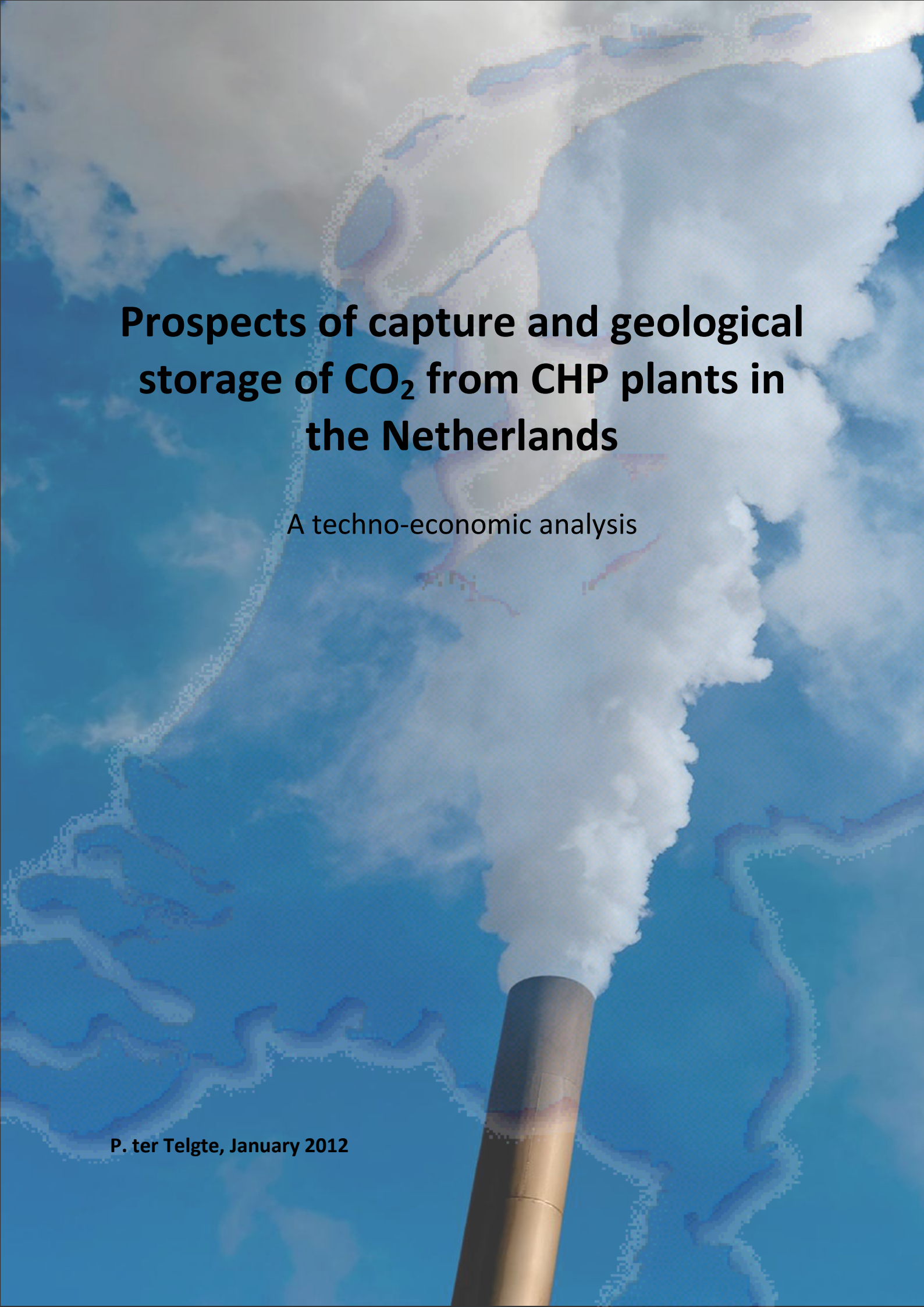




Prospects of capture and geological storage of CO₂ from CHP plants in the Netherlands

A techno-economic analysis

P. ter Telgte, January 2012

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Abstract

This study provides insight in the potential of combined heat and power plants combined with carbon capture technology (CHP-CCS). An overview is presented of the different CHP technologies and their applications in the Netherlands. This study identifies combined cycles and gas turbines as the most suitable CHP technologies to apply CCS to, and the chemical sector as the most feasible sector for CHP-CCS application. Different carbon capture technologies are assessed to show their suitability for CHP-CCS application. The suitable technologies identified are: Post combustion absorption (amines or chilled ammonia), Auto thermal reformer, auto thermal reformer sorption enhanced-water gas shift, and chemical looping combustion.

In a quantitative analysis the costs of CCS application to typical Dutch CHP are calculated. The costs of avoided CO₂ emissions are 81-306 €/tCO₂ in 2030, and 51-240 €/tCO₂ in 2050. The high costs and operational difficulties make the CHP-CCS compared to other CCS applications less feasible, CHP-CCS is therefore expected to be one of the last CCS applications to be applied.

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Table of Contents

1.	Introduction.....	1
2.	Method overview	3
2.1	CHP plants.....	3
2.2	Carbon capture technologies	4
2.3	CHP-CCS combination.....	6
2.4	Potential CHP-CCS in 2030 and 2050.....	10
3.	Data collection.....	16
3.1	General calculation data.....	16
3.2	CHP data	17
3.3	Carbon capture data.....	19
3.4	Reference case data	25
3.5	Sensitivity analysis	27
4.	Combined heat and power plants	28
4.1	CHP technologies.....	29
4.2	Overview characteristics CHP technologies	39
5.	CHP in the Netherlands	41
5.1	CHP application in different sectors	42
5.2	Role of CHP in different sectors.....	44
6.	CO ₂ capture technologies	49
6.1	Post combustion technologies	49
6.2	Pre combustion.....	52
6.3	Oxy-fuel carbon capture	55
6.4	Operability of capture principles	62
6.5	CO ₂ capture technology summary.....	64
6.6	Carbon capture and Boilers and Furnaces.....	67
7.	CHP and Capture technology combined.....	68
7.1	CHP-CCS technology match	68
7.2	CHP-CCS per sector.....	71
8.	Results quantitative analysis	75
8.1	Results quantitative analysis CHP-CCS cases.....	75
8.2	Sensitivity analysis	82
8.3	Results quantitative analysis CHP-CCS reference.....	85
8.4	Prospects of CHP-CCS in 2030 and 2050	89
9.	Discussion	91
9.1	Data limitations and methodology.....	91
9.2	Research context and comparison with other studies	92
10.	Conclusions and recommendations	96
10.1	Conclusions.....	96
10.2	Recommendations for further research	99

11. References.....	100
Appendix A - Save production model.....	A
Appendix B – Detailed cost overview CHP-CCS options 2030 and 2050	C
Appendix C – CHP(-CCS) literature overview	D

Table of figures

Figure 1. Illustration of methodology steps	3
Figure 2. CHP plant options.....	7
Figure 3. System boundary CHP-CCS calculations.....	8
Figure 4. Schematic view of CO ₂ transport.....	9
Figure 5. System boundary Boiler/Heater (with CCS) Industrial perspective	12
Figure 6. Approximate lowest cost oxygen supply methods - new plants (Universal Industrial Gases 2010)	13
Figure 7. Heat requirement post combustion capture process for different CO ₂ concentrations in 2010 (Egberts et al. 2003)	20
Figure 8. CO ₂ concentration cost factor (Egberts et al. 2003).....	22
Figure 9. CO ₂ transport costs small scale (Kuramochi 2011)	24
Figure 10. Energy saving potential CHP plant (GasTerra 2008)	28
Figure 11. Closed loop heat recovery of gas engines (EPA 2002)	29
Figure 12. Heat recovery by a gas turbine (EPA 2002).....	31
Figure 13. Non-condensing back pressure turbine and extraction turbine (EPA, 2002).....	32
Figure 14. Back pressure CCGT (COGEN Vlaanderen 2006)	33
Figure 15. Fuel cell as CHP schematically (BELCOGEN, 2004)	35
Figure 16. Fuel cell configuration planar (left) and tubular (right)	36
Figure 17. Schematic picture of a Stirling engine (Hirata 1997).....	37
Figure 18. Installed Electric capacity per CHP technology (CBS, 2011)	41
Figure 19. Installed capacity (MW _e) per sector group (left); Electric capacity installed per sector (MW _e) (CBS, 2010) (right)	43
Figure 20. Simplified flow diagram post combustion capture (Kvamsdal et al. 2007).....	49
Figure 21. Simplified flow diagram MSR-H2 (Kvamsdal et al. 2007).....	53
Figure 22. Simplified flow diagram ATR (Kvamsdal et al. 2007).....	54
Figure 23. Simplified flow diagram ATR (IEA GHG 2007)	54
Figure 24. Simplified flow diagram Matiant concept (Kvamsdal et al. 2007)	57
Figure 25. Simplified flow diagram Water cycle (Kvamsdal et al. 2007)	57
Figure 26. Simplified flow diagram Graz cycle (Kvamsdal et al. 2007)	58
Figure 27. Simplified flow diagram AZEP (Kvamsdal et al. 2007).....	59
Figure 28. Simplified flow diagram CLC (Kvamsdal et al. 2007)	60
Figure 29. Simplified flow diagram SOFC-CC (Fontell et al. 2004)	61
Figure 30. Schematically SOFC cell (Harmelen et al. 2008).....	61
Figure 31. Schematic view of an air and oxy-fuel firing boiler (Simmonds and Walker 2005).....	67
Figure 32. Development of heat demand (PJ) per sector in the Netherlands	75
Figure 33. Specification of capture costs in 2030	78
Figure 34. Specification of capture costs in 2050	78
Figure 35. Cost supply curve 2030	80
Figure 36. Cost supply curve 2050	81
Figure 37. Cost (€/tCO ₂) sensitivity to Electricity/Gas price (left), CCS-investment costs (mid), and the load hours (right) of the CCGT-CHP and GT-CHP chemistry cases in 2030 and 2050	83
Figure 38. Sensitivity analysis CHP-CCS CCGT (top) and GT (bottom) in 2030 (left) and 2050 (right)	84
Figure 39. Analysis sensitivity CHP and reference cases to Gas/Electricity price ratio to CCGT (top) and GT (bottom) in 2030 (left) and 2050 (right).....	87
Figure 40. CO ₂ avoidance costs reported in literature from different CO ₂ mitigation technologies (the numbers refer to Table 1), the most left bars shows the CO ₂ mitigation costs from this study of the chemical industry cases in 2030 and 2050.	95
Figure 41. Schematic overview of NEOMS (Wetzels To be published)	A

Table of tables

Table 1. Overview capture technologies compared	4
Table 2. Comparison Criteria for capture technologies	6
Table 3. Annual growth of Gross value added per sector (Daniëls and Kruitwagen 2010)	11
Table 4. General technical and cost parameters.....	16
Table 5. CHP cost development compared to 2010 values (IEA 2010a)	18
Table 6. CHP technical and cost parameters 2030 and 2050	19
Table 7. Technical parameters of CO ₂ capture 2030 and 2050	21
Table 8. Cost parameters of CO ₂ capture 2030 and 2050	25
Table 9. General technical and cost parameters.....	26
Table 10. Parameters in sensitivity analysis	27
Table 11. Characteristics gas engine CHP	30
Table 12. Characteristics gas turbine CHP	31
Table 13. Characteristics steam turbine CHP	33
Table 14. Characteristics combined cycle CHP	34
Table 15. Characteristics fuel cell CHP	37
Table 16. Characteristics Stirling engine CHP	38
Table 17. Characteristics organic rankine cycle CHP	39
Table 18. Characteristics per CHP technology	40
Table 19. Average size of CHP per technology in 2009 (CBS, 2010)	42
Table 20. Number of CHP plants and installed capacity (MWe) per sector in the Netherlands in 2009	42
Table 21. Characteristics CHP plants per sector in 2009 (CBS, 2010)	43
Table 22. Heat distribution per sector in % (Spoelstra 2005)	43
Table 23. Maximum full load hours per CHP technology per sector	44
Table 24. Number of plants and average capacity for agricultural sector (electrical and thermal) (CBS, 2010) ..	45
Table 25. Number of plants and average capacity for chemistry sector (electrical and thermal) (CBS, 2010)	46
Table 26. Number of plants and average capacity for refineries and mining sector (electrical and thermal) (CBS 2010)	46
Table 27. Number of plants and average capacity for paper sector (electrical and thermal) (CBS, 2010)	47
Table 28. Number of plants and average capacity for food industry sector (electrical and thermal) (CBS, 2010) ..	47
Table 29. Number of plants and average capacity for other industry sector (electrical and thermal) (CBS, 2010)	47
Table 30. Number of plants and average capacity for built environment (electrical and thermal) (CBS, 2010) ..	48
Table 31. Number of plants and average capacity for waste incineration sector (electrical and thermal) (CBS, 2010)	48
Table 32. Scores of characteristics per capture technology	65
Table 33. CHP and capture technologies match table	70
Table 34. Score rating of the viability of CHP-CCS	73
Table 35. Overview of CHP-CCS viability per sector	74
Table 36. CHP-CCS cases for quantitative analysis	74
Table 37. Results quantitative analysis 2030	77
Table 38. Results quantitative analysis 2050	77
Table 39. CO ₂ prices used in World Energy Outlook 2010 (IEA 2010d) ¹	81
Table 40. Gas and electricity price used in high and low cost scenario	82
Table 41. Comparison reference cases CCGT in 2030 – Industry perspective	85
Table 42. NPV (M€) for different CHP-CCS options compared to the base, reference and alternative cases	85
Table 43. Comparison reference cases CCGT and GT (2030 and 2050) – Mitigation perspective	88
Table 45. Mitigation costs comparison of alternative mitigation technologies for heat sources, literature values	95

Abbreviations

ASU	Air Separation Unit
ATR	Auto Thermal Reforming
AZEP	Advanced Zero Emission Power Plant
Boiler-CC	Boiler with Carbon Capture
CBS	Central Bureau of Statistics of the Netherlands
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CHP-CCS	Combined Heat and Power with Carbon Capture
CLC	Chemical Looping Combustion
COE	Costs of Electricity (€/kWh)
ECN	Energy Research Centre of the Netherlands
GE	Gas Engine
GT	Gas turbine
HPR	Heat Power ratio
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
ITM	Ion Transport Membranes
MCFC	Molten Carbonate Fuel Cell
MCM	Mixed Conducting Membrane
MSR-H ₂	Membrane Steam Reforming H ₂ production
NG	Natural Gas
NGCC	Natural Gas Combined Cycle (centralized power plants)
NGCC-CC	Natural Gas Combined Cycle-Carbon Capture (centralized power plants)
NPV	Net Present Value (M€)
OCM	Integrated oxygen separation membrane
ORC	Organic Rankine Cycle
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyze Cell
SOFC	Solid Oxide Fuel Cell
SOFC-CC	Solid Oxide Fuel Cell with Carbon Capture
SE-WGS	Sorption Enhanced Water Gas Shift
ST	Steam turbine
(V)PSA	(Vacuum) Pressure Swing absorption
tCO ₂	tonne CO ₂

1. Introduction

To prevent dangerous anthropogenic interference with the climate system greenhouse gas concentrations in the atmosphere need to be stabilized (UN 1992). Many countries agreed to reduce greenhouse gas emissions at least by 8% in 2012 compared to 1990 level to reach stabilization of greenhouse gases in the atmosphere, as stated in the Kyoto protocol (1997) (UNFCCC 1997). In addition to the Kyoto protocol the European Union aims to keep the global temperature increase below 2°C. To achieve this goal, a CO₂ emission reduction of 50-80% is required up until the year 2050 (compared to 2000) (IPCC 2007), (EU Commission 2008).

Despite these ambitious greenhouse gas emission reduction targets, fossil fuels will likely maintain their dominance in the coming decades (IEA 2010b). A reduction of greenhouse gas emissions can be enabled by applying CO₂ capture and Storage (CCS). CCS is the capture of CO₂ from stationary sources (e.g. power plants) and the transportation towards geological fields where it can be stored (e.g. the deep ocean or geological reservoirs) (Damen et al. 2006, IPCC 2005).

It is most cost-effective to apply CCS to a large point source of CO₂, due to the economies of scale (e.g. coal fired power plants or natural gas combined cycle (NGCC)) (Kuramochi et al. In Press). However, the trend in power supply worldwide is decentralization. The share of decentralized systems of the additional yearly installed capacity grew from 13% in 2001 up to 36% in 2006 (WADE, 2006; Kaundinya, et al. 2009). The decentralization of power supply is mainly caused by the out roll of fossil fuel-fired combined heat and power (CHP) plants (in some cases the CHP plant is biomass fired), but also because of the implementation of renewable energy sources (e.g. solar panels, wind turbines, small and medium hydropower systems). The advantage of a CHP plant is the usage of the heat generated by power production, which leads to an overall higher efficiency compared to producing heat and power separately (COGEN 2010). Instead of wasting the heat it is used in for district heating or industrial purposes. Even though the technology is efficient, it still emits CO₂. In case society aims to constrain greenhouse gas emissions to very low levels, decentralized CHPs combined with CCS have to be considered as an emission reduction option. In case of a stringent CO₂ emission policy, COGEN (Trade Organization for the Promotion of Cogeneration) expects a large penetration of CHP-CCS in the energy market to balance intermittent renewable technologies in a non CO₂-intensive way (COGEN, 2010).

Several studies on the techno-economic performance of CHP-CCS plants have been carried out. Kuramochi et al. (2010) made a techno-economic analysis of post-combustion CO₂ capture from industrial NGCC CHP (100-400 MW_e). They concluded that post-combustion CO₂ capture from medium-scale (100-400 MW_e) industrial CHPs may become more economical than the post-combustion capture from the reference NGCC in the early stages of CCS deployment. Furthermore, Kuramochi et al. (2009) did a techno-economic analysis of CO₂ capture from a SOFC (Solid Oxide Fuel Cell) CHP plant. SOFC CCS is identified as a promising option in case the membrane price will be lower and a CO₂ price will be introduced. Solli et al. (2009) did an evaluation of different refinery gas fuelled CHP options delivering heat and power to a refinery. They compared post combustion, and pre-combustion technologies (Auto Thermal Reforming (ATR) and Steam Methane Reforming (SMR)). They concluded that pre combustion options (ATR more than SMR) show lower costs in case of a high valuation of heat, whereas the post combustion performs better in case of a high electricity price¹.

Kvamsdal et al. (2006) classifies the different capture technologies for gas turbine cycles on basis of the operational challenges. The classification is based on a qualitative analysis assessing the

¹ In Appendix C a more extensive literature overview is given.

technological maturity of the subsystems, and the amount of recycles¹ per technology. Kvamsdal et al. (2007) make a quantitative comparison of the different capture technologies, in which is shown that capture cycles based on new technologies (membrane separation reformer (MSR-H2), solid oxide fuel cell with gas turbine (SOFC-GT), and chemical looping combustion (CLC)) have the highest efficiencies and lowest emissions. Some literature focuses on operational performance of the capture technologies. Kvamsdal et al. (2009) makes a start by designing a dynamic model to assess the effect of fluctuating load on a CO₂ absorber; however, further modeling is required to investigate the flexibility of the whole capture system. Naqvi et al. (2007) shows that the theoretical part load behavior of the chemical looping combustion (CLC) combined cycle is promising compared to conventional combined cycles.

However, these studies do not give insights into the techno-economic performance of this technology on a country level. Such insights can be helpful for governments to identify the potential of this CO₂ mitigation technology in its country, thereby enabling governments to implement more effective policies in order to reach mitigation targets. In the Netherlands, CHP is already applied on a large scale. In 2008, about 30% of the installed power plants were CHP plants². Therefore, the CO₂ emission reduction of applying CCS technology to CHP in the Netherlands seems to have potential, which results in the following research question:

What is the techno-economical potential for CCS in CHP plants in the Netherlands in the medium (2030) and long term (2050)?

To answer this research question several sub-questions are formulated.

- Which CHP technologies are installed in the Netherlands, and in which sectors?
- Which CO₂ capture technologies for CHP plants are expected to become available in the coming decades?
- How is the CHP-CCS combination determined by the following CHP characteristics: capacity, load factor, type of sector applied, heat-power ratio and required flexibility?
- What are the costs of CHP-CCS in the Netherlands in the medium and long term?
- What is the potential in terms tonne avoided CO₂ of CHP-CCS in the Netherlands in medium and long term?

The research is carried out as follows. First, the different CHP technologies and their development in the Netherlands are studied in order to estimate the theoretical potential of CHP-CCS. Second, the applications of the different CHP technologies in the Netherlands are investigated. Third, for different CO₂ capture technologies it is assessed to what extent they can match the characteristics of the different CHP technologies. Based on these qualitative analyses a technology match of CHP-CCS is made and different typical cases for different CHP applications are defined. Fourth, in the quantitative analysis the efficiencies, amount of captured CO₂ and the CO₂ avoidance costs are calculated. This will result in a cost supply curve for 2030 and 2050. Based on these curves, an expected CO₂ price, and the qualitative insight in the CHP-CCS technology match, the techno-economical potential of CHP-CCS in the Netherlands is determined.

¹ Exhaust gases are reused in the combustion chamber to control the combustion temperature

² The number of CHP plants excludes centralized power plants, as defined by CBS (see chapter 2.1), e.g. the Amer central is excluded (ECN 2010)

2. Method overview

By making a qualitative analysis of the possible match between CHP and CO₂ capture technologies and quantifying costs and efficiencies, the potential of CCS application to CHP in the Netherlands is estimated for 2030 and 2050. The focus of this study is on decentralized CHP plants. The central CHP plants in the electricity sector are excluded, because power plant CHP-CCS is comparable to other (large scale) gas power plants. Many other studies include large scale CCGT-CCS options (Damen et al. 2006, IEA 2010a, Peeters et al. 2007, Seebregts and Groenenberg 2009, ZEP 2011a, Booth and van Os 2011, Sipöcz et al. 2011). The method consists of several steps as shown in Figure 1; first an overview of the CHP technology is given, the second step focuses on the carbon capture technologies, the third step contains the combination of CHP and capture technologies, the concluding step presents the CHP-CCS potential in 2030 and 2050.

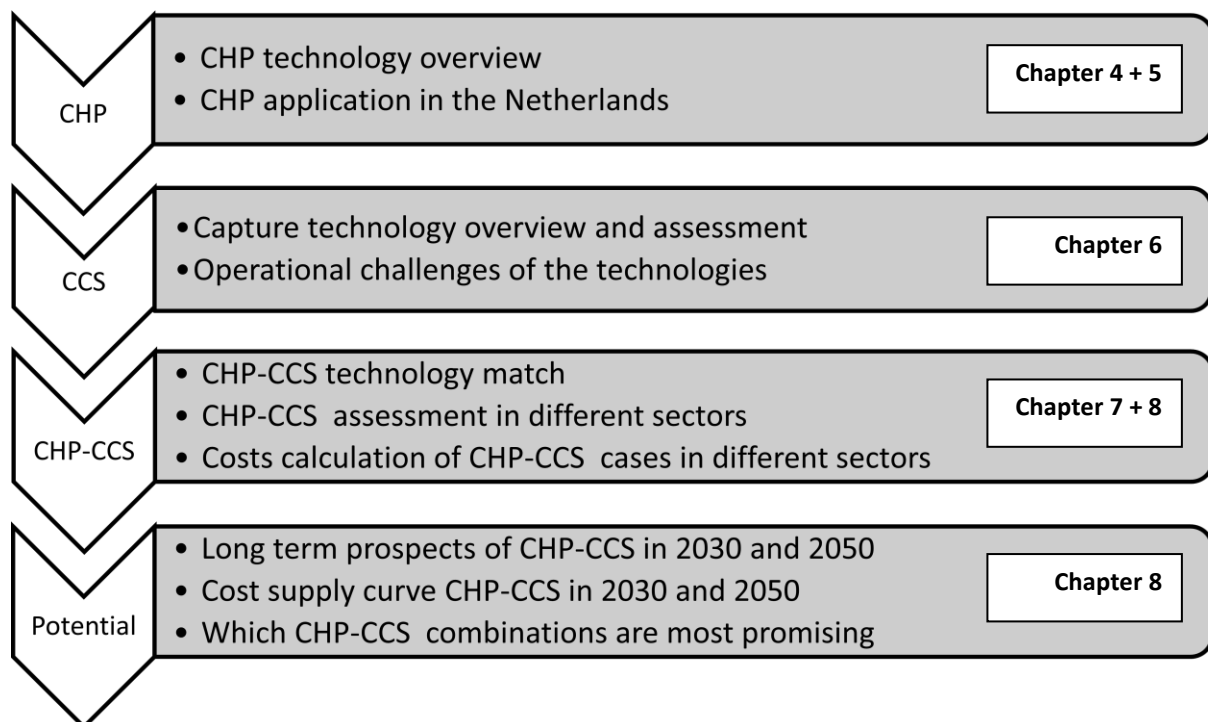


Figure 1. Illustration of methodology steps

2.1 CHP plants

In step 1 an inventory is made of the characteristics of the four main CHP technologies currently applied (gas engine (GE), gas turbine (GT), steam turbine (ST) and combined cycle gas turbine (CCGT)). Also several upcoming technologies (Organic Rankine Cycle, SOFC, Stirling engine) are described. Subsequently, an overview of the current application of those technologies in different sectors is given. The main reason for using a CHP and the most important usage characteristics (type of heat, (changeability of) HPR, continuous/peak load/back up power, load hours) are described.

This first step also includes an overview of the CHP plants installed in the Netherlands based on a literature study. Larger CHP plants are identified individually; the smaller plants are grouped, and listed with average, standardized values, because specific values of those plants were not found. Because the main basis of the CHP inventory is CBS data, the same de-central CHP definition as defined by CBS is used to prevent overlap of a list of centralized power stations and a list of the Dutch CHP plants. The definition used is: a centralized CHP plant delivers regularly to the high voltage grid (110 kV); the decentralized CHP plants do not.

Based on the list of currently installed CHP plants installed CHP capacity in the future is calculated by a simulation model, Save production, developed by ECN. The Save production model is an energy simulation model for the Dutch industry and agriculture. The model is designed to gain insight into the expected energy use and application of energy saving technologies and CHP plants in the industrial and agricultural sectors. It is based on a bottom-up approach, in which energy consumption is disaggregated into different fuels, industrial sectors, and energy technologies. In Save production a separate CHP module is used, in which several subsectors, energy carriers, CHP types, and individual installations are identified. The model is discussed in more detail in Appendix A - Save production model.

2.2 Carbon capture technologies

In the second step the main characteristics of different CO₂ capture technologies are given. Eleven capture configurations are selected which will most likely be developed in the coming decades. The technologies are grouped per capture principle; post combustion, oxy-fuel combustion and pre combustion (see for overview Table 1).

Table 1. Overview capture technologies compared

Post combustion	Oxy-fuel combustion	Pre combustion
Amine absorption	Matiant cycle	Auto Thermal Reformer
Chilled ammonia absorption	Graz cycle	Sorption Enhanced Water Gas Shift
(Membranes)	Water cycle	Membrane Steam Reformer
(Cryogenic distillation)	Advanced Zero Emission Power plant	
	Chemical Loop Combustion	
	Solid Oxide Fuel Cell-CC	

Post combustion technologies

In the study of Olijare (2010) a detailed overview of different post combustion capture technologies is given. Theoretically four different mechanisms can be used for post combustion CO₂ capture: absorption, adsorption, cryogenics and membranes. The most suitable separation mechanism for CHPs is chemical absorption, because the flue gas of CHP plants has a low partial pressure of CO₂ (3-10%) and contains a large quantity of impurities (NO_x) and incondensable gases (O₂) (Olijare 2010). Therefore two chemical absorption technologies are selected, amine absorption, currently the most applied technology, and chilled ammonia absorption, a promising absorption technology.

Oxy-fuel combustion technologies

In the IPCC carbon capture report (IPCC 2005) two main categories of oxy-fuel combustion are identified, direct combustion and indirect combustion. Three direct combustion cycles are taken into account: Matiant cycle, Graz cycle and Water cycle. These cycles represent the three main options for direct combustion: H₂O recycle, CO₂ recycle, or H₂O and CO₂ recycle¹.

The indirect combustion technologies can be divided in membrane based technologies, fuel cell, and chemical looping. Most research on membrane based technology focuses on the Advanced Zero Emission Power plant, e.g. the articles of (Möller et al. 2006, Möller et al. 2007, Sundkvist et al. 2007, and Colombo et al. 2010).

Although a fuel cell is not per definition a carbon capture technology, carbon capture can be combined within the cell. The most important issue is the internal reforming of the fuel. The selected fuel cell, SOFC, is selected because (1) it has the largest scale of the different fuel cells and it has the highest temperatures, which is beneficial (2) in case it is used as CHP (possibility to produce steam).

The chemical loop combustion (CLC) technology is a new technology in which combustion takes place without direct contact of fuel and air. Combustion does take place in an oxidation and reduction reaction. This technology is included as oxy-fuel technology, because this capture technology shows promising efficiencies and is extensively researched, e.g. the articles (Ekström et al. 2009, Naqvi and Bolland 2007, Naqvi et al. 2007, Hurst and Miracca 2005, Kronberger et al. 2005, Petrakopoulou et al. 2010, Lyngfelt and Thunman 2005).

Pre combustion technologies

Pre-combustion technologies capture the CO₂ before combustion by separating the fuel into hydrogen and CO₂ (fuel reforming). The two main principles for fuel reforming are: steam methane reforming (SMR) and partial oxidation. Both principles combined form the auto thermal reforming (ATR). The two main hydrogen producing technologies are SMR and ATR. ATR is the most suitable technology for pre-combustion technology, because it is more economical to capture CO₂ from an ATR, due to a higher partial CO₂ pressure compared to the SMR. On the other hand, despite the lower investment costs, the ATR is more expensive due to the need for oxygen supply. In the long term, however, new oxygen producing technologies could make the ATR more economical (Damen et al. 2006, Lindsay et al. 2009). Therefore the focus of this study will be on ATR as pre-combustion technology. Two other less mature, but promising technologies (Kuramochi 2011, Kvamsdal et al. 2007) are selected as well, a technology developed in the medium term, sorption enhanced water gas shift (SEWGS), and a technology in the long term, membrane steam reforming (MSR).

Next, usage criteria of the capture technologies important to the CHP technologies are discussed. The capture technologies are compared based on the criteria listed in Table 2

Based on the descriptions of the carbon capture technology, scores are given to compare the different capture technologies. The scores are relative to the other capture technologies: ++ (better), + (good), - (bad), -- (worse).

¹ Recycle is the usage of flue gas in the combustion chamber to keep the oxygen concentration lower and therefore reduce flame temperatures (higher flame temperatures affect the turbine material).

Table 2. Comparison Criteria for capture technologies

Criteria	Relevance
Capture level (%) ¹	The higher the capture levels the better.
Small scale	CHP plants are applied at a large range of scales. Therefore the possibility to apply the capture technology to the scale of a few MW _e (<10 MW _e) is mentioned.
Capture effects	The capture technology has effect on the output and characteristics of the CHP plant. The following criteria describe that effect.
Capture electricity use	Does the capture unit need electricity and to what extent
Capture heat demand	Does the capture unit need heat and to what extent
Quality heat supply	Some CHP plants deliver high grade heat (high temperature and high pressure); some integrated CCS technologies are not able to deliver high temperature heat.
Ramp up/down	The possibility to have a quick start up or shut down of the CHP plant to maintain the operational flexibility of some CHP plants.
Partial load	The possibility to fire the CHP with CO ₂ capture in part load and what effects its efficiency
Integration risk	Some capture technologies have a high integration of different parts of the technology. The process integration has implications on the operational challenges, in the sense that higher integration leads to higher operational challenges (Cardona et al. 2008). ²

¹(Damen et al. 2006, Kvamsdal et al. 2007)

²Integration could lead to the existence of multiple steady states. A minor change in operating conditions might result in a shift to a different steady state with a lower productivity, robust control loops are therefore needed, which is expensive and difficult to design (Cardona et al. 2008). However, the role of integration risk is limited, because in case of integrating several process steps into one unit, the amount of transport is limited, resulting in lower probability of transport break down and less energy losses (lower O&M cost) (Cardona et al. 2008).

The main analysis of the capture technologies is focused on the possibilities to apply the capture unit to a turbine. Those options could be applied to a gas engine as well (IEA GHG 2007), but some capture options are less suitable for the (small scale) gas engines. The suitability of the capture technologies is discussed in the following chapter. In case of a steam turbine CHP, the CO₂ emitting source is the steam producing boiler to which the capture unit is applied. Therefore the boiler and heater capture possibilities are taken into account in the capture technology inventory. The discussed capture technologies can be applied to gas engines as well (IEA GHG 2007).

2.3 CHP-CCS combination

In the third step, a selection is made of suitable CO₂ capture technologies per CHP technology. Possible CHP-CCS combinations are compared, looking at, on the one hand the capture technology characteristics and on the other hand the CHP technology characteristics. Based on this comparison contradictory technical properties of the CHP and CCS technology are identified, and used to exclude possible CHP-CCS combinations.

Sets of suitable CHP-CCS combinations are identified in this way. Subsequently, the suitability of carbon capture application per sector is given based on different CHP applications. The most suitable sectors for CHP-CCS are identified by taking into account the following characteristics of the sectors:

Average CHP size; the size relates to economies of scale for the capture unit, the larger the size the higher the likelihood that CCS can be applied economically.

Total installed capacity; the total capacity is an important aspect to determine the potential of a certain sector. The more installed capacity the more emission abatement potential.

Load factors; the costs of capture are largely affected by the load factor. The higher the load factor, the lower the specific capture costs

Continuity; the continuity of CHP units affects the suitability of CCS application, because CCS application could reduce operational flexibility of the CHP (Dijkstra 2011). If a CHP plant is continuously used (must-run) the reduction of flexibility does not have much effect. However, in case flexibility is needed CCS application does have an effect (Kuramochi 2011).

The reasoning for identifying suitable sectors is based on current CHP applications and usage characteristics, because the current application gives insight in important characteristics. Even though specific figures will change in the longer term, the selection of suitable sectors will remain the same. Possible developments in different sectors are taken into account in scenarios for 2030 and 2050: sector growth, increase of scale, and energy savings in different sectors.

2.3.1 CHP-CCS cases

Based on the qualitative analysis a selection of sectors with capture potential is made. For each sector the most representative CHP technology for capture is identified as case for further (quantitative) analysis. Despite the exclusion of certain combinations of CHP with CCS a definitive choice for a certain capture technology on the long term cannot be made, because most capture technologies are currently in an immature phase and a lot of development is to be expected. This research focuses on the possibilities of CHP-CCS in the Netherlands. A detailed techno-economic assessment of different CCS technologies combined with CHP is out of scope. The quantitative analysis is used to compare the potential of CHP-CCS in different sectors. The analysis will therefore focus on one capture technology, post combustion (chemical absorption), because it can be applied to different scales and because data on costs are available at a detailed level compared to other technologies.

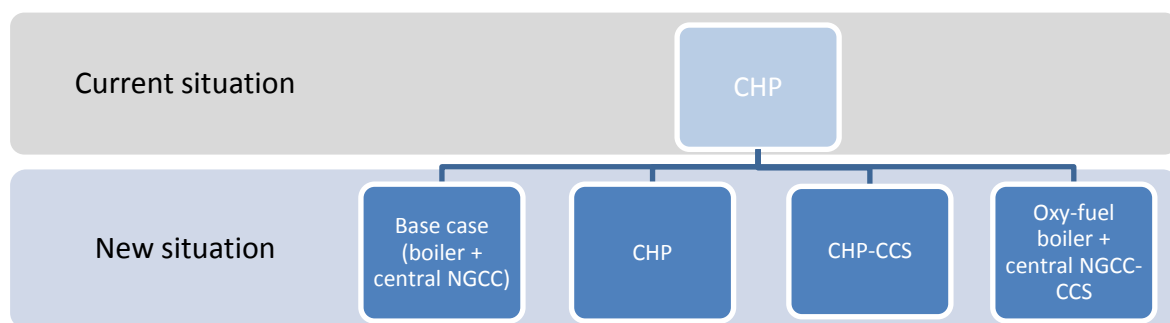


Figure 2. CHP plant options

For each case, four different configurations are possible (Figure 2): the main option is a new CHP-CCS plant; two reference options are installing a boiler and buying electricity from the grid or installing a CHP without CCS; an alternative mitigation option is an oxy-fuel Boiler-CC¹ and buying

¹ For boilers the most convenient way to capture CO₂ will be oxy-fuel boilers. In the mid-term future (2020-2025), oxy-fuel CO₂ capture may compete with or outperform post-combustion capture as a retrofit option for boilers and heaters (IEA 2008). The main advantage is the higher heat flux which allows a compacter boiler design, resulting in a cost saving up to 10% (see chapter Boiler-CC). The calculations for the reference cases of replacing a CHP with a boiler with CCS are therefore based on oxy-fuel boilers. Using a Boiler-CC and buying electricity from the grid instead of using CHP-CCS could be more economical in certain sectors. The choice

electricity from the grid. A fifth option might be the CHP-CCS retrofit option, which is not taken into account in this analysis, because there is a lot of controversy¹ about the ability to retrofit CHP with carbon capture (Ramirez and ter Telgte 2011, den Uijl and ter Telgte 2011).

The quantitative analysis can be divided into two main analyses of the CHP-CCS potential. First, a detailed cost analysis of the different cases, to gain insight in the additional costs of applying CCS to CHP compared to a CHP without CCS. Based on these results the most promising (most economical and large abatement potential) sector is selected.

Second, the most promising CHP-CCS cases are compared to a base case (boiler + central NGCC), a reference case (CHP) and another mitigation option (Oxy-fuel boiler + central NGCC-CCS), in order to gain insight in the development of the economical advantage of a CHP compared to boiler + NGCC, and to what extent a changing 'electricity/gas price ratio' change these benefits. A similar insight is given for the two mitigation options, CHP-CCS and oxy-fuel boiler + NGCC-CCS.

2.3.2 Quantitative analysis CHP-CCS cases

The quantitative analysis comprises the calculation of the following performance indicators for the identified cases.

Technical indicators

- Efficiency of the CHP-CCS plant
- Amount of CO₂ avoided

Economic indicator

- Costs of the avoided CO₂ in €/tonne CO₂

The calculations include direct emissions of producing electricity and heat. Figure 3 shows the system boundaries for the different configurations.

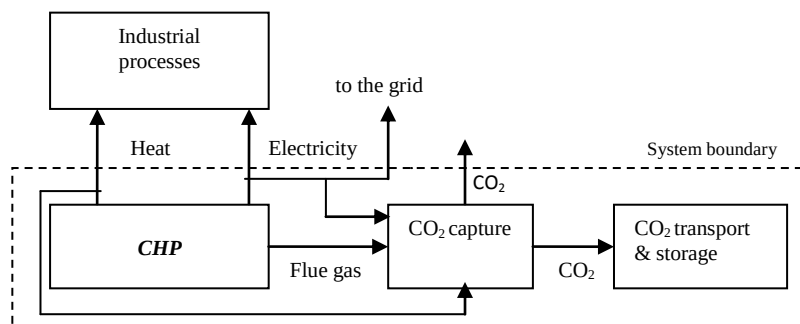


Figure 3. System boundary CHP-CCS calculations

would be based on several criteria: heat/power output ratio, amount of load hours, flexibility needed (more flexibility needed makes Boiler-CC option preferable), costs, scale.

¹ The main issues in this discussion are the space availability at existing CHP plants, and (site specific) costs. The space needed for the capture unit is an issue in case of CHP plants, because the plants are located close to industry to minimize the heat losses during transport (Kuramochi 2011). The costs of retrofitting CHP's with CCS are expected to be high due to the many adaptations needed (for heat integration) and the diminished heat output (due to required regeneration heat).

The research of Kuramochi et al. 2010 is used as basis for the calculations, however their research focuses on combined cycles. Therefore other CHP technologies (GT and GE) calculations are adjusted to take into account the different characteristics of these CHP technologies.

The main calculations are the same for all CHP technologies and are presented here, more specific calculations will be explained in later sections.

