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An Economic and Environmental Assessment of Carbon Capture and Storage (CCS) Power Plants – A Case Study for the City of Kiel

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Abstract:

In the next years several power plants throughout Europe have to be replaced and the questions is whether to build coal fired power plants with carbon capture and storage (CCS). In a study for the city of Kiel in northern Germany only a 800 MW coal power plant reaches a required minimum rentability. We use the study for an additional economic and environmental evaluation of a coal plant with CCS. We find that integrated gasification combined cycle (IGCC) plants with CCS have in two out of three carbon and energy price scenarios the largest rentability. Pulverized coal (PC) plants with CCS can only compete with other options under very favourable assumptions. Life-cycle emissions from CCS are less than 70% of a coal plant – compared to at least more than 80% when only considering direct emissions from plants. Still, life-cycle emissions are lower than in any other assessed option.

Keywords: coal fired power plants, carbon capture and storage (CCS), cash flow analysis, life cycle analysis

JEL classification: Q49, Q54, Q59

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1. Introduction

In the past few years the emerging technology of carbon capture and storage (CCS) - that is capture of CO_2 before or after the combustion of fossil fuels and its subsequent storage in geological formations or the ocean - has received increasing attention as one means to reduce greenhouse gas (GHG) emissions and to mitigate global warming.

CCS is seen not only as a potentially cheap option with high reduction potentials. It would also allow the continued use of coal, which is the most abundant and cheap fossil fuel, currently providing around 40% of global electricity generation (IEA 2008). CCS could be applied to coal-fired power plants, and thus be integrated into the existing fossil fuel infrastructure relatively quick and serve as a mitigation option with an immediate impact (Lackner and Sachs 2005). In many studies (e.g. van der Zwaan and Gerlagh 2008, IPCC 2007, Stern 2007, Lecoq and Chomitz 2001, Narita 2008) analyzing pathways to reach a stabilization of GHG concentrations in the atmosphere CCS plays an important role – either as an interim solution until other options become economically and technological available, or also in the longer term. At the same time, there are concerns about the risks associated with CCS (see e.g. IPCC 2007 for an overview) and about the overall sustainability of this technology. Integration of CCS in the energy sector could decelerate the transition process towards an energy mix based solely on renewable resource. Furthermore, power plants with CCS have a higher energy demand than plants without CCS and when considering the entire lifecycle of a CCS plant, the emission reductions are less pronounced.

With the negotiations for an international climate regime as a follow-up of the Kyoto Protocol that expires in 2012, and with the increased public awareness on the potential effects of global warming as a result of recent flood events, heat spells and hurricanes, the debate about the role of CCS and necessary policy support has gained momentum. Also, there is an increasing number of R&D activities, pilot and demonstration plants and storage projects evolving, as well as activities to develop congruent regulatory frameworks worldwide (see e.g. Praetorius and Schumacher 2008). Besides necessary technological knowledge and a regulatory framework, strong economic incentives are needed to bring CCS to the market. Currently, major institutional impulses for CCS originate from the EU Commission (European Commission 2008). CCS is also increasingly on the agenda of power companies and local politicians, since in the next few years several power plants throughout Europe have to be replaced. For power companies and plant owners the main question is the likely rentability of a new power plant that depends on many – partially highly uncertain – variables on the cost and on the revenue side. Assumptions on investment costs, carbon prices, fuel prices, electricity demand, and their future development strongly affect the optimal plant type and size.

A typical case where currently a decision about a new power plant has to be taken is the city of Kiel in northern Germany, where a coal-fired power plant is getting close to the end of its life time. In 2007, external experts were assigned to evaluate options for a new power plant with respect to their profitability and their impact on the environment. Out of the evaluated six options that include coal-fired power plants of different capacity (800MW and 360 MW, respectively), a combined gas and steam power plant, a multi-fuel power plant and a decentralized option, only the large 800 MW coal power plant reached the minimum rentability set by the municipality (see Freischlad et al. 2007). After a somewhat heated discussion the recommendation was to postpone the decision until the uncertainties about CCS have decreased and then to seriously consider building a coal-fired power plant with CCS. Yet, the profitability of such a plant was not assessed. Meanwhile, the discussion has emerged and there are some signs that the political will is to not consider the option of a coal power plant at all.

In this paper we use the study by Freischlad et al. for an additional economic and environmental evaluation of a coal power plant with CCS. Comparing the profitability and emissions of the different options for a coal power plant with CCS with the options already evaluated in Freischlad et al., can shed light on the current incentives and the relevant trade-offs. For (inter)national policy makers that are concerned with the role of CCS in climate policy the study provides information on whether current climate policies and anticipated carbon prices are already sufficient for CCS plants to be build, or whether additional incentives and regulations are needed if one believes that CCS should play an important role to reach ambitious climate targets. For local policy makers the study helps to identify the trade-offs between profitability and environmental friendliness in a broader setting.

Our main results show that integrated gasification combined cycle (IGCC) plants equipped with CCS are in all scenarios either the first or the second choice when maximizing the net present value (NPV). Even in the first scenario where the 800 MW coal-fired power plant has the highest NPV, an IGCC plant reaches the minimum profitability. These results are mostly not affected by the cost uncertainties for building an IGCC plant. Only very unfavourable cost assumptions lead to a small negative NPV. The life cycle assessment shows that an IGCC plant with CCS is also an option that is leading to low life-cycle CO_2 emissions, even though emission reductions are less then for direct emissions. Finally, building a CCS plant at the beginning is clearly preferable to retrofitting a plant – concerning profitability as well as life-cycle emissions.

The study proceeds as follows. Sections 2 to 4 summarize helpful background information about relevant literature, the situation in Kiel and the CCS technology. Sections 5 and 6 contain the economic and environmental analysis of different options of coal-fired power plants with CCS in Kiel. The economic analysis is based on a cash flow analysis and focuses on the NPV. The environmental assessment contains a life cycle analysis for different environmental impact categories. Section 7 concludes.

2. Literature Review

Several authors have addressed the potential role of CCS for achieving specific GHG reduction obligations. The majority of them start from a certain reduction target. Van der Zwaan and Gerlagh

(2006) for example, see CCS as a suited option to achieve quick emission reductions in the first half of the 21st century when coal will continue to be the dominant form of energy supply worldwide. In order to reach a stabilization target of 450ppmv, however, at least half of the energy system should consist of renewable sources by the year 2100. Lecoq and Chomitz (2001) stress the importance of the permanency of carbon sequestration. If storage shows to be non-permanent, then CCS would be a cost-effective option only in case energy abatement costs are high, and the damages of climate change are significant (see Lecoq et al, page 23). Carbon sequestration would then pose a solution to bridge the time until energy from renewable resources becomes affordable.

