark spread which is substantial for peak products, but may even be negative for off-peak hours.

New CHP units
Not only the operation of existing CHP facilities, but also investment in new CHP units may be influenced negatively. More price variability implies that energy producers have less certainty about the revenues of their investments in new CHP production capacity. Therefore, they are increasingly searching for more flexibility in energy production. This puts CHP at a disadvantage, production of electricity and heat together is generally considered to be less flexible than separate production of electricity and heat.

The higher need for flexibility and negative consequences of that for existing and new CHP units cannot be regarded as market barrier, as it does not directly result from market failures. Still, the liberalisation of the energy markets has put cogeneration in the Netherlands in a more vulnerable position than before the liberalisation.

Policy uncertainty due to the current subsidy scheme
The spark spread also plays a role in the current subsidy scheme for CHP, as the subsidy equals the cost difference between electricity production of CHP, corrected for the avoided costs of heat, and electricity production of conventional sources (non-renewables). Differences in the spark spread are visible in the amount of exploitation subsidy (MEP-WKK), which is established on a yearly basis. This subsidy gives rise to three sources of policy uncertainty.

First, the scheme implies that at the time of investment CHP investors do not know whether or not they will be compensated for uneconomic operations through a production subsidy during the whole lifetime of the CHP unit; the subsidy can be abolished by the government each year, therefore firms cannot reckon with the subsidy in their investment decisions regarding CHP production.

Second, it implies that CHP investors cannot take into account the *amount* of subsidy in their investment decisions; the subsidy could fluctuate due to changes in assessment, changing calculation methods etcetera.

Third, producers face some additional uncertainty in operational decisions, as they have to give forward prices for their production well in advance to buyers (for being able to close forward contracts). At that time, the existence and amount of subsidy in the next year may be still unclear.

[4] Although before the liberalisation of the energy market there was a difference between prices for peak and off-peak periods, these electricity prices were based on the average costs of production. Furthermore, for CHP there existed a special and attractive rate for gas.

As a result of these three sources of regulatory uncertainty, the current subsidy scheme is not limiting the risks of market operation for CHP units. As subsidies are considered to be most important for small CHP units up to now, mainly for them policy uncertainty may be a barrier.

Access to the electricity market
Overall, access to the electricity market appears to be no barrier. The extent to which a CHP may benefit from the wholesale market for electricity depends on the kind of CHP unit. Especially CHP units used in horticulture have a good position because of two reasons. First, they are able to supply electricity during peak hours due to the existence of heat buffers. Second, through aggregating many CHP units in so-called virtual power plants (VPPs) they are able to take part in different markets (bilateral over-the-counter (OTC), day-ahead and imbalance market) for maximising their revenues. For CHP units without heat buffers only the first reason applies.

Access to fuels
Compared to other electricity generation, access to fuels for cogeneration is not a barrier. However, in the Dutch situation, there is not much overlap between areas with a large heat demand and areas with good and cheap physical access to coal.

Access to fuels can be divided into both (1) access to the wholesale[5] market and (2) access to networks. Access to fuels can be understood as economic access and/or physical access to both gas and other sources. Below, we will deal with both types of access for different fuels.

(1) Economic access to the wholesale market of gas by CHP is partly limited by the dominant position of GasTerra, not for competition on the commodity price, but because it is the only supplier that can offer significant flexibility. Therefore, tariff regulation of the flexibility service has been introduced by the Office of Energy Regulation (NMa/DTe). It is uncertain whether there is enough flexibility available to the market at the moment due to lack of public knowledge,[6] at the same time the regulator aims to enhance the availability of flexibility. Physical access to gas is very well due to the extensive gas network and the presence of gas storage and gas fields in the Northern part of the Netherlands and the North sea area.

Economic access for CHP to markets of coal and biomass is more limited than the access to the gas market. The coal market is confined to bilateral trading, without common market platform. For biomass there does not exist a market in the Netherlands and consequently there are small possibilities to cover the risks of shortage of biomass on trade markets.

Physical access for producers to fuels like coal and biomass depends on the geographical location. As the Netherlands have deep-sea harbours and most coal plants are located nearby rivers because of the availability of cooling-water, in general the access can be considered to be sufficient. Concerning biomass, the supply of biomass is an important precondition for selecting plant locations, which implies that biomass based WKK has well physical access to biomass in general.

(2) Network access. There seem to be no major problems for CHP due to the existence of extensive gas and electricity networks. Also the network access prices to obtain gas and to deliver electricity and heat are generally considered to be relatively low. Network access is not considered to be a major barrier by market parties (KPMG, 2006).

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5 On the wholesale market fuel suppliers sell their fuels to (power) producers or other large customers. Trade between suppliers is also performed on the market.

6 NMa/DTe (2006): 'Gas Monitor: Developments on the Gas Wholesale Market in the Netherlands in 2005', The Hague.

Subsidies on indigenous German coal for power generation
Dutch cogeneration operators often point at subsidies on German coal for power generation as a part of the cause for the recent bad situation for especially industrial cogeneration. The coal subsidies supposedly distort the electricity market, resulting in lower electricity prices during the off-peak hours. Especially for cogeneration in a must run situation, this would result in an economic disadvantage.

The main target of the German coal subsidies is to support the indigenous coal mining industry. The economy and employment of some regions heavily depend on the local coal mining. The costs of German coal are much higher than the world market prices and the German subsidies intend to bridge the difference between indigenous coal costs and the world market price. In this way, use of indigenous coal is not more expensive than use of foreign coal. German coal subsidies peaked in the 1990s and are decreasing since. Current targets seem to work towards a complete stop of coal subsidies by 2016 (Tönjes, 2007).

Various sources (IEA, Weber et al, 2000) describe the German coal subsidies, and many criticise them, but not for the reason of giving German coal based electricity production a competitive advantage. As stated in (Weber et al, 2000), the major arguments raised against the coal policy build on perceived dangers for the competitiveness of electricity-intensive industries which have to bear the costs for the coal subsidies. The subsidies on indigenous coal only bridge the gap between indigenous costs and world market prices (Tönjes, 2007), and as such there is no reason to suppose that wholesale electricity prices are influenced by the subsidies. Absence of the subsidies would probably result in substitution of foreign coal for indigenous coal, but not in lower coal based power production and higher electricity prices.

3.3 Grid system issues

Grid access seems currently not a major issue for CHP operators in the Netherlands, but there are some exceptions. This can partly be explained by the long experience DSOs[7] have in the Netherlands with connecting CHP units to the electricity grid. This in contrast with grid connections for wind-energy that give causes for disputes between DSOs and wind-energy operators. Nevertheless, the problem of correct allocation of costs and benefits between DSOs and CHP operators induced by CHP deployment is not solved. There are two reasons to look in to this issue somewhat further:

1. The costs and benefits will become more substantial if the amount of distributed generation (CHP and RES) increases.
2. If CHP receives compensation for the system benefits, subsidies can be reduced.

In the following these reasons will be illustrated by five specific problems regarding the allocation of costs and benefits between DSOs and CHP.

1. Connection of small CHP units takes a lot of time, large units have to pay deep connection charges which are less transparent than shallow connection charges. This may be perceived as barrier by CHP units.

Incremental DSO costs (operational expenditures (OPEX) & capital expenditures (CAPEX)) due to the connection of distributed generation (DG) are generally not taken into account when DSO revenues are calculated under the current regulatory scheme. Connection charges for units below 10 MVA are shallow and regulated, and therefore the reinforcement costs due to DG are not part of DSO revenues. Consequently, the DSO may suffer financial losses and therefore may not be in favour of connecting CHP to the grid. This is illustrated by the long negotiations that are necessary for obtaining grid access for DG. In practise, this problem is more linked to wind,

7 DSO stands for Distribution System Operator, the party who usually owns and operates the network.

as DSOs both have a lot of experience with connecting CHP and at the same time connecting CHP is simplified by the network which is quite dense. However, if the connection is larger than 10 MVA connection charges are deep and therefore the DSO is able to pass-through all necessary reinforcement costs due to DG to the DG-operator. Furthermore, there are no standard rates for that kind of connection ('unregulated' charges), which makes them less transparent for CHP units. As a conclusion, obtaining a connection, especially above 10 MVA, is perceived as costly by CHP units.

2. The positive influence of CHP on network losses and deferral of investment in transformer capacity is currently not accounted for.

CHP and RES may increase or decrease network losses of DSOs, dependent on the penetration of CHP and RES in the distribution grid and grid structure. Network losses (and investments) depend on the amount of energy transported over the grid. A DG penetration below approximately 20%, dependent on the grid structure, may lower network losses and defer network investments, while a higher penetration seems to increase both network losses and investments.[8] A low DG penetration implies that DSOs have to transform less energy from high voltage grids to lower voltage grids. Therefore, fewer investments in transformer capacity are needed or these investments can be deferred (depending on growth in energy demand and with that growth in demand for network and system services).

In the Netherlands, the influence of CHP on network losses is still considered to be positive. Until recently, the positive influence of CHP on network losses was partly rewarded by a very small compensation payment for avoided energy losses in the transmission network (this arrangement was known as 'RUN'). However, last year this compensation mechanism has been abolished by the Court of Appeal for Business (CBb), because of inaccurate foundation by law. In general, no substantial remuneration scheme to account for the positive external effects of CHP production on network and system operation has been put forward during the last decade; this may be perceived as a disadvantage for CHP.

3. DSOs consider DG (CHP) rather as a threat to their businesses than as an opportunity to diversify.

Uncontrolled operation of DG (i.e. CHP) enlarges system operational problems, as was the case in the aftermath of the interruption on 4 November 2006, when uncontrolled DG made it difficult for system operators to re-establish the normal system conditions.[9] It seems that this objection mainly results from the unpredictability of wind, but less from CHP. Yet, CHP also increase DSO risk and uncertainty regarding system reliability. Consequently, the overall conclusion holds that the stance of DSOs to CHP is rather negative than positive, which results in a disadvantage to CHP.

Currently, in the Netherlands problems are arising due to the formation of hot spots of cogeneration. In the Westland, an area with a large concentration of greenhouse horticulture, the growth of cogeneration is very fast. Local production of electricity is much larger than the consumption, and the excess electricity has to be carried away by the high voltage grid. In such as case, grid losses grow considerably, and the operation problems extend even to the Transmission System Operator. The required capacity expansion of the high-voltage grid may take to ten years. Currently, access of cogeneration to the grid in the Westland area is restricted due to the first come first serve access procedure. Capacity is reserved for new-to-build power plants in the Rotterdam areas. These have much longer lead times than small-scale cogeneration, and therefore reserve capacity on the high-voltage grid in advance.

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8 DG-Grid (2007): 'Guidelines for improvement on the short term of electricity distribution network regulation for enhancing the share of DG', WP 4, Report D12/13, June.

9 UCTE (2007): Final report - System disturbance on 4 November.

4. DG is not considered to be an alternative to network expansion and cannot provide ancillary services.

Article 14/7 of the 2003/54/EC Electricity directive requires DSOs to consider DG as an alternative to network expansion. The system of incentive regulation currently does not give incentives to DSOs to consider DG (and with that CHP) as an alternative to network reinforcements. Also the contribution of CHP to network security is only partly taken into account at the moment, although CHP can participate on the balancing market (through commercial aggregators in case of horticulture CHP operators) and the market for reserve power (large industrial CHP as well as large industrial interruptible demand). For provision of other ancillary services, there are still barriers for provision by CHP (communication infrastructure, monitoring devices etc.) and therefore for exploiting the benefits of CHP.

5. Integration of DG in the distribution network may be restricted by network regulation.
The regulatory mechanism to induce efficient investments by DSOs might limit their investments in new innovative approaches for dealing with the network consequences of a high penetration of DG (which in the Netherlands consists mainly of CHP).

The regulatory mechanism ('yardstick competition') induces DSOs to reduce their investments as much as possible (to reduce costs and lower network tariffs for society i.e. higher 'static efficiency') and with that restricts investments for innovations which carry a higher risk (i.e. lower 'dynamic efficiency'). High-risk investments deliver uncertain revenues and therefore necessitate higher returns for the DSO (profits). However, while yardstick competition prunes these profits away, some of the high-risk type of investments needs to be implemented for dealing with higher penetrations of DG, especially CHP. For instance, active network management is a main possibility to improve the position of CHP by acknowledging the network benefits of CHP (see the IEE project DG-GRID).

On the other hand there remains some room for investments with yardstick competition, as it induces DSOs to carry out firm-specific investments rather than general investments in order to reduce costs. With firm-specific investments DSOs are able to achieve comparative advantages which are remunerated by the yardstick competition scheme, whereas more general investments can be replicated by other parties and therefore will not deliver additional revenues (if all DSOs decrease their costs, average costs will decline, which - ceteris paribus - results in lower allowed revenues for all DSOs in the next regulatory period). Regarding network investments, active network management is mainly regarded to be an example of a general investment. Therefore, the regulatory mechanism can be considered as hindering innovative integration of CHP (and DG in general) and consequently prevents CHP to achieve its full benefits.

3.4 Barriers related to administrative procedures

On the whole, administrative procedures do not appear to be a barrier. KPMG interviewed different CHP sectors for a survey into investment factors for CHP (KPMG, 2006). It concerns the following sectors: industrial CHP, the horticulture sector and built environment. Regarding industrial CHP, although the complexity of licenses and obligations has been raised during the last decade, administrative procedures are relatively insignificant. According to the horticulture sector, the administrative burden to receive the exploitation subsidy (MEP-WKK) is high, although the increase of small CHP units in the last years shows the administrative barriers are not really prohibitive. Finally, in the built environment sector procedures and licenses are regarded as relatively unimportant.

3.5 Lack of internalisation of external costs in energy prices

Different external costs and benefits (‘negative costs’) of CHP can be distinguished, concerning (1) sustainability; (2) network and system operation.

External effects on sustainability

The external costs of electricity and heat production on sustainability are internalised in energy prices in different ways. Firstly, the costs of CO_2 emission rights are included in the operational costs by the power generators and therefore passed on to the electricity prices[10] [11]. The price increase has a positive effect on the spark spread. Furthermore, all generators including larger CHP units[12] have been granted CO_2 emission rights. Therefore, power producers have the benefit of a higher electricity price, without having to pay for the CO_2 rights. CHP operators in the Netherlands got an additional benefit because of their higher efficiency, and received more rights than necessary to meet their emissions. Therefore, they could sell their surplus rights.

Second, CHP receives a subsidy, the MEP (Milieukwaliteit Elektriciteitsproductie), which depends on the CO_2 intensity of the CHP unit compared to the CO_2 intensity of separate electricity and heat production. The upper limit of electricity production to subidized is 1000 GWh. Therefore, the positive external benefits (negative external costs) of CHP on sustainability are (partly) internalised in the subsidy scheme for an electricity production up to 1000 GWh.

Small CHP faces environmental requirements less strict than those valid for large scale generation. Especially gas engines emit relatively large amounts of NO_x. Moreover they emit methane which is not accounted for as a CO_2 equivalent in emission trading or CO_2 based subsidies. This situation leads to a relative advantage for small scale cogeneration.

External effects on network and system operation

Besides this favourable effect of CHP on the environment, CHP may also have a positive external effect on networks i.e. on quality regulation (amount of network interruptions) and reserve capacity. Up to now, CHP does not play a part in the limitation of frequency and duration of network interruptions. On the other side, in the Netherlands some CHP participates directly or indirectly through commercial aggregators in the market for regulating power and reserve capacity.

Furthermore, as said before, the positive external effects of CHP production on network losses and investments (deferral of investments in transformer capacity) are not remunerated.

On the whole, this means that the positive external effects of CHP on network and system operation are only partly taken into account in the current situation and CHP receives less revenues than optimal from society’ point of view. The lower external costs of CHP on sustainability are taken into account in the CO_2 price, but current prices are still very low.

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10 In practice this pass on of CO_2 costs is only partial (Sijm, 2005, 2006).

11 Besides, CO_2 emission trading in the Netherlands also national NO_x emission trading is carried out. In the first period, too many rights have been allocated, so prices of NO_x rights are low as is the impact on electricity prices.

12 CHP units with production capacity smaller than 20 MW_t sometimes were forced to participate in CO_2 emission trading, as they were part of a certain sector which was obliged to participate, for instance the paper and cardboard industry.

4. Analysis assumptions

4.1 Base-line scenario and policy variants

As mentioned in Paragraph 1.3, the analysis on the potential for high-efficiency cogeneration in the Netherlands is based on the WLO-GEHP scenario, and set against the background of the policy plans of the Dutch government, the Clean and Efficient project. The CHP analysis derives energy prices, economic growth, sector development and other key parameters from these starting points. In order to broaden the validity of the results, the analysis often departs from a simplified starting-point, and will explore the influence of key parameters by means of sensitivity analyses.

GEHP
The reason for using the WLO-GEHP scenario is that of the five available long-term scenarios, WLO-GEHP is the starting point for Dutch policy plans; the to be expected effects of the Clean and Efficient project have also been determined against the WLO-GEHP background. Further, the WLO-GEHP matches best with actual developments, especially with regard to energy prices.

Especially important for CHP are the relatively low CO_2 price assumed under the European emissions trade system[13], an unfavourable ratio between natural gas and coal prices and the high economic growth, resulting in a considerable growth of heat demand. Policies assumed in the scenario include policies already active or decided upon as of spring 2006. The baseline scenario used for this analysis assumes the uses the same basic assumptions as the GEHP scenario, but incorporates some important recent insights and developments[14].

> *Analysis on Clean and Efficient*
> (Menkveld et al., 2007) gives estimates on the effects of the Clean and Efficient policy package. The estimates specify estimates for a situation with slack European policies and low (20 €/ton) CO_2 prices, and for a situation with tight policies and high (50 €/ton) CO_2 prices. As many policies are still under development, and many essential details are not yet decided on, (Menkveld et al., 2007) specifies bandwidths for both situations, reflecting the uncertainty in the policies and other uncertainties. The current analysis draws some results from Clean and Efficient, especially with regard to the realisations of other technologies, to provide a context for the potentials on cogeneration that is plausible given the targets and policies of Clean and Efficient. However, for cogeneration it explores a wider range of CO_2 prices, along with varying responses of the electricity prices.

Targets Clean and Efficient
The new Dutch policy plans aim at achieving a greenhouse gas emission reduction in 2020 of 30% relative to 1990/1995, an average increase of energy efficiency of 2% a year, and a share of renewable energy in 2020 of 20%. In addition, the plans formulate indicative targets for 2030. Specifically for cogeneration, the Clean and Efficient plans aim at 50 PJ additional savings by CHP in 2011, as compared to 2007. Policies are still under development, and there is also much uncertainty about the contribution of European policies. The analyses on the estimated effects of the policy plans (Menkveld, 2007) cope with the European uncertainties by as-

13 In the GEHP scenario, CO_2 prices ($€_{2000}$) are 2 €/ton CO_2 from 2005 to 2007, 7 €/tonne CO_2 from 2008-2012, and 11 €/tonne from 2013 to 2020

14 Examples include recent plans for power plans, recent data on CHP developments in the agriculture.

suming two sets of assumption with regard to European policies and ETS CO_2 prices. In case of weak European policies, a CO_2 price of 20 €/tonne CO_2 is assumed, and in case of strong European policies, a 50 €/tonne CO_2 prices is assumed. To cope with the uncertainties in the Dutch policies, the analysis estimates e bandwidths within each of these European sets of assumptions, based on the remaining uncertainty with regard to the eventual shape of the policies.

Calculated variants

The current analysis copes with these uncertainties by exploring the effects of a range of assumptions with regard to CO_2 prices, European policies, and effects on other technologies required to attain the targets.

For the electricity production sector, the ETS CO_2 price and the support scheme for renewable electricity will be dominant forces, along with the electricity demand reduction by the consuming sectors. In addition, current plans for new power plants are very important. Before 2020, support for CCS will probably play only a limited role. The analyses explore the bandwidths of the developments that may result because of the aforementioned factors, thereby determining the room for cogeneration and influencing its competitiveness on the electricity market.

In the industry and agriculture, the CO_2 price in the ETS is a suitable generic measure for determining the economic potential of CHP in relation to other options. The analysis explores the effects of a range of CO_2 prices up to 100 €/ton CO_2, with a fixed response of the electricity price for each €/ton CO_2 price rise. This response is based on the emission factor of the power generation capacity as projected in the GEHP baseline. Further it explores the effects of different responses of the electricity price for a fixed CO_2 price of 50 €/ton CO_2, as this CO_2 price value is close to the value assumed in the Clean and Efficient in case of strong European policies. This results in a bandwidth for the economic potential, valid for a wider range of circumstances. Table 4.1 shows the calculated variants, among other with regard to CO_2 prices and the electricity price rise per 10 €/ton CO_2 price increase as of 2020. For the baseline situation, a modified version of GEHP has been made, that reflects some new insights and recent developments in the industry and agriculture. This baseline is referred to as GEH or GEH baseline, contrary to the original GEHP scenario.

The analysis starts with a simplified starting point, assuming a linear relation between CO_2 prices and electricity prices. As assumed for the calculations, the CO_2 prices attain their final, maximum level from 2013 onwards, and are on average half this level during the period 2008-2012. As assumed, electricity prices rise 0.57 ct per kWh for each 10 €/ton CO_2 price rise, based on the average emission factor in the baseline scenario[15]. The results do incorporate the effects of decreasing heat demand in response to the CO_2 prices, thereby taking into account a relative reduction of the technical potential for CHP.

In case the power production sector shows a strong response to rising CO_2 prices, or in case the production mix contains more coal than projected, the actual price response may be higher or lower. 0.45-0.65 ct/kWh per 10 €/ton CO_2 appears a reasonable range, with the former representing a situation with a lot of renewables, cogeneration, efficient gas plants and/or coal equipped with CCS, and the latter representing a situation with a much higher share of coal power. Only in extreme cases the prices may go out of this range. The electricity price response variants are all based on a 50 €/ton CO_2 price. At this price, the difference between the highest and lowest average electricity prices in 2020 equals 0.75 ct/kWh.

The calculations assume all existing support policies directed at cogeneration or other energy saving technologies to remain active, but they do not assume the introduction of new support policies directed at specific technologies, such as the new SDE for CHP.

