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Life cycle assessment of a pulverized coal power plant with post-combustion capture, transport and storage of CO_2

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ARTICLE INFO

Article history:
Received 4 January 2008
Received in revised form
25 April 2008
Accepted 5 June 2008
Published on line 23 July 2008

Keywords:
Carbon capture and storage
Life cycle assessment
Environmental impacts

ABSTRACT

In this study the methodology of life cycle assessment has been used to assess the environmental impacts of three pulverized coal fired electricity supply chains with and without carbon capture and storage (CCS) on a cradle to grave basis. The chain with CCS comprises post-combustion CO_2 capture with monoethanolamine, compression, transport by pipeline and storage in a geological reservoir. The two reference chains represent sub-critical and state-of-the-art ultra supercritical pulverized coal fired electricity generation. For the three chains we have constructed a detailed greenhouse gas (GHG) balance, and disclosed environmental trade-offs and co-benefits due to CO_2 capture, transport and storage. Results show that, due to CCS, the GHG emissions per kWh are reduced substantially to 243 g/kWh. This is a reduction of 78 and 71% compared to the sub-critical and state-of-the-art power plant, respectively. The removal of CO_2 is partially offset by increased GHG emissions in up- and downstream processes, to a small extent (0.7 g/kWh) caused by the CCS infrastructure. An environmental co-benefit is expected following from the deeper reduction of hydrogen fluoride and hydrogen chloride emissions. Most notable environmental trade-offs are the increase in human toxicity, ozone layer depletion and fresh water ecotoxicity potential for which the CCS chain is outperformed by both other chains. The state-of-the-art power plant without CCS also shows a better score for the eutrophication, acidification and photochemical oxidation potential despite the deeper reduction of SO_x and NO_x in the CCS power plant. These reductions are offset by increased emissions in the life cycle due to the energy penalty and a factor five increase in NH_3 emissions.

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Abbreviations: ADP, abiotic depletion potential; AP, acidification potential; BAT, best available technology; CCS, CO_2 capture and storage; CO_2 equiv., carbon dioxide equivalents; EP, eutrophication potential; ESP, electrostatic precipitator; FGD, flue gas desulphurization; FWAETP, fresh water aquatic ecotoxicity potential; GHG, greenhouse gas; GWP, global warming potential; HSS, heat stable salt; HTP, human toxicity potential; HWI, hazardous waste incinerator; IPCC, intergovernmental panel on climate change; kt, kilo tonne (metric); LCA, life cycle assessment; LCI, life cycle inventory; LCIA, life cycle impacts assessment; MAETP, marine aquatic ecotoxicity potential; MEA, monoethanolamine; Mt, mega tonne (metric); ODP, ozone layer depletion potential; PAH, polycyclic aromatic hydrocarbons; PM, particulate matter; POP, photochemical oxidation potential; SCR, selective catalytic reduction; TEP, terrestrial ecotoxicity potential.

1750-5836/$ – see front matter
doi:10.1016/j.ijggc.2008.06.008

1. Introduction

Worldwide emissions of greenhouse gasses (GHG's) due to human activities are increasing and with it the concentration of GHG's in the atmosphere, resulting in climatic change. One of the options to mitigate GHG emissions is the implementation of CO_2 capture and storage (CCS) in the electricity supply system. The basic idea is that CO_2 is captured from power plants and sequestrated in the underground for many thousands of years.

However, the use of fossil fuels for electricity generation contributes not only to the greenhouse effect. It also has other environmental impacts, for instance: acidification, eutrophication and the depletion of natural resources.

In the IPCC[1] Special Report on CO_2 capture and storage it is already discussed that adding CO_2 capture to a pulverized coal fired power plant will result in a reduction of net generating efficiency and will proportionally increase[2]: emissions to air of substances not affected by the capture process, the use of resources (limestone and ammonia for respectively SO_x and NO_x reduction) and the formation of by-products (IPCC, 2005; p. 143). It is thus to be expected that the amount and composition of direct emissions to air, water and soil will change when a coal fired power plant will be equipped with CO_2 capture.

Other, more recent, publications have shown that a trade-off can be expected in the direct emissions of acidifying gasses (i.e. a deeper reduction of SO_2 and an increase of NO_x) from coal-fired power plants equipped with a CO_2 capture facility. Also, the consumption of resources, formation of wastes with adverse environmental impacts and by-products will increase (Davison, 2007; Thitakamol et al., 2007; Tzimas et al., 2007).

The IPCC also propounded the statement that upstream processes (fuel mining, processing and transport) are expected to have a relative small impact on the environment compared to the direct emissions and subsequent impacts from electricity generation. As far as we can ascertain this still has to be confirmed for power generation with post-combustion CO_2 capture, transport and storage.

Thus, we need a full chain perspective, from cradle to grave, to assess whether and to what extent the implementation of CCS will increase environmental impacts upstream or downstream of the power plant. Life cycle assessment (LCA) is a powerful tool to explore the GHG emission reduction potential of CCS and simultaneously disclose other relevant environmental impacts. For several CCS technologies a LCA or similar analysis has already been performed (see for instance (Carpentieri et al., 2005; Doctor et al., 2001; IEA GHG, 2006; Khoo and Tan, 2006a,b; Lombardi, 2001, 2003; Muramatsu and Iijima, 2002; Odeh and Cockerill, 2008; Raugei et al., 2005; Ruether et al., 2004; Viebahn et al., 2007)).

These studies vary considerably in the CCS technologies investigated, their goal and scope, and with that the results. Regarding the scope we can discern various orders of processes that can be included in the study: First-order processes, also referred to as foreground processes, represent the final production processes of the product or service. Environmental interventions due to these processes are labelled direct interventions, or, in the case of emissions, direct emissions. Second-order processes are those processes that produce and transport (half) products (or raw materials) and energy carriers required for the final production process. Finally, third-order processes are processes that provide the infrastructure, or capital goods, for processes in the life cycle. Environmental interventions allocated to second- and third-order processes, also labelled background processes, are often referred to as indirect interventions.

A review of the scope of LCA's performed on pulverized coal combustion including post-combustion CO_2 capture with the use of an amine based solvent is presented in Table 1.

The table depicts that the focus of the existing LCA's is often the determination of GHG emissions over the life cycle, although in one study not the full life cycle is taken into account. Thereby, environmental impacts not following from GHG emissions are often omitted. Furthermore, environmental interventions which arise from second- and third-order processes are not always included. When included, they are more then once estimated with the use of economic data, e.g. with economic Input/Output tables (Muramatsu and Iijima, 2002; Odeh and Cockerill, 2008; Viebahn et al., 2007).

Thus, far as we can ascertain, no complete LCA has been performed yet on the generation of electricity with a pulverized coal combustion power plant including post-combustion CO_2 capture, transport and storage. We hope to fill this gap by including in our study:

- The full life cycle including CO_2 transport and storage;
- The effect of implementing CO_2 capture on the direct emissions of the power plant, including additional waste formation and the reaction of flue gas constituents with the solvent;
- The assessment of the impact on environmental themes other then climate change when implementing CCS;
- All three orders of processes with the estimation of environmental interventions based on process data instead of the allocation of interventions with the use of economic data. This holds explicitly for the determination of environmental interventions due to the infrastructure for CO_2 capture, compression, transport and injection.

In this study we compare three pulverized coal fired electricity supply chains with and without post-combustion CO_2 capture, transport and storage. The power plants are assumed to be operated in the Netherlands. Through this analysis it is possible to construct a detailed greenhouse gas balance for the three chains and disclose environmental trade-offs and co-benefits due to CO_2 capture, transport and storage. The GHG balance is an essential result as it yields insights into the overall mitigation potential of CCS and with that a basis for the allocation of CO_2 credits to CO_2 storage projects. Furthermore, this study can be used to identify processes in the total life cycle that contribute heavily to the total of potential environmental impacts and to recommend further research to be undertaken in order to optimize the environmental profile of power generation with CCS.

[1] Intergovernmental panel on climate change.

[2] Compared to a PC power plant without CCS, on a kWh basis.

Table 1 – Scope of LCA's on coal fired power generation with amine based CO_2 capture

Study	Environmental interventions and impacts				Processes in life cycle			
	1st order (non-GHG)	2nd order	3rd order	Other impact categories	Capture	Compression	Transport	Storage
Viebahn et al. (2007)[a]	NR	✓	✓	✓	✓	✓	✓	✓
IEA GHG (2006)[b]	✓	✓	x	✓	✓	✓	x	x
Muramatsu and Iijima (2002)	x	✓[c]	✓[c]	x	✓	✓	✓	✓
Khoo and Tan (2006a)[d]	✓	NR[e]	NR	✓	✓	✓	✓	✓[f]
Khoo and Tan (2006b)[d]	✓	✓	NR	✓	✓	✓	✓	✓
Spath and Mann (2004)[g]	x	✓	✓[h]	x	✓	✓	✓	✓
Odeh and Cockerill (2008)[i]	✓	✓[c]	✓[c]	x	✓	✓	✓	✓

NR = not reported.

[a] Not considered [in this study] is that some flue gas emissions (SO_2, dust, HCl) will react with the solvent. Viebahn et al. (2007) performed a sensitivity analysis by varying methane emissions from coal mining and leakage from CO_2 storage. 3rd-order environmental interventions for storage are estimated with the use of cost data.

[b] Other direct emissions to the atmosphere are reported (O_2, H_2O, N_2, NO_x, SO_2 and MEA) as well as direct resource consumption and waste and by-product formation.

[c] Environmental interventions of 2nd and 3rd order processes are estimated with the use of input/output tables.

[d] The only emissions generated in this [chemical absorption] technique are those caused by energy use. Life cycle missions are derived from (Spath et al., 1999). Spath et al. (1999) performed a LCA for coal fired power generations without CCS.

[e] Only energy requirement for compression, transport and storage are reported.

[f] CO_2 is used for enhanced coal bed methane recovery and enhanced oil recovery.

[g] The study is focused on reporting the GHG and energy balance, furthermore "the emissions and energy consumption from the production and regeneration or disposal of the MEA were not included in this study".

[h] 3rd order processes are only included for the CO_2 pipeline.

[i] Focus in this study is on GHG emissions, though also other environmental interventions are mentioned: resource use (MEA, coal, limestone, NH_3 and water; emissions to air (SO_2, NO_x, NH_3, PM) emission of heavy metals to water. Odeh and Cockerill (2008) also performed a sensitivity analysis by varying: coal transport distance, use of wastes in construction, CO_2 pipeline length and CO_2 Capture efficiency.

The three cases that are assessed in this study are:

Case 1: the reference case and representing the average sub-critical pulverized coal fired power plant operating in the Netherlands in the year 2000 (see Table 2 for more details).

Case 2: a state-of-the-art ultra-supercritical pulverized coal fired power plant as proposed by several companies to be installed in the coming years (2011–2013) in the Netherlands (Arcadis, 2007; KEMA, 2006a,b). This power plant can be considered best available technology at present.