The avoided CO₂ emissions can be calculated by the following formula:

$$EM_{av} = EM_{CHP} - EM_{CHP-CC} \quad (2-1)$$

In which EM_{CHP} represent the emissions of the reference CHP; EM_{CHP-CC} the emissions of the CHP with carbon capture. Em_{av} = tonnes CO₂ emission avoided (tons)

The costs of capturing the CO₂ is calculated in € per avoided tonne CO₂. The additional investments compared to the replaced CHP plant and the additional operating costs are taken into account, including the transport and storage costs. Due to the scaling of the CHP, the amount of heat delivered remains constant, but the electricity sales increase. The additional revenues are taken into account.

$$C_{CO_2} = \frac{\alpha \cdot (I_{CHPCC} - I_{CHP}) + \Delta C_{O\&M} + C_e}{Em_{av}} + C_{transport} + C_{storage} \quad (2-2)$$

C_{CO_2} = costs (€/tCO₂) per avoided CO₂

I_{CHPCC} = Investments for CHP with Carbon Capture (€)

I_{CHP} = Investments for reference CHP (€)

$\Delta C_{O\&M}$ = Additional operational and maintenance costs for CHP-CC compared with reference CHP (€)

C_e = Increase of electricity revenues due to extra electricity produced, caused by the increase of size (€)

α = Annuity factor

2.3.2.1 CO₂ transport

The CO₂ captured from a CHP needs to be transported from the industrial site to a storage area. It is assumed that the trunk pipelines to the storage area have been developed. The CO₂ transport from the industrial site to the trunk pipeline is part of the CCS investment for the industry. Kuramochi et al. (2011) have studied the small scale transport for two options: truck transport or pipeline transport. Figure 4 shows the schematic view of the CO₂ transportation, the figures are explained in section: **Cost Parameters**.

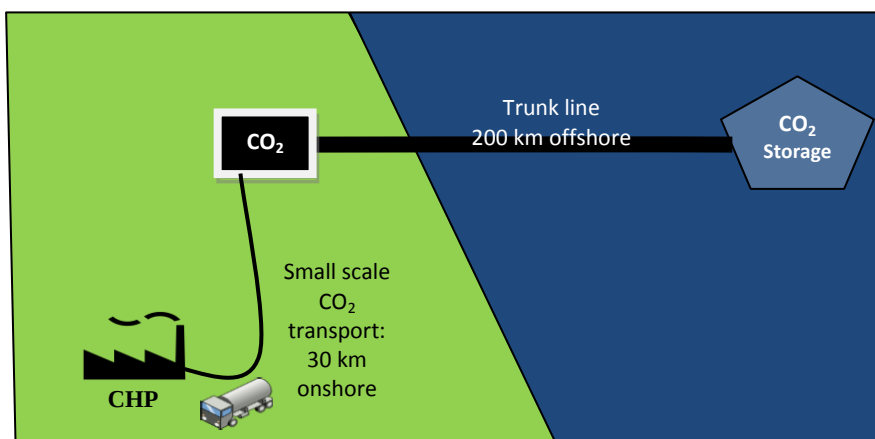


Figure 4. Schematic view of CO₂ transport

2.3.2.2 CO₂ storage

In the Netherlands many gas fields can be used for CO₂ storage (van den Broek et al. 2008, van der Meer and Yavuz 2009, EBN and Gasunie 2010). However, controversy about CO₂ storage at Barendrecht (Kuijper 2011; Feenstra et al. 2010) has led to a (political) debate about onshore storage. After aborting pilot projects in Barendrecht and the north of the Netherlands (Noord-Nederland) (Verhagen 2011b), the Minister of Economic Affairs, Agriculture and Innovation, decided to support offshore storage instead of onshore projects (Verhagen 2011a). The cost figures will therefore be of offshore gas fields.

2.3.3 CHP-CCS calculations

The CHP-CCS calculations are based on the assumption that the heat demand is kept constant. A constant heat demand is likely to be the case since CHP plants are typically sized according to the heat demand. The new size of the gas turbine is calculated assuming a constant HPR, and heat demand, and an efficiency penalty due to the capture unit. By installing a larger CHP with capture unit the energy demand can still be met.

The energy penalty for capture is taken into account as a reduction of the efficiencies. The new net electric and heat efficiencies are calculated taking into account the efficiency penalties. The new efficiencies are used to calculate the required capacity to meet the heat and electricity demand:

$$\eta_{\text{heat new}} = \eta_{\text{heat old}} - (EF_{\text{NG}} \times \eta_{\text{capture}} \times \text{Reg Heat}) \quad (2-3)$$

$$\eta_{\text{new electric}} = \eta_{\text{electricity old}} - (EF_{\text{NG}} \times \eta_{\text{capture}} \times \text{Elec Capture}) \quad (2-4)$$

In which:

$\eta_{\text{electricity old}}$ = old electricity efficiency (%)

$\eta_{\text{heat old}}$ = old heat efficiency (%)

EF_{NG} = Emission factor for Natural gas (tonne/GJ)

η_{capture} = capture ratio (%)

Reg Heat = Regeneration Heat for CO₂ capture (GJ/tonne)

Elec Capture = Electricity needed for capture CO₂ capture (GJ/tonne)

Based on the new efficiencies and the constant heat output the new size can be calculated by the following formula.

$$\text{New Capacity (MW}_e\text{)} = \eta_{\text{new electric}} \times \frac{\text{Heat demand (MW)}}{\eta_{\text{new heat}}} \quad (2-5)$$

2.4 Potential CHP-CCS in 2030 and 2050

The efficiencies and costs of specific cases are calculated. The heat demand per sector in 2030 and 2050 is used to determine the maximum amount of emissions to be abated in the different sectors. Combining the maximum amount of emissions to be avoided and cost figures of different cases a cost supply curve is made. The cost supply curve can be used to determine the capture potential of CHP plants at different CO₂ prices.

2.4.1 Scenario description

The scenario used in the Save-production model is based on the 'Reference Projections 2010-2020' (Daniëls and Kruitwagen 2010) updated with newer cost data from the IEA World Energy Outlook 2010 (IEA 2010d).

Updates based on recent figures are:

- Inflation of 2% per year from 2010 onward
- Natural gas price 2011-2014: average forward prices of ENDEX of November 1st till January 28th 2011
- Fuel costs (Coal, Natural gas, Oil) after 2014: prices consistent with Current policies scenario of World energy outlook 2010 (IEA 2010d).

The projection is a business-as-usual scenario; planned policy is taken into account. The assumed macro-economic growth is based on an annual 1.7% increase of labor productivity, and a size estimation of the working population (Daniëls and Kruitwagen 2010). For the short term (2010-2020) specific policy effects are calculated as well. However, the main energy cost developments of the short term estimations are calculated up to 2040. The fuel price trends are even up to 2050 and used as exogenous input. The gas and electricity price in this analysis are based on these calculations.

2.4.2 Assumptions

The report of (Daniëls and Kruitwagen 2010) contains an extensive description of the scenario used as basis. The most important assumptions and expected developments for the energy demand development are mentioned below.

Energy demand development

Three developments mainly determine the change in energy demand per sector: the energy savings rate determines the expected decline; the expected economical and population growth determines the expected growth in energy demand. In the model an energy savings rate of 0.7% per year up to 1.2% per year of energy use per GDP is expected.

Table 3. Annual growth of Gross value added per sector (Daniëls and Kruitwagen 2010)

	2011-2050
Agriculture	1.5%
Industry	1.9%
- Chemical industry	2.6%
- Basic metal industry	1.7%
- Other industry	2.0%
- Food industry	1.3%
Tertiary sector	2.3%
Government	1.7%
Total	1.7%

Due to the economic recession the energy demand between 2005 and 2010 has decreased. After 2010 increase is expected. The industry (1.9% per year) and tertiary sector (2.3% per year) have higher economic growth compared to the agriculture (1.5% per year) and other sectors, i.e. mining/gas exploitation (0.3% per year), see Table 3. Within the industry the highest growth is expected to take place in the chemical industry (2.6% per year), basic metal industry (1.7% per year) and other industry (2% per year); the food industry is expected to have a growth of 1.3% per year). The main argument for the higher growth rate in the chemical industry is the presence of strong clusters of chemical companies and the well developed logistics in the Netherlands.

Some important developments are expected to play a role in the heat demand (Daniëls and Kruitwagen 2010). The factors influencing the demand in the built environment are: the increase of buildings, and better insulation. The refinery sector is expected to slightly decrease due to the lower demand for fuels (more efficient cars and more bio-fuels). An important development within this sector is the decrease in the maximum sulfur-content of fuels. Strict legislation results in the need for better desulfurization, which requires a lot of heat. As a result, the heat demand in the refinery sector slightly increases, despite the expected increase of efficiency of the refineries.

Development CHP

The focus for the CHP development is on the heat demand development, because the heat demand determines the installed CHP-capacity. In the horticulture an increase up to 2010 of installed CHP capacity took place, in 2010 saturation of CHP capacity was reached and the growth stagnated.

2.4.3 Future potential

In the chapter on future potential the role of CHP-CCS as mitigation option is described, based on a synthesis of the qualitative and quantitative analysis. First, the future role of the CHP technologies in meeting the heat demand in different sectors is described. Subsequently, possible capture technologies to apply to CHP are identified. Finally, the role of CHP-CCS is compared with other mitigation technologies to determine its potential in 2030 and 2050.

2.4.4 Quantitative analysis CHP-CCS reference

In this analysis the most promising sector, identified in the previous cost comparison, is compared to different alternatives, boiler + central NGCC, the reference CHP, and an alternative mitigation option, Oxy-fuel boiler + central NGCC-CC. First to see whether CHP is still beneficial compared to the base case (separate electricity and heat production). Secondly, compare CHP-CCS with another mitigation option (oxy-fuel boiler + NGCC-CCS).

To show different views on these options, the analysis is done taking into account two perspectives, national and industrial. The industrial perspective takes into account onsite costs, revenues and emissions. The national perspective looks into the effect nationwide by taking into account the total emissions, the amount of fuel used and the costs of the produced electricity.

2.4.4.1 Industrial perspective

To compare the different options from an industrial perspective the NPV value is calculated, using the system boundaries, shown in Figure 5. Because the NPV values depend largely on the gas/electricity price ratio, a variety of electricity/gas price ratios is taken into account to calculate the NPVs. The ratio is changed by adapting the electricity price and keeping the gas price constant. The values in the graphs should therefore only be interpreted relatively and not absolute.

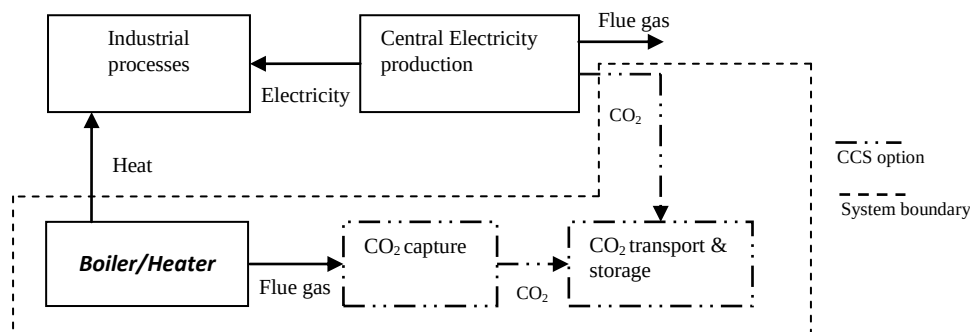


Figure 5. System boundary Boiler/Heater (with CCS) Industrial perspective

For each case the Net Present Value (NPV) is calculated in 2030 and 2050 using the following formulas (Blok 2007):

$$CF = \alpha \cdot -I + (B - C) \quad (2-6)$$

$$NPV = \frac{CF}{\alpha} \quad (2-7)$$

$$\alpha = \frac{r}{1 - (1 + r)^{-L}} \quad (2-8)$$

In which:

I = Investment costs (M€)

B = Annual benefits (value of electricity and heat) (M€/yr)

C = Annual costs (O&M, fuel and CO₂ transport/storage costs) (M€/yr)

α = Annuity factor

CF = Cash flow (M€/yr)

r = Discount rate (%)

L = Life time of CHP / CCGT (yr)

The investment costs of the boiler are not taken into account, because in all cases a boiler is installed, in case a CHP is used the boiler is needed as back up facility. The value of heat is equal to the costs to produce heat with a boiler (90% efficiency). The value of electricity is calculated using the commodity price of electricity in 2030 and 2050.

An assumption about the revenues of the electricity sales needs to be made, because in reality many CHP plants use a part of the produced electricity, however the extent to which electricity is privately used differs a lot per CHP. To take into account the value of all electricity produced, the CHP cases are assumed to deliver all electricity to the grid except the electricity needed to capture the CO₂.

Oxygen supply

Purchasing liquid oxygen from an industrial gas producer is preferred up till an oxygen demand of ~150 tO₂/day (3000Nm³/h) (Universal Industrial Gases 2010), since this is the most cost effective production mode according to the scheme as shown in Figure 6. The cases have an oxygen demand of 550 and 850 tO₂/day (95% purity); therefore, an ASU is the most economical way of producing oxygen. The advantage of using an ASU in terms of consistency in the analysis is the ability to use the same electricity price development as in the other part of the analysis. In case of buying oxygen, the electricity price is included in the oxygen costs and cannot be leveled with the electricity price used in the analysis.

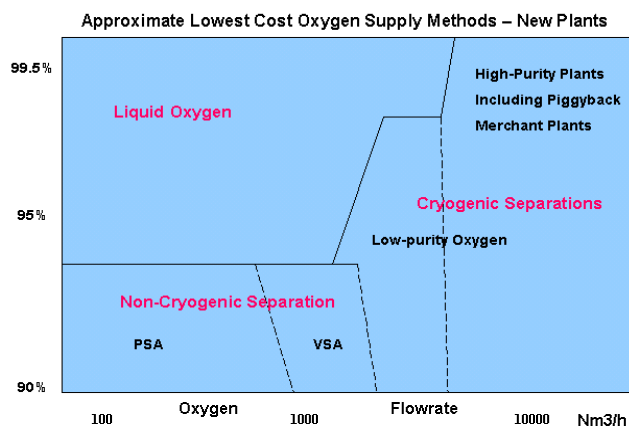


Figure 6. Approximate lowest cost oxygen supply methods - new plants (Universal Industrial Gases 2010)

2.4.4.2 Mitigation perspective

The mitigation perspective compares two alternative mitigation technologies. This perspective calculates the costs, emissions and fuel needed to meet an electricity and heat demand. The mitigation perspective takes into account onsite emissions and fuel use, and the emissions and fuel use of centralized power production, the industrial perspective, in contrast, takes only onsite emissions and fuel use into account. The perspective embodies four aspects which affect of the whole society:

- Total CO₂ emissions (tCO₂)
- Fuel used (GWh/yr)
- Costs of electricity produced (€/kWh)
- Avoidance costs (€/tCO₂)

Mitigation targets aim for reduction in the total emissions, and also for reducing fuel consumption (IEA 2002) which make the first two aspects relevant for society. The costs of electricity and the avoidance costs are both relevant, because consumers and businesses will have to pay the higher price of the new mitigation technologies. The value of the heat produced is assumed to be equal in all cases, and therefore not included in this comparison.

Total emissions and fuel use

The total CO₂ emissions include the emissions of the boiler and centralized power production. The fuel use does include the fuel needed for the boiler and also for the centralized power production.

Electricity prices

The production costs of the electricity are calculated, because these costs determine the final price of electricity the consumers shall pay. The final price of electricity will be higher, due to taxes, distribution costs. These additional costs are not taken into account, because they are equal for the different options. To calculate the electricity prices of the CHP and CHP-CCS the following formula is used:

$$COE = \frac{C_{CHP} - B_{heat} - B_{electricity}}{E_{CHP}} \quad (2-9)$$

In which:

COE = costs of electricity (€/kWh)

C_{CHP} = Annual costs CHP(-CCS) (€/yr)

B_{Heat} = Value of heat produced by CHP(-CCS) (€/yr)

B_{Electricity} = Value of electricity produced by CHP(-CCS) (€/yr)

E_{CHP} = Electricity produced by CHP(-CCS) (kWh)

The cost data of producing electricity with a CCGT(-CCS) are found in literature, because a cost calculation is out of scope for this research.

Avoidance costs

The avoidance costs of the CHP-CCS are taken from the previous quantitative analysis. The avoidance costs of the oxy-fuel boiler + NGCC-CCS are calculated by taking a weighted average. Based on the HPR of the reference CHP the avoidance costs of the oxy-fuel and the NGCC-CCS are weighted and averaged.

$$C_{CO_2} = \frac{\gamma_{\text{electricity}} \times C_{CO_2\text{-NGCC}} + \gamma_{\text{heat}} \times C_{CO_2\text{-oxyboiler}}}{2} \quad (2-10)$$

In which:

C_{CO_2} = avoidance costs (€/tCO₂)

$C_{CO_2\text{-NGCC}}$ = avoidance costs NGCC-CCS (€/tCO₂)

$C_{CO_2\text{-oxyboiler}}$ = avoidance costs oxy-fuel boiler (€/tCO₂)

$\gamma_{\text{electricity}}$ = ratio electricity production

γ_{heat} = ratio heat production

The avoidance cost data of the NGCC-CCS are found in literature, because a cost calculation is out of scope for this research. The avoidance costs of the capture unit are adjusted by taking into account the trunk transport costs and storage costs used in this study. The avoidance costs of the oxy-fuel boiler are calculated with the following formula:

$$C_{CO_2\text{-oxyboiler}} = \frac{\alpha \cdot (I_{\text{oxyboiler+ASU}} - I_{\text{boiler}}) + \Delta C_{O\&M}}{Em_{av}} + C_{\text{transport}} + C_{\text{storage}} \quad (2-11)$$

$C_{CO_2\text{-oxyboiler}}$ = avoidance costs of the oxy-fuel boiler (€/tCO₂)

$I_{\text{oxyboiler+ASU}}$ = Investments of Oxy-fuel boiler with ASU (€)

I_{boiler} = Investments reference boiler (€)

$\Delta C_{O\&M}$ = Additional operational and maintenance costs for oxy-fuel boiler compared with reference boiler (€)

3. Data collection

To quantify the potential CHP-CCS potential several data are needed and assumptions have to be made. In this section a description is given of the data used. First, the general data, and fuel prices are presented. Second, CHP data are discussed. Subsequently, carbon capture data and the expected developments are discussed. Fourth, the data of the reference cases (oxy-fuel boiler and NGCC-(CCS) are presented.

3.1 General calculation data

In the quantitative analysis the following parameters are used (Table 4). The same natural gas price and electricity price are used as taken into account in the Save production model as discussed in section 2.4.1 Scenario description.

Table 4. General technical and cost parameters

		Unit		
Technical parameters				
Emission factor NG ^a	kgCO ₂ /GJ	56.6		
Energy content NG ^a	MJ/m ³	31,65		
Economic parameters				
Lifetime (yr) Industry ^a	yr	20		
Lifetime (yr) Gas engine ^b	yr	15		
Discount rate ^a	%	12%		
		2030	2050	
Natural Gas price ^c	€ ₂₀₁₀ /m ³	0.34	0.35	
Commodity Electricity price peak ^c	€ ₂₀₁₀ /kWh	0.107	0.107	
Commodity Electricity price off-peak ^c	€ ₂₀₁₀ /kWh	0.080	0.080	
Non-Commodity Electricity price ^d	% _{commodity price}	125%	125%	

^a Based on article of (Kuramochi et al. 2010)

^b Based on report of (van der Marel and Goudappel 2008)

^c Derived from ECN model calculations for reference projection 2010-2020 (**Daniëls and Kruitwagen 2010**)

^d The price for buying (non-commodity) electricity is 125% of the commodity price (Plomp and Kroon 2010), due to e.g. taxes, transportation costs.

The commodity electricity prices are used in case a CHP sells electricity to the grid. In case of a Boiler-CC, electricity is bought from the grid. In that case the price is higher due to e.g. taxes, transmission costs. The non-commodity prices are assumed to be 125% of the commodity electricity prices (Plomp and Kroon 2010). As fuel price the commodity gas price is used, because CHP does not pay energy taxes (Wetzels et al. 2011). The transport and distribution costs are not included because they differ per case.

3.2 CHP data

In order to gain insight in the CHP plants in the Netherlands a list of CHP plants installed in the Netherlands is made. Per CHP plant several characteristics are described.

- | | |
|-------------------------|------------------------------------|
| - CHP type | - Load hours in practice |
| - Sector | - Maximum load hours |
| - Location | - Input |
| - Owner | - Efficiencies (electric, thermal) |
| - Year of commissioning | - Production (electricity, heat) |
| - Capacity installed | - Heat Power Ratio |
| - Type of heat used | - Must run character |
| - Type of fuel | |

The data is gathered using the following sources:

- CBS figures (CBS 2010)
- Databases ECN (Essent and ECN 2010, ECN 2007, ECN 2011)
- LEI Report (Smit and van der Velden 2008)
- Environmental Annual report of Nuon (Nuon 2010)

Identified cases provide case specific data. In case certain old plants are still in place, for which no new data are found, values from the previous (ECN) database are used. The other (unspecified) capacity is characterized with average values of CBS. For some characteristics certain standardizations and assumptions have to be made.

Year of commissioning

Years of commissioning for gas turbines, combined cycles and steam turbines are based on CHP-inventory 2007. For large groups of gas engines the year of commissioning is difficult to identify, but is important in order to know when new gas engines should be installed. The gas engine commissioning in the horticulture is based on the LEI report of CHP application in the horticulture (Smit and van der Velden 2008), and the period 2008-2009 (CBS 2010) is used. The gas engine commissioning assumption in other sectors is based on a report of (Wetzels et al. 2009). The assumption states that of the current engines installed the percentage commissioned is as follows: 1990-1993 20%; 1994-1997 40%; 1998-2009 40%; in which the commissioning is distributed equally over the years within the periods.

Must run character

For the must run installations, the definition of Wetzels et al (2010) is used, a 'must-run' CHP does not react on differences in electricity price (Wetzels et al. 2010). Following are assumptions for must run installations per sector:

- All plants using chemistry gas, refinery gas or coke oven gas are must run installations, because those gases are produced anyway
- 25% of the gas engine capacity in service sectors
- 50% of the capacity in the chemistry sector
- 70% of the capacity in the refinery sector
- 10% of the capacity in the Paper, Food en Other industry sectors

3.2.1 CHP technical parameters

The current efficiencies of the CHP cases are calculated on basis of the fuel input and energy output identified for the CHP-inventory list. In case the input is not published, the input is calculated based on CO₂ emissions (taking into account the type of fuel and its emission factor). The technology development over time has influence on the efficiencies. The development taken into account is based on the report Energy Technology Perspective (IEA 2010a). Other technical aspects are assumed to be constant over the coming decades: full load hours, average size.

Peak load hours

The electricity price varies; prices during day are higher compared to the night prices. This difference in price is taken into account, assuming peak load hours from 7.00 – 23.00 during the working days with exception for official holidays (Alle Energieleveranciers 2011, EON 2011). This results in 80 peak hours per week, taking into account holidays subsequently, the amount of peak hours in a year is 4080 (Hers and Wetzels 2009). The assumed availability of CHP plants is: for gas turbines and combined cycles 90%; and for gas engines 96% (Hers et al. 2008). It is assumed that CHP plants produce as much as possible during peak load hours, to optimize their income of electricity sales. Therefore the maximum of peak load hours is used, taking into account the availability of the different technologies.

3.2.2 CHP cost parameters

The cost data used is based on the cost data provided by Jacobs consultancy for the GT and CCGT (van der Marel and Goudappel 2008) the GE and the O&M costs (for all cases) are based on (Hers et al. 2008). The cost development in the future is based on the cost development in the report Energy Technology Perspectives 2010 (IEA 2010a), shown in Table 5. The cost development of the combined cycle is assumed to be the same as the gas turbine (IEA 2010a). All cost data used is presented in €₂₀₁₀, corrected for inflation (Eurostat 2011b, Nederlandsche Bank 2011), dollars are converted to Euros based on Eurostat conversion values (Eurostat 2011a). Table 5 gives an overview of the used CHP data.

Table 5. CHP cost development compared to 2010 values (IEA 2010a)

	2010 (small scale)	2010 (large scale)	2030	2050
Gas engine				
Installation costs	856 €/kW _e ^a	589 €/kW _e ^a	-11%	-24%
Fixed O&M	15.28 €/MWh ^b	6.93 €/MWh ^b	-19% ^c	-43% ^c
Gas turbine				
Installation costs	1268 €/kW _e ^a	961 €/kW _e ^a	-12%	-26%
Fixed O&M	7.34 €/MWh ^b	5.40 €/MWh ^b	-1%	-2%
CCGT				
Installation costs	1197 €/kW _e ^a	880 €/kW _e ^a	-12%	-26%
Fixed O&M	10.91 €/MWh ^b	5.71 €/MWh ^b	-1%	-2%

^a 2010 value based on (van der Marel and Goudappel 2008).

^b 2010 value based on (Hers et al. 2008).

^c The large change in the O&M costs is caused by a change in O&M cost range, the upper limit is lowered to a large extent, resulting in a large decrease of the average GE O&M costs.

Table 6. CHP technical and cost parameters 2030 and 2050

		Gas engine		Gas turbine		CCGT	
		2030	2050	2030	2050	2030	2050
Technical Parameters							
Electrical efficiency ^a		+7%	+13%	+6%	+11%	+6%	+11%
Heat efficiency ^a		-1%	-2%	+1%	+2%	+1%	+2%
CO ₂ concentration ^b	%	9%	9%	4%	4%	4%	4%
Cost Parameters							
Capacity large scale ^c	MW	2	2	45	45	250	250
CHP investment costs large scale ^d	€ ₂₀₁₀ /kW _e	521	416	1110	932	770	647
O&M costs large scale ^e	€ ₂₀₁₀ /MWh	6.1	5.2	7.2	7.0	5.6	5.4
Capacity small scale ^c	MW	0.4	0.4	25	25	60	60
CHP investment costs small scale ^d	€ ₂₀₁₀ /kW _e	758	649	1273	1069	1048	1137
O&M costs small scale ^e	€ ₂₀₁₀ /MWh	13	11	11	11	9.7	9.7

^a Based on (IEA 2010a), compared to 2010 values^b Mentioned in CHP chapter^c GT and CCGT values based on (van der Marel and Goudappel 2008), GE values based on (Hers et al. 2008)^d 2010 value based on (van der Marel and Goudappel 2008); future values are adapted, using the growth shown in Table 5^e 2010 value based on (Hers et al. 2008); future values are adapted, using the growth shown in Table 5

3.3 Carbon capture data

The third dataset is the carbon capture data, which is based on specific values for gas turbine-combined cycles. To use the figures also for capture from gas engines changes should be made, because for gas engines the size, the %CO₂ in, and the temperature, pressure of the flue gas is different than in case of gas turbines/combined cycles. Therefore, the specific capture energy parameters and the specific capture cost parameters of CCS to gas turbines are adjusted for gas engines. The specific capture energy is corrected for the %CO₂ in the flue gas with a correction factor based on an article of Egberts et al. (2003). The specific capture costs are corrected for the difference in size using a size factor and in %CO₂ in the flue gas using a correction factor derived from Egberts et al. (2003). The NO_x emissions of the different CHP technologies and (oxy-fuel) boiler may differ, and could result in additional investments to meet the emission constraints. Because in Peeters et al. (2007) and Kuramochi et al. (2010) the NO_x removal costs are not specified, it is assumed that the reference costs of the NO_x removal is included in the investment costs. Further analysis of the NO_x removal costs of the different options is out of scope for this study.

3.3.1 Technical parameters CCS

The technical parameters in the research of Kuramochi et al. (2010) are based on figures of (Peeters et al. 2007), presented in Table 7. Based on a literature study Peeters et al. (2007) defined parameters for a hypothetical solvent¹ in 2010 and 2030. The decrease in energy use for capture is extrapolated towards 2050, assuming a same energy efficiency improvement from 2030 to 2050.

Gas engine energy parameters

The specific energy use for capture at gas engines (GJ/tCO₂) is lower than in case of gas turbines, because the higher CO₂ content results in a lower amount of regeneration heat needed (per CO₂ captured), and less electricity for pumping (Egberts et al. 2003). The research of (Egberts et al. 2003)

¹ The hypothetical solvent is a solvent which is only theoretically possible yet. The 2010 values are based on existing MEA (monoethanolamine) solvent; the 2030 values are based on possible future energy saving developments of the solvent (Peeters et al. 2007).

is used to adjust the energy use parameters of the gas turbine into parameters usable for gas engines, based on Figure 7 the heat requirement is determined. Taking into account the following CO₂ concentrations: Combined cycle: 4%; Gas engine: 9%; the correction factor is 0.88. The same ratio is used for the correction of capture electricity demand.

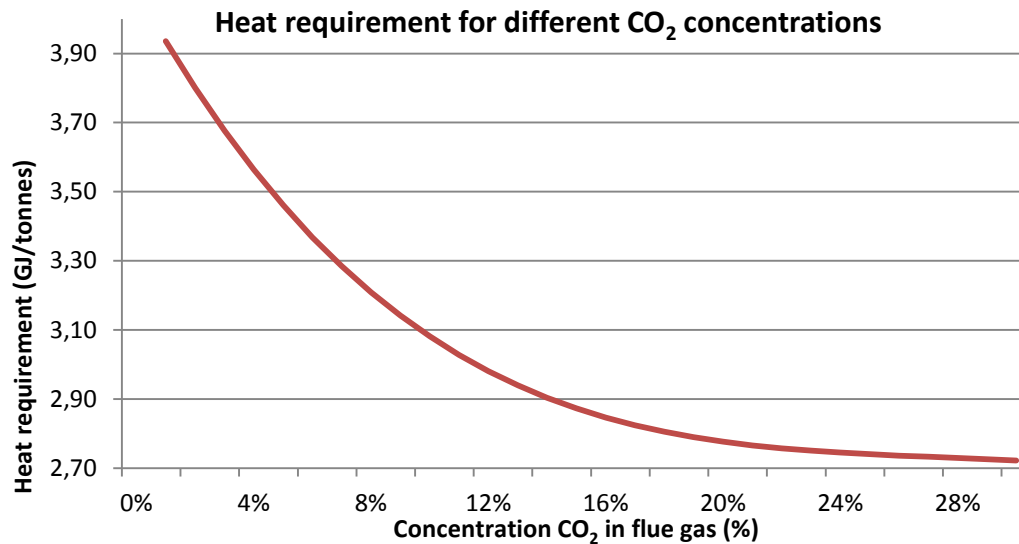


Figure 7. Heat requirement post combustion capture process for different CO₂ concentrations in 2010 (Egberts et al. 2003)

Oxy-fuel boiler energy parameters

A conventional boiler has an efficiency up to 85% (Saygin et al. 2011, Einstein et al. 2001), with improvements the boiler efficiency for industrial steam can be over 90% (Saygin et al. 2011). The efficiency used for 2030 and 2050 is therefore 90%. The increase of the efficiency of an oxy-fuel boiler compared to a conventional boiler is derived from Allam et al. (2005), 4.2% less fuel is needed (increase efficiency of 3.9%).

The oxygen is assumed to be provided by an air separation unit (ASU). The electricity use of an ASU is 0.20 MWh/tO₂ (Meerman et al. 2011); the improvement of energy consumption has been 1% per year (Castle 2002). The same development is expected to continue the coming decades¹ (Knoops 2010).

Energy use CO₂ compressor and dryer

The captured CO₂ is compressed to 110 bar and dried (by removing water during compression) for pipeline transport. The CO₂ is compressed up to the critical pressure (7.38 MPa); a pump is used for further compression (Kuramochi 2011). In (Peeters et al. 2007) the specific electricity requirement is 0.403 GJ/tCO₂ to compress to 110 bar, based on a literature research. In (Egberts et al. 2003) 0.416 GJ/tCO₂ is needed for compressing CO₂ to 120 bar. Using the following formula (Kuramochi 2011) to correct the outlet pressure to 110 bar, the specific electricity requirement is 0.414 GJ/tCO₂. For this research the average value is used 0.408 GJ/tCO₂.

¹ This development does not take into account a thermodynamic minimum

$$E_{P,Comp} = \frac{p_{out} - p_{in}}{\rho \eta_P} \quad (3-1)$$

$E_{P,comp}$ = specific electricity requirement pump (MJ/tCO₂)

p_c = inlet pressure (kPa),

p_{out} = outlet pressure (11000 kPa),

ρ = density of CO₂ during pumping (630 kg/m³)¹,

η_P = pump efficiency (75%).

The development of the energy use of the CO₂ compressor over time is studied in (Knoops 2010), based on interviews a decrease of energy consumption is expected, in 2030 12% and in 2050 24% of the specific electricity use. Resulting in a specific electricity consumption of CO₂ compression in 2030 0.36 GJ/tCO₂captured and in 2050: 0.31 GJ/tCO₂captured

Table 7. Technical parameters of CO₂ capture 2030 and 2050

	Unit	2030	2050
Technical parameters			
Efficiency conventional boiler ^a	%	90%	90%
Post combustion capture			
Capture efficiency ^b	%	90%	90%
Heat for regeneration ^b	GJ/tCO ₂ captured	2.60	1.69
Electricity equivalent for regeneration ^b	GJ/tCO ₂ captured	0.48	0.29
Electricity for absorption ^b	GJ/tCO ₂ captured	0.08	0.03
Electricity consumption for compression and separation ^b	GJ/tCO ₂ captured	0.36	0.31
Power factor for regeneration heat ^b	J _e /J _{th}	0.186	0.17
Gas engine capture values			
Heat for regeneration ^c	GJ/tCO ₂ captured	2.29	1.35
Electricity for absorption ^c	GJ/tCO ₂ captured	0.07	0.03
Electricity consumption for compression and separation ^b	GJ/tCO ₂ captured	0.36	0.31

	Unit	2030	2050
Oxy-fuel boiler			
Increase efficiency Oxy-fuel boiler ^d	%	3.9%	3.9%
ASU power demand ^e	GJ/tO ₂	0.59	0.39
Electricity consumption for compression and separation ^b	GJ/tCO ₂ captured	0.36	0.31
CO ₂ /O ₂ ratio ^f	kgCO ₂ /kgO ₂	0.69	

^a 2010 value based on (Saygin et al. 2011, Einstein et al. 2001), future values based on (Saygin et al. 2011)

^b 2010 value based on (Peeters et al. 2007), extrapolated based on trend in (Peeters et al. 2007)

^c Gas turbine values adapted based on (Peeters et al. 2007), adapted based on values from a report of (Egberts et al. 2003)

^d Value based on (Allam et al. 2005b), assumed to be constant over time.

^e Value based on (Meerman et al. 2011), improvement of energy consumption over time is based on (Castle 2002) and (Knoops 2010).

^f Value based on Bolland et al. (2003). The ratio is specific for NG as fuel (Kuramochi et al. 2010)

3.3.2 Cost parameters CCS

The investment costs of the capture unit depend on size. C is capital costs of the capture system, S is the size (capacity in MW_e) and the SF is the scaling factor. A SF of 0.7 (Kuramochi et al. 2010) is used

¹ Value based on the research of Kuramochi et al. (2011), which is the density to be reached by pumping.

for post combustion capture costs; the boiler SF used is 0.67¹; the ASU SF used is 0.8 (Meerman et al. to be published); the compressor SF used is 1 (Meerman et al. to be published).

$$C_X = C_{Ref} \times \left(\frac{S_X}{S_{Ref}} \right)^{SF} \quad (3-2)$$

Capture costs

Because in literature a large range of capture costs is used, the costs in this study are averages of a range based on literature study (2010 cost range 350-500 €/kW_e) (IEA 2010b, IEA 2010a, Booth and van Os 2011, Sipöcz et al. 2011, Kuramochi et al. 2010, Rubin et al. 2007a, Rubin et al. 2007a, IEA and NEA 2010, Rubin et al. 2007b, IEA 2005). The costs presented in literature are current costs; reduction of these costs over the years is expected. The amount of reduction is based on the Energy Technology Perspectives 2010 of the IEA (IEA 2010a). The annual investment cost reductions compared to 2010 are, in 2030: 15%, and in 2050: 27%. The expected cost reduction in 2030 is similar to expectations in (Kuramochi et al. 2010). The cost reduction discussed above results in the values presented in Table 7.

To avoid double counting of the investment costs of the CO₂ compressor, the compressor costs are subtracted from the total investment costs. The compressor costs range from 40-50 €/kW_e² (Booth and van Os 2011, Sipöcz et al. 2011, Kuramochi et al. 2010, Rubin et al. 2007b), the average, 44 €/kW_e is used in this analysis. The investment costs for the CO₂ compressor are included in the small scale transport costs which are based on an extensive research of Kuramochi et al (2011).

Gas engine capture cost parameters

The CO₂ content in the flue gas of GE differs compared to a GT/CCGT, because the air/fuel ratio of a GE differs from a GT/CCGT. The specific costs of capture are lower in case the CO₂ content in the flue gas is higher, the capture investment costs for GE are therefore corrected. The correction factor of a GE is derived from Figure 8. Taking into account the following CO₂ concentrations: Gas turbine/Combined cycle: 4%; Gas engine: 9%; the correction factor is 90%/125% = 72%.

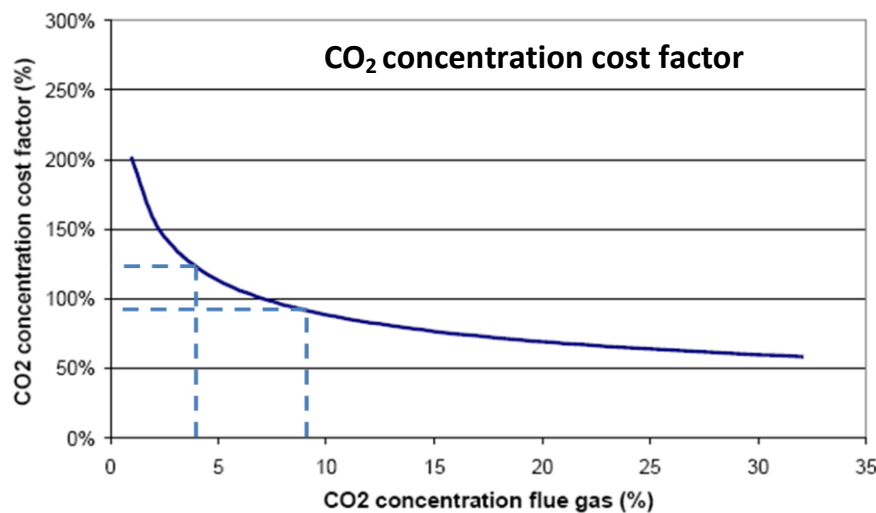


Figure 8. CO₂ concentration cost factor (Egberts et al. 2003)

¹ The boiler SF is 0.67, because its capacity increases with the third power (volume) of the size, whereas the costs only increase quadratic of the size (surface area) (Blok 2007).

² The kW_e refers to the size of the power plant, not to the size of the compressor itself.

Oxy-fuel boiler cost parameters

The investment costs of the oxy-fuel boiler $C_{\text{oxy-boiler}}$ can be calculated with the following formula:

$$C_{\text{oxy-boiler}} = C_{\text{boiler}} + C_{\text{retrofit}} + C_{\text{ASU}} + C_{\text{sepr,comp}} - C_{\text{comp}} \quad (3-3)$$

C_{boiler} = Conventional boiler costs (€)

C_{retrofit} = retrofit costs boiler to oxy-fuel boiler (€)

C_{ASU} = Air separation costs (€)

$C_{\text{sepr,comp}}$ = CO₂ separation and compression costs (€)

C_{comp} = Correction for compression costs, to avoid double counting for compression costs (€)

Boiler costs

The costs of a conventional boiler are based on (IEA GHG 2007, Lazzarin and Noro 2006), 91.8 €/kW_e, those are assumed to be constant over time, because boilers are a mature technology. The adaptation needed to use a boiler for oxy-fuel firing result in additional costs, which are derived from (Allam et al. 2005b): Boiler modifications per boiler (€2010/kW_{th}) = 0.82. All costs are corrected with the scaling factor 0.67, the standard equipment scaling factor¹ (Blok 2007).

ASU costs

The costs of the air separation unit (ASU) are based on (Meerman et al. to be published). In the article values from different sources (NETL 2008, Arienti et al. 2008, Hamelinck et al. 2004), are compared and standardized, taking into account the scale factor and installation factor². Based on their analysis the medium cost case is selected with the corresponding scale factor, 110 M€₂₀₀₇ for 5150 t/d and a scaling factor of 0.8 and an installation factor of 53% (Arienti et al. 2008). Because the ASU is a mature technology the costs are assumed to be constant over time (Meerman et al. To be published).

CO₂ Compressor costs

The CO₂ compressor costs are based on the article of (Meerman et al. to be published), in which it is argued that the CO₂ compressor costs are different compared to regular (air) compressors, because the supercritical CO₂ compressor must handle a phase change during compression (Meerman et al. to be published). In the article a comparison is made of compressor costs from different sources (NETL 2008, Arienti et al. 2008, and Kreutz et al. 2008). In case of an oxy-fuel system the compressor is combined with drying of the flue gas. One of the options discussed in (Meerman et al. to be published) includes the costs of the drying compartment (NETL 2008) and is therefore selected: 11M\$₂₀₀₆ for 28 MW_e, with a scaling factor of 1 and an installation factor of 109%. The CO₂ separation (condensing CO₂ and H₂O) and compression technologies are seen as mature and its costs are therefore not expected to decrease (Peeters et al. 2007).