Table 4.1 *Calculated variants*

Variant	Natural gas commodity price 2020 [€/GJ]	Coal price 2020 [€/GJ]	CO_2 price 2013-2020+ (2008-2012) [€]	Electricity price rise [€/MWh] per 10 €/ton CO_2 price rise relative to baseline
GEH (Baseline)	5.8	1.7	11 (7)	-
GEH20_5.7	5.8	1.7	20 (10)	5.7
GEH30_5.7	5.8	1.7	30 (15)	5.7
GEH40_5.7	5.8	1.7	40 (20)	5.7
GEH50_5.7	5.8	1.7	50 (25)	5.7
GEH60_5.7	5.8	1.7	60 (30)	5.7
GEH70_5.7	5.8	1.7	70 (35)	5.7
GEH80_5.7	5.8	1.7	80 (40)	5.7
GEH90_5.7	5.8	1.7	90 (45)	5.7
GEH100_5.7	5.8	1.7	100 (50)	5.7
GEH50_4.5	5.8	1.7	50 (25)	4.5
GEH50_5.0	5.8	1.7	50 (25)	5.0
GEH50_6.0	5.8	1.7	50 (25)	6.0
GEH50_6.5	5.8	1.7	50 (25)	6.5
GE	4.1	1.7	11 (7)	-

In the services sector and the households, the policies aimed at lowering the energy use of both new and existing buildings are far more dominant than CO_2 prices. Therefore, the analysis explores the economic potential of cogeneration as compared to competing and additional measures that are likely to play a role in attaining the targets for the residential sector. Due to limited data availability and the different nature of policies, this will be only qualitative for the services

[15] The electricity price rise per 10 €/ton CO_2 price rise very roughly corresponds to specific emission factor. For example the 5.0 €/MWh per 10 €/ton CO_2 corresponds to an emission factor of 500 g CO_2/kWh. In their turn, the CO_2 price and the presumed emission factor, correspond with a roughly equivalent support level per CO_2 free. For example, a support level given with a CO_2 price of 11 €/ton that corresponds with the incentive provided by CO_2 price of 50 €/ton CO_2 is (50-11)*0.50*100 ~ 2.0 ct per CO_2 free kWh.

sector. The analysis on micro-cogeneration in the households is a quantitative investigation on the influence of assumptions on several key parameters, which appeared the only way to cope in a sensible way with the great uncertainty on nearly every aspect of micro-CHP.

4.2 Energy prices

Table 4.2 shows representative prices of electricity and natural gas for three groups of energy users in the GEHP scenario. These prices are merely indicative for the groups shown. Especially within the middle size and large energy users large variations in actual prices for individual customers exist. Variations in the actual consumption result in strongly different marginal energy taxes in both electricity and natural gas. Specifically for natural gas prices, the ratio between maximum hourly demand and the total yearly demand determines the transport and capacity tariff. Further, the commodity price of a user depends on the distribution of the consumption between peak hours and off-peak hours. The numbers, as shown, consider price differences between the commodity prices for users of different sizes as part of the distribution costs.

Table 4.2 *Electricity prices and gas prices GEHP*

Households Electricity price [ct/kWh]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	2.85	4.48	5.14	5.52	4.65
Distribution	3.83	4.22	4.42	4.53	4.27
Energy taxes	5.56	6.12	6.12	6.12	6.12
Value added tax	2.33	2.82	2.98	3.07	2.86
Total	14.57	17.64	18.65	19.24	17.91

Households Natural gas price [ct/m^3]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	10.32	15	17.31	18.5	19.92
Distribution	6.46	7.57	8.03	8.27	8.55
Transport and capacity	6.11	6.01	6.01	6.01	6.01
Energy taxes	12.45	13.08	13.08	13.08	13.08
Value added tax	6.71	7.92	8.44	8.71	9.04
CO_2 price	0	0	0	0	0
Total	42.06	49.57	52.87	54.57	56.6

Middle size energy users Electricity price [ct/kWh]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	2.85	4.48	5.14	5.52	4.65
Distribution	3.27	3.74	3.93	4.05	3.79
Energy taxes	1.85	2.81	3.17	3.17	3.17
Value added tax	0	0	0	0	0
Total	7.97	11.03	12.24	12.74	11.61

Middle size energy users Natural gas price [ct/m^3]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	10.32	15	17.31	18.5	19.92
Distribution	2.53	2.69	2.69	2.69	2.69
Transport and capacity	3.6	3.65	3.65	3.65	3.65
Energy taxes	6.34	10.06	11.52	11.52	11.52
Value added tax	0	0	0	0	0
CO_2 price	0	0	0	0	0
Total	22.78	31.4	35.17	36.36	37.78

Large energy users Electricity price [ct/kWh]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	2.85	4.48	5.14	5.52	4.65
Distribution	0.76	0.73	0.79	0.76	0.68
Energy taxes	0	0.04	0.04	0.04	0.04
Value added tax	0	0	0	0	0
Total	3.6	5.25	5.97	6.33	5.38

Large energy users Natural gas price [ct/m^3]	*2002*	*2005*	*2010*	*2020*	*2030*
Commodity	10.32	15	17.31	18.5	19.92
Distribution	0.25	0.25	0.25	0.25	0.25
Transport and capacity	0.72	0.96	0.96	0.96	0.96
Energy taxes	0.65	0.67	0.67	0.67	0.67
Value added tax	0	0	0	0	0
CO_2 price	0	0.36	1.24	1.95	0
Total	11.94	17.23	20.43	22.33	21.79

The tables also include the CO_2 price for the large energy users that participate in the ETS. This is not an actual component of the natural gas price, but an indication of the increase in marginal costs of natural gas combustion for companies participating in the ETS participants. The GEHP CO_2 price in 2020 equals 11 €/ton. With higher CO_2 prices, this component will become proportionally higher. Clean and Efficient does not include an automatic correction of the energy taxes in the non-ETS companies to prevent marginal costs of energy use in non-trading companies becoming lower than those in trading companies.

The electricity commodity price already reflects the influence of the CO_2 price in GEHP. With higher CO_2 prices, the commodity price will rise as well.

4.3 Policy framework

In addition to the ETS and the energy tax exemption, various policies aim at the support of CHP, of which some exclusively.

Policies directly relevant for cogeneration

ETS
The CO_2 emission trade system provides a general incentive for measures that reduce CO_2 emissions. As such, it could lead more or less automatically to the near optimal mix of options, as companies just experience an incentive, and are left the choice how to respond to it. However, the current allocation of emission rights by grandfathering does not guarantee that the full weight of the CO_2 price is taken into account in investments decisions. Auction of emission rights, or alternatively allocation based on energy performance standard perform better in this respect. The calculations performed for the current analysis assume that the CO_2 price is taken fully into account, as in the case of an auction, and thereby anticipate modification relative to the current ETS system.

Energy tax exemption
Electricity producing installations do not have to pay energy tax on their fuel consumption, provided that the electrical efficiency is higher than 30%, and the electrical power is higher than 60 kW. This is a considerable incentive for especially smaller users with higher energy tax tariffs, as the heat output becomes exempt of energy tax as well.

EIA
The Energie-investeringsaftrek is an exemption of taxes on company profits for investments on energy savings measures and renewable energy. 44% of the invested amount may be subtracted from the profits. With current tax rates (25%), it is roughly equivalent to a subsidy percentage of 11%. Being an existing and generic policy instrument directed at energy savings, the EIA is included in the current calculations.

MEP/SDE
The MEP is an operational support per kWh produced. It exists for both CHP and renewables. In its older variant, the MEP intends to compensate the financial gap per kWh, the additional profits required per kWh to compensate for the additional costs of cogeneration. In its current shape, the MEP for CHP is a tariff per ‘blue’ kWh. These blue kilowatt-hours are the CO_2 free kilowatt-hours, calculated by comparison of the cogeneration with separate generation of heat and electricity. Originally, the MEP was especially intended to support existing cogeneration installations during the adverse circumstances after the liberalisation of the electricity market. The tariff is determined yearly and does not give any certainty. For this reason, companies generally do not take it into account in their investment decisions on CHP. As a result, the MEP

does not provide any substantial incentive for new cogeneration or the replacement of older cogeneration.

For this reason, a successor for the MEP is under development, the SDE. This is also based on a support tariff per blue kilowatt-hour to compensate the financial gap. The support level will probably be yearly tuned to actual market conditions in a predefined way. This offers additional certainty to investors, while preventing over stimulation. The SDE is still under development

Neither the MEP nor the SDE, being policy instruments specifically directed at CHP, are included in the current calculations. However, the analyses for Clean and Efficient indicate that the effect will depend strongly on the extent to which the instrument in its final shape discriminates between cogeneration requiring support and free riders. In addition, the additional effect of the SDE is likely to be much lower in case of higher CO_2 prices.

EPN

In the households and services sector, the Energy Performance Standard defines the maximum energy use for newly constructed buildings. This enforces the application energy saving measures. The actual mix of energy saving measures depend on the stringency of the standard, the characteristics of the building, the cost-effectiveness of the individual measures and the interactions between the various candidate measures.

Other policies

Other policies are only relevant insofar they stimulate options that may act as direct competitors of cogeneration, or that reduce or increase the potential for cogeneration. An example of the first category is the MEP/SDE directed at renewable electricity, a direct competitor of cogeneration on the electricity market. Other examples may be noted when discussing the potentials for the various sectors.

5. Electricity market

5.1 Room for cogeneration on the Dutch electricity market?

The room for cogeneration on the Dutch electricity market is not easy to define, as there is no clear physical limit to the amount of cogeneration electricity the market can accommodate. For all practical purposes, at a given moment the limit for cogeneration is roughly defined by existing coal plants, nuclear plants, base-load imports and intermittent renewable capacity, such as wind. However, this not an invariable and hard limit: for example high CO_2 prices may strongly deteriorate the position of coal plants and lead to lower production hours and even early abandonment. In addition part of the coal plants could be included in the room for cogeneration[16]. The most recent analysis on the plans for new capacity is (Seebregts, 2007).

Most projections expect the current high imports to decrease, due to the expansion of domestic capacity of which an important part is coal based. According to the analyses for 'Clean and Efficient', higher CO_2 prices will probably favour the Dutch electricity production more than the electricity production in neighbouring countries. The current situation, with the Netherlands being an island of relatively high electricity prices with a high electricity import, is likely to disappear gradually.

Figure 5.1 shows the development of the electricity production in GEHP, and the a possible development of electricity production in case of an optimistic view on the Clean and Efficient policies, both with regard to the actual implementation and the effects, combined with favourable European circumstances, such as a CO_2 price of 50 €/ton CO_2. This figure does not represent the results of an integral analysis of the electricity market, but a mere indication of how policies and CO_2 price might influence the electricity production.

In GEHP, there is a small increase in cogeneration, a relatively large increase in renewable electricity, and an increase of coal based separate generation. New capacity in GEHP until 2020 amounts to around 7GW. For comparison: plans for new construction until 2014, as currently estimated, amount to 13 GW (Menkveld, 2007).

[16] In practice, the most important consideration for choosing a location for a coal plant is cheap access to coal and the access to cooling water. In the Dutch situation most of the favourable coastal locations are not close to heat markets, thereby decreasing the possibilities for coal based cogeneration.

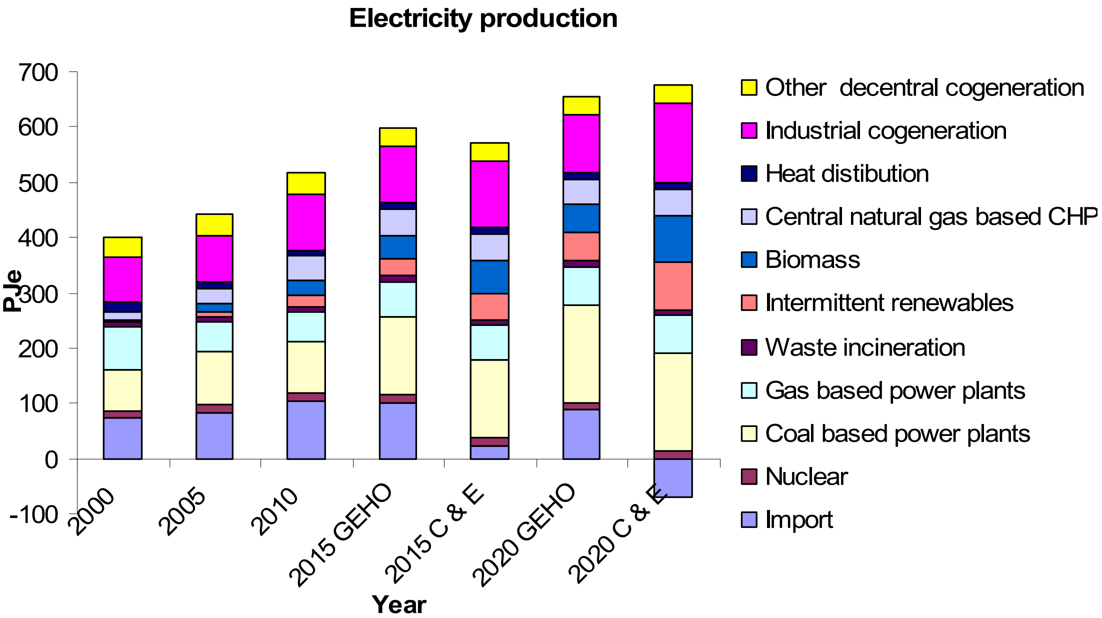

Figure 5.1 *Development of Dutch electricity production in GEHP and possible development of Dutch electricity production with optimistic estimate of Clean and Efficient effects*

The policies of Clean and Efficient, combined with an ETS price of 50 €/ton CO_2 and optimistic assumptions about other European policies, are estimated to result in a maximum of 40 PJ electricity demand reduction, 70 PJ increase in production of renewable electricity, and 40 PJ increase of electricity production by CHP. Even when disregarding the possibility of more construction of new capacity than included in the scenario, this would potentially result in some 70 PJ of electricity export[17].

Concluding, there appears to be room on the Dutch electricity market for renewable electricity as well as cogeneration, but it will result in a net electricity export. It may get crowded, even if only part of the current plans for new construction is realised. Further the economic growth and the growth of electricity demand in the baseline are pretty high, and could be much lower than projected in GEHP. The combined abundance of new capacity and lower demand may result in relatively low electricity prices. The competitiveness of (natural gas based) cogeneration in such a case depends on the price setting of coal and natural gas, and the presence of specific support policies.

5.2 Economic potentials on the electricity market

The GEH baseline assumes an unfavourable ratio between natural gas prices and coal prices, which is connected to an increasing share of coal based power generation in the production mix. The capacity of coal based power generation determines to a large extent the number of hours a year during which it determines the electricity prices. While the GEH baseline assumes a considerable increase of coal based power generation, it is still less than apparent from recent plans (Seebregts, 2007)[18]. For the generally natural gas based Dutch cogeneration, this results in a rather unfavourable ratio between electricity prices and fuel prices. A comparison with the GE-

[17] In the GEHP baseline, 2020 electricity imports are some 10 PJ. The effects of demand reduction (40 PJ), additional renewable electricity (70 (PJ) and CHP 40 (PJ) would result in an excess electricity production of 140 PJ. It is likely that only part of this potential excess will results in abandonment of older production capacity, and that the remainder will result in the Netherlands becoming a net electricity exporter. This is all the more likely as the Dutch generation capacity compares favourably with the German generation capacity in case of high CO_2 prices.

[18] On the other hand, recent price rises of equipment already have led to the postponement of a coal based power plant. These price rises pose more of a threat to coal based power than to natural gas based power generation, because of the higher capital intensity of coal based power.

scenario, with lower natural gas prices and a lower share of coal based capacity, points out that in GEH a CO_2 price of over 50 €/ton is required to compensate for the unfavourable price setting.

As shown in figure 5.1, various alternative electricity supply technologies are likely to grow in response to the policies aimed at renewable energy and higher CO_2 prices. Large-scale introduction of these technologies will result in a slower rise in electricity prices with rising CO_2 prices, thereby decreasing the margins for cogeneration. In addition, increased application of low emission electricity production technologies will decrease the emission reduction by additional cogeneration capacity.

Table 5.1 shows threshold values of CO_2 prices for various technologies[19]. The threshold value is the CO_2 price approximately required to make a technology profitable for investors. When CO_2 prices are above the threshold value of a technology, a further rise of CO_2 prices is likely to provoke increasing shares of this technology in the electricity production. This may dampen the response of electricity prices to a further CO_2 price rise.

Table 5.1 *Indicative threshold CO_2 prices for various technologies*

Technology	Threshold CO_2 price (no special support)	Remarks
Coal power plants with CCS	30-45	Depends on efficiency loss and energy prices
Natural gas power plants with CCS	40-55	Depends on efficiency loss and energy prices
Shift from coal to natural gas (no CCS)	30-60+	Depends on ratio between coal and natural gas prices
Wind onshore*	40-80	Considerable costs decrease assumed towards 2020
Wind offshore*	40-90	Considerable costs decrease assumed towards 2020
Biomass based power generation*	50-120+	Depends on biomass prices and fossil fuel prices
Cogeneration*	0-100+	A more or less continuous wide range of the cost-effectiveness, due to the great variation in thermal power, operating hours and technologies. The majority of the chp-potential is concentrated in the lower part of the range.[20]

* In case of specific support based on compensation of the financial gap, threshold values are zero.

In addition to a lower rise of electricity prices, some developments may also have profound effects on the dynamics of the electricity market. The combination of must run coal capacity equipped with CCS and a large growth of intermittent renewable capacity such as wind energy may result in very adverse conditions for cogeneration during off-peak periods, with very low prices. However, in the same market constellation, on other moments there will be an increased demand for flexible peak capacity that may result in on average higher peak prices. Especially flexible power generation capacity may benefit of such market condition.

[19] The threshold values are only valid in case of auctioning emission right or allocation based on a fixed amount of CO_2 right per kWh produced.

[20] Chapter 6 will provide more detailed insight in the required CO_2 prices to elicit additional CHP-capacity.

6. Potentials for large-scale and small-scale CHP

This chapter describes the potentials for cogeneration in the industry, agriculture and services sectors. The next chapter discusses application of micro-CHP in the residential sector.

6.1 Industry

In the industry, the CO_2 price is a suitable generic measure for determining the economic potential of CHP in relation to other options. However, because of the European targets for renewable energy, specific policies on top of the ETS are required to support renewable energy. The resulting effects on electricity prices are likely to affect the profitability of cogeneration and have to be taken into account in the determination of economic potentials.

As described in Paragraph 4.1, the calculations on the economic potential start with assuming a fixed increase of electricity prices with rising CO_2 prices (0.57 ct/kWh per 10 €/ton CO_2). For a 50 €/ton CO_2 price, the analysis explores economic potential for deviating responses of the electricity price.

First however, an overview follows of important developments with regard to heat demand, cogeneration technologies and competing heat and power supply options. This provides mainly qualitative insights in the way various developments may influence the economic potential of cogeneration. The quantitative analysis will not deal with all underlying components in detail.

6.1.1 Heat demand

Rising CO_2 prices result in a higher share of heat demand for which it is profitable to apply CHP. However, they also result in a decrease of heat demand, due to the application of energy saving technologies. According to the calculations, this impact on heat demand is very small, as CO_2 prices attain their final level only after 2015. Therefore, higher CO_2 prices result in only a slight decrease of the technical potential for cogeneration. Figure 6.1 shows the projected development of industrial heat demand towards 2020 for the baseline scenario.

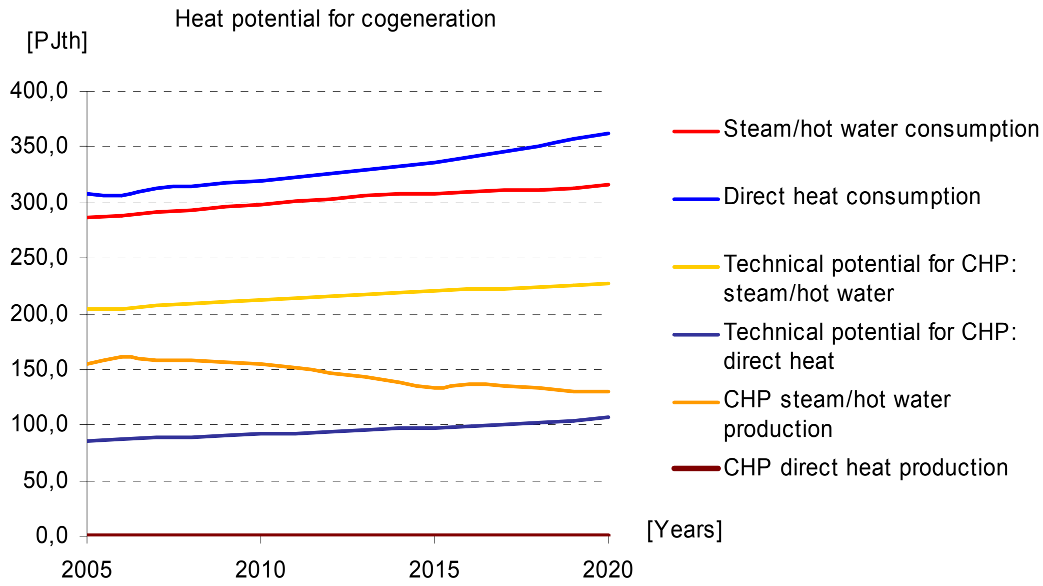

Figure 6.1 P*rojected demand for industrial heat in GEH baseline*

The figure includes steam and hot water, which includes all transportable heat[21], and direct heat, which refers to direct use of heat from exhaust gases. For both the estimated technical potentials and the projected production by cogeneration are shown. In the baseline, heat demand rises slowly towards about 300 PJ for steam/hot water, and towards about 360 PJ for direct heat. The technical potential for cogeneration is estimated at about 220 PJ in 2020 for steam/hot water, and at about 100 PJ for direct heat. In the baseline, actual steam/hot water production by co-generation decreases to approximately 130 PJ[22]. Direct heat production by cogeneration is negligible.