Case 3: a state-of-the-art coal fired power plant, equal to case 2, equipped with a post-combustion capture facility based on chemical absorption of CO_2 with monoethanolamine (MEA). CO_2 capture with the use of MEA is already widely applied in the chemical industry, though it is still in the pilot and demonstration phase for application in coal fired power plants. The technology is assumed to be available in the near future. The CCS chain further comprises compression, transport and underground storage of the CO_2.

Two reference cases, case 1 and case 2, have been chosen in this study. This is done to assess whether the implementation of post-combustion capture with transport and storage results in trade-offs and co-benefits compared to the current and future installed base of coal fired power plants in the Netherlands.

The geographical reference for all three cases is the Netherlands. This implies that were possible life cycle inventory data specific for the Netherlands were used. When this is not possible, data for Europe or worldwide average data are used.

The processes investigated in our assessment are depicted in Fig. 1. For each process the full life cycle is considered where possible. Consequently, also second- and third-order processes are included in the analysis. The primary process in the electricity generation chain is the combustion process for which primarily coal supply and the power plant infrastructure are needed. Outputs of this process are heat and electricity (see green arrows), waste (bottom ash) (see blue arrows) and a flow of flue gas. The flue gas is fed in the electro static precipitator (ESP), selective catalytic reduction unit (SCR) and flue gas desulphurization section (FGD) where particulate matter (PM) and gaseous pollutants (NO_x and SO_x) are removed, respectively. These processes require material inputs (ammonia and limestone), and generate by-products and wastes (gypsum and fly ash) and emissions to environmental compartments (see red arrows). The flue gas emitted by the stack still contains environmental pollutants. Also, wastewater effluent from the power plant is released into water bodies with potential environmental impacts. The processes and associated environmental interventions investigated in this study are described in more detail in Section 3.

In this study the unit of comparison, or functional unit, is chosen to be the generation of 1 kWh at the power plant. This means that grid and further conversion losses during electricity usage are not included.

2. Methodology

The life cycle assessment methodology distinguishes three steps following after the definition of the goal and scope of the study, they are: (1) life cycle inventory, (2) life cycle impact assessment and (3) interpretation.

Life cycle inventory (LCI) is the methodological step where an overview is given of the environmental interventions (resource extraction or emission to an environmental com-

Table 2 – Main performance parameters for the three coal fired power plants investigated in this study

Parameter	Unit	Case 1	Case 2	Case 3
Net generating efficiency (LHV)				
without capture	%	35	46	46
with capture	%	–	–	35
Thermal capacity	MWth	1303	1303	1303
Net generating capacity	MWe	460	600	455
Full load hours	h/year	7800	7800	7800
ESP + FGD efficiency particulate matter	%	99.95	99.98	
FGD efficiency SO_2	%	90	98	
FGD limestone and quicklime use	kg/kg SO_2 removed	1.2/0.3	1/0	
FGD gypsum product/limestone use	kg/kg	–	1.85	
SCR efficiency NO_x	%	60	85	
SCR ammonia use	kg/kg NO_x removed	0.3	0.35	
SCR ammonia slip	% of ammonia use	1	1	
HCl reduction efficiency	%	90	98	
HF reduction efficiency	%	70	98	
Hg reduction efficiency	%	56	90	
Emission factors without flue gas cleaning[a]				
NO_x	kg/MJ	2.76×10^{-4}	1.35×10^{-4}	
SO_2	kg/MJ	5.71×10^{-4}	6.40×10^{-4}	
CO_2	kg/MJ	0.0947	0.0947	
HF	kg/MJ	3.77×10^{-6}	6.59×10^{-6}	
HCl	kg/MJ	1.06×10^{-5}	3.30×10^{-5}	
Hg	kg/MJ	4.18×10^{-9}	5.47×10^{-9}	
Particulate matter[b]	kg/MJ	4.29×10^{-3}	8.29×10^{-3}	

Note: values in italics are calculated values.

[a] Emission factors are derived from Röder et al. (2004) for case 1. For cases 2 and 3 they are derived from Arcadis (2007) and KEMA (2006a,b). No emission factor for SO_3 has been defined in this study.

[b] Size distribution for particulate matter for case 1 is: >10 μm (5%), 2.5–10 μm (10%) and <2.5 μm (85%). For case 2 and 3, due to data limitations, all PM emissions from the power plant are assumed to be PM <10 μm.

partment) caused by or required for the processes within the boundaries of the studied system.

In the life cycle impact assessment (LCIA) environmental interventions are characterized. Additionally, characterized scores can be normalized and weighted. In this study the *CML 2 baseline 2000 V2.03* impact assessment method is used to characterize environmental interventions and subsequently estimate the potential environmental impacts of these interventions (Guinée et al., 2002). The environmental impacts are categorized into 10 environmental themes: abiotic depletion potential (ADP), global warming potential (GWP), ozone layer depletion potential (ODP), human toxicity potential (HTP), fresh water aquatic ecotoxicity potential (FWAETP), marine aquatic ecotoxicity potential (MAETP), terrestrial ecotoxicity potential (TEP), photochemical oxidation potential (POP), acidification potential (AP) and eutrophication potential (EP). The potential environmental impacts of the emission of MEA are currently not included in the CML impact assessment method. Therefore, we added characterization factors[3] for MEA emissions estimated by Huijbregts (2005) to the impact assessment method.

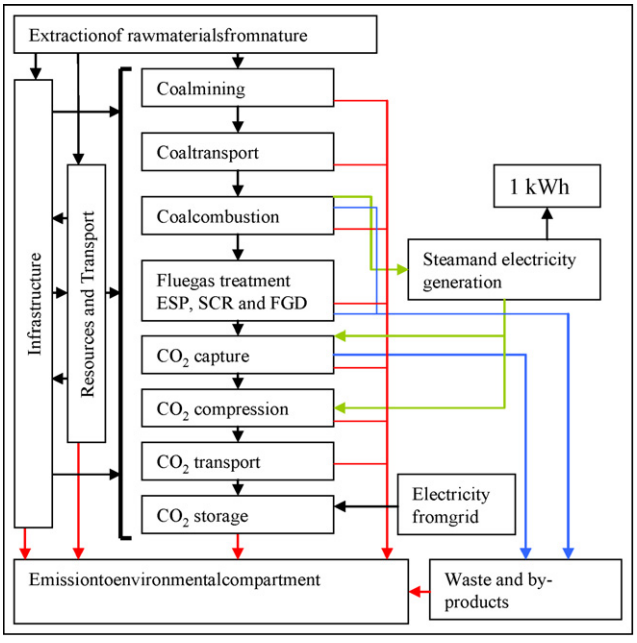


Fig. 1 – Product system for case 3.

After characterization, the normalized impact scores are obtained by dividing the score for an impact category by the total of that category in a reference region in a certain year. The reference region chosen for this study is: the Netherlands in 1997. The derived normalized figure can be used to point out the relative significance of a score for an impact category compared to scores for other impact categories.

An additional step could be the application of weight factors to the impact category scores. This step is not included

[3] Huijbregts (2005) estimated characterization factors for the following impact categories relevant for this study: FWAETP, MAETP, TEP and HTP.

in this study, because of the normative character of weight factors and the loss of information when generating aggregated results.

In this study also a sensitivity analysis is performed to disclose the impact of assumptions made and the uncertainty of input data on the result of the comparison. With that, it provides insight in the overall validity of the results. The results of the sensitivity analysis may be used to focus further research in order to reduce uncertainty regarding input data and model structure.

3. Life cycle inventory

LCI data for the product system for case 1 are taken from the commercial available Ecoinvent database v1.3 (for detailed documentation see (Dones et al., 2004; Röder et al., 2004)). The quality of the data that is available from the Ecoinvent database can be considered high for the power plant, i.e. the coal combustion and flue gas treatment processes. The quality of the data for the modelled upstream processes in the coal supply chain is lower (Dones et al., 2004). For case 2 the processes coal combustion, flue gas cleaning and electricity generation have been updated with more recent data. For case 3 the processes CO_2 capture, compression, transport and injection haven been added. The product systems investigated in this study contain more than 1600 processes and consequently not all processes can be discussed in detail. Here we will present and discuss LCI data for those processes that haven been adapted or added compared to the product system available in the Ecoinvent database.

3.1. *Resource supply and transport*

During the operation of the power plant a vast amount of resources is consumed, such as coal, limestone, ammonia, chemicals and water for cooling and for the steam cycle. In this study, the LCI data for the production chains of these resources are included. To estimate the environmental interventions of the coal supply chain, we use the average coal supply mix[4] imported in the Netherlands as presented by Röder et al. (2004). In the coal supply chain processes such as mining, processing and transport of the coal to the gate of the power plant are included. This also includes infrastructural requirements such as mining equipment and bulk transport ships. For the transport of resources required for the processes within the system boundary, standard distances for Europe defined by Frischknecht et al. (2003) are used, unless otherwise stated.

3.2. *Coal combustion and flue gas cleaning*

LCI data for the coal fired power plant infrastructure and combustion process are mainly derived from the Ecoinvent database. This database provides typical data applicable for the Netherlands (Dones et al., 2004; Röder et al., 2004). The data that is drawn from the Ecoinvent database for case 1 represents the average of environmental interventions caused by the construction, operation and dismantling of eight Dutch coal fired power plants around the year 2000. It also includes third-order process data for the flue gas cleaning units (ESP, SCR and FGD) as well as operational data (1st and 2nd order). LCI data used for case 1 are updated for case 2 and 3. For case 2 and 3 more recent process data on emission reduction technologies are included, which are derived from environmental impact statements for pulverized coal power plants to be built in the Netherlands (Arcadis, 2007; KEMA, 2006a,b). Main performance parameters for the three cases are given in Table 2. They comprise emission factors for various air pollutants without flue gas cleaning. Subsequently, also capture efficiencies and resource requirements for the various flue gas cleaning technologies and the formation of additional emissions (ammonia slip in SCR) waste and by-products are given. The gypsum formed in the FGD section is, in case 2 and 3, assumed to be a saleable by-product. It is assumed to replace the mining of gypsum. As such, associated environmental interventions are avoided.

The parameters have been used to construct a simplified model for the combustion and flue gas cleaning processes. The cases investigated have been modelled using commercially available LCA software (PRé Consultants, 2007).

3.3. *CO_2 capture*

The CO_2 capture process with the use of MEA as chemical absorbent has been described extensively in literature, see for instance (Abu-Zahra et al., 2007; Peeters et al., 2007; Rao and Rubin, 2002).

Key performance parameters (CO_2 removal efficiency, removal efficiencies for impurities in the flue gas, emissions, resource consumption and waste formation) and equations (see Eqs. (2) and (3)) used to model the capture process are presented in Table 3 and in the Appendices.