CO₂ transport costs

The transport costs of CO₂ can be split into small scale transport to a CO₂ hub and trunk transport to the storage site (as shown in Figure 4)

The small scale transport costs to a trunk pipeline are based on the research of Kuramochi et al. (2011). In this research a comparison is made between small scale truck and pipeline CO₂ transport,

¹ The standard equipment scale factor is determined by the ratio between the quadratic increase of the costs (the surface) and the third power increase for the size (volume) (Blok 2007).

² The base costs are the bare equipment costs. These were increased by the installation factor (IF), which consisted of direct (instrumentation and control, buildings, grid connection, site preparation, civil works, electronics and piping) and indirect (engineering, building interest, contingency, fees, overhead, profits and start-up costs) costs (Meerman et al. to be published).

by taking into account the investment costs, operational costs of onsite compression, recompression for trunk transport, transport, and temporary storage. In case of truck transport the CO₂ is compressed to 15 bar and later on re-pressurized to 100 bar for trunk transport; in case of pipeline transport compression to 110 bar is used (Kuramochi 2011). In Figure 9 the result of small scale transport research of Kuramochi (2011) is shown. The small scale transport costs are derived from the graph in Figure 9, taking the most economical option, truck or pipe transport.

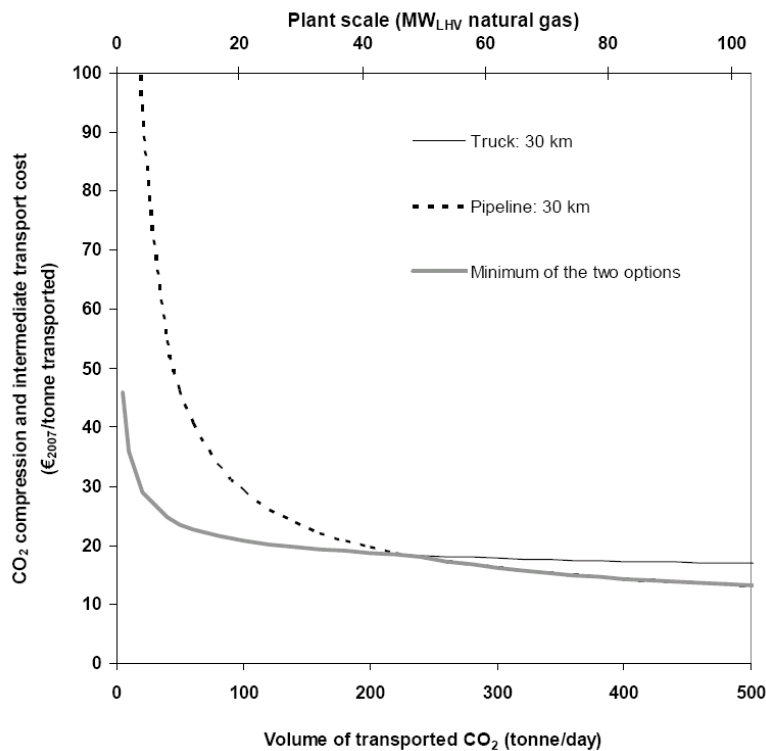


Figure 9. CO₂ transport costs small scale (Kuramochi 2011)

The distance estimation for industry site to trunk (30 km) is conservative, however the largest share of the costs are for CO₂ compression (Kuramochi et al. 2010). Even though the costs could be lower due to a shorter distance the effect will be limited due to the compression costs.

The long distance transport costs to a storage site are based on figures from (van den Broek et al. 2008). Taking into account the necessity to transport to offshore storage (section **CO₂ storage costs**) the case selected is: transportation of 200 km offshore, which result in total costs of 0.69 €/tCO₂.

CO₂ storage costs

The offshore storage costs are based on (van den Broek et al. 2008). Van den Broek et al (2008) have made some specific cost estimates for storage in the Netherlands, the costs per tonne CO₂ are for the period 2000-2020 5.6 €/tCO₂ and in the period 2020-2050 4.7 €/t CO₂. These costs are within the range presented in (EBN and Gasunie 2010, ZEP 2011b).

Table 8. Cost parameters of CO₂ capture 2030 and 2050

	Unit	2030	2050
Cost parameters			
Existing boiler cost ^a	€/kW _{th}	91.8	91.8
O&M costs boiler ^a	€/MWh _{th}	0.49	0.49
Scaling factor boiler ^b		0.67	
Post combustion capture			
Reference size ^c	MW	474	
Capture investment costs ^c	€/kW _e	335	286
Capture O&M costs ^d	%-of investment	4%	
Correction factor Gas engine ^e		0.72	
Scaling factor Capture costs ^d		0.7	
Oxy-fuel boiler costs			
Boiler oxy-fuel adaption costs ^f	€/kW _{th}	0,82	
O&M costs oxy-fuel boiler ^d	% of investment	3%	3%
ASU capital costs ^g	M€/(tO ₂ /day)	0.17	0.15
Scaling factor ASU ^d		0,8	
CO ₂ separation and compression capital costs ^h	k€/(MtCO ₂ /day)	1.1	1.1
Scaling factor compressor ⁱ		1	
CO₂ transport and storage			
Transport CO ₂ small scale ^d	€/tCO ₂ captured	Figure 9	Figure 9
Transport trunk line costs (Offshore) ^j	€/tCO ₂ captured	0.69	0.69
Storage costs ¹⁰	€/tCO ₂ captured	4.79	4.79

^a Value based on article of (Lazzarin and Noro 2006), assumed to be constant over time.

^b Value based on book of (Blok 2007), assumed to be constant over time.

^c Value based on average of literature values (IEA 2010b, IEA 2010a, Booth and van Os 2011, Sipöcz et al. 2011, Kuramochi et al. 2010, Rubin et al. 2007a, Rubin et al. 2007a, IEA and NEA 2010, Rubin et al. 2007b, IEA 2005), future values based on the Energy Technology Perspective 2010 of the IEA (IEA 2010a)

^d Value based on dissertation of (Kuramochi 2011), assumed to be constant over time.

^e Correction factor is based on article of (Egberts et al. 2003)

^f Based on article of (Allam et al. 2005b), value 0.93 M€/ktO₂/yr.

^g 2010 value based on article of (Arienti et al. 2008); because the ASU is a mature technology the costs are assumed to be constant over time (Meerman et al. To be published).

^h 2010 value based on report of (NETL 2008), because compression is seen as a mature technology the cost are assumed to be constant over time (Peeters et al. 2007).

ⁱ Value based on article of (Meerman et al. to be published).

^j Value based on article of (van den Broek et al. 2008)

3.4 Reference case data

The CHP(-CC) cases are compared with the reference technology (boiler + CCGT) and an alternative technology (oxy-fuel boiler + CCGT-CC). The technical and cost data of the boiler and oxy-fuel boiler are discussed in the previous section. To make a good comparison the costs, efficiency and emissions of the CCGT should be taken into account as well. In case a CHP is replaced by a boiler the electricity needed should be bought from the grid, because the increase of electricity consumption from the grid leads to more electricity production and emissions of the centralized power plants. Taking into account the change in CO₂ emissions of centralized electricity production an assumption about the emission factor has to be made.

Due to its high position on the merit order¹, the (gas fired) combined cycle has the possibility to increase the load. Therefore the calculations take into account a new combined cycle for changing electricity demand, with an efficiency of 59% in 2030 (Kuramochi et al. 2010, Seebregts et al. 2009) and 63% in 2050 (Kuramochi et al. 2010). The emission factors of such combined cycle plant are 0.347 tCO₂/MWh in 2030, and 0.323 tCO₂/MWh in 2050.

Emission factor NGCC(-CC)

The efficiency of NGCC-CC (CCGT with carbon capture) in 2030 is 53.8% (Kuramochi et al. 2010). The value of 2050, 59.1%, is calculated by taking into account the lower efficiency penalty. The factor, used to calculate the lower capture energy penalty in 2050, is applied to the efficiency penalty as well. The lower efficiency and the application of carbon capture result in a different emission factor of the NGCC-CC, which is calculated, assuming a capture efficiency of 90%. The emission factors of the NGCC-CC in 2030 are: 0.038 tCO₂/MWh; and in 2050: 0.034 tCO₂/MWh.

Electricity costs NGCC(-CC)

The costs to produce electricity centrally are calculated, taking into account the investment costs, O&M costs, and the fuel costs of a NGCC(-CC). The costs of investment and O&M are based on (Sipöcz et al. 2011), in which the electricity costs are presented of NGCC(-CC). The additional costs (15€/MWh) of a CCGT-CC compared to a CCGT are similar to the additional costs presented in (Booth and van Os 2011) (17€/MWh). The fuel costs are based on the same NG price as used in the whole quantitative analysis.

Table 9. General technical and cost parameters

	Unit	2030	2050
Technical parameters			
Efficiency centralized CCGT ^a	%	59%	63%
Efficiency centralized CCGT-CC ^a	%	53,8%	59,1%
Emission factor CCGT ^b	tCO ₂ /MWh	0.347	0.323
Emission factor CCGT-CC ^c	tCO ₂ /MWh	0.038	0.034
Electricity price CCGT ^d	€/MWh	9.20	
Electricity price CCGT-CC ^d	€/MWh	24.2	

^a The 2030 values are based on the articles of (Kuramochi et al. 2010, Seebregts et al. 2009) and the 2050 values are based on the article of (Kuramochi et al. 2010).

^b The values are calculated based on the efficiencies and the gas emission factor (56.6 kgCO₂/GJ).

^c Values calculated, based on the assumed efficiencies and a capture ratio of 90%.

^d Future value based on (Sipöcz et al. 2011), including installation costs and O&M costs. The 2030 and 2050 values are assumed to be similar.

¹ Ranking of centralized electricity production based on short term marginal costs.

3.5 Sensitivity analysis

The sensitivity analysis discusses the effect of changes in input parameters. Four important parameters with high uncertainty in the future are selected: electricity price, natural gas price, load hours and the investment costs.

First, the electricity price and natural gas price are two important criteria in the investment decision of a CHP plant; both are difficult to project for the future. Therefore those two variables are taken into account in the sensitivity analysis. Since the electricity price is influenced by the NG price, the sensitivity to the electricity and NG prices are calculated combined, using the prices from the scenario 'ECN Reference projections' (Daniëls and Kruitwagen 2010). The ECN reference estimation provides a low energy price case, because there is no high energy cost case available. The high cost case is defined by using the same relative change of the lower bound to determine the upper bound.

The investment costs of the capture unit are an important part of the avoided CO₂ costs. Besides uncertainty in the cost data estimations, the capture unit investment costs can differ a lot per CHP plant, due to the differences in industrial sites where the capture unit would be located. Therefore a sensitivity analysis of the investment costs is performed. Two cases based on literature values are used as high and low cost cases. The high cost data are based on (Rubin et al. 2007b), the lower cost data are based on (Booth and van Os 2011). The values are presented in Table 10.

The amount of load hours influences the economic potential a lot, because a higher usage rate of the installation makes the investment more economical. The amount of load hours is determined based on a maximum number of load hours. It is therefore essential to see the effect of a lower amount of load hours. The lower bound is defined as 60% of the maximum amount of load hours per sector.

Per parameter the effects on the capture costs in 2030 and 2050 are investigated. The range we are looking into is shown in Table 10.

Table 10. Parameters in sensitivity analysis

Parameter	Lower bound		Value used		Upper bound	
	2030	2050	2030	2050	2030	2050
Electricity peak price (€/MWh) ^a	83.0	93.1	106.6	106.6	130.2	120.1
Electricity off-peak price (€/MWh) ^a	63.3	69.3	80.4	80.4	97.6	91.6
Natural gas price (€/m ³) ^a	0.261	0.261	0.339	0.351	0.457	0.486
Investment costs (€/kW _e) ^b	254	216	335	286	416	355
Load hours (hours)	5250		8000		-	

^a Values lower bound based on ECN reference estimation (Daniëls and Kruitwagen 2010), upper bound is based on the assumption that the prices could increase with the same rate as it could decrease.

^b High cost data are based on (Rubin et al. 2007b), lower cost data are based on (Booth and van Os 2011), future values based on the Energy Technology Perspective 2010 of the IEA (IEA 2010a)

4. Combined heat and power plants

This chapter gives an overview of the different combined heat and power technologies. Many companies need electricity and heat for industrial processes, or for space heating and lighting. Facilities using CHP conventionally generate heat and/or steam with boilers or furnaces, and purchase centrally produced electricity from the grid. Combined heat and power (CHP) plants, however, combine the production of heat and power in a single process on-site. By using the, normally wasted, heat of electricity production, CHP can reach higher efficiencies than conventional alternative. Figure 10 illustrates this. The energy saving potential depends on the reference case and the type of CHP technology and ranges between 15-35% (GasTerra 2008).

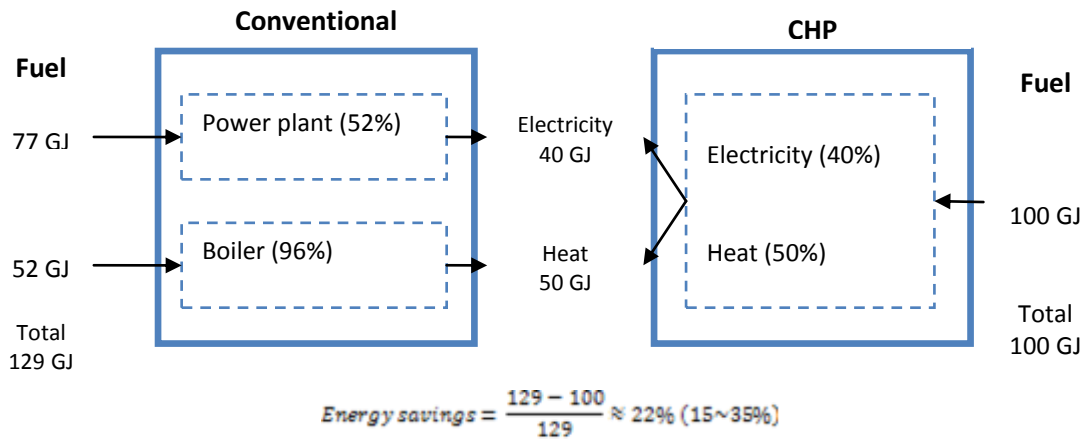


Figure 10. Energy saving potential CHP plant (GasTerra 2008)

Due to the higher efficiency, CHP can reduce energy costs, reduce CO₂ emissions, and provides users possibilities for selling electricity, while making them less dependence on electricity from the grid. However, CHP application also has some drawbacks. CHP users can have less flexibility to produce heat. It also requires major investments upfront, increases technical complexity, and requires qualified employees for operation and maintenance. CHP systems also need more space than boilers, and increase onsite emissions (e.g. NO_x) (GasTerra 2008). The financial revenue from selling electricity depends on the gas and electricity price ratio, which entails risk, as the investment in a CHP plant needs to be earned back by producing cheaper electricity than can be bought from the grid. A drop in electricity prices relative to gas prices raises CHP higher production costs, thereby reducing its revenues and economic viability.

The possibilities for operating CHP flexibly depend on the application. In continuous industrial processes, for instance, flexible operation is difficult. Using CHP flexibly, however, is an important way to increase its economic benefit, as it allows for producing electricity when prices are high.

Different technologies can be applied as CHP plant. The main ones are;

- Gas engine
- Gas turbine
- Steam turbine
- Combined cycle
- Fuel cell
- Stirling engine
- Organic Rankine cycle

4.1 CHP technologies

This section first discusses mature CHP technologies: gas engines, gas turbines, steam turbines, and combined cycle gas turbines (CCGT). Besides these common CHP technologies, several technologies are still being developed and applied to a minor extent: fuel cells, Stirling engines, and organic rankine cycle systems. In the longer term they could play a larger role. This section gives an overview of the technical aspects and the typical use of the different technologies. The different technologies deliver different kinds of heat. Here a distinction is made between high grade steam (>220°C, >8 bar), low grade steam (<220°C, 3-7 bar), and warm water (<120°C, 1 bar).

4.1.1 Gas engine

A gas engine is a gas fired internal combustion engine coupled to a generator to produce electricity, the waste heat can be used to deliver warm water. Gas engines have total efficiencies of 60-90% (Hers et al. 2008, COGEN Vlaanderen 2006), and are used as CHP in sizes ranging from 5 kW_e up to 5 MW_e. In the Netherlands, installed gas engines are mostly 0,5 MW_e or larger, of which the largest part is installed in the horticulture with a capacity of about 2 MW_e (van der Marel and Goudappel 2008), the engines in the built environment are smaller (<1 MW_e). The electrical efficiency depends on size, the larger the engine the higher its electrical efficiency. Full load efficiency ranges from 34-41% (Hers et al. 2008, COGEN Vlaanderen 2006). The thermal efficiency depends on the temperature of the produced heat: at a temperature of 70°C the efficiency is 45-55%, at a temperature of 90°C the efficiency is 20-30%. The thermal capacity of a gas engine depends on the temperature of the output heat. The ratio of heat and power production (HPR) decreases in case of high temperature heat output. At 70°C the HPR is 1 to 1.7; at 90°C the HPR is 0.5-1. Gas engines can supply warm water up to 120°C; or a limited amount of low grade steam of 120°C, but this decreases the total efficiency (GasTerra 2008). The flue gas of the gas engine has a CO₂ concentration of 9-10% (IEA GHG 2007).

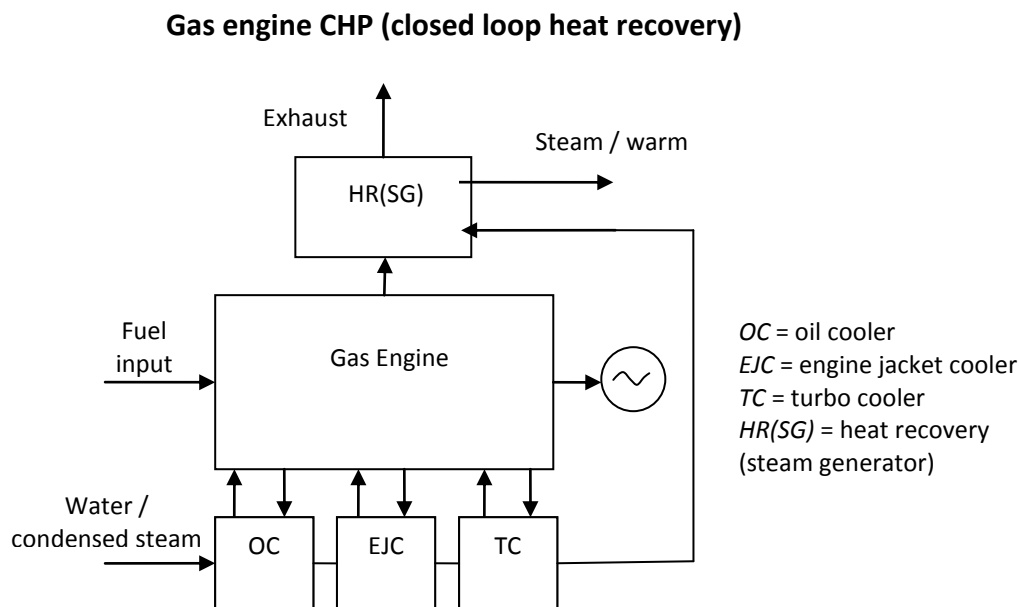


Figure 11. Closed loop heat recovery of gas engines (EPA 2002)

Gas engines can produce heat from several sources: exhaust gasses (400-550°C), turbo cooling (75-120°C), engine jacket cooling (30-80°C) and the lube oil cooling (75-95°C). Figure 11 shows the most common way of recovering the heat: a coolant (water) is circulated through the different cooling elements of the engine (turbo cooler, engine jacket cooler and turbo cooler) to an external heat exchanger. In the heat exchanger (HRS) the preheated coolant (water) is extra heated by the

exhaust gasses to produce warm water with high temperature or medium pressure steam (COGEN Vlaanderen 2006, EPA 2002).

Engine can start up rapidly (up to a minute (EPA 2008)) and have relatively high part load efficiencies. In part load, thermal efficiency decreases less than electrical efficiency, resulting in a rising HPR. At half load the electrical efficiency of the engine is 80% of the full load efficiency. Due to its part load behavior and the fast start up time the gas engine is often used as backup power unit (EPA 2002, BELCOGEN 2004, Kuhn et al. 2008). Important disadvantages of gas engines include maintenance costs and high noise levels. Table 11 summarizes the characteristics of gas engine CHP.

Table 11. Characteristics gas engine CHP

System		Gas engine
Electrical capacity	MW_e	< 5
Availability	% per Year	95
Electrical efficiency	100% load	30-40
	50% load	25-35
Total efficiency	%	60-88
CO ₂ -concentration	%	9-10
CHP investment costs	€/kW _e	590-850
Start up time		< 1 minute
HPR		0.5-1.7
Changeability HPR		Limited
Type of heat		Hot water (70-120 °C) and low grade steam (<220°C; 3-7 bar)
Typical application		Backup power; heating of buildings/ greenhouses; waste fermentation

4.1.2 Gas turbine

Gas turbine CHP generates electricity by expanding hot gases in a turbine, pre-heated and compressed air is led into the combustion chamber where it is combusted with injected gaseous fuel (mostly natural gas). The heated gasses are expanded in a turbine. The expanded gas has a high temperature (450-550°C) which is used in a heat regeneration steam generation (HRSG) to produce high grade steam (Figure 12). The electrical efficiencies for 3-20 MW_e plants are 20-30% (COGEN Vlaanderen 2006) and for 20-40 MW_e plants 30-40%, the thermal efficiency is between 40-60% (COGEN Vlaanderen 2006), which result in total efficiency up to 90% (COGEN Vlaanderen 2006). For gas turbines lower pressures and temperatures result in lower efficiency of the turbine itself. The part load efficiencies are therefore considerable lower than full load efficiencies, since lower output is achieved by lowering combustion temperature. The lowest part load normally applied is 70-75% of full capacity. Gas turbines are available at sizes ranging from 1 to 200 MW_e; the larger capacities are applied in power plants. Due to a limited (continuous) heat demand CHP applications are mostly up to the size of 40 MW_e, in case of larger capacities gas turbines are combined in parallel (GasTerra 2008, COGEN Vlaanderen 2006, BELCOGEN 2004).

Gas turbines can supply saturated steam at 10 bar with a rate of 2 t/h per MW_e. Since turbines are fired with excess air, the flue gas contains up to 15% of oxygen, allowing for after-burning, producing extra heat by firing flue gas with additional fuel in the HRSG up to 750-800°C. The HPR can be regulated in this way and the steam production can be doubled. The HPR is generally between 1.25 and 2, and the CO₂ concentration of the flue gas is 3-4% (IEA GHG 2007).

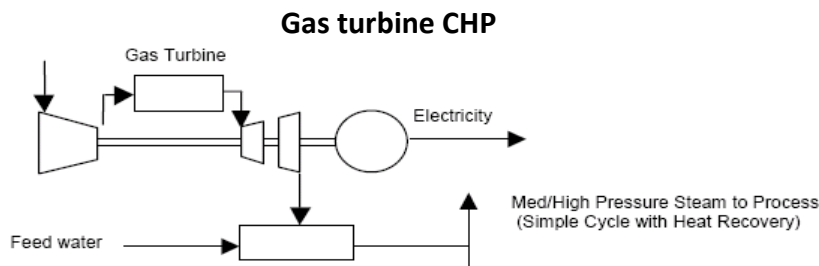


Figure 12. Heat recovery by a gas turbine (EPA 2002)

Gas turbines are mostly used for full-load applications, operating continuously, because of its low part-load efficiency, and continuous use prevent mechanical wear (the amount of starts and stops must rather be kept under 20 stops a year). The startup time of gas turbines varies between 10 minutes up to 1 hour (EPA 2008). Due to their reliability gas turbines are often applied in (large) industrial processes (GasTerra 2008, COGEN Vlaanderen 2006, EPA 2002, BELCOGEN 2004, Kuhn et al. 2008).

Gas turbine CHP is also possible by using the heat produced by the gas turbine directly, instead of using a HRSG. By integrating the CHP in an industrial process (in the chemical industry, refineries or for drying processes, for example) the exhaust gasses can be used directly within the process. This direct use of heat results in a lower flexibility due to the tight integration of (mostly) continuous industrial processes, and because switching to a different heat source is more difficult than to switch to a different steam source. The current application of direct heating CHP in the Netherlands is low, e.g. in the chemical industry only 5% of the direct heat is supplied by CHPs, however the companies estimate a potential of 25% in the chemical sector (Davidse 2010). Table 12 summarizes the characteristics of gas turbine CHP.

Table 12. Characteristics gas turbine CHP

System		Gas turbine
Electrical capacity	MW_e	1-250 (1-40)
Availability	% per Year	92
Electrical efficiency	100% load	20-40
	50% load	18-30
Total efficiency	%	60-80
CO ₂ -concentration	%	3-4
CHP investment costs	€/kW _e	960-1,450
Start up time		< 1 hour
HPR		1.25-2
Changeability HPR		Limited
Type of heat		Heat, low-high grade steam (10-100 bar; 220-540°C) and hot water
Typical applications		Large demand for high grade steam.

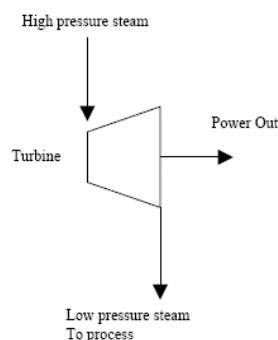
4.1.3 Steam turbine

The two main steam turbine types used for CHP plants are back pressure turbines and extraction turbines. For both types an external heat source is used to compress water to high pressure (40-80 bar) and heat it to superheated steam. A multistage turbine expands the pressurized steam to lower pressure (5-20 bar) before the steam is fed to industrial application. The back-pressure (non-condensing) steam turbine delivers steam at a fixed pressure level, the steam expands until it has reached the required conditions for its use. The HPR of such a turbine cannot be adjusted, in case no steam is required no electricity is produced either. In the extraction turbine the condensed water is returned to the feed water pump to complete the cycle, steam needed for the industrial process is tapped at certain point in the turbine where the pressure is at the required level. Since the extraction rate can be managed the HPR is changeable.

Steam turbine CHP is different than other CHP technologies, because its heat source is external, e.g. boilers, furnaces or steam produced in an industrial process. Because electricity is a subsequent product of heat generation, the electrical efficiency (14-35%) is relatively low compared to other CHP technologies, and the HPR is high, 2-10 (COGEN Vlaanderen 2006). The total efficiencies on the other hand, are comparable with other CHP technologies (60-88%) (COGEN Vlaanderen 2006). Steam turbines can be up to 600 MW_e for central power plants, but CHP plants are generally smaller (up 40 MW_e). Depending on their size, the start-up time is up to several hours (EPA 2008). The CO₂ concentration of the flue gas is 8-10% (IEA GHG 2007).

Steam turbines can deliver a broad range of steam pressures. The turbines are custom designed to deliver the thermal requirements of the CHP applications through use of backpressure (rest steam, after the expanding in the turbine) or extraction steam at appropriate pressures and temperatures (Figure 13). Small steam systems produce low-pressure lines used for space heating and food preparation (low grade steam). Industrial processes, cogeneration and utility power generation typically require high grade steam (GasTerra 2008, EPA 2002, BELCOGEN 2004).

Back pressure steam turbine CHP



Extraction steam turbine CHP

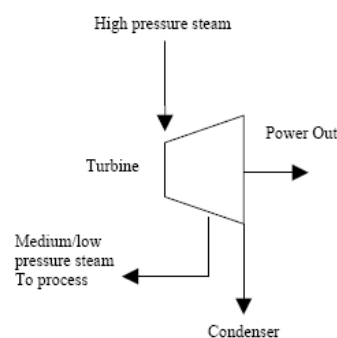


Figure 13. Non-condensing back pressure turbine and extraction turbine (EPA, 2002)

Steam turbines are most suited for medium and large scale industrial application where inexpensive fuels can be used (coal, residual gas/oil). Currently, steam turbines are only installed in the case a high grade steam production (boiler or furnace) is already in place, otherwise a gas turbine is preferred (GasTerra 2008, EPA 2002, BELCOGEN 2004). Table 13 summarizes the characteristics of steam turbine CHP.

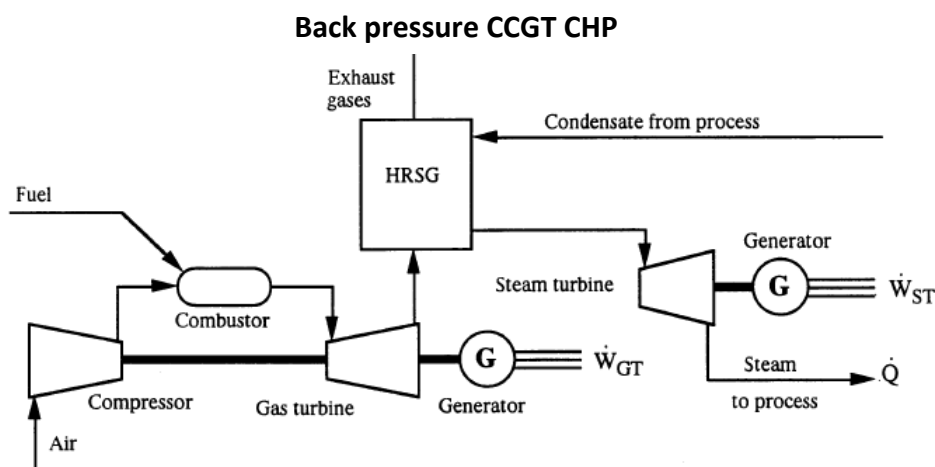
Table 13. Characteristics steam turbine CHP

System		Steam Turbine
Electrical capacity	MW_e	0.5 – 600
Availability	% per Year	93
Electrical efficiency	100% load	14-35
	50% load	12-28
Total efficiency	%	60-88
CO ₂ -concentration	%	8-10
CHP investment costs	€/kW _e	350-1,300
Start up time		< 1 day
HPR		2-10
Changeability HPR		Only a extraction turbines
Type of heat		Low- high grade steam (5-20 bar; 150-220°C)
Typical applications		Producing electricity from an external heat source (e.g. boiler).

4.1.4 Combined Cycle

Gas-fired combined cycle (CCGT) combines a gas turbine and steam turbine integrated in one cycle. The gas turbine exhaust gas is used to produce steam in a HRSG which is used into a steam turbine as bottoming cycle. Due to the combination of two turbines a CCGT produces relatively much electricity compared to steam. The most important condition for a CCGT as CHP is that the industry needs large amounts of electricity and a lot of steam at medium-high pressure (7-10 bar) (GasTerra 2008, COGEN Vlaanderen 2006, EPA 2002, BELCOGEN 2004). Its total efficiency can be 80-90%, of which the electrical efficiencies vary between 42% and 58% depending on the heat supply (COGEN Vlaanderen 2006, EPA 2002). The CCGT has capacities ranging from 5 MW_e to 400 MW_e. The startup time is up to one hour (DEA 2010), and its CO₂ concentration of the flue gas is 3-4% (IEA GHG 2007).

The pressure of the process steam has a direct influence on the enthalpy drop of the steam turbine, the higher the pressure, the lower the power output. A need for high pressure steam in the industrial process limits the possibilities of using of a steam turbine , since the remaining pressure differential is then too small (Kehlhofer 1997). In these cases, the revenues from the additional electricity production by the steam turbine do not outweigh the extra investment needed for a CCGT (steam and gas turbine), so a gas turbine with afterburning is than preferred.


Figure 14. Back pressure CCGT (COGEN Vlaanderen 2006)

CCGT installations exist in several configurations. The high grade steam produced in the HRSG can be fed into the steam turbine or directly to an industrial process. Two different steam turbines can be used, the back pressure turbine and the extraction turbine (Figure 14). All installations can be equipped with supplementary firing, which offers greater design and operating flexibility than by using waste heat. The production of steam or thermal energy can be controlled independently of the electrical power output, because the gas turbine has control of the power output and the auxiliary firing handles control of the steam or heat generation (Kehlhofer 1997). In this way the HPR can be adjusted between 0-2. Especially large CCGT use this kind of configuration. However, in this set-up efficiency deteriorates at part load, due to load control of the gas turbine (by changing the turbine inlet temperature) (Kehlhofer 1997). Table 14 summarizes the characteristics of CCGT CHP.

Table 14. Characteristics combined cycle CHP

System		CCGT
Electrical capacity	MW_e	5-400
Availability ¹	% per Year	93
Electrical efficiency	100% load	42-58
	50% load	30-35
Total efficiency	%	80-90
CO ₂ -concentration	%	3-4
CHP investment costs	€/kW _e	880-1,200
Start up time		< 1 hour
HPR		0-2
Changeability HPR		Possible
Type of heat		Low-high grade steam (7-10 bar; 150-220°C)
Typical applications		High electricity and steam demand at industrial site.

4.1.5 Fuel cell

Fuel cells are an emerging technology, which uses an electrochemical process to convert the chemical energy of the fuel into water and electricity instead of making use of combustion. Fuel cells system consist of three sub parts: the electricity producing part, the fuel conversion part, and the power conditioner, which converts DC into AC current.

The fuel cell itself (electricity producing part) consists of a cathode (positively charged electrode), an anode (negatively charged electrode) and an electrolyte. The steam reformed fuel enters the anode side of the cell, reacts into ions (H⁺) and electrons, forming H₂O at the cathode side of the cell. The electrons produced flow through an external electrical circuit. Compressed and pre-heated air enters the cathode side of the cell, so the oxygen source and the fuel are separated. Oxygen is reduced to O²⁻ ions, and moves through an electrolyte to react on the fuel/anode side with the H⁺ produced there (electrochemical reaction) (Figure 15). Since in practice higher voltages are needed (up to hundred) cells are installed in series into a fuel stack.

Several types of cells are being developed. The focus will be on the cells which provide opportunities to operate at larger scale at higher temperatures, since these cells have more CHP opportunities. The high temperatures create two possible benefits, (1) when using hydrogen as fuel, high grade steam

¹ Values from (Hers et al. 2008)

can be produced or (2) when using natural gas as fuel, this can be reformed internally. The two types of fuel cells able to operate under these conditions are Solid Oxide Fuel Cell (SOFC) and Molten Carbonate Fuel Cell (MCFC). In SOFCs, the electrolyte is a ceramic material; in MCFCs, a molten salt is used as electrolyte (GasTerra 2008, COGEN Vlaanderen 2006, EPA 2002, and BELCOGEN 2004). For both technologies the heat output ranges from warm water to high grade steam. However, as the internal reforming already requires most of the produced steam, the main output is warm water. The CO₂ concentration of the flue gas is 2-3% for SOFCs, 7% for MCFCs (Kuramochi et al. 2011).

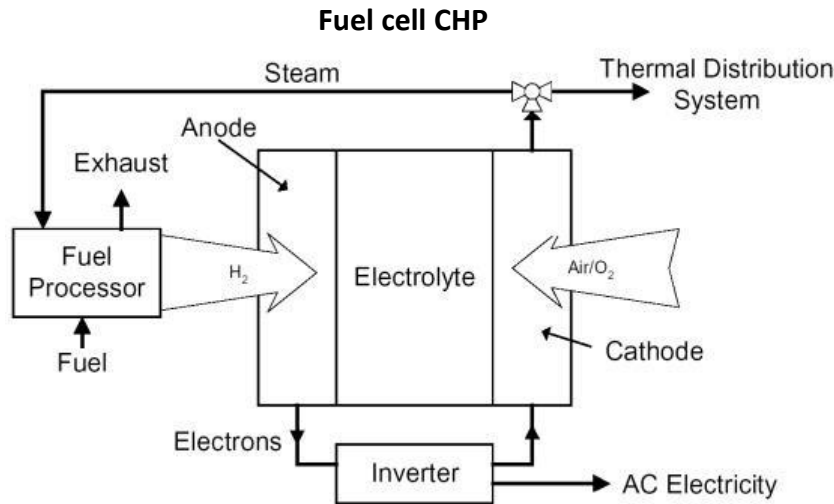


Figure 15. Fuel cell as CHP schematically (BELCOGEN, 2004)

The ratio of the operating voltage and the theoretical voltage achievable (1.48 volt in case of SOFC) determines the efficiency of the fuel cell. Compared to existing technologies, the fuel cells have several benefits: high electrical efficiencies (45-60%), good part load behavior (same efficiency up to ¼ load), modular design, low noise levels, absence of moving parts, and low SO₂ and NO_x emissions. However, given their immaturity, further research is necessary. Even after extensive testing (SOFC (Siemens, Mistubishi) and MCFC (Fuel Cell Energy, MTU)), the lifetime, reliability and maintenance of the fuel cells still need to be proven. The main disadvantages, however, are high costs, long start-up times (10-20 hours (DEA 2010)), and the need to reform fuel to hydrogen in many cases¹.

Fuel cells require hydrogen or methanol for the electrochemical reaction, which requires reforming conventional fuels. Fuel cells operating at high temperatures can reform fuel (usually natural gas) by internally steam reforming, the heat produced by the electrochemical reactions is used in the steam reforming process. This requires a high integration of the two processes which makes such cells more difficult to design and operate.

MCFC (Molten Carbonate Fuel Cell)

Although different developers (e.g. Fuel Cell Energy) have demonstrated MCFC in different sized pilot plants, further research is necessary to obtain further cost reduction (Moreno and McPhail 2008). The operating temperatures of the cell are in the range of 600 to 750°C, which is needed in case of internal reforming of the fuel. This also increases the possible applications as CHP, because high-temperature cells can produce warm water as well as steam. The electrical efficiencies are expected to be around 50% (COGEN Vlaanderen 2006, EPA 2002). The disadvantages are high operating temperature and the corrosive nature of the electrolyte, which cause degradation of the cell components. Therefore the main technological issue to overcome is degradation by improving

¹ An exception is a new model in the early stage of development, direct methanol fuel cell, which can be fired with methanol (EERE 2011)

component material. Another disadvantage of the MCFC is the necessity of recirculation of CO₂ from the anode to the cathode. The recirculation is needed to keep O₂ : CO₂ with the molar fraction 1 : 2 to keep the ion flow constant (GasTerra 2008, COGEN Vlaanderen 2006, EPA 2002, and BELCOGEN 2004).

SOFC (Solid Oxide Fuel Cell)

SOFCs are less mature than MCFCs, but have several advantages: high efficiency, stability and reliability, and high internal temperatures. Two types of SOFC cells are currently in development, tubular cells and planar cells (Figure 16). Tubular cells are further developed than planar cells, and are easier to seal and have a more robust structure. In the planar cells it is more difficult to seal the oxidant from the fuel, but the advantage is a higher volumetric power density due to a shorter current path. The tubular cells have been tested more extensively and their stability has been proven. However, most developers see a clear advantage in the cost reduction potential of the planar cell technology, due to the potential higher volumetric power density. Therefore, the planar cells are the better option for the longer term (Kuramochi et al. 2011, Blum et al. 2005).

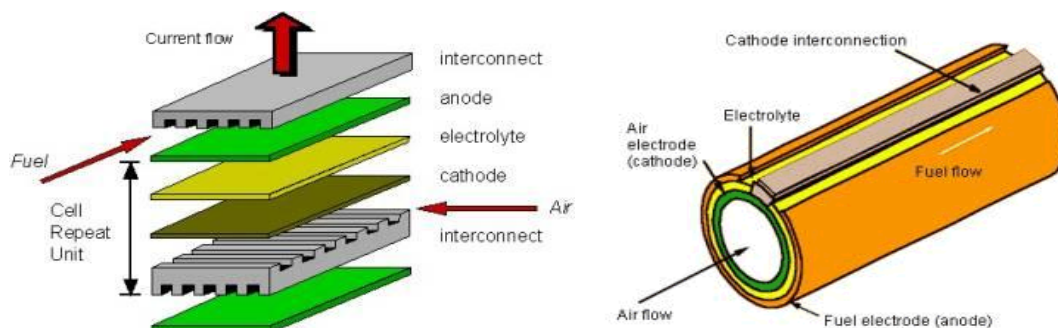


Figure 16. Fuel cell configuration planar (left) and tubular (right)

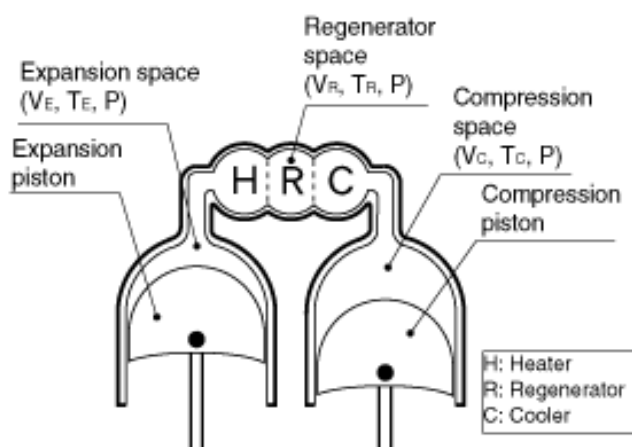
The reached electrical efficiencies of smaller SOFC units are up to 60% and even higher for larger combined cycle plants. SOFC can be combined with gas turbines (SOFC-GT) to increase scale (Damen et al. 2006, COGEN Vlaanderen 2006). These cycles are only proven for scales up to 1 MW_e, theoretical cycles are up to 20 MW_e (Damen et al. 2006). Due to its all-solid-state ceramic construction, SOFCs are more stable and reliable than MCFCs. High internal temperatures 800 to 1000°C (COGEN Vlaanderen 2006) makes internal reforming possible, but high temperatures make mechanical design and material use more difficult (GasTerra 2008, COGEN Vlaanderen 2006, EPA 2002, BELCOGEN 2004). Despite 30 years research on SOFC cells, the costs are still 10.000 €/kW_e (DEA 2010). Table 15 summarizes the characteristics of fuel cell CHP.