The baseline assumes a relatively high economic growth rate. If an overall lower economic growth leads to lower economic and physical growth rates of industrial sectors, this will result in a slower growth, or even a slight decline, of heat demand and technical potentials.

6.1.2 Cogeneration technologies

Industrial cogeneration is dominated by large scale technologies, small-scale technologies being only important in less energy intensive industries. Historically, steam turbines and gas turbines have played an important role. Current capacity includes some installations that date back to the 1950s. In recent years, for new plants combined cycle gas turbines have taken the lead and they are very likely to maintain this dominant position up to and after 2020.

Only for processes that require direct heat from exhaust gases, gas turbines as such may still be important. Such applications often require a far-reaching integration of the cogeneration unit in the heart of industrial processes, and this may increase the probability of process failures. For this reason, industries are generally very hesitant about applying cogeneration in such cases.

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[21] Including for example oil as a heat carrier.

[22] This is partly explained by a lower heat over power ratio of newer cogeneration, combined with abandonment of older installations. Another part of the explanation may be that cogeneration statistics could to some extent be polluted by boilers.

Though innovative concepts such as fuel cells will be favoured by ambitious CO_2 targets and high CO_2 prices, they are unlikely to play an important role before 2020.

In the Netherlands, natural gas is more or less the default fuel for on site cogeneration, due to its wide availability and easy handling. Currently, the application of other fuels is more or less limited to cases where companies have by-product energy resources at their disposal, which have otherwise limited value. Examples include coke oven and blast furnace gases of the base metal industry, chemical gas and oil by-products in the petrochemical industry and refinery gas and oil by-products in the refineries. Especially steam turbines have large fuel flexibility and this may explain their large historical share in the consumption of the alternative fuels. The scenario assumes a large increase in the generation of gaseous energy by-products, especially in the chemical industry, and assumes these to be applied in combined cycle based cogeneration. In the future, rising CO_2 prices and renewable energy policies may lead to an increase in the use of biomass based fuels.

6.1.3 Competing options and other developments

Electricity production

Competing options relevant for industrial cogeneration include especially alternative electricity production options, such as renewable electricity and fossil capacity with carbon capture and storage. Other relevant developments include the plans for new Dutch coal based power plants, and the development of energy prices, especially the ratio between natural gas and coal prices. As pointed out in chapter 5, the electricity market will require a lot of flexible power, to cope with the larger amount of base-load capacity combined with a lot of intermittent renewables. Many older industrial CHP-plants do not have such flexibility, but new plants can be designed to meet the demand of such an electricity market. This will result in additional costs.

Heat production

CO_2 prices and other policies not only affect the application of cogeneration, but that of other technologies as well. In the industry, decreasing heat demand is not likely to have a large impact on the potential for cogeneration before 2020. In addition, alternative heat supply technologies are not very likely to play an important role before 2020 as well, with the possible exception of more use of residual heat from processes. Further, heat pump may play a role for upgrading low temperature heat.

6.1.4 Potentials

Figure 6.2 shows the baseline development of the production of electricity and heat by industrial CHP, fuel use, and energy savings, the latter both according to the definition of the CHP-directive and according to the Protocol Monitoring Energy-efficiency (Boonekamp, 2001)[23]. The baseline shows a slight increase in electricity production, a decrease in heat production, roughly constant fuel use and rising savings according to both definitions. This combination of developments implies that the increase in savings reflects the efficiency improvement of cogeneration itself as much as the increase in capacity. An important cause of this is the abandonment of older, inefficient cogeneration capacity partly due to the unfavourable energy prices. Comparison with the GE baseline, with much more favourable energy prices, shows that there more of the older capacity remains active. The striking difference between the savings according to the directive and those according to the PME mainly result from the reference efficiencies applied (See Appendix B).

[23] All excluding steam turbines. These represent the most inefficient part of decentralised capacity, and statistics probably include steam turbines that do not produce heat, as well. Some steam turbines have a negative saving according to the definitions of the CHP-directive. To prevent an unrealistic view on high-efficiency cogeneration, steam turbines have been left out.

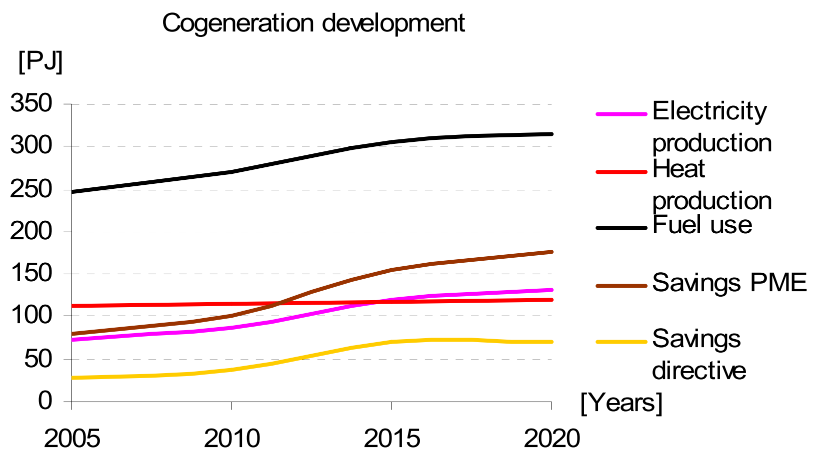

Figure 6.2 *Baseline industrial CHP heat and electricity production, fuel consumption and savings*

Figure 6.3, Figure 6.4 and Figure 6.5 show the various results on industrial CHP in 2010, 2015 and 2020 for a range of CO_2 prices up to 100 €/ton CO_2 and an electricity price rise which is up to 5.7 € /MWh higher than without ETS.[24] The figures show the production of electricity and heat, fuel use, and energy savings both according to the definition of the CHP directive and to the Protocol Monitoring Efficiency (Boonekamp, 2001). Higher CO_2 prices invariably lead to higher production and savings. The increase in savings is almost entirely due to the higher volume of cogeneration capacity, as increasing CO_2 prices do increase the competitiveness of older, inefficient cogeneration.

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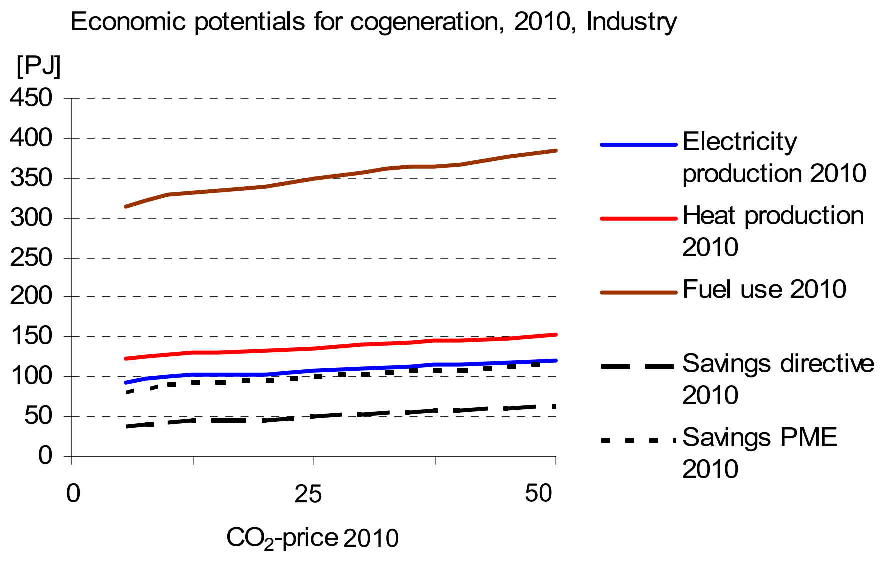

Figure 6.3 *2010 Industrial CHP heat and electricity production, fuel consumption and savings*

[24] Note that 2010 CO_2 prices, as assumed in the analysis, are only half that of 2020. The 50€/ton CO_2 price in 2010 corresponds with the path towards the 100€/ton CO_2 price in 2020.

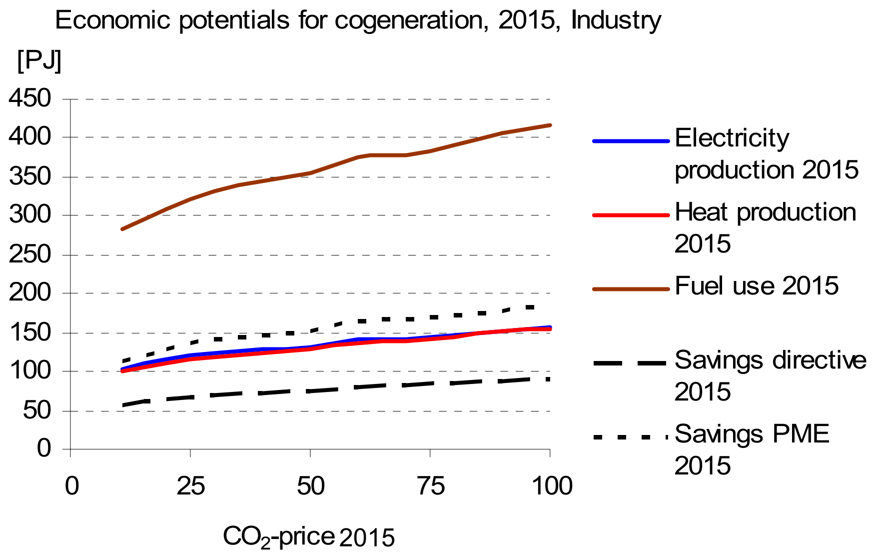

Figure 6.4 *2015 Industrial CHP heat and electricity production, fuel consumption and savings*

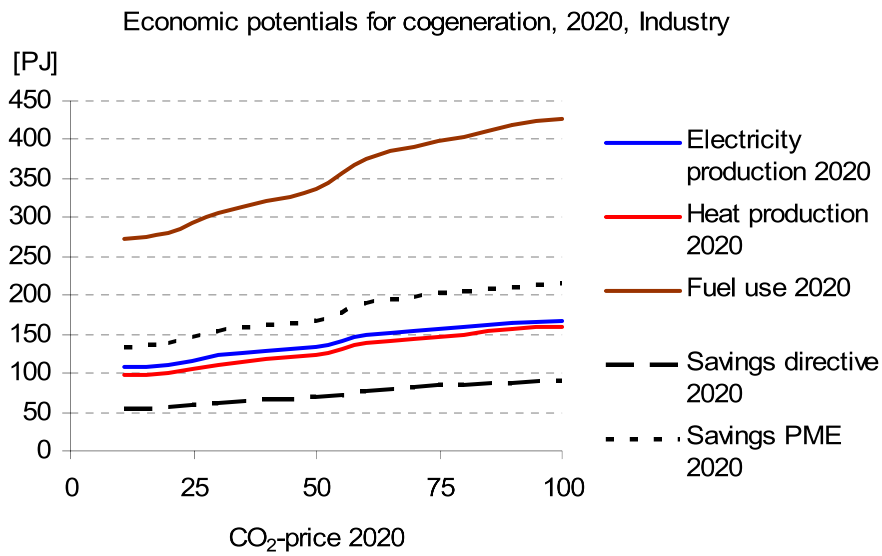

Figure 6.5 *2020 Industrial CHP heat and electricity production, fuel consumption and savings*

Figure 6.6 and Figure 6.7 show industrial cogeneration electricity and heat production for different responses of the electricity price on the 50 €/ton CO_2 price. As a reference, the figures include the GEHP and GE baselines. The results show that with electricity price rises between 4.5 and 6.0 €/MWh for each 10 € per ton CO_2 price rise, the projected development of industrial cogeneration is relatively robust. At 6.5 €/MWh, cogeneration grows faster. Further, the figures indicate that a CO_2 price of 50 €/ton CO_2 results in about the same development of cogeneration as in the GE-scenario with more favourable gas and coal prices.

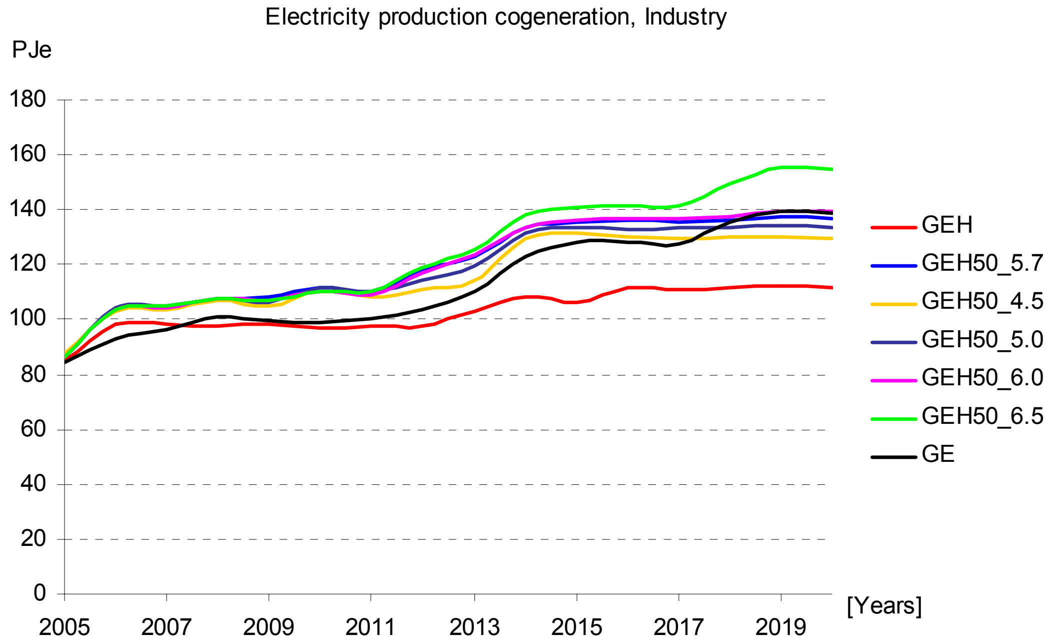

Figure 6.6 *Projected development of industrial CHP electricity production, given various electricity market responses to CO_2 prices*

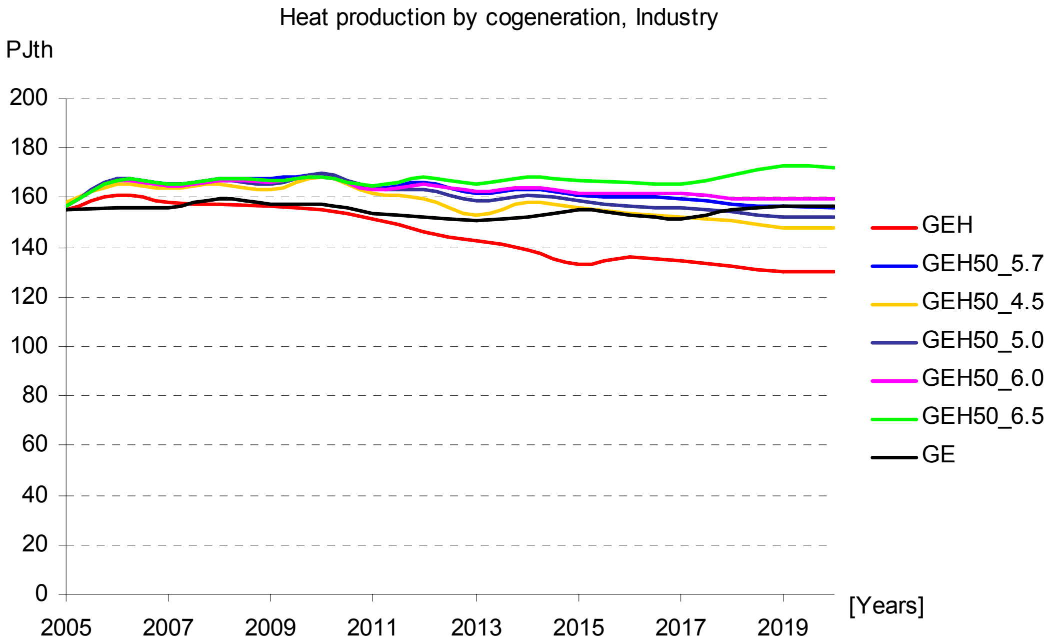

Figure 6.7 *Projected development of industrial CHP heat production, given various electricity market responses to CO_2 prices*

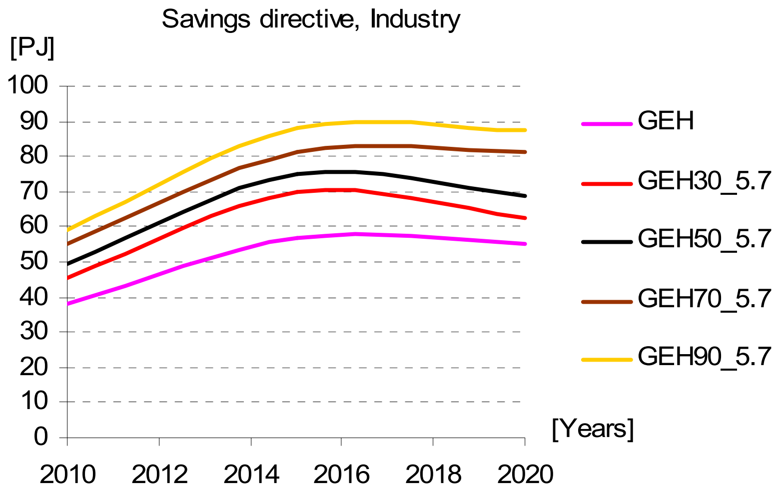

Figure 6.8 *Projected savings by industrial CHP according to the directive definition, given various CO_2 prices*

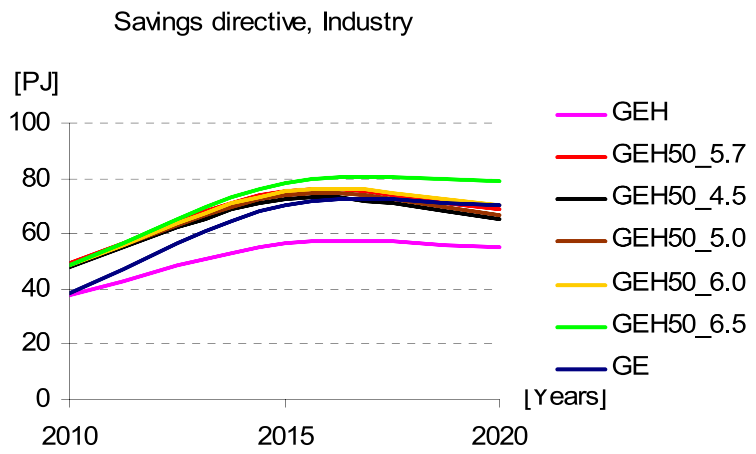

Figure 6.9 *Projected savings by industrial CHP according to the directive definition, given various electricity market responses to CO_2 prices*

Figure 6.8 and Figure 6.9 show the energy savings by cogeneration as calculated according to the directive for various CO_2 price variants and for various electricity market response variants. All variants show an increase in savings, even the GEH baseline, despite the decrease of heat production by cogeneration here. Part of the explanation is the projected abandonment and replacement of older installations that realise very low or even negative savings according to the definitions of the directive. Both increase of the electricity production and rejuvenation of the existing cogeneration capacity are important components of the increase in savings.

Variation in the results of industrial cogeneration is considerable in the CO_2 price variants, larger than in the electricity price response variants. Factors other than the response to CO_2 prices may also have a considerable impact on electricity prices.

Uncertainties and other factors
The calculations cover only a limited range of circumstances. Table 6.1 indicates the effects of the factor investigated and some other factors in a qualitative way.

Table 6.1 *Qualitative overview of the effects of some changes on industrial CHP*

Change	Effect	Remarks
Higher gas prices	-	
Higher coal prices	+	
Lower economic growth	-	
Better use of residual heat from processes	-	
Faster growth of renewable electricity	-	Depends on flexibility of CHP
Larger differences between peak and off-peak prices	-/+	Adverse for older cogeneration, possibly positive for newer capacity
Auction of CO_2 emission rights	-/+	Increases relative competitiveness of cogeneration compared with separate generation, but decreases financial room as compared to allocation

6.2 Agriculture

Cogeneration in agriculture is almost exclusively applied in greenhouse horticulture. Here, the CO_2 price in the ETS also is a suitable generic measure for determining the economic potential of CHP in relation to other options. The Dutch greenhouse horticulture sector is busy setting up its own emission trade system. This will merge into the ETS by 2012. As for the industry, the analysis explores the effects of a range of CO_2 prices up to 100 €/ton CO_2, assuming a linear relation between CO_2 prices and electricity prices. Subsequently, the analysis evaluates the impact deviating responses of the electricity price, for a CO_2 price of 50 €/ton CO_2.

6.2.1 Heat and electricity demand

Greenhouse horticulture requires low temperature heat for maintaining the greenhouse temperatures within favourable range and for decreasing air humidity within the greenhouse In addition, combustion of natural gas is applied for CO_2 fertilisation. Demand for heat, CO_2 and higher electricity prices often do not coincide, and many greenhouses apply heat buffers. These are very attractive when combined with cogeneration, as they allow electricity production during peak hours, and can provide heat when required.

Figure 6.10 shows the projected development in the GEH baseline of heat and electricity demand, as well as the estimated technical potentials for cogeneration heat and the actually projected production of heat and electricity by cogeneration.