We have estimated the infrastructural requirements for the CO_2 capture process after consulting a manufacturer of CO_2 removal facilities (Fluor Netherlands, 2007). It comprises the material requirements for the absorber, stripper, piping and small equipment (see Appendix C for details). Due to data limitations we have not included: energy requirement for production and dismantling, material and energy requirement for maintenance of the infrastructure, and waste processing and recycling after dismantling. This omission of processes, and environmental interventions attached, is expected to result in an underestimation of environmental impacts caused by infrastructural requirements.

In the largest part of the infrastructure, the absorber, MEA is used to absorb the CO_2 from the flue gas. The solvent with the CO_2 is then pumped to the stripper, where stripping of the CO_2 is performed by the addition of heat. This heat is assumed to be low-pressure steam drawn from the power plants steam cycle. This steam would otherwise have been used to generate electricity. The amount of electricity otherwise generated by the amount of heat withdrawn for CO_2 stripping is represented by the power equivalent factor.

[4] The average Dutch coal mix comprises coal mining in, and transport from: Western Europe (0.2%), Australia (15%), Eastern Europe (9%), South America (20%), North America (17%), South Africa (26%), Russia (2%) and Eastern Asia (12%).

Table 3 – Main performance parameters CO_2 capture process

Parameter	Unit	Value	Remarks/references
CO_2 removal	%	90	IPCC (2005), 85–96%
SO_2 removal	%	90	Rao and Rubin (2002), 99.5; Knudsen et al. (2006), 40
NO_x removal[a]	%	1.25	Rao and Rubin (2002), 1.25; Knudsen et al. (2006), 0.8
HCl removal	%	95	Rao and Rubin (2002)
HF removal[b]	%	90	Own assumption based on Strazisar et al. (2003)
PM removal	%	50	Iijima et al. (2007) and Rao and Rubin (2002)
NH_3 emission	kg/t CO_2	0.21	See Eq. (3)
MEA consumption	kg/t CO_2	2.34	Knudsen et al. (2006) 2.4; Chapel et al. (1999), IEA GHG (2006), 1.6; Rao et al. (2004), 3.1. See Eq. (2) for calculation
Nominal		1.5	From Rao et al. (2004)
HSS formation[c]		0.75	HSS formation due to MEA oxidation
Acid gasses		0.28	See Eq. (2) for calculation
MEA emission		0.014	From IEA GHG (2006); Thitakamol et al. (2007), 0.11–0.72
MEA reclaimed[d]		0.20	
NaOH use	kg/t CO_2	0.13	From Rao and Rubin (2002) and Rao et al. (2004)
Activated carbon use[e]	kg/t CO_2	0.075	From Chapel et al. (1999)
Reclaimer bottoms (dry)	kg/t CO_2	2.4	IEA GHG (2006), 3.2 (wet); Thitakamol et al. (2007), 3.73–14.92
Heat requirement capture	GJ_{steam}/t CO_2	4	Alie et al. (2005), 4 (optimum); Chapel et al. (1999), 4.2; Rao et al. (2006), 4.32 (3.5–6); Abu-Zahra et al. (2007), 3.89 (optimum: 3.01); Knudsen et al. (2006), 4.2
Power equivalent factor	GJ_e/GJ_{steam}	0.20	See Peeters et al. (2007) for detailed review
Electricity requirement (fans, pumps)	kWh/t CO_2	23.6	From IPCC (2005), range 16.6–30.5

Note: Values in italics are calculated values.
[a] 5% of NO_x is assumed to be NO_2. 25% of the NO_2 is assumed to be removed in the CO_2 capture process.
[b] Removal efficiency for HF is estimated to be lower than for HCl, as the ratio of fluoride ion concentration in the reclaimer bottoms to the concentration in lean MEA were found to be lower for fluoride compared to chloride (Strazisar et al., 2003).
[c] MEA loss due to heat stable salts (HSS) formation assumed to be caused by the reaction between 1 mole MEA degraded by oxygen with 1 mole virgin MEA. 50% of MEA degradation is assumed to be caused by oxygen degradation.
[d] It is assumed that one mole MEA is reclaimed for every mole NaOH consumed.
[e] In the LCI charcoal is used as a proxy for activated carbon.

There is also directly electricity used in the capture process by pumps and fans. Pumps are used to transport the solvent through the various parts of the CO_2 capture unit, and fans are installed to overcome the pressure drop encountered in the absorber. The withdrawal of steam and electricity together leads to a reduced thermal efficiency of the power plant (see Table 2 and Eq. (1)).

Efficiency calculation case 3:

$$\eta_{ccs} = \eta_{ref} - \frac{W_{capture}}{E} - \frac{Q_{capture}Pef}{E} - \frac{W_{compression}}{E} \quad (1)$$

where η_{ccs}, thermal efficiency of plant with post-combustion CO_2 capture; η_{ref}, thermal efficiency of plant without CO_2 capture; $W_{capture}$, power requirements of flue gas fan plus pumps (MWe); $Q_{capture}$, heat requirements CO_2 regeneration (MWth); Pef, power equivalent factor or ratio incremental power reduction to incremental heat output (MWe/MWth); $W_{compression}$, power requirements for CO_2 compression (MWe); E, coal input (MWth).

The capture process not only requires infrastructure, heat and electricity. Also, resources such as MEA, caustic soda (NaOH) and activated carbon are consumed. LCI data on the production chain of MEA (see Appendix G) and NaOH are drawn from the Ecoinvent database (Althaus et al., 2004). It should be emphasized that the LCI data on the production process of MEA comes with high uncertainty. The emissions of ethylene oxide and ammonia to the atmosphere during production are calculated from the mass balance and are not the result of actual measurements. The same holds for emissions to water.

MEA is consumed in the capture process mainly through degradation by oxygen and impurities in the flue gas. Important impurities are sulphur oxides (SO_x), nitrogen dioxide (NO_2), hydrogen chloride (HCl), hydrogen fluoride (HF) and particulate matter as they react with the MEA or cause foaming of the solvent (see Eq. (2)). Some MEA degradation pathways may result in the formation of heat stable salts (HSS). To limit MEA consumption a deep reduction of acid gasses is required in the flue gas cleaning sections prior to CO_2 capture. The capture process is thus expected to affect (i.e. lower) the emission of these air pollutants directly and indirectly.

MEA loss in CO_2 capture process due to acid gas removal. Derived from Rao et al. (2004):

$$mole_{MEA} = \frac{\text{emission factor}_{\text{acid gas}}(1 - \eta_{precapture})\eta_{MEA,\text{acid gas}}N}{M_{\text{acid gas}}} \quad (2)$$

where $mole_{MEA}$, moles of MEA lost/coal input (MJ_{in}); $emission\text{-}factor_{acid\ gas}$, emission factor of acid gas (g/MJ_{in}); $\eta_{precapture}$, total removal efficiency of acid gas in upstream flue gas cleaning technologies (%); $\eta_{MEA,acid\ gas}$, removal efficiency for acid gas in MEA capture process (%); N, moles of MEA lost per mole of acid gas captured ($SO_2 = 2$, $NO_2 = 2$, HCl = 1, HF = 1); $M_{acidgas}$, molar mass of acid gas (g/mole).

A consequence of MEA degradation in the capture process is the generation of waste, the reclaimer bottoms. Degradation of MEA may also lead to the formation of ammonia (NH_3), which is then emitted by the absorber together with cleaned flue gas (see Eq. (3)). Also, a MEA slip can be expected, which results in the emission of MEA to the air. To limit MEA consumption, NaOH is used to reclaim some of the MEA. (Iijima et al., 2007; Rao and Rubin, 2002; Rao et al., 2004; Strazisar et al., 2003; Thitakamol et al., 2007).

NH_3 formation in CO_2 capture process. Derived from Rao et al. (2004):

$$NH_{3emission} = \frac{MEA_{nom.loss} f_{oxidation} M_{NH_3}}{M_{MEA}} \quad (3)$$

where $NH_{3emission}$, ammonia emission to air (kg/t CO_2 captured); $MEA_{nom.loss}$, nominal MEA loss (1.5 kg/t CO_2 captured); $f_{oxidation}$, fraction of nominal MEA loss lost due to oxidation (0.5); M_{NH3}, molar mass NH_3 (g/mole); M_{MEA}, molar mass MEA (g/mole).

The remaining reclaimer bottoms have to be disposed off. The associated environmental interventions depend mainly on the quantity and composition, and the manner of disposal[5]. There is currently no certainty on all of these three factors mentioned. (IEA GHG, 2006; Thitakamol et al., 2007) In this study we have estimated the dry elemental composition of the reclaimer bottoms (see Appendix A) using measurements from Strazisar et al. (2003). These measurements were performed at a MEA based CO_2 capture facility, separating CO_2 from the flue gas of a coal fired boiler. These reclaimer bottoms are assumed to be incinerated, in a hazardous waste incinerator (HWI). With this elemental composition potential environmental interventions are calculated with the use of an existing HWI process model developed by Doka (2002).

Standard transport distances (100 km by truck and 600 by train) are used to estimate the transport of resources for the capture process. For the reclaimer bottoms a transport distance of 100 km by truck is assumed. (Frischknecht et al., 2003).

3.4. CO_2 compression

After the capture process, the CO_2 flow is dehydrated and assumed to be compressed to 11 MPa for transport. This process requires the production, operation and dismantling of the compressor and electricity from the power generation process during operation. Process and material requirements for the production of the four stage compressor train are roughly estimated (see Appendix D). This is done by using LCI data for a 10 MWe (34–38% net efficiency) gas turbine as approximation. Personal communications with MAN Turbo yielded an estimate for the material requirements for a 31 MW centrifugal compressor, i.e. 64 tonnes (MAN Turbo, 2007). The estimate in this study for a 40 MW compressor is within that order of magnitude. The LCI data for the infrastructure omits information on disposal and recycling of materials after dismantling.

[5] Possible options for disposal are suggested in literature. They are: incineration, landfill, co-combustion in the boiler or co-feed in a cement kiln (Chapel et al., 1999; IEA GHG, 2006).

The electricity requirement for the compression process is determined with the use of Eq. (4).

Compressor power requirement. Derived from Damen (2007):

$$W = \frac{ZRT_1}{M}\frac{N\gamma}{\gamma-1}\left[\left(\frac{p_2}{p_1}\right)^{\gamma-1/N\gamma} - 1\right] \quad \text{and} \quad E = \frac{W}{\eta_{is}\eta_m 3600} \quad (4)$$

where W, specific work (kJ/kg CO_2); E, specific electricity requirement (kWh/kg CO_2); Z, compressibility factor (0.9942); R, Universal gas constant (8.3145 J/(mole K)); T_1, suction temperature (313.15 K); γ, specific heat ratio (cp/cv) (1.293759); M, molar mass (44.01 g/mole); p_1, suction pressure (MPa) (transport = 0.101325, injection = 10.7); p_2, discharge pressure (MPa) (transport = 11, injection = 15); N, number of compressor stages (transport = 4, injection = 2); η_{is}, isentropic efficiency (80%); η_m, mechanical efficiency (99%).