Table 15. Characteristics fuel cell CHP

System		Fuel cell
Electrical capacity	MW_e	< 1 (SOFC-GT <20MW _e)
Availability	% per Year	unavailable
Electrical efficiency	100% load	45-60
	50% load	45-60
Total efficiency	%	85-90
CO ₂ -concentration	%	8-10
CHP investment costs	€/kW _e	10,000
Start up time		10-20 hours
HPR		0.5-1.25
Changeability HPR		?
Type of heat		Small amount of high grade steam (220°C; 10 bar); warm water.
Typical applications		Space heating, small industrial sites.

4.1.6 Stirling engine

Stirling engines are external combustion engines, closed systems, in which energy exchange only takes place from a heat source (H in Figure 17). They can use any heat source above 750 °C (gas fired, wood oven or even waste heat). The electricity efficiency might be 40-50% for the large cases in the future (BELCOGEN 2004), the current micro-CHP plants have an electrical efficiency of 15-26% (Sommer 2011). The main advantage compared to a gas engine is a higher electric efficiency because the Stirling cycle comes closer to the Carnot cycle than the joule cycle (gas engine principle) (COGEN Vlaanderen 2006). The engine has a warm and a cold part, the working gas (helium or air) is compressed in the cold side and expanded in the heated side. A regenerator (internal heat exchanger) is used to make the process reversible (Figure 17). The cold side is cooled with cooling water, which can be used for space heating (in case of a CHP configuration). Two types of pistons, the compression piston and the expansion piston, drive a flywheel to generate electricity (COGEN Vlaanderen 2006, Hirata 1997).

Stirling engine

Figure 17. Schematic picture of a Stirling engine (Hirata 1997)

Stirling engine efficiency increases as the temperature difference rises, making it essential to keep the cold side at a low temperature. The Stirling engines CHP is therefore only used to heat water up to 100°C. Slow start-up is a disadvantage of Stirling engines, caused by the need to warm up taking up to an hour (EPA 2008). Current commercial Stirling engine CHP systems include mostly micro-CHP with a capacity of just several kWe up to 55 kWe. Larger CHP plants (1-1.5 MW_e) are still under development. The HPR is around 0.8-1.7 (COGEN Vlaanderen 2006). The CO₂ concentration of the flue gas is assumed to be similar to a steam turbine, i.e. 8-10%, because the Stirling engine uses also an external heat source. Table 16 summarizes the characteristics of Stirling engine CHP.

Table 16. Characteristics Stirling engine CHP

System		Stirling engine
Electrical capacity	MW _e	< 1,5
Availability	% per Year	unavailable
Electrical efficiency	100% load	40-50 (14-26% for micro-CHP)
	50% load	39-49
Total efficiency	%	60-80
CO ₂ -concentration	%	8-10%
CHP investment costs	€/kW _e	2,200
Start up time		< 1 hour
HPR		0.8-1.7
Changeability HPR		?
Type of heat		Warm water (70-100°C).
Typical applications		Space heating

4.1.7 Organic rankine cycle

Organic rankine cycle (ORC) systems are based on a normal (water) steam turbine, using a different operating fluid. Unlike water, organic fluids can be expanded without condensing, with the advantage that they evaporate at lower temperatures, keeping a relatively high pressure. Due to this characteristic it is not necessary to superheat the steam before using it in a turbine, and it is possible to capture the energy from low temperature heat streams. The ORC system has capacities up to 10 MW_e, and is increasingly used at larger scales. Its electrical efficiencies are between 10-25% (part load 8-24%) (COGEN Vlaanderen 2006), its total efficiency is 60-85%, and the HPR is similar to the steam turbine, 2.5-10. The ORC differs from other cycles, because heat is the main product from which some electricity is generated, while other CHP technologies produce electricity and make the 'waste heat' useful (COGEN Vlaanderen 2006). ORC systems need up to an hour to warm up, so ramping up is not as quick as with gas engines and gas turbines (EPA 2008). The CO₂ concentration of the flue gas is assumed to be similar to the steam turbine, 8-10% (IEA GHG 2007). Table 17 summarizes the characteristics of ORC CHP characteristics.

Table 17. Characteristics organic rankine cycle CHP

System		Organic Rankine cycle
Electrical capacity	MW_e	< 10
Availability	% per Year	unavailable
Electrical efficiency	100% load	10-25
	50% load	8-24
Total efficiency	%	60-85
CO ₂ -concentration	%	8-10
CHP investment costs	€/kW _e	1,500-4,000
Start up time		< 1 hour
HPR		2.5-10
Changeability HPR		Limited
Type of heat		-
Typical applications		Producing electricity from waste heat

4.2 Overview characteristics CHP technologies

In general, CHP plants are tailor-made for their application, except for gas engines, which are mass-produced. CHP plants are designed to fit the heat demand, and to ensure heat supply most CHP plants have back-up boilers. This provides operational flexibility, but adjusting to a structural change of heat demand (due to a capture facility or energy saving processes) is difficult though, unless the HPR can be adjusted (e.g. a combined cycle with a flexible HPR or a gas turbine with afterburner). Table 18 gives an overview of the main characteristics of CHP technologies. Two of the recent technologies: Stirling engines and ORC systems are only available at small scale. Their small scale limits their possible applications (they can only replace gas engines), and makes them less suitable to combine with carbon capture. Therefore these technologies will not be taken into account in further analysis. The other emerging technology, fuel cells (SOFCs), can be integrated with capture, making it a potential integrated CHP-CCS solution. SOFCs are therefore taken into account as capture option, despite their small scale.

Table 18. Characteristics per CHP technology

System			Gas engine	Gas turbine	Steam Turbine	CCGT	Fuel cell	Stirling engine	Organic Rankine cycle
Electrical capacity	MW _e		< 5	1-250 (1-40)	0.5 – 600	5-400	< 1 ^a	< 1,5	< 10
Availability ^b	% per Year		95	92	93	93	Unavailable	Unavailable	Unavailable
Electrical efficiency	100% load		30-40	20-40	14-35	42-58	45-60	40-50	10-25
	50% load		25-35	18-30	12-28	30-35	45-60	39-49 ^c	8-24
Total efficiency	%		60-88	60-80	60-88	80-90	85-90	60-80	60-85
CO ₂ concentration	%		9-10	3-4	8-10	3-4	8-10	8-10 (assumed)	8-10 (assumed)
CHP installation costs	€/kW _e		590-850 ^b	960-1,450 ^b	350-1,300 ^d	880-1,200 ^b	10,000 ^e	2,200 ^b	1,500-4,000 ^f
Start up time			< 1 minute ^g	< 1 hour ^g	< 1 day ^g	< 1 hour ^e	10-20 hours ^e	<1 hour ^e	< 1 hour ^e
HPR			0.5-1.7	1.25-2	2-10	0-2	0.5-1.25	0.8-1.7	2.5-10
Changeability HPR			Limited	Limited	Only at extraction turbines	Possible	?	?	Limited
Type of heat			Hot water (70-120 °C) and low grade steam (<180°C; 3-7 bar)	Heat, low-high grade steam (10-100 bar; 220-540°C) and hot water	Low- high grade steam (5-20 bar; 150-220°C)	Low-high grade steam (7-10 bar; 150-220°C)	Small amount of high grade steam (220°C; 10 bar); warm water.	Warm water (70-100°C).	-
Typical applications			Backup power; heating of buildings/ greenhouses; waste gas use	Large demand for high grade steam.	Producing electricity from a heat source.	High electricity and steam demand at industrial site.	Space heating, small industrial sites.	Space heating	Producing electricity from an external heat source, e.g. boiler

^a The size of the fuel cell is currently up to 1 MW, by combining several stacks larger plants would be possible in the future (SOFC-GT < 20MW_e)

^b Values from (Hers et al. 2008),

^c Electrical efficiencies for future larger scales, micro-CHP plants have electrical efficiencies of 15-26% (Sommer 2011).

^d Values from (WADE 2006)

^e Values from (DEA 2010)

^f Values from (Nored et al. 2009, Siada et al. 2010)

^g Values from (EPA 2008)

5. CHP in the Netherlands

In the Netherlands various sectors use CHP, which can be clustered in four main groups of sectors:

- Agriculture
- Industry
- Built environment
- Other sectors

This chapter describes the CHP application in the Netherlands in these different sector clusters.

Compared to European countries the Netherlands generates a relatively large part of its electricity with CHP plants. In 2009 32% of the electricity is produced with CHP plants (compared to an average of 11% for European countries). Only Denmark (45%) and Finland (36%) have higher market shares for CHP plants than the Netherlands (Eurostat 2011a).

Installed CHP capacity in the Netherlands doubled compared from 1990 to 1998, reaching 20 GW_e (Klooster et al. 2005). The main reason was the beneficial regulatory environment for CHP; distribution companies were obliged to buy the electricity produced by CHP plants for a fixed price, which was high compared to the gas price (GasTerra 2008, Klooster et al. 2005, and van Oostvoorn 2003). However in 1998 the Electricity act was introduced in order to liberalize the electricity market. As a consequence the fixed electricity price for CHP was abolished, the off-peak electricity price dropped and the gas price increased. These factors, combined with the fact that many CHP plants had been installed at the most suitable sites already, resulted in a stagnation of the CHP market from 1998 onwards (Klooster et al. 2005). Until 2005-2008, when a large number of gas engine CHP systems was installed in horticulture (Smit and van der Velden 2008) (see Agriculture chapter). These trends are shown in Figure 18. During 2003-2007 CHP was eligible for subsidies from the MEP-regulation (Environmental quality and Electricity production), but when the MEP-regulation was replaced by the SDE-regulation (Stimulation of renewable energy production) in 2008, the subsidy for CHPs was abolished.

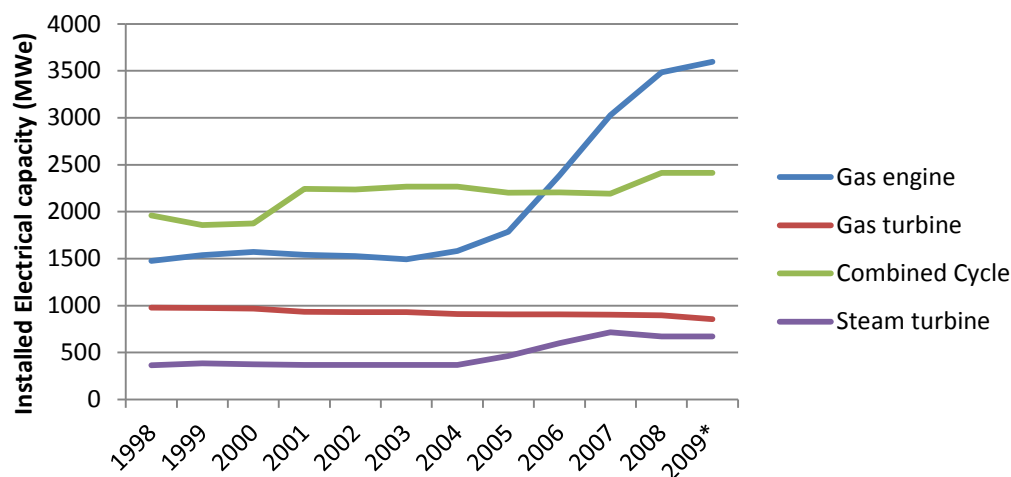


Figure 18. Installed Electric capacity per CHP technology (CBS, 2011)

Table 19 presents the average size per CHP technology in 2009, calculated based on CBS data of 2010 for the year 2009, showing large differences between the different technologies. Combined cycle gas turbine CHP installations have a large average capacity (65 MW_e), whereas gas and steam turbines are typically medium sized (13 and 18 MW_e). The average gas engine capacity is less than 1

MW_e (0.8 MW_e), which is smaller compared to the current gas engine sizes, because older gas engines have smaller capacities.

Table 19. Average size of CHP per technology in 2009 (CBS, 2010)¹

	Number of installations	Electrical capacity (MW _e)	Average size (MW _e)
Gas engine	4366	3597	1
Gas turbine	64	857	13
Combined cycle	36	2412	65
Steam turbine	36	670	18
Total	4502	7536	

5.1 CHP application in different sectors

The main clusters: agriculture, industry, built environment, and other sectors, consist of several sectors (CBS division) as shown in Table 20. These different clusters have different usage characteristics of the CHP.

Table 20. Number of CHP plants and installed capacity (MWe) per sector in the Netherlands in 2009

Sectors	Installed CHP plants	Installed power (MW _e)
Agriculture		
Agriculture: includes cattle breeding and the greenhouse horticulture.	2900	3050
Industry		
Chemical industry (chemistry): The chemical industry implies manufactures (non-) organic basic chemicals, fertilizers, plastics, paint, cleaning products, glues, synthetic and artificial fiber.	48	2045
Refineries and mining companies: Oil refinery and extraction of oil, natural gas, sand, gravel or salt.	31	394
Paper industry: Production and processing of paper and cardboard.	25	308
Food industry: Producing food, drinks and processing tobacco.	76	487
Other industry: includes several industries producing materials (i.e. cotton, wood, glass, cement, lime, metal, and gypsum), machinery industry, and publishers.	58	86
Built environment		
Distribution companies: Companies producing, distributing electricity, natural gas, warm water.	79	315
Other producers: All other producers (e.g. fishery, building sector, retailers, financial sector).	813	294
Healthcare: hospitals, nursing homes.	450	159
Other sectors		
Waste sector: environmental services processing waste by incineration.	30	398
Total	4105	7536 MW_e

¹ The figures in this chapter are based on decentralized CHP data from CBS of the year 2009 (CBS 2010), as mentioned in the method CHP data chapter

Two sectors do not entirely fit in the classification: the waste sector and distribution companies. In this study the waste sector is therefore included in other sectors and distribution companies are taken into account in the built environment, because most CHP plants are used for district heating (heating of houses).

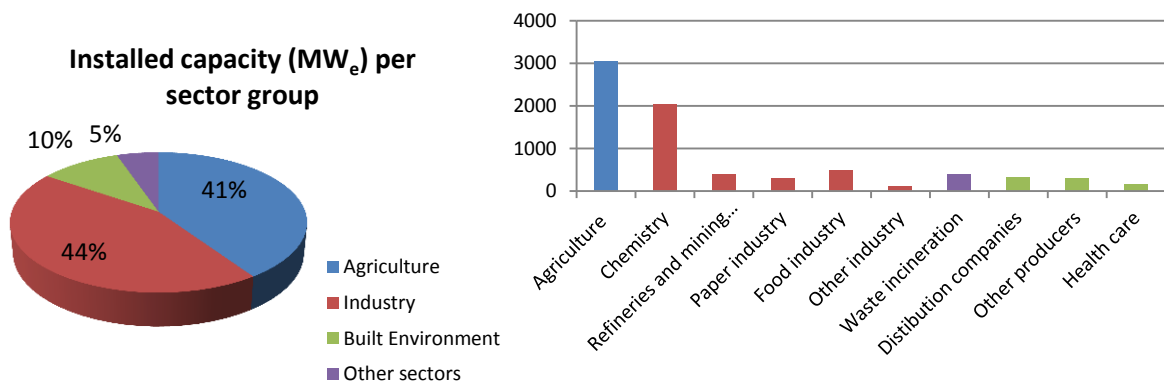


Figure 19. Installed capacity (MW_e) per sector group (left); Electric capacity installed per sector (MW_e) (CBS, 2010) (right)

Figure 19 shows that industry and agriculture represent the main sectors using CHP in the Netherlands. The contributions of the built environment and other sectors are much smaller. Table 21 gives an overview of characteristics per sector and Table 22 the type of heat demand. Both tables show the diversity of the different sectors.

Table 21. Characteristics CHP plants per sector in 2009 (CBS, 2010)

	Production	Steam/heat production	Average HPR	Average electrical efficiency	Average thermal efficiency
	Electricity production				
	PJ	PJ		%	%
Agriculture	42	56	1.3	36%	47%
Chemistry	41	69	1.7	30%	49%
Refineries and mining companies	7.7	16	2.1	27%	55%
Paper industry	5.4	10	1.9	28%	52%
Food industry	7.6	18	2.3	24%	56%
Other industry	1.0	4.2	4.2	17%	72%
Distribution companies	4.4	2.2	0.5	39%	20%
Other producers	3.7	4.2	1.1	35%	39%
Health care	2.4	3.8	1.6	31%	50%
Waste incineration	7.6	3.7	0.5	21%	10%
Total	123	186			

Table 22. Heat distribution per sector in % (Spoelstra 2005)

Type of heat supply	Temperature	Agriculture	Chemistry	Metal	Other industry	Other producers
Warm water	< 120°C	100%	5%	15%	29%	100%
Steam	100-250°C		11%	0%	38%	
	250-500°C		27%	5%	13%	
	500-750°C		21%	0%	0%	
	750-1000°C		26%	10%	0%	
	>1000°C		10%	70%	21%	

The number of load hours is an important factor determining the economic viability of CHP plants. A high number of load hours is preferred to recover the additional investment costs of CHP compared to conventional heat and electricity supply. For this study, an expected maximum of load hours has been determined, differing by CHP technology and by sector (Table 23). CBS average values form the basis for this, but to determine the maximum load hours per CHP technology per sector, the CBS values have been adjusted based on literature (Wetzels et al. 2010), case studies from the CODE project (EERE 2010), and opinions of CHP experts (Sytze Dijkstra, ECN; Wouter Wetzels, ECN; Simon Minett, Challock Energy; Jacob Klimstra, Wärtsilä). Table 23 shows that steam turbines usually have fewer load hours than other CHP technologies, because they have lower electrical efficiencies and better part-load efficiency. They therefore have less incentive to operate as full load than other technologies, resulting in to slightly fewer load hours.

Table 23. Maximum full load hours per CHP technology per sector

	Gas engine	Gas turbine	Combined cycle	Steam turbine
Agriculture	4500	-	-	-
Chemistry	8000	8000	8000	7500
Refineries and mining companies	8000	8000	8000	7500
Paper industry	6500	6500	6500	6000
Food industry	7000	7000	7000	6500
Other industry	5000	5000	-	5000
Built environment	4000	4000	4000	4000
Waste incineration	5000	-	-	5000

In practice, the number of load hours differs substantially from installation to installation, as explained in the examples given in the coming sections. The analysis in this study requires a choice for a characteristic number of load hours per technology per sector. As it is energetically and economically most attractive to operate CHP at full load, the maximum number of full load hours (as given in Table 23) has been selected in the further analysis. The effects of fewer full load hours are taken into account by performing sensitivity analysis on full load hours.

Must-run CHP installations are those that do not respond to differences in electricity prices, such as between base and peak prices (Wetzels et al. 2010). The share of must-run CHP varies by sector this study adopts the assumptions on must-run installations from Wetzels et al. (2010):

- All plants using waste gases from chemical processes, refinery gas or coke oven gas are must-run installations, because those gases are produced anyway
 - o 50% of gas-fired CHP in the chemistry sector is must run
 - o 70% of gas-fired CHP in the refinery sector is must run
- 25% of the gas engines in service sectors are must-run
- 10% of CHP in de paper, food en other industry sectors

5.2 Role of CHP in different sectors

This section describes the sectors in detail; more precise numbers will give a better insight in the Dutch CHP situation. Per sector the main reason to install a CHP plant is identified, followed by the characteristics of the CHP that affect the possibilities for combining CHP and CO₂ capture technology. In general natural gas is used as fuel CHP plants in the Netherlands, but in some cases also other gases (e.g. refinery gas) are used. In case the fuel is not natural gas, the type of fuel used is mentioned. Per sector the operation mode and the amount of full load hours are discussed as well.

5.2.1 Agriculture

In the Dutch agricultural sector, CHP is mainly used in greenhouses. In the Netherlands agriculture is developing towards more intensive cultivation, especially in horticulture (vegetables, flowers and plants) (Smit and van der Velden 2008), so that heat demand has been increasing. More importantly, electricity demand has also been rising due to increasing use of lighting and automation. The increase in energy demand has made efficient energy supply essential for profitability, driving an increase in installed CHP capacity in the horticulture in the period from 2000 to 2008. The benefits of cheaper electricity than bought from the grid, and the opportunity to generate extra revenues by selling excess electricity to the grid are the main economic drivers of this development (Smit and van der Velden 2008). Since electricity price fluctuates, the ability to produce electricity flexibly is important to optimize electricity income, as more electricity can be produced when electricity prices are high and vice versa.

Greenhouses require low-temperature heat at 85-90°C (COGEN Vlaanderen 2006), so gas engines are the most suitable CHP technology (which is also able to operate in flexible mode), as shown in Table 24. To increase flexibility many greenhouses have heat buffers (isolated storage tanks) to allow for decoupling heat production and heat use (Smit and van der Velden 2008). In case of high electricity prices the excess heat can be stored, and subsequently used when electricity prices are low. The heat buffer has limited size and heat retention, so only extreme peaks can be accommodated this way. Due to the increasing energy demand the past few years, the size of gas engines applied in the horticulture has increased too. The average size of the engines nowadays installed is currently 2 MW_e (Smit and van der Velden 2008).

The amount of full load hours differs per subsector: vegetables (3700h), flowers (4200h) and plants (3800h) (Smit and van der Velden 2008). Full load hours depend on dimensioning of the system (a small CHP with a heat buffer, for example, can constantly run at full load, while larger systems often must operate at partial load). However, in practice the full load hours per year cannot increase much from the current figures, because heat demand differs per season. In the winter full load is needed; in the other seasons, especially summer, less heat needs to be produced, leading to a varying amount of load hours (Koolwijk and Goudswaard 2010).

Table 24. Number of plants and average capacity for agricultural sector (electrical and thermal) (CBS. 2010)

	Number of installations	Total	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	2900	3050	1.1	1.4	1.3

5.2.2 Chemistry

The chemical industry covers manufacturing of (non-)organic basic chemicals, fertilizers, plastics, paint, cleaning products, glues, and synthetic fiber. In chemical industries large amount of heat is needed at different temperatures (Table 22) (Spoelstra 2005), which require installation of large CHP systems, as shown in Table 25. The large range of different chemical industry processes result in application of many different CHP types. Continuous chemical processes, for instance, provide opportunities for installing large single cycle and combined cycle gas turbines. CHP in the chemical industry usually operates at high loads, and many installations are must-run, as they use waste gases from the production processes.

Many large chemical plants use multiple CHP units to meet their heat demand, e.g. Swentibold (delivering to DSM): a gas turbine and three steam turbines, with total capacity 106 MW_e; Delesto (delivering to Akzo Nobel and EDON): three combined cycles, total capacity of 530 MW_e. Both plants are installed at Akzo Nobel facilities. Other (smaller) combined cycles deliver to different smaller chemical companies, e.g. EMMTECH in Emmen delivers to e.g. DSM Advanced Polyesters, Applied

Polymer Innovations Emmen, and Dutch Polymer Handling. This CHP system consists out of two combined cycles with a total capacity of 55 MW_e. Several large central CHP plants also deliver heat to chemical industry, including the combined cycle WKC Moerdijk (339 MW_e), which supplies Shell Nederland Chemie.

Table 25. Number of plants and average capacity for chemistry sector (electrical and thermal) (CBS, 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	15	7	0.5	0.7	1.3
Gas turbine	11	283	25.7	99.1	4.3
Combined cycle	13	1625	125	277	1.1
Steam turbine	9	128	14.2	133	3.5

5.2.3 Refineries and mining companies

This sector includes oil refinery and extraction of oil, natural gas, sand, gravel or salt. The CHPs installed in this sector are mainly at refinery sites. Refineries cluster a number of energy intensive processes (Wetzels et al. 2009), which require electricity and large amounts of heat continuously (DNV 2010). An additional reason to use a CHP plant in refineries is the release of waste gases during the refining process, which can be used as fuel for the CHP. These refinery gases are produced continuously, so the CHP systems need to be fired continuously as well. The main energy demand is in the form of heat (for oil cracking), explaining the high HPRs of the installed units (Table 26).

Table 26. Number of plants and average capacity for refineries and mining sector (electrical and thermal) (CBS 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	15	14	0.9	0.7	1.5
Gas turbine	8	180	22.5	67.6	2.5
Combined cycle	2	124	62.0	172	1.5
Steam turbine	5	76	15.2	139	11.2

Almost all refineries in the Netherlands are located in port of Rotterdam, as are many large power plants, which supply steam to the refineries (e.g. Rijnmond (820 MW_e) supplies steam to a Shell refinery) (Port of Rotterdam authority 2010). Most CHP units installed are at Shell Nederland, ESSO and are medium sized gas turbines (15-50 MW_e) or small sized steam turbines (15 MW_e). In the past steam turbines were also used, but these have been replaced by gas turbines, which are more efficient (Plomp and Kroon 2010).

5.2.4 Paper industry

Paper production is energy intensive, entailing a high electricity and heat demand (medium temperature (100-300°C)) (IEA 2010c). The paper sector was therefore one of the first industries to use CHP. Due to the different type of processes within the paper industry different sized CHPs with different HPR are installed. Another explanation for the different HPRs is the difference in age of the plants. Initially, CHP plants were designed to meet the heat demand of the factory, while newer plants have been optimized for power production (which results in a lower HPR). Making paper is a continuous process, implying continuous use of CHP plants (VNP 2003). An example of a CHP in the paper sector is the WKC Maastricht at Sappi Maastricht, a combined cycle of 54 MW_e, operating more than 5000 load hours annually (Table 23).

Table 27. Number of plants and average capacity for paper sector (electrical and thermal) (CBS. 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	6	4	0.7	0.8	1.2
Gas turbine	12	67	5.6	20.7	2.9
Combined cycle	6	234	39.0	78.3	1.6
Steam turbine	1	3	3.0	61.1	7.0

5.2.5 Food industry

The food industry is a diverse sector, including producing, processing, packaging, transportation and catering of different kinds of food, and tobacco. The sectors in which CHP plants are installed are dairy, sugar, breweries and distilleries. The sugar industry requires large amount of steam of medium temperature (100-300°C) (COGEN Vlaanderen 2006). The dairy industry, in which CHP plants are widely used during whey and milk drying, requires high steam temperatures and pressures, e.g. 220 - 240°C and 32 – 34 bar (IPCC 2006). For the sugar and dairy industries steam turbines, large gas turbines and combined cycles are suitable technologies, since large amounts of heat are needed at high pressures. In sectors without drying process, heat demand is lower and gas engines and small gas turbines are more appropriate (IPCC 2006).

In the Netherlands most companies in the food industries are Small and Medium Enterprises (SMEs), so that gas engines and small gas turbines are the dominant CHP technologies (Table 28). EPA (2002) describes a ‘typical’ example of a food processing CHP plant of 2 MW_e, using a natural gas engine-driven CHP system consisting of multiple 500 to 800 kW engine sets. The system provides base-load power to the facility and approximately 2.2 MW_{th} low-pressure steam for process heating and wash down. In general the food production processes have become increasingly continuous, so that the number of full load hours of the CHPs installed has also risen (Klimstra, 2011). A few specific plants in the Netherlands use medium to large sized gas turbines, including Dobbestroom (40 MW_e) and Hunzestroom (25 MW_e) of Essent. Two medium sized combined cycles systems are installed at Heineken Den Bosch (35 MW) (beer producer) and Philip Morris Bergen op Zoom (35 MW_e) (tobacco producer).

Table 28. Number of plants and average capacity for food industry sector (electrical and thermal) (CBS. 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	34	18	0.5	0.8	1.3
Gas turbine	24	167	7.0	24.9	2.7
Combined cycle	11	258	23.5	48.6	1.6
Steam turbine	5	44	8.8	59	6.1

5.2.6 Other Industry

The category other industry covers several industries producing materials (i.e. cotton, wood, glass, cement, lime, metal, gypsum), machinery industry, and publishers. The wide range of industry types (and therefore different heat demands (Table 22)) explains the use of different CHP technologies (Table 29). The cement, metal and glass industries require extremely high temperature heat (>700°C), which can be generated by gas turbines and in some cases with boilers coupled to steam turbines (COGEN Vlaanderen 2006). The cement industry is a large CO₂ emitting industry, but only a small amount is caused by energy production (IEA GHG 2007). Gas engines are mostly used for drying processes in the other material producing and machinery industry, mainly in batch processes, resulting in a low number of load hours (Klimstra 2011).

Table 29. Number of plants and average capacity for other industry sector (electrical and thermal) (CBS. 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	45	20	0.4	0.7	1.2
Gas turbine	6	35	5.8	99.1	3.1
Steam turbine	3	31	10.3	76.7	8.3

5.2.7 Built environment

CHP in the built environment mainly supplies space heating. Using CHP requires a stable and sufficient heat demand, but in most buildings the energy demand is fluctuating between day and night, and differs by season (NUON 2010). In the winter, heat for space heating is required, and in the summer buildings use electricity for the air conditioning. New types of cooling systems use absorption chilling which use heat instead of electricity and can be combined with CHP, opening up new opportunities for applying CHP in buildings (Energy Institute 2003, Stadler et al. 2010).

Two types of CHP application dominate in the building sector. On the one hand wide spread small (0.4 MW_e) gas engines are common, since they are attractive by providing secure energy supply in for instance hospitals or data centers. Larger CHP plants (40 MW_e), on the other hand, are used for district heating. Three examples of large district heating CHP plants in the Netherlands are WKC Helmond, Eindhoven, Enschede, with a size between 50-60MW_e. Typical load hours differ between 3600 to 5000 hours per year.

Table 30. Number of plants and average capacity for built environment (electrical and thermal) (CBS. 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	1333	474	0.4	0.6	1,4
Gas turbine	2	120	60	96.7	0,0
Combined cycle	4	163	40.8	28.7	0,6
Steam turbine	1	1	1	3.8	4,3

5.2.8 Waste sector

Table 31 shows the CHP used in the waste incineration sector. The main reason to use CHP plants is to produce as much energy from waste as possible, making as the process more sustainable, because incineration produces emissions anyway.

Two CHP types are common in waste processing: gas engines (small scale) and the steam turbines (large scale). Heat produced by waste incineration is partly used for district heating (COGEN Vlaanderen 2006, SenterNovem 2007), and to produce electricity in steam turbines, mostly for the grid (80%) (SenterNovem 2007). Waste digestion produces gas, which can be fired in gas engines or used in steam turbines to produce electricity and heat. The installations typically use most electricity on-site, and supply heat to district heating (Essent 2005). The use of waste (gases) as fuel increases maintenance needs of the installations, as the fuel is dirtier than natural gas. This lowers the number of full load hours (Klimstra 2011).

Table 31. Number of plants and average capacity for waste incineration sector (electrical and thermal) (CBS, 2010)

	Number of installations	Total installed capacity	Average electrical capacity	Average thermal capacity	HPR
		MW _e	MW _e	MW _{th}	
Gas engine	18	11	0.6	0.94	1.5
Steam turbine	12	387	32.3	15.0	0.5

6. CO₂ capture technologies

This chapter describes the main characteristics of the capture technologies. Three general groups of capture technologies can be distinguished. Firstly, the CO₂ can be separated from the flue gas (post combustion capture). Secondly, the CO₂ can be captured before combustion by reforming the fuel into CO₂ and H₂ (pre combustion capture). Lastly, fuel can be combusted with pure oxygen which result in flue gas that mainly consists of CO₂ and H₂O (oxy-fuel).

In the second part of the chapter, an overview of the capture technology operability is given. The operability of power plants and especially CHP plants are an important aspect which is under research. Operability refers to the flexibility, controllability and the start/shut down characteristics of power plants.

The first sections of this chapter describe the three capture groups of capture technologies, respectively, 6.1 post combustion capture technologies; 6.2 pre-combustion capture technologies, and 6.3 oxy-fuel capture technologies.

The capture technology operability is discussed in section 6.4. Followed by a comparison of the different capture technologies in section 6.5. The final section discusses the capture possibilities from a boiler, to look into the mitigation options for steam turbine CHP plants as well.

6.1 Post combustion technologies

Post combustion CO₂ capture consists of removal of the CO₂ from the flue gasses (see Figure 20). If the fuel is natural gas, which is common for CHP plants, then the partial pressure of CO₂ in the flue gas is low (3-15 kPa). Due to this low partial pressure chemical absorption based capture is currently the most likely technology to be applied. The most frequently used chemical absorption technology is based on amines (Kanniche et al. 2010). Three other technologies which are in an earlier stage of development are chilled ammonia, direct chilling and CO₂ selective membranes.

A major advantage of post combustion technologies is the possibility of retrofitting. However retrofitting is not always possible because it depends on site specific conditions like: size, age, efficiency, turbine type, required load flexibility, and the availability of space on site (Simmond and Hurst 2005). This section describes the different post combustion capture technologies, amines-based, chilled ammonia, cryogenic separation, and membrane-based capture.

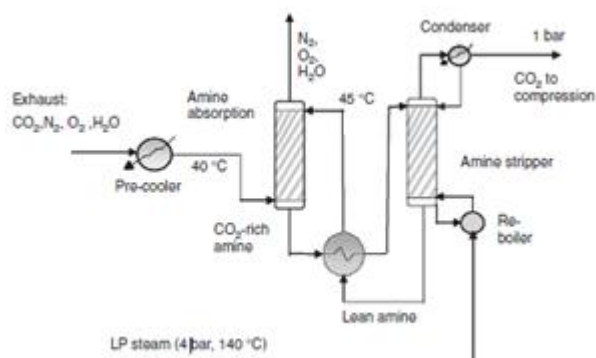


Figure 20. Simplified flow diagram post combustion capture (Kvamsdal et al. 2007)

6.1.1 Amine-based

The amine-based technology removes the CO₂ from the flue gas with absorption. The flue gas is cooled and subsequently fed into an absorber. The absorber removes the CO₂ with a chemical absorbent, e.g. MEA (mono ethanol amine). Next, the saturated solvent is fed into a stripper, which heats the solvent to release the CO₂ and to regenerate the solvent. The CO₂ is separated and the solvent is reused in the absorber. The stripping process needs heat (steam) for solvent recovery, so part of the steam generated in the CHP is used for this process (IPCC 2005). Post combustion is currently the most mature technology to capture CO₂ (Olajire 2010). According to Simmonds (2005) and Choi et al. (2005), costs associated with post combustion technology can be reduced in the future so it can remain competitive with pre-combustion and oxy-fuel capture technologies.

The major advantage of the amine-based technology is its maturity; of all capture technologies it is the most developed one. However, the technology is only applied in the chemical industry, and has not been built at power plants as large-scale system. Additionally, several other drawbacks of the technology are: large volumes of flue gas have to be handled; the amines degrade; the solvents are corrosive; a lot of plot space is required; cooling of the flue gas is required which result in an energy penalty of reheating the solvent; the solvent has limited absorption capacity (Kanniche et al. 2010, Harmelen et al. 2008, Eimer 2005). The current efficiency in case applied to a combined cycle is 48% (Kvamsdal et al. 2007).

So despite its maturity, plenty improvement options are left for amine absorption. Important opportunities for optimizing the capture process are: minimizing corrosion and degradation of the solvent; lower the regeneration energy; and optimizing the absorption rate. So, solvent optimizations are the most important technology developments; in general, the technology is in the pre commercial phase (IPCC 2005, Harmelen et al. 2008, and Choi et al. 2005)

6.1.2 Chilled ammonia

The chilled ammonia technology operates accordingly a similar process as the amine process, but with a different absorbent. This absorbent, ammonia, operates at a lower temperature (0-10°C instead of 40°C). Ammonia reacts with CO₂ in various ways, one of which is the reaction of ammonium carbonate, CO₂ and water to form ammonium bicarbonate. The ammonium bicarbonate can either be thermally decomposed in ammonium and CO₂, or used as fertilizer¹. The technology is in a pilot phase, and is able to reduce the required absorption energy according to some researchers, Bandyopadhyay (2011) and Darde et al. (2010). Compared to the amines-based technology chilled ammonia require less steam for regeneration and less electricity for CO₂ compression. The electricity reduction is because the regeneration can be done at high pressure. On the other hand, extra power is needed for cooling the ammonia (Harmelen et al. 2008).

Next to its energy saving potential, the most important advantages are (Bandyopadhyay 2011, Darde et al. 2010):

- tolerance to oxygen in the flue gas,
- having higher loading capacity (mol CO₂ absorbed/mol of absorbent),
- no corrosion problems,
- ammonia does not react irreversible with SO₂ and NO_x (making pretreatment of the gas unnecessary).

¹ Ammonium bicarbonate is normally not used as fertilizer, it is, however, being explored in China (Bandyopadhyay 2011).

In total the estimated total energy requirement for the NH₃-based process is 1.1-2.1 MJ/kg-CO₂ which is low compared to 3.7-4.2 MJ/kg-CO₂ of the MEA-based process (Bandyopadhyay 2011, Darde et al. 2010).

This promising energy penalty still needs to be proven and is still debated among many scientists (Dijkstra 2011), which explains the large range of the energy penalty. Other disadvantages are (Olajire 2010, Harmelen et al. 2008):

- difficulty to cool flue gas below 10°C to prevent emissions of ammonia and equipment fouling with deposition of ammonium bicarbonate;
- compared to MEA, ammonia has a higher volatility which result in a ammonia slip into the flue gas;
- ammonia is consumed by forming irreversible compounds (e.g. sulfates and nitrates)

6.1.3 Cryogenic separation

Separation through direct chilling is based on the different condensation temperatures of the flue gases. By cooling down the flue gas, liquefied CO₂ can be separated from the nitrogen. However, the cooling requires an enormous amount of energy which makes direct chilling not a realistic option, especially for flue gas with a low partial pressure (3-4%) (Harmelen et al. 2008, Eimer 2005). This option will therefore be excluded from further analysis.

6.1.4 Membranes

Another separation technology is based on membranes. The principle of membranes is comparable with a sieve. Some molecules can pass the membrane whilst others cannot. Membrane separation technologies have several benefits: no regeneration energy is required, a simple modular system, requiring less space (compared to absorption), and no waste streams. Despite these advantages, it is not likely that the membranes will be applied in post combustion capture. Several disadvantages make the option less suitable, like the lower separation efficiency in case of low concentrated gases, the difficulties in preventing membrane wetting and plugging by impurities in the gas stream and the immaturity of the membranes (Olajire 2010). Natural gas fired gas turbine CHP-plants have a low CO₂ content in the flue gas, because of a high air/fuel ratio and a low carbon content of the fuel (Desideri and Corbelli 1998). The most important disadvantage for gas turbines is therefore the lower efficiency in case low concentrated gas. To separate the CO₂ after gas turbine CHP plants multiple stages of membranes are needed to reach high purity of CO₂, resulting in high costs (Harmelen et al. 2008).

6.1.5 Summary of post combustion capture technologies

The two suitable post combustion capture technologies for gas fired CHP plants are chilled ammonia and amine absorption, both based on the chemical absorption process. Amines absorption has been proven and can be applied right away, ammonia absorption seems promising, but still needs to be proven. Direct chilling is due its high energy requirement not an option. Membranes separation still needs a lot of development and seem to be less of an option for gas fired turbines, since the carbon content of the fuel is too low.

6.2 Pre combustion

Pre combustion capture consists of a number of steps. The first step is producing hydrogen and CO (syngas) from fuel, using steam reforming or partial oxidation. Subsequently, steam is added, and the CO and H₂O are converted into CO₂ and H₂ through the water gas shift reaction. Finally, CO₂ is separated from the H₂ with a solvent or membranes.

An advantage of the pre-combustion technologies is the fact that H₂-production is a proven industrial-scale technology, applied in refineries, for instance. Physical sorbents can be used instead of chemical solvents, because the concentration of CO₂ in the flue gas is higher than in post combustion (15% compared to 3-4%). Physical solvents need less regeneration heat, leading to lower energy penalties. An even more suitable separation technology is pressure swing absorption, in which the CO₂ is separated from the process gas, and H₂ purified (removal of trace elements of CO, CH₄) (IPCC 2005). In this way pressurized CO₂ is generated, which leads to a lower energy requirement for compression for transport of the CO₂ (Nord et al. 2009, Blomen et al. 2009). Another advantage of the pre-combustion technology is the possibility to install a standalone facility to produce hydrogen centrally. The hydrogen can be sold to small CHP plants as fuel. A pre-condition is the adjustment of those gas turbine or gas engine CHP plants to be able to use hydrogen as fuel (Andersen 2005). The hydrogen turbines do not exist yet, however it is expected to be developed soon (Kanniche et al. 2010, Nord et al. 2009).