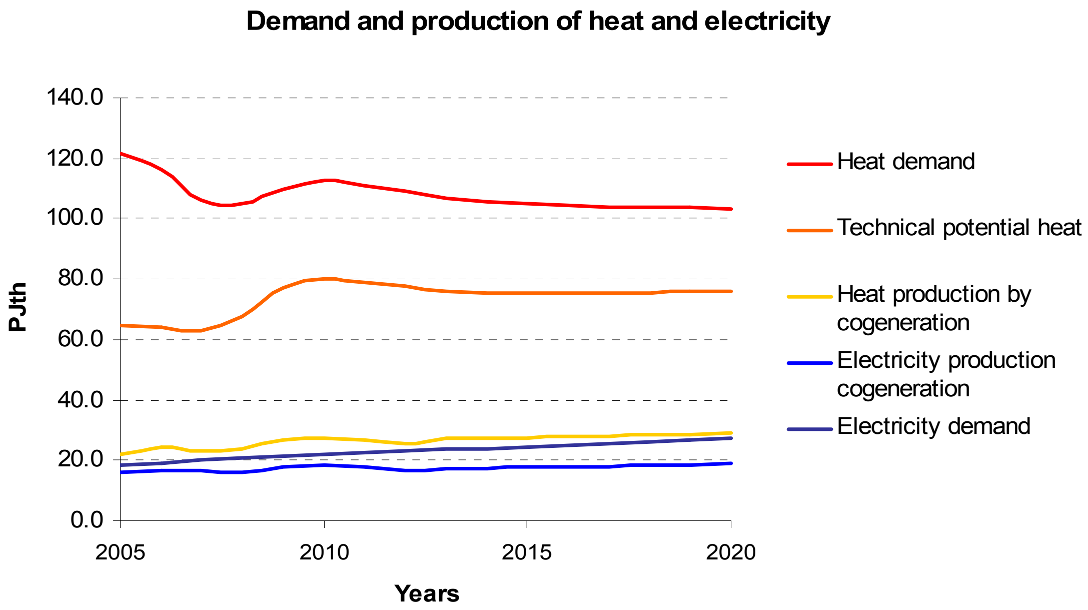

Figure 6.10 *Demand for heat and electricity in agriculture and production by cogeneration in the GEH baseline*

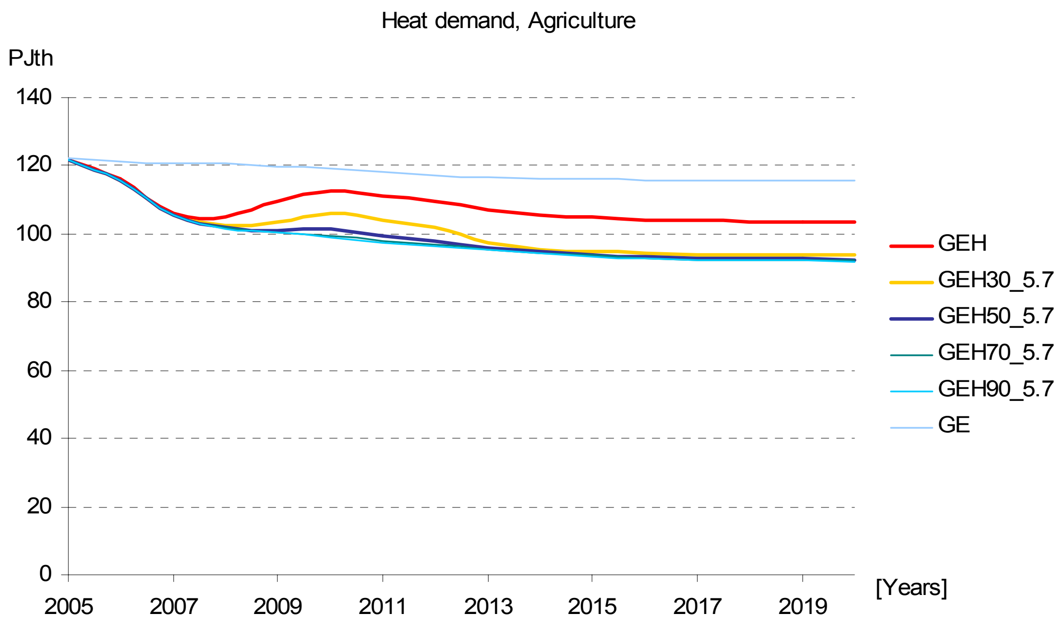

Figure 6.11 *Projected heat demand in agriculture, given various CO_2 prices*

Many greenhouses apply assimilation lighting. Lamps provide light for photosynthesis when natural light sources fail. The electricity consumption for assimilation lighting generally improves the economic performance of cogeneration, as on-site production of electricity is usually cheaper than purchasing electricity.

CO_2 fertilisation is something of an anomaly. In statistics, energy use for CO_2 fertilisation registers as final demand. However, the desired output is CO_2, rather than heat. As a consequence, electricity revenues of cogeneration applied for CO_2 fertilisation do not have to compensate for additional fuel consumption: CO_2 production per unit fuel remains constant. This results in relatively low marginal costs of electricity production by cogeneration in case of CO_2 fertilisation, despite the fact that the required purification of exhaust gases results in additional costs. Availability of external CO_2 sources, such as the OCAP[25] near Rotterdam, makes application of cogeneration less profitable.

The combined demand for heat, CO_2 and electricity, supplemented by the application of heat buffers can make application of cogeneration relatively profitable. However, actual profitability differs by crop, and by company scale. The economic potential for cogeneration is mainly concentrated in the large-scale companies with energy-intensive crops. Current trends show considerable increase of the average size of greenhouse companies, resulting in a higher demand for heat per location.

As in the industry, rising CO_2 prices result in a higher share of heat demand for which it is profitable to apply CHP. But much more so than in the industry, they also result in a decrease of heat demand, due to the application of energy saving technologies. Therefore, higher CO_2 prices may result in a considerable decrease of the technical potential for cogeneration. Figure 6.11 shows the projected development of horticultural heat demand towards 2020 for the baseline scenario and for various CO_2 price variants. This figure only shows the heat demand to be provided by fossil sources, the heat already supplied by renewable energy is not shown.

6.2.2 Technologies

The dominant cogeneration technology in the greenhouse horticulture is the natural gas fuelled internal combustion engine. When applied for CO_2 fertilisation, gas engines have to be equipped with denox installations, which result in considerable cost increases. Micro-turbines may offer an alternative in the near future, as well as fuel cells. Cogeneration in greenhouse horticulture is always combined with back-up boiler capacity. As a result horticultural cogeneration does not have to run when electricity prices are too low, while it can take maximal profit from peak prices. Many separate units together may operate as a virtual power plant, which can gain additional profits.

The availability of by-product organic matter sometimes offers opportunities for biomass based boilers or cogeneration, if required supplemented with purchased biomass. As such, this does not alter the decision on applying cogeneration as opposed to boilers, but it may be more expensive to achieve sufficiently clean exhaust gases with cogeneration.

6.2.3 Competing options and other developments

Alternative heat sources

The targets sets for greenhouse gas emission reduction, energy savings and renewable energy will result in considerable decrease of heat demand, and in the rise of alternative heat production technologies. Current plans aim at so-called (semi-)closed greenhouse concepts, which apply seasonal heat storage in aquifers. Closed greenhouses store excess heat in the summer period for use during the winter period, and allow for more control of growing conditions. This development is projected to result eventually in net energy producing greenhouses. These export excess heat to other greenhouses, or other buildings. Further candidates for alternative heat production are the application of geothermal heat, and the application of residual heat from nearby industrial agglomerations. These alternative technologies offer the possibility of much further CO_2 reduction than cogeneration.

Electricity production

For agricultural cogeneration, the same dynamics on the electricity market apply as for industrial cogeneration. Like industrial cogeneration, it will suffer from the combination of rising CO_2 prices and lagging electricity prices. However, current agricultural cogeneration takes advantage of its very flexible response to electricity prices. If developments such as increased coal capacity, CCS and intermittent renewable capacity result in higher price fluctuations, this may prove to be beneficial for flexible agricultural cogeneration. As a consequence, the position of horticultural cogeneration may be more robust than that of industrial cogeneration.

CO_2 fertilisation
The introduction and further development of CCS may provide the opportunity to supply CO_2 to more areas with a concentration of greenhouse horticulture. This would provide competition to on-site production of CO_2 with boilers or cogeneration. Recent comparisons between companies with external delivery of CO_2[25] and on-site production with gas engines indicate that the latter results in lower crop yields, probably due to insufficient cleansing of the exhaust gases. As the economical interest of growers is in the first place the maximisation of their crop yields, this will make the application of cogeneration less attractive. However, the introduction of cleaner technologies such as fuel cells may tip the balance again to more CO_2 production by cogeneration.

Biomass availability
The targets for renewable energy will probably lead to a considerable increase in biomass application. Current applications include electricity generation and biofuels, and future candidates include green gas and biomass based feedstock. Biomass based cogeneration will have to compete with other consumers of biomass. The competition for biomass may lead to high biomass prices.

6.2.4 Potentials
Figure 6.12 shows the development of cogeneration in the GEH baseline, including electricity production, heat production fuel use and savings according both to the directive and the PME. With nearly constant heat and electricity production, and decreasing fuel use, the slight increase in savings arises for the major part from the rejuvenation of the cogeneration capacity.

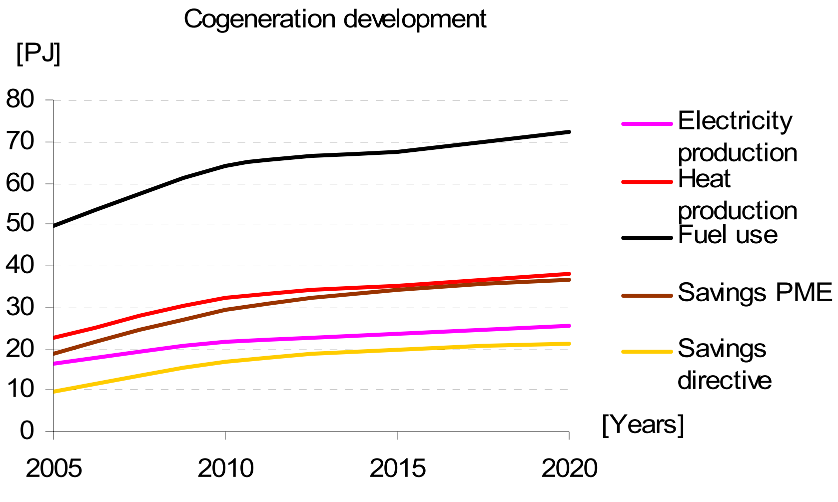

Figure 6.12 *Baseline agricultural CHP heat and electricity production, fuel consumption and savings*

Figure 6.13, Figure 6.14 and Figure 6.15 show the various results on industrial CHP in 2010, 2015 and 2020 for a range of CO_2 prices up to 100 €/ton CO_2 and an electricity price rise of 5.7

[25] The OKAP- CO_2 pipeline that delivers CO_2 form refineries to greenhouses in the Westland region.

€ /MWh. The figures show the production of electricity and heat, fuel use, and energy savings both according to the definition of the CHP-directive and to the Protocol Monitoring Efficiency (Boonekamp. 2001). Contrary to the industry, higher CO_2 prices do not invariably lead to higher cogeneration volumes. The decrease of heat demand and growth of alternative heat production may have stronger effects than the increased profitability of cogeneration. From CO_2 prices of 30 €/ton upwards, cogeneration production does increase, as calculated. However, in reality, some of the new technologies under development, such as the new greenhouse concepts, may benefit much more than cogeneration. In that case, cogeneration growth could be much less at higher CO_2 prices. From the policy goals point of view, this would not present any problems, as the alternative technologies offer even better perspectives for energy savings and GHG emission reduction.

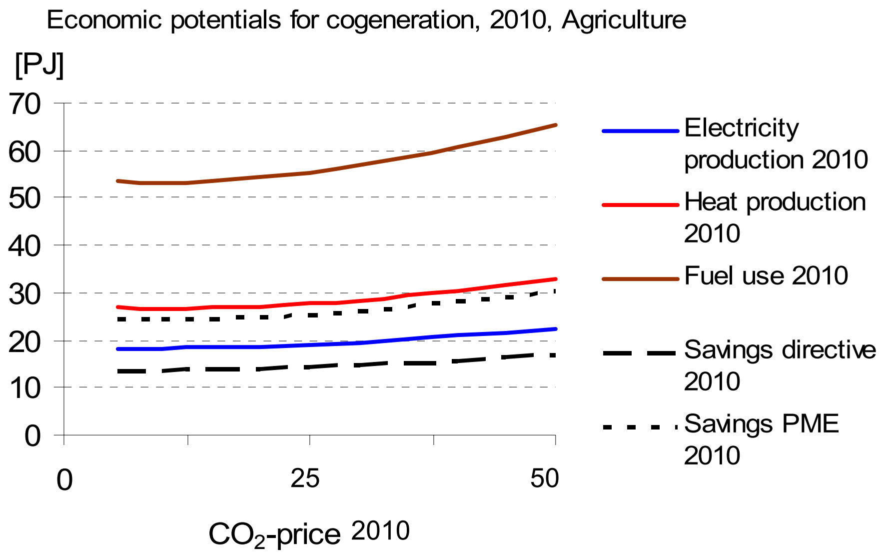

Figure 6.13 *2010 Agricultural CHP heat and electricity production, fuel consumption and savings*

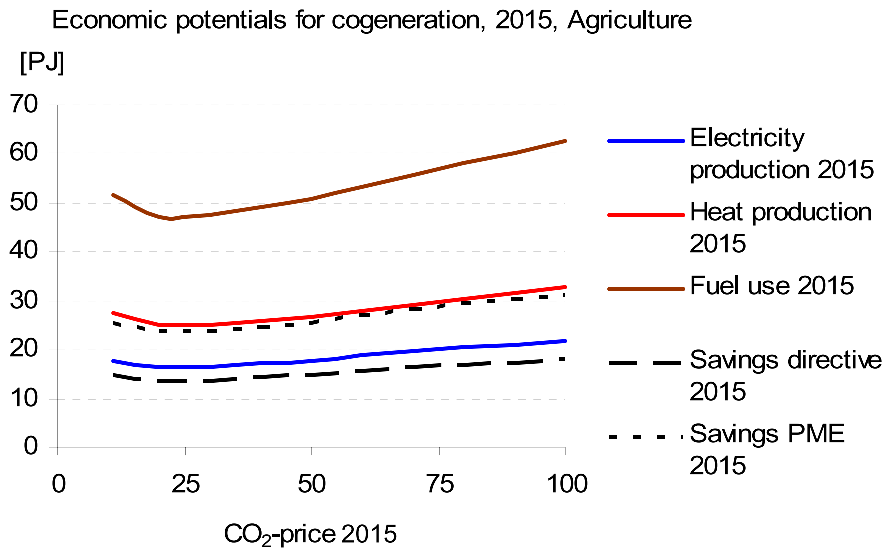

Figure 6.14 *2015 Agricultural CHP heat and electricity production, fuel consumption and savings*

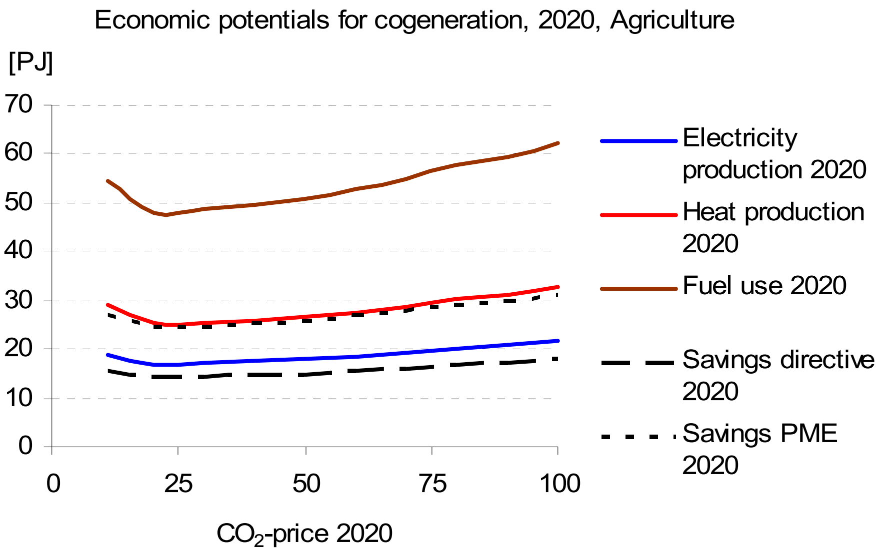

Figure 6.15 *2020 Agricultural CHP heat and electricity production, fuel consumption and savings*

Figure 6.16 and Figure 6.17 show agricultural cogeneration electricity and heat production for different responses of the electricity price on the 50 €/ton CO_2 price. As a reference, the figures include the GEH and GE baselines. The GE baseline offers comparably beneficial economic circumstances for cogeneration as most 50 €/ton variants, but due to the higher heat demand, the absolute volume of cogeneration is higher. The 2020 difference between the variants with differing responses of the electricity price is 2 PJ or 20% at the most, which would indicate a fairly robust response of cogeneration to the higher CO_2 prices.

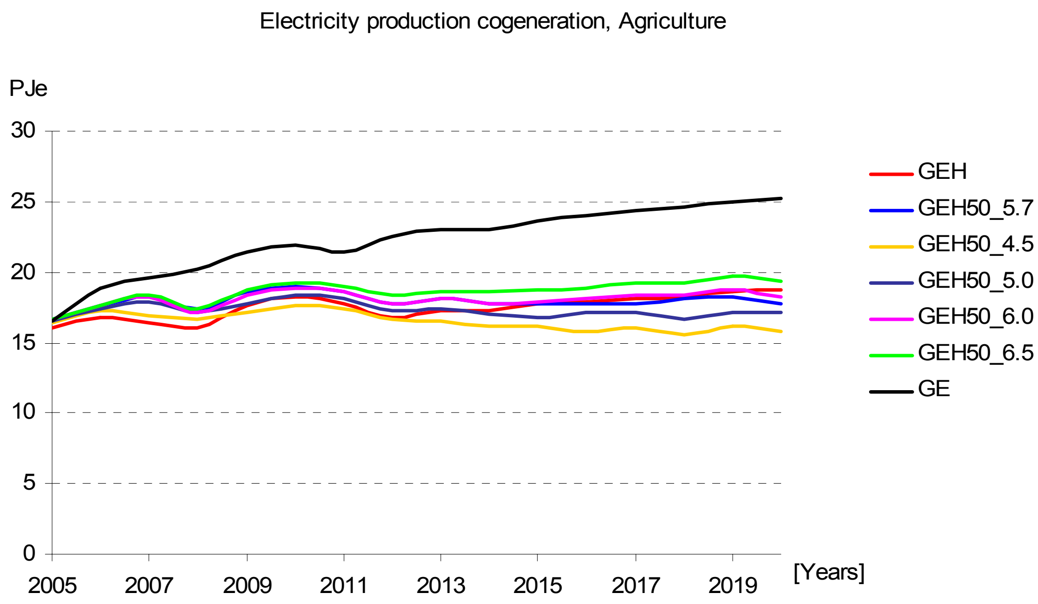

Figure 6.16 *Projected development of agricultural CHP electricity production, given various electricity market responses to CO_2 prices*

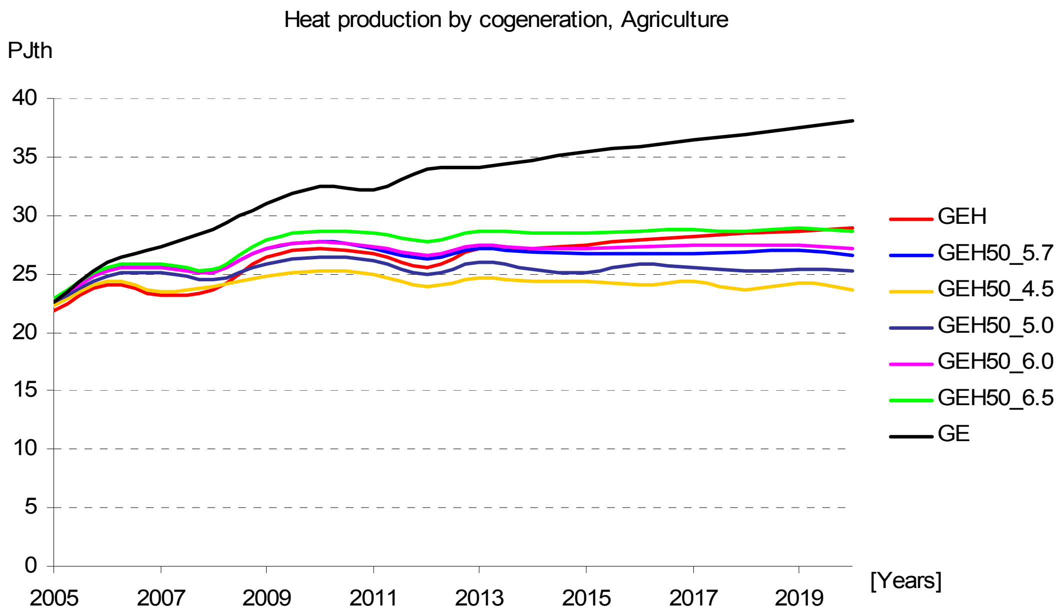

Figure 6.17 *Projected development of agricultural CHP heat production, given various electricity market responses to CO_2 prices*

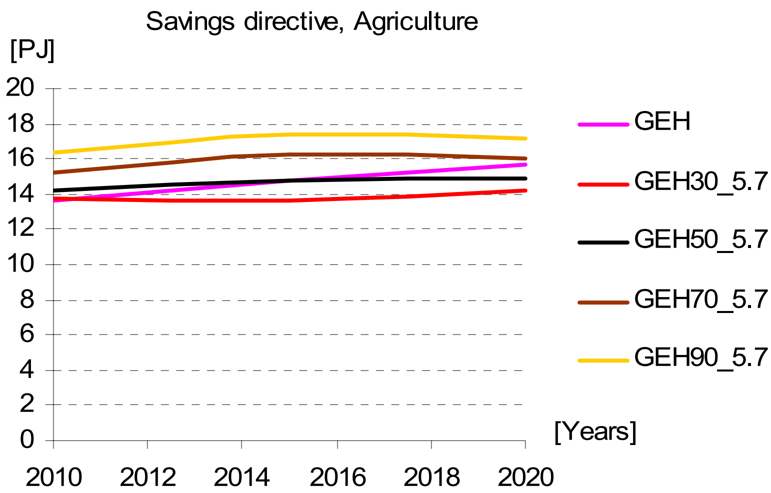

Figure 6.18 *Projected savings by agricultural CHP according to the directive definition, given various CO_2 prices*

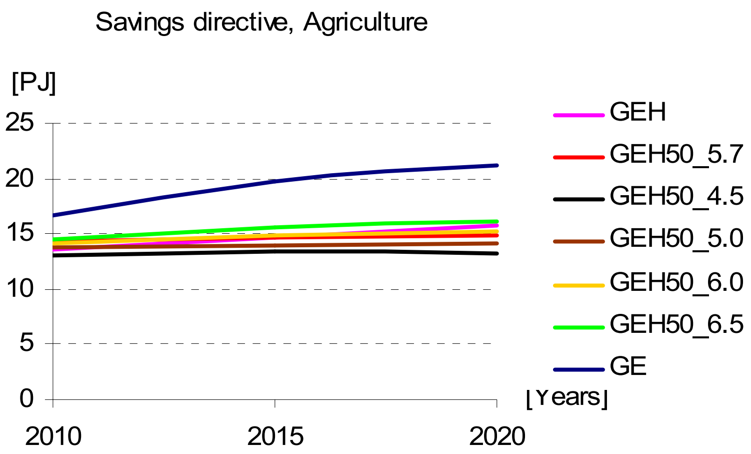

Figure 6.19 *Projected savings by agricultural CHP according to the directive definition, given various electricity market responses to CO_2 prices*

Figure 6.18 and Figure 6.19 show the energy savings by cogeneration as calculated according to the directive for various CO_2 price variants and for various electricity market response variants. All variants show an increase in savings, with the exception of GEH50_4.5, in which savings remain about the same. This includes the GEH baseline, despite the decrease of heat production. In the agriculture, the effects of abandonment and replacement of existing capacity are less outspoken than in the industry, due to the generally newer production capacity.