In his extensive review on the economics of climate change, Stern (2007) argues that carbon storage could mount up to 6 Gt CO_2 in 2050, and pose an important element along with energy efficiency improvements, biofuels, and solar-, wind- and hydropower. The IPCC has estimated that CCS holds the potential of sequestering up to 2,000 Gt CO_2, an amount representing the total global CO_2 emissions of several decades (IPCC 2005). Narita (2008) analyzes the optimal use of CCS under two sets of assumptions. In one parameterization CCS implementation would occur only by the middle of the century, while in the other, CCS should be implemented immediately. This implies for policy making that in case CCS becomes cost-effective rather late, the technology will remain a niche technology, while the latter assumptions support a strong policy for CCS's immediate and wide implementation. The Wuppertal Institute (2008) analyses the role of CCS technology for reaching a 75% GHG emissions reduction by 2050 (compared to 1990s level) in the German energy sector by developing three scenarios. In the first scenario with CCS as the main instrument, the technology would run towards a capacity limit. In the second scenario, energy efficiency improvement and extension of renewable energy would play the dominant role. In the third scenario, CCS is used as a support tool for improved efficiency and renewable energy. Energy efficiency and infrastructure for renewable energy could be improved until the year 2020, while at the same time the opportunity is given to explore the development and cost potentials of CCS thoroughly and without pressure of time.

Studies that take similar directions than our study are the studies by Rubin et al. (2005), Sekar et al. (2007) and Bohm (2006). Rubin et al. evaluate the cost and performance of power plants equipped with CCS using the Integrated Environmental Control Model (IECM) to estimate costs and emissions, as well as efficiency and resource requirement of current CCS technologies. The analysis is done for pulverized coal (PC) plants, natural gas combined cycle (NGCC) plants, and integrated gasification combined cycle (IGCC) plants using coal. In particular, the effect of increases in capital cost for these three plant types, as well as variations in plant sizes are examined. Rubin et al. conclude that costs of electricity are lower for PC plants without capture, while cost of current IGCC plants with CCS are lowest: total capital requirements for PC plants with CCS are calculated at 2345 $/kw, while IGCC plants with CCS have a capital requirement of 2076 $/kw, showing that IGCC plants could be an attractive option for the investor, if CCS technology becomes mandatory. Output loss (capacity derating) is significantly higher with PC plants (23.9%) then with IGCC plants (13.4%).

Sekar et al. (2007) calculate the NPV of IGCC and PC plants in different carbon tax scenarios for the United States. Power plants are set to be constructed in 2010, and retrofitted with a capture unit four years later. Cost assumptions are similar to Rubin et al. (2005): Capital cost requirements of an IGCC plant with CCS are only 987 million USD, compared to 1258 million USD for a PC plant with CCS. The latter shows annual CO_2 emissions of 0.38 million tonnes, and and IGCC plant emissions of 0.31 million tonnes. Without carbon taxation the NPV for the PC plant is 2,000.4 million USD and for the IGCC plant it is 1,679.5 million USD. If the carbon tax rate is growing at less than 4% per year, IGCC plants become more profitable once the tax exceeds 23.27 USD/t CO_2. If the tax rate grows at a higher rate, the switch point occurs earlier, at approximately 13.71 USD/tCO_2.

Bohm (2006) and Bohm et al. (2007) estimate the NPV of PC and IGCC plants with differing levels of pre-investment for CO_2 capture in different carbon tax scenarios and determine the optimal year for a retrofit. They find that PC plants have the highest NPV under low carbon prices, and IGCC plants have the highest NPV at higher CO_2 prices (initial price of about 22 USD/t CO_2, growth rate of 2%). A retrofit for PC plants would only occur if the initial CO_2 price is at 35 USD /t CO_2, whereas for IGCC plants a retrofit could be economical at an initial price of 20 USD / t CO_2.

Our study uses the results of the cost estimates of these existing studies to assess the net present value of a coal plants with capture technology in Kiel. While the studies by Bohm et al. and Sekar et al. focus on CCS plants only and assess the optimality of different plant types under different carbon prices, this study takes a wider approach. Besides the cost for carbon capture we also consider transport and storage costs. Furthermore, CCS plants are also compared to other options, and finally, the evaluation is intended to be an integrated environmental and economic evaluation with a stronger focus on environmental impacts.

3. The Situation in Kiel

Currently, the replacement of an aging coal-fired power plant in the city of Kiel is discussed, and carbon capture and storage technology is used as a support argument to build again a coal-fired power plant. The existing plant has a net output capacity of 323 mega watts (MW) and covers 35% of Kiel's heat energy demand. In 2007, the local municipality initiated a report to evaluate options for a possible replacement of the power plant. Potential successors were assessed by their profitability and environmental impact. Profitability to the plant owner was analyzed in three scenarios, each underlying different assumptions for future trajectories of CO_2 permit prices, fuel prices, and power revenues. As requested by the municipality, six plant options were evaluated: a 800 MW, as well as a 360 MW power plant fired with black coal; a 400 MW natural gas and steam power plant combined or not with a 360 MW coal power plant; a 280 MW multi-fuel power plant, consisting of coal- and biomass-firing (hay) plus a 70 MW gas turbine; and finally, a decentralized option consisting of a 100 MW natural gas and steam power plant, a 4 MW block heat and power plant (BHPP), 30 MW geothermal energy and a 40 MW biomass power plant.

The final report (Freischlad et al. 2008) finds that the 800 MW coal-fired plant is the most economical choice in all scenarios. The municipality defined an internal return of investment or internal rate of return of 6.5% as the minimum level of profitability. The coal options exceed this level in all scenarios. Returns of the other options fall below this level, except for the scenario with high permit prices and high fuel prices (for a detailed overview see Freischlad et al. 2008, page 150). On the downside, total greenhouse gas emissions of the coal-fired plant are between 20% and 40% higher compared to the other options. Here, the natural gas and steam power plant solution shows the lowest overall greenhouse gases emissions, followed by the decentralized option.

CCS is mentioned in the report as a possible option for a newly built coal-fired power plant in the expected starting year of 2014. The retrofit of a plant with CCS will likely play a key role in Kiel, which could become attractive for the plant owner in case of very stringent climate policies implying a high permit price. Investment costs for retrofitting are calculated at 300 – 400 $/kW (Freischlad et al. 2008). The recommendation of Freischlad et al. included a delay in the decision over a plant successor for another three to five years. It is assumed that by then more reliable assumptions could be made about technological progress in CCS, the cost of the technology, fuel and permit prices, as well as about the implementation of relevant political decisions.