Furthermore, fugitive CO_2 emissions from the compressor train have been estimated with the use of the methodology developed by the IPCC and is determined by installed compressor capacity and duration of operation (IPCC, 2006). More assumptions are presented in Table 4.

3.5. CO_2 transport

The compressed CO_2 is transported through a pipeline. This process mainly requires the construction and dismantling of the pipeline and maintenance during its lifetime. For the CO_2 pipeline existing LCI data for an onshore natural gas transport pipeline constructed in the Netherlands with a diameter of 95 cm, thickness of 10 mm and length of 50 km is used (see Appendix E). A CO_2 pipeline with these dimensions can transport about 30 Mt per year. The environmental interven-

Table 4 – Performance parameters CO_2 compression, transport and injection

Parameter	Unit	Value
Compression and transport		
Suction pressure	MPa	0.101325
Discharge pressure	MPa	11
Compression energy[a]	kWh/t CO_2	111
Fugitive CO_2 emission compressor[b]	t CO_2/MW/yr	23.2 (7.0–116.1)
Pipeline length	km	50
Diameter	cm	95
Pressure drop	MPa/km	0.006
Fugitive CO_2 emission pipeline[b]	t CO_2/(km year)	2.32 (0.2–23.2)
Injection		
Number of wells		6
Injection capacity	Mt/year	7.3
Suction pressure	MPa	10.7
Discharge pressure	MPa	15
Injection—compression energy[a]	kWh/t CO_2	7

[a] Compression and injection energy have been calculated with Eq. (4).
[b] Fugitive emissions of CO_2 during compression and transport haven been calculated with the use of the methodology developed by the IPCC (IPCC, 2006).

Table 5 – Life cycle inventory results for key air pollutants, emissions to water, resource consumption and production of waste and by-products

Substance	Unit (per kWh)	Case 1	Case 2	Case 3
Emissions to atmosphere				
CO_2	g	1050	805	200
NO_x	g	1.94	1.03	1.39
SO_2	g	1.41	0.71	0.84
Methane	g	1.47	1.13	1.51
HF	mg	11.98	1.38	0.64
HCl	mg	14.10	7.68	3.90
Hg	μg	22.01	6.77	9.66
Particulate matter <10 μm	mg	97.83	67.33	84.92
Particulate matter >10 μm	g	1.51	1.11	1.46
MEA	mg	2.63×10^{-4}	1.99×10^{-4}	12.25
NH_3	mg	63.73	47.03	248.48
PAH[a]	μg	46.39	35.52	48.02
NMVOC[b]	mg	119.35	91.06	127.23
Emissions to water				
Hg	μg	3.75	3.22	4.53
PAH[a]	μg	7.22	5.49	8.70
Nitrate	mg	28.86	26.84	67.97
Resources				
Coal direct	g	441	338	444
Coal total	g	447	343	451
NH_3	g	0.75	0.39	2.13
MEA	g	2.60×10^{-7}	1.97×10^{-7}	2.04
NaOH	g	0.12	0.11	0.39
Limestone	g	7.73	5.64	7.51
Quicklime	g	1.06	0.01	0.03
Wastes and by-products				
Gypsum	g	-1.39×10^{-5}	9.08	11.91
Reclaimer bottoms	g	–	–	2.10
Total waste	g	140.42	107.74	146.31

[a] Polycyclic aromatic hydrocarbons.
[b] Non-methane volatile organic compounds.

tions associated with this pipeline are allocated to the CO_2 transported from the power plant to the storage reservoir in case 3. Hence, this will likely result in an overestimation of environmental interventions. On the other hand the wall thickness, and material requirement related to the pipeline, is probably a underestimation, as other sources (Hooper et al., 2005; Turner et al., 2006) report a thickness of 18–30 mm for CO_2 pipelines with similar diameters. The length of the pipeline is representative for a pipeline from a location in the northern coast of the Netherlands to one of the several possibly available onshore reservoirs, which are predominantly situated in the northern part of the country.

Finally, fugitive emissions of CO_2 during operation are estimated with the use of the methodology developed by the IPCC (IPCC, 2006).

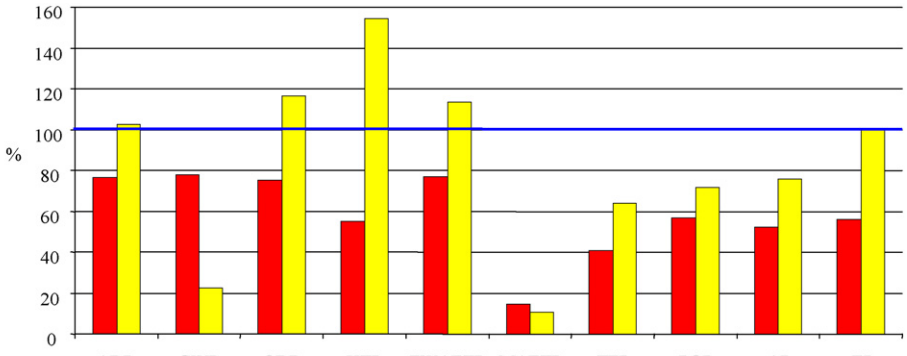
3.6. CO_2 injection

LCI data for the injection facility has been estimated by using environmental reports on underground natural gas storage (UGS) (NAM, submitted for publication; NAM/GASUNIE, 1991). The UGS is scaled to inject 24 million cubic meters of natural gas per day. Assuming 0.83 kg/m^3 this equals 7.3 Mt of natural gas. The LCI data of this project are assumed to be valid for a surface facility for CO_2 injection with a capacity of 7.3 Mt per year. The UGS, however, comprises the injection, production and treatment of the natural gas prior to transport. Considering that CO_2 treatment (i.e. cleaning and drying) is probably not required prior to injection, the data used will likely result in an overestimation of environmental impacts. The energy requirement during construction and dismantling of the surface infrastructure is not known and consequently not included in the LCI. Data on environmental interventions associated with the dismantling of the surface facility, the recycling of materials and the disposal of wastes are also not included.

Additional to the material requirements for the surface facility it is assumed that six onshore wells, with a length of 3 km each, have to be drilled, operated and abandoned. LCI data for the wells are taken from Jungbluth (2003) to estimate the environmental interventions of the subsurface infrastructure.

During operation the CO_2 is assumed to be re-compressed from 10.7[6] to 15 MPa before injection in the geological reservoir. This represents a scenario where pipeline delivery pressure is not enough to overcome reservoir pressure. Electricity use for re-compression is calculated with Eq. (4) and is assumed to be taken from the

[6] We assumed a pressure drop over the 50 km pipeline of 0.3 MPa.



	ADP	GWP	ODP	HTP	FWAETP	MAETP	TEP	POP	AP	EP
Unit (kg eq)	Sb	CO_2	CFC-11	1,4-DB	1,4-DB	1,4-DB	1,4-DB	C_2H_4	SO_2	PO_4^{3-}
Case 1	$8.25*10^{-3}$	1.092	$8.52*10^{-9}$	0.106	$1.19*10^{-2}$	513	$8.03*10^{-4}$	$9.06*10^{-5}$	$2.76*10^{-3}$	$2.88*10^{-4}$
Case 2	$6.32*10^{-3}$	0.837	$6.41*10^{-9}$	$5.84*10^{-2}$	$9.17*10^{-3}$	75.5	$3.26*10^{-4}$	$5.13*10^{-5}$	$1.44*10^{-3}$	$1.61*10^{-4}$
Case 3	$8.45*10^{-3}$	0.243	$9.93*10^{-9}$	0.164	$1.34*10^{-2}$	55.0	$5.11*10^{-4}$	$6.49*10^{-5}$	$2.10*10^{-3}$	$2.90*10^{-4}$

Fig. 2 – Relative scores for case 2 and 3 compared to case 1 and absolute impact scores for all cases after characterization (*note*: 1.4-DB = 1.4-dichlorobenzene, CFC-11 = chlorofluorocarbon-11).

grid, i.e. the average Dutch electricity supply in the year 2000. Further, it is assumed that leakage of the injected CO_2 to the atmosphere will not occur or is limited to insignificant amounts.

4. Results and discussion

In Table 5, a selection of the results of the life cycle inventory step is given. Over the full life cycle case 3 shows to have the highest level of coal and other resource consumption (except quicklime and limestone), waste formation and the lowest atmospheric emissions of CO_2, HF and HCl. For the remaining substances depicted, case 2 has the lowest emissions to the atmosphere and water. Case 2 also shows the lowest level of resource consumption and waste formation. These environmental interventions and their potential environmental impacts will be discussed below in more detail.

In Figs. 2 and 3, the results of the characterization and normalization step are given. In Fig. 4 a detailed breakdown into the discerned orders of processes in the life cycle is presented for the global warming impact category. In Figs. 5–7, the relative contributions of the first, second and third orders of processes are depicted. In Fig. 8, a breakdown into substances for the eutrophication and acidification potential is given for case 3.

4.1. *Abiotic depletion*

The impact category abiotic depletion is a measure for the extraction of raw materials from nature. As expected, the scores show that there is an increase in abiotic depletion for the CCS case compared to the other two cases. This increase is primarily caused by the efficiency penalty in power generation and the use of more natural resources for the construction and operation of the CCS chain (see also Table 5).

4.2. *Global warming*

The results for the global warming impact category show a significant reduction in CO_2 equivalents for the CCS case compared to case 1 (78%) and case 2 (71%), see Fig. 4. Direct emissions from the power plant for case 1 to 3 are respectively 976, 749 and 107 g CO_2 equiv. In case 3983 g CO_2 equiv. are generated in the combustion process of which 875 g CO_2 is captured, equalling 89% of the direct emissions. This figure is lower than the assumed 90% CO_2 removal. This is due to the fact that other substances with global warming potential are emitted during the operational phase of the power plant too, such as nitrous oxide (N_2O), methane and carbon monoxide.

In Table 6, we can see for case 3 that the remaining CO_2 equiv. are mainly emitted in the coal supply chain (110 g CO_2 equiv.). Relative large contributors in that chain are CO_2 emissions from oceanic transport of coal and GHG emissions, predominantly methane, from coal mining (see Table 5). Two small but not insignificant contributions come from the production chain of MEA and the disposal chain of reclaimer bottoms. An explanation for the latter is that we assumed a heating value of zero for the reclaimer bottoms. Hence, fossil fuels are used in the HWI to incinerate the bottoms, with an increase of GHG emissions as a consequence.