This section describes three pre-combustion capture technologies, membrane steam reformer (MSR-H₂), Auto-thermal reformer (ATR), and sorption enhanced water gas shift (SE-WGS).

6.2.1 Membrane Steam Reformer (MSR-H₂)

A membrane steam reformer (MSR-H₂) is a membrane based fuel reforming technology. The first step in the reforming process is to remove the sulfur compounds from the fuel. Next, steam is added to the gas, resulting in the following endothermic reaction: $\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3 \text{H}_2$. The heat required for the endothermic reaction is supplied by firing fuel, e.g. natural gas. The reformed gas, CO and H₂, is cooled in a waste heat boiler generating steam, needed in the reforming process. Subsequently the cooled CO and H₂ are led into a CO shift (membrane) system, where CO with H₂O is converted in CO₂ and H₂ (Harmelen et al. 2008). The next step is to separate the CO₂ and H₂. Membranes can combine the separation and reaction of hydrogen. Due to the single reforming step the CO₂ remains at a relative high pressure.

The membranes can be combined with a gas turbine if the membrane reformers pressure increases or the process steam is used as sweep gas (Kvamsdal et al. 2007, Harmelen et al. 2008). The mixture of steam and H₂ is then combusted and expanded in a gas turbine. The exhaust gases of the turbine are heated with supplemental firing to produce steam in a Heat Recovery Steam Generator (HRSG). Subsequently, the HRSG steam and rest products (CO₂ and steam from MSR) are expanded in a CO₂/steam turbine, in which the CO₂ is separated by condensing (Harmelen et al. 2008).

The MSR reactor is still in development, and currently in the laboratory/pilot phase (Kvamsdal et al. 2007, Harmelen et al. 2008, IEA and OECD 2004). The expected efficiencies of the gas turbine plants with CO₂ capture are 56% (IEA and OECD 2004).

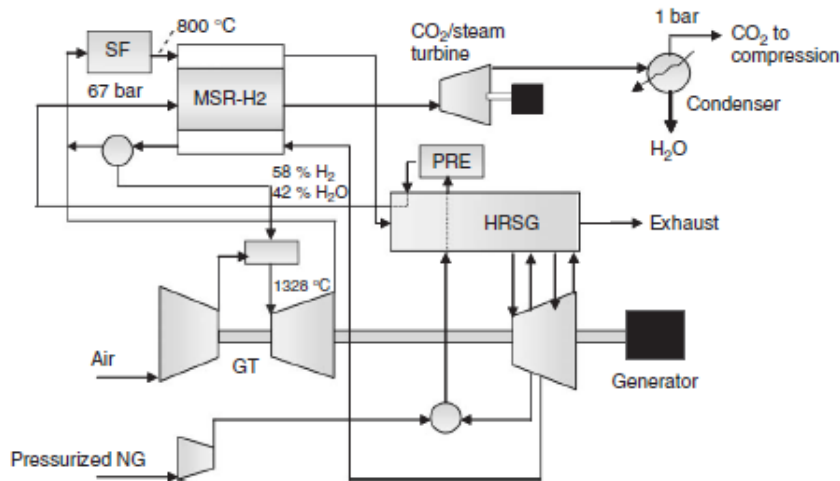


Figure 21. Simplified flow diagram MSR-H2 (Kvamsdal et al. 2007)

6.2.2 Auto Thermal Reformer (ATR)

The Auto Thermal Reformer (ATR) is (together with SMR) the most mature pre combustion technology. The reforming section first converts heavier carbons into CH₄ and H₂ in the pre-reformer. Then the natural gas is led into the ATR with oxygen (or in some cases compressed air) and is mixed with steam to generate syngas. Subsequently, the syngas is shifted to H₂ and CO₂ in the water gas shift reactor. The H₂O is condensed and separated by cooling and condensing; CO₂ is removed in an absorber resulting in a stream of high concentrated H₂ (+N₂ in case of air). The H₂ is expanded the gas turbine, and subsequently fed into the HRSG to generate steam for the steam turbines (Kvamsdal et al. 2007, Harmelen et al. 2008).

The ATR can be fed with air or oxygen. The advantage of oxygen is the possibility to use the solvent Selexol which has a less energy intensive absorption process, since the CO₂ can be recovered by letting down pressure, or stripping with steam/inert gas (Olajire 2010). In case of using air, the solvent MDEA (methyldiethanolamine) is used, which needs steam to regenerate (but is still less energy intensive than the post combustion solvent MEA) (Dijkstra 2011).

Compared to SMR, the advantage of ATR is a lower conversion temperature and a smaller investment for the reactor (IEA and OECD 2004). The main bottleneck is the turbine, since it has to cope with H₂ rich fuels, however existing turbines can be adjusted, which makes retrofit possible (Allam et al. 2005a). The ATR technology combined with gas turbines is close to the demonstration (Harmelen et al. 2008). The expected efficiency is 47% (Kvamsdal et al. 2007).

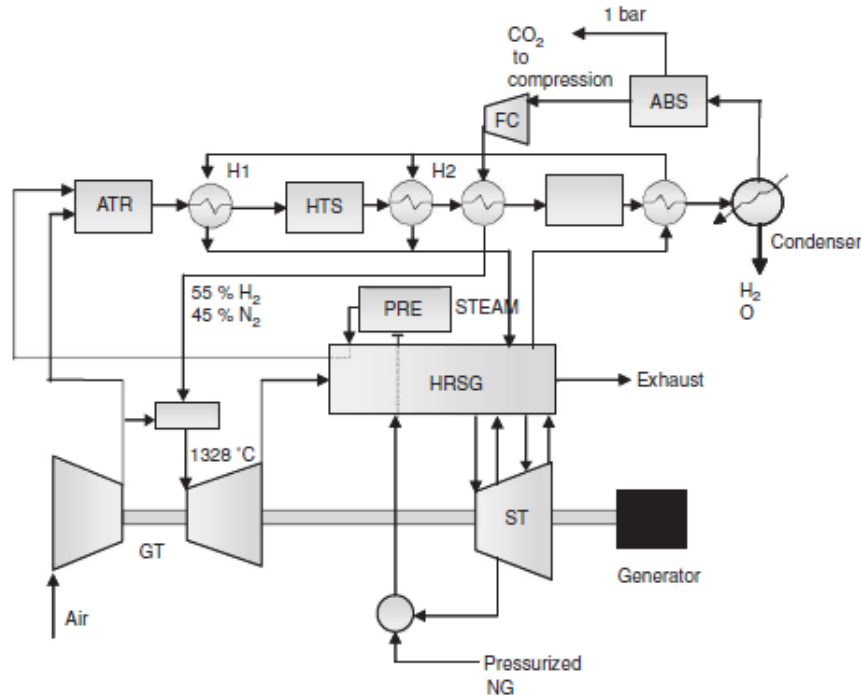


Figure 22. Simplified flow diagram ATR (Kvamsdal et al. 2007)

6.2.3 Sorption enhanced water gas shift (SE-WGS)

ATR and SMR can both be combined with a sorption enhanced water gas shift reactor (SE-WGS). Since the focus of this study is on ATR, the ATR-SE-WGS combination is discussed. The difference with a normal ATR is the simultaneous occurrence of the water gas shift reaction and the absorption of CO₂. Steam, Natural gas and oxygen are the only inputs used. The main new component is the SE-WGS unit. The system works as multi bed pressure swing adsorption unit at high temperatures to shift CO into H₂ and H₂O and remove CO₂. All sulfur compounds should be removed in advance to prevent degradation of the adsorption unit.

The main benefits are:

- less cooling requirement of the syngas
- higher shift to H₂ due to the removal of CO₂,
- the surplus of process steam is fed into the gas turbine, reducing the NO_x emissions

The benefits mean a reduction in heat loss and therefore higher cycle efficiency, the additional process steam leads to lower NO_x emissions, despite higher temperatures (Harmelen et al. 2008, Allam et al. 2005a). A major disadvantage is the need of an ASU to produce the oxygen, which needs a lot of energy.

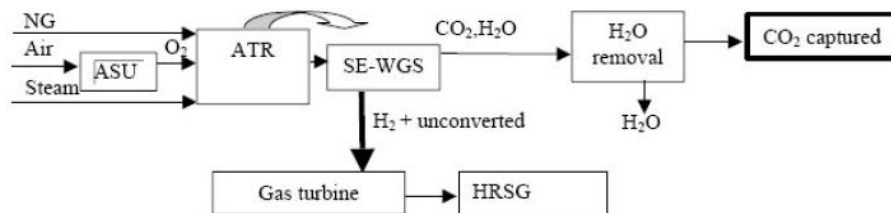


Figure 23. Simplified flow diagram ATR (IEA GHG 2007)

The stability of the absorbent and the use of steam for cleaning the sorbent need improvements in order to reliably operate the SE-WGS. Another operational aspect is the operating pressure, increasing the operational pressure decreases the energy requirement. The technology is currently in the pilot phase, and its overall efficiency is expected to be 47-48% (Damen et al. 2006, Harmelen et al. 2008).

6.2.4 Summary of pre-combustion capture technologies

The application of pre-combustion technologies will be limited to large plants (>10 MW_e), because the investment costs and size of the fuel reforming plant are large. For smaller plants, a link to a hydrogen supply system seems much more likely (IEA and OECD 2004). In that case it is possible to create a central hydrogen production plant with pre combustion CO₂ capture. The main cost component of the pre-combustion technologies is the reformer (Kanniche et al. 2010). For the advanced concepts the sorbent reactor and membrane reactor might be expensive as well, however this could be compensated with higher efficiency (Dijkstra 2011). An advantage of pre combustion capture is the possibility to use a standalone capture unit and distribute the hydrogen to small CHP units. From the different options the ATR and SMR are the most mature options. However, it is not possible to identify the most promising technology, because the MSR-H₂ and SE-WGS are still in the developing phase.

6.3 Oxy-fuel carbon capture

Oxy-fuel power plants are fired with pure oxygen instead of air, resulting in a flue gas consisting of just CO₂ and water. The CO₂ is separated by condensing the water, which is an inexpensive and simple process. An effect of oxy-firing is a higher flame temperature in the combustion chamber. Even though this higher temperature in theory results in a higher efficiency, the currently used turbines cannot reach those higher efficiencies, because materials currently used are not able to withstand the temperatures. For the shorter term, several options with diluents are designed to lower the combustion temperature. The used diluents options are CO₂ or H₂O recycles. The diluents make it possible to use existing combustion chambers. However, turbines with CO₂ and H₂O gas as working gas (CO₂-turbines) still need to be designed, which is a complex process, and therefore takes a lot of time (up to 10 years) (Blomen et al. 2009, Miracca et al. 2005).

Oxy-fuel capture technologies require external oxygen production, and are therefore non integrated technologies. This is an important distinction with the technologies which combine oxygen and energy production, the integrated technologies (i.e. AZEP, CLC and SOFC-CC). In this section first the oxygen production technologies are described. The next sections are about the three non-integrated oxy-fuel capture cycles, Matiant cycle, Water cycle, Graz cycle. Subsequently, the integrated technologies, AZEP, CLC, and SOFC-CC, are discussed.

6.3.1 Oxygen production

This section reports the development of the oxygen producing technologies, because oxygen production has a major effect on the costs and efficiencies of the non-integrated oxy-fuel technologies.

The most used oxygen producing technology is cryogenic air separation. This technology embodies pressurizing air and leading it through fixed bed absorbers to absorb water, hydrocarbons, and CO₂. These beds can be regenerated through a pressure or temperature swing. Subsequently, the air is

cooled in a cryogenic distillation tower through several heat exchangers. The cooling process leads to separation of air in pure oxygen and nitrogen.

The auxiliary power consumption of a cryogenic air separation unit is high and has a major impact on the overall efficiency of the power plant. Power consumption of O₂ production (typical for oxy-fuel application) is 240 kWh/tO₂ (IPCC 2005, Blomen et al. 2009), which is around 350 kWh/tCO₂ captured (Bolland and Undrum 2003). Higginbotham et al (2011) describe the new cryogenic ASU concept, in development at Air Liquid, which has a 15% lower energy demand and is expected commercially available in 2015 (Higginbotham et al. 2011).

Oxygen production on a small scale is based on (vacuum) pressure swing adsorption ((V)PSA). These technologies are expected to continue to reduce oxygen production costs and increase the production scale. The scale reduces at which the oxygen production costs of (V)PSA break even with cryogenic separation costs (Kuramochi et al. 2011). The highest oxygen purity currently reached with (V)PSA is 95% with an energy use up to 400 kWh/tCO₂ (Kuramochi et al. 2011). Current size the (V)PSA is applied to is several tonnes a day (Kuramochi et al. 2011).

In case of natural gas fired plants the amount of O₂ molecules needed per CH₄ molecule is high compared to other fossil fuels (e.g. coal, oil). Compared to coal and oil, natural gas has a higher demand for oxygen per MJ electricity/heat produced¹. The costs of oxy-fuel carbon capture in case of natural gas-fired technologies are therefore higher than in case of coal-fired technologies. As a result non-integrated oxy-fuel cycles using cryogenic air separation are less likely to be an option for natural gas based plants. Oxy-combustion is a more promising option for coal fired power plants.

The upcoming technology for the next generation of oxygen production is membrane based oxygen separation (Simmonds et al. 2005). The membranes (ITM) are ceramic mixed oxides in which transport of oxygen ions take place at high temperatures. The difference in feed and permeate partial pressure is the main determining factor of the oxygen flux through the membrane (IPCC 2005, Allam et al. 2005c). The membrane systems are in the development state, a pilot plant stage. The costs of the full size system have been looked into, and are expected to be commercially deployed 7 years after industrial demonstration (IPCC 2005). Allam et al. (2005) argue that the integration of ITMs with gas turbines is a good option, because by producing extra electricity the costs of avoided CO₂ is reduced (Allam et al. 2005c).

6.3.2 Matiant cycle

The Matiant cycle is similar to an air based combined cycle. However, the combined cycle is fired with oxygen instead of air (schematically shown in Figure 24). The oxygen is produced in a non-integrated air separation unit (ASU). The gas expands in a turbine, whereupon the hot exhaust gases are used to produce steam in an HRSG for the steam turbine. The usage of oxygen results in flue gas composed of CO₂ and H₂O. After condensation of the water, 90% of the CO₂ is recycled to lower the turbine inlet temperature to the required level (IPCC 2005, Harmelen et al. 2008). The efficiency is expected to be about 47% (Kvamsdal et al. 2007).

The challenge for direct combustion oxy-fuel cycles is the combustion. During the combustion the fuel and the oxygen are supposed to react at the same time. The simultaneous reaction requires a good mixture of the fuel with the oxygen, and the gas mixture should have enough residence time. To prevent incomplete combustion oxygen could be oversupplied. An essential development is;

¹ Natural gas and coal require respectively 4 kg and 0.684 kg O₂ (Weston 2000). The energy content of natural gas and coal are respectively 53.6 MJ/kg and 24-31 MJ/kg (Blok 2007). Which results in a specific oxygen consumption of 0.075 kg O₂ per MJ for natural gas, and 0.022-0.029 kg O₂ per MJ for coal.

turbines capable to use a CO₂/H₂O working fluid at high pressures and temperatures. This requires a complete new design of the turbines, since the combustion characteristics are different compared to NG/air turbines (Bolland et al. 2005, Kvamsdal et al. 2006). The speed of sound in the turbine (about 80% compared to air, which has implication for the acoustics within the turbine), and the aerodynamics in the turbine (the gas density is 50% higher) are important differences. The lower specific heat ratio of CO₂/H₂O makes a higher pressure ratio possible, because the lower heat ratio result in a lower temperature changes in the adiabatic processes, compression or expansion. The higher pressure ratio results in an exhaust gas of about 600 °C, (optimal for the steam cycle). These different characteristics have a significant effect on the new design (aerodynamic changes, and acoustic feedbacks in the compressors and combustors) (IPCC 2005, Rezvani et al. 2009).

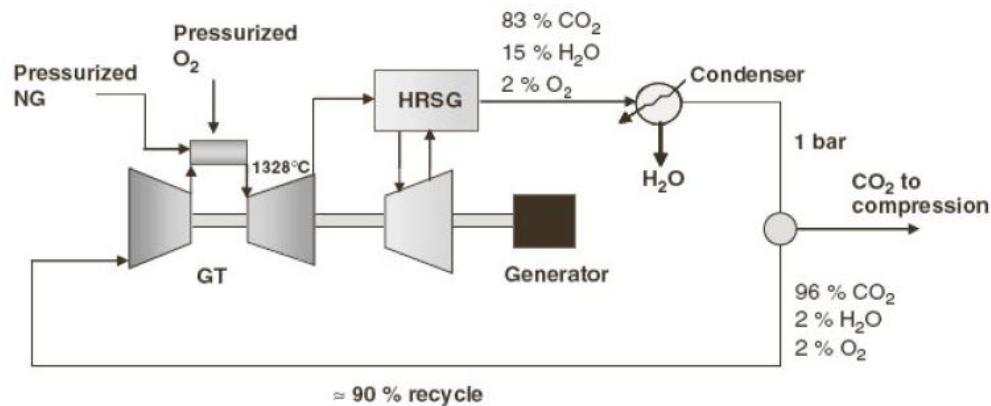


Figure 24. Simplified flow diagram Matiant concept (Kvamsdal et al. 2007)

6.3.3 Water Cycle

The water cycle is an oxygen-fired cycle with steam recycle (shown in Figure 25). It can be categorized as a Rankine power cycle (Bolland et al. 2005). The natural gas and oxygen are combusted in presence of water producing a high pressure, superheated mixture of mainly H₂O and CO₂. The superheated mixture is expanded in several turbines to generate electricity, resulting in flue gases of mainly H₂O and CO₂ (Harmelen et al. 2008). The oxygen is delivered by an ASU unit. The efficiency of the water cycle is 44% (Rezvani et al. 2009), which is slightly lower compared to the Matiant cycle and Graz cycle efficiencies. Bolland et al. (2005) explain the difference with thermodynamic principle: *'the Graz and Matiant cycles have a higher ratio of the temperatures at which heat is supplied to, and rejected from, the cycle, compared to that of a Water cycle. According to the Carnot cycle efficiency definition, the efficiency is improved when this temperature ratio increases.'*

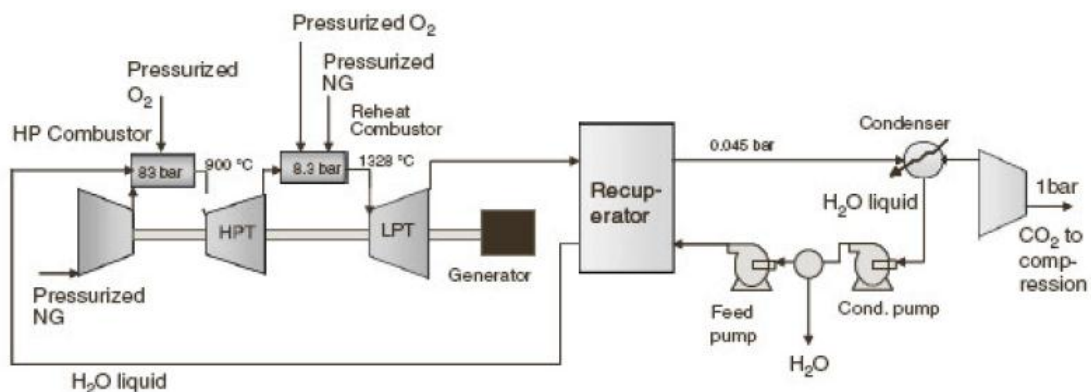


Figure 25. Simplified flow diagram Water cycle (Kvamsdal et al. 2007)

6.3.4 Graz Cycle

The Graz cycle is an oxy-fuel direct heating gas turbine cycle. The cycle consists of a high pressure combustor with steam injection and a recuperated gas turbine with a steam cycle (Figure 26). A mixture of compressed steam, Natural gas, oxygen, and CO₂ is combusted to generate a hot gas mixture, steam, and CO₂. The mixture is fed into a high pressure gas turbine, then into a HRSG to produce steam for the steam turbine. The low temperature steam/CO₂ mixture is fed into a low pressure turbine and a condenser to separate the CO₂ (Damen et al. 2006, Harmelen et al. 2008).

The main technology developments needed for the graz cycle are the low and high pressure turbines with the working fluid CO₂/H₂O. Both turbines concepts need to be designed, like the turbines in the Matiant cycle (IPCC 2005, Harmelen et al. 2008). The electrical efficiency of the cycle is about 49% (Kvamsdal et al. 2007, Rezvani et al. 2009).

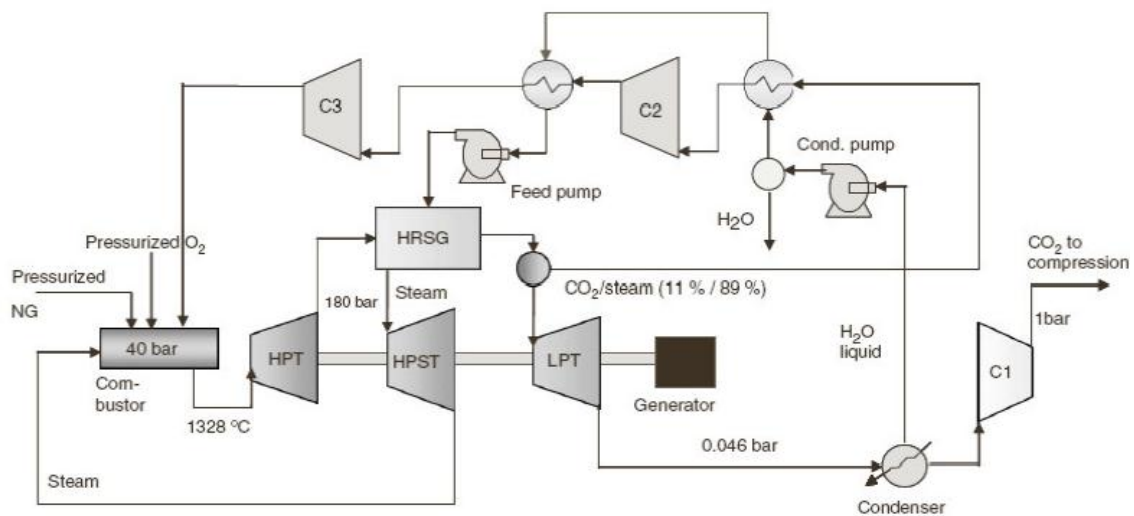


Figure 26. Simplified flow diagram Graz cycle (Kvamsdal et al. 2007)

6.3.5 Advanced Zero Emission Power plant (AZEP)

The advanced zero emission power plant (AZEP) is an indirect heating gas turbine combined cycle. The combustion chamber is replaced by a high temperature oxygen transport membrane (Mixed conducting membrane, MCM) (Figure 27). The membrane separates oxygen from air and transports it to the combustion part, where it is compressed. The oxygen depleted air is heated, and then expanded in a gas turbine. The exhaust gas of the turbine and are used to produce steam. After condensing the flue gas of the membrane (H₂O and CO₂) the CO₂ is captured at a pressure of 20 bar. The MCM material and the reactor design constraints make the turbine inlet temperature lower than in the conventional NGCC plants. The lower inlet temperatures result in a lower efficiency of the cycle. The lower exhaust gas temperature results in a lower steam temperature and steam production, which reduces the efficiency of the steam cycle. To increase the efficiency, an afterburner can be coupled to the gas turbine. The afterburner requires additional fuel input, creating extra CO₂ emissions which cannot be captured. As a consequence, the total capture efficiency is reduced to 85%. An efficiency of 49-50% LHV is claimed for an AZEP with 100% capture rate, for an AZEP with afterburner the efficiency can be increased to 52% (Damen et al. 2006, IPCC 2005, and Möller et al. 2006).

This technology is compatible with current technology, only minor adaptations to the turbine and HRSG are required (Damen et al. 2006). The main drawback is the low temperatures in the turbine,

to keep the turbine operating stable an afterburner is needed. Using afterburners result in a lower capture rate of 85% (Damen et al. 2006). Another disadvantage of the AZEP process is that changes in operation conditions, e.g. during start up and shut down, must be performed at a slow rate to prevent excessive stresses to the membranes (Botero et al. 2009). The CO₂/steam turbine and the MCM reactor need further development. The MCM membrane requires high temperature materials and enlargement of its size, which still need some breakthroughs (Harmelen et al. 2008).

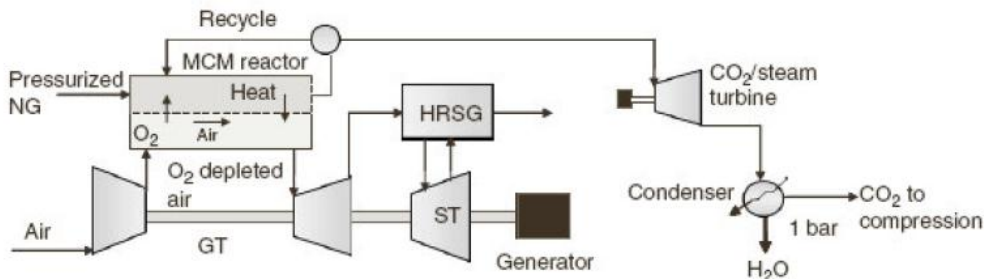


Figure 27. Simplified flow diagram AZEP (Kvamsdal et al. 2007)

6.3.6 Chemical Looping Combustion (CLC)

The main principle of chemical looping combustion is to split combustion into an oxidation and reduction reaction. The two reactions take place in different reactors (Figure 28). A suitable metal oxide (iron, nickel, copper, iron and manganese) is used as an oxygen carrier between the two reactions. Compressed air is fed into the oxidization reactor where metal oxide is formed (Oxides of Cu, Co, Ni, Fe and Mn). The hot oxygen-depleted air from the oxidization reactor is fed into a gas turbine where it expands. Subsequently, the hot exhaust gases are fed into a HRSG, which generates steam for a steam turbine. The combustion takes place in the reduction reactor where the oxygen is released in presence of natural gas. The exhaust gases of this process (CO₂ and H₂O) first preheat the NG, and are then fed into a condenser, where the water and CO₂ are separated. The reactors are normally two inter-connected fluidized bed reactors, in which the oxygen carrier circulates. A second, but less studied option is to use multiple fixed beds and operate these in a temperature swing cycle process (Damen et al. 2006, IPCC 2005, and Harmelen et al. 2008). The expected electrical efficiency of the cycle is 51-52% (Naqvi et al. 2007, Kvamsdal et al. 2007, and Harmelen et al. 2008).

A crucial issue is the maximum reactor temperature allowed for stability of the oxygen carrier (Damen et al. 2006). The recycle rate of the metal is therefore an important aspect, because it determines the heat balance between the two reactors.

At part load conditions the relative net plant efficiency of a CLC is higher compared to conventional combined cycles. At part load the TIT (turbine inlet temperature) is reduced. To keep the pressures in both reactors equal, the pressure ratio is reduced of the air compressor feeding into the oxidation reactor (compressor 1 in Figure 28). By reducing the pressure ratio, less energy is needed for compression, which leads to a higher outlet temperature of the gas turbine. The higher outlet temperature causes a better part load behavior of the steam cycle (higher efficiency), and in that way also better part load performance compared to the conventional combined cycle (Naqvi and Bolland 2007, Naqvi et al. 2007). Another benefit is the possibility to integrate a CLC with an existing turbine with minimal modifications (however, these should be tailor made). Even though the CLC is in a pilot plant phase the prospects are promising.

Similarities of CLC with existing circulating fluidized beds create possibilities for scale up with reasonable risks (Miracca et al. 2005); however scale up of the manufacturing process is still a major

concern (Hurst and Miracca 2005). So are the materials, which are in the research phase (IPCC 2005), and still have several bottlenecks. The main bottlenecks are the gas solid separation performance of the fluidized bed concept, and the wear and loss of oxygen carriers. The key development for CLC is the mix of metal oxides, which should be capable of withstanding repeated oxidation/reduction cycles, and keeping a useful level of chemical activity without causing mechanical damage (Hurst and Miracca 2005, Simmonds et al. 2005).

Future looping combustion involves membrane assisted fixed bed reactors, which act as reductor or oxidator, depending on the gas input. By using a membrane the oxygen carriers do not need to cycle through the reactor, but are fixed within the membrane. The main advantage is the avoidance of the wear of the metals, and the separation problems of the solids and the gas stream. By using a membrane, the use of the oxygen carrier is more effective. However, the membrane assisted fixed bed reactor still is in an early research stage (Harmelen et al. 2008).

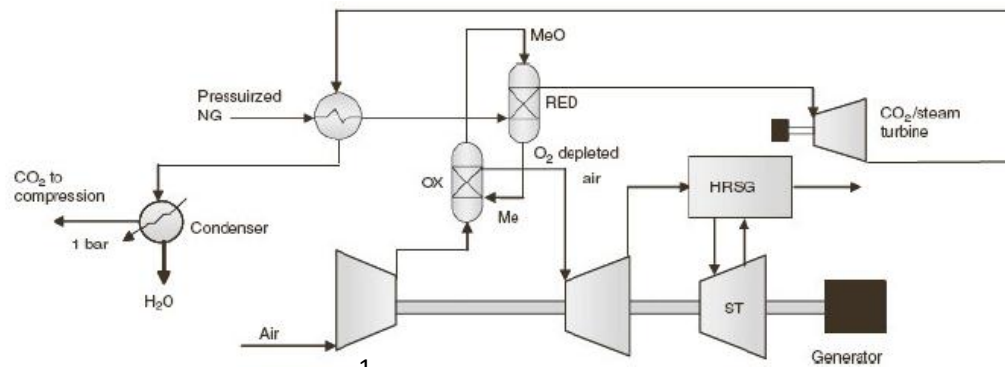


Figure 28. Simplified flow diagram CLC (Kvamsdal et al. 2007)

6.3.7 Solid Oxide Fuel Cell Carbon Capture (SOFC-CC)

The solid oxide fuel cell (SOFC-CC) produces electricity through an electrochemical process instead of combustion. The process in the SOFC-CC can be split into several sections: reforming, shifting, power generation, heat recovery and CO₂ recovery (Figure 29). A SOFC-CC operates at 600–1000°C; the higher the temperature, the higher the efficiency. The heat released during the processes needs to be inter-cooled to keep the cell at the right temperatures. By integrating the coolers with the steam reformer, a large part of the heat requirement is provided. This integration avoids the production of high grate heat by firing Natural gas, which leads to an efficiency loss (Adams II and Barton 2010). The SOFC can have several configurations: it can operate as standalone unit, be combined with a gas turbine or be combined with a combined cycle configuration. The expected efficiency in combination with a combined cycle is 62-67% (Kvamsdal et al. 2007, Park et al. 2011).

The fuel (natural gas) is reformed into CO₂, CO and H₂, and enters the anode side of the cell. Compressed and pre-heated air enters the cathode side of the cell, so the oxygen source and the fuel are separated. Oxygen is reduced to O²⁻ ions; the ions are moved through an electrolyte and react on the fuel/anode side (electrochemical reaction). The fuel reacts into H₂O and yields electrons. The internal reforming of hydro carbons and the water gas shift reaction takes simultaneous place in the membrane (Figure 30). To increase the thermal output, the off gases from the SOFC could be combusted in an afterburner, since the SOFC-CC only oxidizes 80-90% of the gaseous fuel input (Kuramochi et al. 2011, Harmelen et al. 2008).

The exhaust gas from the cathode is expanded in turbines to produce additional electricity; the remaining heat can be delivered at different temperatures, or be used to produce steam in the HRSG. In the HRSG different heat sources (high temperature heat 950 °C; medium temperature heat of 550°C; low temperature steam up to 216°C) are integrated to produce steam at different

temperatures. The steam is used for the reforming, pre-reforming and water gas shift units. The remaining heat could be used in the steam cycle to produce electricity (Adams II and Barton 2010), or it can be used as process steam in case of a CHP configuration. Colson et al (2011) argue that a SOFC CHP is a suitable option for residential electricity and heat supply in a distributed form (Colson and Nehrir 2011).

The existence of H₂, CO and N₂ dilutes the main output of H₂O and CO₂, therefore purification of the CO₂ is needed. Different technologies can be used for the clean up, but the most suitable would be an integrated oxygen separation membrane (e.g. OCM). However, those membranes are still in the laboratory phase. Other small scale oxygen production technologies, currently commercially available, are (vacuum) pressure-swing adsorption (PSA/VPSA). In the longer term membrane based air separation technologies might be used, e.g. solid oxide electrolyze cell (SOEC, which is a reverse SOFC)) or OCM (Kuramochi et al. 2011).

Despite the low cost prospects of the SOFC-CC technology, the membranes are still really expensive and need a lot of R&D to become economically attractive (Hendriks et al. 2009). The current size of a cell is 250 kWe, and is not likely to increase to a large extent, mostly due to the material difficulties and stack designs. The size development stagnated around 500 kWe (Dijkstra 2011). The research intensity around the SOFC-CC has been decreased; the major players have abandoned the research projects, because of the long development track until becoming profitable and the diminishing subsidy (Kuramochi et al. 2011, Dijkstra 2011).

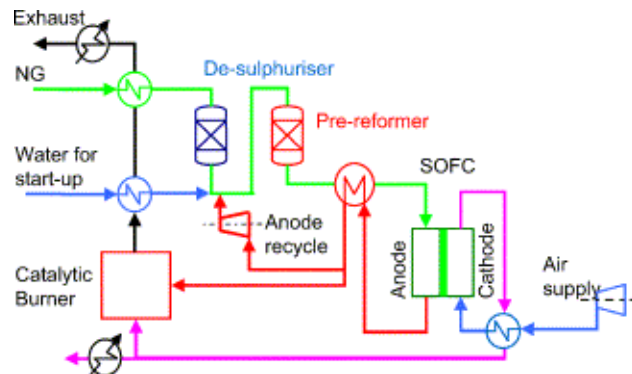


Figure 29. Simplified flow diagram SOFC-CC (Fontell et al. 2004)

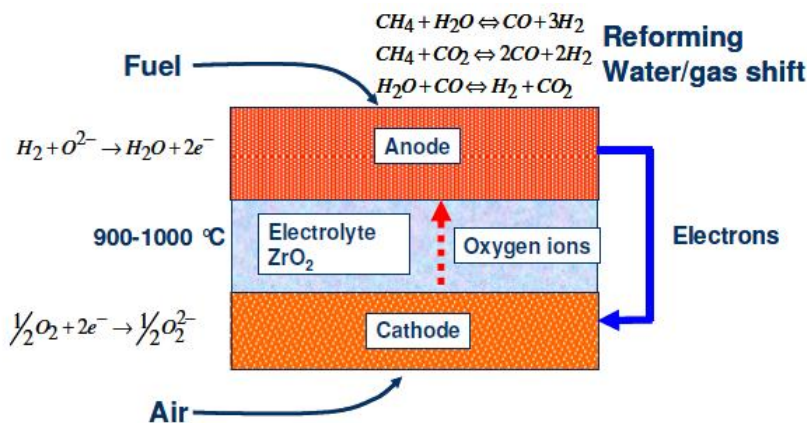


Figure 30. Schematically SOFC cell (Harmelen et al. 2008)

6.3.8 Summary of oxy-fuel capture technologies

The efficiencies of the direct oxy-fuel technologies are equal to post- and pre-combustion capture technologies. In general, the potential advantage of oxy-fuel firing are the possibilities of using

smaller equipment and a simpler capture process; the disadvantages are the energy requirement, the costs of cryogenic air separation, and the flue gas recycle to lower the flame temperature (Blomen et al. 2009, Miracca et al. 2005, Notz et al. 2010). The ASU is already a mature technology, however, to reduce CO₂ capture costs the oxygen production needs to be further developed (e.g. oxygen production based on membrane technology) (Miracca et al. 2005, Bolland et al. 2005). The development of the new gas turbine, for the oxy-fuel cycles with the working fluid CO₂/H₂O, still needs to be done.

The indirect oxy-fuel fired technologies are more promising than the direct oxy-fuel technologies, because the oxygen production unit is not required, avoiding its large investment and its high energy penalty. All three options (AZEP, CLC and SOFC) would be an option from that point of view.

Even though the AZEP cycle is promising for electricity production, its main disadvantage is its low turbine temperature. The low gas turbine temperature results in low temperatures in the steam cycle. The high temperatures in the steam cycle are essential in case a combined cycle is used in an industrial CHP configuration, so to make the AZEP technology suitable for a CHP configuration, an afterburner is necessary. The afterburner results in a lower capture efficiency, 85%. Since the other technologies provide a larger capture rate the AZEP 85% is a less promising option. Due to its low temperature the AZEP is less suitable for a combined cycle CHP.

Small scale application of most capture technologies is not discussed in any literature. However, SOFC-CC power plants have already been tested at a small scale without a combined cycle. The other cycles are all combined with a gas turbine or combined cycle, which makes medium-large scale more likely to occur (scale of most installed gas turbines and combined cycles).

6.4 Operability of capture principles

This section describes the operability of the capture technologies. The operability of power plants is an essential aspect, especially for CHP plants, because the flexibility of the CHP plants is a major reason to install a CHP unit. Aspects of the operability are the flexibility (Alie et al. 2009) and the integration risk. The *flexibility* embodies the start up and shut down possibilities of the technology, and the ability to operate in an acceptable¹ manner in part load. The *integration risk* measures the ability of the capture technology to be turned off, in order to have continuous electricity and heat production². The capture technology implies operational challenges due to its high integration level. The higher the integration level, the more difficult it is to keep operating in case of a failure in the capture system.

6.4.1 Operability post combustion capture

The post combustion absorption capture techniques are less integrated than other capture cycles. The heat flows of the gas turbine and capture unit are integrated, but can be switched off in case of a failure in the capture system, which makes the operational difficulties low (Kvamsdal et al. 2006, Kvamsdal et al. 2009). The part load efficiency of the post combustion plant is similar to a normal combined cycle / gas turbine (Möller et al. 2007). The capture unit does not influence the gas turbine itself, which is the most restrictive factor for part load conditions. The absorber does have a

¹ Acceptable: CHP is stable at part load and its efficiency is not diminished to a large extend ($\eta_e < 30\%$)

² Integration could lead to the existence of multiple steady states. A minor change in operating conditions might result in a shift to a different steady state with a lower productivity, robust control loops are therefore needed, which are expensive and difficult to design (Cardona et al. 2008). However, the role of integration risk is limited, because in case of integrating several process steps into one unit, the amount of transport is limited, resulting in lower probability of transport break down and less energy losses (lower O&M cost) (Cardona et al. 2008).

similar efficiency at part-load as in full load. The startup procedure does imply a short time without CO₂ capture, because the capture unit needs to warm up and start up the solvent flow. Because the capture unit is an add-on, the normal start up time of a gas turbine is not prolonged. To prevent CO₂ emissions storage of solvent is needed (Dijkstra 2011, Chalmers and Gibbins 2007).

6.4.2 Operability of pre combustion capture

Pre combustion processes (ATR, ATR-SE-WGS and MSR-H₂) involve several catalytic steps, including heating and cooling steps. The catalytic steps require a high degree of process integration to create a high efficiency (Andersen 2005). The integration makes pre combustion a rather complex technology, which is difficult to optimize (Nord et al. 2009, Notz et al. 2010). The carbon capture plant is a (extended) chemical plant in front of the turbine, which result in another disadvantage, additional shut-downs due to its complicated chemical processes. These possible shut-downs may result in a lower operating hours (or increase of emissions in case power output is continued with natural gas as fuel) (Blomen et al. 2009).

The part load behavior of ATR is good; the efficiency reduction is comparable with conventional combined cycles. It is possible to operate at part loads down to 60% of the gas turbine load (Nord et al. 2009).

The start-up procedures of the ATR and ATR- SE-WGS are similar. First the gas turbine is started with natural gas, and second the pre combustion unit is started to replace the natural gas with hydrogen again. The MSR-H₂ start up procedure is more difficult, because the process involves membrane technology which needs a stable temperature (comparable with the AZEP, SOFC technologies) (Dijkstra 2011).

The ATR and SE-WGS are integrated systems, however a lot of experience with the IGCC (integrated gasification combined cycle) decreases the controllability complexity. For the MSR-H₂ however, the reforming, hydrogen separation and heat exchange are integrated which makes the controllability more difficult, and the integration risk high.

6.4.3 Operability of oxy-fuel capture

The integrated oxy-fuel cycles have inherent high process integration (Kvamsdal et al. 2006):

- AZEP: oxygen separation, combustion, and heat exchange in the MCM membrane;
- CLC: two reactors coupled through recycling of electron carrier (solid material);
- SOFC: oxygen separation, reforming, electrochemical reaction, and heat exchange.