4. CCS Technologies

Carbon dioxide capture and storage (CCS) is a greenhouse gas mitigation option in which CO_2, released from the combustion of fossil- or biomass-based fuel, is captured and sequestered in suitable storage sites. During the capture of the flue gas, CO_2 must be separated from other present gases and can then be transported to the site where it is stored away from the atmosphere (IPCC 2005).

CO_2 can be captured from fossil-fuelled streams using three basic systems: post-combustion capture, pre-combustion capture and capture via oxyfuel combustion. Important characteristics of the different options are summarized in table 1. A plant owner has the option to build a power plant with the capture system readily installed, or to first erect a power plant and install the capture system at a later point in time. This is referred to as **retrofitting** a plant (Bohm et al. 2007). Technically, all capture systems can be retrofitted. In addition, the plant owner has the option to invest in pre-designing certain components of the power plant so that a retrofit later on saves costs and improves the overall performance of the retrofitted plant.

Table 1: Comparison of capture options

	Post-combustion capture	**Pre-combustion capture**	**Oxyfuel combustion capture**
Energy demand	medium	low	high
Experience with CCS	few pilot plants exist	low, pilot plants planned	not existing in context with CCS
CO_2 capture efficiency	low	medium	high
possibility to retrofit	generally possible	generally possible	generally possible

Today, the primary focus in research and development of CCS is on cost reduction of the technology and improvement of the feasibility of the entire process chain from capture to storage. There is large uncertainty when CCS will be applicable on a large scale and become commercially viable. While the majority of studies assumes CCS to be commercially viable no earlier than 2020 (Wuppertal Institute 2008; IPCC 2005), the World Business Council for Sustainable Development (WBCSB) is less optimistic and does not see CCS viability before the year 2030 (WBCSB 2006). In contrast, many leading power companies have a more optimistic stance on this issue and assume the technology to be available as early as 2015.

Concerning transportation, CO_2 is primarily transported via pipelines, but could also be moved by tank trucks, ships or even on railroad systems. For our case study transport via pipelines is considered. For this purpose, CO_2 is required to be in a gaseous state, dried and under high pressure. Plenty experience exists with transport of carbon dioxide via this method.

A summary of opportunities to store carbon dioxide is given in table 2. The indicated storage depth presents a range in which storage has been shown to be most feasible (IPCC 2005). The global capacity range reflects a summary of several assessment studies. Results shown are based on assessment methods that decrease in accuracy with increasing size and numbers of storage basins.

Based on calculations from depth, pressure and temperature of fields, storage potential for northwestern Europe is estimated at 40 Gt CO_2 (Wildenborg et al. 2005b). For Germany, May et al. (2005) assessed the storage capacity in saline aquifers and found it to range from 12 – 28 Gt CO_2.

In the case of the power plant in Kiel, we assume a pipeline construction of 100 – 150 km to a sediment basin located in northwestern Schleswig-Holstein (Nordfriesland). The basin shows characteristics of a saline aquifer and could potentially serve as a suitable storage site. A research group at the University of Kiel is currently investigating the feasibility for sequestering CO_2 (Dahmke 2008).

Table 2: Geological storage options (after IPCC, 2005)

Geological Storage Options for	**storage depth** kilometers	**on-/offshore**	**global capacity** Gt CO_2
Depleted oil and gas reservoirs	0.8 -2	both	675 - 900
Use in enhanced oil recovery	0.6 - 2	both	61 - 123
Saline aquifers	0.8 - 2	both	1.000 - 10.000
Deep unmineable coal seems	0.6 -1	onshore	3 - 200
Use in enhanced coal bed methan recovery	0.4 - 0.8	onshore	not assessed
Storage in basalts, oil shales, cavities	0.6 - 1	onshore	not assessed

5. Economic Evaluation of a CCS Plant

The economic and also the following environmental evaluation is undertaken for three plant types: an IGCC plant with pre-combustion, a pulverized coal plant with post-combustion and a pulverized coal plant with oxy-fuel combustion capture technology. For the first two plant types also retrofitting of capture technologies is possible and evaluated.

5.1 Methodology and Cost Assumptions

As in Bohm (2006), Bohm et al. (2007), Sekar et al. (2007) and Freischlad et al. (2008), we perform a cash flow and net present value (NPV) analysis for the different plant types. For all plant types we assume a lifetime of 45 years. The calculations are based on the cash flow analysis of Freischlad et al. for an 800 MW coal-fired power plant in different scenarios. The assumptions for this base plant are summarized in table 4.3. In a first step, the analysis is extended to the described CCS plants. In a second step, the option to retrofit a PC or IGCC plant is analysed. We calculate the earliest year for an installation of a capture unit such that the NPV is positive and analyse how the NVP develops for later retrofit dates. The earliest year for which we analyse a retrofit is 2020.

To derive the costs of an IGCC plant we assume a 5% increase in investment costs between the PC base plants and the IGCC plants based on a survey by Sekar (2005). Cost assumptions for plants equipped with post-combustion, pre-combustion or oxyfuel capture technology are derived from studies discussed in the IPCC Special Report on CCS (2005). Capture technologies affect certain key cost components of plants described in table 3.

The analysis of cost differences between coal-fired plants and CCS plants can be concentrated on investment costs required for the capture unit, increased fuel costs due to a higher energy demand, plant derating and related decrease of power revenue, as well as annual costs for transport and storage. We derive average values for the additional costs from IEA GHG (2004), IPCC (2005), Rubin et al. (2005), Parsons (2002) and Mitretek (2003). Costs for retrofitting are adopted from Bohm et al. (2007) and Sekar (2005). Retrofitting power plants with capture units decreases the performance of plants more than capture units that are integrated from the start. In particular, Bohm finds that fuel requirements increase about 29% after retrofitting PC coal plants, and 22% after retrofitting IGCC plants, as opposed to 25% and 20% respectively for plants with a capture unit readily installed (Bohm 2006, p. 79). Also, plants experience a stronger derating after the retrofit. For PC power plants a derating of 30% of the base plants output capacity can be expected, respectively 18% for IGCC plants.

Investment costs for the capture unit are, however, similar in costs regardless if they are retrofitted, or readily installed. For a plant retrofit we assume that during necessary constructions the existing plant is shut down for one year. The loss in heat revenue during that year is made up by the other available plant options in the region around Kiel.