Table 6 also discloses that for case 3 the contribution of third-order process to the greenhouse gas balance cumulates to more than 5% and is dominated by infrastructural requirements for the coal supply chain (see also Fig. 7). The contribution from infrastructural requirements for CO_2 capture, transport and storage is relative small. The contribution from the CO_2 capture facility (0.006% of total emissions) is more than one order of magnitude smaller than figures presented in earlier studies; from both (Lombardi, 2001) and (Muramatsu and Iijima, 2002) a contribution of 0.16% can be

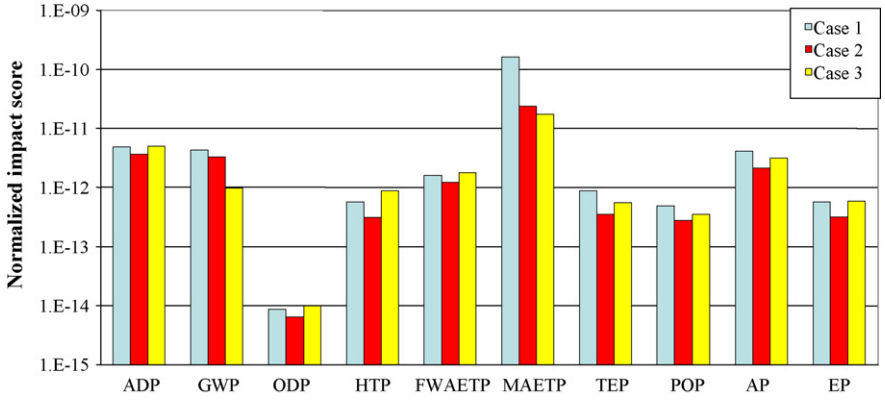


Fig. 3 – Impact scores after normalization.

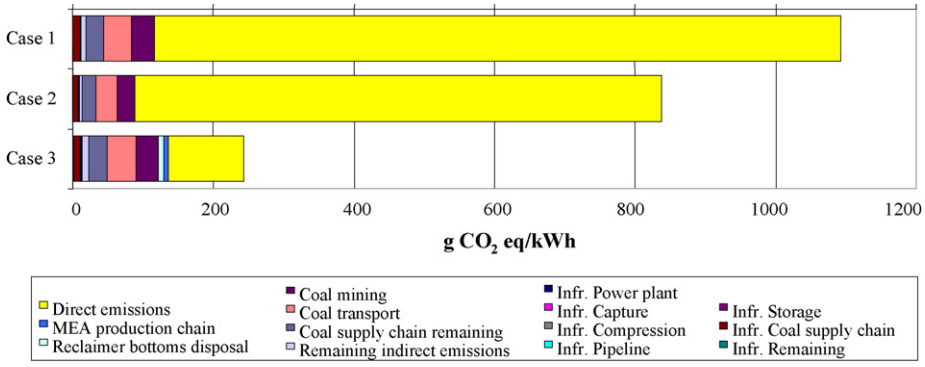


Fig. 4 – Breakdown of global warming potential into first, second and third-order processes for cases 1, 2 and 3.

calculated[7]. Although the LCI data are based on information supplied by a manufacturer of CO_2 removal facilities that are operational in present day industry, the result presented here may be an underestimation of actual environmental interventions. The contribution of infrastructural requirements for CO_2 transport and injection are about equal. However, as mentioned earlier, we have probably overestimated actual environmental interventions by using LCI data from an UGS facility. For CO_2 transport, the LCI data also cannot considered to be accurate, though results from this study are not expected to be incorrect by more than one order of magnitude.

In conclusion, and despite the uncertainties, we can state that the capture and compression of CO_2 and the associated efficiency penalty results in both a relative and absolute increase of the contribution of up- and downstream processes to the total emission of CO_2 equivalents.

To calculate the amount of kilograms CO_2 avoided, normally the direct emissions from the power plant with capture (case 3) are subtracted from the direct emissions from the power plant without capture (case 2). If we would apply this method we find that 0.641 kg CO_2 equiv. are avoided per kWh. If we would take into account the emissions over the full life cycle we find 0.594 kg CO_2 equiv. avoided per kWh. With these figures we also can calculate the avoidance efficiency, defined as the kg CO_2 equiv. avoided per kg CO_2 injected. Using the CO_2 avoidance figure calculated with the conventional method we find an efficiency of 73%. However, when we take into account the indirect emissions as well, we find an avoidance efficiency of 68%.

In case 3 we assumed that CO_2 will not leak from the reservoir. However, if such leakage would occur, the avoidance efficiency would be lower. Wilson and Monea (2004) have performed a modelling exercise to predict the release of injected CO_2 from the target reservoir into the biosphere[8]. They estimated that on average, after 5000 years, 0.2% (95% confidence interval: 0.005–1.3%) of the total amount of CO_2 injected would be released into the biosphere. Kreft et al. (2006) performed a risk assessment for a CO_2 storage reservoir, in this case an aquifer, and estimated in the scenario for a well leakage that 60% of stored CO_2 could leak, which was deemed highly unlikely to occur. For indicative purposes, 60% leakage would result in an avoidance efficiency of 8%, a decrease of 60 percent points. The release of 1.3%, which is the highest value of the 95% confidence interval estimated by Wilson and Monea (2004; p. 214–242), would result in an avoidance efficiency of

[7] These results from Lombardi (2001) are calculated for gas fired power plant. The results from Muramatsu and Iijima (2002) are calculated with the use of input/output methodology, which is primarily based on economic data and does not yield detailed process data.

[8] The biosphere, in this case, includes the atmosphere and extends to a depth of 300 m.

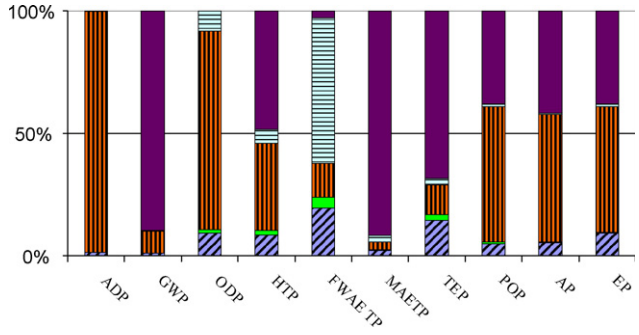


Fig. 5 – Process contribution for case 1: (▬) direct emissions; (▬) remaining process operation; (▬) coal supply operation; (▬) remaining infrastructure; (▬) coal supply infrastructure.

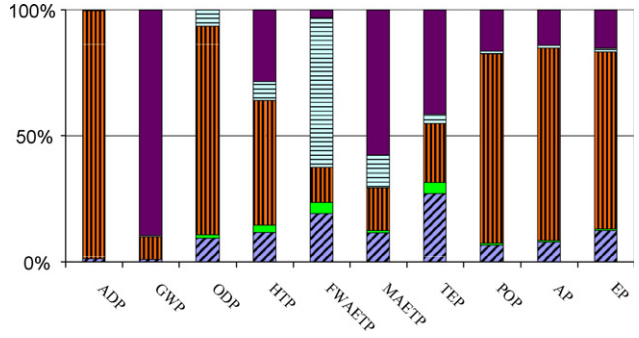


Fig. 6 – Process contribution for case 2: (▬) direct emissions; (▬) remaining process operation; (▬) coal supply operation; (▬) remaining infrastructure; (▬) coal supply infrastructure.

67%, a decrease of 1% point. Thus, every percent of CO_2 leaked will result in a decrease in avoidance efficiency with an equal amount.

This reduction in avoidance efficiency stresses the need for proper screening and selection of underground storage reservoirs. This to avoid unacceptable leakage rates from storage reservoirs.

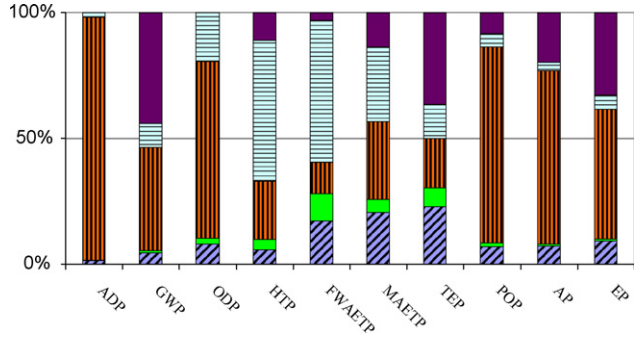


Fig. 7 – Process contribution for case 3: (▬) direct emissions; (▬) remaining process operation; (▬) coal supply operation; (▬) remaining infrastructure; (▬) coal supply infrastructure.

4.3. *Ozone layer depletion*

The most important processes that contribute to ozone layer depletion are the production of crude oil and transport of natural gas. The emission of trifluorobromomethane, a halocarbon, to the atmosphere dominates (84% or higher) the score for all cases. For this impact category the results show that case 3 has the highest score. Furthermore, case 3 scores higher than would be expected just on the generating efficiency alone. This additional increase is mainly due to the addition of multiple processes required for the production and operation of the CCS system, which at some point in their respective production chains require crude oil or natural gas as input. Examples are the MEA production chain and the disposal of reclaimer bottoms contributing 6 and 7%, respectively.

4.4. *Human toxicity*

The human toxicity potential (HTP) of case 1 is dominated by the emission of HF to the atmosphere, which accounts for 32% of the score. The score for case 2 shows a decrease compared to case 1. This is due to the assumed improvement of both generating efficiency and capture efficiency for mainly HF, but also for NO_x, SO_2, HCl and particulate matter in the flue gas cleaning sections. Despite the assumption that these substances are reduced further in the CO_2 capture process, case 3 scores significantly higher then the other cases. An increase of 54% and 181% compared to, respectively, case 1 and 2 is found. This is predominantly the consequence of MEA consumption, or more specific, the emission of ethylene oxide to the air and to water during MEA production. Direct emission of 12 mg MEA/kWh from the CO_2 capture process contributes only to a very small extent (0.005%) to the HTP score of case 3. The MEA production chain accounts for 51% of the HTP score for case 3 (see Fig. 7). However, it should be noted that the LCI data used for the production process has a high uncertainty due to a lack of accurate process data. This holds explicitly for data on emissions to air and water, which are based on rough estimations (Althaus et al., 2004). A more recent published environmental product declaration for the production of ethylene amines[9] suggests that these rough estimations may result in overestimation of the HTP score by several orders of magnitude (AKZO NOBEL, submitted for publication), although data provision in this publication is scarce too.

Furthermore, the MEA consumption of 2.55 kg MEA/tonne CO_2 calculated in this study can be considered as a relative high value compared to the 1.6 kg/tonne CO_2 mentioned by IEA GHG (2006) and Chapel et al. (1999). Nonetheless, the value is in line with estimates by Rao et al. (2004) and pilot plant measurements (Knudsen et al., 2006) and low compared to estimates by Thitakamol et al. (2007). Next to MEA production, also transoceanic coal transport (18%) and the power generating process (13%) are large contributors to the HTP score (see Figs. 5–7). A minor contribution of 1.6% comes from the reclaimer bottoms disposal chain. An even smaller contribution comes from the emission of particulate matter,

[9] Ethylene amines are produced by the reaction of MEA with NH_3.

