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Life cycle assessment of novel CCS technologies

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MASTER THESIS

for

Lisbeth Jeanette Bøe

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Life Cycle Assessment of Novel CO_2 Capture Technologies

Livsløpsanalyse av nye teknologier for CO_2-fangst

Background

The production of energy from fossil fuels has resulted in large amounts of CO_2 being emitted into the atmosphere. CO_2 has become the largest source of man-made gases responsible for climate change and ocean acidification. Carbon capture and storage (CCS) entails the capture of CO_2 from large anthropogenic sources, transport to an (underground) storage location and long-term isolation from the atmosphere. CCS is an interesting technology because it allows the continued use of fossil fuels with reduced increase in CO_2 emission levels. Since fossil fuel use is expected to dominate the world's primary energy supply for the next decades to come, CCS can play a key role on decarbonizing the energy sector.

With large amounts of R&D work on various CO_2 capture techniques, and techno-economic evaluation of CCS; environmental studies, mainly in the form of life cycle assessments (LCA), have been conducted mostly focusing on coal systems and particular CO_2 capture and utilization technologies.

The most studied CO_2 capture technologies, from an LCA perspective, are post-combustion capture with monoethanolamine (MEA), followed by pre-combustion (IGCC) with Selexol. This is followed by a lower number of studies addressing NGCC with MEA and Oxyfuel. However the assessment of novel capture technologies has been less explored.

Aim

The main objective is to assess the life cycle impacts of selected novel CO_2 capture technologies in the context of electricity generation. The secondary goal is to benchmark these technologies with current technologies.

The analysis should include following elements:

1. Selection of cases of near term novel CO_2 capture technologies in dialogue with supervisor and co-supervisor.
2. Compilation of life cycle inventories for the selected cases.
3. Life cycle assessment of the selected cases, including sensitivity analysis on key parameters.
4. Analysis and discussion.

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Within 14 days of receiving the written text on the master thesis, the candidate shall submit a research plan for his project to the department.

When the thesis is evaluated, emphasis is put on processing of the results, and that they are presented in tabular and/or graphic form in a clear manner, and that they are analyzed carefully.

The thesis should be formulated as a research report with summary both in English and Norwegian, conclusion, literature references, table of contents etc. During the preparation of the text, the candidate should make an effort to produce a well-structured and easily readable report. In order to ease the evaluation of the thesis, it is important that the cross-references are correct. In the making of the report, strong emphasis should be placed on both a thorough discussion of the results and an orderly presentation.

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☐ Work to be done in lab (Water power lab, Fluids engineering lab, Thermal engineering lab)
☐ Field work

Department of Energy and Process Engineering, 1 February 2013

Olav Bolland
Department Head

Anders Hammer Strømman
Academic Supervisor

Abstract

CO_2 emissions from the combustion of fossil fuels are the largest sources of anthropogenic greenhouse gas emissions to the atmosphere. Carbon capture and storage (CCS) is one of the better options to mitigate these emissions and thereby limit global warming even while continuing the use of fossil fuels for power generation. As CCS increases the energy consumption of the power plant itself, there will be an increased use of fuel and therefore also increased environmental impacts connected to this. To calculate these impacts it is important to include the entire supply chain and life cycle of the power plant.

This thesis involves a tiered hybrid life cycle assessment of natural gas- and coal power plants with chilled ammonia process (CAP) and sorption enhanced water-gas shift (SEWGS) capture technologies. These novel capture technologies are two of the least studied when it comes to environmental assessments. The results from this assessment are compared to two of the more studied capture technologies, post-combustion capture by monoethanolamine (MEA) and oxyfuel combustion capture.

Both the CAP capture alternative and the SEWGS alternative have been shown to decrease the global warming potential (GWP) in a natural gas plant by 70%. For the coal-fired power plants, the CAP technology managed a decrease in GWP of 77% while the SEWGS technology showed a decrease of 77.5%. This decrease comes at a cost of other impact categories where for example the freshwater ecotoxicity potential (FETP) has an increase of 87-88% for both the CAP and SEWGS capture technologies in NGCC plants. This impact category has an increase of 25 and 22% for the CAP and SEWGS technologies in the coal-fired power plants.

Compared to post-combustion capture by MEA and oxyfuel combustion capture, the results were clear on MEA being the least preferable option in an environmental perspective for both coal- and natural gas-fired power plants. Oxyfuel combustion capture, on the other hand, was shown to be the most preferable option.

Sammendrag

CO_2-utslipp fra forbrenningen av fossile brensler er den største kilden til menneskeskapte utslipp av klimagasser. CO_2-fangst og lagring er en av våre beste muligheter til å redusere disse utslippene og dermed begrense den globale oppvarmingen samtidig som vi kan fortsette kraftproduksjon med fossile brensler. Et fangstanlegg for CO_2 krever energi og vil øke energibehovet til kraftverket, noe som vil øke forbruket av brensel og dermed øke utslippene med de tilhørende miljøinnvirkningene. For å kunne beregne disse miljøinnvirkningene er det viktig å inkludere hele verdikjeden og livssyklusen til kraftverket.

I denne oppgaven er det blitt tatt i bruk en såkalt «tiered hybrid» livssyklusanalyse av kull- og gasskraftverk med chilled ammonia process (CAP) og sorption enhanced water-gas shift (SEWGS) fangstteknologi. Disse nye og lovende CO_2-fangstteknologiene er to av de minst studerte teknologiene når det kommer til miljøanalyser. Resultatene fra denne analysen blir sammenliknet med to mer studerte fangstteknologier, etterforbrenningsfangst ved hjelp av monoetanolamin (MEA) og oksybrensel-forbrenning.

Både CAP og SEWGS-teknologiene viste å kunne redusere det globale oppvarmingspotensialet (GWP) i et gasskraftverk med 70%. For kullkraftverkene klarte CAP-teknologien en reduksjon på 77% mens SEWGS-teknologien førte til en reduksjon på 77,5%. Denne reduksjonen fører for øvrig også til en økning i andre miljøpåvirkningskategorier hvor for eksempel potensialet for økotoksisitet i ferskvann (FETP) økte med 87-88% for både CAP og SEWGS-teknologi i gasskraftverk. Denne miljøpåvirkningskategorien hadde en økning på 22 og 25% for CAP og SEWGS i kullkraftverkene.

Ved sammenlikningen med MEA og oksybrensel-alternativene var resultatene klare på at MEA var det minst gunstige fangstalternativet for både kull- og gasskraftverk. Oksybrensel viste seg å være det mest gunstige alternativet i et miljøperspektiv.

Acknowledgements

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First of all I would like to thank my supervisor, Professor Anders Hammer Strømman and my co-supervisor, Bhawna Singh for their invaluable help and guidance throughout the semester. Their help have been greatly appreciated.

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Lisbeth Jeanette Bøe

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Contents

List of tables and figures

Abbreviations

ASU	-	Air Separation Unit
BAT	-	Best Available Technology
CAP	-	Chilled Ammonia Process
CCS	-	Carbon Capture and Storage
EOR	-	Enhanced Oil Recovery
EPRI	-	Electric Power Research Institute
GCCSI	-	Global Carbon Capture and Storage Institute
GHG	-	Greenhouse gas
IEA	-	The International Energy Agency
IGCC	-	Integrated Gasification Combined Cycle
IPCC	-	Intergovernmental Panel on Climate Change
ISO	-	International Organization for Standardization
LCA	-	Life Cycle Assessment
LCI	-	Life Cycle Inventory analysis
LCIA	-	Life Cycle Impact Assessment
MEA	-	Monoethanolamine
NGCC	-	Natural Gas Combined Cycle
SEWGS	-	Sorption Enhanced Water-Gas Shift
USC	-	Ultra-Supercritical (power plant)

Impact categories:

FEP	-	Freshwater Eutrophication Potential
FETP	-	Freshwater Ecotoxicity Potential
GWP	-	Global Warming Potential
HTP	-	Human Toxicity Potential
MEP	-	Marine Eutrophication Potential
METP	-	Marine Ecotoxicity Potential
PMFP	-	Particulate Matter Formation Potential
POFP	-	Photochemical Oxidant Formation Potential
TAP	-	Terrestrial Acidification Potential
TETP	-	Terrestrial ecotoxicity Potential

1 Introduction

1.1 Background

Human activities have been shown to be a contributor to the increased levels of greenhouse gases (GHGs) in the atmosphere. This increase leads to global warming and climate change which will have several effects on humans and ecosystems. The largest contributor to the increased level of GHGs is carbon dioxide (CO_2) which is released from the combustion of fossil fuels. While there are large, easy accessible and low-cost reservoirs of fossil fuels available, fossil fuels will continue to be used for generating power in the future. For instance, the global coal-fired power plant fleet is responsible for roughly a quarter of the world's anthropogenic CO_2 emissions. Despite the concerns for climate change, the coal-fired power generation is expanding faster than ever (IEA, 2012a). Therefore, the most viable option for reducing CO_2 emissions from fossil fuel combustion for power generation is probably carbon capture and storage (CCS).

CCS firstly involves collecting and concentrating the CO2 generated from combustion of fossil fuels, then transporting it by pipeline or ships to a suitable location for storage and lastly storing the CO_2 away from the atmosphere for a longer period of time. CCS is thereby suitable for countries with significant sources of CO_2 accessible storage locations and experience with oil and gas production (IPCC, 2005). CO_2 capture has been used for a long time by the gas processing industry, where there is a need for separating the CO_2 from the natural gas. The transportation and injection of CO_2 into reservoirs has been used by the oil industry for enhanced oil recovery (EOR) since the 70s. The application of CCS at a power plant will lead to an increased need for resources as there will be higher capital expenditures and need for additional energy and thereby additional fuel. The capture processes may also have some direct emissions to air and a trade-off in total environmental impacts is expected. A well suited method to trace and uncover such environmental trade-offs is a life cycle assessment (LCA).

There are different technologies for capturing CO_2 from power generating industries and the three main processes being developed is pre-combustion capture, post-combustion capture and oxyfuel combustion capture, also referred to as oxy-combustion capture. Pre-combustion capture has, as mentioned before, been used for a long time by the gas processing industry and is still mostly

used in gasification-based power plants, particularly in integrated gasification combined cycle (IGCC) (GCCSI, 2012c). The technology involves separating the CO_2 from the gas stream by an acid gas removal process prior to the gas combustion. This process is often done by absorption in a chemical or physical solvent followed by regenerative stripping to release the CO_2. The bulk of the new coal power plants being built today are IGCC plants (IEA, 2008). Post-combustion capture, on the other hand, involves the separation of CO_2 from the flu gas of the combustion of fossil fuels in air. This process can be done with liquid solvents such as monoethanolamine (MEA), ammonia or other amines (absorption), which is currently the most advanced option, or with other technologies that is currently being investigated such as solid adsorbents or membranes (GCCSI, 2012d). Oxyfuel combustion capture involves the combustion of the fossil fuels with higher amounts of oxygen than air contains. This is done by removing the bulk of the nitrogen, which is approximately 80% of air, from the ingoing air with an air separation unit (ASU). This will give the resulting flue gas from the combustion a CO_2 content of up to 90% (GCCSI, 2012a) and the rest mainly water vapor. Depending on the regulations, this flue gas may in the best case be stored directly without further purification.

1.2 Literature Review

The earliest environmental assessment on CCS were published in 1993 (Doctor et al., 1993) where Doctor et al. assessed carbon dioxide recovery by pre-combustion capture in a coal power plant. These calculations were based on mass and energy balance. Not much later there were also environmental assessments that included gas-fired power plants and post-combustion capture ((Summerfield et al., 1995), (Waku et al., 1995), (Audus and Freund, 1997)), but these were also based on mass and energy balance. Rao & Rubin provided a foreground LCA of a coal-fired power plant with post-combustion and multipollutant environmental controls and concluded that the CCS system had some environmental trade-offs (Rao and Rubin, 2002). Lombardi published a full LCA that compared the different capture technologies, including oxyfuel combustion capture, with a focus on GHGs (Lombardi, 2003). Lombardi's study concluded that the oxyfuel combustion capture resulted in the least amount of GHGs. More recently, several published studies have implemented a full or hybrid LCA to assess fossil-fueled power plants with different CCS technologies (e.g. (Hertwich et al., 2008), (Singh et al., 2011b), (Korre et al., 2010), (Odeh and Cockerill, 2008), (Koornneef et al., 2008)).

Recently published literature reviews (e.g. (Schreiber et al., 2012), (Singh et al., 2011a)) shows that most of the published LCA work in the later years involves post-combustion capture often with a focus on capture using MEA and the published LCAs on pre-combustion capture often concerns physical absorption by selexol. There has been few or no published LCA work done for novel post- and pre-combustion capture alternatives such as Chilled Ammonia Process (CAP) and Sorption Enhanced Water-Gas Shift (SEWGS). This means that there is no detailed environmental impact profile on these technologies.

However, there have been done several technological and economic studies on CAP and SEWGS and CAP is claimed to require less energy and emit less NO_x and SO_x than other amine-base capture systems (Zhao et al., 2013). According to Wangen (2012) who has done an LCA on CAP, among other technologies, the CAP technology has higher impacts than the MEA capture technology for both coal and natural gas power plants due to its energy intensive chilling process. SEWGS on the other hand is capable of higher carbon capture rates (90% vs 98%) and lower energy requirement per kg CO_2 captured than the pre-combustion capture option with Selexol (Gazzani et al., 2013a). SEWGS has also been said to have a lower energy penalty and at best a lower energy requirement per kg captured CO_2 in NGCC plants compared to the post-combustion capture by MEA (Manzolini et al., 2011).

1.3 Research Objectives

The objective of this thesis is to do a life cycle assessment (LCA) of two novel carbon capture technologies for both coal-fired and natural gas-fired power plants. The chosen technologies are the Chilled Ammonia Process (CAP), which is a post-combustion capture technology, and Sorption Enhanced Water Gas Shift (SEWGS), which is a concept for pre-combustion CO_2 capture. This study will also include an LCA of the best available technology (BAT) for both coal- and gas-fired power plants without CO_2 capture and storage. The BAT power plants will be used as base cases to enable to locate and evaluate the trade-offs that will occur when applying CCS to a power plant. A contribution analysis will also be presented to get an overview of which foreground process contributes to the different impact categories. This is important info that may show where possible improvements can be made. There will also be presented the best and worst case scenarios for both capture technologies to include as much data on performance parameters in literature as possible.

The LCA results from the CAP and SEWGS capture technologies will be compared to LCA work on post-combustion capture with MEA (Wangen, 2012) and on oxyfuel combustion capture (Bøe, 2012). This comparison will be done to get a better overview on how CAP and SEWGS compete with more studied technologies in terms of trade-offs with CCS.

1.4 Structure of the work

Chapter 2 will present the method used for this study, tiered hybrid LCA, with a brief explanation together with a presentation of the methodological and mathematical framework of LCA and tiered hybrid LCA. Lastly in chapter 2, the Ecoinvent database and the ReCiPe framework used to calculate the assessment results is presented.

Chapter 3 provides a system description which involves the presentation of the foreground processes and the chosen performance parameters for the power plants studied. It will also provide an introduction to the studied carbon capture technologies. This chapter also presents the emission profile and explains what Ecoinvent data the different processes are based on.

The results for the seven different power plants will be presented in chapter 4. Firstly, the actual values for the different impact categories will be shown in a table and then a closer look on the scores for global warming potential is presented. The 10 most relevant impact categories will be presented together with the information on where in the foreground system the impacts have their origin. There will also be presented a sensitivity analysis and a best- and worst case scenario analysis to include all performance parameters found in literature. Lastly in chapter 4, the results for the studied capture technologies are compared to the environmental performance of oxyfuel combustion capture and post-combustion capture by MEA.

The discussion of the results is done in chapter 5. This chapter will also provide an evaluation of the key assumptions made in this study and a benchmarking with other similar studies. Suggestions for further work on the topic and policy recommendations are also provided in this chapter.

Chapter 6 will present the conclusions of this study gathered from the LCA results, comparative analysis and the discussion chapter.

2 Methodology

This chapter will provide an explanation to the methods used in this study, including life cycle assessment (LCA), Input-output analysis (IOA) and the tiered hybrid LCA. The mathematical background of these assessment methods will also be presented. Lastly, an overview of the database and framework for environmental perspectives will be presented.

2.1 Life Cycle Assessment

Life Cycle Assessment (LCA) is a well-established method to better understand the environmental implications of our activities. LCA is used to assess all types of products and product systems and the objective is generally to perform consistent comparisons of technological systems with a focus on their environmental impacts. It may also be used for optimizing the environmental performance of a product or company. It is important to include all phases in a products lifetime and keep a holistic understanding of the processes and the environmental aspects connected to them. It is for example not only the production phase of a mobile phone that is important for its emissions, but also maintenance, use and end of life treatment. In our time of increased focus on global warming it is important to avoid "problem shifting" where seemingly environmental friendly solutions may cause some environmental impacts in some part of its life cycle after all. LCA is a good tool for uncovering cases of problem shifting. LCA has been included in several international standards. ISO 14040:2006 describes the principles and framework of LCA including the goal and scope definition, the inventory modeling phase, the impact assessment phase and the phase of interpreting the life cycle. ISO 14040:2006 also includes an overview of the limitations of LCA (ISO14040, 2006).

2.1.1 LCA Framework

LCA can be divided into four methodological components: goal and scope definition, life cycle inventory analysis, life cycle impact assessment and life cycle interpretation. The LCA framework is illustrated in figure 1.

Goal and scope definition

In this stage, the purpose of the study will be defined in terms of the functional unit which is the quantitative measure of the function of the studied service or product. Examples of functional units could for example be $1m^3$ of delivered product or 1 kWh. The scope will include the system

boundary and the level of detail in the LCA and will depend on the subject of the study. The goal of an LCA will define the depth of the study.