Table 3: Economic parameters of base plant used in this study

Parameter	Value
Investment costs base plant	1040 M€
Specific investment costs Kiel	112.5 M€
Lifetime of plant	45 a
Depreciation	35 a
Variable production costs	technology specific
Staff costs	95 employees a 75 t€
Administration & overhead costs	1.6 M€/a
Escalation factor staff	0.5%/ a real
Escalation factor others	1%/ a real
Revenues, other	1.6 M€ /a
Maintenance costs	1.5% of investment cost
Insurance costs	0.5% of investment costs
Discount rate	6.5%

Source: Freischlad et al. (2008)

Costs for transport and storage can be separated in one-time investment costs and annual (variable-) costs. We assume transport of CO_2 by pipeline for 100km to a storage site in Nordfriesland. Hendricks et al. (2002) show that transport cost vary with diameter and length of the pipe, as well as the mass flow rate. We assume medium values. Average investment costs from the studies by Hendricks & Wildenborg (2005), Chandler (2000) and IEA GHG (2002) are 0.44 M€/km. Annual transport costs are, following IEA GHG (2002), assumed to be 1.2 M€ for a post-combustion plant, 1.9 M€ for an IGCC plant, and 1.6 M€ for an oxy-fuel plant. True transport costs will likely deviate slightly, because of region specific cost factors that might affect the pipeline route, like highways, proximity to property etc. Costs are also expected to increase if protest causes a delay in construction.

Storage costs are region specific, increase with increasing storage depth and vary with the geological storage medium. We assume storage in a saline aquifer in Nordfriesland. Costs are adopted from Hendricks et al. (2002), who proposes a range of storage costs from 1.9 to 6.2 US$/ tCO_2, with a mid range value of 2.8 US$/ tCO_2 in Europe. One time investment costs for storage are assumed to be 12.4 M€. Again, these numbers are most likely to change slightly due to region specific issues. Annual storage costs are estimated to be 11 M€ for a PC coal-fired plant.

Table 4 summarizes the assumptions for the cash flow analysis. Values in brackets give the range of values in the different studies, i.e. minimum and maximum values found in the literature.

Table 4: Investment costs, -revenues, variable and fixed costs of all CCS plant options

	PC-fired plant Post-combustion	**PC-fired plant Oxyfuel technology**	**IGCC plant Pre-combustion**
Capacity after derating (MW)	709 (640 - 720)	624 (584 - 648)	750 (728 - 760)
Investment costs New plant (M€)	 1040	 1393,6 (1211 - 1653.5)	 1092 (1040 - 1144)
Capture unit (M€)	530,4 (495.2 - 565.6)	655 (647 - 663)	404 (385.2 - 423.8)
Transport costs (M€)	44 41 - 48	44 41 - 48	44 41 - 48
Storage costs (M€)	12.4 (9.8 - 15)	12.4 (9.8 - 15)	12.4 (9.8 - 15)
Revenues (% of BP) Power Revenue Heat Revenue	 88 88 (80 - 90)	 77 77 (73 - 81)	 93 93 (91 - 95)
Variable Costs (% of BP) Fuel (black coal) Operating costs	 125 (120-130) 151	 125 (120-130) 151	 120 (113.4 - 126.6) 132
Fixed costs Annual transport (M€) Annual storage (M€)	 1.2 (1.1 - 1.3) 11 (9.6 - 12.4)	 1.9 (1.78 - 2.02) 12.48 (9.2 - 15.8)	 1,6 (1.44-1.76) 11.6 (10.2 - 13)
CO_2 reduction (% of BP)	84 (80 - 88)	95 (90 - 100)	90 (85 - 95)

5.2 Scenarios and Sensitivity Analysis

Costs of power plants are evaluated for three scenarios with different paths of relevant variables. We use the same three scenarios as described by Freischlad et al. (2008) which assume that the key parameters CO_2 permit price, fuel price and power revenue to the plant owner behave as described in table 5 and rise more or less linearly from 2015 to 2050. Prices for fuel follow the World Energy Outlook (2006). The paths for power revenues are dependent on the spot market development for electricity prices, which again is influenced by the future constellation of the energy portfolio in Germany. Permit prices for carbon dioxide are influenced by the applied mitigation strategy in Germany. Scenario 2 and 3 represent an ambitious mitigation strategy, in which the total allowable emissions are reduced accordingly. The constellation in scenario 3 of high fuel prices and high permit prices results in a raise of power revenues (Freischlad et al., 2008).

Table 5: Price range of scenario indicators used throughout this study

Indicator	**CO_2 permit price**	**Fuel price**	**power revenue**
Unit	€/tCO_2	€/Mwh	€/Mwh
Scenario 1 (reference)	23 - 30.5	7.5 - 11.33	62 - 77
Scenario 2	28 - 85	7.5 - 11.33	65 - 90
Scenario 3	28 - 85	22.5 - 34	120 - 201

Besides varying CO_2 and fuel prices and power revenues, we also undertake a sensitivity analysis with respect to our cost assumptions for CCS plants. For this, we calculate the NVP under two extreme assumptions where we either always take the highest costs and derating that we could find in literature or the lowest. This can shed some light on the effects of the large cost uncertainties of CCS plants.

5.3 Results

Our initial question was to compare the different CCS technologies to other power generating options discussed for the city of Kiel in the three scenarios. Figure 1 shows a comparison of the NPV for all options. The values for option 1 (800 MW coal plant) and 5 – 9 are taken from Freischlad et al. (2008). Options 2, 3 and 4 are the different types of CCS plants. The bar shows the NPV for our best-guess cost assumptions. The lines show the variation in the sensitivity analysis.