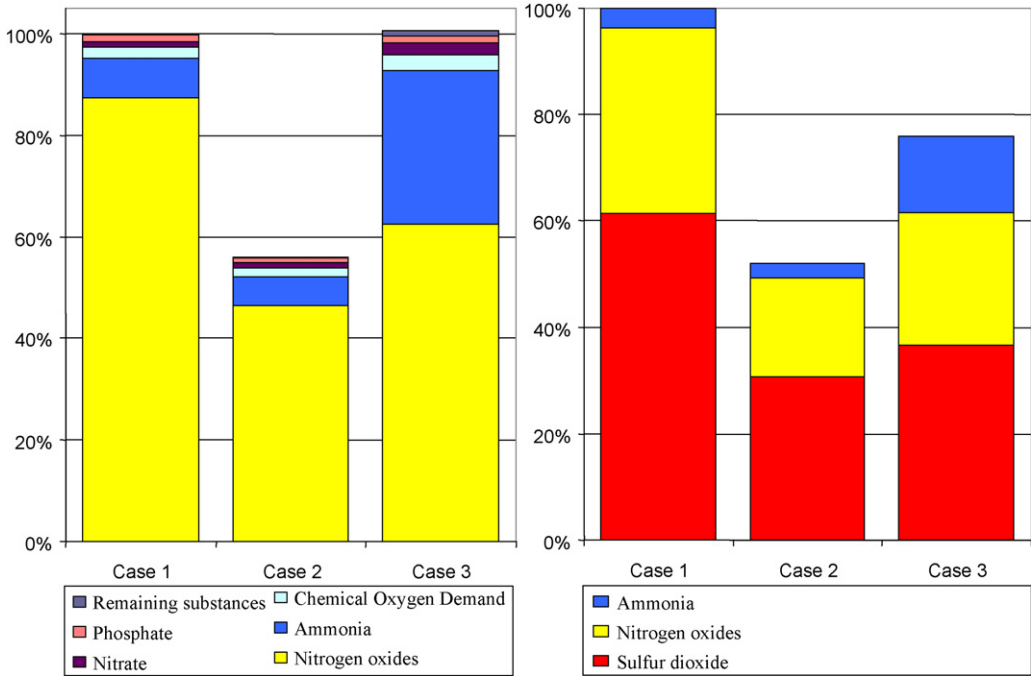


Fig. 8 – Substance contribution to the eutrophication potential (left) and the acidification potential (right) relative to case 1.

which is less than 0.1% for all cases. The direct emissions of particulate matter are the lowest for case 3. However, this is offset by up- and downstream emissions resulting in the lowest life cycle emissions of PM for case 2 (see Table 5).

The emissions of polycyclic aromatic hydrocarbons to the atmosphere are the most dominant substances in the HTP score for case 2 (35%). It is also an important contributor for case 1 (25%) and 3 (17%) As far as we can ascertain there is no information available in the literature on the effect of CO_2 capture on the emission of PAH's. This is a topic worthwhile to investigate further.

4.5. *Fresh water aquatic ecotoxicity*

The score for the fresh water aquatic ecotoxicity impact category is highly dominated by the emission of metals to water (river and groundwater) and to the air. These emissions are assumed to occur due to leaching from land filled wastes. These wastes are mainly formed during coal combustion, flue gas desulphurization and steel production. Other important contributors are background process, such as the coal transport chain which contributes due to direct emissions during transport and indirect emissions from steel production for the transport infrastructure (see Figs. 5–7). This also holds for the additional infrastructural requirements for the CCS system.

4.6. *Marine aquatic ecotoxicity*

The scores for the marine aquatic ecotoxicity impact category show a large reduction for both case 2 and 3 compared to case 1, respectively, 85 and 89%. This is primarily the effect of the assumed increase in the removal efficiency of HF in the wet FGD and in the CO_2 capture process by reaction with MEA. The latter explains the lower score for case 3 compared to case 2, and the deep reduction of direct emissions compared to case 1 (see Fig. 5).

In literature, the MAETP impact category has been subject of discussion. Points of discussion are the characterization factors[10] used for HF emissions in the CML impact assessment method. It is suggested by several authors that they are possibly too high, which consequently will result in an overestimation of the potential environmental impact of HF emissions and to a dominance of these emissions in the contribution to the total MAETP score (Frischknecht et al., 2004; Heijungs et al., 2007).

4.7. *Terrestrial ecotoxicity*

The results for the TEP category show a reduction for case 2 and 3, respectively, 59 and 36%. This reduction is mainly due to the assumed increase in mercury removal in flue gas cleaning sections. Based on the efficiency penalty due to CO_2 capture and compression alone we would expect a 31% higher score for case 3 compared to case 2. From Fig. 2 we can derive that the increase is 57%. The additional increase is caused by emissions in the MEA production chain (10% of total TEP score), during the production of infrastructure and during disposal of the reclaimer bottoms, although the latter only constitutes a small contribution (1.5%).

In this study we did not take into account that mercury (Hg) and other heavy metals may be partially removed in the CO_2 capture process. Measurements on reclaimer bottoms have indicated that mercury is present in the bottoms (Strazisar

[10] The characterization factor is used to calculate the potential environmental impact of an environmental intervention for a certain impact category.

Table 6 – Greenhouse gas balance for the three cases per kWh

Process	Case 1		Case 2		Case 3	
	g CO_2 equiv.	%	g CO_2 equiv.	%	g CO_2 equiv.	%
First-order emissions						
Electricity generation[a]	976	89	749	89	107	44
Second-order emissions						
MEA production chain	–	–	–	–	6	3
Reclaimer bottoms disposal	–	–	–	–	7	3
Coal supply chain total (–infra)	98	9	75	9	99	41
Coal mining	33	3	25	3	33	14
Coal transport	41	4	31	4	41	17
Remaining coal chain	25	2	19	2	25	10
Remaining processes	6	1	4	0.5	10	4
Subtotal	105	10	80	9	123	50
Third-order emissions						
Power plant	1.3	0.11	1.0	0.11	1.3	0.52
CO_2 capture installation					1.4×10^{-2}	0.006
CO_2 compressor					5.4×10^{-3}	0.002
CO_2 pipeline					3.6×10^{-1}	0.15
CO_2 injection facility					3.6×10^{-1}	0.15
Infrastructure coal supply chain	10.4	0.95	8.0	0.95	10.5	4.31
Remaining processes	0.2	0.02	0.1	0.02	0.7	0.29
Subtotal	11.9	1.08	9.1	1.08	13.2	5.42
Total for life cycle	1092	100%	837	100%	243	100%

[a] Electricity generation for case 3 includes CO_2 capture and compression process.

et al., 2003). For indicative purposes, assuming a removal efficiency for Hg of 50% in the CO_2 capture process will lower the TEP score for case 3 by 15%. Not taken into account, however, is if mercury is actually removed from the flue gas in the CO_2 capture process, then this will have an effect on the emission profile of the disposal of the reclaimer bottoms. The actual impact on the results for TEP then also will depend on capture efficiency of mercury emissions in the HWI.

4.8. *Photochemical oxidation*

The scores for the photochemical oxidation potential (POP) show a reduction for case 2 and 3, respectively, 43 and 28%, compared to case 1. This is primarily due to the increase of SO_2 removal in both the FGD and CO_2 capture process. However, a trade-off is found for case 3, as SO_2 and methane emissions in respectively coal transport and mining increase due to the energy penalty associated with CCS.

4.9. *Acidification and eutrophication*

The higher removal of SO_2, together with the lower emission factor and higher removal efficiencies assumed for NO_x, does also result in an overall reduction of acidifying potential (AP) for case 3 compared to case 1, though not compared to case 2 (see Figs. 2 and 8). The explanation for that is that more SO_2 and NO_x are emitted during the transport of coal. Also, there is an increase in NO_x emissions per kWh from the power plant, as the partial NO_x removal in the CO_2 capture process is not enough to offset increased emissions caused by the efficiency penalty.

The increase of NO_x emissions per kWh are also reflected by the high scores for the eutrophication potential (EP) for case 3 by comparison with case 2. For case 3, when compared to both case 1 and case 2, we can see that the lower emission factor for NO_x and increase in removal efficiency of the SCR section are offset by the addition of CCS.

Another important contributor to both the AP and EP impact categories is the emission of NH_3. An increase in NH_3 emissions has been calculated for case 3 compared to case 1 and 2 due to an increase in NH_3 slip from the SCR and the formation of NH_3 from MEA degradation (see Fig. 8 and Table 5). However, the NH_3 emissions, and also MEA slip, from the absorber may be reduced by installing a water wash section at the top of the absorber.

Overall it is found that the coal supply chain contributes heavily to the impact scores of abiotic depletion due to extraction of coal, ozone layer depletion due the production of heavy fuel oil for ship transport, photochemical oxidation and acidification due to SO_x emissions during ship transport, and acidification and eutrophication due to NO_x emissions during ship transport. For the future, however, a decrease in both SO_x as NO_x emissions during transport of coal can be expected. A primary driver for that is the implementation of stricter regulations to reduce sulphur content in marine fuel and to limit NO_x emissions during ship transport (Wahlström et al., 2006).

4.10. *Normalization*

The results of the normalization step (see Fig. 3) indicate that ODP is of relative minor importance compared to the total of characterized environmental interventions in the Nether-

lands in 1997, the used normalization reference. The results also show that potential impacts in the categories marine aquatic ecotoxicity, abiotic depletion, global warming and acidification are of more relative importance compared to the remaining impact categories human toxicity, fresh water aquatic ecotoxicity, terrestrial ecotoxicity, photochemical oxidation potential and eutrophication.

Regarding the normalization methodology it should be mentioned that there is a bias in the normalization of FWAETP results. This is due to the fact that HF emissions to the atmosphere are a dominant contributor to the final score (due to high characterization factors) and yet HF emissions are not accounted in the normalization reference, i.e. there are not included in the normalization set (Heijungs et al., 2007). This results in a (too) high normalized score for this impact category. According to Heijungs et al. (2007), a similar bias can also be expected for all other categories except: global warming, acidification and eutrophication. This also means that one has to be careful with applying weight factors on these normalized scores in order to determine to what extent trade-offs are acceptable and co-benefits are valuable.

4.11. *Limitations of this study*

The main limitations of this study can be divided into data limitations and methodological limitations. Data limitations comprise mainly uncertainty and absence of data on the effect of CO_2 capture on important emissions to the atmosphere. In literature no data is found on the emission of, for example: polycyclic aromatic hydrocarbons, heavy metals (e.g. Hg, Cd and Tl), hydrocarbons and dioxins. Also not included in this study, due to data limitations, are emissions to water affected by the CO_2 capture process directly or by treatment of reclaimer bottoms in a wastewater treatment facility at the power plant before further disposal.