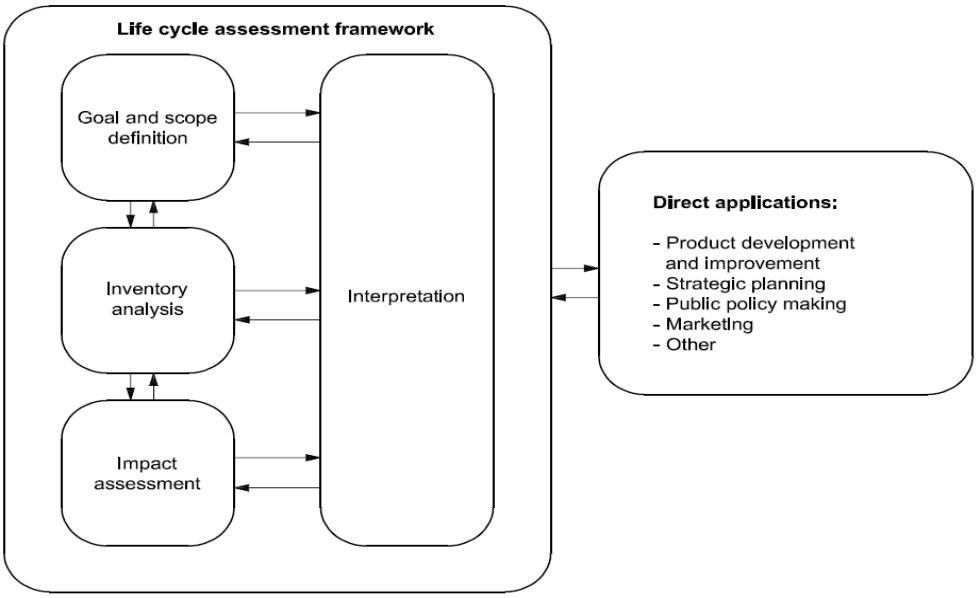

Figure 1 – LCA framework (ISO14040, 2006)

Inventory Analysis

Life cycle inventory analysis (LCI) is the second stage of the LCA and includes the construction of the model decided in the goal and scope definition. This stage is also where the data collection takes place. The LCI is an inventory of input-output data and calculations of the amount of resource use and emissions of the system being studied. The calculations are in relation to the functional unit.

Impact assessment

Life cycle impact assessment (LCIA) ties a number of potential impacts to the resource extraction and the wastes/emissions of the inventory. The results of an LCIA will provide additional information to the LCI results and help to better understand the environmental significance of the system being studied. The results will be on a functional unit basis and in terms of several impact categories such as global warming potential, acidification potential, land use etc.

Interpretation

Life cycle interpretation will take place in every stage of the LCA and often includes sensitivity analysis and benchmarking of different products. Here the results of the LCI or LCIA will be summarized and discussed in accordance with the goal and scope definition.

2.2 Input-Output Analysis

Input-output analysis (IOA) is an analytical framework developed by Nobel laureate Wassily Leontief in the 1930s. The fundamental purpose of this framework is to analyze the interdependence of industries in an economy and consists of linear equations describing the distribution of an industry's product in an economy (Miller and Blair, 1985). The mathematical formulation of IOA is identical to that of LCA, which makes it easy to implement IOA in environmental assessments.

The first step of an IOA is to establish the Make & Use tables, which describes what an industry uses and produces during a given time period. This may be given in either physical or monetary terms. If the emission profile of a given industry is available, this can be used to allocate the emissions of a given product or industry.

2.3 Hybrid LCA

Several studies note that an LCA approach can suffer from incomplete system boundaries and therefore suggests combining economic input-output and process based LCIs to avoid an underestimation of environmental impacts (Strømman et al., 2009). This combination has been referred to as a hybrid LCI and combines the strengths of both methods of analysis. The implementation of hybrid analysis to LCI has been done in different ways and can be grouped into three different categories, namely, tiered hybrid analysis, input-output based hybrid analysis and integrated hybrid analysis (Suh et al., 2003).

In a tiered hybrid analysis, the direct and downstream requirements, such as maintenance and use, and some other important requirements of the system are closely studied in a process analysis, while the remaining requirements are covered by IOA. The important input-output sectors are further disaggregated in an input-output (IO) based hybrid analysis. This is done in case there are

more detailed sectoral monetary data available. This is said to enable full utilization of detailed process-specific data without any double counting (Suh et al., 2003). In an integrated hybrid analysis model, the entire process system is represented in a technology matrix by physical units per unit operation time of each process. The IO system on the other hand, is represented by monetary units. The use of integrated hybrid analysis secures a full incorporation of detailed unit process level information in the IO model. This also prevents double counting by subtracting the commodity flows in the process based system from the IO system.

In this thesis, the tiered hybrid analysis will be implemented for the infrastructure of the power plants. This method is used because there is a small chance for double counting and the IO results can easily be added together with the LCI results. The IO results are gathered by allocating the different monetary values to an EXIOPOL IO database (EXIOPOL, 2011) to best describe the infrastructure.

2.4 Mathematical framework

2.4.1 Mathematical framework of LCA

Every LCA study will have the requirements matrix (A) as a basis. The requirements matrix A is shown in Equation 2.1 and has four sub-sections.

$$A_{ij} = \begin{bmatrix} A_{ff} & 0 \\ A_{bf} & A_{bb} \end{bmatrix} \quad \text{(Eq. 2.1)}$$

The sub-section A_{ff} represents the foreground system and the requirements between the foreground processes. Foreground processes refers to data that is compiled specifically for a study. The inputs for the A_{ff} matrix must be gathered first hand by the analyst. The A_{bb}sub-section is the background requirements matrix. The background processes are processes gathered from a generic database and this data is known, which leads to no requirements for efforts in data collection for the analyst. The A_{bf} sub-section represents upstream inputs of background processes to the foreground system. These inputs must also be gathered by the analyst.

The A matrix will be used to establish the production balance and identify the activity generated as the result of the demand for the functional unit (Strømman, 2010). The production balance is shown in Equation 2.2 and shows the production, x, as a function of intermediate demand, Ax, and external demand, y.

$$x = Ax + y \qquad \text{(Eq. 2.2)}$$

Equation 2.2 is rearranged to solve the unknown output of the processes, the x vector. The x vector will also be expressed in terms of the Leontief inverse, L. This is shown in equation 2.3 and equation 2.4.

$$(I - A)x = y \rightarrow \quad x = (I - A)^{-1}y \qquad \text{(Eq. 2.3)}$$

Where

$$L = (I - A)^{-1} \rightarrow \quad x = Ly \qquad \text{(Eq. 2.4)}$$

The Leontief inverse contains the output required per unit of external demand and the x vector contains the output required for a specific external demand (Strømman, 2010).

To be able to calculate the total emissions resulting from the functional unit, we have to include the stressor matrix, S. The stressor matrix contains stressors per unit output of a given process. A stressor is a general expression for emissions or other imposed burdens on the environment. The stressor matrix is used to find the total amount of stressors a given external demand imposes, e (shown in equation 2.5).

$$e = Sx \qquad \text{(Eq. 2.5)}$$

A characterization matrix, C, has to be established to enable the calculation of the vector of total impacts, d. The calculation of the d vector is shown in equation 2.6. The characterization matrix contains characterization factors that allow us to convert emissions with the same environmental impact into equivalents, e.g. CH_4 into CO_2-equivalents (Strømman, 2010).

$$d = Ce = CSx \qquad \text{(Eq. 2.6)}$$

There may also be an interest of knowing how the different processes in the system contribute to the various impact categories. This matrix is called D_{pro} and the calculation is shown in equation 2.7. It is also possible to calculate which stressors contribute to the different impact categories which are shown in a D_{str} matrix (eq. 2.8). Equation 2.9 shows that the sum of the rows in D_{pro} and the sum of the columns in D_{str} equals the vector of total impacts, d.

$$D_{pro} = CS\hat{x} \quad \text{(Eq. 2.7)}$$

$$D_{str} = C\hat{e} = C\widehat{Sx} \quad \text{(Eq. 2.8)}$$

$$d = \sum_{pro} D_{pro} = \sum_{str} D_{str} \quad \text{(Eq. 2.9)}$$

There are several different frameworks one can use to evaluate the environmental impacts. In this study, the ReCiPe framework has been used.

2.4.2 Mathematical framework of the Tiered hybrid analysis

In a tiered hybrid analysis we operate with the same requirements matrix (A) as in an LCA, but add requirements to the A_{nf} from an IO dataset to create A_{nn}. This creates an additional background system necessary to cover that which is missed out in the LCI (Strømman, 2010). The following form of the hybrid A-matrix is created:

$$A_{ij} = \begin{bmatrix} A_{ff} & 0 & 0 \\ A_{pf} & A_{pp} & 0 \\ A_{nf} & 0 & A_{nn} \end{bmatrix} \quad \text{(Eq. 2.10)}$$

This method allows us to upgrade an existing process LCA to a hybrid LCA, but one need to remember checking for double counting errors. More on correcting for double counting can be read in Strømman et al. (2009).

2.5 Ecoinvent and ReCiPe

The results in this study have been calculated with the software Arda, which is developed by the Industrial Ecology program at the Norwegian University of Science and Technology. This software bases its calculations on the Ecoinvent v2.2 database (Ecoinvent, 2010) and the ReCiPe framework is used to calculate the assessment results. The Ecoinvent database is recognized as the best quality and the most complete LCA database for European purposes. It contains a wide range of process categories, such as energy supply and fuels, and includes capital requirements associated with the various processes.

The ReCiPe framework is a method for LCIA which provides a recipe to calculate life cycle impact category indicators (Goedkoop et al., 2009). This framework (Figure 2***)*** contains 18 impact categories at midpoint level which are further converted and aggregated into three categories at endpoint level. Figure 2 describes the relationship between the LCI parameter on the

left, the midpoint indicator in the middle and the endpoint indicator to the right. In order to make these aggregations, some uncertainties have been incorporated in the form of the perspectives; individualist (I), hierarchist (H) and egalitarian (E).

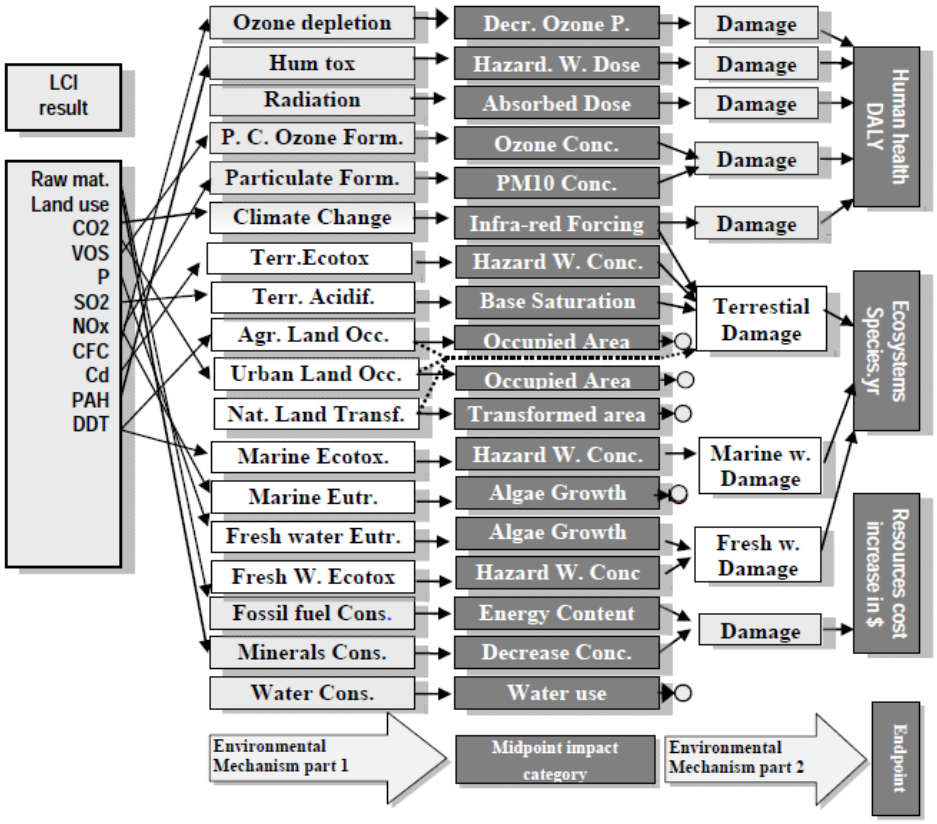

Figure 2 – ReCiPe framework (Goedkoop et al., 2009)

The main difference between these perspectives is their timeframe. The I-perspective has the shortest timeframe (20 years) and is an optimistic perspective when it comes to economy and technology. The H-perspective has a longer timeframe (100 years) and has the view that impacts can be avoided with the proper management. The E-perspective, on the other hand, is the most pessimistic of the perspectives and has an infinite timeframe where the precautionary principle is important (De Schryver et al., 2009). In this thesis the hierarchical perspective is chosen since it represents "the middle way" of the three perspectives.

3 System description

This chapter will firstly present the main performance parameters of the power plants in table 1 and explain how the power plants are modeled from the Ecoinvent database. The value ranges of the performance parameters with their literature references will be presented later, in chapter 4. Secondly, each of the two chosen novel capture technologies, Chilled Ammonia Process (CAP) and Sorption Enhanced Water-Gas Shift (SEWGS), will be presented and explained. Thirdly, there will be an explanation of how the power plants infrastructure is modeled by the tiered hybrid LCA. This will be followed by a brief explanation on how the transport and storage system for CCS is modeled from the Ecoinvent database. Lastly, there will be a brief introduction to two CO_2 capture technologies, oxyfuel combustion capture and MEA, which will be subject of comparison later in this study. Table 1 presents the chosen key performance parameters found in literature.

Table 1 - Chosen key performance parameters for this study.

Parameters	Unit	IGCC BAT	IGCC + SEWGS	USC BAT	USC + CAP	NGCC BAT	NGCC + SEWGS	NGCC + CAP
CO2 capture	**%**	-	90	-	90	-	90	90
Net efficiency	**%**	44,1	36,3	43,4	34,8	58,1	50,9	51,2
Energy penalty	**%**	-	7,8	-	8,6	-	7,2	6,9
TDPC[a]	**2008 M€**	629,2	802,5	437	841,9	399	702,1	522,1
Energy for transport and storage	**kW**		735		735		356	356

[a] Ratio-adapted from Manzolini et al. (2013b) and recalculated into 2008 M€.

3.1 Power plant

All power plants in this study are assumed to have a net electricity output of 400MW and the functional unit is 1 kWh. This means that the results of the LCIA will be given per kWh. This assessment will have the best available technology (BAT) as a basis.

The coal-fired power plants used for the base cases in this study is a supercritical power plant (SC), more specific to this case a so called ultra-supercritical (USC) power plant, and an integrated gasification combined cycle (IGCC) power plant. Both types of power plants have an assumed lifetime of 40 years. The International Energy Agency (IEA) has reported a strong trend towards installing ultra- and supercritical coal-fired power plants the last two decades although

the majority of the power plants still are subcritical. There is also an increasing number of power plants with a capacity above 300MW (IEA, 2012a). An IGCC plant produces electricity in a fundamentally different process than pulverized fuel power plants and is an expensive technology compared to pulverized fuel power plants. IGCC systems is said to be the cleanest and most efficient technology when it comes to electricity production by coal, but needs a lower investment cost to be competitive against pulverized coal technology (IEA, 2008). The combustion of the coal is based on the Ecoinvent process, *"hard coal, burned in power* 10 *plant/ DE/ MJ"* and the production of the fuel is also included in this analysis and the hard coal production is based on *"hard coal supply mix, at regional storage/ US/ kg".* The BAT efficiency assumption is 43.4% for the USC power plant and 44.1% for the IGCC power plant as suggested by the IEA (IEA, 2008).

The natural gas-fired power plant used for the base case is a natural gas combined cycle (NGCC) which has been the preferred technology for gas-fired plants since the early 90's. The assumed lifetime for the NGCC plant is 25 years. The combustion of the gas is based on *"natural gas, burned in power plant/ UCTE/ MJ"* and the natural gas production is based on *"natural gas, high pressure, at consumer/ RER/ MJ".* The BAT efficiency assumption for the power plant is 58.1% also suggested by the IEA (IEA, 2008).

3.2 Chilled ammonia Process (CAP)

The chilled ammonia process (CAP) is an alternative to the much studied amine system where monoethanolamine (MEA) is the most popular amine used in post-combustion capture. The CAP has been developed by Alstom and is said to be the most prominent variant of the processes involving aqueous ammonia (Darde et al., 2011) and can be applied to coal-fired systems, in this case USC, and natural gas combined cycle (NGCC) systems. Aqueous ammonia alternatives for post-combustion capture have been developed because of the large heat requirement and solvent degradation involved in the processes with MEA. Compared to the use of MEA, ammonia is cheaper, requires less regeneration heat and is less corrosive and degrading (Jilvero et al., 2012). However, the study by Wangen (2012) claims that the CAP technology has a less preferable environmental performance compared to MEA. The Global CCS institute (GCCSI) has acknowledged CAP as a near term technology and announced test plants on this technology includes AEPs Mountaineer Power Plant and Statoil Hydro's Mongstad Test Center in Norway

(GCCSI, 2012b). However, when using aqueous ammonia, there is a risk of ammonia slip by the vaporization of ammonia which can be decreased by cooling the absorption process to below room temperature. The CAP does just this by absorbing the CO_2 at a low temperature (0 – 10 ˚C) which minimizes the ammonia vaporization and thereby the ammonia emissions (Darde et al., 2011). Figure 3 shows a simplified process flow chart of a capture unit using the CAP technology.