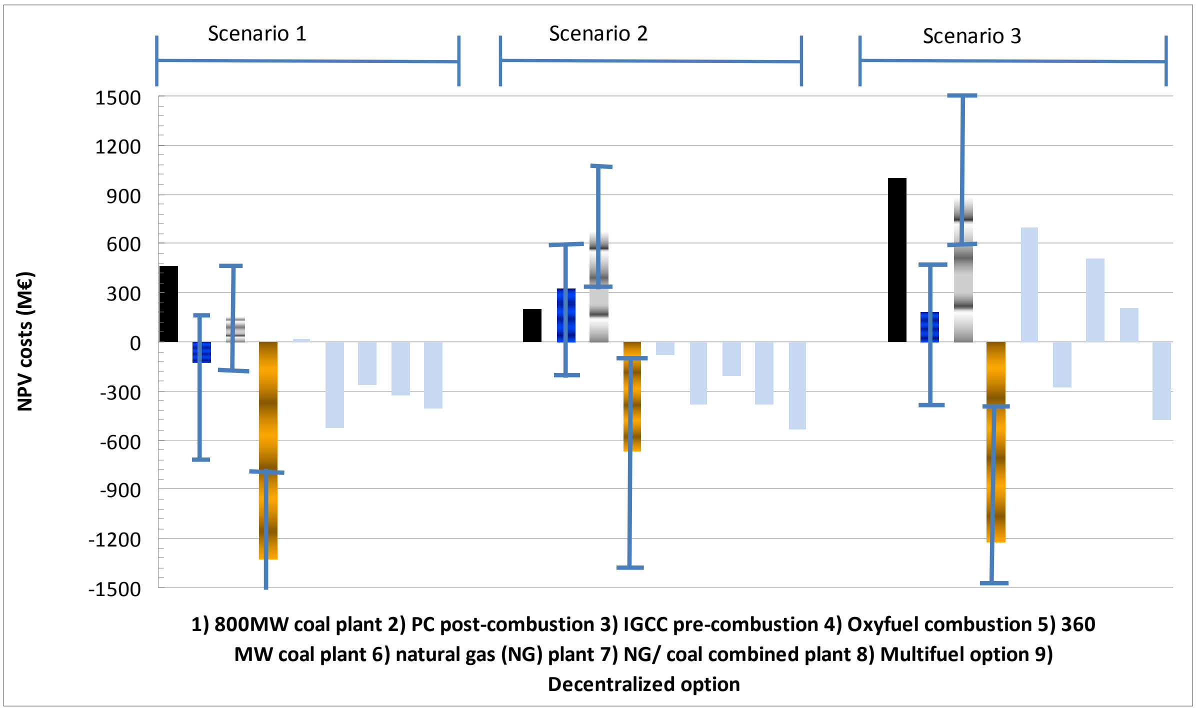

Figure 1: NPV of all plant options in scenario 1 - 3

A number of conclusions can be drawn concerning the optimality of CCS plants. Among the different available technologies for carbon capture, pre-combustion capture applied to an IGCC plant is the most economical choice in scenario 1- 3. IGCC plants with a capture unit experience the lowest decrease in efficiency factors compared to the other two capture technologies. They thus need the least fuel. This is particularly amplified in scenario 3, which includes a fuel price trajectory about three times as high as in scenario 1. In contrast, a capture plant with oxyfuel technology burdens the strongest capacity derating and is the most expensive CCS plant.

A coal-fired plant equipped with oxyfuel capture is not only always the least profitable option among the three capture plants but even among all non-CCS options. Even under the most favourable cost assumptions the NPV of such a plant is negative in all scenarios. Only in scenario 2 with very favourable conditions for CCS in general (high carbon prices, low fuel prices) is such a plant getting close to an internal rate of return of 6.5%. The IGCC plant is the preferable option for maximizing the NPV in scenario 2 where it clearly outperforms all other options – even when taking into account the cost uncertainty. In scenario 3 with high carbon and fuel prices, an IGCC plant has still the second highest NPV of all options. Only a 800 MW coal-fired plant has a higher NPV. Yet, under favourable cost assumptions the IGGC plant has the highest NPV in this scenario as well. This is also true for scenario 1, but here only the lowest cost assumptions leads to a NPV for the IGCC plant that is higher then the NPV of the 800 MW coal-fired plant. Yet, there is also the possibility that an IGCC plant does not reach the minimum internal rate of return of 6.5%.

The non-coal options all have a negative NPV in scenarios 1, 2 and with one exception also in 3 and do not reach the minimum required rate of return. Only the natural gas plant has a small positive NPV in scenario 3. Thus, it must be noted that even a higher permit price reaching 85 €/tCO_2 in 2050 is not effective enough to put plant options that are low in carbon dioxide emissions in a position where they are attractive alternatives to coal-fired options for the plant owner. For carbon capture plants however, the price increase has a high enough impact to make an investment profitable.

Our second major question concerned the optimality of retrofitted CCS plants. To analyze this we calculated the NPV for the two plant types in the three scenarios assuming a retrofit in different years. The results are shown in figure 2. The dotted lines show the level of the plants with CCS from the start.

The earliest year where retrofitting leads to a positive NPV is in 2022 for the IGCC plant in scenario 3, seven years after the initial construction of the plant. Retrofitting of a pulverized coal plant leads to a positive NPV only 14 or even 18 years after construction. In scenario 2 and 3 retrofitting of IGCC plants with pre-combustion technology could occur between 5 and 7 years earlier than post-combustion technology for pulverized coal plants. A price increase for carbon emissions clearly sets the year to retrofit aback. In scenario 1, retrofitting occurs only 19 or 23 years after the initial construction of the base plant, respectively. This late no plant owner is likely to feel the need to retrofit, as the amortization period for the plant is set to 35 years.