Furthermore, the model that was build for this study is based on rather simplified and uncertain causal relationships. We stress therefore that this ex-ante LCA should be regarded as an advanced screening LCA. In order to get more detailed and accurate results, and better understanding of environmental co-benefits and trade-offs associated with the implementation of CCS in coal fired power generation, it is necessary that extensive environmental measurement programmes are conducted at pilot and demonstration plants. Such extensive measurements programmes have been carried out already for other emission reduction techniques implemented at coal fired power plants, see for instance (Meij, 1994; Meij and te Winkel, 2006; Miller et al., 2006; Pavlish et al., 2003; Tolvanen, 2004).

Other environmental interventions are not investigated in this study, as no characterization factors are defined in the used CML impact assessment method, they are: water usage and cooling water (waste heat) discharge to water bodies. Next to that are risks associated with transport and intermediate storage of chemicals (e.g. MEA and ammonia), transport and storage of CO_2, and land occupation by infrastructure not characterized in the methodology, at present. These environmental interventions will increase when implementing MEA based post-combustion CCS.

The used methodology also does not account for spatial and temporal dependency of environmental impacts. This LCA therefore results in insights into non-spatial explicit environmental impacts as spatial explicit impacts depend also on distribution and dispersion of the emission, background concentration and the sensitivity of the environment/receptor to certain stressors. (Finnveden and Nilsson, 2005; Potting, 2000). Huijbregts et al. (2001) have determined spatial explicit characterization factors for NH_3, NO_x and SO_2 for the determination of site dependent acidification and eutrophication potential. The characterization factors for emissions on the ocean are in general lower then those for emissions in the Netherlands. If these factors would have been applied on the emissions of NH_3, NO_x and SO_2 from the power plant and transoceanic ship transport, then the final impact scores for acidification and eutrophication would have been different. To what extent the application of spatial explicit characterization factors would affect the outcome of this study can be the subject of further research.

5. Sensitivity analysis

A sensitivity analysis has been performed for several parameters to check whether assumptions made in this study have a large impact on the final results for case 3. Such an exercise is especially important for parameters that are expected to have a large impact on the final result and for which the input values are uncertain, i.e. the literature shows a wide range of possible input values (see uncertainty ranges as depicted in Table 3). The parameters that meet these criteria are: SO_2 removal efficiency in the FGD section, net generating efficiency of the power plant without CCS, CO_2 removal efficiency, HF removal efficiency in the CO_2 capture process, nominal MEA consumption and thermal energy requirement for the CO_2 capture process. The results of these analyses are shown in Fig. 9.

Fig. 9A shows a negative relationship between SO_2 reduction and all impact category scores, meaning that a higher removal of SO_2 in the FGD section will improve the scores for all impact categories. This is due to the direct contribution of SO_2 emissions to AP and POP. Indirectly, SO_2 reduction shows a strong negative correlation with the HTP score as SO_2 reduction has a direct effect on MEA consumption and reclaimer bottoms formation. The high sensitivity for the HTP score can thus be explained by the high impact of the MEA production chain on the HTP score, as discussed earlier. The chosen value of 98% is considered to be the most likely value for SO_2 removal, although lower values (~95%) are also valid, especially for older FGD installations.

In Fig. 9B, we can see that changing the net generating efficiency of the power cycle without CO_2 capture and compression has a non-linear and equal effect on all impact categories. From these results we can also derive that adding CCS to existing coal fired power plants with sub-critical steam conditions, and consequently lower thermal efficiencies, will have the consequence of substantially higher scores for all impact categories. It also shows that future developments in the steam cycle, that may improve the thermal efficiency towards 50% or higher, will result in a substantial reduction of the scores for all impact categories.

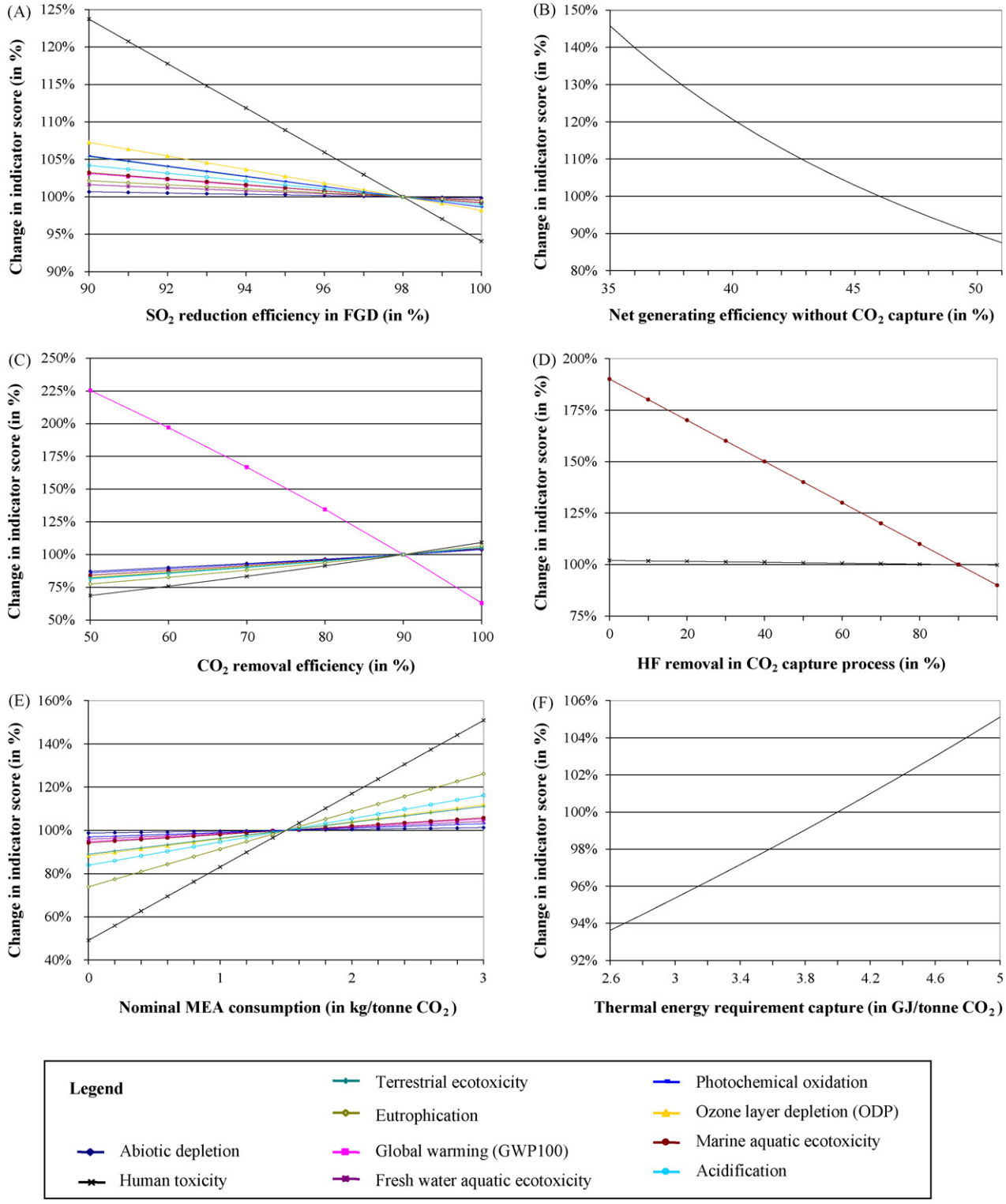


Fig. 9 – Sensitivity analyses for case 3 for selected parameters. On the *x*-axes the parameter values are given and on the *y*-axes the percental change in indicator scores in comparison with the default results for case 3 are presented.

In Fig. 9C, the sensitivity of the GWP score to variance in the CO_2 removal efficiency stands out, obviously. The IPCC (2005) has presented a range derived from literature for the removal efficiency. It comprises values between 85 and 96%. The lower and higher end of this range equals a ~20% increase and ~20% decrease in the score for GWP, respectively. The graph also depicts that with 100% CO_2 removal the score for GWP will be reduced to 63%, equalling 153 g CO_2 equiv./kWh. However, the increase in thermal energy requirement with higher capture rates is not included in the model (see for instance (Abu-Zahra

et al., 2007)). When included, the GWP score would be somewhat less sensitive to CO_2 removal efficiency. For the other impact categories a positive and less sensitive relationship is found. This figure also shows the environmental trade-offs encountered with increasing capture rates.

Fig. 9D, shows the effect of the assumption for HF removal in the CO_2 capture process. It depicts a strong negative relationship with the MAETP score and an insignificant impact on the other categories. These results underline earlier findings that the MAETP score is highly sensitive to HF emissions as for HF possibly too high characterization factors are used. Yet overestimation does not mean that there are no potential environmental impacts attached to HF emissions[11]. However, in literature no value for HF removal is mentioned. The value used in this study is our own assumption based on findings by Strazisar et al. (2003) and thus can be considered an arguable value. This, together with the large impact on the results when varying this value, leads us to conclude that it is desirable to measure HF emissions from coal fired power plants equipped with CO_2 capture and determine the removal efficiency of HF.

Fig. 9E shows the effect of various levels of nominal MEA consumption. What clearly stands out is the sensitivity of the HTP score, ranging between 49 and 151%. To a lesser extent also EP and AP impact categories are dependent on the level of MEA consumed. This is due to our assumption that the emission of ammonia from the capture process is dependent on the MEA degradation by oxidation and, with that, on MEA consumption. The results indicate that MEA consumption and by-product formation due to its degradation, resulting in the formation of NH_3 and solid wastes, should be monitored when MEA-based CO_2 capture facilities are implemented on a pilot, demonstration or commercial scale. These results also indicate that production process data for MEA has to be verified as it has a large impact on the final outcome.

Fig. 9F depicts an almost linear increase of all impact category scores with increasing thermal energy requirement for CO_2 capture. The sensitivity of the results for changes in thermal energy requirement are low compared to the other selected parameters. From literature we can derive that a value in the range of 3–4.32 is likely (see Table 3). This range equals a sensitivity margin of −4.6% and +1.5% change in final results.

From the figure also the impact of technological development can be estimated. Rao et al. (2006) report an estimate, derived from expert solicitation, for the improvement potential of the thermal energy requirement for future amine-based capture systems of 3.3 GJ/tonne CO_2 captured, instead of 4 GJ/tonne assumed in this study. Abu-Zahra et al. (2007) report an optimum of 3.01 GJ/tonne. According to our model, these values would result in, respectively, a reduction of about 3 and 4.5% for all impact categories.

[11] In the environmental impact statement for a pulverized coal power plant, to be built in the Rotterdam harbour area, local HF background concentrations are reported to be above the threshold value for the maximum acceptable risk. The proposed power plant would increase the background concentration with up to 3.5% (KEMA, 2006b). The addition of CCS would, according to our calculations, result in a significant drop of HF emissions and, thus, a reduced contribution to the local background concentration.