In general, variations in cogeneration results are much smaller than those in the industry. An important cause is that the variants do not vary some of the key parameters that determine cogeneration developments. Examples include the introduction rate of the new greenhouse concepts, and economic growth rates. An additional explanation is that the greenhouse cogeneration more depends on profits during the peak periods, and these remain in a comfortably high range within all variants included.

Uncertainties and other factors

The calculations cover only a limited range of circumstances. Table 6.2 indicates the effects of the factor investigated and some other factors in a qualitative way.

Table 6.2 *Qualitative overview of the effects of some changes on agricultural CHP*

Change	Effect	Remarks
Higher gas prices	-	
Higher coal prices	+	
Lower economic growth	-	
Faster growth of renewable electricity	+	Beneficial for flexible cogeneration
Larger differences between peak and off-peak prices	-/+	Beneficial for flexible cogeneration
Auction of CO_2 emission rights	-/+	Increases relative competitiveness of cogeneration compared with separate generation, but decreases financial room as compared to allocation

6.3 Services

The services sector is very diverse. It includes various economic activities and the buildings are very diverse with regard to functionality and scale. Examples of buildings that belong to the services sector include offices, homes for the elderly, swimming pools, small shops, supermarkets, schools, and so on. Attention for energy savings is generally very low, due to the very low share of energy costs in total costs, and due to split incentives: the investor in energy saving technologies often does not take all of the benefits. As result, application of energy saving technologies, including cogeneration, is hardly influenced by total cost considerations, but rather by standards, such as the Energy Performance Norm. In practice, there is only attention for energy savings in newly constructed buildings, due to the aforementioned EPN. In such cases various options to meet the standard may be evaluated for their cost-effectiveness. Due to the limited period of heat demand for space heating, the cost-effectiveness of cogeneration often does not compare favourably to other options.

The services sector does not participate in the ETS. In addition, past and current policies such as energy taxes and the EPN have resulted in marginal costs for further reduction of energy use and CO_2 emissions that are often already amply above the incentive provided by the ETS. On average, the marginal energy taxes on natural gas and electricity are much higher than in the industry and greenhouse horticulture. For these reasons, CO_2 prices are not a good measure for defining the economic potential. Instead, the analysis explores the role cogeneration may play in achieving the targets for savings and CO_2 reduction as translated to the services sector. There is great uncertainty due to limited availability of relevant data on energy use in the services sector. In addition, current policy plans for the services sector, with the exception of a more stringent EPN for new building, are still quite vague. For these reasons, the analysis is predominantly qualitative.

6.3.1 Heat demand

The major part of heat demand concerns space heating, hot tap water being the second largest category. Many buildings, especially offices, have cooling demand for air-conditioning. Heat demand appears to stagnate in recent years, and is likely to show a declining trend in the near future, due to the gradual replacement of older buildings by new ones. The targets on savings and GHG reduction will strengthen this trend, though in the recent policy plans the emphasis appears to lie on households rather than the services sector. Heat demand has strong seasonal pattern, and especially in new, well-isolated buildings, heat demand is concentrated in relatively few hours, which is not very favourable for profitable operation of cogeneration.

6.3.2 Technologies

Currently, on-site cogeneration in the services sector is the almost exclusive domain of internal combustion engines. Generally, only the larger buildings or concentrations of buildings apply cogeneration, such as hospitals and universities. In the future, mini-turbines and fuel cells may play a role as an alternative to internal combustion engines.

After a successful introduction of micro-CHP, smaller buildings in the services sector may offer good opportunities for the application of micro-cogeneration, such as Stirling-engines, small scale internal combustion engines and fuel cells (see Paragraph 7.3). The availability of such technologies may open up a larger cogeneration potential.

An alternative to on site cogeneration is heat distribution. As most heat demand in the services sector is hot water demand for space heating, areas with concentration of services and households could be provided with cogeneration based heat distribution. In the Netherlands, application of district heating is not widespread. Most existing district heating system in the Netherlands already receive their heat from cogeneration or residual heat. For additional district heating systems, in case of new residential areas and offices the costs are relatively low, but here, the heat demand per building is decreasing rapidly, deteriorating the cost-effectiveness of district heating. On the other hand in existing buildings, heat demand is much higher, but the implementation of new district heating system in existing areas is very expensive. As with other cogeneration in the built environment, alternative technologies may benefit more in case of higher targets.

6.3.3 Competing options and other developments

New buildings are generally very well insulated, and the more stringent EPN foreseen in the recent policy plans will increase this. Especially new buildings with demand for heat as well as cold, such as offices, are usually equipped with heat and cold storage in aquifers. In such cases, the potential for cogeneration appears to be very limited.

In existing buildings, the recent policy plans may lead to better insulation, and a lower heat demand. In addition, insulation also decreases the number of hours during which there is heat demand. As a consequence, the technical potential for cogeneration will decrease, and the remaining heat demand has less favourable characteristics.

6.3.4 Potentials

As mentioned before, lack of data does not allow detailed quantitative analysis of the potentials. It is only possible to give rough estimates, and to describe the dominant factors. The technical potential for current cogeneration technologies in the services sector is estimated on between 30 and 60 PJ_{th} in 2010, and will probably decrease towards 2020 due to new construction with better insulation and heat/cold storage technologies. Once micro-CHP is on the market, the technical potential will extend to smaller buildings en be somewhat higher. However, the demand pattern of heat is usually very unfavourable for cogeneration, restricting its application currently to niches of larger buildings and complexes with a more constant heat demand.

7. Potentials for micro-CHP

In the residential sector - unlike in other sectors - economic potentials of technologies not always explain their application. Cost-effectiveness is not always is reason to implement additional saving measures. Many energy saving measures in the residential sector are not cost-effective, when considered from a national perspective: savings in the industry or energy sectors are often much cheaper. Still, the Clean and Efficient policy package specifies ambitious targets for energy savings in the residential sector. Given such targets, economic potentials in the residential sector could be defined by the most cost-effective (or the least expensive) ways to meet these targets.

Further, when households are obliged to meet certain standards, such as in the case of newly built houses, cost effectiveness will become a criterion. Once a technology is applied because it is one of the most cost-effective ways to meet a standard, this often results in increased implementation in other situations. The increased pace of penetration will decrease the price of a technology (because of economies of scale and growing experience with the new technology) and standardisation will lead to a more prominent position, which may eventually result in a technology being the default option.

Along with micro-CHP, various other technologies may play a role in meeting the standards within the residential sector. For this reason, the current analysis concentrates on comparing the cost-effectiveness of micro-CHP and some potential competitors.

7.1 The special position of micro-CHP

Micro CHP for dwellings is - unlike other CHP applications - a relatively new technology that in the Netherlands up to now has only been applied in pilot projects/demonstrations projects. As no (large scale) market introduction has taken place yet and as the technology is still under development, many aspects related to micro CHP are still uncertain. Because of these uncertainties it doe not make sense to estimate an economical potential of micro CHP for the Netherlands. Instead, this chapter explores the influence of some factors on the economic performance of micro-CHP, and performs sensitivity to evaluate the effect of varying assumptions. In this way, it arrives at a bandwidth rather than an indicative potential.

Micro-CHP is still under development. As with any new technology, an important factor for its future success is a smooth market introduction, without technological deficiencies that might give it a bad image. Once such an image sticks to a new technology, it may take many years before a technology gets a second chance. In such a case a negligible number of micro CHP will be sold up to 2020. This document only explores the economic potentials, in case micro CHP technology is technologically fully ripe at the moment of market introduction.

As in other sectors, micro CHP has to compete with other technologies and penetration depends on various technical and policy factors that will be dealt with in the following sections.

7.2 Heat demand

The cost effectiveness of micro CHP depends on many factors. Main variables that are still uncertain are the price of the micro CHP, the amount of electricity that will be delivered to the grid, and the financial compensation that will be received for delivering to the grid. Another important factor is determining cost effectiveness heat demand per dwelling.

To calculate the cost effectiveness of micro CHP, heat demand of a dwelling is taken into account without specifying technical characteristics or the behaviour of its inhabitants.

To analyse of the effect of heat demand on cost effectiveness, the dwelling stock is divided in different categories of heat demands for space heating.

The larger the heat demand, the more cost effective micro CHP becomes. As new dwellings in the Netherlands have to comply with minimum performance requirements, heat demand in these houses is generally low. Therefore, only existing dwellings (constructed before 1995) are taken into account when determining the economical saving potential of micro CHP. Figure 7.1 gives an overview of the number of dwellings (constructed before 1995) in various ranges of heat demand for space heating in 2010 (GEHP scenario).

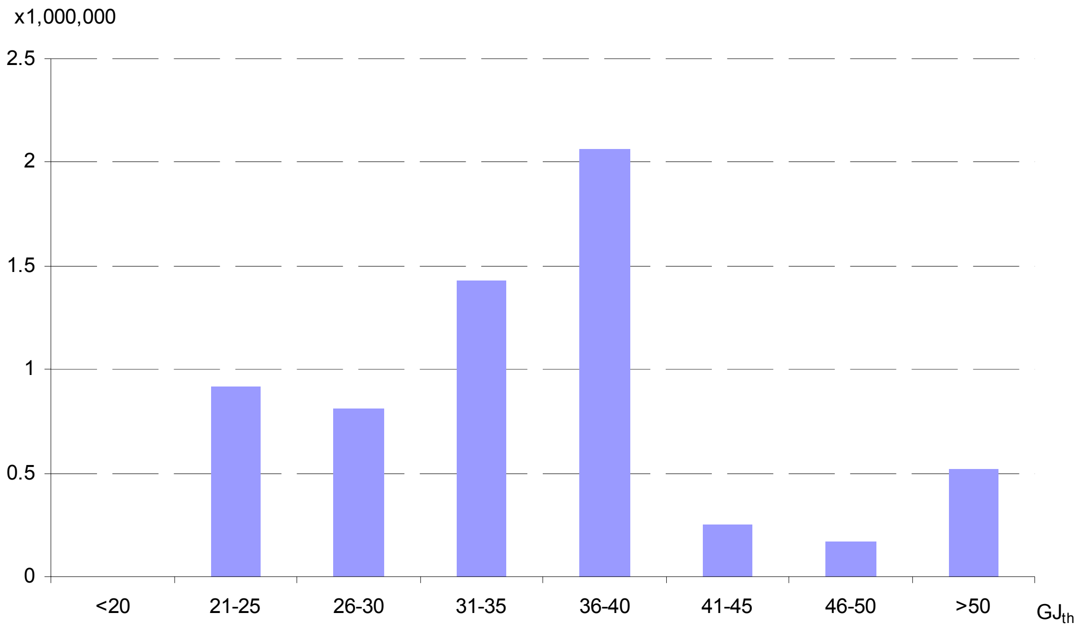

Figure 7.1 *Number of dwellings and related heat demand for space heating (2010)*

The heat demand can be split up in space heating and heating of tap water. Developments in both types of heat demand will affect the cost effectiveness of micro CHP. In the GEHP scenario it is assumed that:

- Heat demand for warm tap water per person will increase. But, because of the decreasing number of persons per dwelling, heat demand per dwelling will decrease over time.
- Heat demand for space heating in existing dwellings will decrease over time. Various factors contribute to this effect: insulation, demolition of old, poorly insulated dwellings and warmer winters (decrease of heating degree days).

The decrease in heat demand reported above does not yet include the effects of the Dutch policy program 'Clean and Efficient' (Menkveld et al., 2007). Under this program, heat demand for space heating is expected to decrease even further. In 'Clean and Efficient' energy savings of 50-100 PJ are assumed for the built environment in existing buildings. The exact effect on the heat demand in dwellings is difficult to estimate, as the 50-100 PJ concerns both the services sector and the residential sector and both electricity use and energy use for heating.

The consequence of the decreasing heat demand (in GEHP and the additional decrease due to 'Clean and Efficient') will have impact on the economical potential of micro CHP in the residential sector. Over time, the number of dwellings where micro CHP is the most cost effective, will decrease.

7.3 Technologies

Various technologies can be used for the simultaneous production of heat and electricity for dwellings. Development programs for the Dutch market exist for three different technologies: Stirling motor, gas motor and fuel cell (Jong et al, 2006). Elsewhere also development programs exist for other technologies (e.g. gas turbines and organic rankine cycle) but these will not be further described here.

The Stirling motor is of the various technologies closest to market introduction, followed by the gas motor and from 2015 also the fuel cell is expected to become available. It is expected that the role of the gas motor in the residential sector will stay limited and will therefore not be analysed in Paragraph 7.4 and 7.5. Table 7.1 shows the characteristics of the various technologies. The performances are based on a consultation of members of the Working group on micro CHP Cogen Nederland in august 2005 (Jong et al, 2006). Exact numbers are not available, as the various types of micro CHP are still under development.

Table 7.1 *Performance indicators*[26]

		2010			2020	
	Stirling	Gas motor	Fuel cell	Stirling	Gas motor	Fuel cell
η_e	14%	20%	35%	25%	25%	40%
	(12-20)	(18-25)	(30-40)	(20-30)	(20-30)	(35-45)
η_{th}	91%	75%	50%	80%	80%	55%
$\eta_{overall}$	105%	95%	85%	105%	105%	95%
	Available	Demo phase	Demo phase	Available	Available	Available

In order to provide heat at sufficient any moment, all micro CHPs are assumed to have a peak burner. The higher heat demand of the dwelling and/or the lower thermal power of the micro CHP, the larger the contribution of the peak burner will be in the production of heat (See Table D.1). The need for a peak burner will have a negative effect on the cost effectiveness of the micro CHP. In order to optimize the system, a micro CHP can be combined with a hot tap water reservoir[27]. However, this will in general not be sufficient to avoid a peak burner.

Micro CHPs can be controlled to run at moments of heat demand or during electricity demand. The calculations in Paragraph 7.4 and 7.5 assume micro CHPs to be dimensioned primarily to the heat demand. If the electricity production can be uncoupled from the heat demand (e.g. by heat storage), virtual power plants would be feasible. This configuration is far more complex (more investments, tariffs, larger heat losses) and outside the scope of the calculations under 7.4 and 7.5.

7.4 Competing options

Three competing options are: insulation, the solar thermal collector and the UHR (Ultra High Efficiency boiler).

[26] In the report Technisch energie- en CO_2-besparingspotentieel van micro-wkk in Nederland (2010-2030), July 2006 also related thermal and electric capacities are shown. But these capacities are under discussion and in a follow up report (not available yet) capacities are different. With the capacities in the report the fuel cell has to run almost all year round (days and nights) to foresee in the heat demand. This is not very realistic, seen the fact that heat demand is much higher in winter than in summer. Therefore, calculations in these and subsequent paragraphs are made without taking into account capacities (but are based on efficiencies (Table 7.1) and contribution of the micro CHP to foresee in heat (Table D.1)).

[27] However, not in all dwellings feasible because of limited space.

Part of the Dutch building stock is not yet insulated, or only partly insulated. Improving insulation not only reduces energy use, but also increases comfort level. Another advantage of insulation is the long lifetime 25-50 or even more, as opposed to a lifetime of about 15 years for solar thermal collector, UHR, micro CHP. A large part of the 50-100 PJ savings in 'Clean and Efficient' is expected to be realised by insulation. Insulation reduces the attractiveness of micro CHP, as it will reduce the heat demand of dwellings, and thereby the cost effectiveness of micro CHP (see Figure 7.4).

Figure 7.2 shows the number of dwellings per category of heat demand for two scenarios. In the low scenario in total 500,000 dwellings will be insulated in the period 2008-2020, in the high scenario 3,200,000 dwellings. Another reason that the number of dwellings with a large heat demand in Figure 7.2 is lower than in Figure 7.1, is demolition (in both scenarios same number of dwellings will be demolished)[28].

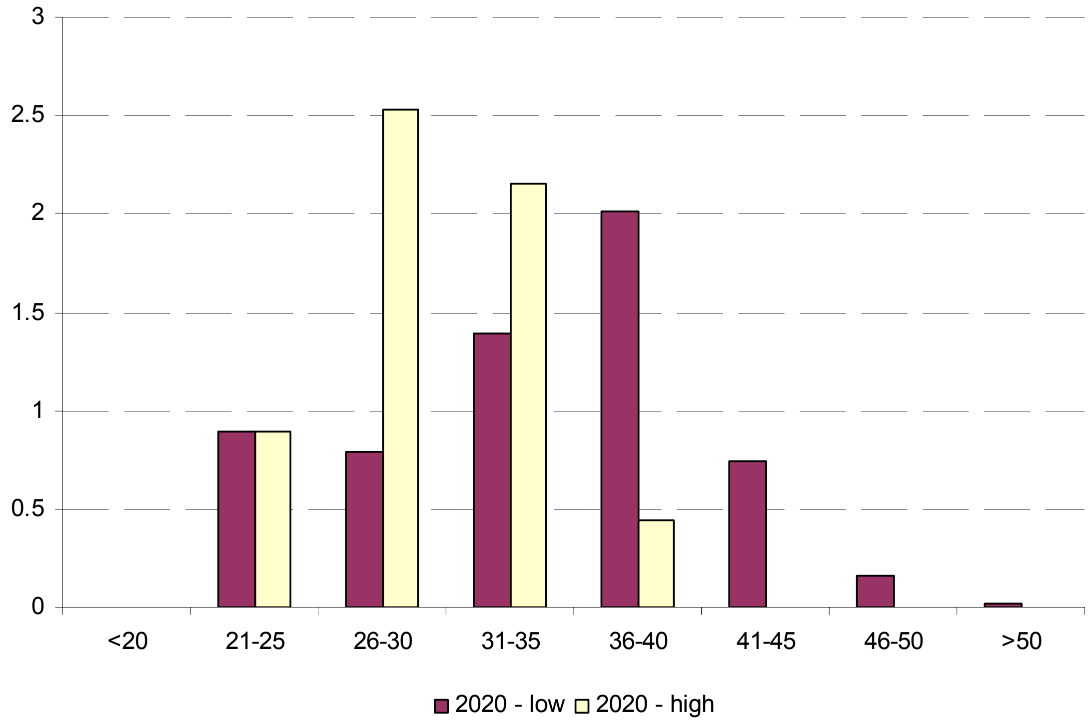

Figure 7.2 *Number of dwellings and related heat demand for space heating for a high and low insulation pace (2020)*

The solar thermal collector is already commercially available for more than ten years. The size of the collector can vary and consequently the savings by the system. The maximum savings that can be realized are about 40% of energy used for heating of tap water. If solar thermal collectors are combined with micro CHP or UHR, the cost effectiveness of these technologies will decrease (high investments costs remain, while the energy savings reduce). Solar thermal collectors will be subsidized coming year, but the amount of subsidy per collector, the total subsidy budget and how many years that subsidies will be paid is not known yet. This makes it difficult to estimate the penetration of the solar thermal collectors for coming years.

The Ultra High Efficiency boiler is available at the market since spring 2007. The UHR is a condensing boiler with an integrated heat pump. The heat pump will provide the largest part of the heat demand, and the condensing boiler will cover peak demand. The UHR can lead to an

[28] Assumed is that insulation will decrease heat demand per dwelling with 10 GJ_{th}. Furthermore, it is assumed that dwellings with the highest heat demand will be first insulated. In practice this will not always be the case.

increase of efficiency relative to a normal condensing boiler of 30-40% in new dwellings. Prerequisite for installing an UHR is mechanical ventilation[29] and a low temperature heating system (LTH). The UHR can also be applied in existing dwellings, if the prerequisites are fulfilled. If no LTH system is available, it can either be installed (not always desirable or possible) or the dwelling can be insulated. By insulating the building envelop, the heat demand will decrease and therefore existing radiators will be over dimensioned for the new heat demand. As a consequence the radiators can be used as a LTH system. In existing dwellings the UHR can lead to an increase of efficiency relative to a normal condensing boiler of about 15-18%. The UHR is already commercially available and is applied in new construction projects. This will help to develop a market penetration (also in existing dwellings), even before micro CHP becomes commercially available. The longer it takes before micro CHP becomes commercially available, the smaller the market potential/saving potential for micro CHP will become up to 2020.

The future penetration of competing technologies is difficult to determine. There are many uncertainties and application of a specific technology may influence the potential and attractiveness of another. For example, insulation of the building envelope reduces the cost effectiveness of a micro CHP to be applied later. On the other hand, insulation will increase the potential for UHR (as existing radiators can be used as LTH system).[30]

Not in all dwellings insulation will be possible/desirable (e.g. in monumental buildings). In this niche market micro CHP may certainly can play a role.