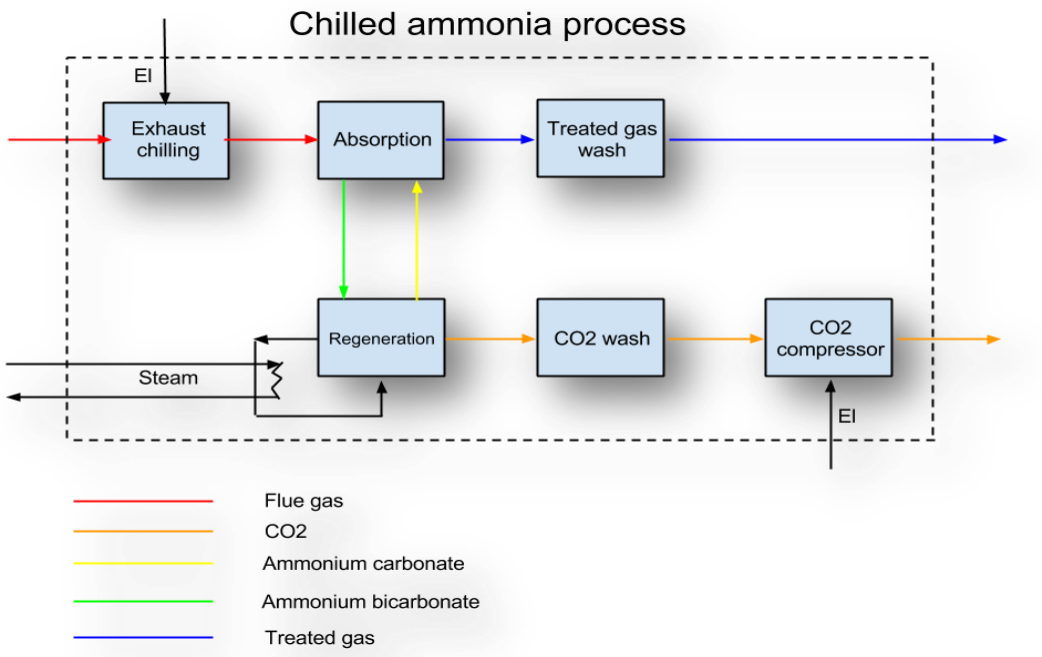

Figure 3 - Simplified CAP (adapted from (Valenti et al., 2009))

The flue gas enters the exhaust chilling where cooling towers and mechanical chillers are employed in order to condense water, capture residual contaminants and reduce the volume of the incoming flue gas. The flue gas then enters the absorption system where ammonia, carbonate and bicarbonate ions react with the flue gas and removes the bulk of the CO_2 (Kozak et al., 2009). The reactions relevant to the capture and regeneration are presented in equation 3.1-3.7.

$$CO_{3\,(aq)}^{2-} + 2NH_{4\,(aq)}^{+} \leftrightarrow (NH_4)_2CO_{3\,(aq)} \quad \text{(Eq. 3.1)}$$

$$(NH_4)_2CO_{3\,(aq)} + CO_{2\,(g)} + H_2O_{(l)} \leftrightarrow 2NH_4^{+} + 2HCO_{3\,(aq)}^{-} \quad \text{(Eq. 3.2)}$$

$$NH_{4\,(aq)}^{+} + HCO_{3\,(aq)}^{-} \leftrightarrow (NH_4)HCO_{3\,(aq)} \quad \text{(Eq. 3.3)}$$

$$(NH_4)HCO_{3\,(aq)} \leftrightarrow (NH_4)HCO_{3\,(s)} \quad \text{(Eq. 3.4)}$$

$$NH_{3\,(aq)} + HCO_{3\,(aq)}^{-} \leftrightarrow NH_2COO_{(aq)}^{-} + H_2O_{(l)} \quad \text{(Eq. 3.5)}$$

$$NH_2COO_{(aq)}^{-} + CO_{2\,(g)} + 2H_2O_{(l)} \leftrightarrow 2HCO_3^{-} + NH_4^{+} \quad \text{(Eq. 3.6)}$$

$$NH_2COO_{(aq)}^{-} + NH_{4\,(aq)}^{+} \leftrightarrow NH_2COONH_{4\,(aq)} \quad \text{(Eq. 3.7)}$$

Equation 3.1 and 3.2 describe the capture of CO_2 sought in the absorber while equation 3.3 and 3.4 describe the precipitation of ammonium bicarbamate salt occurring at low temperatures. However, if a bicarbamate ion is created (equation 3.5) it may lead to an undesirable CO_2 capture (equation 3.6) with a higher reaction enthalpy for regeneration. This ion may however combine with an ammonium ion instead (equation 3.7).

Before sending the residual flue gas to the stack for atmospheric discharge, it is scrubbed in a water wash column. The CO_2 rich solution is pumped through heat exchangers to dissolve the solids which are cooled before being sent back to the absorber. Heat is added in the regenerator using steam in a reboiler in order to release the CO_2 from the rich solution. The amount of heat needed in the reboiler is crucial to determine the energy penalty of a power plant with CAP CO_2 capture, since this is the most energy demanding process. The CO_2 lean stream is finally sent to compression and towards the storage location.

3.3 Sorption Enhanced Water Gas Shift (SEWGS)

The sorption enhanced water gas shift (SEWGS) process is a pre-combustion carbon capture alternative and is best applied in an integrated gasification combined cycle (IGCC) or a NGCC plant. It is said to be one of the most promising technologies in terms of reducing the energy penalty in CCS. The SEWGS process is a combination of a chemical reaction and a gas separation and produces H_2 in a catalytic CO shift reactor while the CO_2 is adsorbed on a high temperature absorbent. The most important parameter of this technology is the capacity of the sorbent which determines the steam consumption and thereby the energy penalty for SEWGS. The CAESAR (**CA**rbon-free **E**lectricity by **S**EWGS: **A**dvanced materials, **R**eactor-, and process

design) project is cooperating with several institutions to create more efficient sorbents in order to bring the CO_2 avoidance cost down and make the SEWGS process closer to the market (CAESAR, 2008). A simplified process flow chart of a power plant with SEWGS capture technology is shown in Figure 4.

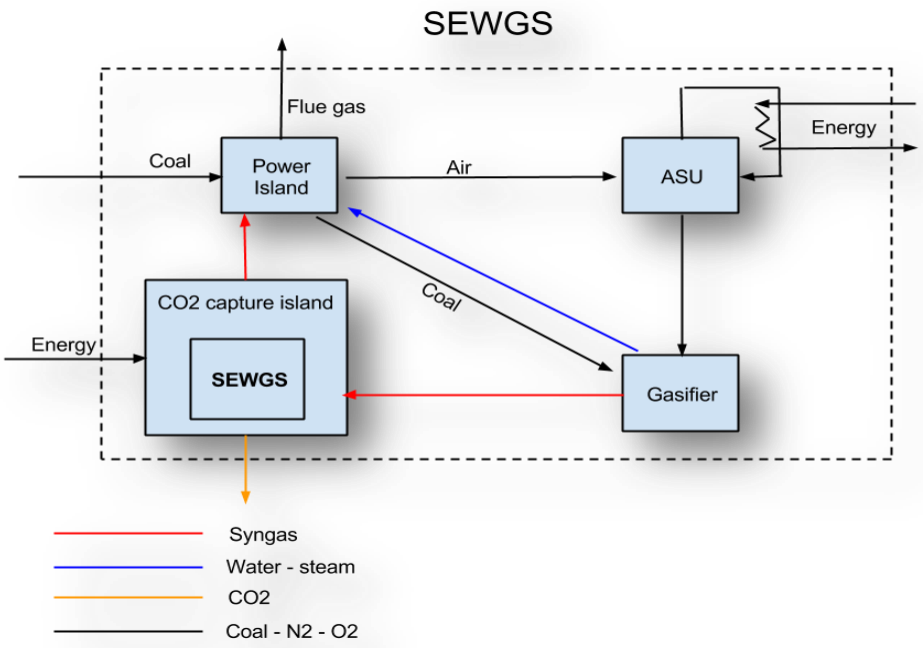

Figure 4 - Simplified power plant with SEWGS (adapted from (Gazzani et al., 2013a))

The process begins as syngas or coal derived gas formed by the air separation unit (ASU) and gasifier enters the SEWGS reactor. Here the CO is converted to CO_2, CO_2 is captured by adsorption and a H_2 rich stream is produced. As shown in equation 3.3, the water-gas shift reaction is an equilibrium reaction which will imply that only a part of the CO can be converted to CO_2 at high temperatures.

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \text{(Eq. 3.3)}$$

The solution to this is to execute the chemical reaction and the CO_2 capture in the same reactor. As the CO_2 is being removed, more CO will react with steam. This is called Le Chatelier's Principle and is also the main principle behind SEWGS. The resulting H_2 and steam mixture can

be fed directly into a gas turbine (ECN, 2009). Figure 4 illustrates an IGCC plant with SEWGS carbon capture technology, but for a NGCC plant with SEWGS the ASU and gasifier processes are replaced with syngas production by reformers and a hydro de-sulphurization reactor.

3.3.1 Adsorbents

The capacity of the adsorber in the SEWGS process is as mentioned important for the performance of the power plant when it comes to its efficiency. Gazzani et al. (2013b) lists some important characteristics of a SEWGS adsorbent: (1) High CO_2 capacity and selectivity over H_2, (2) Low H_2O adsorption, (3) Low specific cost, (4) Mechanical stability under pressure and temperature variation, (5) Chemical stability in the presence of impurities and (6) Easily regenerated by steam (Gazzani et al., 2013b). The chemical principle for the SEWGS reaction with an adsorber is the same for any adsorber and is shown in eq. 3.4-6.(Boon and ISCRE22, 2012)

$$CO + H_2O \leftrightarrow CO_2 + H_2 \quad \text{(Eq. 3.4)}$$

$$CO_2 + \text{ads} \leftrightarrow CO_2\text{ads} \quad \text{(Eq. 3.5)}$$

$$CO + H_2O + \text{ads} \leftrightarrow CO_2\text{ads} + H_2 \quad \text{(Eq. 3.6)}$$

The adsorbent that has been most studied is potassium promoted hydrotalcite, but the MgO_3 formation was shown to lead to a decrease in the carbon capture rate over time. The CAESAR project has thereby, with an aim to form smaller amounts of MgO_3, developed a new sorbent. The new adsorbent is a potassium-carbonate promoted hydrotalcite-based material called K-MG30 (van Selow et al., 2011). This adsorbent will be the represented adsorbent in this thesis since it has been tested in thousands of cycles and has shown to be a better option than the previously mentioned adsorbent.

In addition to sorbent K-MG30, there is also another sorbent being developed today and tested in the laboratories of the Energy research Centre of the Netherlands (ECN). This new sorbent has a more advantageous shape and an adsorption capacity about 60% higher than the K-MG30 sorbent (Gazzani et al., 2013b), but will not be the represented sorbent in this thesis since there has been no long run tests carried out yet. This new sorbent will instead be included in the best- and worst case scenarios for SEWGS in chapter 4.4.

3.4 Power plant infrastructure

The power plant infrastructure has, as mentioned in chapter 2.3, been modeled by the tiered hybrid analysis. This has been modeled from cost estimations of the direct cost of all seven power plants where the costs have been assigned to suitable processes in the EXIOPOL dataset. For the NGCC power plants, the total direct plant cost was estimated to 399M€ for the basecase, 702.1M€ for NGCC with SEWGS (Manzolini et al., 2013b) and 522.1M€ for NGCC with CAP. For the coal-fired power plants, the total direct plant cost was estimated to be 629.1M€ for the IGCC basecase, 802.6M€ for IGCC with SEWGS (estimated from Manzolini et al. (2013a)), 437M€ for the USC basecase and 841.9M€ for USC with CAP (estimated from Versteeg and Rubin (2011)). These costs are given in 2008M€. Detailed cost tables for all seven power plants can be found in appendix 1.

The direct costs are assigned to the EXIOPOL processes "Manufacture of machinery and equipment", "Manufacture of electrical machinery and apparatus" and "Construction". For the direct costs of the base cases, 53% is assigned to the first process, 7% to the second and 40% to the last. For the power plants with CCS, these percentages are 52%, 6% and 42%. This is based on the assumption of electrical apparatus being 11% of the total equipment cost (TEC) (table 11 in Peeters et al. (2007)), the rest of the TEC goes to machinery and the total installation cost (TIC) goes to construction.

3.5 Emissions

The emission profile of the key emissions, SO_2, NO_x, volatile organic compounds (VOC) and particulate matter (PM) emissions is calculated from the no-capture section in table 3 in Koornneef et al. (2010). When it comes to the ammonia slip for the power plants with CAP capture technology, the represented value is 10ppm which is also the maximum allowable slip (Versteeg and Rubin, 2011).

Table 2 presents the emission profile of the fuel combustion for the key emissions for the base case power plants. Note that the values in table 2 shows the emissions from fuel combustion only and represents thereby the emissions before any capture is performed.

Table 2 - Emission profile of fuel combustion in the base case power plants

emissions	unit	NGCC BAT	IGCC BAT	USC BAT
CO_2[a]	kg/MJ	5,60E-02	9,22E-02	9,22E-02
NH_3[b]	kg/MJ	-	8,44E-07	8,44E-07
NO_x[b]	kg/MJ	2,71E-05	2,81E-05	4,51E-05
PM[b]	kg/MJ	5,00E-07[a]	3,43E-06	4,70E-06
SO_2[b]	kg/MJ	5,00E-07[a]	7,84E-06	4,99E-05
VOC[b]	kg/MJ	-	-	1,21E-06

[a] Calculated from the fuel characteristics, [b] Calculated from Koornneef et al. (2010)

Table 3 presents the calculated final emission profile for all seven power plants. The calculations have been done with the emission profiles in table 2 combined with the capture rate and energy penalties. The emission profile in table 3 shows direct emissions from the operation of the plant only.

Table 3 - Total direct emissions

emissions	unit	NGCC BAT	NGCC + SEWGS	NGCC + CAP	IGCC BAT	IGCC + SEWGS	USC BAT	USC + CAP
CO_2[a]	kg/kWh	3,47E-01	3,96E-02	3,94E-02	7,53E-01	9,15E-02	7,65E-01	9,54E-02
NH_3[b]	kg/kWh	-	-	-	6,89E-06	8,37E-06	7,00E-06	8,73E-06
NH_3 slip[c]	kg/kgCO2	-	-	3,85E-04	-	-	-	5,06E-04
NO_x[b]	kg/kWh	1,68E-04	2,69E-04	1,91E-04	2,29E-04	2,79E-04	3,74E-04	4,67E-04
PM[b]	kg/kWh	3,10E-06[a]	4,96E-06[a]	3,52E-06[a]	2,80E-05	3,40E-05	3,90E-05	4,86E-05
SO_2[b]	kg/kWh	3,10E-06[a]	4,96E-06[a]	3,52E-06[a]	6,40E-05	7,78E-05	4,14E-04	5,16E-04
VOC[b]	kg/kWh	-	-	-	-	-	1,00E-05	1,25E-05

[a] Calculated from the fuel characteristics, [b] Calculated from Koorneef et al. (2010), [c] NH_3 emissions per kg captured CO_2, calculated from 10 ppm (Versteeg and Rubin, 2011)

The calculations for the ammonia slip based on 10ppm were done with the following equations:

$$\text{flow rate of } NH_3 = \frac{400MW}{\text{net. efficiency}} * \text{calorific value of fuel} * 10\text{ppm} \quad \text{(Eq. 3.7)}$$

$$\frac{\text{mass of } NH_3}{s} = \frac{P * \text{flow rate of } NH_3 * M_{NH_3}}{R * T} \quad \text{(Eq. 3.8)}$$

$$\frac{\text{mass of } NH_3}{\text{mass of } CO_2 \text{ captured}} = \frac{\frac{\text{mass of } NH_3}{s} * \frac{\text{MJ fuel}}{\text{kWh}}}{400\text{MW} * \frac{\text{mass of } CO_2 \text{ captured}}{\text{kWh}}} \quad \text{(Eq. 3.9)}$$

Equation 3.7 describes the calculation of the flow rate of NH_3 in m^3/s, while equation 3.8 describes the calculation of the mass with the help of the ideal gas law. Equation 3.9 describes the calculation of the mass of ammonia slip per mass CO_2 captured in the power plants with CAP capture technology. The values on the right hand side of this equation is some of the values needed in the foreground modeling in this study and can be found in appendix 4. The full list of processes and the connected emissions used for the power plant modeling can be found in appendix 5.

3.6 Transport and storage

The CO2 transport for the modeled power plants with oxyfuel combustion capture is assumed to be by a 500km pipelines with a diameter of 300mm for coal and 200mm for gas (Singh et al., 2011b). The pipeline is based on the Ecoinvent process *"pipeline, natural gas, long distance, high capacity, offshore/km/GLO"*.

The two compressors needed for recompression and storage for the CO2 is assumed to demand 735kW for the coal power plant and 356kW for the gas power plant from the electricity grid (Singh et al., 2011b).

Storage for the CO2 is assumed to be an offshore site of 1000m and is based on *"well for exploration and production, offshore/m/OCE"* (Singh et al., 2011b).

3.7 Oxyfuel and MEA

In order to have some point of reference, the environmental performance of the novel capture technologies, CAP and SEWGS, will be compared to two capture technologies which have been studied to a larger extent in LCAs. The two technologies are oxyfuel combustion capture and post-combustion capture with monoethanolamine (MEA).

The principle of oxyfuel combustion capture is to burn the coal or gas with a pure oxygen or O_2/CO_2 mixture instead of combustion with air as in conventional combustion. This eliminates the bulk of the nitrogen from the flue gas which now will consist of mainly water vapor and CO_2. The CO_2 is then easily separated by condensation of the water vapor. The removal of nitrogen

also decreases the NO_x emissions from the power plant. The largest contributor to the energy penalty in an oxyfuel power plant is the ASU which separates the oxygen for combustion from air. The energy penalty for oxyfuel combustion capture is about 9.70% for an NGCC plant and 8.30% for a supercritical coal plant (Bøe, 2012). A simplified model of the oxyfuel capture process can be found in appendix 2.

Post-combustion capture with MEA, the flue gas enters an absorber where the CO_2 reacts with the amine solvent and creates a CO_2 rich amine. The temperature of the CO_2 rich mixture is increased and CO_2 is again released from the mixture. This leaves a mixture of CO_2 and water vapor and the CO_2 is separated by the condensation of the water vapor. The energy penalty for CO_2 capture with MEA is estimated to 8% for an NGCC plant and 10.2% for a supercritical coal power plant (Singh et al., 2011b).

4 Results

This chapter will present the LCIA results from the analysis of all seven power plants as well as a description and explanation of the results. A contribution analysis will be presented to show which part of the system that contributes the most/least to each impact category. There will also be presented the results from the best-and worst case scenarios where the ranges of the different performance values will be included. Lastly, there will be presented a comparative analysis where the environmental performance of CAP and SEWGS capture technologies will be compared to oxyfuel combustion capture and post-combustion capture by monoethanolamine (MEA).

4.1 LCIA results

Calculations for 18 impact categories have been made in this study, but this chapter will focus on the ten most relevant categories. The numeric results for all 18 of them can be found in appendix 3. The ten most relevant impact categories are global warming potential (GWP), freshwater ecotoxicity (FETP), freshwater eutrophication (FEP), human toxicity (HTP), marine ecotoxicity (METP), marine eutrophication (MEP), particulate matter formation (PMFP), photochemical oxidant formation (POFP), terrestrial acidification (TAP) and terrestrial ecotoxicity (TETP). As expected, the results show overall higher values for all impact categories for coal compared to natural gas. For a better overview and understanding of the GWP, separate graphs of this category are presented in figure 5 and figure 6. Since it is the reduction of the GWP category that is the main goal of CCS, there will be an extra focus on this impact category.