6. Conclusion and recommendations

The goal of this study was to disclose environmental trade-offs and co-benefits due to the implementation of the capture, transport and storage of CO_2, by comparing three coal fired electricity supply chains in the Netherlands with and without post-combustion capture of CO_2 with monoethanolamine.

The results of this comparison are that case 1, the reference case, is outperformed on all ten environmental impact categories by case 2, the current state-of-the-art coal fired power plant, as both thermal efficiency and removal efficiency of air pollutants (SO_2, NO_x, PM, Hg, HF and HCl) has improved significantly.

The comparison of case 3 to both other cases has brought the insight that the addition of CO_2 capture, transport and storage to a state-of-the-art coal fired power plant results in multiple environmental trade-offs and co-benefits.

First, the greenhouse gas emissions are reduced substantially, as intended, to 243 g/kWh due to the implementation of CCS. However, to some extent the capture and storage of CO_2 is offset by increasing GHG emissions due to second- and third-order process emissions. Compared to current operating and state-of-the-art coal fired power plants a GHG reduction of 78 and 71% was found, respectively. The contribution of infrastructural requirements for CO_2 capture, transport and storage to the total of GHG emissions is expected to be limited, i.e. cumulating to 0.3%. Taken into account the GHG emissions over the full chain, we have calculated the avoidance efficiency of 1 kg CO_2 stored at 68%. This figure shows clearly that storing a tonne of CO_2 does not equal one tonne of CO_2 avoided. This should not be neglected when attributing CO_2 emission credits to CCS projects.

Co-benefits that are expected with the addition of CCS are a deeper reduction of direct emissions of sulphur oxides, particulate matter, hydrogen chloride and hydrogen fluoride per kWh. The latter results in an improvement of the score for the marine aquatic ecotoxicity impact category.

Important trade-offs are however expected in direct emissions of NO_x and NH_3 respectively due to the energy penalty associated with CO_2 capture and compression and emissions from the CO_2 capture process. A trade-off is also expected due to the formation and disposal of wastes from the combustion and CO_2 capture process. The energy penalty results in a trade-off in potential environmental impacts due to an increase of upstream environmental interventions, primarily in the coal supply chain. Another important trade-off is found in the impact category human toxicity, which to a large extent can be ascribed to the emission of ethylene oxide during MEA production.

The consequence of these trade-offs is that case 3, the CCS case has higher scores for three (ozone layer depletion, human toxicity and fresh water aquatic ecotoxicity) out of ten environmental impact categories compared to the reference case, has almost equal scores for two (abiotic depletion and eutrophication) and outperforms case 1 on the remaining five (global warming potential, marine aquatic ecotoxicity, terrestrial ecotoxicity, acidification and photochemical oxidation potential) impact categories. The conclusion from comparing case 3 with case 2 is that the addition of CCS is expected to result in a reduction in global warming potential (71%) and

marine aquatic ecotoxicity (27%) scores and an increase of the scores between 27 and 181% for all other impact categories. Impact categories that show a relative high increase are eutrophication (80%) and human toxicity potential (181%). It should, however, be stressed that the score for the human toxicity potential for case 3 is highly uncertain due to possible inaccurate data on the production chain of MEA.

Overall assessment of the three cases indicates that the implementation of present day technology for the post-combustion capture installation at a state-of-the-art coal fired power plant reduces the emissions of greenhouse gasses substantially and may have other direct environmental benefits due to increased removal of particulate matter, SO_2, hydrogen chloride and hydrogen fluoride. However, with the generation of 1 kWh, direct and indirect environmental interventions together, in general, will increase, resulting in the deterioration of the score for eight other environmental impact categories. The judgement on whether these trade-offs are acceptable or not is not within the scope of this study and should be the subject of public debate.

This study has also put forward some important data limitations for the environmental performance of the CO_2 capture process. This is primarily due to lack of detailed process emission data for the CO_2 capture process and, in particular, the impact of the process on trace elements in the flue gas. The results from the sensitivity analysis show that these uncertainties may have a large impact of on the final outcome. This holds especially for the human toxicity and marine aquatic ecotoxicity score, which are sensitive to assumptions for, respectively, the MEA consumption and HF removal in the CO_2 capture process. It is therefore recommended to implement environmental measurement programmes at CO_2 capture pilot and demonstration projects.

These measurement programmes should then measure emissions to various environmental compartments under various operating regimes including the interaction with other flue gas cleaning technologies. Emissions that should be monitored are: SO_x, NO_x, HF, HCl, Hg, PAH, dioxins, hydrocarbons, heavy metals, NH_3, MEA and PM. For particulate matter it is especially of interest to discern the removal efficiencies for the various sizes of particulate matter. For heavy metals it is of interest to measure to what extent the transposition occurs from atmospheric emission to waste water effluent and solid waste. Also, reclaimer composition and emissions during disposal should be monitored and assessed on its environmental impacts in order to prevent the transfer of environmental impacts from the power plant to the waste disposal chain.

Taking into account uncertainties and knowledge gaps, this study does provide insight into desirable improvement directions for CO_2 capture. Technological development regarding absorption-based post-combustion capture should focus on reducing sorbent consumption, ammonia emission and thermal energy requirement by optimizing solvent characteristics and system integration. Another possibility is the development of other types of sorbent, such as chilled ammonia and carbonates (Ciferno et al., 2005; Corti and Lombardi, 2004; Yi et al., 2007). Consecutively, these alternatives should be screened on potential environmental impacts as well.

Acknowledgements

We would like to thank the reviewers for their valuable comments. This work is part of the CATO (carbon capture, transport and storage) research programme, which is supported by the government of the Netherlands and implemented by a consortium of Dutch companies, research institutions, universities and environmental organizations.

Appendix A. Estimated dry elemental composition of reclaimer bottoms from CO_2 capture unit

Element	Mass (kg/kg)
LHV	0.00
O	2.53×10^{-1}
H	8.83×10^{-2}
C	4.28×10^{-1}
S	8.33×10^{-5}
N	1.79×10^{-1}
P	7.51×10^{-5}
Cl	4.90×10^{-2}
Br	8.00×10^{-5}
F	1.50×10^{-3}
As	1.70×10^{-6}
Cu	1.00×10^{-7}
Hg	1×10^{-9}
Se	1.74×10^{-5}
Zn	2.00×10^{-7}
Fe	1.10×10^{-6}
Ca	1.30×10^{-6}
Al	4.00×10^{-7}
K	1.80×10^{-5}
Na	8.21×10^{-4}
Total	1

Note: The composition has been estimated based on Strazisar et al. (2003). No information is available on the heating value of reclaimer bottoms. The LHV is conservatively set at zero.

Appendix B. LCI data for pulverized coal power plant infrastructure (after (Röder et al., 2004))

Material/process	Amount	Unit
Diesel and fuel oil	462	TJ
Electricity (UCPTE[a])	15	GWh
Concrete	62,600	m^3
Rock wool	571	t
Aluminium	332	t
Steel[b]	44,801	t
Copper	710	t
Polyethylene	401	t
Waste to disposal	145,972	t
Transport	14,040,000	t × km
Lifetime	30	Year

[a] UCPTE represents the average electricity generated in Austria, Belgium, France, Germany, Greece, Italy, former Yugoslavia, Luxembourg, the Netherlands, Portugal, Spain, and Switzerland, Portugal, Spain and Switzerland.

[b] Steel composition: 90% un-alloyed, 9% low alloyed and 1% high alloyed.

Appendix C. LCI data for CO_2 capture infrastructure

Material/process	Amount	Unit
Steel (absorber + stripper)	235	t
Steel (piping and small equipment)	82	t
Concrete	1	m^3
Transport	9.5	kt × km
Lifetime	30	Year
Total CO_2 captured over lifetime	94	Mt

Note: All steel is assumed to be high alloyed steel for support of piping and small equipment only.

Appendix D. LCI data for CO_2 compressor infrastructure (altered from (Faist Emmenegger et al., 2003))

Material/Process	Amount	Unit
Concrete	65	m^3
Diesel and heavy fuel oil	1978	GJ
Electricity (UCPTE)	61	MWh
Steel[a]	65	t
Copper	7	t
Polyethylene	20	t
Compressor capacity	40	MW
Lifetime	20	yr
Total CO_2 compressed over lifetime	62	Mt
Total leakage of CO_2 over lifetime	18	kt

Note: Transport is implicitly included in energy consumption. Disposal and recycling are not included.

[a] Steel comprises 5% high alloyed and 95% low alloyed.

Appendix E. LCI data for onshore CO_2 pipeline infrastructure (altered from (Faist Emmenegger et al., 2003))

Material/process	Amount	Unit
Sand	97,500	t
Diesel for construction	165,500	GJ
Reinforcing steel	12,000	t
Drawing of steel pipes	12,000	t
Bitumen	116	t
Polyethylene	232	t
Transport total	11,415,000	t × km
Total disposal of wastes[a]	55592.5	t
Lifetime	30	Year
Total CO_2 transported over lifetime	94	Mt
Total leakage of CO_2 over lifetime	3.5	kt

[a] It is assumed, after (Faist Emmenegger et al., 2003), that 50% of the pipeline materials are removed and disposed off, and that the other 50% remains in the ground.

Appendix F. LCI data for CO_2 injection facility

Material/process	Amount	Unit
Well construction[a]	18	km
Sand	712,000	t
Steel (un-alloyed)	3,800	t
Steel (high alloyed steel)	8,100	t
Concrete	10,463	m^3
Transport (truck)	74,922,800	t × km
Copper (for cables)[b]	425	t

Appendix F (*Continued*)

Material/process	Amount	Unit
Lifetime	30	Year
Total injection capacity over lifetime	219	Mt

Note: Energy use during construction of the surface facility is not included. The dismantling and disposal phases are also not included.

[a] Assuming six wells with a depth of 3000 m.

[b] Assuming 1000 kg copper/km cable, which is a value in the midrange of specific cable weights. These cables are for the transport of data and electricity.

Appendix G. LCI data for MEA production (after (Althaus et al., 2004))

Material/process	Amount	Unit
Input		
Ethylene oxide	816	g
Ammonia	788	g
Electricity	0.333	kWh
Natural gas	2	MJ
Transport (truck and train)	11.23	t × km
Infrastructure chemical plant	4×10^{-10}	p
Output		
Monoethanolamine	1	kg
Waste heat	1.2	MJ
Ethylene oxide to air	1.63	g
Ethylene oxide to water	1.47	g
Ammonia to air	1.58	g
Ammonium to water	3.04	g
CO_2	26.5	g
Nitrate [NO_3^-] to water	6.97	g
COD, BOD	21.3	g
TOC, DOC	8.02	g

Note: COD = chemical oxygen demand, BOD = biological oxygen demand, TOC = total organic carbon and DOC = dissolved organic carbon; solid wastes are not included.

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