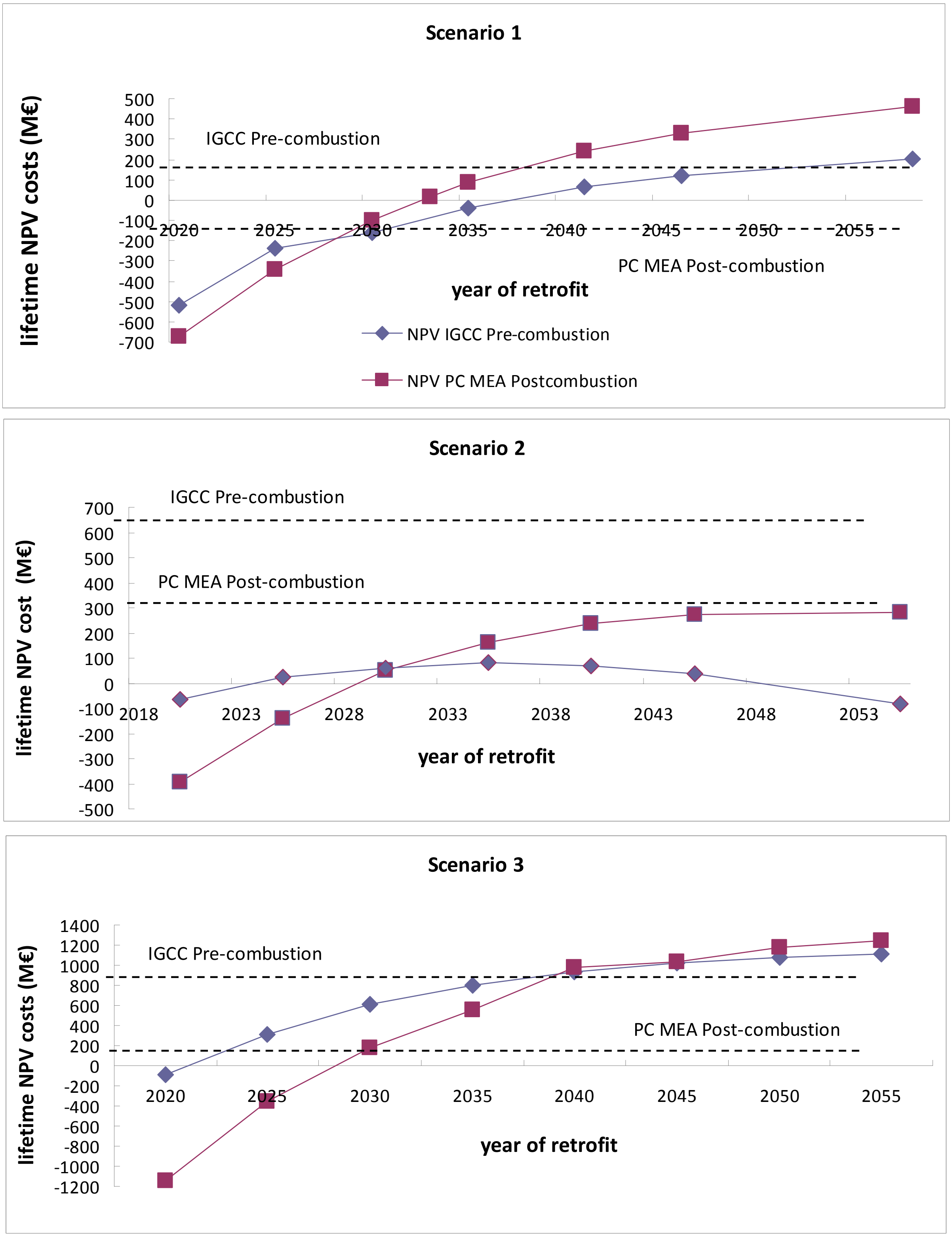

Figure 2: Lifetime NPV vs. year of retrofit

In terms of profitability a later retrofit is preferable and the NPV rises with longer run-times without the retrofit. The same investment costs are discounted more the further they appear in the future. Also, a CCS plant leads to lower costs under high permit prices – and these are assumed to grow over time. The one exception in this case is the IGCC plant in the very favourable CCS scenario 2, where the permit prices are rather high and fuel prices are rather low so that the variable costs of the IGCC plant are already considerably lower then for a coal-plant without CCS, so that this effect dominates the less-discounted investment cost at some point in time. As a result the NPV starts to fall after 2035 and becomes negative for a very late retrofit after 2048.

Retrofitting an IGCC plant is never preferable to investing in an IGCC plant with CCS from the start. The NPV of a retrofitted plant is always lower and it only reaches the NPV of the IGCC plant with CCS from the start for a retrofit close to the end of the lifetime in scenario 3. Retrofitting a PC plant is also less preferable than building an IGCC plant with CCS from the start in the scenarios 2 and 3. Only in scenario 1, retrofitting a PC plant after the year 2035 leads to the same or even higher NPV as the IGCC plant with CCS from the start.

As a final remark, our results are also in line with Bohm (2006). Our carbon price in scenario 1 is already in a range where Bohm finds that IGCC plants are preferred to PC plants. Our results for early retrofit years are also in line with his findings.

6. Environmental Evaluation of a CCS Plant

In this section we assess potential environmental impacts of all relevant power generating technologies considering the whole process chain of materials based on Freischlad et al. (2008), Wuppertal Institute (2008) and Viehbahn & Nitsch (2006).

6.1 Life Cycle Analysis

A life cycle assessment stands for a holistic approach to analyse a full range of environmental impacts of products and services (Guinee, 2002). It encompasses all specific steps a product undergoes from manufacture to disposal. The sum of all steps (phases) is considered to be the life cycle of the product. The LCA analysis is part of the ISO 14000 environmental management standards. In the case of modelling life cycles of plants that are built in the future, as in this study, a so called prospective LCA is performed.

Inventory and modelling of life cycles are commonly done using software packages. Wuppertal Institute (2008) and Viehbahn & Nitsch (2006) used the software Umberto to model life cycles of power plants, while Freischlad et al. use the model GEMIS for their analysis (Eco Institute 2008, IFEU, 2007).

An entire life cycle assessment for CCS plants is beyond the scope of this paper. We thus compare existing results from studies of the third phase of an LCA (the environmental impact assessment) and attempt to draw conclusions about environmental impacts of CCS plant options for Kiel. The analysis encompasses the entire impact chain associated with power plants: starting from initial mining of coal (in case of coal-fired power plants), along transport to the power plant, impacts related to burning of fuel and transport of carbon dioxide to storage sites (in case of CCS plants). In particular we choose the following six impact categories:

- Global Warming Potential in $MtCO_2$ eq.
- Energy Demand in GWh/a
- Photooxidant Formation in g Ethen-eq/kWhel
- Eutrophication in g PO4^-3 eq/kWh
- Acidification in 10. g SO_2 eq/kWh el
- Particulate Matter in 10g PM 10-eq/kWhel

We compare all power plants (including CCS plants) in these six environmental impact categories, with the exception of the energy demand category, where we only compare the 800 MW coal-fired base plant with the different CCS plants.

Small adjustments and assumptions are necessary to match our specific situation. First, we assume that all plants run at full capacity throughout the entire year. In reality, it is possible that power plants are running low for a set time, which would have an impact on the emissions of the plant. Secondly, it is assumed that the magnitude of all impacts increase linearly with increased output capacity of plants. This relationship is stated by Viehbahn & Nitsch (2006). The Wuppertal Institute (2008) analysed plants with a standardized 500 MW capacity. Results are adjusted to fit the capacity of plants discussed in this paper.

6.2 Results

The most important impact category is the global warming potential of plant options which describes the amount of specific emissions released to the air that contribute to the greenhouse gas effect. Table 6 shows a comparison of emissions originating from power plants and the summary of emissions from the entire process chain, including upstream emissions. The last column shows the increased resource consumption expressed in energy demand of carbon capture plants, compared to an 800 MW base plant with coal combustion.