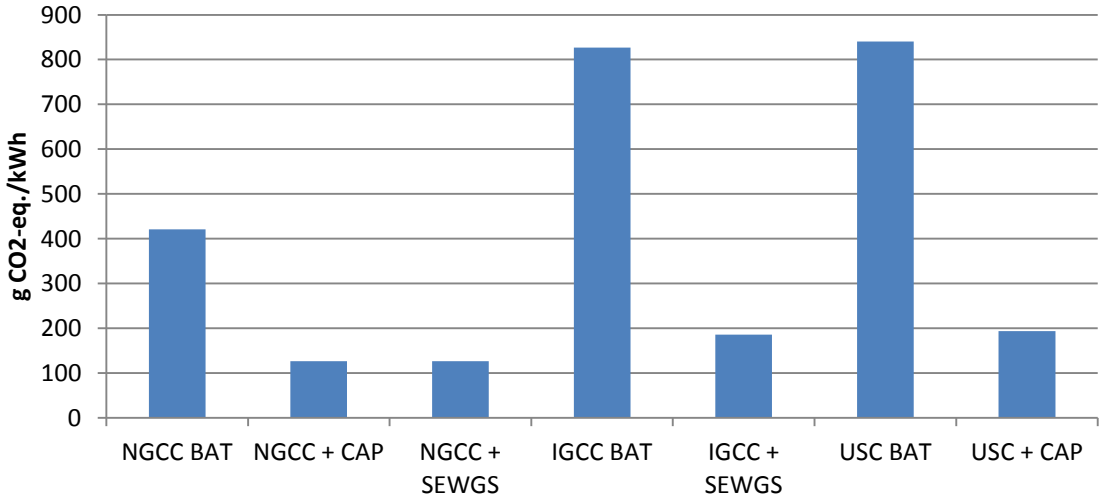

Figure 5 - results for global warming potential (in CO2 equivalents)

Figure 5 shows that the coal power plants has the highest emissions of CO_2-equivalents with USC slightly higher than the IGCC plant. The coal power plants also get the highest reduction in GWP from the CCS alternatives (CAP and SEWGS) and that CAP and SEWGS shows quite similar scores for both coal and natural gas plants. The natural gas plants with CCS has quite similar total emissions of CO_2-equivalents and show a decrease in GWP of 70.0% for CAP and 69.9% for SEWGS. The coal power plants show a decrease of 77.0% for CAP and 77.5% for SEWGS. The reason of why the GWP reduction is not the same as the plants capture rate is mainly that more fuel is needed when implementing CCS together with CO_2 equivalents occurring in other parts of the plants life cycle. This is relative to the power plants without capture. Figure 6 shows how the different foreground processes in the analysis, especially "CO_2 capture", contributes to the GWP category.

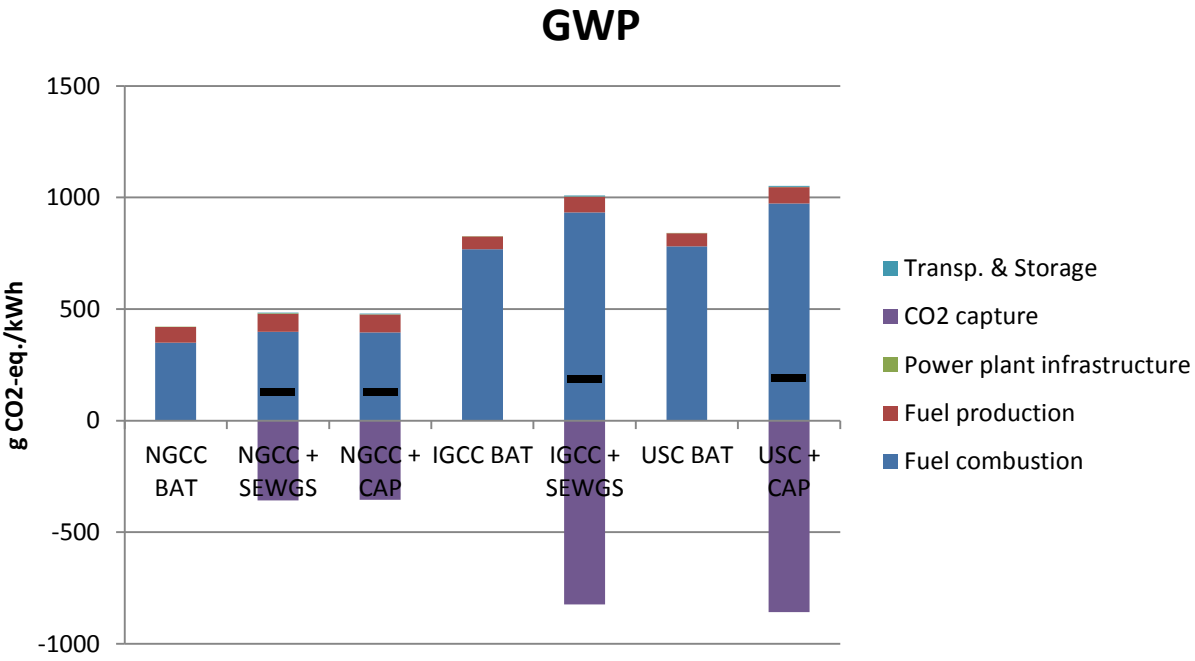

Figure 6 - Contribution analysis for GWP by each foreground process

According to the contribution analysis in figure 6, the processes "Transport & storage" and "Power plant infrastructure" give a negligible impact on GWP while the "fuel combustion" with the connected CO_2 emissions naturally stands for the bulk of the impact scores. Figure 6 shows that the CCS alternatives give the highest scores on the positive side of the graph, which describes the increased need for fuel and thereby the energy penalty when applying CCS. CCS

contributes however negatively to the emissions of CO_2 equivalents, shown as "CO_2 capture" and therefore sums up to be the results as shown in figure 5. The total score in GWP as shown in figure 5 is marked with a black line in the power plants with CCS in figure 6.

As mentioned earlier, there are trade-offs connected to the removal of CO_2 and reduction of GWP and there is therefore expected a rise in the other impact categories after implementing CCS technology. These trade-offs are normalized and illustrated in figure 7 and figure 8 together with the results of the power plants without capture. The normalized figures show the impact scores for each capture alternative relative to the highest scoring alternative for each impact category. The total impact value of the highest scoring technology is given at the top of the graphs.

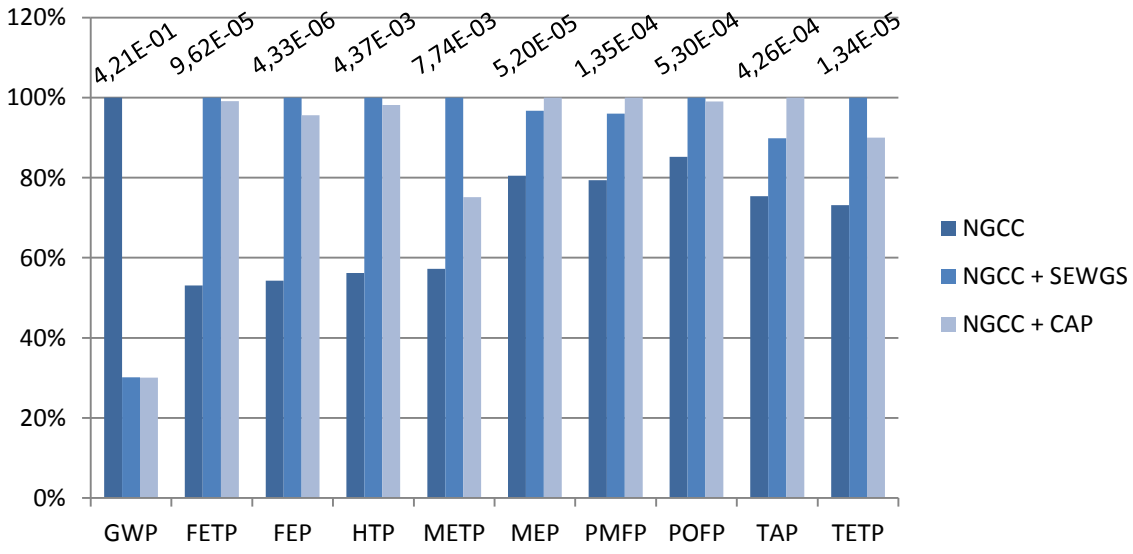

Figure 7 – Relative scores in impact categories for the natural gas-fired power plants

The normalized impact scores for the natural gas fired power plants in figure 7 show that the SEWGS option has the highest impacts in 6 out of 10 impact categories. It is however followed closely by the CAP alternative except for the METP category where the largest differences can be found. For METP, the SEWGS alternative is 33.2% higher than the CAP alternative which again is 31.1% higher than the alternative without capture. This is mainly due to the zinc and nickel emissions to water from the storage-well and nickel disposal, which is a bit higher for SEWGS than for the CAP plant. There is also a quite large increase in FETP, FEP and HTP for both CAP and SEWGS as shown in figure 7 and the increase from no capture to SEWGS is 88.3% for FETP, 84.3% for FEP and 78.4% for HTP, closely followed by the CAP alternative. The

increases in these impact categories is also mainly due to disposal of metals which leads to emissions to water. The impact category with the lowest increase from base case to both capture technologies is POFP, where the increase from base case to the SEWGS alternative is 17.5%. Overall both the CAP and SEWGS alternatives show quite similar impact scores except for METP.

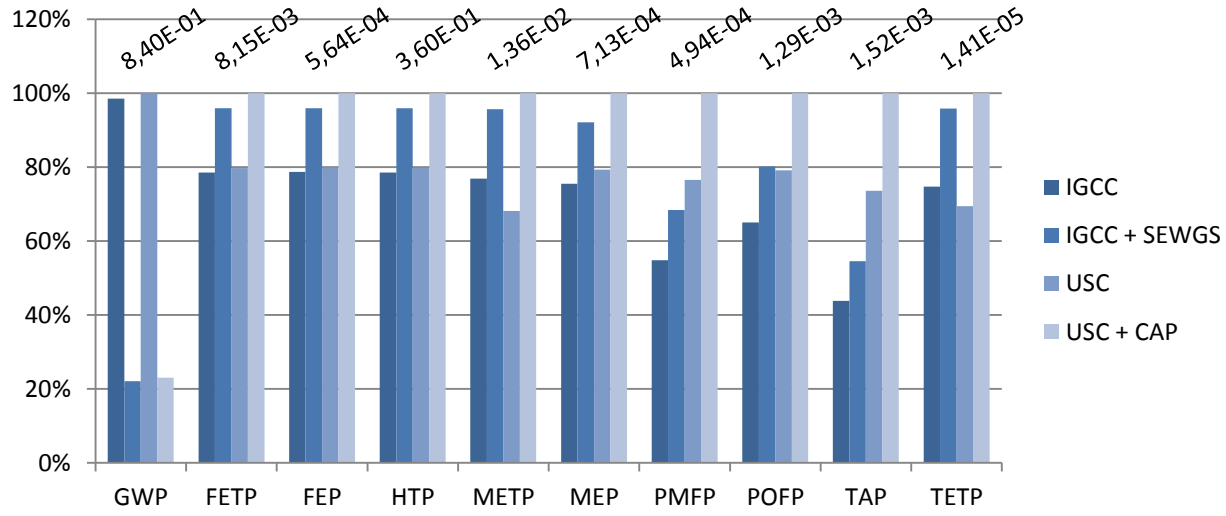

Figure 8 – Relative scores in impact categories for the coal-fired power plants

The normalized impact categories for the coal-fired power plants in figure 8 also show quite similar results for both CAP and SEWGS, but the exception for the coal cases is TAP. For TAP the SEWGS alternative is 24.6% higher than IGCC without capture and the CAP alternative is 35.7% higher than USC without capture. The USC plant shows however 67.7% higher TAP scores than the IGCC plant. TAP is mainly due to SO_2 and NO_x emissions for these power plants and the USC with CAP capture technology shows higher impact scores in this category due to higher levels of these emissions in an USC plant than an IGCC plant. Figure 8 also show that the CAP alternative scores notably higher for PMFP and POFP as well, where the CAP alternative is 46.1% higher than SEWGS for PMFP and 25.2% higher for POFP. These impact categories are also influenced by SO_2 and NO_x emissions. The impact categories, FETP, FEP and HTP show similar increases from base case with an increase of 22% for SEWGS and 25% for CAP. The highest increase from base case to CCS is in METP for the CAP alternative and TETP for the SEWGS alternative (47 and 28% increase). The most important contributor to TETP for the coal power plants is mercury emissions to air. As opposed to the natural gas plants, it is the CAP

capture alternative that scores the highest for most of the impact categories and the SEWGS alternative currently seems as the "winner" for the coal-fired power plants.

It is difficult to compare the different impact categories to each other (e.g. does a reduction in marine eutrophication weigh up for the increase in human toxicity?). However, we could say that for NGCC plants, the SEWGS capture alternative show slightly less trade-offs than the CAP alternative. For the coal power plants, it is the SEWGS alternative that seems to have the smallest trade-offs of implementing CCS.

4.2 Contribution analysis

To better understand where in the system the different emissions for the impact categories occur, it is useful to look at the impact categories divided into the foreground processes as done with GWP in figure 6. Figure 9 to figure 15 shows normalized impact categories and to what extent the different foreground processes contribute to them. For the power plants with CCS, the process "CO_2 capture" has been aggregated into "fuel combustion" where the only impact of the CO_2 capture is reduction of CO_2 emissions. In the cases of power plant with CAP (figure 11 and figure 15), the process "CO_2 capture" describes the ammonia slip connected to the capture process. The "power plant infrastructure" processes is the results from the tiered hybrid analysis which are added to the LCI results.

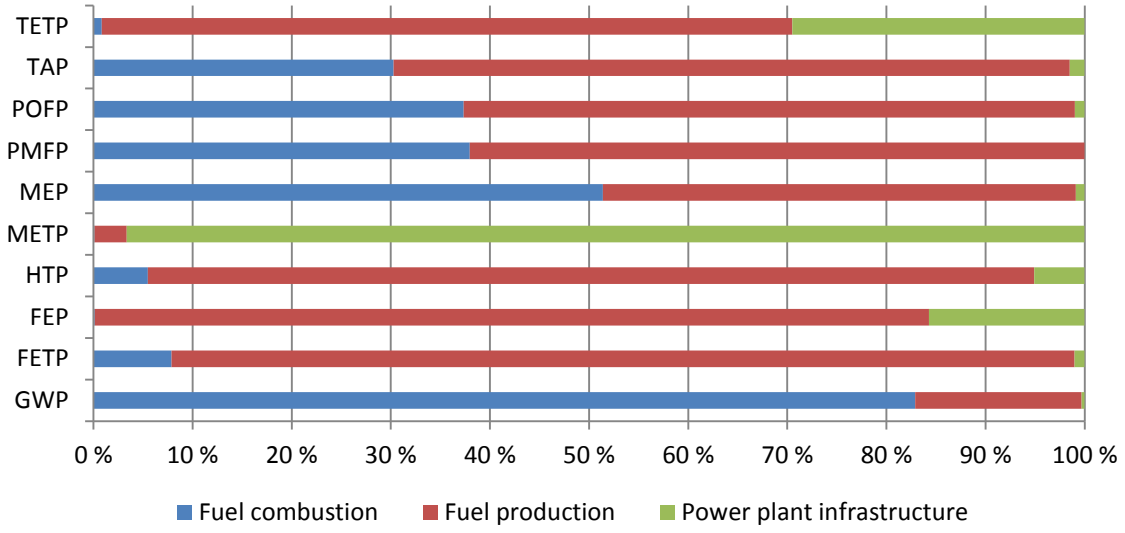

Figure 9 - Contribution analysis with normalized impact categories for the NGCC BAT power plant, divided into foreground processes

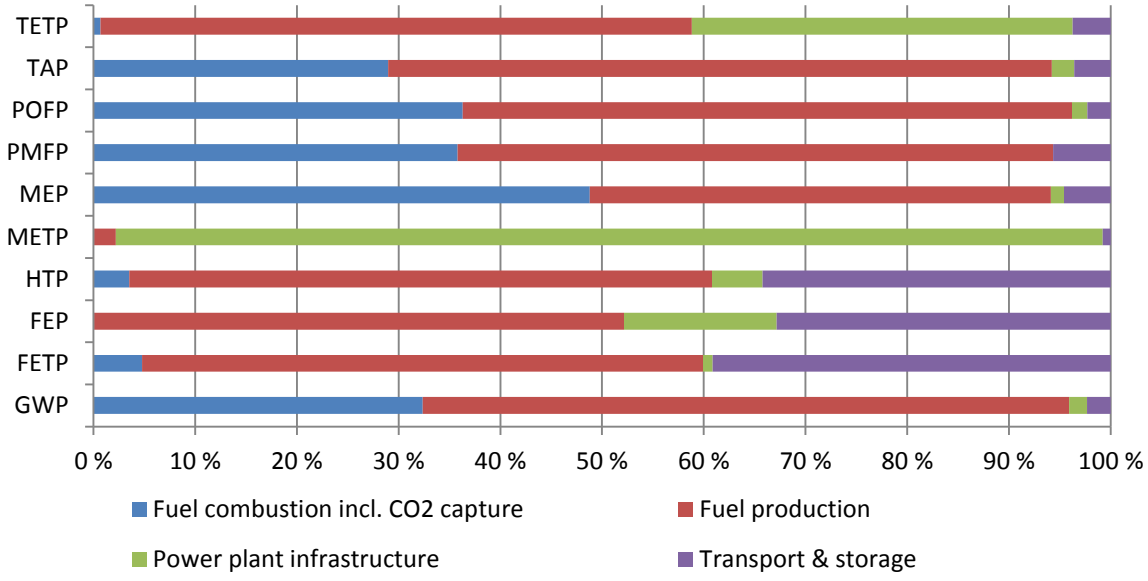

Figure 10 - Contribution analysis with normalized impact categories for the NGCC with SEWGS power plant, divided into foreground processes

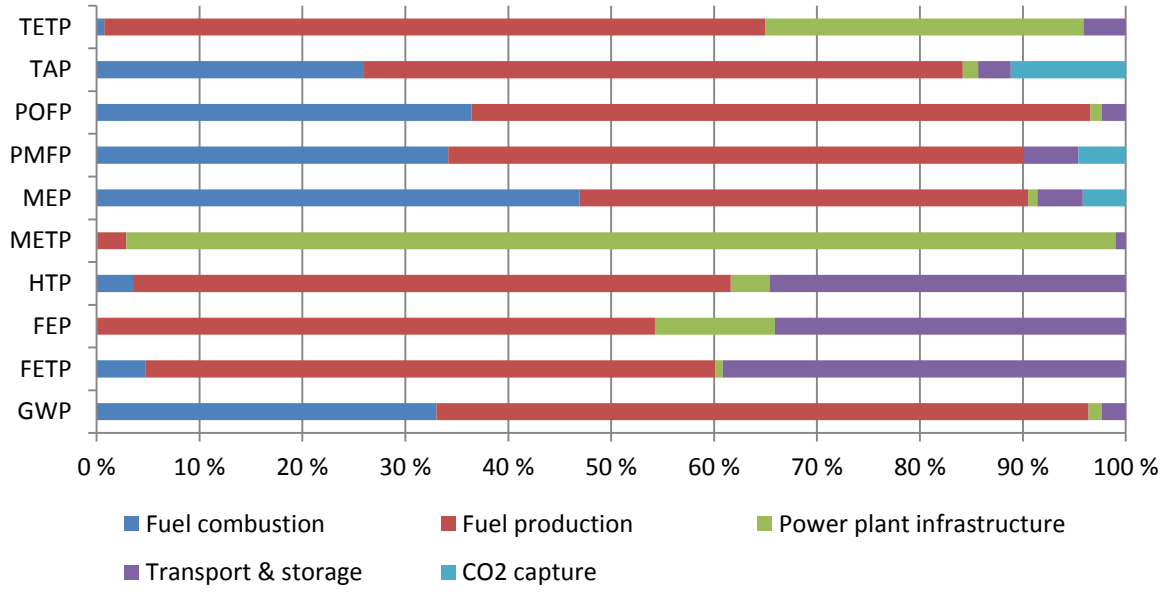

Figure 11 - Contribution analysis with normalized impact categories for the NGCC with CAP power plant, divided into foreground processes

The most noticeable results for the natural gas power plants (figure 9, 19 and 11) is the dominance of the power plant infrastructure in METP while this process is small to negligible for the other impact categories. Power plant infrastructure stands for 96 – 97% of the total METP

impacts for all the gas-fired power plants and 0% of the PMFP category. The largest background processes with the highest contribution to METP in the power plant infrastructure is the production of electricity in the electricity mix by coal, the casting of metals and the construction itself. These background processes are also the main reason for the contribution by power plant infrastructure on the TETP category. The other impact categories are mainly dominated by the fuel production and fuel combustion processes. Another notable result is that fuel combustion has a negligible contribution to the FEP category, which is dominated by fuel production and transport & storage in the CCS cases. Transport and storage contribution can mainly be traced back to the transport pipeline. The main difference between the NGCC BAT and the two CCS options is the contribution by transport & storage especially to HTP, FEP and FETP. For the FETP category, the transport and storage process stands for about 39% for both CCS options while it stands for about 34% for HTP and FEP. For the NGCC power plant with CAP capture technology, one can clearly see the impact on TAP, PMFP and MEP of the ammonia slip connected to the CO_2 capture process. CO_2 capture contributes to 11% of TAP, 5% of PMFP and 4% of the total MEP in the NGCC plant with CAP capture technology. Overall, the distribution of the different foreground processes in the 10 impact categories for CAP and SEWGS technology is quite similar.