Due to the high integration it is not possible to decouple the carbon capture unit and produce electricity whilst emitting CO₂. Therefore, in case the capture unit breaks it is not possible to continue the electricity production, as is the case with post combustion.

6.4.3.1 Operability of direct combustion oxy-fuel

All three direct oxy-fuel concepts, Matiant cycle, Water cycle and Graz cycle, involve recirculation of exhaust gases. Such a closed loop with high integration of components makes such a system vulnerable for mechanical failure caused by start-up, shut-down and load changes (Kvamsdal et al. 2006). Since the Graz cycle involves two recycle loops (water and CO₂), the operational challenges are expected to be higher than in case of the other two. If the load changes can be gradually, then the relative efficiency drop of partial load is lower than for conventional combined cycle (Riethmann et al. 2009). For all three cycles the slowest part of the start-up procedure is the start-up of the ASU which needs some time to reach the required temperature (Dijkstra 2011).

6.4.3.2 Operability of AZEP

In case 100% capture ratio needs to be achieved the afterburners cannot be used, leading to a bad part load behavior of the cycle and a lower steam output temperature. The load can be reduced down to minimal 74% (58% with afterburners). To guarantee membrane stability the temperature and pressure needs to be constant. Variable guide vanes (VGVs) in the compressor can be used to obtain the target temperatures of the membrane modules as well as the demanded power output. At the AZEP without afterburners VGVs cannot control the turbine exit temperature, which implies negative impacts on the steam turbine and process steam production (Bolland et al. 2010, Bolland et al. 2010). Because the AZEP has many process steps integrated, it has a high integration risk.

6.4.3.3 Operability of CLC

The relative efficiency drop by lower loads in CLC combined cycle is less than a conventional combined cycle. At 60% of full load the efficiency drops with 2.6%-points (Naqvi et al. 2007), but below the 60% load the plant cannot be controlled. Even though the reactor itself can be regulated above a 60% load, load changes are complicated due to the tight integration of two reactors with the gas turbine. The start-up and shut-down procedure of the CLC cycle is difficult, because chemical reactions are involved which should reach their steady state conditions (Lyngfelt and Thunman 2005).

6.4.3.4 Operability of SOFC-CC

The SOFC-CC technology requires stable temperature conditions, because it is a membrane based technology. Rapid load changes are, therefore, operational challenging (Kvamsdal et al. 2006); leading to long start up times (EPA 2002). Part load efficiencies, however, are better compared to a conventional combined cycle (increasing instead of decreasing) (COGEN Vlaanderen 2006). The SOFC-CC integrates different processes in one fuel cell, which makes controllability more complex, and results in high integration risk.

6.5 CO₂ capture technology summary

In this section, the findings of the different capture technologies are summarized by giving a score to several capture characteristics essential for CHP application (Table). Those characteristics are:

- Small scale: is it possible to apply the capture technology to small scale CHP plants (smaller than 10 MW)
- Capture energy use: the energy use is expected to decrease for existing technologies and already lower for capture technologies in development. Therefore the score is not based on quantitative numbers but on expected energy use in the future. The score identifies whether the capture processes requires heat and/or electricity.
 - Capture electricity use: The electricity usage of the capture process
 - Capture heat demand: The heat requirement of the process
- Ramp up/down: the ability of a technology to perform start-up and shut-down procedures, or rapid change of loads
- Partial load: is it possible to operate in part load, and what are the effects on the performance (efficiency)
- Integration risk: operational challenges due to level of process integration, the more integrated subsystems, the more recycle streams the lower the integration risk score.

The scores are given comparing the different technologies based on the descriptions given in the previous sections. The scores will be: ++ (very good), + (good), - (poor), -- (bad). So the scores are relative to the other capture technologies.

Table 32. Scores of characteristics per capture technology

	Post combustion		Pre combustion			Oxy-fuel					
	<i>Amines</i>	<i>Chilled Ammonia</i>	<i>ATR (air)</i>	<i>ATR SE-WGS</i>	<i>MSR-H2</i>	<i>Matiant cycle</i>	<i>Graz cycle</i>	<i>Water cycle</i>	<i>AZEP</i>	<i>CLC</i>	<i>SOFC-CC</i>
Capture level (%) ^a	85-90	85-90	90	90	100	90-100	100	100	100	100	100
Efficiency (%) (in combination with a combined cycle)	48%		47%	47-48%	56%	47%	44%	49%	49-50%	51-52%	62-67%
Small scale	Possible, but less economical than large scale (-)	Possible, but less economical than large scale (-)	Possible, but less economical than large scale (-) ^b	Possible, but less economical than large scale (-)	Possible, but less economical than large scale (-)	Cycle intrinsically include a combined cycle (large scale) (--)	Cycle intrinsically include a combined cycle (large scale) (--)	Cycle intrinsically include a combined cycle (large scale) (--)	Possible, but less economical than large scale (-)	Possible, but less economical than large scale (-)	Only applicable at small/medium size (++)
Capture electricity use	Electricity for solvent pumps and flue gas compression (+)	Electricity for solvent pumps and chilling (-)	Electricity for solvent pumps, less compression needed due to higher CO ₂ concentration (++)	High electricity demand due to oxygen production (--)	Electricity for solvent pumps, less compression needed due to higher CO ₂ concentration (++)	High electricity demand due to oxygen production (--)	High electricity demand due to oxygen production (--)	High electricity demand due to oxygen production (--)	Electricity for flue gas compression (+)	Electricity for flue gas compression (+)	Electricity for flue gas compression (+)
Capture heat demand	High heat demand for regeneration heat (--)	Lower heat demand for regeneration heat compared to Amines (-)	Lower heat demand for regeneration heat compared to Amines (-)	Lower heat demand for regeneration heat compared to Amines (-)	Steam is needed as sweep gas in membranes (-)	No additional heat required (++)	No additional heat required (++)	No additional heat required (++)	No additional heat required (++)	No additional heat required (++)	Internal reforming reduces steam output (-)

^a (Damen et al. 2006, Kvamsdal et al. 2007)^b The capture unit itself cannot be combined at small scale; a central capture unit can deliver hydrogen to different CHP units.

Table 1 continued. Scores of characteristics per capture technology

	Post combustion		Pre combustion			Oxy-fuel					
	<i>Amines</i>	<i>Chilled Ammonia</i>	<i>ATR (air)</i>	<i>ATR SE-WGS</i>	<i>MSR-H2</i>	<i>Matiant cycle</i>	<i>Graz cycle</i>	<i>Water cycle</i>	<i>AZEP</i>	<i>CLC</i>	<i>SOFC-CC</i>
Ramp up/down	Normal start up procedure with short time of CO ₂ emissions (++)	Normal start up procedure with short time of CO ₂ emissions (++)	Normal start up (with CH ₄) procedure with short time of CO ₂ emissions (++)	Normal start up (with CH ₄) procedure with short time of CO ₂ emissions (++)	Membrane based, slow warm up needed (--)	Normal start up (with stored O ₂) procedure with short time of CO ₂ emissions (++)	Normal start up (with stored O ₂) procedure with short time of CO ₂ emissions (++)	Normal start up (with stored O ₂) procedure with short time of CO ₂ emissions (++)	Membrane based, slow warm up needed (--)	Start up procedure is comparable with normal start up time (++)	Membrane based, slow warm up needed (--)
Partial load	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	Gas turbine is limiting factor (+)	maximum 74% partial load (--)	maximum 60% partial load (+)	At partial load higher efficiencies (++)
Integration risk	Add-on technology (++)	Add-on technology (++)	External H ₂ source can replace capture unit (+)	External H ₂ source can replace capture unit (+)	Fully integrated (--)	Oxygen production can be decoupled (+)	Oxygen production can be decoupled (+)	Oxygen production can be decoupled (+)	Fully integrated (--)	Reactors highly integrated with turbine and compressor (--)	Fully integrated (--)

6.6 Carbon capture and Boilers and Furnaces

This section describes the carbon capture options combined with boilers and furnaces. Insights in boilers and furnaces with carbon capture are important, because it determines which capture technologies can be used in case of steam turbines. Applying capture technologies to boilers/heaters provides might be an alternative for CHP-CCS. If the Boiler-CC is more economical, then it might replace existing CHP plants.

Capture technologies applied to boilers and heaters

In the mid-term future (2020-2025) oxy-fuel CO₂ capture is expected to outperform post-combustion capture as carbon capture options for boilers and heaters (IEA 2008). Therefore, post-combustion is not further investigated in this study. In case of pre-combustion CO₂ capture, the burners need to be adjusted (Lowe et al. 2010). In the medium term the SE-WGS process might be applied, in the longer term the MSR-H₂ can be used, making use of a water gas shift membrane reactor (WGS-MR). However, oxy-fuel capture is the most suited technology for heater and boilers combined with carbon capture. In this analysis the oxy-fuel boiler is therefore used as (alternative) mitigation option.

Currently, a number of pilot oxy-fuel boiler plants up to 30 MW_{th} scale (e.g. Schwarze Pumpe in Germany) are being tested (Kluger et al. 2011). At an oxy-fuel boiler (without flue gas recycle), the heat flux is higher than the conventional boiler due to higher temperatures. This allows a slightly (10%) more compact boiler design. However, the increased temperature also causes a problem for existing boilers, because those cannot stand such temperatures (Cieutata et al. 2009). Additionally, a key criterion of a process heater is to ensure a constant peak heat flux to the tube surfaces, which will not be the case by firing with pure oxygen. Recycling some of the flue gas (CO₂ and water) is a solution to manage this problem. The advantage of recycling is the possibility to apply oxy-fuel firing to developed boilers (Figure 31), the disadvantages are the cost penalty due to the addition of the recycle flue gas blower and ducting, and the need for larger equipment for higher gas throughputs (Simmonds and Walker 2005, Wilkinson et al. 2003).

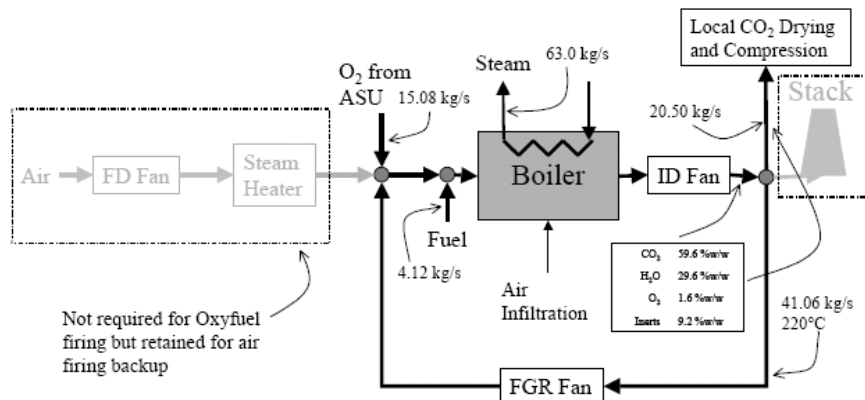


Figure 31. Schematic view of an air and oxy-fuel firing boiler (Simmonds and Walker 2005)

Applying oxy-fuel combustion to furnaces and heaters differs from the application to boilers (Wilkinson et al. 2003). The conversion of heaters to oxy-fuel operation is more difficult than the conversion of boilers (Kuramochi 2011), because heaters have compared to boilers:

- a greater air in-leakage due to wider range of furnace designs and different techniques being used for their construction,
- hydrocarbons present in the furnace tubes,
- no automatic control of air/fuel ratio and draught.

In the longer term advanced oxy-fuel boilers and heaters are feasible, using an oxygen conducting membrane (OCM). OCM can produce high purity oxygen while reducing energy consumption (35-68%) and capital costs (35-48%) compared to cryogenic separation (Kuramochi 2011).

7. CHP and Capture technology combined

This chapter discusses the most likely combinations of capture technologies and CHP technologies. These combinations are based on the characteristics of the different technologies, as identified and described in the previous chapters: size, high temperature supply and operational characteristics (ramp up/down, partial load performance, controllability). Subsequently, the suitable sectors to apply capture technologies are identified based on the sector characteristics: average size, total installed capacity, amount of load hours, operational continuity.

7.1 CHP-CCS technology match

7.1.1 CCS and Gas engines

Gas engine CHP is mainly applied for the following purposes:

- For space heating and electricity production in buildings (hospitals, offices, greenhouses)
- As back-up systems for power and heat

Size

Gas engines are small sized and have relatively low investment costs, because they are (often) mass-produced. CCS equipment is therefore relatively expensive compared to the investment costs of gas engines, especially because the small size raises the costs of the capture unit. Gas engine-CCS is therefore expected to be costly except when using SOFC-CC capture technology, which is especially suitable at small scale.

Heat temperature supply

Gas engines are used to supply low grade steam or warm water. All capture technologies are able to maintain the warm water supply.

Operational characteristics

Important characteristics of gas engines are a fast start up, good part load behavior and a high controllability (for the back-up units). In case of technologies using membranes, which have a long start up time, the capture technology compromises the fast start up. Therefore the membrane technologies, Membrane Sorption Reformer-H₂, Advanced Zero Emission Power plant and SOFC-CC can be excluded as CCS-option. The Chemical Looping Combustion cycle includes a gas turbine within the cycle, which has a slower start-up time than an engine, and less optimal part load behavior, therefore this option can be excluded as well (IEA GHG 2007).

The possibility of applying indirect oxy-fuel combustion to gas engines has not been researched. The application of an indirect oxy-fuel cycle does not seem economic, because the increase of combustion temperature (due to pure oxygen use) requires a whole new engine design including recycle streams. Such a new design would make the CHP-CCS combination expensive, and entail significant technology risk.

The CO₂ content of the flue gas of the gas engine is higher than that of gas turbines, which makes post-combustion more effective. Post-combustion and pre-combustion ATR technology are technological possibilities to combine with a gas engine, however economically less attractive than large scale application.

7.1.2 CCS and Gas turbines

Gas turbines are mostly applied for supplying high temperature heat, or in case the heat demand is large. Gas turbine CHPs can deliver heat in two ways, producing steam in a HRSG, or using directly the

exhaust heat in a process. Gas turbine CHP with HRSG is usually sized to produce the amount of heat needed in the industrial process, so additional heat for capture is not available. In case CCS is applied to a gas turbine, the CHP system should therefore have a larger size.

Size

The size of gas turbine CHP differs from small to medium (5-30 MW_e). Small sized gas turbines are unlikely to be equipped with CCS, but for medium size CHP however, this might be economically viable.

Heat temperature supply

Gas turbines applied in all sectors have a rather high HPR (2.5-4.3) to deliver high grade steam to processes, therefore capture technologies that comprise the heat output (SOFC-CC and AZEP) are not suitable as capture option.

Operational characteristics

Gas turbines are preferably used continuously at full load (see Gas turbine chapter). These characteristics make gas turbine CHP suitable for applying CCS. The reliability of gas turbines is one of the key characteristics affecting the integration risk. A low score on the integration risk¹ does not imply technological unfeasibility, but it makes applying capture technology less suitable. Integrated technologies, like MSR-H₂, Graz cycle, AZEP, CLC and SOFC-CC, are therefore less likely to be applied.

Capture possibilities which require heat to capture CO₂ (post- and pre- combustion technologies) are less suitable, but by using an oversized CHP it would be possible to implement such capture technology. Other capture technologies, which only need electricity for the capture process, can be installed without the need for a larger CHP plant in most cases, as gas turbines CHP plants normally produce excess electricity to sell to the grid. This makes the water cycle and oxy-fuel combined cycle suitable capture technologies for gas turbine CHP plants.

Operational characteristics of direct heat supply

For gas turbines that supply heat directly instead of making steam, limited capture possibilities exist. All post combustion capture and direct oxy-fuel capture technologies require flue gas treatment (cooling) to capture CO₂, which makes the flue gas unusable for direct industrial use. Pre-combustion technologies and the SOFC-CC need steam for their capture process, and because direct heat CHP plants do not produce steam these capture technologies are not likely, but can be used if an additional steam source (boiler) is applied. Space for an additional boiler exists with pre-combustion capture due to its (large) size; for SOFC-CC, however, space is limited. The AZEP technology without afterburners is not suitable since the output temperature is hard to regulate, which is essential if the heat is used directly. The most suitable capture technology for direct heat use is CLC in which the combustion chamber is replaced but the other gas turbine parts and characteristics remain the same.

7.1.3 CCS and Steam turbines

Steam turbines do not produce flue gas, so for combining steam turbines and carbon capture the capture system must be attached to the steam generator, or the steam turbine must be replaced by a different CHP technology. The most suitable capture technology for steam turbine CHP should be fitted to the boiler, which is discussed in Carbon capture and Boilers and Furnaces chapter

Size

The size of the boiler attached to a steam turbine is small to large (10-150 MW_{th}). Medium and large sized steam turbines are more likely to be fitted with CCS.

¹ A low score corresponds with high integration risks as described in the CO₂ capture

Heat temperature supply

The temperature supplied by the CHP system is determined by the steam turbine output and is therefore not influenced by the capture technology which is coupled to the boiler.

Operational characteristics

All post combustion and pre-combustion technologies are technological suitable. For the oxy-fuel technology the conventional boiler must be replaced by an oxy-fuel boiler. All oxy-fuel cycles are designed to be combined with gas turbines or combined cycles, and therefore not suitable to apply to steam turbines.

7.1.4 CCS and Combined cycle (CCGT)

In general, combined cycle CHP plants are large compared to other CHP technologies. CCGT can adjust its HPR by reducing the electricity output of the steam turbine and increase the steam output.

Size

Combined cycle CHP is normally applied at large scale. Due to size restrictions of the membrane technology the SOFC-CC is excluded as suitable CCS option.

Heat temperature supply

Combined cycle CHP is mostly used for high grade steam production. AZEP and SOFC-CC capture technologies have a lower temperature heat output than normal combined cycles, so these capture options are excluded.

Operational characteristics

The ability of combined cycle plants to adjust the HPR (by reducing the electricity output of the steam turbine) and the possibility to use the electricity produced for the capture process makes it possible to apply all other capture technologies.

The application of steam turbine CHP plants will decrease, the gas turbine technology replaces former steam turbine applications. The role of steam turbine CHP-CCS will therefore be limited.

Overview technology combinations CHP-CC

Table 33 gives an overview of the different CHP-CCS combinations. Per combination the application possibility is indicated as suitable (+), possible but adaption required (+/-) or unsuitable (-).

Table 33. CHP and capture technologies match table

	Gas engine	Gas turbine		Steam turbine	Combined cycle
		HRSG	Direct		
Post combustion					
Amines	+	+	-	+	+
Ammonia	+	+	-	+	+
Pre combustion					
ATR	+	+	+/- ^a	+	+
ATR-WEGS	+	+	+/- ^a	+	+
MSR-H2	-	+/- ^b	+/- ^a	+	+

Table 33 continued - CHP and capture technologies match table

	Gas engine	Gas turbine		Steam turbine	Combined cycle
		HRSG	Direct		
Oxy-fuel					
Oxy-fuel CC	-	+	-	+ ^d	+
Water cycle	-	+	-	-	+
Graz cycle	-	+/- ^c	-	-	+
AZEP	-	-	-	-	-
CLC	-	+	+	-	+
SOFC-CC	-	-	-	-	-

^a Requires an additional heat source to provide steam for the capture process.

^b Technological feasible, but less likely to be applied due to membrane technology

^c Technological feasible, but challenging due to two recycle streams

^d Oxy-fuel boiler replaces a conventional boiler

7.2 CHP-CCS per sector

In this section the most suitable sectors to apply CHP-CCS are identified on the basis of current application of CHP plants in each sector. Within sectors CHP installations differ, but an overall picture can be drawn. The sectors differ on several aspects which affect the possibilities for applying CCS

1. **CHP size:** The size relate to economies of scale for the capture unit, the larger the size the higher the likelihood that CCS can be applied economically.
2. **Total installed CHP capacity:** The total installed CHP capacity is an important aspect to determine the potential of a certain sector. The more installed capacity the more emission abatement potential
3. **Load factor:** The costs of capture are largely affected by the load factor. The higher the load factor, the lower the specific capture costs (Kuramochi 2011). The likelihood of CCS is therefore increased by a higher load factor (Kuramochi 2011).
4. **Continuity of heat demand:** The continuity of heat demand relates to the reduction of operational flexibility of the CHP due to application of CCS. If a CHP plant operates continuous (must-run) the reduction of flexibility does not have much effect, in case flexibility is needed the capture unit will limit the flexibility (e.g. in case of gas engines in greenhouses).

For every aspect a score (+ or -) is given per sector which add up to a final score.

7.2.1 Agriculture

In the agriculture sector the CHP applications are in the horticulture sector, so the focus will be on this sub-sector.

Horticulture

The recent increase of CHP in the agriculture sector creates a large potential for emission abatement. However, the usage of small scale gas engine CHP and the disperse application are major drawbacks because both factors increase the CO₂ capture and transport costs. The reason to install gas engine CHPs in the agriculture is a combination of their own need for heat, electricity and CO₂ and a financial incentive, i.e. revenues from the excess electricity sold to the grid. By actively anticipating to fluctuation of the electricity price farmers create an important new income source. If the systems are fitted with capture technology revenues will drop due to the higher investment needed for the capture unit, reducing the financial incentive to install CHP. The compromised financial incentive for the gas engine raises opportunities for renewable heat technologies such as geothermal, heat pumps, or the use of waste heat from power plants. The possibility to install other low-carbon technologies instead of gas engines combined with CCS reduces the CHP-CCS potential. So the potential of CO₂ abatement by installing capture units by CHP in the agriculture sector is low compared to the other sectors.

7.2.2 Industry sectors

Chemical industry

The chemical industry is the industry sector with the largest installed CHP capacity, predominantly in the form of combined cycle and gas turbine CHP plants. The operating characteristics of the CHPs are high amount of load hours and many installations are must-run. These characteristics create good possibilities to apply capture technologies. These factors give the chemical industry a high potential for CHP-CCS.

Refineries and mining companies

Refineries are a cluster of CO₂ emitting sources, among which CHP plants. The high continuous steam demand results in CHP plants operating continuously, a typical CHP plant (mostly applied) is a medium sized gas turbine CHP. The operational characteristics make the CHP-CCS combination likely to be viable, especially if it can be combined with capture from other CO₂ sources at the refinery. Several studies have explored the possibilities for CO₂ capture at refineries (Wilkinson et al. 2003, van Straelen et al. 2010).

Paper industry

In the paper industry different types of CHP systems are installed, of which the most likely to apply CCS are medium sized combined cycle CHP plants. Combined cycles typically operate with continuously, making them suitable for applying capture technologies.

Food industry

The food industry covers a range of different sectors using different types of CHP, the most suitable CHP technology for CCS in this sector are medium sized combined cycles that operate continuously (Klimstra 2011).

Other industry

In other industry sector, CHPs installed are small, the total installed capacity is small and the amount of load hours is low, which make the CHP-CCS application in this sector unlikely.

7.2.3 Built environment

CHP in the built environment can be split into two main groups. First, large CHP (gas turbines and combined cycles), which deliver heat for district heating and electricity to the medium voltage grid (10 kV). Second, the small gas engines (average size: 0.35 MW_e) used in individual buildings. Based on size the large CHP plants are better suited for applying capture technology. However, both types have a relatively low amount of load hours (4000h) due to fluctuating heat demand (day-night and differences per season) which makes them less suitable for CCS. Gas engines are widely dispersed and the small CO₂ stream makes coupling capture to the CHP infeasible (see chapter 7.1.1). The characteristics of the CHP in the built environment therefore result in little potential for CHP-CCS.

7.2.4 Other sectors

Waste sector

CHP in the waste sector can be divided in two types: one based on incineration of waste in steam turbines, and one based on firing fermentation gas in gas engines. For capture, incineration has higher potential, due to the larger size of the steam turbine CHP. Since only part of both electricity and heat is used within the process, all capture technologies are technologically feasible. However, the low amount of load hours (4000-5000h) and its flexible operation makes CO₂ capture in the waste sector less viable.

7.2.5 Overview suitability CHP-CCS per sector

The suitability of CCS application per sector is determined by allocating scores to their characteristics, as identified in section 7.2. Table 34 clarifies the scoring methodology. Size, installed capacity, load hour and continuity criteria are divided in categories, corresponding to a three-tier rating: low, medium and high.

Average size per sector that defines different groups the division in size of the gas turbines is taken from van der Marel et al. (2008):

- Small scale, <8 MW_e; including sectors which have mainly gas engines and small gas and steam turbines;
- Medium scale, 8- 20 MW_e; sectors including a mix of small and large sized CHP.
- Large scale, >20 MW_e; sectors which have mainly combined cycles, large scale gas and steam turbines.

Total installed capacity is rated based on the total installed capacity per sector:

- Low; less than 5% of total CHP capacity, less than 350 MW_e
- Medium; between the 5-20% of total CHP capacity, between 350-1500 MW_e
- High; more than 20% of total CHP capacity, more than 1500 MW_e

Load hours are rated as follows:

- Low; less than 60% of the time in operation, which equates to 5500 full load hours.
- Medium; between 60 and 90% in operation, which equates to 5500-8000 full load hours
- High; continuously high load in operation, over 90%, which equates to more than 8000 full load hours

Continuity of operation is divided into:

- Low; <50% of the CHPs are must run installations.
- high; >50% of the CHPs are must run installations

Table 34. Score rating of the viability of CHP-CCS

	Low (-)	Medium (0)	High (+)
Size: Average size per sector	<8 MW _e	8-20 MW _e	>20 MW _e
Installed capacity: Total capacity installed CHP plants	<350 MW _e	350-1500 MW _e	>1500 MW _e
Load hours: Average full annual load hours per sector.	<5500h	5500-8000h	>8000h
Continuity: Share of must run installations,	<50% must-run		>50% must-run

The scores add up to an overall sector score, shown in Table 35. The overall score indicates the viability of CCS application in each sector.

Table 35. Overview of CHP-CCS viability per sector

	CHP + CCS				
	Size	Installed capacity	Load hours	Continuity	Total
Agriculture	-	+	-	-	--
Chemical industry	+	+	+	+	++++
Refineries and mining companies	0	0	+	+	++
Paper industry	0	-	0	-	--
Food industry	-	0	0	-	--
Other industry	-	-	-	-	----
Waste sector	0	0	-	-	--
Build environment	-	0	-	-	---

7.2.6 Case selection

To quantify the potentials of the different sectors in the subsequent analysis, typical cases have been identified. Two sectors are excluded, the other industries sector and the waste sector. The other industries sector is qualitatively identified as a low potential sector, because the total CHP capacity is small, the systems are small on average and have a low number of annual load hours on average. The waste sector is excluded because CHP used is not included in the ETS (Crawford 2010) and use of waste as fuel is seen as emission reduction option since it prevents fossil fuel use.

For the other sectors one or two typical cases¹ have been defined. Each case is based on the most common CHP technology, while the size (MW_e), electrical and thermal efficiencies are based on CBS-averages. The maximum number of load hours per sector is used as the typical amount of load hours.

Table 36. CHP-CCS cases for quantitative analysis

Case nr.	Sector	CHP-technology	Size (MW)	Load hours (h)	Electrical Efficiency (%)	Thermal Efficiency (%)
1	Chemistry	Large scale CCGT	125 MW _e	8000	36%	38%
2		Medium scale GT	25 MW _e	8000	19%	63%
1a		Large scale Boiler-CC	126 MW _{th}	8000	-	90%
2a		Medium scale Boiler-CC	78 MW _{th}	8000	-	90%
3	Refinery	Medium scale GT	22 MW _e	8000	27%	56%
4	Paper industry	Medium scale CCGT	39 MW _e	6500	24%	41%
5	Food industry	Medium scale CCGT	23 MW _e	7000	24%	44%
6	Horticulture	Small scale Gas engine	2 MW _e	4000	41%	50%
7	Built environment	Medium scale CCGT	40 MW _e	4000	40%	27%
8		Small scale Gas engine	0.4 MW _e	4000	34%	45%

¹ If two types of CHP plants are mainly used in a sector, two cases are defined.

8. Results quantitative analysis

In this chapter, the results of the quantitative analysis are presented. Firstly, the development of the heat demand in the different sectors is used to determine the limits of the technical potential¹ of the CHP-CCS. Secondly, the cost analyses of the CHP-CCS cases in different sectors are discussed, giving insight in the additional costs of applying CCS to CHP compared to a conventional CHP. Thirdly, the results of the CHP-CCS cases are compared to the base case (boiler + NGCC), the reference case (CHP), and an alternative mitigation option (oxy-fuel boiler + NGCC-CCS). Fourthly, the results of the sensitivity analysis are discussed.

8.1 Results quantitative analysis CHP-CCS cases

To determine the technical potential, the heat demand per sector gives an indication of the maximum amount of emission abatement. Based on the report of (Daniëls and Kruitwagen 2010), the development of the heat demand in the different sectors is plotted in Figure 32. In general, the heat demand does not change to a large extent; the most important changes are the slight decrease of the heat demand in the building sector and the increase in the agricultural sector.

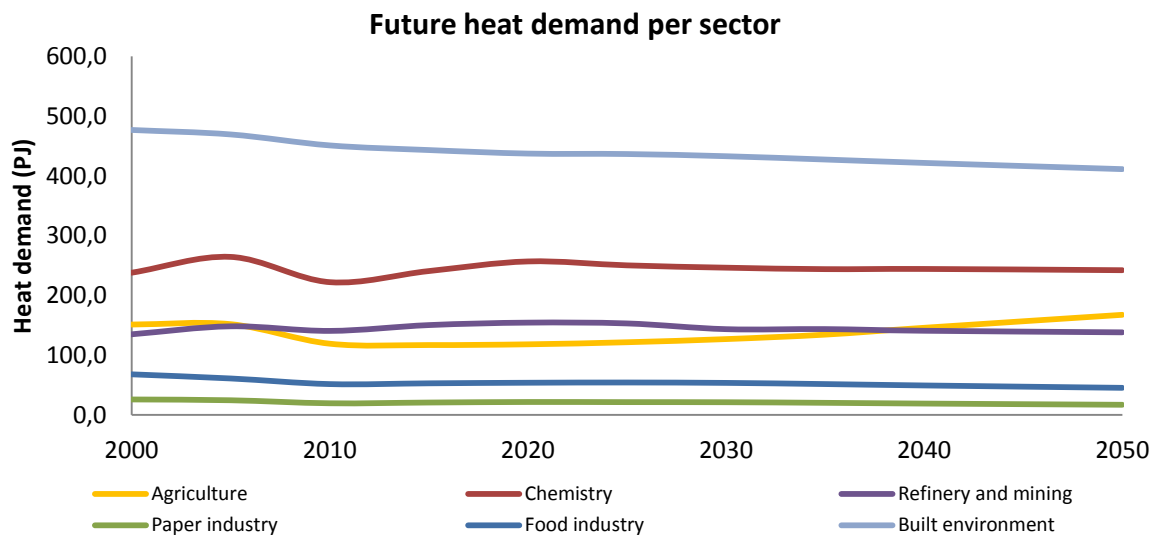


Figure 32. Development of heat demand (PJ) per sector in the Netherlands

To meet the heat demand, a typical² CHP-CCS case per sector is identified. In Table 37 and Table 38 the technical and cost indicators of the different CHP cases in 2030 and 2050 are shown. These indicators give insight in the costs, the additional fuel needed, and the amount of avoided emissions of the technical CHP-CCS potential. In case of the chemical and built environment sectors a difference is made between CHP types (CCGT, GT or GE). To determine the potential of the sector, the potential of these different CHP types cannot be added up, because the total heat demand is used to calculate the total technical abatement, which will lead to double counting within a sector.

First, the cost range of the CHP-CCS options is 93-291 €/tCO₂ in 2030 and 68-228 €/tCO₂ in 2050. This cost range is higher compared to the range of current costs, 51-82 €/tCO₂, of recent studies of CCS

¹ The technical potential includes abatement options technological possible (Masselink 2008). The maximum is based on the total heat demand per sector.

² The typical CHP cases are identified in the CHP chapter.

applied to centralized power plants, an overview of these studies is published in the world energy outlook of the IEA (IEA 2010d).

Another aspect of abating CO₂ emissions is the additional amount of fuel needed. This differs per technology, because the CCGT-CHPs have a lower heat to power ratio (HPR) compared to the GT and GE-CHPs. Because the heat demand determines the size and the HPR of the CHP-CCS are kept constant, the electricity output of the CCGT-CHP increases therefore to a large extent. Due to the CO₂ capture application to the GE and GT the fuel increases with 26-36% and in case of the CCGT with 42-91% in 2030. Due to a more efficient capture technology and increase of CHP efficiency the additional fuel needed decreases over time, in 2050 the GE and GT need 14-19% more fuel, the CCGT 21-39%.

Furthermore, the amount of CO₂ avoided, which is one of the key elements, depends on sectors heat demand, and on the type of CHP-technology installed. The chemistry and built environment sectors show the effect of using different technologies to meet the same heat demand. The CCGT options abate more CO₂ compared to the GT and GE, because its amount of electricity produced is larger (due to a higher HPR). The CCGT-CHP provides, therefore, a higher technical potential compared to the GT and GE, although with more additional fuel. In the horticulture, the amount of CO₂ emissions avoided does slightly increase over time, because the increase of electrical and thermal efficiencies is offset by the increase in heat demand.

The figures presented in this chapter are characteristic sector values. The figures are averages of the most commonly used technology per sector. However, per sector different CHP technologies are used, and the sizes range to a large extent. To show the representative power of each case the different types and sizes installed per sector are discussed briefly.

Chemical industry:	the GT and CCGT together are 88% of the installed capacity. The CCGT 16% of the installations are smaller than 100 MW _e , which will lead to higher costs compared to the average.
Refinery sector:	about 70% are GT CHPs, next to a few old steam turbines and gas engines. The GT ranges in size between 4-48 MW _e , of which 14% is lower than 15 MW _e . The small turbines will be more expensive, the larger ones, however, will be cheaper.
Paper industry:	75% of the installed capacity is medium sized CCGT CHPs.
Food industry:	a large mixture of the different CHP technologies is installed, the CCGT is only 53% of the installed capacity, the other CHP installations are mainly small scale GE and GT. The installed CCGT capacity does not vary much in size; the average size gives a good indication of all CCGT's installed.
Built environment:	only some small scale GT and ST are installed, but the GE and CCGT's together form about 95% of the total amount of installed capacity. The installed CHPs do not vary much in size, so the average values give a good picture of the potential.
Horticulture	all installations installed are GE. And the new installed installations are all large scale gas engines (>2 MW _e), and since the older ones are slowly replaced, this size will give a good representation of the GE size.

Table 37. Results quantitative analysis 2030

2030			CHP Installation					Sector		
<i>Sector</i>	<i>Size</i>	<i>Type</i>	<i>Electrical efficiency</i>	<i>Thermal efficiency</i>	<i>Avoided CO₂</i>	<i>Additional fuel use</i>	<i>Avoided CO₂ costs¹</i>	<i>Avoided CO₂ per sector</i>	<i>Additional fuel use per sector</i>	<i>Abatement costs in sector</i>
	MW _e		%	%	ktCO ₂ /yr	MWh _{th} /tCO ₂	€/tCO ₂	MtCO ₂ /yr (%)	TWh _{th} /yr (%)	x1000 M€/yr
Chemical industry	125	CCGT	36%	25%	455	3.1 ²	105	31 ² (85%)	95 (53%)	3.2
Chemical industry	25	GT	18%	50%	174	1.5 ²	93	19 ² (87%)	28 (26%)	1.8
Refineries	22	GT	26%	43%	111	1.7	109	13 (87%)	22 (31%)	1.4
Paper industry	39	CCGT	23%	28%	175	2.7	134	2 (85%)	7 (47%)	0.3
Food industry	23	CCGT	43%	32%	62	2.4	139	6 (86%)	14 (42%)	0.8
Built environment	40	CCGT	40%	14%	62	5.5 ²	259	71 ² (81%)	396 (91%)	18.5
Built environment	0.4	GE	34%	32%	0.89	2.0 ²	291	38 ² (86%)	79 (36%)	11.2
Horticulture	2	GE	42%	37%	3.24	1.8	247	16 (87%)	28 (31%)	3.9

Table 38. Results quantitative analysis 2050

2050			CHP Installation					Sector		
<i>Sector</i>	<i>Size</i>	<i>Type</i>	<i>Electrical efficiency</i>	<i>Thermal efficiency</i>	<i>Avoided CO₂</i>	<i>Additional fuel use</i>	<i>Avoided CO₂ costs¹</i>	<i>Avoided CO₂ per sector</i>	<i>Additional fuel use per sector</i>	<i>Abatement costs in sector</i>
	MW _e		%	%	ktCO ₂ /yr	MWh _{th} /tCO ₂	€/tCO ₂	MtCO ₂ /yr (%)	TWh _{th} /yr (%)	x1000 M€/yr
Chemical industry	125	CCGT	38%	31%	447	1.4 ²	68	31 ² (87%)	44 (25%)	2.1
Chemical industry	25	GT	20%	56%	168	0.8 ²	68	19 ² (89%)	15 (14%)	1.3
Refineries	22	GT	28%	49%	107	0.9	80	12 (88%)	11 (16%)	1.0
Paper industry	39	CCGT	25%	34%	172	1.3	86	2 (88%)	3 (23%)	0.2
Food industry	23	CCGT	46%	38%	60	1.2	103	5 (88%)	6 (21%)	0.5
Built environment	40	CCGT	43%	20%	63	2.2 ²	152	72 ² (86%)	158 (39%)	10.9
Built environment	0.4	GE	36%	37%	0.85	1.0 ²	228	38 ² (88%)	39 (19%)	8.5
Horticulture	2	GE	45%	42%	3.11	0.9	186	22 (88%)	20 (17%)	4.0

¹ Including transport and capture costs.² The difference within a sector is caused by a different HPR of the different CHP type, the GTCC has a lower HPR, and produces more additional electricity, causing a higher amount of additional fuel and more avoided emissions.

8.1.1 CHP-CCS cost structure

This section zooms in into the mitigation costs to address and explain the most important differences between the CHP-CCS options.

A main difference in the costs is, on the one hand the higher costs of small scale gas engines, and on the other hand less expensive gas turbines and combined cycles. For example, the gas engines in the horticulture sector, which show high technical potential against high costs. The differences in costs can be explained by looking into the specific cost structure (Figure 33 and Figure 34) in which the costs per avoided tCO₂ are split into the different cost components¹.