The 800 MW coal option emits the most CO_2. Clearly, CCS plants show the lowest amount of emissions. Literature focusing on CCS commonly mentions a CO_2 reduction potential of CCS plants in the range of 80 % - 99% compared to the base plant, depending on the capture technology. These values are clearly only applicable to the plant emissions. Life cycle analysis reveals that emissions of the entire process chain are in fact significantly higher. Sources of additional CO_2 emissions can be found in the production process of chemicals for flue gas scrubber, as well as those associated with the increased fuel extraction at the mining site. Thus, the relative emission reduction potential compared to the base plant without CCS decreases significantly once the entire process chain is considered. GHG emissions of the life cycle of CCS plants make up about 32% of emissions from the base plant (5.6 MT CO_2 compared to 1.8 MT CO_2). In contrast, emissions from direct CCS power station operation are between 10% and 14% of those from the base plant. It follows that about 1.15 MT of additional emissions occur during the transport and storage processes.

Table 6: Environmental impacts of different plants

Power plant option for Kiel	**emissions (Mt CO2 eq.)**		**Annual Demand of black coal (Gwh/a)**
	direct	**entire process chain**	
800 MW PC power plant	4.9	5.6	13270
360 MW PC power plant	2.1	4.6	
400 MW NG/steam power plant	1.0	3.2	
360 MW PC plant & 400 MW NG plant	3.0	4.0	
Multifuel power plant option	1.4	4.1	
decentralized power plant	0.3	3.5	
CCS PC MEA post combustion plant	0.68	1.85	16985.6
CCS IGCC pre-combustion plant	0.72	1.79	16454.8
oxyfuel combustion	0.05	0.56	17914.5
retrofit IGCC pre-combustion plant (2024)	1.57	2.57	15798.1
retrofit PC MEA post-combustion (2029)	2.02		15735.3

Sources: Freischlad et al (2008), Wuppertal Institute (2008), Viehbahn and Nitsch (2006), own calculations.

Plants retrofitted between 9 and 14 years after the initial base plant construction do in fact have higher plant emissions than some of the other options, i.e. the multifuel option, the gas and steam plant, and the decentralized option. The situation improves slightly in favour of retrofited plants when looking at the entire process chain. However, every year the retrofit is postponed, lifetime emissions increase as well. If a pulverized coal plant is retrofitted in 2029 it would emit similar quantities than a natural gas and steam power plant. If the retrofit occurs in the year 2024 or 2029, GHG emissions are only 48% or 27% lower than they are for the two discussed coal-fired options, respectively.

Concerning resource consumption, energy demand for CCS plants increases between 20% and 40% as compared to the reference plant without CCS. Oxyfuel capture requires the largest energy demand but is also able to capture the most carbon dioxide among all capture technologies. Energy demand for retrofited plants strongly depends on the year of the retrofit. Given this example of a retrofit in 2024 for an IGCC plant and a PC post-combustion retrofit in 2029, both plants show similar energy demand.

We now turn to the remaining impact categories. Photo-oxidant formation, eutrophication, acidification and dust and particles emissions increase because CCS requires increased energy consumption, and also because of extensive usage of other materials like substances for capture. On the other hand, some parameters are reduced when the solvent reacts with the captured flue gas. For example, SO_2 is completely eliminated by monoethanolamine and selexol, the two reagents for post-combustion and pre-combustion. Then again, other processes like those associated with transport and storage cause emissions of SO_2. It is therefore important to consider the entire process chain of products and substances in order to determine the overall emissions.

Photo-oxidants, like hydroxyl radicals, are very reactive with trace gases like hydrogen, carbon and oxygen. They atmosphere promote the formation of ozone in the atmosphere. During the process of producing the chemical solvent monoethanoleamine, photo-oxidants are primarily formed as a by-product (Viehbahn & Nitsch 2006). Other chemicals promote eutrophication. Those are also formed during production of the flue gas scrubber. The overall increase of pollutants is somewhat balanced by the reduction of NO_x during the capture of carbon dioxide from flue gas.

7. Summary and Conclusions

In this paper we have undertaken an economic and environmental analysis for different technological options of coal-fired power plants with carbon capture and storage (CCS) to be built in the city of Kiel. Our starting point was a study of Freischlad et al. (2008) that evaluated six options for a plant replacing the current ageing coal-fired plant. The options included a coal-fired power plant with either 800MW or 360 MW capacity, a combined gas and steam power plant, a multi-fuel power plant and a decentralized option. The recommendation of Freischlad et al. (2008) to the municipality was to postpone the decision until the uncertainties about CCS have decreased and then to seriously consider building a coal-fired power plant with CCS. Yet, the profitability of such a plant was not assessed. Meanwhile, the discussion has emerged and there are some signs that the political will is to not consider the option of a coal power plant at all. But the final decision has not yet been taken and the aim of this paper is to see whether there is a justification to opt for a CCS plant.

For the economic analysis we undertook a cash flow analysis by modifying and extending Freischlad et al.’s assumptions of costs and revenues to account for differences in fuel use, output and necessary investments of CCS plants. The indicator used for the economic evaluation was the net present value (NPV). The environmental assessment contained a life cycle analysis for different environmental impact categories with the main focus on CO_2 emissions.

The economic evaluations show that integrated gasification combined cycle (IGCC) plants equipped with CCS are in all scenarios either the first or the second choice when maximizing the NPV. Even in the reference scenarios where the 800 MW coal-fired power plant has the highest NPV, an IGCC plant has a positive NPV and reaches the minimum rentability. These results are mostly not affected by the cost uncertainties for building an IGCC plant. Only in the reference scenario very unfavourable cost assumptions lead to a profitability that is slightly below the set level. According to our analysis an IGCC plant with CCS is in this sense indeed an option that can be accepted by the operators. Yet, there is very little experience with the IGCC technology and only 4 GW of IGCC power plants have been installed in the world so far. Even though it should be possible to build an IGCC plant with CCS in Kiel there is clearly some uncertainty associated with commercializing this technology that goes beyond the cost uncertainties that are covered by our sensitivity analysis.

The picture changes if investors want to rely on a technology where experiences are larger. A pulverized coal (PC) plant with oxyfuel combustion is clearly not a real choice since it has a large negative NPV under all scenarios. A PC plant with post-combustion does not reach the minimal rentability in the reference scenario where it has a small negative NPV. In the two alternative scenarios the NPV is positive, but under unfavourable cost assumptions it might also turn negative. In the reference scenario and in scenario 2 the PC plant with post-combustion is the third choice after the large coal plant without CCS and the IGCC with CCS. In scenario 3 though, it is more or less clearly outperformed by a small coal power plant without CCS, by a natural gas plant and by a combined coal/natural gas plant.