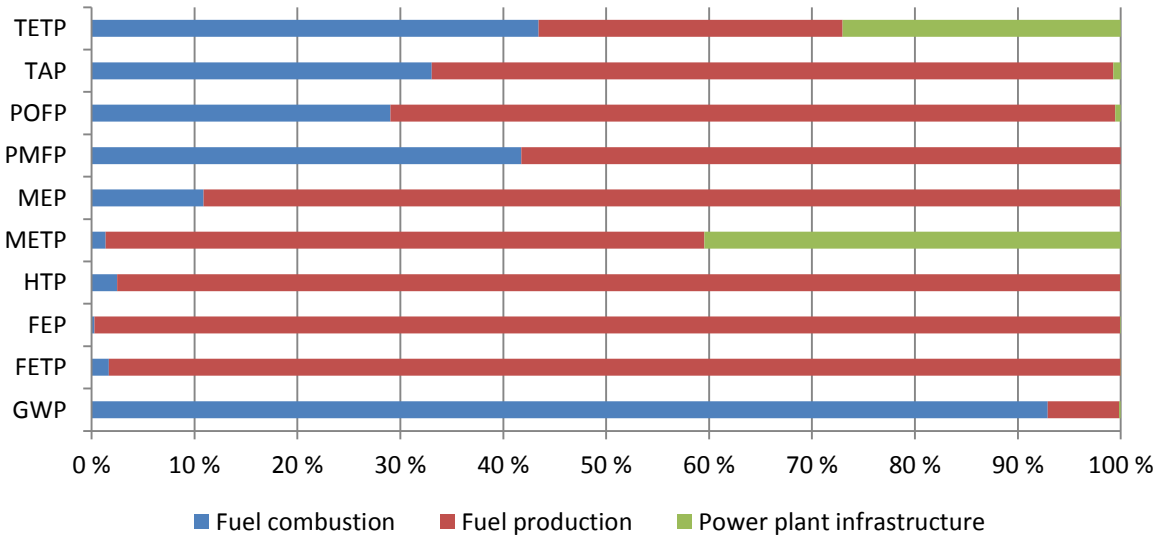

Figure 12 - Contribution analysis with relative impact categories for the IGCC BAT power plant, divided into foreground processes

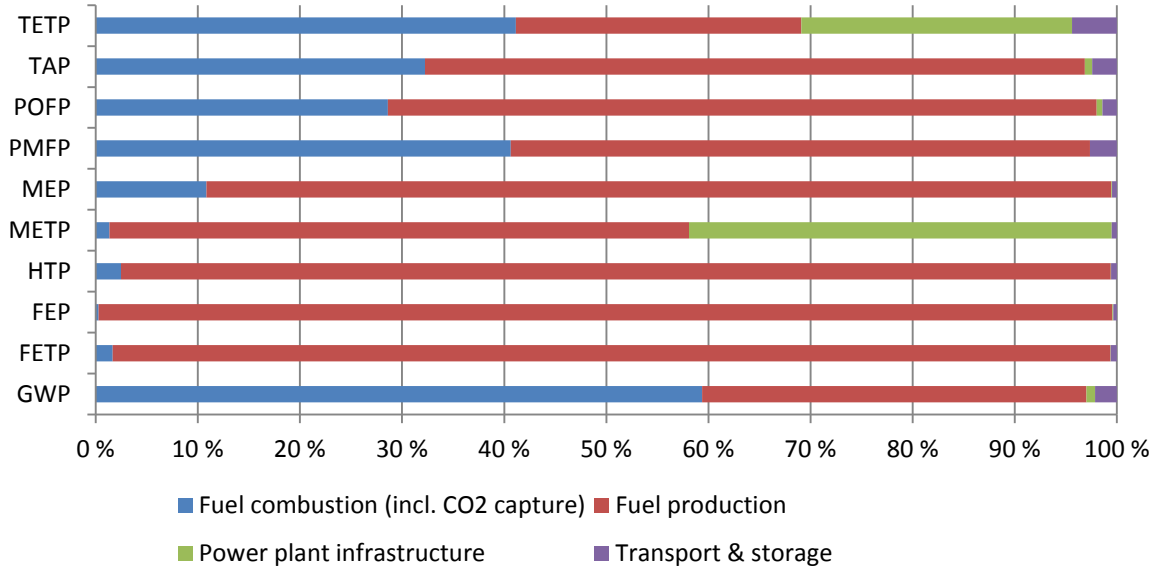

Figure 13 - Contribution analysis with relative impact categories for the IGCC with SEWGS power plant, divided into foreground processes

For the IGCC power plants (figure 12 and 13) there are far less impact from the power plant infrastructure than for the NGCC plants, but this is mainly because of the increased impact from fuel production and combustion. The impact categories with the biggest contribution from power plant infrastructure is the ecotoxicity categories, TETP and METP, where the contribution is about 27% for TETP and 41% for METP for both the IGGC and the IGCC + SEWGS power plant. This contribution comes mainly from the same background processes as for the NGCC plants. The contribution of the power plant infrastructure is more or less negligible for the other impact categories. Another interesting difference from the NGCC plants is the dominance of "fuel production" in HTP, FETP and FEP where there was a large contribution from "transport & storage" in the NGCC plants with CCS. The contribution of transport and storage in the SEWGS coal plant is more or less negligible compared to fuel production. The maximum contribution from transport and storage in the SEWGS plant is 3.7% contribution to total TETP. The background processes that contribute the most to HTP, FETP and FEP are the disposal of spoil and tailings from the coal mining. These processes emit manganese and nickel which contributes to FETP, phosphate which contribute to FEP and manganese also contributes to HTP. Overall, the distribution of the contributions from the foreground processes is quite similar for both IGCC plants as well.

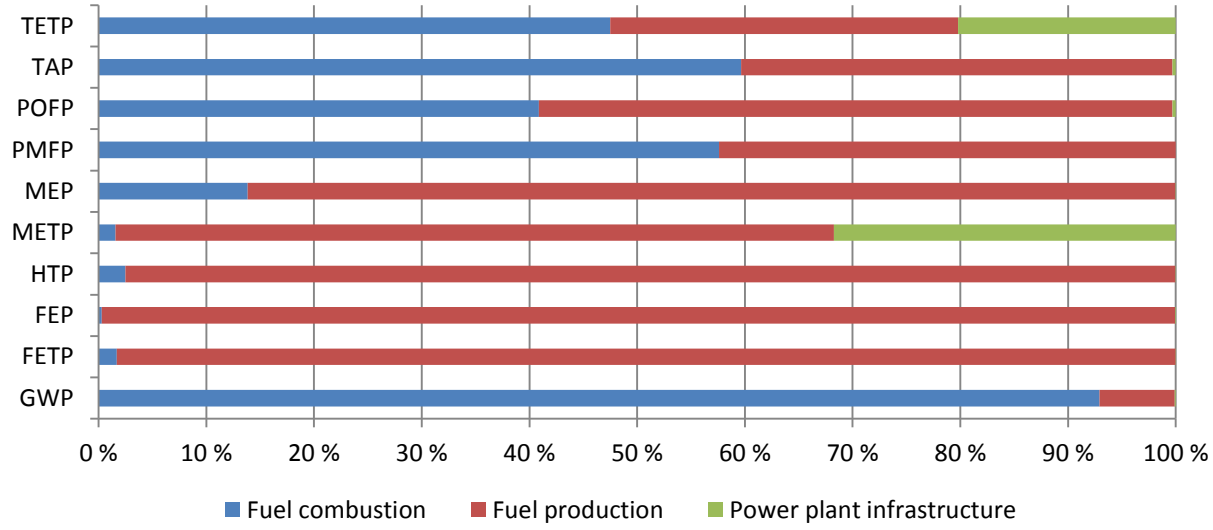

Figure 14 - Contribution analysis with relative impact categories for the USC BAT power plant, divided into foreground processes

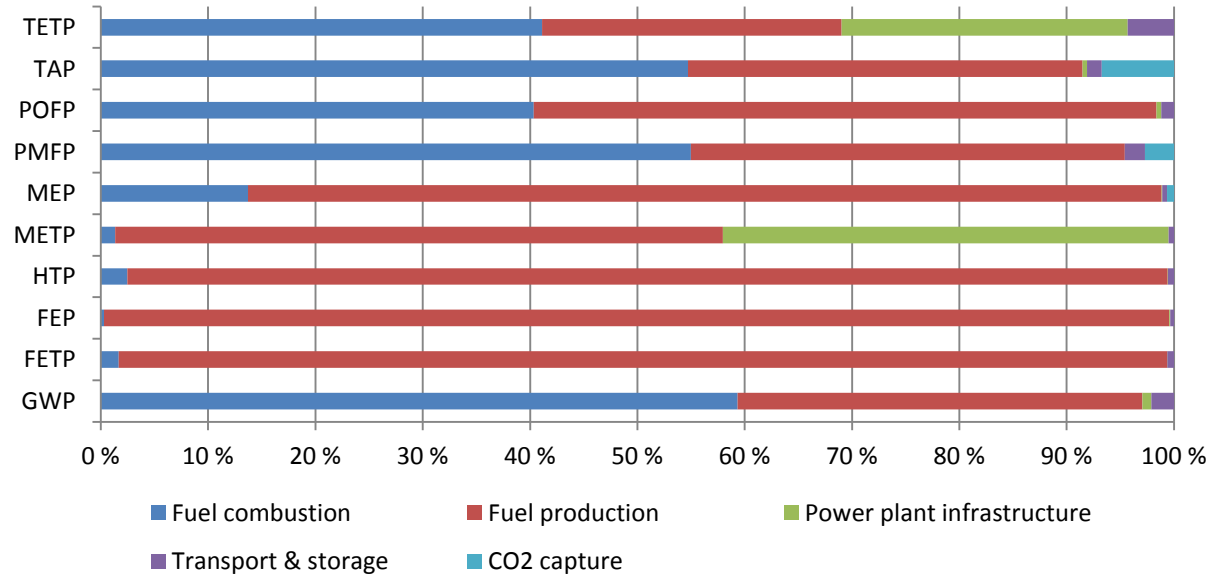

Figure 15 - Contribution analysis with relative impact categories for the USC with CAP power plant, divided into foreground processes

For the USC power plants (figure 14 and 15) there are also large similarities in contribution distribution between the CAP plant and the power plant without capture. One can, however, see a change where the ammonia slip is illustrated by "CO_2 capture". CO_2 capture contributes to 6.8% of total TAP, 2.7% of PMFP and 0.7% of MEP in the USC + CAP power plant. The results for

power plant infrastructure are more or less similar to the distribution in the IGCC power plants, with high contribution in TETP and METP and negligible in the other impact categories. The dominance of fuel production in the HTP, FEP and FETP categories comes from the same processes in coal mining as the IGCC plants.

For all seven power plants, there is also a notable change in GWP from the plants without CCS to the plants with CCS. The contribution from fuel combustion goes drastically down while the contribution from fuel production goes up. This is due to the aggregation of CO_2 capture into the fuel combustion process for the GWP category only. An area of possible improvement can be the disposal of spoil and tailings from the coal mining which leads to increases in FETP, FEP and HTP in the coal power plants.

4.3 Sensitivity analysis

In addition to the results, there may be an interest to see what happens when important performance parameters of the power plants change. This chapter will present a sensitivity analysis of changing energy penalties' influence on the GWP category. There will also be presented the best- and worst case scenarios for the CCS alternatives, including change in energy penalty, capture rate and sorbent for SEWGS plants and amount of ammonia slip for CAP plants. Table 4 summarizes the ranges of performance parameters for the seven power plants found in literature and shows that only SEWGS plants has changes in capture rate and that the NGCC + CAP plant only has changes in ammonia slip in literature.

Table 4 - Ranges in key performance parameters in literature

Parameters	CO2 capture	Net efficiency	Energy penalty	Ammonia slip [a]	Source
Unit	%	%	%	kg NH3/CO2 cap	
IGCC BAT	-	44,1	-	-	(IEA, 2008)
IGCC + SEWGS	90 – 98	35,6 – 36,3	7,8 – 8,5	-	Gazzani et al. (2013a)
USC BAT	-	43,4	-	-	(IEA, 2008)
USC + CAP	90	32,2 – 35,4	8 – 11,2	4,81E-5 – 2,25E-4	(Valenti et al., 2011), (Valenti et al., 2012), (Versteeg and Rubin, 2011), (Jilvero et al., 2012), (Zhao et al., 2013) ,(Koornneef et al., 2010)
NGCC BAT	-	58,1	-	-	(IEA, 2008)
NGCC + SEWGS	90 – 98	50,5 – 50,9	7,2 – 7,6	-	(Gazzani et al., 2013b)
NGCC + CAP	90	51,2	6,9	5,48E-5 – 1,69E-4	(Versteeg, 2012), (Koornneef et al., 2010)

[a] Calculated from 10 ppm (Versteeg and Rubin, 2011) and NH_3 emission profile in Koornneef et al. (2010)

Figure 16 and figure 17 illustrates how the emissions of CO_2-equivalents change with changing energy penalty. The other performance parameters will stay as shown in table 1. As shown in figure 16, the emissions of CO_2-equivalents will stay linear for both NGCC plants with CCS and the SEWGS capture alternative will stay as the highest emitting option with varying energy penalty. An increase of 1% in energy penalty will lead to an increase in GWP of about 2% for both capture alternatives. Since there are no variations of energy penalty in SEWGS + CAP plants in literature, the same range as for NGCC + SEWGS has been chosen for simplicity. These illustrations will be a help in understanding how sensitive a power plant and its emissions are to a higher energy penalty. This may also point out the importance on working towards lower energy penalties in different CCS technologies.

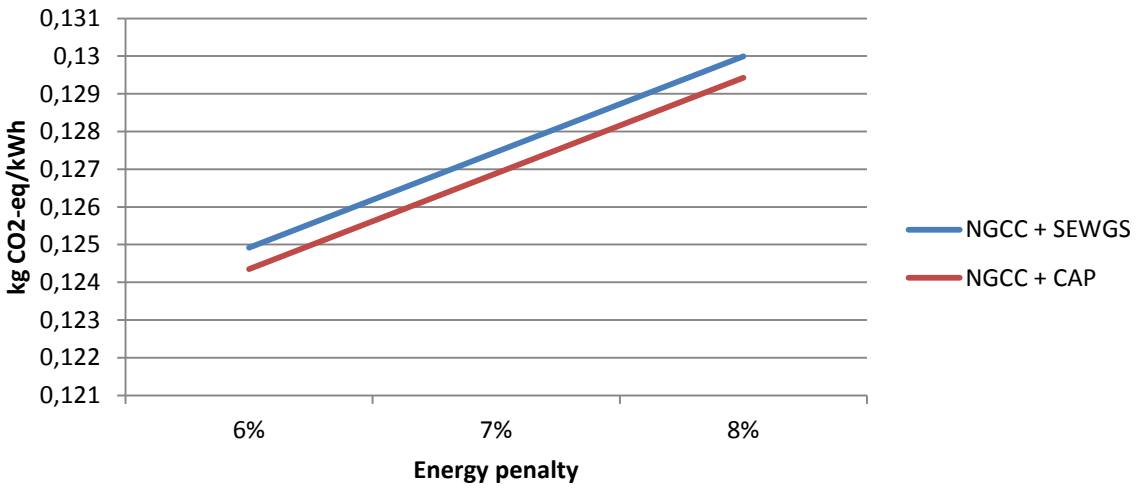

Figure 16 - GWP scores for the NGCC plants with change in energy penalty

Figure 17 illustrates how the roles change for the coal power plants compared to the NGCC power plants. For the coal power plants, the USC + CAP power plant stays as the highest emitter of CO_2-equivalents with varying energy penalty. An increase of 1% in energy penalty will lead to an increase in GWP of about 3% for both capture alternatives. The range of energy penalty in a USC + CAP plant also ranges higher than that of the IGCC + SEWGS power plant and can therefore be seen as the least ideal option of the two power plants when it comes to the GWP impact category. The linearity of the results in Figure 16 and Figure 17 is a natural and expected result of the increased need for fuel combustion with increased energy penalty.