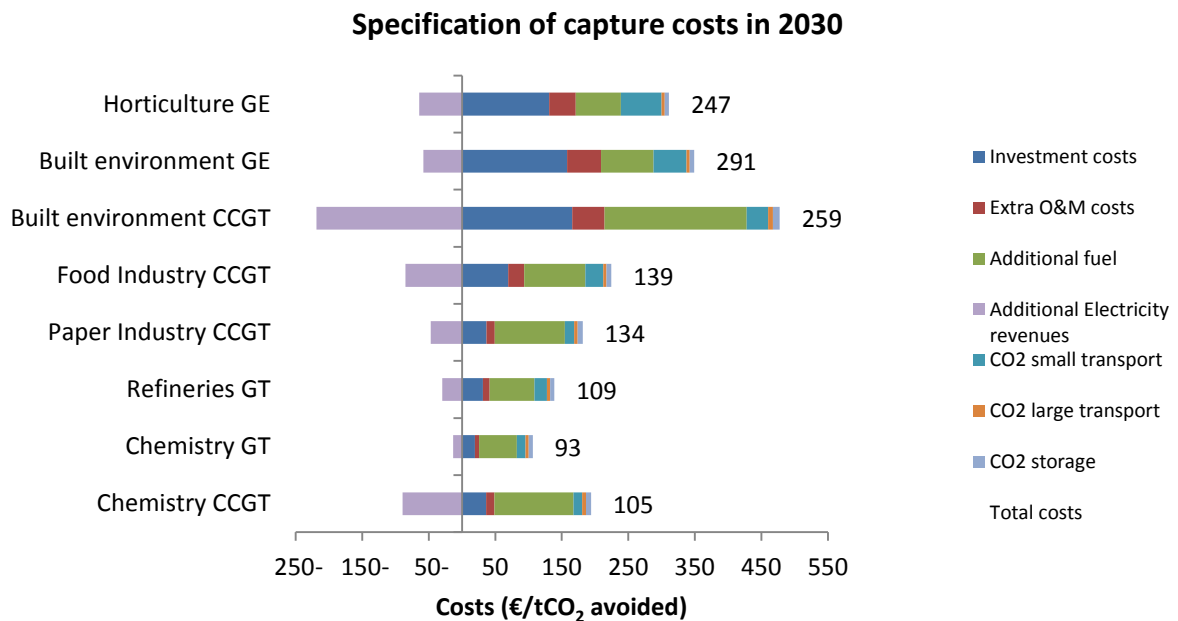


Figure 33. Specification of capture costs in 2030

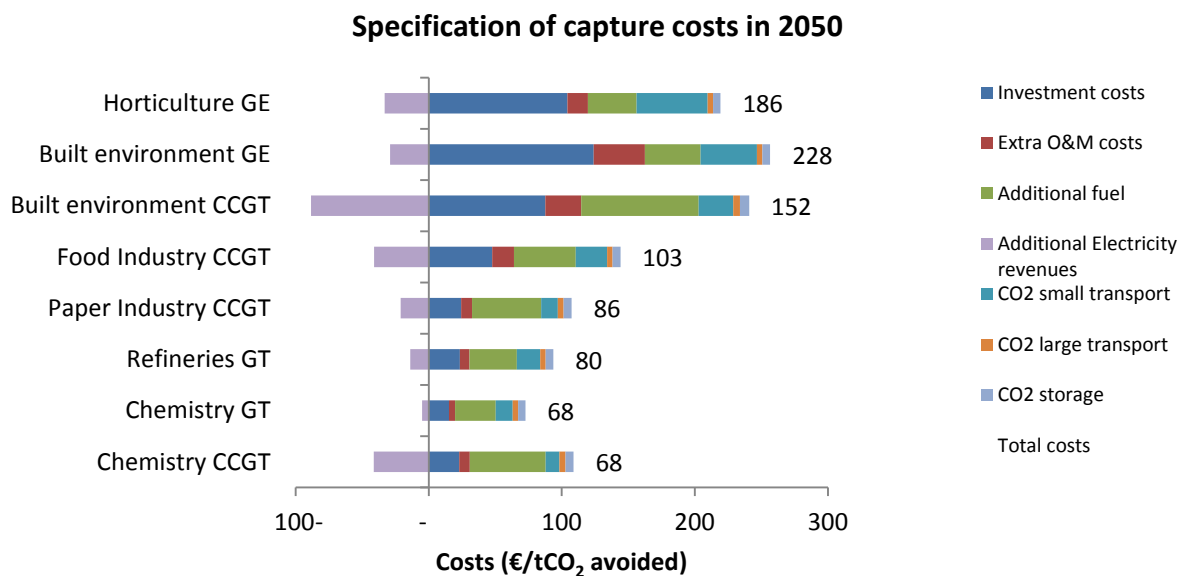


Figure 34. Specification of capture costs in 2050

¹ Appendix B shows the specific values of the cost components

The cost aspects can be grouped into three main topics, capture, transport and storage. The capture costs form the largest share for all cases; the transport costs have higher importance for small cases, but are still relatively small compared to the capture costs; the storage costs are the smallest cost component. The cost aspects within the capture costs are the investment costs, the O&M costs, the additional fuel costs, and the additional electricity revenues. Those cost aspects show a large decrease in 2050 compared to 2030, resulting in lower abatement costs.

A difference between the CHP types is a different cost structure of the CCGT compared to the GT. The CCGT cases have, on the one hand, a high amount of additional fuel and higher investment costs, which result in higher costs compared to the GT cases, on the other hand the electricity sales revenues are relatively high compared to the GT cases, which is also the case for CHP installations without CO₂ capture. Those two cost criteria add up to similar mitigation costs for the chemistry GT and CCGT. The difference can be explained by the lower HPR of the CCGT compared to the GT. The smaller CCGT's have higher costs, due to a smaller size and lower amount of load hours. The gas engine cases have extra high 'small scale transport' costs, because the amount of captured CO₂ is low.

The lower the amount of load hours, the higher the cost component of the investment costs, because the total investment costs are spread over the amount of CO₂ avoided. In case of less load hours the investment is spread over fewer tonnes of CO₂ than in case of a high amount of load hours. Therefore a decrease in investment costs has more effect on cases with low amount of load hours. The difference in influence of cost reduction can be seen in the difference of investment costs over time (which is largest for the built environment and horticulture cases) Figure 35 and Figure 36.

The difference between the two GT cases can be explained by the difference in fuel input. The size is given in the electrical output, which is similar for both cases (chemistry (25 MW_e), refinery (22 MW_e)). However, due to differences in thermal and electrical efficiencies (see Table 37. Results quantitative analysis 2030), the fuel input (MW_{th}) has a larger difference, chemistry (122 MW_{th}), refinery (78 MW_{th}). The amount of emissions of the chemistry GT is larger compared to the refinery GT. The larger amount of emissions, which are also captured, result in lower investment costs per tonne CO₂ avoided for the chemistry CHP compared to the refinery CHP and therefore lower abatement costs.

The difference between the chemistry cases (GT and CCGT) is counter intuitive; compared to the (small) GT, the larger CCGT has instead of lower costs, higher costs in 2030 and similar costs in 2050. Two reasons explain the unexpected outcome. First, the total efficiency of the CCGT case is lower compared to the GT case (average data of the Dutch installations). Secondly, the difference in HPR of the GT and CCGT explains the difference. The GT-CHP has a higher HPR which result in a smaller increase of size compared to the reference case, the low HPR of the CCGT-CHP result in a large increase of size and therefore larger investment costs.

Figure 34 shows the specification of costs in 2050. The decrease in costs over time is mostly due to less additional fuel costs, caused by lower energy requirement of the capture system and an increase of CHP efficiency. The decrease in additional fuel costs has more effect on the CCGT cases compared to the GT and GE cases, because the additional fuel costs is a relatively larger cost component in the CCGT cases.

8.1.2 Cost supply curves

Looking at the cost supply curves (Figure 35 and Figure 36) the most promising types of CHPs are the GT and CCGT in the chemistry sector, based on price and maximum amount of CO₂ to abate. The explanations of the lower costs are the large amount of load hours and the (relative) large size. The

capture units applied to gas engines are clearly the most expensive abatement options, because of the small scale and the low amount of load hours. The costs per tCO₂ are much higher than all other options, which make those sectors economically less attractive despite its large abatement potential (especially in the horticulture sector).

The cost supply curves show the maximum amount of CO₂ emissions which could be abated. In the graphs the maximum abatement potential is used. In case of two CHP technologies per sector (chemistry and built environment), the most abating options (CCGT) are used to come to the total abatement potential. The CCGT, however, will not be applied to the whole sector, because it is not able to be installed for all types of heat demand (too small heat demand, or a high HPR is required).

In reality the total amount of avoided emissions is much lower, because the application of CHP will be limited, and the selected cases are not able to meet all types of heat demand in the sectors. First the limitation of CHP application, some (small) heat demanding sources are too small to apply CHP as option. The current heat production is CHP 183 PJ (CBS 2010), which is 13% of the total heat demand. Second the limitation of the selected cases, which are based on sector averages. For the much smaller CHP plants, it might not be possible to apply CCS.

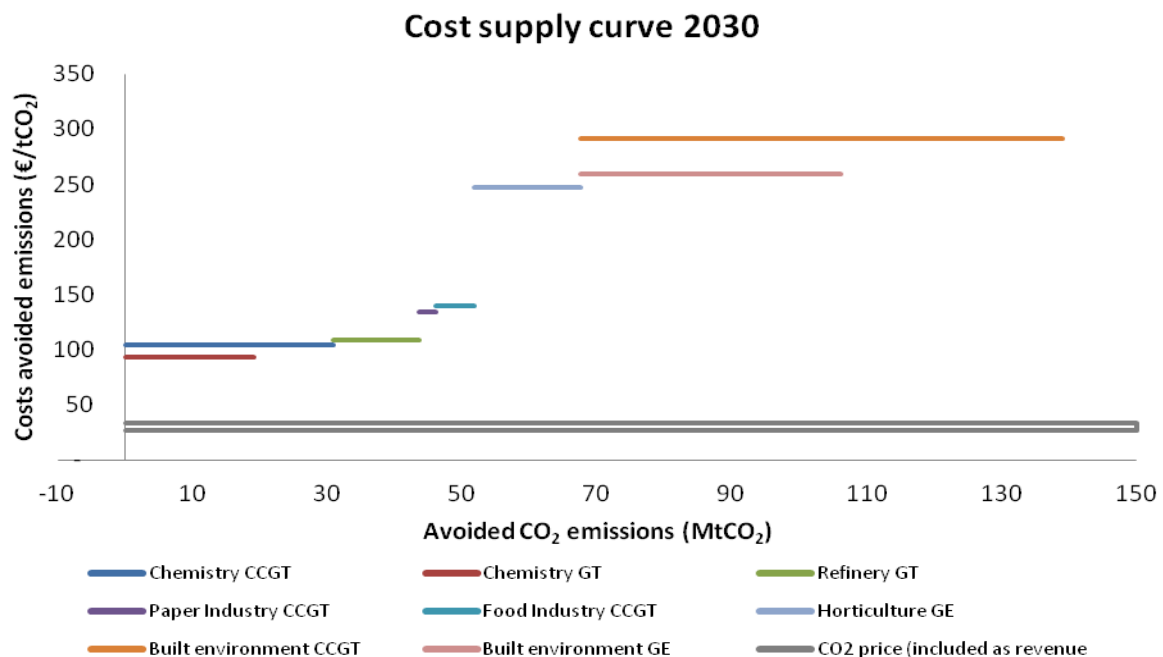


Figure 35. Cost supply curve 2030

The development over time shows a decrease of the cost range. In 2030 the cost range of the CHP-CCS options is 93-291 €/tCO₂, in 2050 the cost range is 68-228 €/tCO₂.

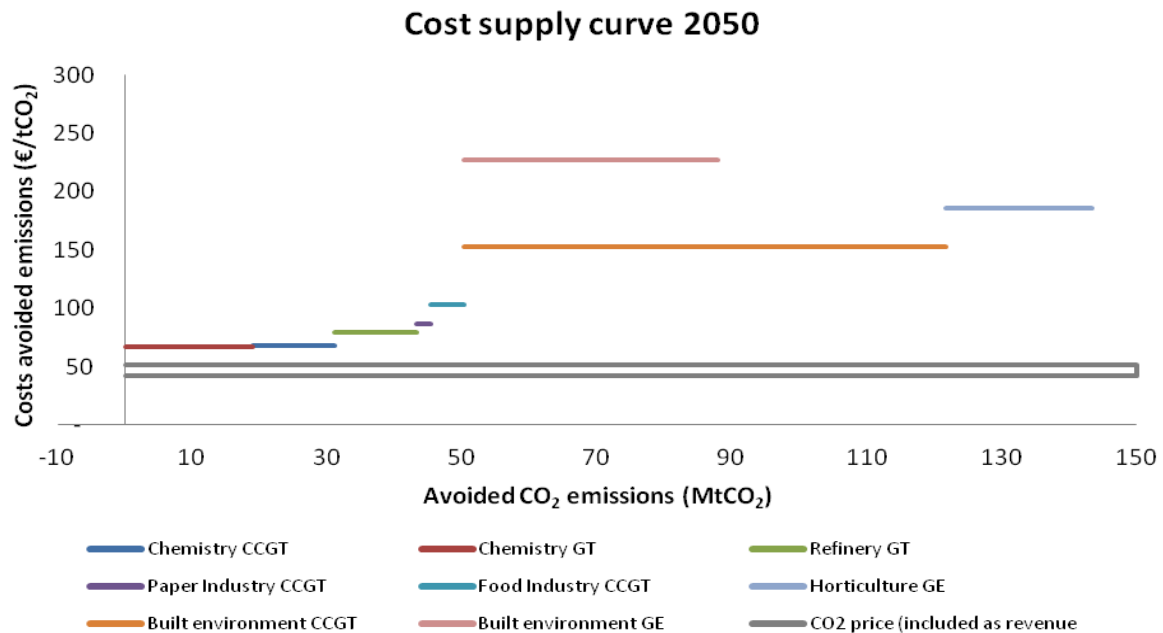


Figure 36. Cost supply curve 2050

To place the CHP-CCS abatement options in perspective to the CO₂ price, a possible CO₂ price development presented in World energy outlook (IEA 2010d) is used (Table 39 and the gray lines in the cost supply curves). The CO₂ price scenarios describe the expected costs in case the Emission Trading System (ETS) is implemented in Europe (current policies), or in Europe, Japan, and other OECD countries (new policies) (IEA 2010d).

Table 39. CO₂ prices used in World Energy Outlook 2010 (IEA 2010d) ¹

		2020	2030	2050
Current policies	€/tCO ₂	22	27	42
New Policies	€/tCO ₂	28	34	52

¹The CO₂ price in 2020 and 2030 are based on the World Energy Outlook 2010 (IEA 2010d), the CO₂ price in 2050 is determined based on IEA ETP 2010, in which an increase of 2.2% per year is assumed (IEA 2010a).

The lowest CHP-CCS abatement cost in 2030 is 93 €/tCO₂ (chemistry GT), which is much higher compared to the CO₂ price range of 27-34 €/tCO₂ in the IEA scenarios. In 2050 the lowest abatement cost is 68 €/tCO₂ (chemistry CCGT and GT), which comes closer, but is still higher compared to the IEA CO₂ price range, 42-52 €/tCO₂. The CHP-CCS option is therefore a non-economical option to abate carbon emissions. It is cheaper to buy carbon credits and still emit CO₂ instead of installing a CHP-CCS. So in case only market forces play a role and the CO₂ prices will be in the IEA range, the CHP-CCS are not an economical option. Therefore, the CHP-CCS mitigation option requires policy support to become an economical abatement option.

8.2 Sensitivity analysis

The sensitivity analysis is applied to the two most promising cases: the chemistry CCGT and GT. The sensitivity to respectively the gas and electricity price, the CCS investment costs, and the amount of load hours are discussed.

8.2.1 Gas and Electricity price

In Figure 38 the sensitivity scenario results of the gas and electricity price are shown¹, in which a high and low cost scenario has been taken into account, shown in Table 40.

Table 40. Gas and electricity price used in high and low cost scenario

Parameter	Low cost scenario		High cost scenario	
	2030	2050	2030	2050
Electricity peak price (€/MWh _e)	83.0	93.1	130	120
Electricity off-peak price (€/MWh _e)	63.3	69.3	97.6	91.6
Natural gas price (€/m ³)	0.261	0.261	0.457	0.486

The increase of the energy prices in the scenarios has two effects. The increase of the gas price results in higher avoidance costs, due to higher fuel costs. The increase of the electricity price result in lower abatement costs, because the revenues of the electricity sold increase. The CCGT is affected to a higher extent compared to the GT (see Figure 38), because the additional fuel and the electricity revenues are relative a larger component in case of the CCGT compared to the GT. The sensitivity decreases over time, due to improvements of efficiencies. Taking into account the sensitivity to the gas/electricity price the avoidance cost ranges (see Figure 37) are for CCGT, 81-127 €/tCO₂ in 2030; 51-84 €/tCO₂ in 2050; the GT case is 75-110 €/tCO₂ in 2030; and 56-79 €/tCO₂ in 2050 (Figure 37 (left)). These ranges have a maximum spread of ±25% in case of the CCGT case and a spread of ±20% in case of the GT case.

8.2.2 Carbon capture investment costs sensitivity

In Figure 38 the sensitivity scenario results of the CCS investment costs are shown. The change in specific investment costs taken into account is -24% in the low cost case and +24% in the high cost case. Figure 38 shows the sensitivities, the most important change is the increase of sensitivity over time, despite the decrease in costs. This change is due to the larger part of the capture investment costs of the total costs in 2050, because due to better efficiencies the energy costs reduces more than the investment costs. Taking into account the sensitivity, the avoidance cost ranges are: 96-113 €/tCO₂ for CCGT in 2030, 61-74 €/tCO₂ in 2050; the GT case is in 2030 87-99 €/tCO₂; and in 2050 63-73 €/tCO₂ (Figure 37 (mid)). These ranges have a maximum spread of ±9% in case of the CCGT case and a spread of ±7% in case of the GT case.

8.2.3 Load hours sensitivity

In Figure 38 the sensitivity to the amount of full load hours is shown, varying from maximum 91% (8000 full load hours) to 60% (5250 full load hours). The more hours a CHP is operated, the more CO₂ is emitted, lowering the costs per tCO₂. Since investment is a large part of the costs the effect of changing load hours is significant. So to minimize costs per tCO₂ it is better to produce as much CO₂ as possible. The sensitivity of the CCGT (+16%) is higher compared to the GT (+13%), because the CCGT investment cost component is larger. Over time the sensitivity does not change much (<1%).

¹ Due to a high correlation between the gas and electricity price, the sensitivity assesses the combined effect, using scenario values. In Figure 38 the input parameter change is the gas price change, the electricity price is changed to a smaller extent, see Method chapter.

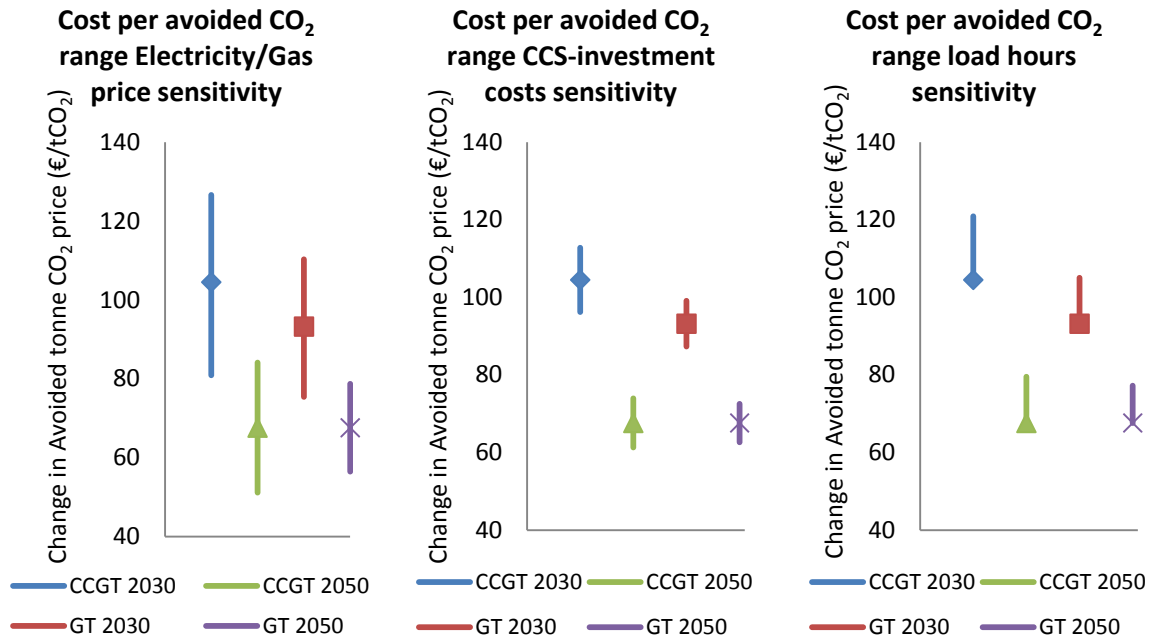


Figure 37. Cost (€/tCO₂) sensitivity to Electricity/Gas price (left), CCS-investment costs (mid), and the load hours (right) of the CCGT-CHP and GT-CHP chemistry cases in 2030 and 2050

8.2.4 Sensitivity analysis insights

The sensitivity analysis shows the significant effect of changing input parameters, gas/electricity price, CCS investment costs, and the load factor. Figure 37 show the avoidance cost ranges, the highest sensitivity to the gas/electricity price result in the largest cost range. The maximum change results in a range of 25% in case of the original values. So the results should be interpreted with an uncertainty range of 25%.

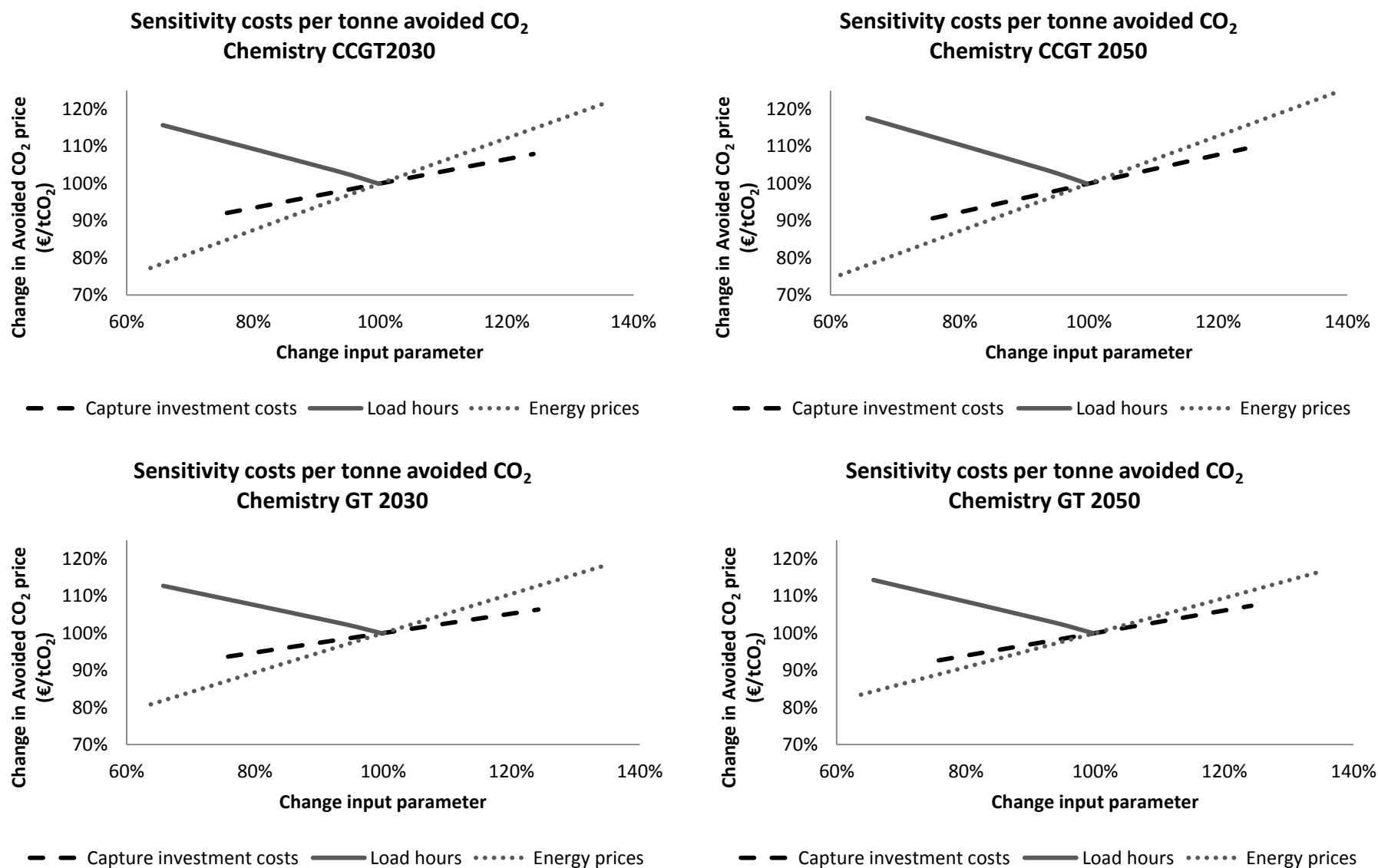


Figure 38. Sensitivity analysis CHP-CCS CCGT (top) and GT (bottom) in 2030 (left) and 2050 (right)

8.3 Results quantitative analysis CHP-CCS reference

In this section the results of the additional quantitative analysis are presented. The analysis comprises a comparison of the two most promising cases of the first part of the quantitative analysis, chemistry GT and chemistry CCGT, to a boiler + NGCC, a reference case (CHP) and an alternative mitigation option (Oxy-fuel boiler + NGCC-CCS). First the comparison is discussed from an industrial perspective; secondly a societal perspective is used.

8.3.1 Industrial perspective

Table 41 gives an overview of the different NPV values for the different options. Table 42 shows the intermediate results of the comparison; the CCGT case in 2030 is shown. The negative electricity revenues for the oxy-fuel boiler option are due to the electricity purchased for the oxy-fuel boiler (the air separation unit and CO₂ compression). The CHP options have higher fuel costs, but also higher revenues due to electricity sales. Table 41 shows that in all cases the CHP option is more economical compared to the base case (boiler + NGCC). The two mitigation options have both negative NPV values. Comparing the CHP-CCS with the oxy-fuel boiler, the CHP-CCS has a higher NPV in the longer term (2050), in the medium term (2030) the CCGT-CHP is less economical (lower NPV) compared to an oxy-fuel boiler.

Table 41. Comparison reference cases CCGT in 2030 – Industry perspective

		Boiler + Central NGCC	CHP	CHP-CCS	Oxy-fuel boiler + NGCC-CCS
Electrical efficiency	%	59%	38%	25%	54%
Thermal efficiency	%	90%	38%	36%	94%
Onsite emissions	ktCO ₂ /yr	227.9	537.6	82.34	0
Fuel input	GWh/yr	1118	2889	4425	1071
Investment costs	M€/yr	1.55	12.3	31.0	8.51
O&M ¹	M€/yr	0.49	5.56	11.3	1.60
Fuel costs	M€/yr	43.6	101.7	156	45.4
Transport and storage costs	M€/yr	-	-	12.0	3.35
Annual Costs (total)	M€/yr	45.6	119.6	210	58.8
Heat	M€/yr	45.6	45.6	45.6	45.6
Electricity	M€/yr	0	92.4	133	-9.9
Annual revenues (total)	M€/yr	45.6	138	179	35.7
Cash Flow	M€/yr	0.0	18.5	-31.2	-23.1
NPV	M€	0	138	-233	-173

¹ The boiler options have lower O&M costs compared to the CHP options, because the NGCC O&M costs are not taken into account, only the boiler O&M costs.

Table 42. NPV (M€) for different CHP-CCS options compared to the base, reference and alternative cases

	CCGT+ boiler	CHP	CHP-CCS	CCGT-CCS + Oxy- fuel boiler	Difference CHP-CCS and Oxy-fuel boiler
CCGT 2030	0	138	-233	-173	-60
CCGT 2050	0	148	-77	-158	81
GT 2030	0	22	-100	-113	13
GT 2050	0	29	-56	-104	48

Sensitivity - Gas/Electricity price ratio

The ratio between the gas price and the electricity price influences the different NPV values to a different extent. The CHP cases are more economical in case the 'gas/electricity price ratio' is low. Since both gas and electricity price are expected to fluctuate the sensitivity to a change in the price

ratio is discussed. Figure 39 shows the different sensitivity graphs. The range in which the price ratio is expected to fluctuate is based on different scenarios in the ECN reference estimation 2010, in which the maximum shift in price ratio is 30% (the low energy cost case). The sensitivity graphs show for both CHP technologies and both timeframes, that the CHP is a better option compared to a boiler + CCGT for a wide range of gas/electricity price ratios. If the gas/electricity price ratio becomes lower in the long term the CHP-CCS option becomes more profitable compared to the conventional boiler.

The difference between the economic value of the CHP-CCS and the oxy-fuel boiler is a higher sensitivity to the gas/electricity price ratio for the CHP-CCS option, because the fuel (natural gas) costs and the electricity revenues form a larger share of the total costs (see Table 42). Due to the large amount of electricity sold, as discussed in section **Results quantitative analysis CHP-CCS cases**, the CCGT-CHP options are really sensitive to the price ratio. For the CCGT-CHP case, the difference between the CHP-CCS NPV and oxy-fuel boiler NPV is smaller compared to the GT-CHP cases, because the HPR of the CCGT is small compared to the GT. The GT and CCGT are applied to different industrial processes, the GT is used in case of a high heat demand, and the CCGT is used in case of both a large heat and electricity demand. The GT produces more heat than electricity (a high HPR), the oxy-fuel boiler will therefore be of a similar size compared to the GT (in this case is the CHP fuel input 122 MW_{th}, and the oxy-fuel fuel input 83 MW_{th}). The CCGT in contrast has a low HPR, which result in a larger difference in size between the CHP and oxy-fuel boiler (CHP fuel input 330 MW_{th}, and the oxy-fuel fuel input 133 MW_{th}). So, a small HPR result in a small boiler compared to the CHP installed, resulting in relative low investment and fuel costs.

In 2030 the difference between the CHP-CCS case and the oxy-fuel case is small. If the gas/electricity price ratio is changed more than 10%, then the order of most economic cases is changed. In 2050 the GT is more economical than the oxy-fuel boiler for the whole range of price ratios. The CCGT is more sensitive, the oxy-fuel boiler becomes more economical than the CHP-CCS if the price ratio changes more than +10%.

CHP-CCS from an industrial perspective

In this analysis the NPV value and the sensitivity to the gas/electricity price ratio are taken into account on a sector level. The conclusions therefore do not take into account site specific criteria, e.g. complexity of the process, required flexibility, and way of financing. From an industrial perspective an economical incentive to install a CHP instead of a boiler still exists in 2030 and 2050. The role of CHP-CCS as abatement option in 2030 and 2050 is largely influenced by the gas/electricity price ratio. A low gas/electricity price ratio creates an economical situation in which it is preferable to apply CHP-CCS. A high HPR results in a more economical situation for the CHP-CCS option compared to the oxy-fuel boiler.

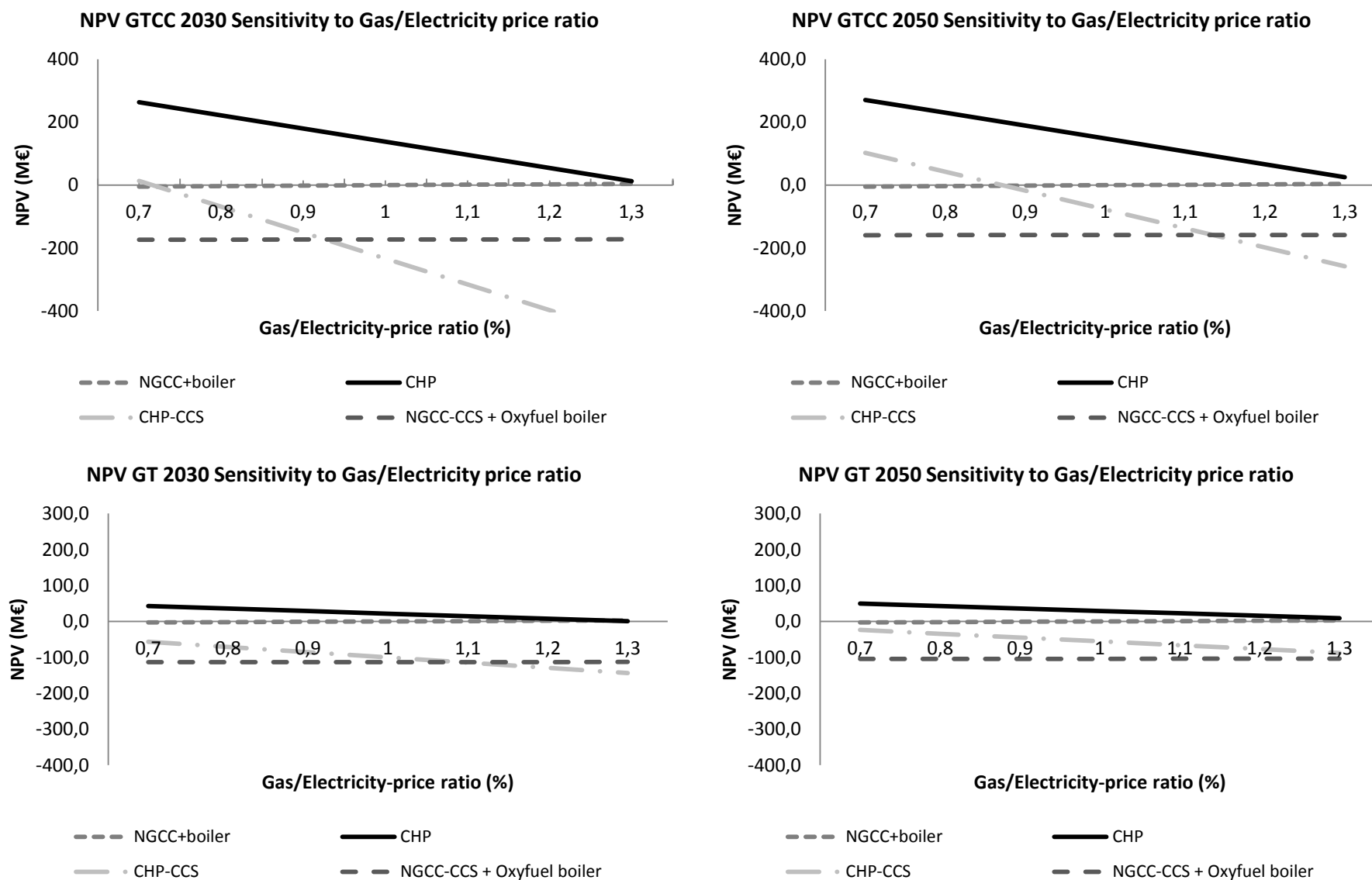


Figure 39. Analysis sensitivity CHP and reference cases to Gas/Electricity price ratio to CCGT (top) and GT (bottom) in 2030 (left) and 2050 (right)

8.3.2 Mitigation perspective

Four main aspects, relevant to society are compared; the value of the heat production is equal in all cases and therefore not taken into account. Comparing the boiler + NGCC and CHP, the CHP option emits less CO₂; the fuel use, however, is slightly higher (except for the CCGT-CHP in 2050). The electricity costs of the CHP option are higher compared to the boiler + CCGT. In general the reference CHP and boiler case are cheaper, use less fuel and emit more CO₂ compared to the mitigation cases, because no capture investment have to be made. Looking into the difference between the mitigation options, the oxy-fuel boiler + CCGT-CCS abates the most CO₂ and uses less fuel compared to the CHP-CCS. However, the abatement costs of the CHP-CCS are lower, the oxy-fuel boiler makes the oxy-fuel + NGCC-CCS option an expensive mitigation option. From a mitigation perspective the Oxy-fuel boiler + CCGT-CCS has lower electricity cost for consumers, and the fuel use and amount of emissions are lower too, but the avoidance costs are higher compared to the CHP-CCS option.

Table 43. Comparison reference cases CCGT and GT (2030 and 2050) – Mitigation perspective

			Boiler + Central NGCC	CHP	CHP-CCS	Oxy-fuel boiler + NGCC-CCS
CCGT 2030	Total emissions	ktCO ₂ /yr	575	538	82,3	38,7
	Total fuel use	TWh/yr	2.8	2.9	4.4	3.0
	COE ^a	€/kWh	0,08	0,09	0,11	0,10
	CO ₂ avoidance costs ^b	€/tCO ₂	-	-	105	188
CCGT 2050	Total emissions	ktCO ₂ /yr	542	511	64,1	34,8
	Total fuel use	TWh/yr	2.8	2.7	3.4	2.9
	COE ¹	€/kWh	0,07	0,09	0,10	0,09
	CO ₂ avoidance costs ^b	€/tCO ₂	-	-	68	185
GT 2030	Total emissions	ktCO ₂ /yr	210	199	25,2	8,1
	Total fuel use	TWh/yr	1.0	1.1	1.4	1.1
	COE ¹	€/kWh	0,08	0,11	0,14	0,10
	CO ₂ avoidance costs ^b	€/tCO ₂	-	-	93	272
GT 2050	Total emissions	ktCO ₂ /yr	200	190	21,6	7,2
	Total fuel use	TWh/yr	1.0	1.0	1.2	1.0
	COE ¹	€/kWh	0,07	0,10	0,12	0,09
	CO ₂ avoidance costs ^b	€/tCO ₂	-	-	68	271

^a COE is the production costs of electricity, since power plants are commercially exploited the industrial discount rate is taken into account. One should realize that the electricity costs for consumers will be higher due to for instance transport costs and taxes.

^b The CO₂ avoidance costs are only available for the mitigation options. The Oxy-fuel boiler + NGCC-CCS option has two avoidance costs, to combine those two, a weighted average (weights based on HPR of the CHP) is used.

8.4 Prospects of CHP-CCS in 2030 and 2050

Based on the results of the quantitative analysis the prospects of CHP-CCS in 2030 and 2050 are determined.

8.4.1 Prospects CHP-CCS in 2030

In the qualitative analysis the chemical sector and the refineries were the most promising sector, showing a high reduction potential with the lowest CO₂ avoidance costs. The most suitable technologies are the gas turbine and combined cycle. This result is confirmed by the quantitative analysis, in which the gas turbine, the combined cycle of the chemical sector and the gas turbine of the refinery sector are the most promising cases. Note that the avoidance costs of these cases (93, 105 and 109 €/tCO₂, respectively) are still high compared to avoidance costs presented in Kuramochi et al. (2010). However, the cost range 36-59 €/tCO₂ (Kuramochi et al. 2010) in the midterm future (2020-2025), is calculated for retrofitting 50-200 MW_e CCGT CHP plants, whereas this study considers only CCS for newly built plants. The difference in gas price (Kuramochi et al. (2010) 7.5 €/GJ; this study 10.7 €/GJ), and the possibility to adapt the heat power ratio in Kuramochi et al. (2010) explain the difference in outcome. Also the Zero Emission Platform (2010) reports avoidance costs of 80 €/tCO₂ for centralized NGCC power plants (420 MW_e) with post combustion (OPTI case¹) for the year 2025 (ZEP 2011a). The lower gas price (8 €/GJ) in ZEP compared to 10.7 €/GJ in this study, and the larger scale explain the difference in CO₂ avoidance costs.

The choice between CHP-CCS and an oxy-fuel boiler in 2030 depends on the electricity price, gas price, and the HPR. In case of a high gas price, low electricity price, and a large HPR, the CHP-CCS is preferred in terms of absolute CO₂ avoidance costs. However, the difference between those options is not large enough to determine the economically most attractive option. In each case other aspects play a role as well; for instance, the existence of price-deals, the development of the electricity market, the complexity of heat demand, and the financing power of the industrial player. So both mitigation options should be considered in case an industrial player wants to apply CCS to its heat and power delivering system.

CHP-CCS could become a techno-economic feasible mitigation option in case several preconditions are met. The mitigation costs have to be comparable to the CO₂ market price. The CHP-CCS potential will increase if the capture technology can be applied to small scale, and can operate flexibly and partial load. This study shows that CHP-CCS has high costs, and that operational insights need to be attained by investigating CCS applications. CCS is, therefore, expected to be applied first to power plants and/or pure CO₂ sources, and CO₂ intensive industry. Hence, the potential of CHP-CCS in 2030 is considered to be low.

8.4.2 Prospects CHP-CCS in 2050

In the used scenario, the heat demand will not change to a large extent for the year 2050. Therefore, the theoretical mitigation potential of CHP-CCS will remain the same. Further insights in CCS technology are expected, because CCS application is likely to be applied to either centralized power plants, industrial plants, or both. In the scenarios of the IEA (World Energy Outlook and Energy Technology Perspective), CCS is applied as a CO₂ mitigation option to centralized power plants by the year 2050 (IEA 2010a; IEA 2010d). Furthermore, the mitigation targets in 2050 are more severe, making the low hanging fruit (easy mitigation options) not sufficient to reach those targets. In that case, CHP-CCS may become an interesting mitigation option.

¹ OPTI case is State of the art technology, expected to be applied around 2025 (ZEP 2011a).

The cost curve presented in this study shows large costs differences among the different CHP-CCS options. Cases with high costs (130-240 €/tCO₂), are the small scale options (gas engines in horticulture and built environment), and options in sectors with low numbers of operating hours (also built environment and horticulture). In the horticulture and built environment, other mitigation options (geothermal heat supply, heat pumps, fuel cells) are, therefore, more likely to be installed. The CHP plants in the food and paper industry (69-115 €/tCO₂) are also expensive options, due to their medium sized CCGT plants, and medium number of load hours. Despite their medium size, the case(s) for the refinery GT-CHP plants are economically more attractive (68-92 €/tCO₂), due to their continuous use, and high load hours. The most techno-economic feasible CHP-CCS options are the CCGT and GT in the chemical industry (51-84 €/tCO₂), due to their large size (125 MW_e and 25MW_e), high number of load hours and continuous use.

The costs of the CHP-CCS cases are expected to decrease over time. In the long term (after 2030), other technologies are expected to become available, e.g., H₂ membranes, SOFC fuel cells, oxy-fuel boilers (membrane based), AZEP (Kuramochi 2011). For the medium to large scale distributed energy systems (10-300 MW_{th} fuel input), the avoidance cost range is expected to be 10-90 €/tCO₂ (Kuramochi 2011).

Although, the CO₂ avoidance costs for the medium and large sized CCGT and GT are within this range, it is still expensive compared to the range of Kuramochi (2011). If CHP-CCS becomes economic feasible, its application in large chemical clusters (e.g. Rotterdam) has a high potential, because the heat demand will remain substantial, and capture of several sources may be possible. Advantages of a cluster are the possibility to have scale advantages for both the CO₂ capture and transport step. When capturing CO₂, clustering CHPs with industrial plants may show significant economic benefits compared to separate capture. However, more research is required to confirm this statement.