The current analysis is mainly based on payback times. The text box shows the assumptions for the calculations.

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[29] The heat pump will detract heat partly from the out going ventilation air and partly from outdoor air.

[30] If firstly the conversion technology (UHR/micro CHP) is installed and insulation is realised afterwards, the conversion technology will be over dimensioned for the new heat demand. This will have a negative impact on the cost effectiveness.

Assumptions for the pay back time calculations in Paragraph 7.4 and 7.5.

Reference Technologies
Payback times for micro CHP and competing technologies are determined relative to reference technologies. For heat, this is the condensing boiler, with assumed efficiencies of105% for space heating and 83% (2010) and 89% (2020) for heating of tap water. For electricity production the electricity price is used (reflecting the average power production park). Financial compensation for electricity delivered to the grid is based on commodity prices for electricity. For electricity delivered by the grid end user prices (including energy tax) are paid[31].

Efficiencies of micro CHP
The efficiencies in the calculations are based on the efficiencies shown in Table 7.1 and based on full load operation. Year round efficiencies are not available.

Delivery to grid
The Stirling motor is assumed to deliver 50% of the electricity to the grid, for the fuel cell this is higher (70%), because of the larger amount of electricity produced per year.

Technology prices 2010
Prices are relative to the reference technology (condensing boiler). In 2010, the additional price of the UHR is € 1500, for the Stirling € 3000 and for the solar thermal collector € 1300 (€ 2000 minus € 700[32] subsidy).[33] The price of the Stirling includes a peak burner, but no hot tap water reservoir. Effects of higher investment costs are shown by a sensitivity analyses (Paragraph 7.5).

Technology prices 2020
2020 prices for Stirling, UHR and solar thermal collector are 25% lower than in 2010. The price for a fuel cell is estimated to be € 3000 (same price as the Stirling in 2010).

Subsidies for micro CHP
The calculations do not assume subsidies, in order to allow a fair comparison of competing technologies[34]

Peak burner
A peak burner will be needed to provide heat during peak demand. As no detailed simulations have been made on the hourly heat demand it is not exactly clear what part of the heat demand will be produced by the peak burner. Therefore Table D.1 (Appendix D) is used for calculations. Table D.1 shows that for all configurations 100% of heat for tap water will be delivered by the micro CHP. This is not considered as realistic. Because of lack of better data, Table D.1 is used anyway. In the costs, a peak burner is taken into account for all configurations. The peak burner is assumed to be a condensing boiler.

Hot tap water reservoir
A hot tap water reservoir can be used to optimize the configuration. Table D.1 used for the calculations, assumes the presence of a hot water reservoir. The efficiency of the buffer for warm tap water is assumed to be 75%.

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31 As a consequence, for part of the electricity consumption double energy tax is paid: namely for the amount of electricity delivered to the grid (energy tax included in the price for natural gas used to generate electricity) that is at another moment delivered to the household by the grid (energy tax is included in end user prices). Present law obliges this unfavourable double energy tax payment and therefore it is taken into account in the calculations.

32 Estimation of subsidy based on subsidies available under the EPR (Energie Premie Regeling).

33 For the UHR and the solar thermal collector no price decrease has been expected between 2007 and 2010. For the UHR this is maybe a little pessimistic, as it is a new technology that is expected to increase fast in market share in new dwellings. This might lead to a decrease in price also for UHRs in existing dwellings.

34 However, the cost levels assumed for the Stirling in 2010 and 2020 are only feasible with a sufficient number of micro-CHPs produced. In order to achieve this, financial support during the introduction period will be necessary.

Heat demand
Furthermore the heat demand for tap water and the electricity demand is assumed to be equal for all dwellings, like the assumption in GEHP.

Technical lifespan
The technical lifespan of UHR, micro CHP and solar thermal collector is assumed to be 15 years.

Field of implementation
Solar thermal collectors and UHRs can be applied both in new and existing dwellings, micro CHP will be implemented in existing dwellings. So, in existing dwellings these three technologies compete. However, the UHR will in existing dwellings mainly be applied in dwellings with over dimensioned radiators, or in other words dwellings that have been insulated after construction. As a consequence, the UHR will in general not compete with the UHR in dwellings with very high heat demands for space heating.

Figure 7.3 shows the cost effectiveness of three competing technologies for various heat demands for space heating in 2010. The main goal of this and the following figure is not to specify exact pay back times, but rather to give an indication of how payback times of the technologies vary with heat demand and how they are related to each other.

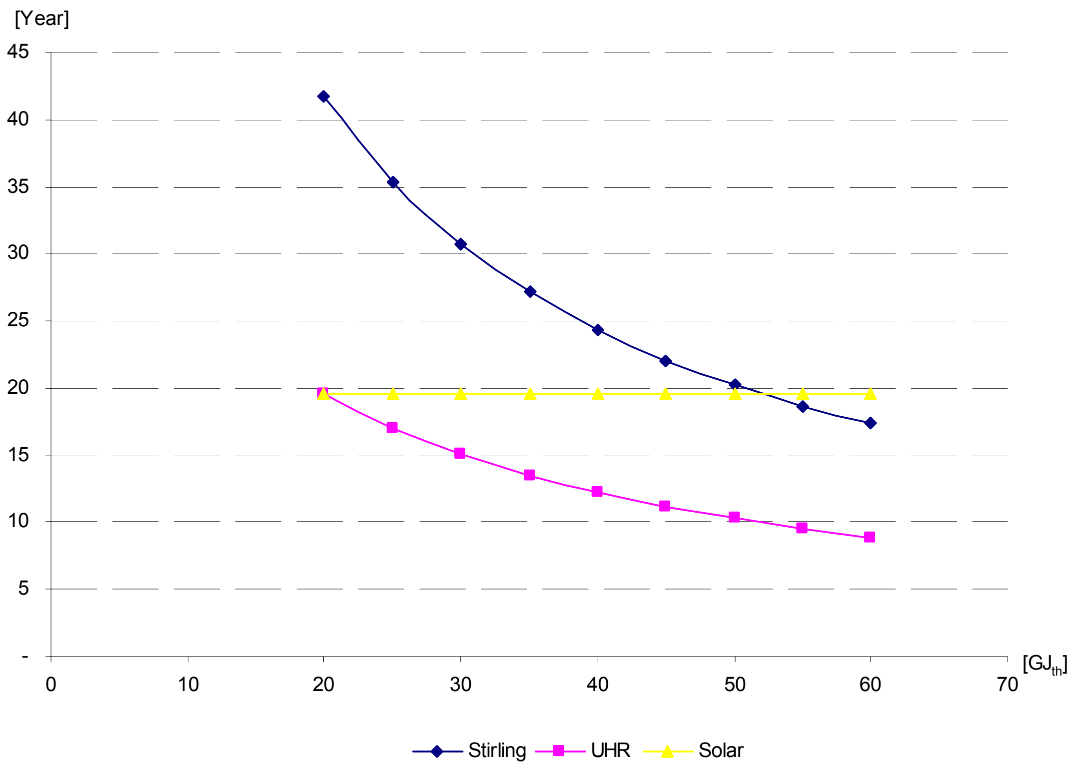

Figure 7.3 *Payback times for competing technologies in 2010 for various heat demands for space heating (assumptions in text box)*

Figure 7.3 shows clearly that for both the Stirling motor and the UHR payback times decrease with an increasing heat demand. Under the assumptions made, in 2010 only the UHR will have payback times shorter than its technical lifespan (15 year). As explained above, the UHR will mainly be applied in dwellings that have been insulated after construction (and therefore have radiators that can be used for LTH). So the UHR will not be applied in dwellings with the highest heat demands. Consequently, in 2010 the payback time of UHR will be about 10 years or more. Expected is that in 2010 the UHR will be applied in existing dwellings.

Figure 7.4 shows 2020 payback times. The assumed Stirling prices are only attainable for a sufficiently large number installed[35].

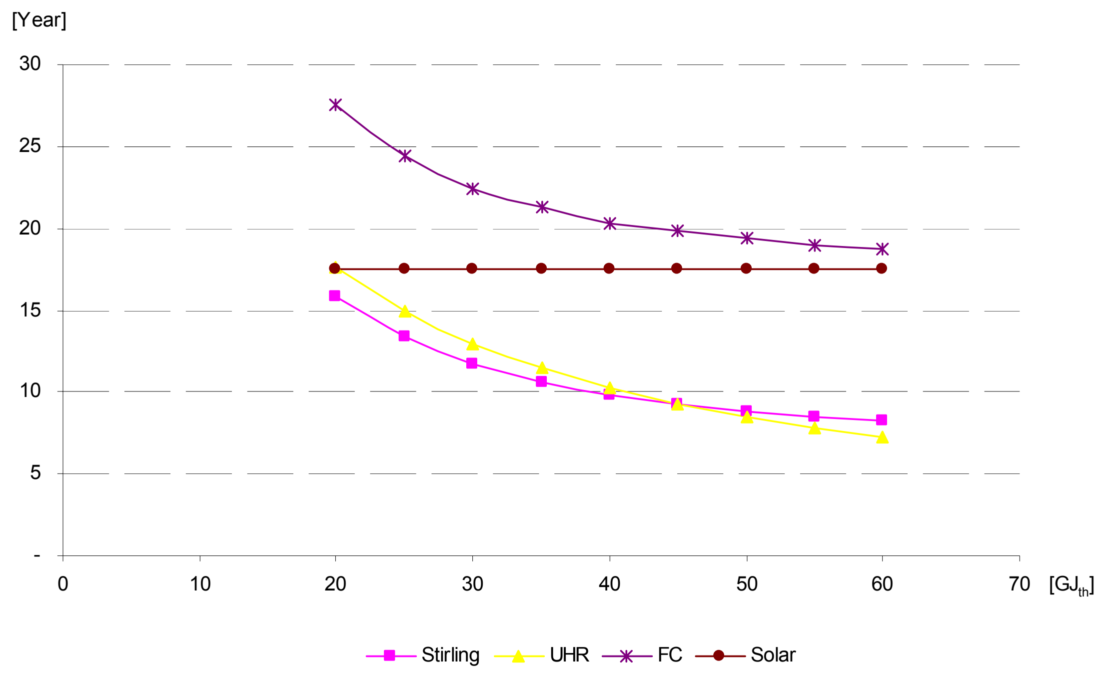

Figure 7.4 *Payback times for competing technologies in 2020 for various heat demands for space heating (assumptions in text box)*

Figure 7.4 shows for 2020 that both UHR and micro CHP will have payback times shorter than their technical lifespan, with a minimum of about 8 years. The differences between the payback times for these two technologies fall in the range of uncertainties. Payback time of micro CHPs not only depends strongly on the price of the micro CHP unit, but also on the part of the electricity delivered to the grid and the related financial compensation. A sensitivity analysis on these aspects is described in Paragraph 7.5.

So far, the analysis has been based on end consumer payback times. The market success of micro CHP depends strongly to what degree cost price reduction can be realized. All analyses assume 2020 prices that are only attainable with considerable economies of scale. The required number of installations presupposes considerable financial support of the government during the introduction trajectory. However, such financial support is only expected if micro CHP will lead to advantages on national scale, as compared to technologies that receive no or much less support. Therefore two aspects of micro CHP on national scale will be described: cost effectiveness and security of supply.

From a national perspective, costs effectiveness is expressed by costs per avoided ton of CO_2 emissions. The costs effectiveness of different CO_2 reduction options are compared in Table 7.2.

35 Without financial support from the government it is not expected that economies of scale can be reached to realize the prices assumed for 2020. In other words, without governmental support payback times for the Stirling will be comparable to that of Figure 7.3 (or even longer).

Numbers in this table are derived from the Optiedocument (Daniëls & Farla, 2006b), but adapted to recent insights.

Table 7.2 *National costs effectiveness (adapted from Optiedocument)*

Technology	[€/ton CO_2]	Remarks
UHR	600-800	Based on new insights costs per ton of avoided CO_2 will be roughly half of what they are in the Optiedocument
Micro CHP	600-700	Based on additional costs of 2500 relative to reference technology. This is approximately the average of the costs assumed in the text box for 2010 and 2020. These costs can only be realized if market introduction is financially supported by the government
Solar collector	700-800	Investment costs in Optiedocument about 30% higher than the investment costs (without subsidies) in the text box. Based on new insights the costs per ton of avoided CO_2 will be close to that of micro CHP
Insulation	<0 - 260	

Insulation is the most cost effective saving technology of the competing options defined in Paragraph 73. Cost effectiveness for UHR, micro CHP and solar thermal collectors are roughly comparable in 2020. However, while the cost effectiveness of UHR will be realized without any financial support from the government, the micro CHP requires a considerable support to realize the specified cost effectiveness.

If the percentage of RES will increase relative to the reference scenario GEHP, cost effectiveness will change. Costs per ton of avoided CO_2 emissions for energy saving technologies will increase, as investments and savings will stay the same while reduction of CO_2 emissions will decrease. The actual cost increase will depend on the amount of RES and the kind of RES (electricity production or gas supply). In the short and middle term, renewable electricity will probably grow much faster, thereby reducing the cost-effectiveness of electricity generating options such as CHP. Apart from RES, CCS (carbon capture and storage) may also play a role (in future) in reducing CO_2 emissions. This will have the same effects as renewable electricity.

Another item relevant on national scale is security of supply. With large-scale application of micro CHP households will increase the Dutch consumption of natural gas. From a security of supply point of view this might be undesirable.

7.5 Potentials

Paragraph 7.4 includes two figures with payback times for micro CHP, based on the assumptions in the text box. A sensitivity analysis has been performed for three important factor: investment costs, share of electricity delivered to the grid and the related financial compensation (see figures Appendix D). Sensitivity analyses are carried out for both 2010 and 2020, but for the fuel cell only a sensitivity analysis is carried out for 2020. No sensitivity analysis is carried out on the efficiencies.

The analyses are made to show how payback times vary with assumptions and to see what investment costs, delivery to the grid and financial compensation are needed to realize acceptable payback times. The variations in the sensitivity analyses are not necessarily ‘realistic’. For example, reductions of investment costs are quite extreme[36]. An accurate estimate of the share of

[36] For a Stirling motor in 2020 a price of € 750 additional to the reference would mean (assumed that a condensing boiler is used as peak burner) that the Stirling motor itself costs € 750, this is about half of the price of a condensing boiler.

electricity delivered to the grid requires a detailed simulation of hourly demands and productions[37].

All in all the economical feasible saving potential in 2020 depends on many factors, not only of micro CHP itself, but also on the success of competing technologies (mainly UHR) and on financial support by the government. Therefore, it is difficult to estimate the penetration of micro CHPs in 2020.

Table 7.3 *Influence of main assumptions on payback times*

Adapted assumptions	Effect on payback time of micro CHP (-/0/+)	Effect on payback time of UHR (-/0/+)
Higher part of electricity delivered to grid	-	
Higher financial compensation of electricity delivered to the grid	+	
Higher cost of technology	-	-
Less financial support	-	0
Higher heat-power ratio of micro CHP	-/+[38]	
Other configuration (CHP without boiler)	0[39]	
More insulation	-	-/+[40]

Table 7.3 shows the influence of the various assumptions for micro CHP and UHR. Despite all uncertainties and assumptions, an estimation will be made of the potential numbers of micro CHP in 2020.

In order to make an estimation of the upper boundary, it is assumed that the payback time acceptable for dwelling owners is 10 years[41]. Figure 7.4 shows that the minimum heat demand for space heating for a payback time of 10 years or less is at least 40 GJ_{th}. The related number of dwellings for 2020 is 921 thousand for the low scenario and zero for the high scenario, see Figure 7.2[42]). Therefore the analysis will only continue with the 'low' insulation scenario.

The maximum number of dwellings with a micro CHP depends roughly on two factors:

- The moment at which a price of € 2250 is realized[43]. With a boiler lifetime of 15 year, only part of the dwellings will replace the boiler in the period 2010-2020).
- The effect of competing technologies (the market share of the UHR and the condensing boiler).

37 It is assumed that the thermal power of the micro CHPs available at the market in 2020 is lower than the that of micro CHPs available in 2010. This is a consequence of a changing heat-power ratio. Because of the smaller thermal power, operation hours will increase and therefore the production of electricity that can not directly be used in the household. Therefore, it is expected that the percentage of electricity delivered to the grid will be larger in 2020 than in 2010 (in the text box equal percentages are assumed for both periods).

38 There's an optimum for the heat-power ratio, that will depend on many factors (heat demand of dwelling, operational hours, part of electricity delivered to the grid, financial compensation). For the Stirling a higher heat-power ratio might be favourable, whereas it is undesirable for the fuel cell that has already a very high heat-power ratio.

39 The effect of 'no boiler' depends strongly on the increase of the part of heat generated by the peak burner. If this strongly increase, pay back time will increase. If it only effects tap water heating (50% delivered by the peak burner) pay back time hardly changes.

40 On the one hand insulation leads to over dimensioned radiators (technical requirement for the UHR), on the other hand, lower the heat demands leads to higher payback times.

41 This means that during 1/3 of the technical lifespan of the micro CHP, the households will have savings. Probably households will not accept such long pay back times, five years seems to be a more acceptable payback time. This would mean that under the assumptions the penetration would be zero (see Figure 7.4).

42 High and low scenario are defined in Paragraph 7.2. Other assumptions as defined in the text box.

43 Depending on governmental support this can be in 2010 or e.g. 2015.

Table 7.4 shows the effects for the two factors. With a net price of € 2250 in 2010 (unlike assumptions in the text box), and if in all cases of boiler replacement a Stirling is installed, then at maximum 610 thousand houses will have a micro CHP in 2020[44]. However, it is unlikely that the price will drop so fast, and part of the boilers will be replaced by a new condensing boiler (or UHR) which will mean a lower share of boilers replaced by micro CHPs. Based on Table 7.4 it can be concluded that in 2020 the absolute upper boundary on the number of micro CHPs is about 600 thousands.

Table 7.4 *Numbers of Stirling motors in 2020 for the low insulation scenario*

x1000 Share of boilers replaced micro CHP [%]	Year that price of 2250 is realised 2010	 2015
25	153	78
50	305	155
75	458	233
100	610	310

Because of the many uncertainties, real penetration of the Stirling motor can differ from the calculations. The government can strongly influence the penetration by giving financial support. Penetration can range from negligible numbers[45] (see also Paragraph 7.1) to very large numbers. To determine the upper limit of numbers of micro CHPs in 2020, Figure 7.5 is illustrative. This figure is based on cumulative numbers of condensing boilers sold just after market introduction[46]. Figure 7.5 shows what numbers of Stirling motors can be on the market in 2020 for different years of market introduction, under the assumption that sale of Stirling motors follows a trend similar to the trend of the condensing boiler[47].

Presumably, it will take about four years from market introduction to large scale sale of micro CHPs[48]. With micro CPH commercially available in 2008, at the most 1 million micro CHPs will be on the market in 2020[49].

So, the number of micro CHPs can vary considerable (from zero to about one million). There are too many uncertainties to make at this stage a realistic estimation of the saving potential. Very important are the technical reliability at the moment of market introduction, and the amount of financial support/ financial conditions during market introduction.

44 Under the assumption that 100% of all boiler replaced will be replaced by a Stirling motor.
45 E.g. if payback times of 5 years are required by the dwelling owners.
46 In contrast with micro CHP, condensing boilers are not only applied in existing dwellings but also in newly constructed dwellings.
47 The condensing boiler is a technology with fast market penetration, relative to technologies like e.g. heat pumps and solar thermal collectors - while all three technologies have received subsidies at some point in time. It is unclear if micro CHP will have a penetration pace similar to condensing boilers, or similar to that of heat pumps and solar thermal collectors. As the trend in Figure 7.5 is based on the sale of condensing boilers, it can be considered as an optimistic one.
48 This is an optimistic approach, as it took the condensing boiler much more years after market introduction to reach large scale sales.
49 If it takes only two year from market introduction to large scale sales (instead of four years) and micro CHPs become commercially available in 2008 already, about 1.5 million micro CHPs can be installed in 2020. This is an unrealistically optimistic estimation. It is comparable to the number of micro CHPs assumed in the report 'Technisch energie- en CO_2-besparingspotentieel van micro-wkk in Nederland (2010-2030). In this report it is assumed that the payback time of the micro CHP will be some five years, which is not to expected from the figures shown here.

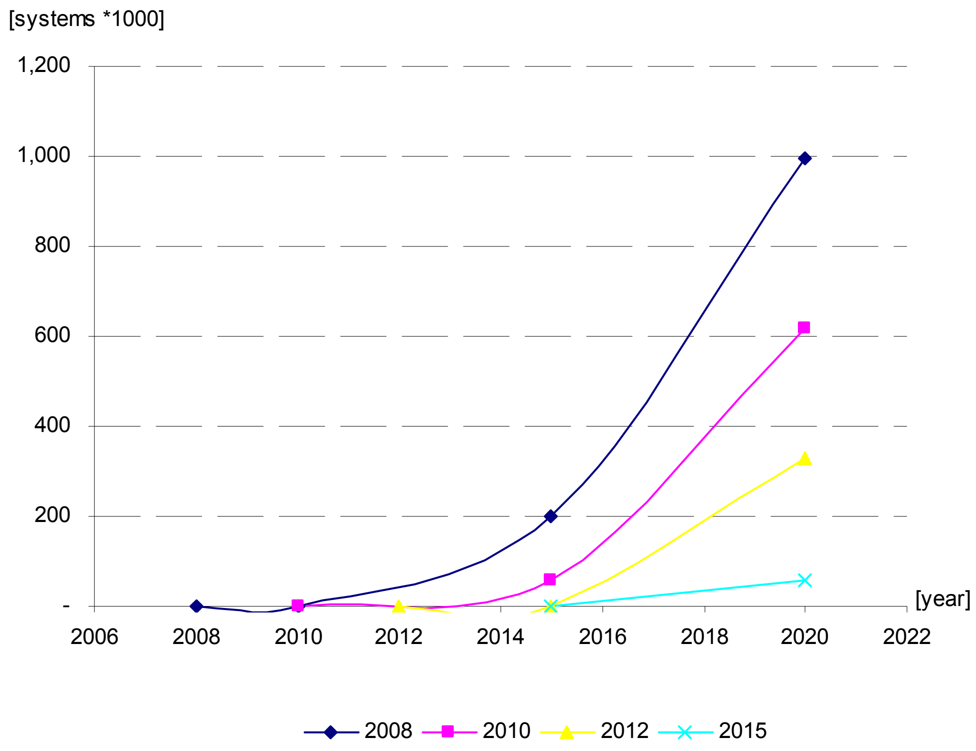

Figure 7.5 *Upper limits of numbers of micro CHP on the market in 2020*

8. Conclusions

8.1 Limitations

The current analysis draws on existing studies, complemented by new analyses. It takes new developments into account, but only in a fragmentary way. For example, this means that the impact of new developments on the electricity market and the resulting electricity prices cannot be taken fully into account. As a result, there are considerable uncertainties attached to the potentials shown.