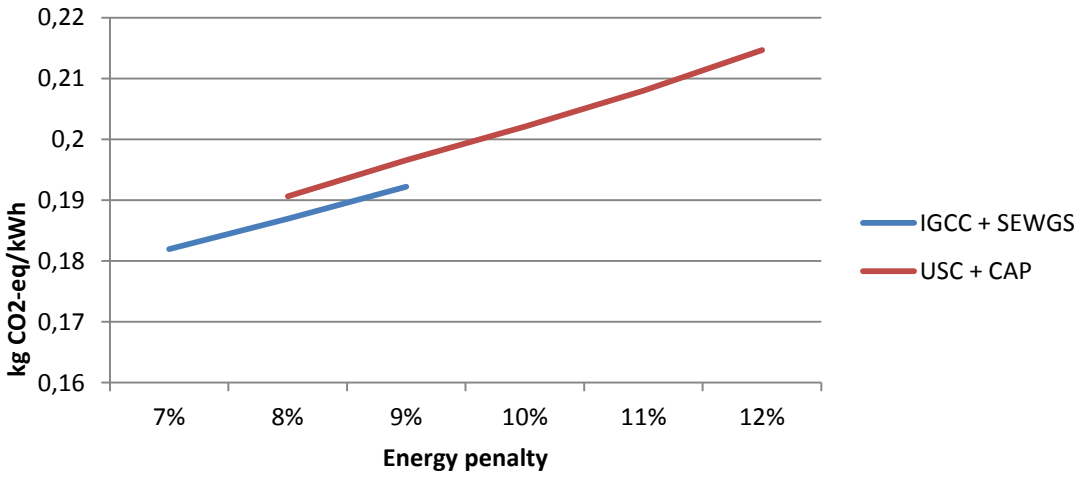

Figure 17 - GWP scores for the coal-fired plants with change in energy penalty

4.4 Best and worst case scenarios

The best and worst case scenarios for the power plants with CCS will include the ranges of performance values presented in table 4, including the new improved sorbent for the SEWGS technology mentioned in chapter 3.3.1. An improved sorbent will influence the energy penalty of the power plant. The columns in figure 18 and 19 represent the results with the performance parameters as presented in table 1 while the black error bars represent the ranges as presented in table 4. The results are presented relative to the coal or gas plant without CO_2 capture and the results for the no capture plant is marked with a line at 100%.

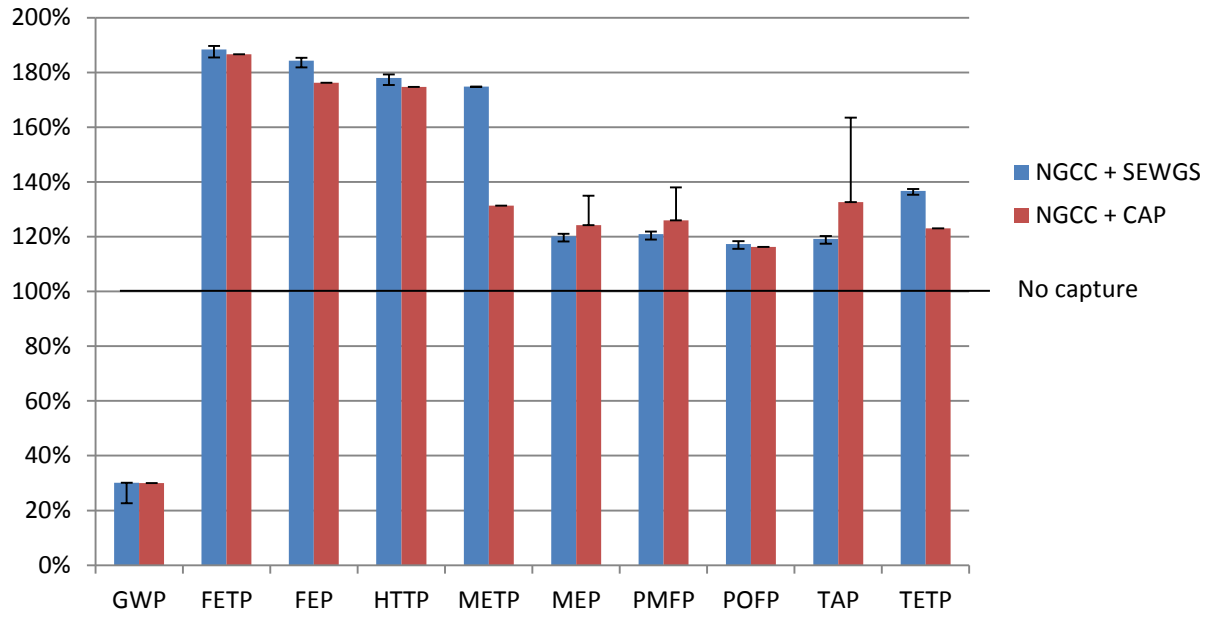

Figure 18 - Best and worst case results for the NGCC power plants

The results for the NGCC power plants in Figure 18 shows that there are small variations in the impact categories for the CAP capture alternative, except for MEP, PMFP and especially TAP. The variations in the other impact categories can be considered as negligible. The represented values (bars) are also the best case values for the USC + CAP power plant and the worst case scenarios for MEP, PMFP and TAP is due to the amount of ammonia slip. The bars present an ammonia slip of 10 ppm, while the error bars show the ammonia slip presented by Koornneef et al. (2010). The best to worst case difference is 10.8% for MEP, 12.1% for PMFP and 30.9% for TAP relative to the plant without capture.

When it comes to the NGCC power plant with SEWGS capture technology, the represented values is somewhere in the middle of the best and worst case results. The largest difference is in the GWP category where the worst case is the represented value and the best case is 7.4% lower relative to the NGCC plant without capture. This difference in GWP is due to a higher capture rate (98%) in the best case scenario. The difference between best and worst case scenarios in the other impact categories lies between 0.1 to 4.3% relative to the NGCC plant without capture. This means that the trade-offs of SEWGS will not be considerably larger as the capture rate rises, as one might think at first, since a higher capture rate also usually gives a higher energy penalty.

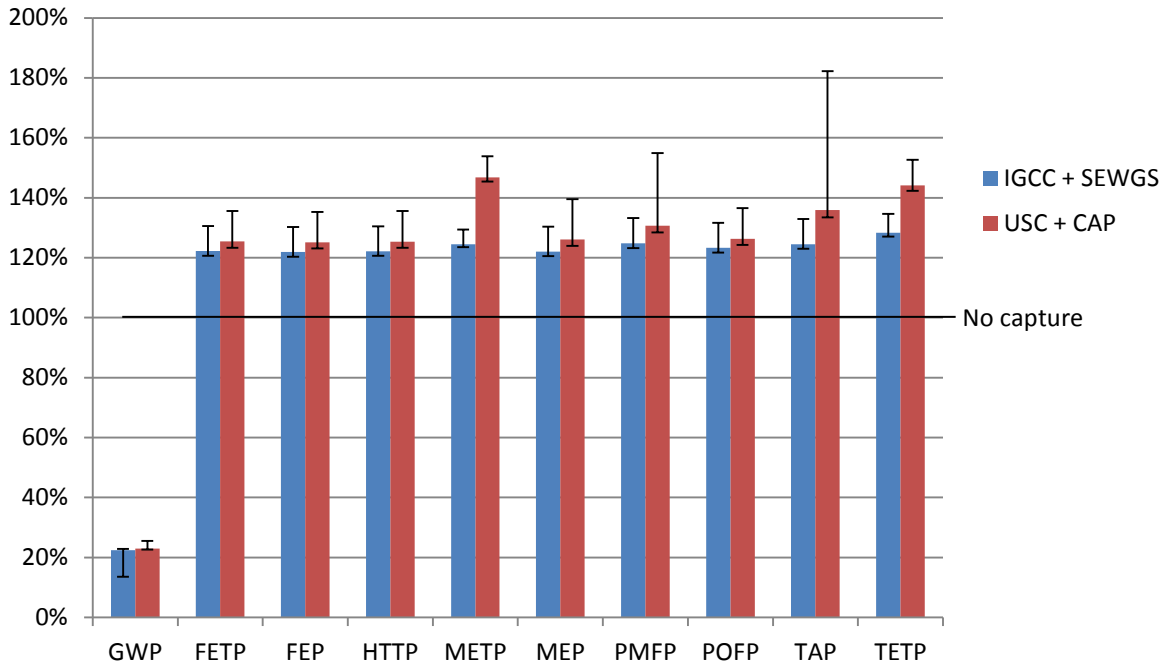

Figure 19 - Best and worst case results for the coal-fired power plants

For the CAP capture alternative when it comes to the coal-fired power plants, the largest effect of the best case scenario is also to be found at the MEP, PMFP and TAP impact categories, similar to the NGCC + CAP plant. This is also mainly due to the variation in ammonia slip parameters together with the energy penalty. The highest point in the error bars for these three impact categories represent both the highest energy penalty and highest ammonia slip value mentioned in literature. For the USC + CAP plant the difference from the represented value to the best case scenario is 13.4% for MEP, 24.3% for PMFP and 46.4% for TAP, relative to the USC plant

without capture. The other impact categories varies with about 12% between best and worst case scenario.

When it comes to the IGCC plant with SEWGS capture technology, the differences between the best and worst case scenario are quite similar for all impact categories. The most notable result is the best case scenario for GWP with an improvement possibility of 8.9% which is, similar to the NGCC + SEWGS plant, due to a possible capture rate of 98%. Overall, the difference between the best and worst case scenarios is about 10%, relative to IGCC without capture, for all impact categories. This means a higher trade-off for the coal power plants compared to the NGCC plants when it comes to increasing the capture rate.

4.5 Comparative analysis

Figure 20 and Figure 21 shows the environmental performance of the two novel capture technologies, CAP and SEWGS, together with the more studied technologies, oxyfuel combustion capture and post-combustion capture with monoethanolamine (MEA). The values for the oxyfuel capture is gathered from earlier work of the author (Bøe, 2012) and the values for the MEA plant is gathered from Wangen (2012). It is important to note that the infrastructure of the oxyfuel plant and the MEA plant is not modeled by tiered hybrid analysis. This will mainly show in the ecotoxicity categories (METP and TETP). There have also been made some updates in the emission profile of the oxyfuel plants to have a "fair" as possible comparison. A short process description of the MEA and oxyfuel plant can be found in chapter 3.7. Figure 20 and figure 21 shows, as in figure 7 and figure 8, the impact scores for each capture alternative relative to the highest scoring alternative for each impact category.

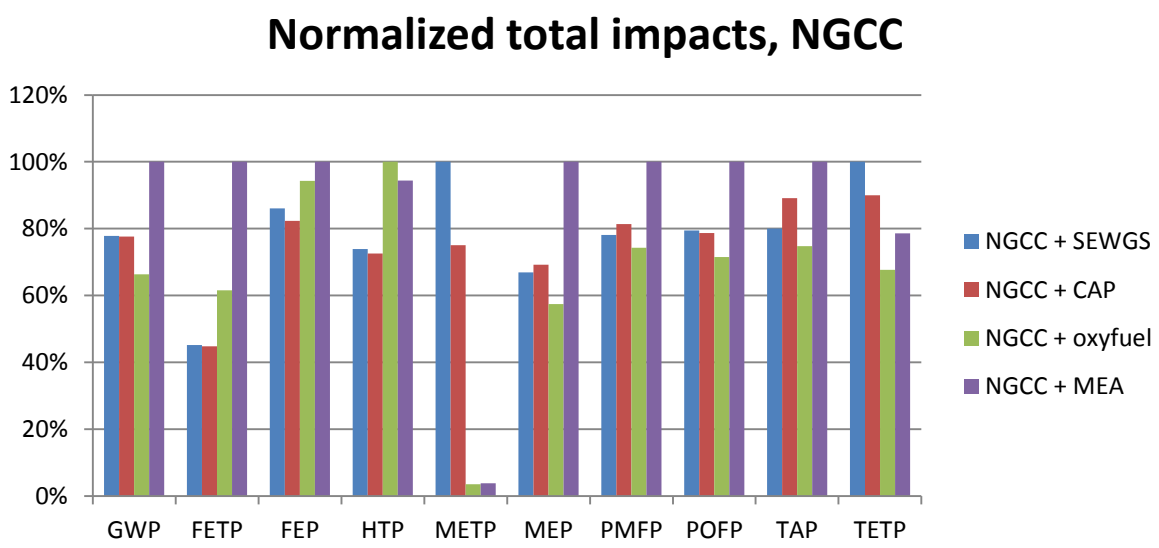

Figure 20 – Normalized benchmarking between CAP, SEWGS, Oxyfuel and MEA capture technologies for NGCC power plants

As shown in Figure 20, the results from the NGCC plants with CAP and SEWGS are comparable to the results of the oxyfuel and MEA plants without too large deviations. The largest difference between this study and oxyfuel and MEA can be found in the METP category which, as mentioned earlier, is mainly due to the power plant infrastructure from the tiered hybrid when it comes to the CAP and SEWGS plants. Figure 20 also shows that NGCC with SEWGS or CAP capture technology scores the highest in the ecotoxicity categories only, which could mean that these two novel capture technologies can compete with the more studied technologies when it comes to environmental performance. The capture alternative with MEA have the highest scores on most of the impact categories and can, in addition to have the highest GWP results, be said to have the most trade-offs of CO_2 capture. Oxyfuel combustion capture, on the other hand, scores the lowest in all impact categories with the exception of FETP, FEP and HTP. This could mean that oxyfuel is the better option of these four capture technologies in terms of environmental performance in NGCC plants, especially for its low GWP results for.

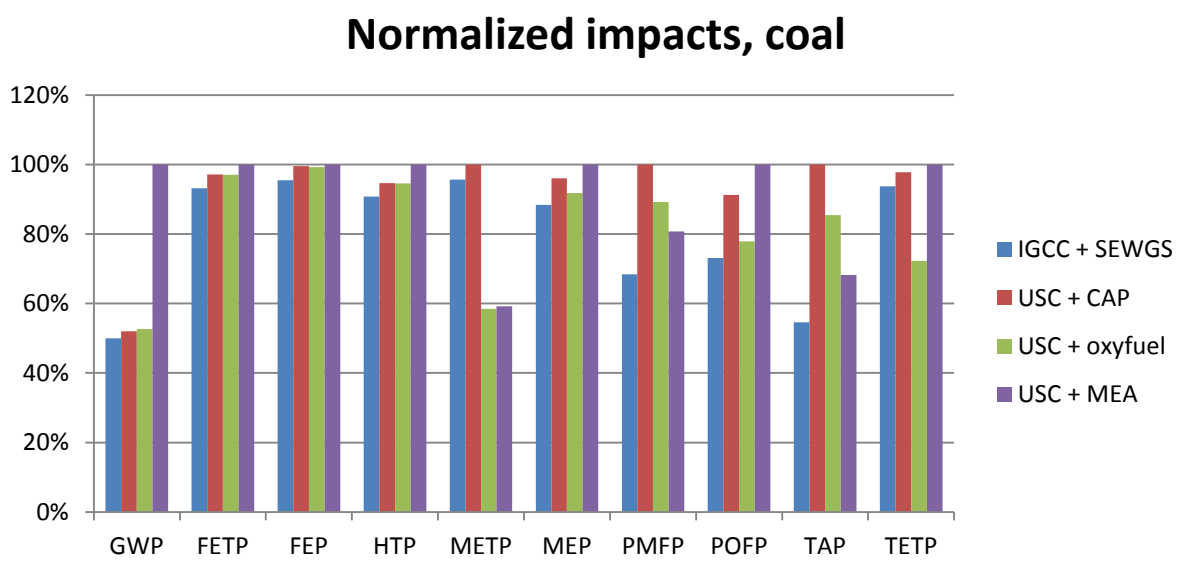

Figure 21 – Normalized benchmarking between CAP, SEWGS. Oxyfuel and MEA capture technologies for coal-fired power plants

For the coal power plants, Figure 21 shows that the USC plant with MEA capture technology has the highest scores in most impact categories for the coal power plants as well. The MEA plant can therefore be seen as the capture technology with the most and highest trade-offs here as well. The USC plant with CAP capture technology scores in the remaining impact categories and is therefore not the most preferable technology according to this figure either. The IGCC plant with SEWGS capture technology scores overall slightly lower than oxyfuel combustion capture in most impact categories. This can be influenced by the lower combustion emissions from an IGCC plant compared to a supercritical pulverized coal plant.

An IGCC plant should have a better environmental performance compared to a USC plant even without any of them having carbon capture and it might therefore be difficult to compare between the total impact scores of capture technologies with different base plants. Therefore, an overview of the increase/decrease in impact categories relative to their respective base case power plant may be useful in order to see the real changes in environmental performance when applying CCS to the power plants. Figure 22 and Figure 23 shows the increase or decrease in each impact category when going from a power plant without CCS to a power plant with the different capture technologies plus transport and storage. The values for the base case power plants are gathered

from their respective studies. The best capture technologies will have a high decrease in GWP and a low increase in the other impact categories.