Retrofitting an existing coal power plant with CCS in the future leads to a lower profitability than building a CCS plant at the beginning. A mandatory retrofit e.g. in 2020 would lead to a negative NPV. Only for a retrofit after the year 2025 or even later, depending on the scenario, the NPV becomes positive. Only in scenario 1 retrofitting after 2030 (PC plant) respectively 2047 (IGCC plant) leads to a higher NPV than building a CCS plant from the start. In this case though, the emission savings become minimal.

Altogether, the economic evaluation has shown that there are already incentives to build CCS plants given the current expectations of costs and revenues. Yet, if politicians believe in this technology, support for demonstration projects of IGCC plants with CCS and additional R&D to reduce the technological uncertainties of this technology would be helpful. Also, a decision on whether and when retrofitting plants with CCS technology becomes mandatory is important for the choice of technology and the decisions of plant owners.

The discussion of the results derived from the comparison of the performed life cycle assessment can be focused on the impact categories: “Global Warming Potential” and “Energy Demand”. The retrieved data for the other impact categories does not support the decision process as the overall increase of pollutants caused by CCS plants can be seen as balanced by the reduction of NO_x emissions.

Results clearly show that the 800 MW coal plant has the highest GHG emissions; this holds true for emissions from the plant only, as well as the entire life-cycle. Calculating life-cycle emissions from CCS plants reveals that CCS saves far less GHG emissions then it is commonly stated in the literature. Compared to the coal-fired plant, overall greenhouse gas emissions are only reduced by 67% for a pulverized coal (PC) plant with CCS post-combustion. Yet, life cycle emissions are the lowest for CCS plants. Plant retrofit has a significant impact on lifetime emissions, i.e.: the later a retrofit occurs, the higher are the total emissions of the plant. A PC-plant, retrofitted 15 years after the base plant installation, would reduce total greenhouse gas emissions by 27%, compared with a PC plant with no CCS. All retrofit plants discussed in this paper showed either similar (best case), or higher GHG emissions (worst case) than the multi-fuel plant option, the gas plant or the decentralized plant option.

The overall goal of the economic and the life cycle analysis is to support the decision making process. Both presented instruments allow to rule out non sustainable options – in this case to replace the existing power plant in Kiel and to allow to focus the discussion on the most promising options in economic and ecological terms. This strategy allows decision makers to focus their discussion on normative elements like the evaluation of acceptable risks. While the study by Freischlad et al. (2008) proved the economic viability of a power plant without any measures to reduce GHG emissions, the economic analysis in this study shows that an IGCC plant could be an economic viable option as well – provided that the community of Kiel and the power company are willing to invest in a technology which has not been applied for a power plant with the requested capacity before. Decision makers might be encouraged to take this risk based on the results of the Life Cycle Analysis which clearly show that an IGCC plant with CCS is an option that is leading to low life-cycle CO_2 emissions. Though, at this stage it should not be neglected that the long term security and environmental integrity of CCS is not fully proven yet. Hence the decision for an IGCC plant in Kiel requires the acceptance of ecological risks as well. However, our analysis shows that an IGCC plant with CCS is an option that has an acceptable, although not maximal, profitability and is leading to low life-cycle CO_2 emissions at the same time.

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9. Appendix -Sample cash flow calculation

Table A: IGCC- plant, pre-combustion capture, Scenario 1

		Infl.	2014	2015	2016	2058	2059	2060
variable costs			**0,0**	**155,4**	**157,3**	**203,3**	**203,3**	**0,0**
fuel costs	Mio. €			133,2	134,9	176,5	176,5	
operating costs	Mio. €			12,0	12,1	14,0	14,0	
CO(2)-permit costs	Mio. €			10,2	10,3	12,8	12,8	
fixed costs			**0,0**	**42,0**	**42,3**	**51,0**	**51,0**	**0,0**
maintenance cost		0,50%		25,0	25,1	29,6	29,6	
insurance cost		0,50%		8,3	8,4	9,9	9,9	
labour costs		1,00%		7,1	7,2	10,0	10,0	
overhead costs		0,50%		1,6	1,6	1,6	1,6	
other costs			**0,0**	**13,6**	**13,6**	**13,6**	**13,6**	**16,6**
abandonment costs								16,6
Transport Costs	Mio. €			2,0	2,0	2,0	2,0	
Storage Costs	Mio. €			11,6	11,6	11,6	11,6	
total costs			**0,0**	**211,0**	**213,1**	**267,9**	**267,9**	**16,6**
Amount								
Power generation	GWh			5.579,5	5.570,8	5.527,3	5.527,3	
Heat	GWh			1.067,5	1.106,1	1.287,8	1.287,8	
Fuel	GWh			15.924,0	15.924,0	15.924,0	15.924,0	
CO2	Mio. t	20,3		0,5	0,5	0,5	0,5	
Power revenue			**0,0**	**350,9**	**353,7**	**386,4**	**386,4**	**0,0**
Electricity revenue	Mio. €			349,4	352,2	384,6	384,6	
Regulating energy		0,50%		1,5	1,5	1,8	1,8	
Heat revenue			**0,0**	**12,8**	**13,4**	**17,4**	**17,4**	**0,0**
Heat revenue				12,8	13,4	17,4	17,4	
Total revenues			**0**	**363,7**	**367,1**	**403,7**	**403,7**	**0,0**
EBIT margin			**0,0**	**102,5**	**103,8**	**135,8**	**135,8**	**-16,6**
EBIT margin cumul.			0,0	102,5	206,3	5.409,3	5.545,2	4.170,2
Tax expenditure	-		0,0	-30,8	-31,1	-40,7	-40,7	5,0
EBIT after tax			0,0	71,8	72,7	95,1	95,1	-11,7
Amortization	+		0,0	50,2	50,2	0,0	0,0	0,0
Working Capital Change	+		**0,0**	**-12,7**	**-0,1**	**0,0**	**0,0**	**12,7**
Sum working capital			*0,0*	*12,7*	*12,8*	*11,3*	*11,3*	*-1,4*
Allowances L&L			0,0	30,3	30,6	33,6	33,6	0,0
Liabilities L&L			0,0	17,6	17,8	22,3	22,3	1,4
CF oper. activities	=		**0,0**	**109,2**	**122,7**	**95,1**	**95,1**	**1,1**
CF invest. activities	+		-1.755,6	0,0	0,0	0,0	0,0	0,0
Free Cashflow			**-1.755,6**	**109,2**	**122,7**	**95,1**	**95,1**	**1,1**
Discount rate			1,0650	1,0000	0,9390	0,0667	0,0626	0,0588
Present value			**-1.869,7**	**109,2**	**115,2**	**6,3**	**6,0**	**0,1**