8.2 Potentials for high-efficiency CHP

Despite the uncertainties, it is possible to sketch bandwidths for the economic potentials for energy savings in the industry and agriculture. All estimates are based on a high economic growth. Potentials will be much lower when a lower growth is assumed.

Electricity production
The room for cogeneration on the Dutch electricity market is not easy to define, as there is no clear physical limit to the amount of electricity by cogeneration. For all practical purposes, at a given moment the limit for cogeneration is roughly defined by existing coal plants, nuclear plants, base-load imports and intermittent renewable capacity, such as wind. However, this is not an invariable and hard limit, but subject to price developments and policies. Concluding, there appears to be room on the Dutch electricity market for renewable electricity as well as cogeneration, but it will result in a net electricity export. Anyway, the physical room for cogeneration on the electricity market appears to be less constraining than the potentials on the heat markets. With regard to the economic position of cogeneration, uncertainties are much larger.

Of these, prospects for additional cogeneration based heat production appear to be most favourable in the industry, and less favourable in agriculture and services, where there is probably stronger competition from alternatives. The latter is also the case in the household, where micro-CHP may be applied. However, very large uncertainties prevent sensible estimates for the economic potential energy savings by micro-cogeneration.

Industry
Technical potential for cogeneration in the industry are large, with some 320 PJ of heat production estimated as being possible to provide with cogeneration. However, some 100 PJ of this concerns demand for direct heat rather than demand for steam or hot water. Application of cogeneration for the production of direct heat requires far-reaching integration of the cogeneration unit into the industrial process. Industrial producers often consider this as introducing too high a risk for process failure into the heart of their core-business. For this reason, even high incentives are unlikely to elicit large application of direct heat cogeneration.

In the industry, rejuvenation of the existing CHPs contributes to additional savings as well as expansion of capacity. Within the sector, competing options are limited to increased residual heat use. On the electricity market, existing cogeneration is unfavourably influenced by large price fluctuations, but new cogeneration may be more competitive in such circumstances. Electricity production of cogeneration will increase relative to heat production, as the share of newer installations increases. Savings may increase from a current 30 PJ to nearly 100 PJ in case of high incentives, equivalent to CO_2 prices of 100 €/ton CO_2. Without additional incentives, the savings may increase to over 50 PJ, but then they are mainly due to abandonment of older, less efficient CHP installations rather than expansion of CHP capacity. The economic potentials depend strongly on the development of energy prices. A combination of high gas prices and low coal prices is very unfavourable for CHP. Favourable electricity prices as such, but without discrimination between more and less efficient cogeneration may hinder the realisation of the savings due to rejuvenation.

Agriculture
In the agriculture, some 80 PJ of heat production is estimated to be the technical potential for cogeneration. However, for a large part of this potential alternative technologies may present the more attractive option in case of higher CO_2 prices or other generic incentives.

Agricultural cogeneration is generally very flexible, and thrives on electricity markets with large price fluctuations. Even in circumstances with large coal capacity and intermittent renewable capacity, agricultural CHP is likely to be very competitive. Nevertheless, projected growth is limited, as important competing heat generating options are required to meet the targets. Lifetimes of agricultural CHPs are limited, and before 2020, almost the entire capacity will be replaced anyway, even without specific incentives. Current savings are estimated to be some 12 PJ, and may rise to between 17 and 21 PJ. Generic incentives hardly increase savings by cogeneration, as the same incentives favour important competitors of cogeneration that will probably result in higher reductions of CO_2 emissions.

Services
The potentials in the services sectors are very uncertain. Data availability is very poor, and in addition, there are important alternatives for cogeneration. In newly constructed office buildings for example, the application of heat pumps combined with heat and cold storage in aquifers is more or less becoming a standard technology. Such technologies offer possibilities for much deeper CO_2 emissions reduction than possible with cogeneration. As such, higher incentives or more stringent standard are likely to elicit more application of alternative technologies rather than cogeneration. For the smaller buildings in the services sector, micro-CHP may play a role.

Households
New heat distribution networks become increasingly expensive, as new houses are very well insulated and heat demand per units decreases. For existing residential areas, the construction of new heat networks is extremely expensive. In the households, micro-CHP is the most important option, but mainly for existing houses. The cost-effectiveness of micro-CHP is the better as houses have higher demand, and are worse insulated. As a result, the potential for micro-CHP will become smaller as the insulation of existing houses progresses. This tendency is strengthened by the fact that some competing technologies are favoured by the energy use standards for new houses. Uncertainties are very high, and economic potentials may very between zero and 1 million houses equipped with micro-CHP in 2020. Given the uncertainties, it is not possible to specify the resulting energy savings

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Appendix A Reference efficiency values for separation production of heat and electricity in the Netherlands

Table A.1 *Reference efficiency values for separation production of electricity in the Netherlands*

[%]	1996 and before	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006-2011
Hard coal/coke	40.2	41	41.7	42.3	42.8	43.2	43.6	44	44.3	44.5	44.7
Wood fuels	25.5	26.8	28	29	30.1	30.9	31.6	32.2	32.7	33.1	33.5
Agricultural biomass	20.5	21.5	22.1	22.6	23.1	23.6	24	24.5	24.9	25.2	25.5
Biodegradable (municipal) waste	20.5	21.5	22.1	22.6	23.1	23.6	24	24.5	24.9	25.2	25.5
Non-renewable (municipal and industrial) waste	20.5	21.5	22.1	22.6	23.1	23.6	24	24.5	24.9	25.2	25.5
Oil (gas oil + residual fuel oil), LPG	40.2	41	41.7	42.3	42.8	43.2	43.6	44	44.3	44.5	44.7
Biofuels	40.2	41	41.7	42.3	42.8	43.2	43.6	44	44.3	44.5	44.7
Biodegradable waste	20.5	21.5	22.1	22.6	23.1	23.6	24	24.5	24.9	25.2	25.5
Non-renewable waste	20.5	21.5	22.1	22.6	23.1	23.6	24	24.5	24.9	25.2	25.5
Natural gas	50.5	50.9	51.3	51.6	51.9	52.2	52.4	52.6	52.8	52.9	53
Refinery gas/hydrogen	40.2	41	41.7	42.3	42.8	43.2	43.6	44	44.3	44.5	44.7
Biogas	37.2	38	38.8	39.5	40.1	40.6	41.1	41.5	41.9	42.2	42.5
Coke oven gas, blast furnace gas, other waste gases, recovered waste heat	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5	35.5

Table A.2 *Reference efficiency values for separation production of heat in the Netherlands*

	Steam (*) /hot water	Direct use of exhaust
Hard coal/coke	88,00	80,00
Wood fuels	86,00	78,00
Agricultural biomass	80,00	72,00
Biodegradable (municipal) waste	80,00	72,00
Non-renewable (municipal and industrial) waste	80,00	72,00
Oil (gas oil + residual fuel oil), LPG	89,00	81,00
Biofuels	89,00	81,00
Biodegradable waste	80,00	72,00
Non-renewable waste	80,00	72,00
Natural gas	90,00	82,00
Refinery gas/hydrogen	89,00	81,00
Biogas	70,00	62,00
Coke oven gas, blast furnace gas + other waste gases	80,00	72,00

Appendix B Calculation of savings by CHP directive and Dutch approach

The report specifies energy savings according to the definition of the CHP-directive, and according to the definition of the Protocol Monitoring en Energy-efficiency. Each method serves its own purposes, and the logic of this purpose dictates the approach followed. In order to prevent confusion, this appendix explains the two approaches.

1 The Directive definition serves the first place to determine how new cogeneration capacity compares with the alternative of separate generation built at the same time, applying the same fuels. However, it cannot be used to determine the contribution of cogeneration, among other components, to the development of energy use.

The savings of the directive are based on comparison with separate generation of heat and electricity with the same energy carriers. This gives a good indication of the effects of cogeneration as such, but disregards the fact that in practice the applied energy carriers for heat production and electricity generation might differ.

2 The PME has been developed for decomposing the development of energy use into its different constituents, since a specific reference starting year, 1995. In addition, it can be used to determine the contribution of a specific component between two different years. A consequence of this function is that the various constituents as calculated should add up to the total development of energy use as observed

As a result, it compares cogeneration, including new cogeneration, with fixed historic reference efficiencies for heat and electricity, based on the averages in 1995. For heat, the reference is almost entirely natural gas based, but for electricity, teh reference contains both coal based and natural gas based electricity generation. In this way, the PME accounts for the fact that in the Dutch situation, growth of CHP implicitly changes the fuel mix. However, a consequnce of the PME -approach is that the effects of fuel substitution and the actual savings due to cogeneration as opposed to separate generation are mixed up.

Another important characteristic is that the PME only discerns the savings by cogeneration in the end-use sector.

Appendix C Data sources and models

The potentials for cogeneration have been analysed using models from the Netherlands Energy Outlook Modelling System (NEOMS). The model Save production (Daniëls and Van Dril, 2007) simulates the development of CHP in industry, refineries, agriculture and services for a gives scenario of economic growth, energy prices and policies. In addition, it provides projections of industrial and agricultural heat demand. Other models provide the heat demand in the refineries (SERUM), services sectors (Save-services), households (SAWEC). The analysis on micro-cogeneration involves manual calculations, though it draws information from various models, especially SAWEC. The Powers model provides electricity prices. Save-production is the most important model for analysing the potentials of large-scale and small scale cogeneration. The other models are mainly important for determining the heat demand (SERUM, Save-services) or electricity prices. Currently, the application of micro-CHP is not calculated automatically by models from the NEOMS, but results from the SAWEC model are an important ingredient for the analysis of micro-CHP. The models of the NEOMS discern steam and hot water demand as opposed to the direct use of exhaust gases.

Save-production and Powers (Rijkers et al, 2001) are the most important models for cogeneration. Of the 210 PJ total heat production in 2006 by cogeneration, about 160 PJ falls in the domain of Save-production and the remainder falls in the domain of Powers. In broad lines, Save-production covers the cogeneration which is heat demand following, and powers covers the cogeneration for which the electricity market dominates the application.

SERUM
SERUM (Stienstra, 2007) simulates the operation of the Dutch refineries. Given a specified input mix of crudes and several other specifications, the model optimises the operation of Dutch refinery capacity to meet the required product mix against the lowest possible costs. The results include the energy use of the refineries, which allows calculation of the demand for steam and direct use of exhaust gases that may be provided with cogeneration. Save-production calculates the application of cogeneration in the refineries, based on the output of SERUM.

Save-services
The Save-services model simulates energy use in the services sector. Given various input parameters that describe among others economic growth, building surface, number of labourers, energy prices and policies, the model calculates the application of energy saving technologies and energy use. Among the results is the demand for space heating. While the model calculates the application of several space heating technologies such as boilers and heat pumps, Save-production calculates the application of cogeneration based on the output of Save-services.

Powers
Powers is the Dutch electricity market model. It simulates the application of the Dutch central power generation units, and its results include electricity prices and fuel consumption, among others. Apart from generating results on part of the cogeneration in its own right, it also provides peak and off-peak electricity prices, allowing Save-production to perform its calculations on the heat-following cogeneration potential.

Save-production
Save-production simulates the demand for electricity and heat in the industrial and agricultural sectors, and it simulates the application of cogeneration in the industry, refineries, agriculture and services. Important input data include economic and physical growth of sectors, energy prices and policies, and techno-economic data on savings technologies. Save-production is the

most important model for CHP, covering all CHP apart from micro-CHP and central power units.

Part of the data input is especially important for the CHP-simulation, and some data even exclusively serve the CHP-module. Techno-economic data on cogeneration types include investment number, power ranges, heat-power ratios. For each energy function discerned by the model[50], the database includes the ratio between demand for steam and demand for heat from exhaust gases, the average number of hours a year there is demand for heat and the average thermal power required on an individual location. For each energy function and separately for steam/hot water as opposed to exhaust gases, the database provides a technical limit for the application of CHP. For each sector the database specifies the ratio between the demand for electricity and the demand for heat. Data sources include the Icarus4 database(), energy statistics(), economic statistics and communications with sectoral representatives. For some data categories, expert estimates are very important. These are tested by calibration of the model results on reference points from the other data sources, and modified if necessary.

The model receives separate electricity prices for peak hours and off-peak hours from the Powers model, to allow calculation of profitable production hours.

The simulation of cogeneration includes investment decisions, operational decisions and the decision to abandon or upgrade cogeneration plants after their maximum production hours.

[50] Examples: *heating* in the horticulture, *naphtha cracking* in the petrochemical industry.

Appendix D Detailed results and assumptions on micro-CHP

Table D.1 *Degree of coverage of micro-CHP with warm tap water with the capacity of providing heat 16 hours a day*

	2010		2015		2020		2030	
	Heat demand for warm water tap							
	8550		8325		8100		8000	
micro CHP	Category C 6 kW thermal		Category C 6 kW thermal		Category B 3.2 kW thermal		Category A 2 kW thermal	
Heat demand for space heating [MJ]	Space heating [%]	Heating of tap water [%]	Space heating [%]	Heating of tap water [%]	Space heating [%]	Heating of tap water [%]	Space heating [%]	Heating of tap water [%]
60000	98	100	98	100	75	100	53	100
55000	99	100	99	100	79	100	57	100
50000	99	100	99	100	84	100	61	100
45000	100	100	100	100	88	100	66	100
40000	100	100	100	100	92	100	72	100
35000	100	100	100	100	96	100	78	100
30000	100	100	100	100	99	100	85	100
25000	100	100	100	100	100	100	92	100
20000	100	100	100	100	100	100	98	100
15000	100	100	100	100	100	100	100	100

Table D.2 *Variations in the sensitivity analyses*

Investment costs	
Assumed price [€]	-1500, -750, +750, +1500
Part delivered to the grid	
Assumed part [%]	-20, -10, +10, +20
Financial compensation	
Assumed compensation [€/GJ_e]	*50, *75, *125, *150

The sensitivity analyses for the Stirling motor (Figure D.1 - D.3) shows that 2010 payback times below 15 years require considerable cost decreases can be reached. For a 9 year payback time the costs additional to the reference technology have to decrease to € 1500. Such a strong reduction is only feasible with additional financial support of the government.[51] Lower amounts of electricity delivered to the grid and a higher financial compensation can lead to payback times (slightly) below 15 years. It can be concluded that in 2010 market penetration of the Stirling motor is only likely with considerable financial support. The amount of support will affect both the payback time, and the part of the building stock where the Stirling motor will be applied.

The 2020 sensitivity analyses for the Stirling (Figure D.4-D.6), shows that very low technology costs, low percentage of electricity to the grid and a higher financial compensation for the electricity, lead to payback times up to 5 years. However, also conditions for competing technologies can be more favorable[52]. Less favorable conditions still lead to payback times of 15 year or lower for at least part of the building stock, and in that case the Stirling is not competitive any-

[51] Next to financial support in 2008-2009 to realize economies of scale to reach a price of € 3000 in 2010, additional support will be needed of about € 1500 per micro CHP in 2010 to realize a payback time of 9 years.

[52] If the same sensitivity analysis is made for the UHR, the UHR is more sensitive on variations in investment costs. While both technologies have more or less the same payback times in 2020, a reduction of investment costs of € 750 (relative to assumptions in the text box) will lead to different payback times: micro CHP 6-11 years and UHR 2-6 years.

more to the UHR. So in 2020, the Stirling motor may be at a pair with the UHR, but only if economies of scale can be realized[53] and prices of the UHR will not further decrease.

In Figures D.7-D.9 of Appendix D on the fuel cell, lines diverge much more than in the figures on Stirling motors. This means that payback times for the fuel cell are much more sensitive to variations in assumptions than payback times for the Stirling motor. Although in Figure 7.4 the fuel cell has a payback time longer than its technical lifetime, lifetimes below 15 years are feasible under more favorable conditions. However, payback times will be - for the same variations - longer than that of the Stirling motor. For this reason it is expected that the penetration of the fuel cell in 2020 will be negligible. Other reasons that support this assumption is the fact that fuel cells will be come commercially available only in about 2015 and the (for existing dwellings) unfavourable ratio between thermal power and electric power of fuel cells.

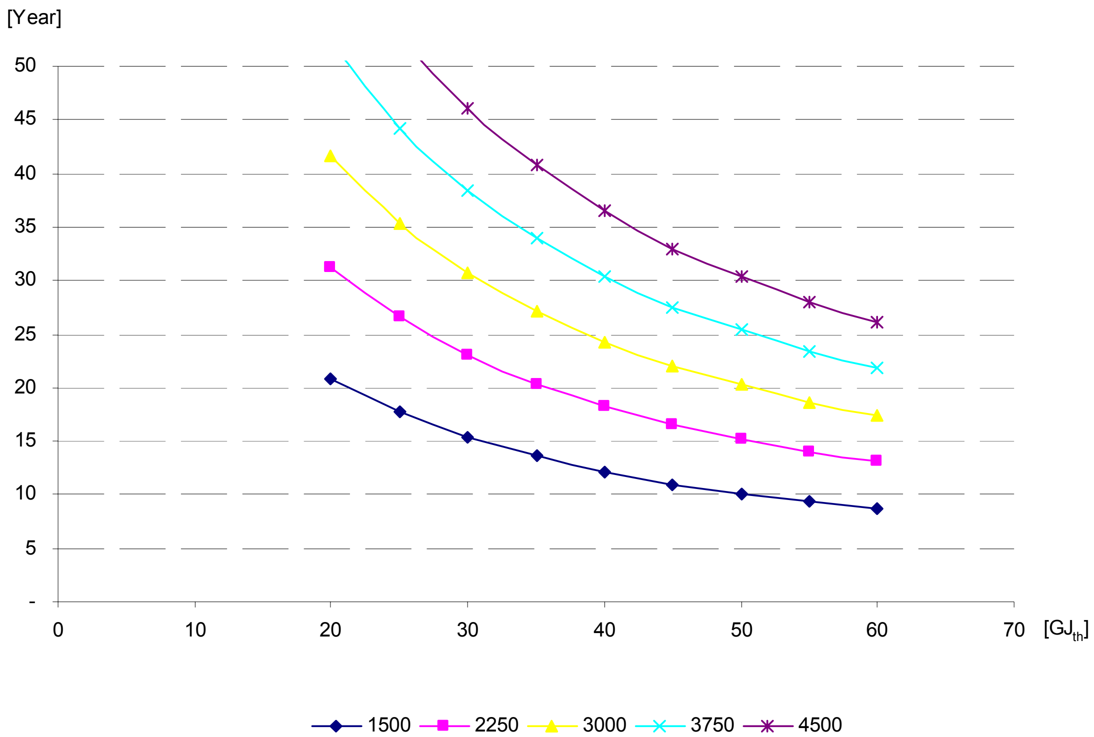

Figure D.1 *Payback times for different costs for Stirling motors (additional to the reference technology) in 2010*

[53] And thus financial support of the government has been realized also after 2010.