9. Discussion

In this section we first reflect upon the research by discussing the underlying data and a number of methodological issues in more detail. Secondly, we discuss the research context and a comparison with literature values is made. In this discussion we assess the study results concerning the prospects of CHP-CCS in the Netherlands in the long term more carefully.

9.1 Data limitations and methodology

In the quantitative analysis certain assumption had to be made in order to perform the calculations. In this section the issues concerning the quantitative analysis are discussed.

9.1.1 Underlying data

In this research the capture technology is considered as one system. Therefore, the cost development (learning rate) and the scaling factor are values of the total capture unit instead of more value specific for each individual part of the capture system (e.g. scrubber, stripper, pumps). Further research into the capture system and its costs (development) could lead to more accurate and reliable results of the techno-economic performance of CHP-CCS.

The CCS data used for the gas engine CHPs are adapted values of CCS for gas turbines. Even though the data accuracy is less for these options, further research into the costs of capture units for gas engines is not needed. These CHP-CCS options are not likely to occur anyway, because of their small size, wide distribution and the flexible operation mode.

Centralized power production (NGCC-CCS) data is based on literature values. To improve the comparison between the oxy-fuel boiler and the CHP-CCS, the costs of the NGCC-CCS should be calculated with the same CCS cost data, fuel, and electricity prices as the CHP in further research. Using the same data may result in higher costs of centralized NGCC-CCS, due to the higher energy prices. The higher mitigation costs would lead to a lower feasibility of the oxy-fuel boiler from a mitigation point of view.

9.1.2 Methodological issues

In the calculations the commodity prices of gas and electricity, excluding tax, are used. This is a disadvantage for the CHP, because currently a CHP an owner does not pay taxes and in case of a boiler he does. However, it is uncertain whether the tax-advantage of the CHP is maintained in the long term. The tax-advantage has a large impact on the costs of CHP-CCS, because of its large additional fuel use.

The Heat Power Ratio (HPR) is kept constant in the calculations. In practice, a new CHP might have a different HPR, which lead to lower costs. The adaptation rate depends on how much electricity is privately used, and how much is delivered to the grid. Because insight in the private use is not available due to the more aggregated data, this adaptation is excluded in the analysis.

This study used costs for offshore storage, since this is currently the only realistic option to dispose captured CO₂ in the Netherlands. However, in the long run on-shore storage might be possible as well, leading to lower costs for transport and storage. However, the effect of a different storage place will be low, because the storage and transport costs are a small fraction of the total costs.

The costs of pipeline transport may be higher, in case the terrain is already full with pipelines for gas, water, etc. (Kuramochi et al. 2010). The assumed transport distance of 30 km to the transport hub might be longer, resulting in higher costs than assumed in this study.

In the reference calculations the CHP-CCS is compared with an oxy-fuel boiler from two different perspectives, industry and mitigation. In the industrial perspective only the costs and emissions on the industrial site are taken into account. In the mitigation perspective, the costs and emissions to produce the same amount of heat and electricity are taken into account. In the industrial perspective calculations, the exclusion of the own electricity use influences the differences between the NPV value of the different cases. The electricity revenues taken into account for the CHP-CCS (centralized NGCC electricity prices without CCS) are lower than the possible costs (centralized NGCC with CCS electricity prices) of the oxy-fuel boiler in case private electricity use is taken into account. As a result, the oxy-fuel boiler currently has an advantage compared to the CHP, especially in case of high electricity production, as is the case with a GTCC.

9.1.3 Sensitivity analysis

The sensitivity analysis shows that the results are most sensitive to a change in the energy prices. The development of the natural gas price and electricity price is important for the economic performance of CHP-CCS. The sensitivity of the amount of load hours show that operating at less than full load (down to 60%) result in significant higher costs (+16%). The maximum impact on costs expected, due to sensitivity to energy prices, is a range of 25% with reference to the original values. So the results should be interpreted with an uncertainty range of 25%. Despite these uncertainty ranges the mitigation costs of the oxy-fuel boiler is still higher compared to the CHP-CCS. However, the Net Present Value of the CHP-CCS is affected to a larger extent by a shift in the ratio between the electricity price and gas price, which could lead to less economic performance of the CHP-CCS compared to the oxy-fuel boiler.

9.2 Research context and comparison with other studies

9.2.1 Context of the research

This research focuses on the CHP application in the Netherlands. Frame conditions, which make the role of CHP-CCS relevant, need to be taken into account to place the potential in perspective.

The policies, gas and electricity price developments, and efficiency improvements taken into account are based on Dutch figures derived from 'ECN Reference projections' (Daniëls and Kruitwagen 2010). The sensitivity of the energy prices is important, because the prices determine the economic performance of CHP and CHP-CCS. The sensitivity of the results ($\pm 25\%$) should, therefore, be taken into account, as discussed in 9.1.3 Sensitivity analysis.

Most preconditions for CHP-CCS are related to the drivers of CCS application. To develop the CO₂ capture technologies, the need for CO₂ mitigation should be clearly stated. Moreover, related mitigation policy, CO₂ mitigation targets, and a CO₂ price should be in place. Subsequently, CCS should be socially accepted as a mitigation option, especially the CO₂ storage. Other pre-conditions are the developments of a CO₂ network, a transportation grid, and exploration of geological storage sites. All of these aspects are essential for the possible implementation of CCS.

Frame conditions required for a role of CHP plants in the Netherlands is the existence of large heat demands. Especially the presence of the large chemical industry and refineries is essential to provide potential for large CHP plants. In the future, the amount of oil to be refined is expected to decline

(Plomp and Kroon 2010), which might lead to less refineries and petro-chemical industry in the Netherlands.

The reliability of the production process, and with that the reliability of the CHP, is a decisive element for an operator. The operational challenges of CO₂ capture technologies are, therefore, relevant for CHP-plants, because the steam demand of industry plants should be guaranteed at all times. Better insights in the operability of the CO₂ capture technologies will give better insights in the techno-economic feasibility of CHP-CCS.

Gas engines (<5 MW) with CO₂ capture are economically unattractive, because capture units are relatively expensive at small scale (<10MW). In addition, the scattered¹ application is a second barrier to apply capture technologies to small scale gas engines (<2MW) in the agriculture, healthcare, and built environment. Depending on the transport distance, CO₂ transport may require either a high investment in an extensive network of CO₂ pipelines, or higher operational costs by using CO₂ transportation trucks. These disadvantages limit the capture possibilities for gas engines. Small and medium size gas turbines (<20MW_e) have similar issues as gas engines. CO₂ capture at a central level is, therefore, more interesting. Like applying carbon capture to a central hydrogen plant to produce hydrogen as fuel for the gas engine/turbine. This option overcomes both the size and scattered application barrier. The most likely capture technologies to apply to a hydrogen plant are pre-combustion technologies (ATR, WEGS or MSR-H₂), since those capture technologies imply already hydrogen production (Damen et al. 2006). A precondition for this solution is the adaption of gas engines and turbines to hydrogen-firing, or to replace these units with fuel cells. The disadvantage of this option is the fuel transition, which requires the installment of a hydrogen network. Realization of a hydrogen network does imply high costs, and also practical barriers due to the nationwide impacts (Van Vliet 2010). An additional disadvantage in horticulture is the use of CO₂ in the greenhouses. In case hydrogen is used as fuel additional CO₂ needs to be produced. Therefore both direct capture and hydrogen network are not likely to become a financially attractive abatement options in the horticulture sector. Other technologies which could abate CO₂ emissions related to heat production in the horticultural sector are geothermal heat supply and heat pumps. Other options to supply CO₂ are Hot CO₂² and OCAP³. Further research is needed to determine the full potential of these options.

Another possibility to abate CO₂ emissions is by up-scaling gas engines (up to 20 MW) or gas turbines and use the additional heat output for industrial purposes or district heating. Large sized gas engines have economic scale effects, higher electric efficiencies and could make decentralized capture possible in the agriculture sector. Disadvantages are the increase of energy losses during heat transport and the decrease of flexibility, due to the use of just one installation instead of several small ones⁴.

¹ Gas engines are applied at many places

² TNO is developing HotCO₂, which is a technology to produce heat and CO₂ for greenhouses from natural gas. By using a metal bed buffer the flexibility is high (TNO 2011).

³ OCAP (Organic Carbondioxide for Assimilation of Plants), a pipeline network which delivers CO₂ from the industry to the greenhouses (OCAP 2011).

⁴ In case of several small CHPs, several could be turned of, while others still operate. In case of a large CHP, you should operate in part load, which result in lower efficiencies. This effect may be less important if the CHP technology can ramp up/down easily.

9.2.2 Comparison with other studies

In this section a comparison with mitigation costs presented in other studies is made. One should realize that those costs represent only capture costs, and are based on different assumptions, fuel prices, and electricity prices. The transport and storage costs are not taken into account in this comparison, because most other studies do not include costs.

The comparison includes the mitigation costs of the most feasible CHP-CCS option identified in this study, i.e., CHP-CCS in the chemistry sector. The CO₂ avoidance costs of the CHP-CCS are: 56-102 €/tCO₂ in 2030 and 31-64 €/tCO₂ in 2050. The alternative mitigation option in this study, the oxy-fuel boiler with an air separation unit and electricity purchase from the grid, shows costs of 102-247 €/tCO₂ in 2030 and 101-246 €/tCO₂ in 2050.

Kuramochi (2011) presents CHP-CCS mitigation options for decentralized energy systems in the long term (after 2030), e.g., H₂ membranes, SOFC fuel cells, oxy-fuel boilers (membrane based) and Advanced Zero Emission Power plant. The medium sized technologies (10-300 MW_{th} fuel input) result in an avoidance cost range of 10-90 €/tCO₂ (Kuramochi 2011).

To reach emission reductions at heat delivering systems, other mitigation technologies might complement CHP-CCS as mitigation option, such as biomass-fired CHP (with CCS) and Boiler-CCS. The biomass combustion in CHP plants is identified in the World Energy Outlook (IEA 2010d) as a CO₂ mitigation option for heat production. Biomass-fired CHP systems are already applied in Sweden, Denmark and Germany. Eastern European countries are expected to follow in the future. Other studies, e.g. (IEA GHG 2007) (Kuramochi 2011), give additional insights in the expected costs for other Boiler-CCS options. Table 44 gives an overview of mitigation costs for the different options found in literature¹. Figure 40 shows the mitigation costs found in this study, and of the mitigation technologies found in literature. The chemical industry cases have the lowest CO₂ avoidance costs compared to the other sectors in this study. CHP-CCS post combustion capture has higher mitigation costs compared to other mitigation technologies, e.g., some energy efficiency measures and the Boiler-CCS options as presented in Kuramochi (2011). However, one should realize that the potential of the cheaper energy efficiency measures is limited; to achieve far-reaching CO₂ emissions using solely energy efficiency measures would result in much higher costs (shown in the large cost range).

However, a more extensive assessment of the different mitigation options has not been made, a more in-depth research into the possibilities of Boiler-CCS and biomass-fired CHP will provide a thorough basis for a comparison of the different mitigation options.

¹ A more extensive description is given in **Appendix C**

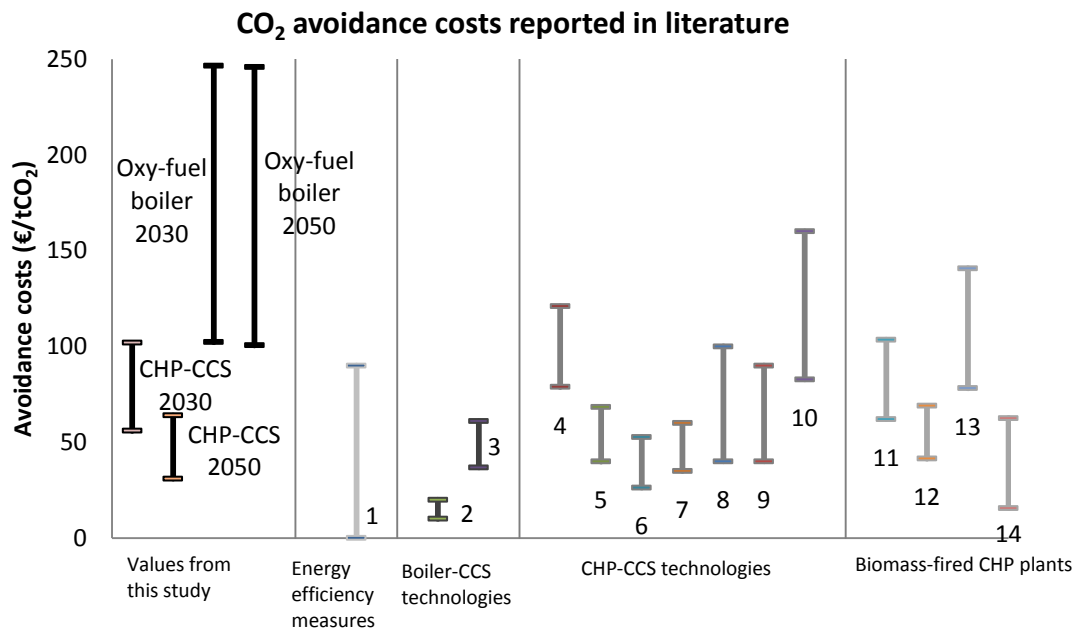


Figure 40. CO₂ avoidance costs reported in literature from different CO₂ mitigation technologies (the numbers refer to Table 1), the most left bars shows the CO₂ mitigation costs from this study of the chemical industry cases in 2030 and 2050.

Table 44. Mitigation costs comparison of alternative mitigation technologies for heat sources, literature values

# ^a	Technology	Mitigation costs	Source
1	Energy efficiency measures	up to 90 €/tCO ₂ ^b	IEA Energy technology transitions for industry report (IEA 2009).
Boiler Carbon Capture technologies			
2	NG oxy-fuel boiler membrane O ₂ production	10-20 €/tCO ₂	(Kuramochi 2011).
3	Oxy-combustion NG boiler (5 MW _{th}) with membrane O ₂ production	35-60 €/tCO ₂	IEA GHG report (IEA GHG 2007)
CHP-Carbon Capture technologies			
4	Gas engine (1,5 MW _e) with post combustion capture membrane assisted liquid absorption	80-120 €/tCO ₂	IEA GHG report (IEA GHG 2007)
5	Gas turbine (5 MW _e) with pre-combustion PSA capture	40-70 €/tCO ₂	IEA GHG report (IEA GHG 2007)
6	Solid oxide fuel cell (0,5 MW _e) with O ₂ conducting membrane afterburner	25-55 €/tCO ₂	IEA GHG report (IEA GHG 2007)
7	Industrial SOFC-Oxyfuel	35-60 €/tCO ₂	(Kuramochi 2011).
8	SOFC-combined cycle with OCM O ₂ production	40-100 €/tCO ₂	(Kuramochi 2011).
9	AZEP (85% capture)	40-90 €/tCO ₂	(Kuramochi 2011).
10	CHP-NGCC-CC	80-160 €/tCO ₂	(Uddin, et al 2007)
Biomass-fired CHP technologies			
11	CHP-Biomass Steam turbine-Carbon Capture	60-105 €/tCO ₂ ^c	(Uddin, et al 2007)
12	CHP-Biomass integrated gasification combined cycle Carbon Capture	40-70 €/tCO ₂ ^c	(Uddin, et al 2007)
13	CHP-Biomass Steam turbine-Carbon Capture	80-140 €/tCO ₂ ^d	(Uddin, et al 2007)
14	CHP-Biomass integrated gasification combined cycle Carbon Capture	15-60 €/t CO ₂ ^d	(Uddin, et al 2007)

^a The number relates to the ranges shown in figure 40

^b The energy efficiency measures can result in cost savings, so the avoidance costs can be negative as well

^c The sensitivity range is assumed to be 25% (similar as in this study)

^d the sensitivity takes into account different gas prices with a variation of 25% as presented in (Gustavsson and Madlener 2003)

10. Conclusions and recommendations

The objective of this study was to provide insight into the techno-economic potential of CHP-CCS in the medium (2030) and long term (2050). In this chapter conclusions are drawn for each research question. Furthermore, several recommendations for further research are given.

10.1 Conclusions

Which CHP technologies are installed in the Netherlands, and in which sectors?

CHP is widely applied in the Netherlands (installed capacity of 7 GW_e), and is spread over many different sectors. The technologies used are gas engines, gas turbines, steam turbines, and combined cycles. The sectors with the main CHP technologies used are: horticulture (gas engines), chemical industry (combined cycles and gas turbines), refinery sector (mainly gas turbines), paper industry (mainly combined cycle), food industry (mainly combined cycle), built environment (gas engines and combined cycle) and waste sector (gas engines and steam turbines). The most important clusters are industry and horticulture.

The heat demand development over time, as modeled in this study, shows no major changes, but a similar heat demand in the future. The role of CHP is, therefore, expected to be significant in the future. Some CHP developments are expected to take place irrespective of the policy development. The steam turbine is applied less, and replaced by gas turbines, because the gas turbines can reach same heat power ratios with higher efficiencies. The small gas engines and small steam turbines may be replaced by new technologies, such as the Organic Rankine Cycle (ORC), Stirling engine, and fuel cell. However, as these upcoming technologies are expected to be applied mainly at small scale (<10 MW_e), they are most likely less relevant for CHP-CCS application. The larger scale gas turbines and combined cycles applications remain similar.

Which CO₂ capture technologies for CHP will become available in the coming decades?

The assessment of the different capture technologies is based on the capture energy use, possibility to apply to small capacities, ramp up/down possibilities, and the partial load conditions. This study selected the following capture technologies as the most suitable for CHP-CCS: post-combustion absorption (amine or chilled ammonia), pre-combustion Auto Thermal Reformer, Sorption Enhanced-Water Gas Shift and oxy-fuel Chemical Loop Combustion. These technologies were selected because they are able to ramp up/down quickly and without any expected problems, and operate in partial load.

How is the CHP-CCS combination determined by the following CHP characteristics, capacity, load factor, type of sector applied, heat-power ratio and required flexibility?

In order to apply CO₂ capture to CHP, several aspects are important to determine the suitability of the CHP technology:

Capacity

The capacity is important, because the specific costs (€/tCO₂) of both the capture and transport step decrease with larger capacities. Small scale application is important because of the relatively small output capacity range of CHP plants compared to power plants. If a capture technology is applicable at large scale, with large scale advantage (economies of scale), then the capture technology may be less suitable to apply at small scale. In such case the costs for small scale application will be high, due to the lack of scale advantages.

Heat temperature supply

The type of heat supplied by the CHP plant affects the CHP-CCS combination, because some capture technologies require steam, which cannot be delivered by all types of CHP (some CHP plants (gas engines) only deliver warm water; post combustion capture, however, requires low-grade steam).

Ramp up/down characteristics

Many CHP plants operate in a flexible fashion. If the heat demand of the industrial process fluctuates, the load of the CHP plant fluctuates as well. For some gas engine CHP plants the load is influenced by the electricity price, i.e., when electricity prices are high the CHP operates in full load; in case of a low electricity price the CHP operates in reduced load or is ramped down. The possibility to ramp up and down is therefore essential for flexible CHP plants.

Partial load

The partial load behavior of the capture technology is essential for CHP plants, because a large share of CHP plants are used in varying loads, as described above. Based on these criteria the gas turbine and combined cycle are the most suitable technologies for CHP-CCS.

Heat demand characteristics

Next to the CHP technologies, the application in different sectors is also important. A CHP is applied because of its ability to supply heat and power profitably, but also because of its operational characteristics, ability to operate different fuel loads, fast start up, fast load changes, and in some cases, a flexible Heat Power output ratio (HPR). These characteristics demand much of the capture technology installed to the CHP. Next to the CHP technologies, the application in different sectors is also important.

1. the amount of heat
2. the temperature of the required heat
3. continuity of heat demand
4. the number of load hours.

All aspects are sector specific, and are used to determine the suitability to apply CCS in the sectors. The aspects are reflected in the type, size, and number of CHP plants installed. The amount and type of heat supplied to the (industrial) process is important, because both affect the size and the CHP technology installed. The higher the continuity, the lower the flexibility of the capture unit has to be. And the more load hours, the lower the avoidance costs per tonne CO₂, and therefore the higher the suitability. The lower the amount of load hours, the higher the cost component of the investment costs, because the total investment costs are spread over the amount of CO₂ avoided. In case of less load hours the investment is spread over fewer tonnes of CO₂ than in case of a high amount of load hours. (See Results quantitative analysis chapter)

The technology match of CHP and CCS indicates the different CHP and CO₂ capture technologies that could be matched; however, further research is needed to come to definitive matches. More insight in the operational characteristics of the different capture technologies is needed. The suitable capture technologies are post-combustion absorption (amines, ammonia), Auto Thermal Reformer, Auto Thermal Reformer-Sorption Enhanced Water Gas Shift, and Chemical Looping Combustion. All these technologies can be applied to the most suitable CHP technologies, gas turbine and gas turbine combined cycle.

What are the costs of CHP-CCS in the Netherlands in the medium and long term?

In 2030, the projected CO₂ avoidance costs of CHP-CCS range from 81-127 €/tCO₂ for the chemistry cases. Other cases involve lower uncertainties, resulting in smaller cost ranges; the refinery sector (91-126 €/tCO₂), paper industry (107-161 €/tCO₂), food industry (125-153 €/tCO₂), the horticulture (236-256 €/tCO₂), and the built environment cases (230-306 €/tCO₂). In 2050, the costs for the chemistry cases were projected to be 51-84 €/tCO₂; the other cases have the following avoidance costs; the refinery sector (68-92 €/tCO₂), paper industry (69-104 €/tCO₂), food industry (90-115 €/tCO₂), the horticulture (176-196 €/tCO₂), and the built environment cases (130-240 €/tCO₂).

What is the potential in terms of tonne avoided CO₂ of CHP-CCS in the Netherlands in medium and long term?

Some important outcomes of the scenario modeled in this study are used to determine the role of CHP in the future. Those outcomes are: (1) the heat demand in different sectors experiences only minor changes (<±1%/yr), mainly because the heat intensive sectors (chemical sector and refineries) will still be present in the Netherlands in the long term; (2) the heat demand will not change significantly due to efficiency improvements or changes in industrial processes.

Based on the modeled heat demand the theoretical mitigation potential of CHP-CCS can be determined. Currently, the heat production of CHP plants is 183 PJ (CBS 2010), which is 13% of the total heat demand. In 2030, the heat demand will be 1352 PJ resulting in a projected abatement potential of 140 MtCO₂. In 2050, the heat demand will be 1338 PJ, resulting in a projected abatement potential of 145 MtCO₂. In reality, the total amount of avoided emissions is much lower, because the application of CHP will be limited. The selected cases are not able to meet all types of heat demand in the sectors, some (small) heat demanding sources may be too small for CHP applications.

The central research question of this research is: What is the techno-economic potential for CCS in CHP plants in the Netherlands in the medium (2030) and long term (2050)?

This study gives insight in the costs, operational characteristics, and the theoretical implementation potential of the CHP-CCS combination. These criteria differ per sector; the most suitable sector indicated in this study is the chemical sector. However, despite its large theoretical implementation potential, the high costs and flexible operation required for CHP production make the CHP-CCS application more expensive and more technological challenging compared to other CCS applications (centralized power production and industrial plants). CHP-CCS is, therefore, expected to be one of the last CCS applications to be applied. Moreover, other mitigation technologies, such as boiler-CCS, biomass fired CHP, that reduce CO₂ emissions related to heat production might be preferred over CHP-CCS.

CHP-CCS might become economic feasible over time, because cost improvements of the CHP-CCS technology can be expected, and the application of large scale CHP plants in industrial clusters might minimize the transportation costs. To create techno-economic potential for CHP-CCS, important pre-conditions are: better insight in operational difficulties of CHP-CCS (which requires further research), and lower mitigation costs of CHP-CCS. Moreover, another important condition is the political desire to reach the strict mitigation goals, the European 2°C target, which requires a CO₂ emission reduction of 50-85% in 2050.

10.2 Recommendations for further research

In the discussion we mentioned several options for further research. We use these insights to come to several recommendations for further research. The focus of further research should be on extending the insight of the operability of carbon capture technologies; e.g. partial load conditions, ramp up/down characteristics, in order to assess their suitability for CHP application. Furthermore placing the CHP-CCS in perspective of alternative mitigation options for heat supply.

This study is based on a literature research about the operational characteristics of the CO₂ capture technologies. However, further research and operational tests are needed to gain more insight into those characteristics.

Furthermore, a comprehensive analysis of CO₂ mitigation options could place the results of this research into perspective. First, a similar CHP-CCS quantitative analysis can be performed using other suitable capture technologies for CHP. This study identified ATR, SE-WGS, and CLC as suitable CO₂ capture technologies. In further research the prospects of CHP combined with pre-combustion Auto Thermal Reformer, Sorption Enhanced-Water Gas Shift, or oxy-fuel Chemical Loop Combustion could be identified in a similar way as was done in this research that focused on post-combustion absorption.

Second, CHP-CCS should be placed in perspective of other CO₂ reducing options related to heat supply, such as Boiler-CC, coal-fired CHP-CCS, biomass-fired CHP and CHP-CCS with flue gas recycle (a way to improve the capture from natural gas fired CHP plants is to recycle the flue gas to increase the CO₂ concentration, thereby lowering the steam costs for regeneration (Kuramochi et al. 2010)). This research made a start by comparing the oxy-fuel boiler with CHP-CCS. Further research could extend this comparison with the mentioned mitigation options.

11. References

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Appendix A - Save production model

The - Simulation and Analysis of Virtual Energy use in Energy scenarios (Save)- production model is an energy simulation model for the Dutch industry and agriculture. The model is designed to get insight in the expected energy use and application of energy saving technologies and CHP in the industry and agriculture sectors. It is based on a bottom-up approach, disaggregating energy consumption into different fuels, industrial sectors and energy technologies. In Save production a separate CHP module is used, in which the amount of CHP plants installed and their produced energy is modeled. In the module several subsectors, energy carriers, CHP types and individual installations are identified.

The use of the CHP installations is driven by the steam demand. Once the total thermal energy demand is determined the CHP module simulates the operation of new and existing CHP units and whether a new CHP plant would be installed. The investment decision of a CHP is based on the economic value of the CHP, possible investment barriers and the sector properties (Wetzels To be published).

The Save production model has interaction with several other energy models in the NEOMS database (shown in Figure 41). The NEOMS database is built based on the different models shown in Figure 41. The Dutch electricity market model Powers provides electricity commodity prices and the Tariffs model information about delivery and tax cost components on natural gas and electricity. Between Powers and Save production a direct link exists, because the CHP plants in Save production deliver to the grid as well. So several iterations are run until electricity prices, electricity demand and CHP production remain constant (Daniëls and van Dril 2007). The scenarios can include a CO₂ price and the time horizon can be up to 2050.

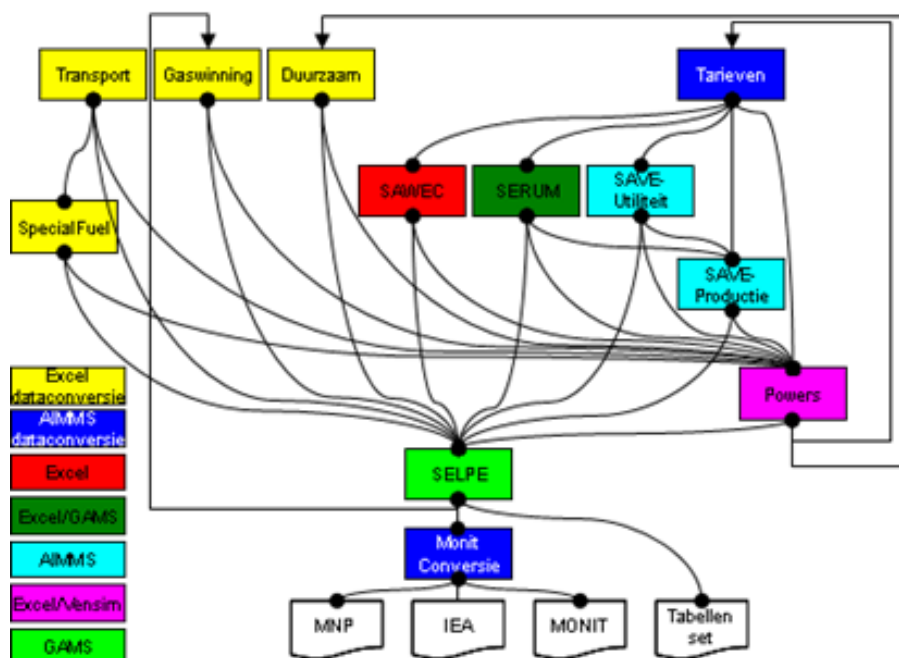


Figure 41. Schematic overview of NEOMS (Wetzels To be published)

CHP investments

The modeling of discrete installations allows modeling of operational decisions and deciding on shutdown or upgrade. The end of lifetime is determined in production hours; once reached, an installation should be closed or upgraded. An upgrade is taken place in case several criteria have been met: the IRR of the upgrade has to be higher than the IRR-criterion, a new installation should not result in an even higher IRR, and there should be no saturation of the potential within the subsector (e.g. due to decrease of thermal demand or to higher process efficiency).

Many economic factors determine whether to invest in new CHP plants or not. The thermal power required determines what kinds of CHP types are technically possible. Their size influences the investment costs per kW_{th}. Production hours determine the revenues from electric and thermal output. Production of electricity for onsite consumption, especially in smaller companies, could be more economical than selling excess production. Therefore both the onsite electricity consumption and the synchronism with demand for thermal energy are important determinants. As the electricity price depends on the moment electricity is produced, the model calculates during which hours it is profitable to produce and sell electricity, and during which the CHP can be switched off and the back-up boiler is used instead.

The model incorporates all these factors in the calculation of cash flows. Once the cash flows have been determined, the model calculates the IRR, which is the basis for the penetration of CHP types. Based on the IRR the economic CHP-potential is given, taking into account the expected prices of natural gas and electricity for the next ten years.

The model also deals with the competition between various CHP types. The model calculates the aggregate potential per production hours category and thermal power category for which it is economically attractive to install CHP regardless of the CHP type, and scales down the economic potentials for the specific CHP types accordingly.

A part of the economic potential is already occupied by existing CHP plants. In case of a new CHP plant the model starts with the CHP types with the largest difference between economic potential and already occupied potential, until there is no free space left. This way the model generates an appropriate distribution of the potential among the various competing CHP types.

Appendix B – Detailed cost overview CHP-CCS options 2030 and 2050

2030			<i>Investment costs</i>	<i>Extra O&M costs</i>	<i>Additional fuel costs</i>	<i>Additional Electricity revenues</i>	<i>CO₂ small transport</i>	<i>CO₂ large transport</i>	<i>CO₂ storage</i>
Sector	Size	Type	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂
Chemical industry	125 MW	GTCC	36	13	119	89-	13	6	8
Chemical industry	25 MW	GT	20	6	57	13-	13	4	6
Refineries	22 MW	GT	32	10	67	30-	19	5	6
Paper industry	39 MW	GTCC	37	13	105	47-	14	5	7
Food industry	23 MW	GTCC	69	24	92	85-	27	5	7
Built environment	40 MW	GTCC	166	48	214	219-	32	7	10
Built environment	0,4 MW	GE	158	51	79	58-	50	5	7
Horticulture	2 MW	GE	131	40	68	64-	61	5	7
2050			<i>Investment costs</i>	<i>Extra O&M costs</i>	<i>Additional fuel costs</i>	<i>Additional Electricity revenues</i>	<i>CO₂ small transport</i>	<i>CO₂ large transport</i>	<i>CO₂ storage</i>
Sector	Size	Type	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂	€/tCO ₂
Chemical industry	125 MW	GTCC	23	8	57	41-	10	4	6
Chemical industry	25 MW	GT	15	5	31	5-	13	4	6
Refineries	22 MW	GT	23	7	35	14-	18	4	6
Paper industry	39 MW	GTCC	24	8	52	21-	13	4	6
Food industry	23 MW	GTCC	48	16	46	41-	23	4	6
Built environment	40 MW	GTCC	88	27	88	88-	26	5	7
Built environment	0,4 MW	GE	124	39	42	29-	42	4	6
Horticulture	2 MW	GE	104	15	37	33-	53	4	6

Appendix C – CHP(-CCS) literature overview

Source	Topic	Main conclusions
Kuramochi et al. (2010)	Techno-economic analysis of post-combustion CO ₂ capture from industrial NGCC CHP	The economic performance results showed that CO ₂ capture from industrial NGCC-CHPs may become economically attractive when the CHPs are operated at a low HPR. CO ₂ avoidance costs for industrial NGCC-CHPs at scales as small as 100 MW _e in the short term (41–44 €/t CO ₂) and as small as 200 MW _e in the mid-term future (33–36 €/t CO ₂) may become comparable to those for 400 MW _e NGCCs (46–50 €/t CO ₂ short term, 30– 35 €/tCO ₂ mid-term). From the results obtained in this study, it can be concluded that post-combustion CO ₂ capture from medium-scale industrial CHPs may become more economical than the post-combustion capture from the reference NGCC in the early stages of CCS deployment (Kuramochi et al. 2010)
Kuramochi et al. (2011)	Techno-economic analysis of CO ₂ capture from a SOFC (Solid Oxide Fuel Cell) CHP plant	SOFC CCS is identified as a promising option in case the membrane price will be lower and a CO ₂ price will be introduced. With an assumed stack price of 500 \$/kW the avoidance costs are 36 €/tCO ₂ . This study suggests a possibility for significant CO ₂ emissions reduction from small-scale industrial power systems in a cost-effective manner in the mid-term future if the CO ₂ transport and storage infrastructure is available (Kuramochi et al. 2011)
Kuramochi (2011)	Prospects for CO ₂ capture in distributed energy systems in the short/medium term and long term	The findings of the study indicate that in the short term (2020-2025) energy penalties for natural gas-fired plants is 10-28%. CO ₂ avoidance costs are between 30-140 €/tCO ₂ for plants with a fuel input larger than 100 MW _{LHV} ; 50-150 €/tCO ₂ for 10-100MW _{LHV} fuel input. The longer term, after 2030, the efficiency penalty reduces to 4-9% and the CO ₂ avoidance costs reduces to 10-90 €/tCO ₂ for 100 MW _{LHV} ; 25-100 €/tCO ₂ for 10-100 MW _{LHV} ; 35-150 €/tCO ₂ for <10MW _{LHV} . The main conclusion of this research is that CO ₂ capture from distributed energy systems is not too expensive and it has a significant cost reduction potential in the long term (Kuramochi 2011) (Chapter 6)
Solli et al. (2009)	Evaluation of different refinery gas fueled CHP options delivering heat and power to a refinery.	Pre combustion options (ATR more than SMR) perform better in case of a high valuation of heat, whereas the post combustion performs better in case of a high electricity price. The economic analysis is done non-transparent, and no economic value is presented (Solli et al. 2009).
Knuutila et al. (2009)	CO ₂ capture from coal-fired power plants based on sodium carbonate slurry; a systems feasibility and sensitivity study	In a comparison of a coal-fired power plant with a district heating CHP. CHP plants seem to be attractive for CO ₂ capture because of the high total energy efficiency of the plants, due to better heat integration options. In a condensing power plant the CO ₂ capture decreases directly the electricity production whereas in a combined heat and power plant the loss can be divided between district heat and electricity according to demand (Knuutila et al. 2009).
IEA GHG (2007)	CO ₂ capture from medium scale combustion installations.	Gas engine 1,5 MW _e with post combustion capture membrane assisted liquid absorption 79 €/tCO ₂ ; Gas turbine (5 MW _e) with pre-combustion PSA capture 37 €/tCO ₂ ; oxy-combustion natural gas boiler (5 MW _{th}) with membrane oxygen production 32 €/tCO ₂ ; Solid oxide fuel cell (0,5 MW _e) with oxygen conducting membrane afterburner 26 €/tCO ₂ . The assumed gas price was 4 €/GJ. Main conclusion of this study are: the costs of CO ₂ capture from medium scale energy systems depend strongly on local conditions: size, operating load factor, ability to make low grade heat for the capture process. Post combustion amine absorption is already commercially available, in the longer term a boiler with membrane oxygen production offers prospects of significant lower costs. CCS from medium sources depends on the proximity of other CO ₂ sources to reach economies of scale for transport and storage (IEA GHG 2007).
IEA (2009)	Energy technology transitions for industry	In the industry sector the most important emission abating option is energy efficiency. However, to reach significant emission reduction the use of biomass and electricity as CO ₂ -free energy carriers will be important. While the technologies required are often sector-specific, the development and deployment of carbon capture and storage (CCS) is essential. The most

		energy-intensive sectors (75% of total direct CO ₂ emissions) are iron and steel, cement, chemicals and petrochemicals, pulp and paper, and aluminium. CHP plants are seen as energy saving technologies, but in the chemical industry the usage of CHP-CCS is expected to be needed for further CO ₂ emission reduction. In the chemical industry the emission avoidance costs are expected to be around 35 €/t CO ₂ for energy efficiency measures and up to 145 €/t CO ₂ for CO ₂ capture measures (IEA 2009).
Taljan et al. (2011)	Optimal sizing of biomass-fired Organic Rankine Cycle CHP system with heat storage in Austria	The results of the study show that Organic Rankine Cycle CHP system with heat storage increase the operation flexibility of the CHP plant, and therefore increase the amount of full load operating hours and profits. However, these profits are not sufficient to compensate for the increased investment costs. So the ORC-CHP with heat storage is not yet economically viable. Further results show that an ORC plant without heat storage is currently viable for annual heat demands higher than 5 GWh _{th} and for biomass prices lower than 17 €/MWh. This study assumes a fixed feed-in tariff of 156,3 €/MWh for the first ten years and 75% and 50% of that price in the eleventh and twelfth year of the project, respectively. The heat prices assumed are 64.07 €/MWh _{th} (Taljan et al. In Press)
Wood and Rowley (2011)	A techno-economic analysis of small-scale, biomass-fuelled combined heat and power for community housing	Feasibility of a number of biomass-fuelled CHP (BCHP) systems when operated in a community housing context. Six systems comprising differing technologies have been analyzed, with the assumption that the systems operate within an ESCO (energy services company) supply scenario. The maximum biomass costs to attain a positive NPV are: Gasifier and internal combustion engine (56€/ODT), Organic rankine cycle (56€/ODT), Indirectly fired gas turbine (43€/ODT), Updraft gasifier Stirling engine (45€/ODT), direct combustion Stirling engine (45€/ODT), Vegetable oil-fired internal combustion engine (26 c/liter). The results indicate that within specific realistic ESCO operating scenarios, biomass CHP can demonstrate positive net present values without the need for capital subsidies. In general, smaller systems are less profitable than larger platforms. An optimal system design and implementation is critical for profitable operation and it is found that the best economic performance occurs for high load factors when the maximum quantity of both electricity and heat sold on-site is maximized (Wood and Rowley 2011).
Uddin and Barreto (2007)	Biomass-fired cogeneration systems with CO ₂ capture and storage	This study looks into the CO ₂ mitigation costs of biomass-fired cogeneration system based on steam turbine technology with carbon capture (CHP-BST-CC), integrated gasification combined cycle technology with carbon capture (CHPBIGCC-CC), and a NGCC CHP plant with carbon capture (NGCC-CHP-CC). All systems were analyzed for three different scales with capacities ranging between 50 and 200MW, the assumed biomass feedstock is logging residues with 50% moisture content. When the same output was assumed and the cogenerated power was credited, the CO ₂ mitigation cost for CHP-BST-CC is 80 €/tCO ₂ , for the CHP-BIGCC-CC 40 €/tCO ₂ , both are lower compared to the CO ₂ mitigation cost for CHP-NGCC-CC (110 €/tCO ₂) in this study. The mitigation costs of CHP-NGCC with CO ₂ capture and CHP-BIGCC with CO ₂ capture are sensitive to changes in the capacity of the plants (Uddin and Barreto 2007).
Gustavsson and Madlener (2003)	CO ₂ mitigation costs of large-scale bioenergy technologies in competitive electricity markets	In this study two biomass-fired cogeneration systems, the biomass steam turbine (Bio-ST) and biomass-based gasification combined cycle (BIG/CC) are compared to a natural gas-fired cogeneration plant. The assumed biomass prices is 13 \$/MWh _{fuel} . Based on typical conditions for Sweden, the price of natural gas for cogeneration and condensing plants is assumed to be \$ 16 and \$ 13/MWh _{fuel} respectively The thermal capacity is between 50 and 100 MW _{th} . The utilization of the conversion plants is assumed to be 5500 full load hours. Using the natural gas-fired cogeneration plant as reference, and taking into account the avoided electricity production in a natural gas condensing plant, the carbon mitigation cost is about 55 €/t CO ₂ for BIG/CC cogeneration plants, and 35 €/t CO ₂ for the Bio-ST cogeneration plant (Gustavsson and Madlener 2003).