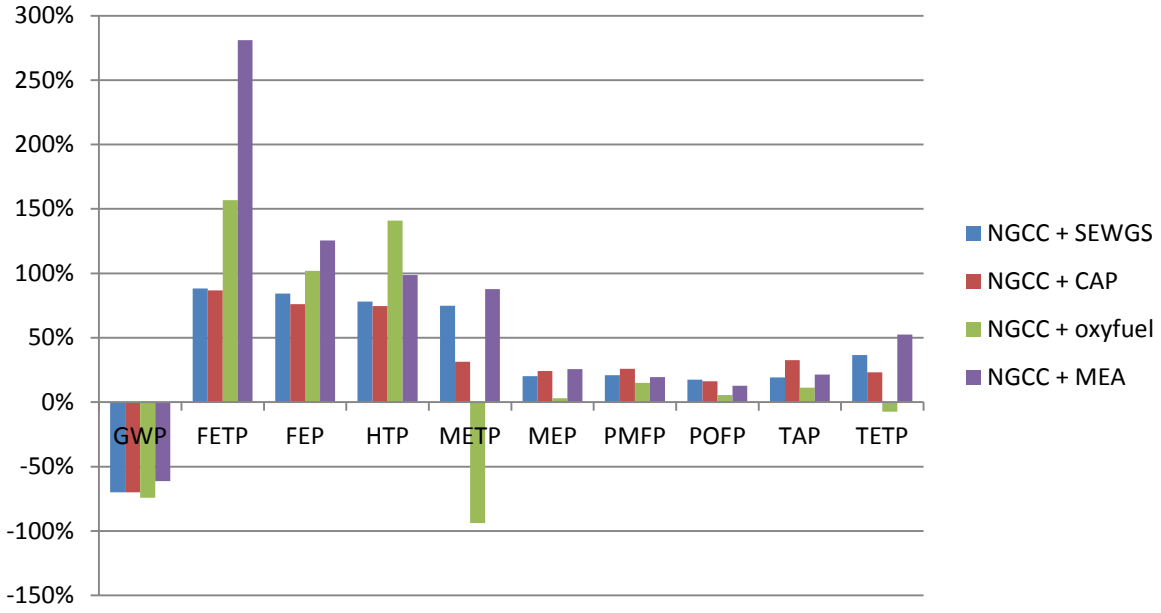

Figure 22 – NGCC plants comparison: Percent increase/decrease in impact categories relative to no capture NGCC

For the NGCC plants in Figure 22, the post-combustion capture with MEA alternative show to still have the highest values in five of the impact categories in addition to have the lowest decrease in GWP. The most worrying result is the increase in FETP of 281% for the MEA alternative. The oxyfuel combustion capture has the lowest increase in most impact categories in addition to have the largest decrease in GWP. One should, however, remember that the decrease in METP would not be as large as pictured in figure 22 if the oxyfuel option were modeled with the tiered hybrid, but the oxyfuel combustion capture continues to be the better option of the four. The main purpose of showing the percent change from base case was to determine the actual performance of the SEWGS plant compared to the other technologies, without the advantage of a more environmental advantageous base plant. The increase from no CCS to CCS for the CAP and SEWGS alternative shows to be quite similar for all impact categories, but the CAP alternative shows an overall lower increase for most impact categories. This means that the SEWGS capture technology does not look as good as first thought and that CAP technology is a slightly more preferable technology when it comes to the NGCC power plants.

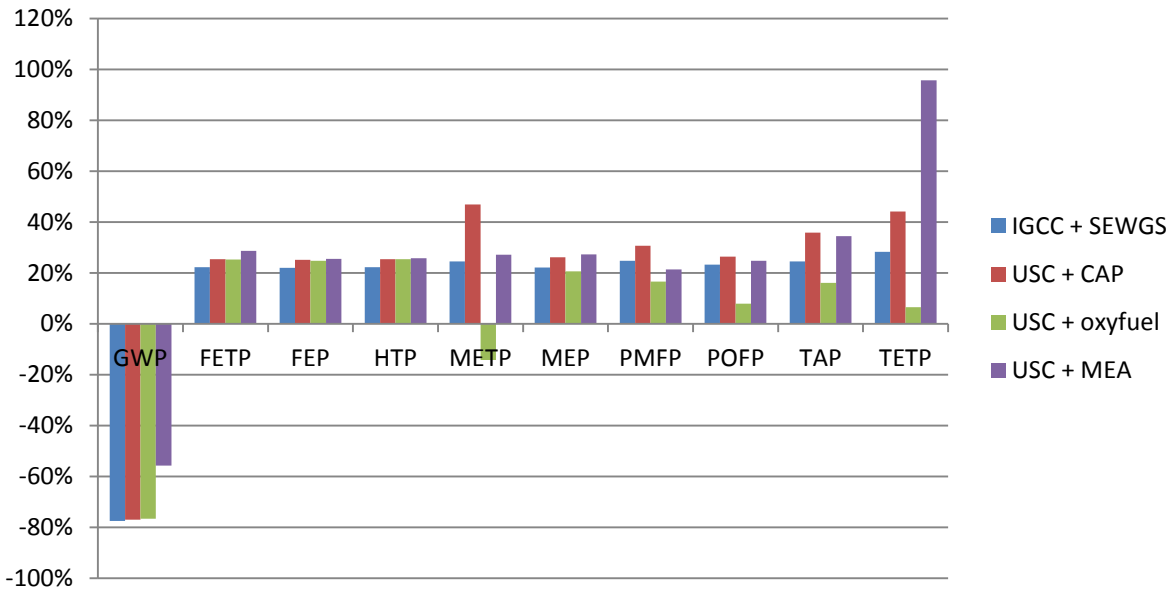

Figure 23 – Coal plants comparison: Percent increase/decrease in impact categories relative to no capture coal power plants

Figure 23 shows that the MEA capture has the lowest decrease in GWP for the coal power plants as well as having the highest increase in most of the other impact categories. This means that MEA continues to be the least preferable alternative for the coal power plants as well and makes the CAP alternative the most preferable post-combustion technology. SEWGS shows to be able to compete with the other three capture technologies and shows similar environmental performance to both oxyfuel and CAP. Since SEWGS show slightly lower increase than CAP, the SEWGS alternative is the better of the two technologies for coal power plants studied in this thesis. When considering both total values (figure 21) and percent increase (figure 23) one may, however, say that oxyfuel is the better option for the USC plants.

The results presented in figure 20, 22 and 23 disagrees with Wangen (2012) on CAP having overall higher environmental impacts compared to MEA capture technology.

5 Discussion

The goal of this study was to perform a life cycle assessment (LCA) of novel carbon capture technologies. This includes producing complete LCI results of the level of different impact categories and the environmental trade-offs of implementing carbon capture and storage (CCS) on power plants. The secondary goal was to compare the results to current and more studied capture technologies. This comparison is useful for deciding whether or not the novel capture technology could compete with the current technologies on the market.

This chapter will present to what extent the goal of this study was reached together with some of the main findings of the analyses. Also there will be given an overview of the main assumptions and the limitations of this study both with an internal view and an external focus on comparison to earlier studies on the subject. There will also be some suggestions to further work on this topic and CCS in general together with some suggestions for policy in the LCA and CCS area.

5.1 Goal Completion

An LCA has been done on the two novel carbon capture technologies, pre-combustion chilled ammonia process (CAP) and post-combustion sorption enhanced water-gas shift (SEWGS) for both natural gas- and coal-fired power plants. A tiered hybrid assessment was done to better model the power plant infrastructure. These analyses have also been done on the base cases which are gas and coal power plants without CCS. To better understand where in the power plants life cycle the emissions occur, a contribution analysis has been done to assign environmental impacts to the right foreground process. A sensitivity analysis was done to see how the GWP category changes with changes in energy penalty. There have been found varying performance parameters for both the CAP and SEWGS technologies in literature, therefore there have also been performed a best and worst case scenario analysis.

The chosen cases for comparison have been the post-combustion capture technology with monoethanolamine (MEA) and oxyfuel combustion capture.

For the natural gas power plants, the CAP capture alternative was found to be the better of the two capture technologies studied in this thesis when it comes to the total score of the different impact categories. The highest increase from base case NGCC to the CCS alternatives was for FETP, FEP and HTP due to the disposal of metals. For the coal power plants, the SEWGS option

was shown to be the capture alternative with the lowest total score on most impact categories. However, and IGCC plant will have the lowest impact scores compared to an USC plant in any case. In the comparison between the two novel technologies and oxyfuel combustion capture and post combustion with MEA, the oxyfuel had the lowest increase from base case for both NGCC power plants and coal-fired power plants. The MEA, on the other hand, had the highest. The CAP capture alternative is thereby the more preferable of the two post-combustion capture alternatives.

5.2 Key assumptions and limitations

In an LCA, one will often need to do some assumptions and gather information from a large amount of different sources which may lead to some uncertainties in the study. It is therefore important to map the different sources of uncertainties to evaluate a study's liability both internally and externally.

5.2.1 Internal evaluation

Data availability has been an area of uncertainty in this study especially since there have been no earlier life cycle assessments on power plants with the SEWGS capture technology and only one LCA found on the CAP technology. This makes a comparison to earlier results difficult. There have, however, been several technical and economic studies done on both CAP and SEWGS technology and the inputs for the LCA in this study have been adapted from these studies. When it comes to the NGCC plant with CAP technology, there was only one study found in literature which makes the study of best and worst case scenarios difficult and trust have to be put to only one source. This being said, the sources found were quite recent studies and the performance parameters used for input in this study should be as up to date as possible.

There will also be uncertainties connected to the tiered hybrid part of the analysis where the costs of the power plants were the basis for calculating the emissions from the power plant infrastructure. Basing the infrastructure of a power plant on its costs is an uncertainty in itself, but the tiered hybrid method ties these costs to emissions in a reasonable way. The costs chosen was the total direct plant cost (TDPC) as described in Manzolini et al. (2013b). The only power plant with a given TDPC in literature was the NGCC base case plant and the NGCC plant with SEWGS combustion capture. The TDPC for the other power plants were calculated by the method described in table 1 in Manzolini et al. (2013b) or by ratio of total capital requirement.

These assumptions could have some uncertainties, but not large enough to give noticeable impact on the results.

A source of inaccuracy in the comparative analysis is the fact that the subjects of comparison (oxyfuel and MEA) have not been modeled by the tiered hybrid method. Since the results of the tiered hybrid part of this study is noticeable in mainly METP and TETP, one can assume somewhat higher values for these impact categories for oxyfuel and MEA. This means that the oxyfuel combustion capture might not be the better capture option of the four or at least not as much better as shown in tables 20-23. When it comes to post-combustion by MEA, one can assume that the impact scores are even higher and the MEA option continues to be the least preferable option in an environmental perspective.

5.2.2 External evaluation

According to the study by Wangen (2012), the CAP capture alternative scores higher for most impact categories compared to the MEA alternative. This study claims the opposite, but agrees in some areas. The biggest difference between CAP and MEA in the Wangen-study is the TAP category where the CAP alternative is 80% higher than MEA for the NGCC plants and 81% higher for the coal power plant. In this study, the results imply that the TAP values for the CAP alternative is lower than that of MEA for the NGCC power plants, but agrees with Wangen (2012) when it comes to CAP being the highest scoring option for TAP in the coal power plants. Overall, this study does not correspond to the Wangen-study's claim of MEA being a better environmental choice compared to CAP, especially when it comes to the NGCC power plants. This is probably due to a higher energy penalty chosen for CAP in the Wangen-study, which can have large impacts on the emissions for the power plant.

This study agrees to a larger extent with the study by Jilvero et al. (2012) that claims that the CAP capture technology requires less energy compared to capture with MEA. This will also imply a lower energy penalty for CAP compared to MEA, which is also what the results in the comparative analysis in chapter 4.5 imply. The lower energy requirement for CAP is also one of the motivations for the development of the CAP technology.

The results for the SEWGS capture technology in this study has shown smaller trade-offs of CCS than the post-combustion with MEA technology for both gas-fired and coal-fired power plants.

This agrees with the claims by Manzolini et al. (2011) that SEWGS technology on an NGCC plant should have a lower energy penalty compared to an NGCC plant with MEA capture technology.

5.3 Implications for future LCA work

From this study we have seen how an LCA on this type of industry and processes can help map the environmental effects of its entire lifetime and supply chain. Small changes in key performance parameters may have large impacts on several impact categories and a reduction in one impact category does not necessarily mean a reduction in the other categories. To the contrary, this study has shown that a reduction in the GWP by CCS on a power plant means an increase in practically every other impact category measured in this study. Post-combustion capture by MEA is the most studied and most tested capture alternative evaluated in chapter 4.5, but were also shown to be the least preferable in an environmental perspective for both coal and natural gas plants. This shows the importance of an LCA analysis on these types of processes to make sure that the solution to one problem does not cause too high problems in another area.

It is however difficult to decide on what carbon capture technology the investments should lie, depending on whether or not the power plant in question is an already existing one or a power plant about to be built. Most of the new coal power plants being built are IGCC plants and most of the existing coal power plants are pulverized coal (PC) power plants. The capture technologies are specified to fit different types of power plants (e.g. SEWGS is designed to fit an IGCC plant) and it is as important to retrofit existing power plants with CCS as it is to implement it on new plants. LCAs on the world's power plant fleet and GWP reduction potentials by different types of CCS technologies should be performed to better understand how to implement and allocate the existing and novel capture technologies on the worlds planned and existing power plants.

Improvements in inventories used to model the infrastructure of the power plant should also be made. This will improve the accuracy of the LCA and thereby improve the liability of LCAs on these types of industry.

5.4 Relevant policy insights

According to IEA (2008) there is a need for high levels of innovation and investments to manage the progressive decarbonisation of the power generation sector needed to reach the goals for CO_2 emission reductions. They specify that for CCS, the research, development and demonstration (RD&D) needs to be directed towards reducing capture costs, improve overall system efficiencies and storage integrity and monitoring. An improved system efficiency will, as shown in this thesis, lead to less environmental trade-offs of the implementation of CCS. From an LCA practitioner's perspective, it is natural to include a higher focus on the environmental performance and LCA in research and development (R&D) as well. This implies in particular work on improving and updating inventories for emission profiles to improve the liability of LCAs. An increased focus on LCA in R&D is not something that should be exclusively for the power producing industries, but also in practically every other industry.

It has been claimed that the technologies with the greatest potential for energy saving and CO_2 reduction are also making the slowest progress due to lack in investments (IEA, 2012b). Full-scale demonstration projects are not receiving the necessary rates of investments and almost half of the new coal-fired plants are being built with inefficient technology (GCCSI, 2012d). Investors are given too little incentives to invest in new technologies such as CCS. It may be possible to encourage investments to CCS projects by introducing LCAs in the early stages in a project to map possible risks to the environment and comparing them to the alternatives. This may provide a safer outlook for a power plant with CCS in a longer time perspective. This study has shown that post-combustion capture by MEA, which is the technology assessed in this study which receives the highest investments, is also the least environmentally preferable. This may indicate that there needs to be shifting of investments towards the novel capture technologies instead. However, one cannot always wait for a better technology to be introduced. This describes the importance of investing more in the evaluation of a technology and not just the technology itself. LCA is an excellent way of evaluating a technology such as CCS and it seems natural to include this tool in a project. But in the end, it is the pay-off of an investment that is the biggest incentive for investors and the carbon price of today is still too low to make CCS cost-effective. This means that the cost of emitting CO_2 is lower than the cost of CO_2 capture ($ per t CO_2 emitted/captured). Now, higher cost CCS projects are dependent on strong government support to match the low carbon prices which describes the need for carbon pricing arrangements.

The GCCSI points out that the main challenge for governments when it comes to CCS, is to ensure that CCS is treated equally with other novel clean-energy technologies. This implies establishing international carbon pricing arrangements such as carbon tax and trading schemes to hold CCS a competitive option for decreasing greenhouse gas emissions. If the price/tax of CO_2 emissions continues to be low, the IEA fears that CCS will be limited to EOR only (IEA, 2008). Public awareness is also a barrier that the deployment of CCS meets. A continuing focus on CCS and its contribution to GHG reduction from the government's side can help build trust between a developer and the stakeholders. It is important to focus on the environmental aspects as well as the financial aspects of implementing CCS. To gain the public's trust when it comes to environmental concerns, it may be helpful to have LCAs to refer to, to insure that there will be no problem-shifting connected to projects such as CCS deployment. This study has shown that LCA is a good tool for mapping the environmental impacts that can occur when trying to mitigate another. An LCA can help to balance the costs of large projects against its environmental gain and can be a good tool for policymakers when making investments for environmental purposes.

6 Conclusion

This study has shown how CCS has positive effects on the mitigation of CO_2 emissions from fossil fueled power plants and at the same time leads to an increase in other environmental impacts. This study has also shown how suitable the LCA approach is to uncover such trade-offs. The novel carbon capture technologies studied in this thesis are the chilled ammonia process (CAP) and sorption-enhanced water gas shift (SEWGS).

For the natural gas-fired power plants, the CAP capture alternative was shown to be the most preferable option due to the lowest total scores in the bulk of the relevant impact categories. Both capture technologies showed, however, a decrease in the global warming potential (GWP) of 70%. The highest increase in an impact category from base case to a CCS alternative was an 87% increase in freshwater ecotoxicity potential (FETP) for the CAP alternative and 88% for the SEWGS alternative. For the coal-fired power plants it was the SEWGS capture alternative that was shown to be the most preferable option. The SEWGS alternative showed a decrease in GWP of 78% while the CAP alternative had a decrease of 77%. The highest increase in an impact category from base case to a CCS alternative was 47% increase in marine ecotoxicity potential (METP) for the CAP alternative and a 28% increase in TETP for the SEWGS alternative.

When including the value ranges of the key parameters in the systems for the best- and worst case scenarios, the SEWGS alternative showed a capability of reducing the GWP even more without significant increases in the other impact categories. The CAP capture alternative, on the other hand, showed a high possible increase in terrestrial acidification potential (TAP) in particular. This increase is due to a possibility of higher ammonia emissions from this capture technology.

In the comparative analysis between these two novel capture technologies and the more explored post-combustion capture by MEA and oxyfuel combustion capture, the MEA option were shown to be the least environmental preferable. In particular because of the lower decrease in GWP and an entire 281% increase in FETP for the natural gas plant. This was the case for both the coal-fired and natural gas- fired power plants. This may imply a need for shifting of investments towards the novel capture technologies instead of the MEA capture alternative. The oxyfuel combustion capture, on the other hand, was shown to be the most preferable of the four capture alternatives. This is mainly due to its decrease in the METP category.

This thesis has also pointed out how an LCA can contribute to the evaluation of a new technology and shown the importance of including an LCA into such projects. The inclusion of LCA can help balance the cost of the technology against the environmental gain in the best way currently available.