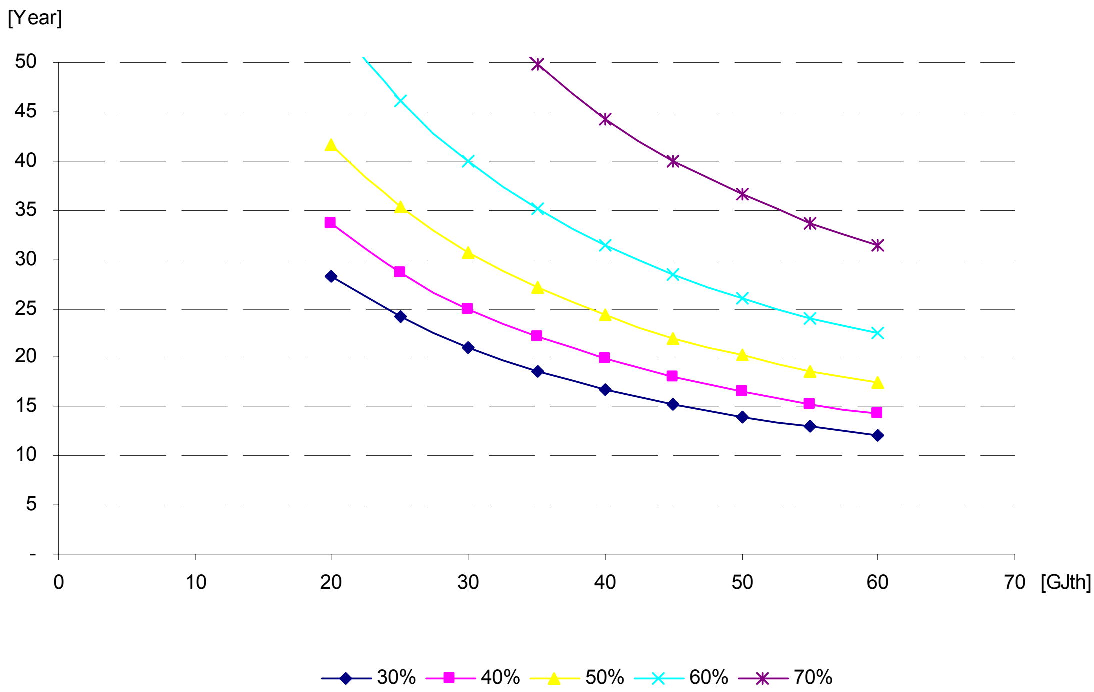

Figure D.2 *Payback times of Stirling motors for different amounts of electricity delivered to the grid in 2010*

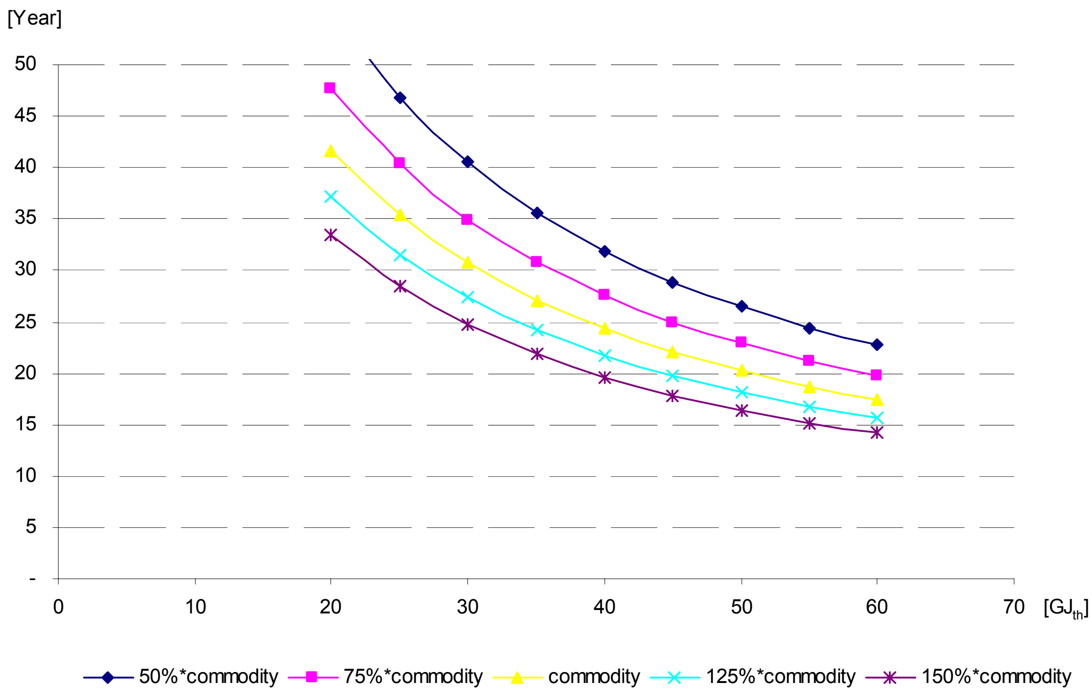

Figure D.3 *Payback times of Stirling motors for different financial compensation for electricity delivered to the grid in 2010*

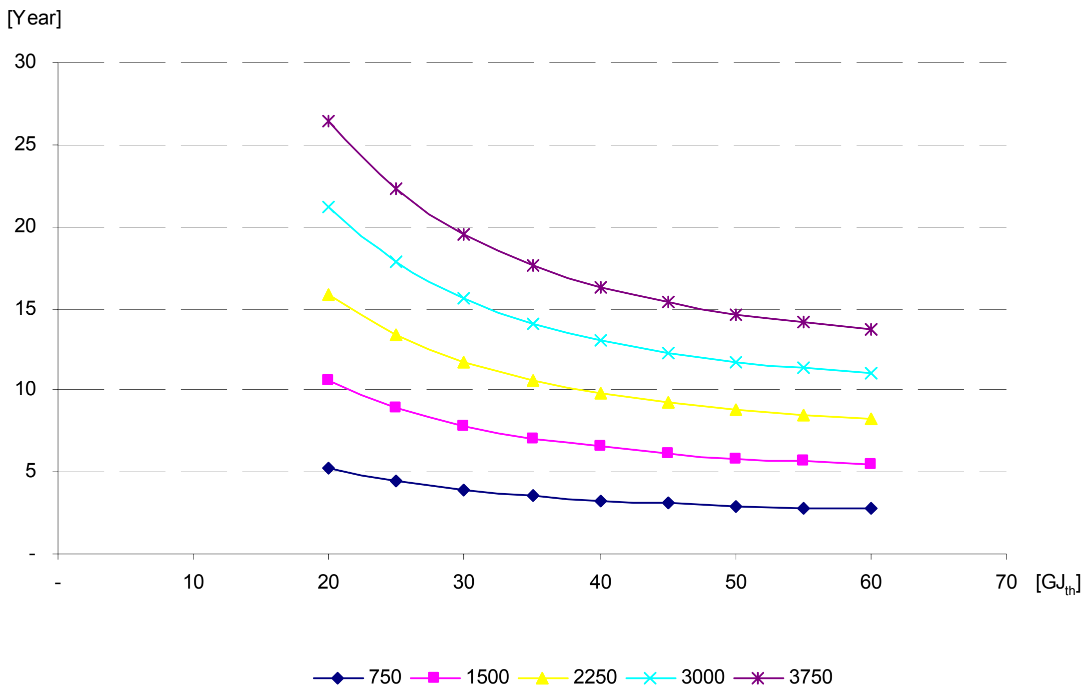

Figure D.4 *Payback times for different costs for Stirling motors (additional to the reference technology) in 2020*

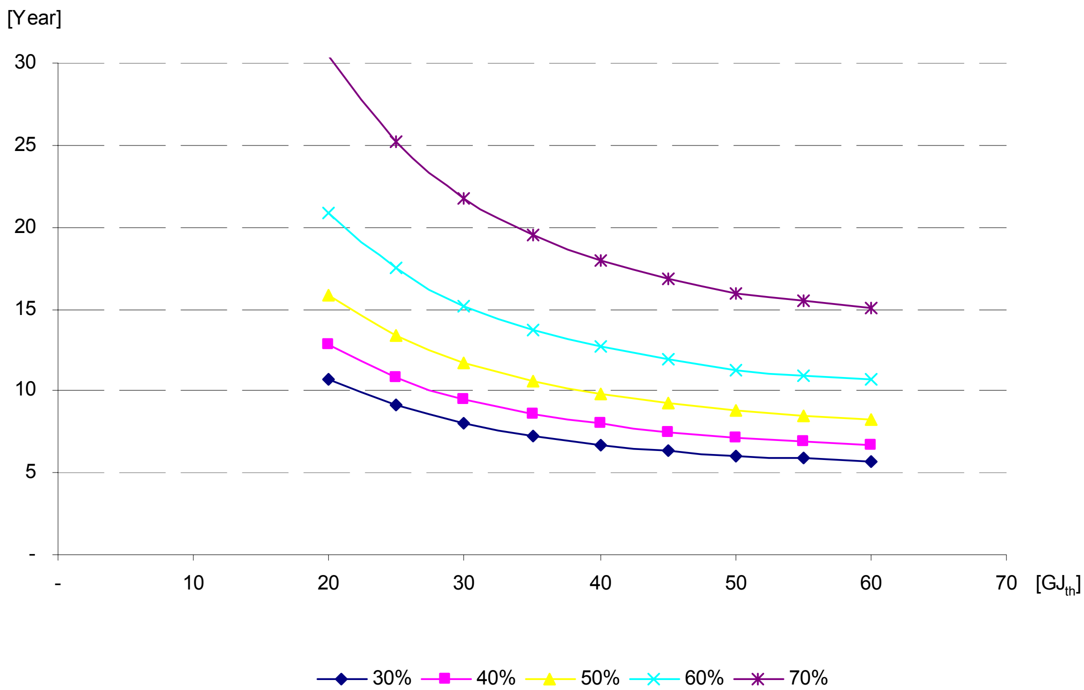

Figure D.5 *Payback times of Stirling motors for different amounts of electricity delivered to the grid in 2020*

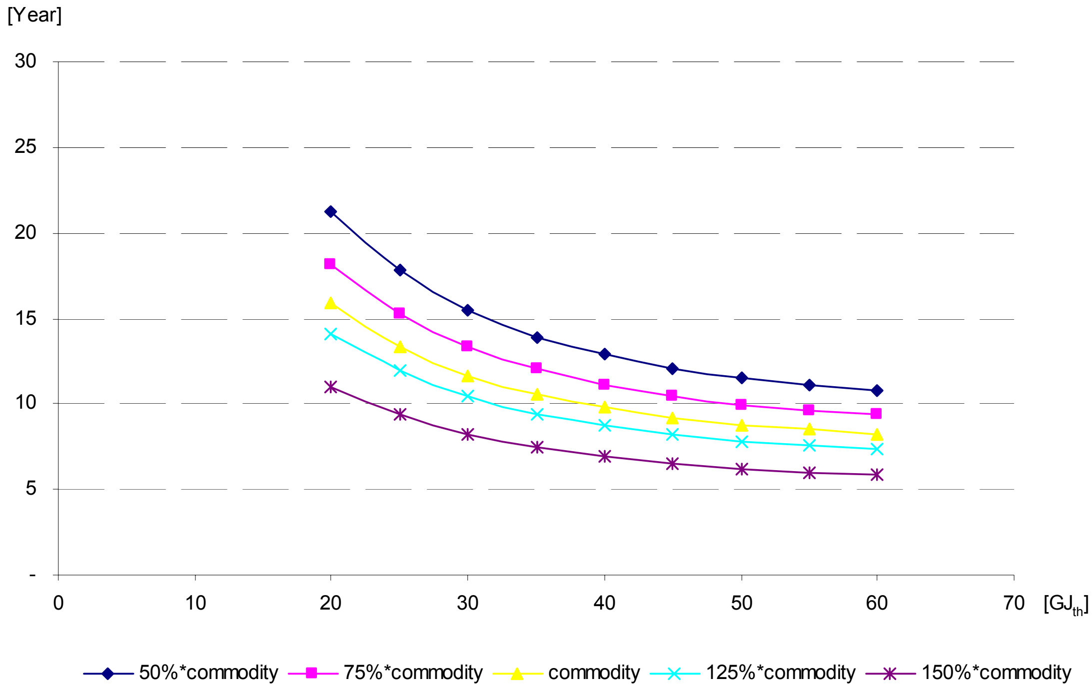

Figure D.6 *Payback times of Stirling motors for different financial compensation for electricity delivered to the grid in 2020*

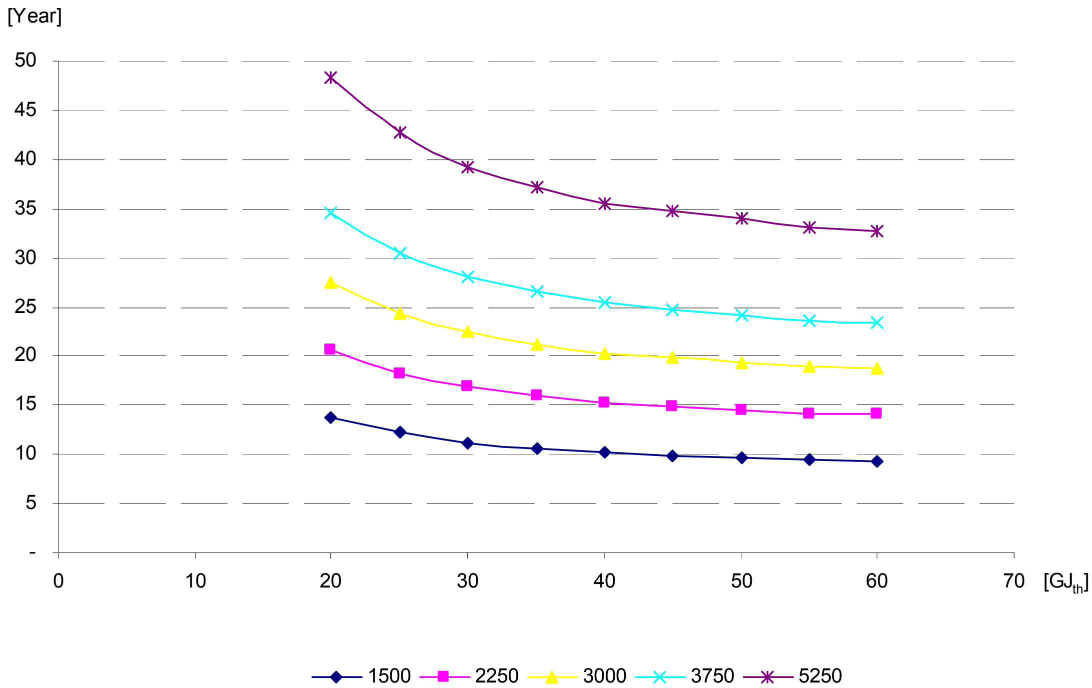

Figure D.7 *Payback times for different costs for fuel cells (additional to the reference technology) in 2020*

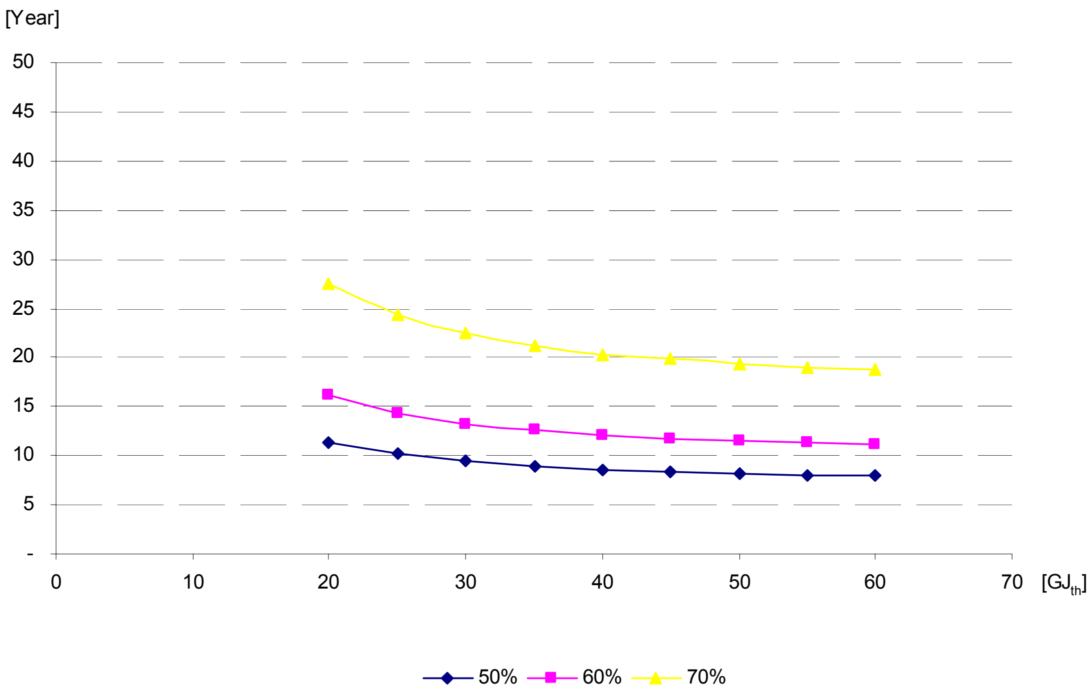

Figure D.8 *Payback times of fuel cells for different amounts of electricity delivered to the grid in 2020*

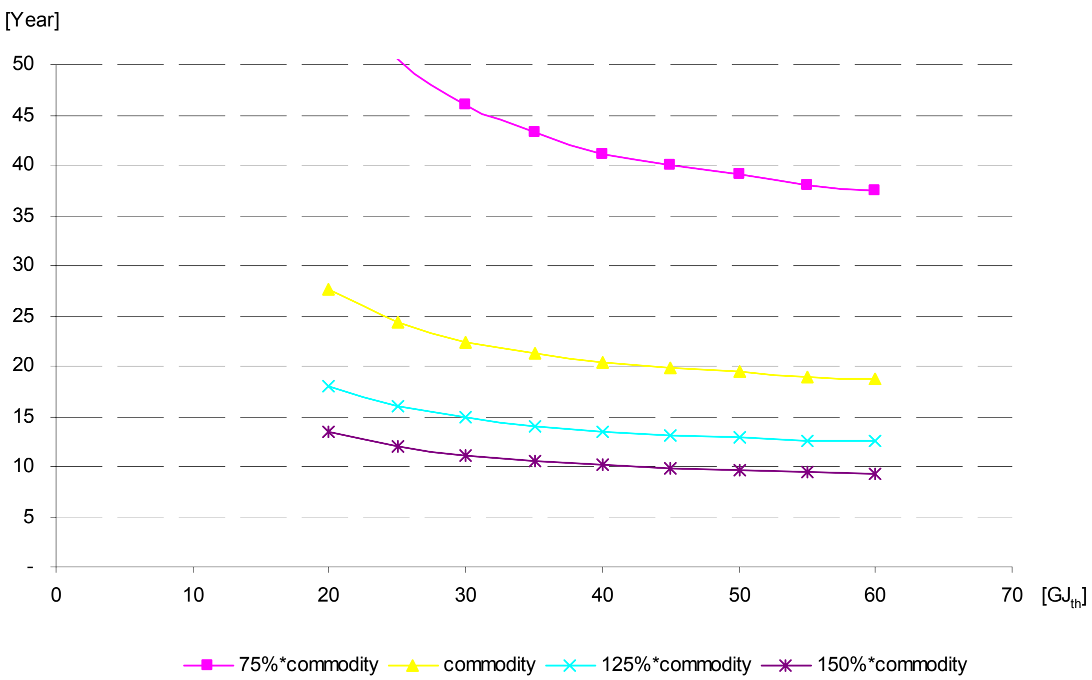

Figure D.9 *Payback times of fuel cells for different financial compensation for electricity delivered to the grid in 2020*

Appendix E Terminology

Table E.1 *Explanation of terminology for CHP installation types*

Dutch terminology (as used by CBS)	English terminology
Gasmotor	Gas motor: piston engines using natural gas or fermentation gas as fuel
Stoomturbine	Steam turbine: steam back pressure turbines, including coal-fueled installations. CBS does not include steam condensing extraction turbines in the CHP statistics.
Steg-eenheid	CCGT: Combined Cycle Gas Turbine with heat recovery
Gasturbine	Gas turbine: gas turbine with heat recovery
Overige installaties	Other installations: this includes diesel engines, gas expansion turbines and dual fuel motors

Appendix F Calculated energy savings for historical years

Table F.2 *Energy savings for steam turbines (central)*

Steam turbine, central	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	106.0	44.0	4.9	8.1	7
1999	83.1	32.6	4.9	2.8	3
2000	93.6	36.9	5.5	3.0	3
2001	101.8	40.4	5.4	2.9	3
2002	101.1	39.9	5.0	2.3	2
2003	93.4	36.7	4.8	1.3	1
2004	96.5	38.5	4.9	2.2	2
2005	99.1	39.4	4.7	1.8	2
2006	104.3	42.0	4.8	2.0	2

Table F.3 *Energy savings for CCGT (central)*

CCGT, central	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	87.5	38.6	20.5	15.7	15
1999	85.3	37.3	18.5	12.5	13
2000	96.9	40.4	27.0	16.7	15
2001	102.1	43.1	26.0	14.7	13
2002	101.9	43.6	26.9	17.7	15
2003	105.1	43.8	27.9	16.5	14
2004	126.6	57.3	29.2	22.4	15
2005	135.0	63.0	29.0	25.0	16
2006	130.9	59.1	29.8	21.4	14

Table F.4 *Energy savings for gas turbines (central)*

Gas turbine, central	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	1.5	0.4	0.8	0.2	12
1999	1.5	0.5	0.6	0.3	15
2000	0.3	0.1	0.1	0.0	12
2001	1.5	0.4	0.8	0.2	12
2002	1.3	0.3	0.7	0.2	11
2003	3.6	0.9	1.8	0.3	7
2004	15.3	3.6	8.1	0.7	4
2005	15.7	3.4	9.3	1.3	7
2006	12.3	2.9	7.8	2.2	15

Table F.5 *Energy savings for gas engines (decentral)*

Gas engine, decentral	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	56.0	18.6	27.4	13.7	20
1999	58.7	19.4	28.5	13.7	19
2000	58.9	19.7	28.3	13.7	19
2001	56.2	18.6	26.7	12.6	18
2002	55.3	18.3	26.4	12.4	18
2003	54.8	18.4	26.3	13.0	19
2004	52.9	17.8	25.9	13.0	20
2005	56.4	19.0	28.2	14.4	20
2006	65.6	22.5	33.5	18.1	22

Table F.6 *Energy savings for steam turbines (decentral)*

Steam turbine, decentral	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	47.8	5.4	33.4	4.8	9
1999	51.2	5.9	36.6	6.7	12
2000	50.7	5.9	36.0	6.7	12
2001	49.0	5.7	34.1	5.7	10
2002	49.9	5.6	35.1	5.9	11
2003	48.9	5.6	34.6	6.1	11
2004	46.6	5.3	33.2	5.9	11
2005	53.4	6.6	31.6	1.1	2
2006	70.9	10.1	32.4	-4.7	-7

Table F.7 *Energy savings for CCGT (decentral)*

CCGT, decentral	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	139.2	44.2	63.3	26.2	16
1999	140.0	45.6	59.7	22.7	14
2000	136.2	45.2	60.8	26.8	16
2001	149.1	51.4	58.8	24.5	14
2002	147.2	50.2	61.2	26.2	15
2003	146.1	50.6	60.1	27.4	16
2004	148.3	51.1	59.1	25.1	14
2005	143.1	48.7	59.0	25.3	15
2006	133.9	44.7	56.4	22.8	15

Table F.8 *Energy savings for gas turbines (decentral)*

Gas turbine, decentral	Total energy input [PJ]	Electricity production [PJ]	Steam/heat production [PJ]	Energy savings [PJ]	Savings compared to reference [%]
1998	98.4	23.1	58.3	19.1	16
1999	97.7	23.3	57.3	18.9	16
2000	101.8	23.4	58.8	16.8	14
2001	98.6	21.8	58.6	16.5	14
2002	92.4	20.8	55.4	16.2	15
2003	94.4	21.0	55.7	14.1	13
2004	92.0	20.3	54.5	13.4	13
2005	94.1	19.9	58.1	14.9	14
2006	90.1	19.1	54.9	13.3	13