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Appendices

Appendix 1: Detailed cost tables

Table A 1 - Cost table for the SEWGS plants and their base case plants

Cost in M€ (2008)	SEWGS plants			
Parameter	**NGCC BAT[a]**	**NGCC + SEWGS[a]**	**IGCC BAT**	**IGCC + SEWGS**
Coal handling			28,8	31,4
Gasifier			94,4	102,8
LTHR			6,4	6,9
Cooling			37,5	41,2
ASU			29,6	32,4
Ash removal			10,1	10,9
AGR & gas cleaning			16,6	4,4
Water treatment			11,2	12,2
WGSR				2,9
Nitrogen compressor			11,3	6,9
SEWGS expanders				14,3
FGD/catalytic combustion				7,5
Claus			8,4	
Air blower		6,2		
CO2 + Steam exp.		19,7		
Desulfurizer		2,5		
GHR-ATR/ATR		27,7		
HTS		6,4		
CO2 compressor		22,8		19,6
SEWGS		69,6		56,8
Gas turbine	98,8	99,2	50,4	51,1
HRSG	45,7	52,1	36,4	36,5
Steam turbine	43,2	37,8	33,4	27,2
Heat rejection	49,4	55,1		
Heat exchangers	0,3	5,9		
BOP	0,1	1,8		
TEC	237,5	406,8	374,5[c]	465[c]
TIC	161,5	295,3	254,7[c]	337,5[c]
TDPC	399	702,1	629,2[c]	802,5[c]

[a] Gathered from Manzolini et al. (2013b), [b] Gathered from Manzolini et al. (2013a), [c] Ratio-estimated from Manzolini et al. (2013b)

Table A 2 - Cost table for the CAP plants

Cost in M€ (2008)	CAP plants		
Parameter	**NGCC + CAP[a]**	**USC BAT[b]**	**USC + CAP[b]**
DCCs	30,2		37,8
Flue gas blower	3,5		4,4
Heat exchangers	28,6		35,7
Heat exch. pumps	1,1		1,3
Cooling water circ. pumps	0,4		0,5
Chiller system	30,4		38,0
Absorber	58,5		73,2
Absorber pumps	1,3		1,7
Solvent circ. pumps	4,4		5,5
Solvent heater	1,2		1,5
Solvent cooler	1,2		1,5
CO2 Stripper	19,5		24,5
CO2 Stripper reboiler	7,5		9,3
Water wash	1,2		1,5
NH3 stripper	0,8		1,0
NH3 cleanup pumps	0,5		0,6
Steam extractor	1,8		2,3
Sorbent reclaimer	0,6		0,8
Sorbent processing	0,6		0,8
Drying and compr. unit	10,4		13,0
CO2 system	203,7		254,9
Fees and contingencies	81,5		81,5
Base plant	399,0[c]	467,3	615,9
Cooling tower		24,9	43,7
NOx control		17,4	23,5
TSP control		26,1	34,7
SO2 control		78,1	96,6
Tot. Capital requirement	684,2	613,8	1150,7
Ass. TEC[d]	302,4	260,2	487,9
Ass. TIC[d]	219,6	176,8	354,4
Ass. TDPC[d]	522,0	437,0	842,3

[a] Gathered from Versteeg and Rubin (2011) and adjusted from coal/gas ratio in Versteeg (2012), [b] Versteeg and Rubin (2011), [c] Manzolini et al. (2013b), [d] Ratio-estimated from Manzolini et al. (2013b)

Appendix 2: Simplified model of oxyfuel combustion capture

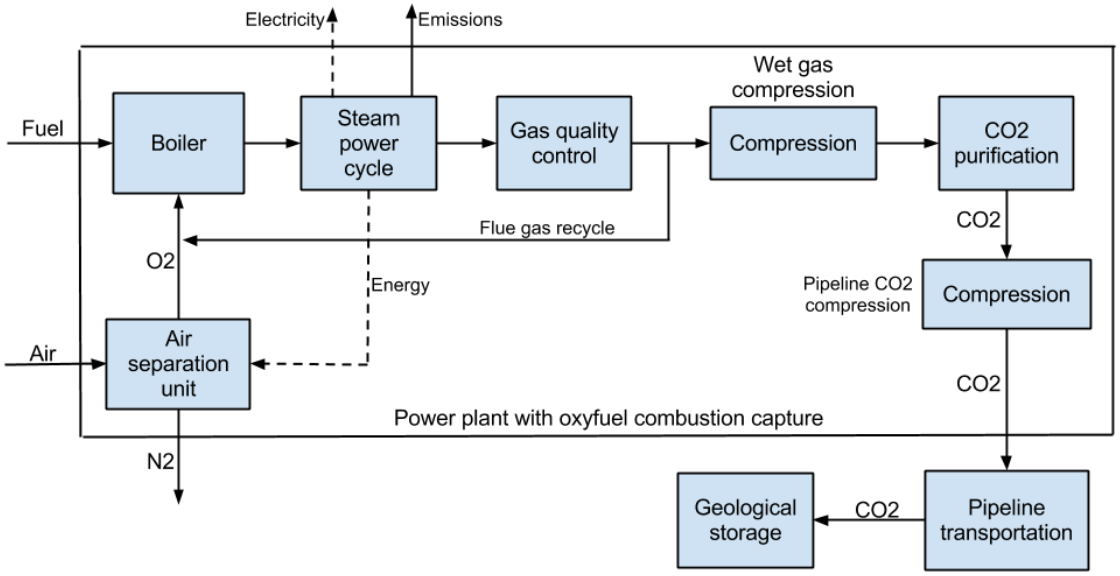

Figure A 1 – Simplified oxyfuel combustion capture (Bøe, 2012)

Appendix 3: LCIA results

Table A 3 - LCIA results for all 18 impact categories

Category	Unit	NGCC BAT	NGCC + SEWGS	NGCC + CAP	IGCC BAT	IGCC + SEWGS	USC BAT	USC + CAP
ALOP	m2a	8,48E-05	1,52E-04	1,51E-04	1,16E-02	1,41E-02	1,18E-02	1,47E-02
GWP	kg CO2	4,21E-01	1,27E-01	1,27E-01	8,27E-01	1,86E-01	8,40E-01	1,93E-01
FDP	kg oil	1,74E-01	1,99E-01	1,98E-01	2,19E-01	2,67E-01	2,23E-01	2,79E-01
FETP	kg 1,4-DCB	5,11E-05	9,62E-05	9,54E-05	6,39E-03	7,82E-03	6,50E-03	8,15E-03
FEP	kg P	2,35E-06	4,33E-06	4,14E-06	4,43E-04	5,40E-04	4,50E-04	5,64E-04
HTP	kg 1,4-DCB	2,45E-03	4,37E-03	4,29E-03	2,83E-01	3,46E-01	2,87E-01	3,60E-01
IRP_HE	kg U235	9,92E-04	1,69E-03	1,68E-03	7,06E-03	9,43E-03	7,17E-03	9,82E-03
METP	kg 1,4-DCB	4,43E-03	7,74E-03	5,81E-03	1,04E-02	1,30E-02	9,23E-03	1,36E-02
MEP	kg N	4,19E-05	5,03E-05	5,20E-05	5,38E-04	6,57E-04	5,66E-04	7,13E-04
MDP	kg Fe	1,18E-03	2,24E-03	2,22E-03	2,25E-03	3,64E-03	2,28E-03	3,78E-03
NLTP	m2	9,30E-05	1,10E-04	1,10E-04	4,22E-05	5,43E-05	4,29E-05	5,65E-05
ODP	kg CFC-11	6,05E-08	6,92E-08	6,88E-08	3,45E-09	4,38E-09	3,51E-09	4,56E-09
PMFP	kg PM10	1,07E-04	1,30E-04	1,35E-04	2,71E-04	3,38E-04	3,78E-04	4,94E-04
POFP	kg NMVOC	4,51E-04	5,30E-04	5,25E-04	8,37E-04	1,03E-03	1,02E-03	1,29E-03
TAP	kg SO2	3,21E-04	3,83E-04	4,26E-04	6,68E-04	8,32E-04	1,12E-03	1,52E-03
TETP	kg 1,4-DCB	9,78E-06	1,34E-05	1,20E-05	1,05E-05	1,35E-05	9,77E-06	1,41E-05
ULOP	m2a	1,50E-04	2,03E-04	2,02E-04	7,98E-03	9,74E-03	8,11E-03	1,02E-02
WDP	m3	1,34E-03	1,54E-03	1,52E-03	1,82E-03	2,23E-03	1,85E-03	2,32E-03

Appendix 4: Foreground values

Table A 4 - Calculated foreground input for all power plants, requirements for 1 kWh el. produced

	unit	NGCC BAT	NGCC + SEWGS	NGCC + CAP	IGCC BAT	IGCC + SEWGS	USC BAT	USC + CAP
Materials/fuel								
Compressor	p	-	7,13E-11	7,09E-11	-	7,59E-11	-	7,79E-11
Electricity	kWh	-	1,02E-03	1,01E-03	-	2,23E-03	-	2,29E-03
Injection well	p	-	1,43E-11	1,42E-11	-	9,49E-12	-	9,74E-12
Pipeline	p	-	1,43E-11	1,42E-11	-	9,49E-12	-	9,74E-12
Processes								
CO2 capture	kg	-	3,57E-01	3,54E-01	-	8,23E-01	-	8,58E-01
Fuel combustion	MJ	6,20E+00	7,07E+00	7,03E+00	8,16E+00	9,92E+00	8,30E+00	1,03E+01

Appendix 5: Inventories

Table A 5 - Inventory for coal and natural gas combustion

1 MJ fuel combustion			
	Unit	Hard Coal[a]	NGCC[b]
Materials/fuel			
chlorine, liquid	kg	1,00E-05	
water, decarbonised	kg	1,50E-01	2,00E-01
light fuel oil	kg	1,70E-05	
water, completely softened	kg	6,00E-03	6,00E-03
Natural gas	MJ		1,00E+00
Hard coal	kg	4,17E-02	
Processes			
disposal, hard coal ash	kg	2,63E-04	
disposal, residue from cooling tower	kg	5,00E-06	1,00E-06
NOx retained	kg	2,34E-04	
SOx retained	kg	6,16E-04	
transport	tkm	4,82E-04	
Waste heat			
Heat, waste/ air	MJ	5,47E-01	7,20E-01
Heat, waste/ water	MJ	1,44E-01	
Emissions to air			
Acetaldehyde	kg		8,00E-10
Acetic acid	kg		1,21E-07

Acenaphthene	kg		7,93E-13
Ammonia	kg	8,44E-07	
Antimony	kg	8,65E-11	
Arsenic	kg	1,29E-09	
Barium	kg	5,71E-09	
Benzo(a)pyrene	kg	2,00E-13	5,29E-13
Boron	kg	1,23E-07	
Bromine	kg	6,36E-08	
Cadmium	kg	5,76E-11	
Carbon dioxide, fossil	kg	9,22E-02	5,60E-02
Chromium	kg	6,56E-10	
Chromium VI	kg	8,11E-11	
Cobalt	kg	3,26E-10	
Copper	kg	1,65E-09	
Dinitrogen monoxide	kg	3,97E-06	1,00E-06
Dioxins, measured as 2,3,7,8-tetrachlorodibenzo-p-dioxin	kg	7,00E-15	2,90E-17
Formaldehyde	kg	5,80E-08	3,31E-08
Hydrogen chloride	kg	2,08E-06	
Hydrogen fluoride	kg	1,30E-06	
Iodine	kg	2,37E-08	
Lead	kg	5,53E-09	
Lead-210	kg	1,61E-06	
Manganese	kg	1,22E-09	
Mercury	kg	4,10E-09	3,00E-11
Molybdenum	kg	3,62E-10	
Nickel	kg	2,49E-09	
Nitrogen oxides[c]	kg	4,51E-05/2,81E-05	2,71E-05
PAH, polycyclic aromatic hydrocarbons	kg	1,00E-09	8,00E-09
Particulates, < 2.5 um	kg	4,73E-06	5,00E-07
Particulates, > 10 um[c]	kg	4,70E-06/3,43E-06	
Particulates, > 2.5 um, and < 10um	kg	5,56E-07	
Propionic acid	kg		1,60E-08
Polonium-210	kBq	2,95E-06	
Potassium-40	kBq	2,12E-06	
Radium-226	kBq	4,16E-07	
Radium-228	kBq	4,16E-07	
Radon-220	kBq	4,16E-07	
Radon-222	kBq	4,85E-04	
Selenium	kg	5,45E-09	
Strontium	kg	7,14E-10	
Sulfur dioxide[c]	kg	4,99E-05/7,84E-06	5,00E-07

Thorium-228	kBq	1,14E-07
Thorium-232	kBq	1,79E-07
Uranium-238	kBq	3,47E-07
Vanadium	kg	6,53E-10
VOC[c]	kg	1,21E-06/0
Zinc	kg	4,11E-09

[a] Based on *"Hard coal, burned in power plant/DE/MJ, #1432"*, [b] Based on *"natural gas, burned in power plant/UCTE/MJ, #2193"*, [c] USC power plant/IGCC power plant, gathered from Koornneef et al. (2010)

Table A 6 - Inventory for hard coal and gas production

1 MJ fuel production			
	Unit	**Hard Coal[a]**	**Natural gas[b]**
Materials/fuel			
electricity	kWh	7,20E-03	7,20E-05
hard coal, at mine	kg	1,00E+00	
natural gas, burned in industrial furnace >100kW	MJ		1,67E-03
natural gas, at long-distance pipeline/ RER/ Nm3	Nm3		2,72E-02
pipeline, natural gas	km		7,88E-10
Processes			
transport, lorry >16t	tkm	6,88E-03	
transport, barge	tkm	1,26E-01	
transport, freight	tkm	1,04E+00	
transport, natural gas, pipeline	tkm		9,63E-03
Waste heat			
Heat, waste/ air	MJ	2,59E-02	1,09E+07
Emissions to water			
Arsenic, ion/ water	kg	4,00E-11	
BOD5, Biological Oxygen Demand	kg	1,00E-07	
COD, Chemical Oxygen Demand	kg	1,00E-07	
Cadmium, ion	kg	1,00E-11	
Chloride	kg	2,00E-06	
Chromium, ion	kg	2,00E-10	
Copper, ion	kg	1,00E-09	
Dissolved solids	kg	1,00E-04	
Iron, ion	kg	2,00E-09	
Lead	kg	2,00E-10	
Manganese	kg	2,00E-07	
Nickel, ion	kg	4,00E-10	
Selenium	kg	2,00E-10	
Solids, inorganic	kg	1,00E-05	

Sulfate	kg	4,00E-05	
Tin, ion	kg	2,00E-10	
Emissions to air			
Butane	kg		3,10E-08
Carbon dioxide, fossil	kg		9,30E-08
Ethane	kg		4,03E-07
Heat, waste	MJ		2,59E-04
Mercury	kg		1,55E-14
Methane, fossil	kg		1,09E-05
NMVOC	kg		1,55E-08
Particulates, > 10 um	kg	2,00E-03	
Propane	kg		9,30E-08
Other			
Occupation, industrial area	m2a	1,00E-03	
Transformation, land	m2	1,00E-05	
Transformation, to industrial area	m2	1,00E-05	

[a] Based on *"hard coal supply mix, at regional storage/US/kg, #1460"*, [b] Based on *"natural gas, high pressure, at consumer/RER/MJ, #2089"*

Table A 7 - Inventory for the transport pipelines

Transport pipeline (500km)			
	Unit	**Hard Coal CCS[a,b]**	**Natural gas CCS[a,c]**
Materials/fuel			
concrete	m3	5,42E+04	3,61E+04
diesel	MJ	3,80E+08	2,53E+08
MG-silicon	kg	7,88E+02	5,25E+02
aluminium	kg	4,98E+05	3,32E+05
cast iron	kg	6,30E+02	4,20E+02
copper	kg	3,15E+01	2,10E+01
reinforcing steel	kg	9,08E+07	6,05E+07
zinc	kg	2,63E+04	1,75E+04
Processes			
drawing of pipes, steel	kg	9,08E+07	6,05E+07
transport, lorry >16t	tkm	1,14E+07	7,61E+06
transport, transoceanic freight ship	tkm	2,73E+07	1,82E+07
transport, freight	tkm	1,83E+07	1,22E+07
disposal, hazardous waste	kg	1,70E+05	1,13E+05
disposal, natural gas pipeline	kg	4,55E+07	3,03E+07
disposal, municipal solid waste	kg	1,89E+05	1,26E+05
Emissions to water			
Aluminium	kg	4,23E+04	2,82E+05

Copper, ion	kg	2,67E+01	1,78E+01
Iron, ion	kg	5,36E+02	3,57E+02
Silicon	kg	6,69E+02	4,46E+02
Titanium	kg	1,12E+02	7,44E+02
Zinc, ion	kg	2,24E+04	1,49E+04
Other			
Occupation, industrial area	m2a	8,25E+05	5,50E+05
Transformation, from industrial area	m2	8,25E+03	5,50E+03
Transformation, from sea and ocean	m2	1,65E+04	1,10E+04
Transformation, to industrial area	m2	1,65E+04	1,10E+04
Transformation, to sea and ocean	m2	8,25E+03	5,50E+03
Water, unspecified natural origin	m3	1,21E+05	8,05E+04

[a] Based on *"pipeline, natural gas, long distance, high capacity, offshore/GLO/I"*, [b] 30% inventory for 300mm diameter, [c] 20% inventory for 200mm diameter

Table A 8 - Inventory for the injection well

1 Injection well (1000m)[a]		
	Unit	**Well**
Materials/fuel		
barite	kg	2,70E+05
chemicals inorganic	kg	4,22E+04
chemicals organic	kg	9,05E+03
lubricating oil	kg	6,00E+04
bentonite	kg	2,00E+04
portland cement	kg	2,00E+05
lignite	kg	2,00E+02
reinforcing steel	kg	2,10E+05
natural gas	MJ	9,51E+05
diesel	MJ	1,80E+04
crude oil	kg	3,16E+04
natural gas	Nm3	4,10E+03
Processes		
transport, lorry >16t	tkm	8,11E+04
transport, freight	tkm	4,87E+05
disposal, hazardous waste	kg	4,00E+03
disposal, drilling waste	kg	3,00E+04
Emissions to water		
Water, salt	m3	1,73E+03
AOX	kg	4,78E-04
Arsenic	kg	3,78E+00

BOD5	kg	1,39E+04
Barite	kg	1,62E+05
COD	kg	1,39E+04
Cadmium	kg	3,02E-01
Carboxylic acids	kg	1,70E+03
Chloride	kg	1,30E+03
Chromium, ion	kg	1,72E+00
Copper, ion	kg	9,15E+00
DOC	kg	3,80E+03
Glutaraldehyde	kg	2,00E+01
Hydrocarbons, aromatic	kg	2,31E+02
Hydrocarbons, unspecified	kg	3,00E+03
Lead	kg	1,32E+01
Mercury	kg	2,79E-01
Nickel, ion	kg	3,44E-01
Nitrogen	kg	3,40E+00
Oils, unspecified	kg	4,39E+03
Phenol	kg	4,02E-04
Potassium, ion	kg	1,60E+02
Silicon	kg	3,06E-02
Sulfate	kg	6,00E+02
Suspended solids	kg	5,70E+05
TOC	kg	3,80E+03
Zinc, ion	kg	7,60E+03
Other		
Particulates, > 10 um	kg	1,48E+01
Occupation, dump site	m2a	2,60E+05
Transformation, from sea and ocean	m2	2,60E+05
Transformation, to dump site	m2	2,60E+05

[a] Based on "well for exploration and production, offshore/m/OCE"

1 kg CO2 capture			
	Unit	**Natural gas plants**	**Coal plants**
Emissions to air			
Carbon dioxide	kg	-1,00E+00	-1,00E+00
Ammonia[a]	kg	5,48E-05	4,89E-05

[a] For the plants with CAP capture, based on 10 ppm Versteeg and Rubin (2011)