Near zero emission technology for CO_2 capture from power plant

Technical Study

Report Number: 2006/13

Date: October 2006

INTERNATIONAL ENERGY AGENCY

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IEA Greenhouse Gas R&D Programme (IEA GHG), “Near zero emission technology for CO_2 capture from power plant”, 2006/13, October 2006”.

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NEAR ZERO EMISSION TECHNOLOGY FOR CO_2 CAPTURE FROM POWER PLANT

Background to the Study

The IEA Greenhouse Gas R&D Programme has issued reports assessing the cost of CO_2 capture technologies for power generation using all of the three main types of process, i.e. pre-combustion, post-combustion and oxy-combustion capture. A report has also been issued on the implications if other impurities are co-captured along with the CO_2. In most of the variants of these processes there is an economic or practical limit to the percentage of the CO_2 which can be captured. There has been increasing interest in recent years in the concept of “zero emission power generation” which would in essence be the complete 100% capture of all CO_2 and other emissions of gaseous components, principally the sulphur and nitrogen oxides. A study has thus been proposed, building on the previous work, to explore this concept in more depth. In formulating this study it is considered more appropriate to consider the concept as providing “near zero” emissions to the atmosphere since thermodynamic limitations make complete capture inappropriate for some of the contending processes.

Approach

The Energy Centre Netherlands (ECN) was engaged to perform the study. Their approach was to first map all of the separation methods which have been proposed as part of capture processes for applicability in each of the three main capture routes i.e. post combustion, pre-combustion and oxy-combustion capture. A list of all candidate processes was then drawn up and the map used to ensure that all possible combinations had been covered. This resulted in a list of about 20 processes. Each of these was then screened and a short description prepared which identified the nature of the intrinsic thermodynamic limitations of the processes in the context of reaching high percentages of capture. Further screening was then carried out to identify in qualitative terms how amenable the processes would be to increasing the capture ratio for CO_2. Four separate factors were considered which were, how close to 100% capture the basic process normally operates, how technically easy it would be to stretch to 100% capture, what effect the stretch would have on other emissions and finally what effect this would have on power generation efficiency. The assessment was done on a three point scale (i.e -,0,+).

A shorter list of about 10 processes was then drawn up. This list eliminated processes which were substantially similar and aimed to cover the full range of candidates. For each of these processes an order of magnitude quantitative estimate was made of the costs (relative to a baseline of 100% for a process with the “normal” level of capture) for extending the capture towards 100%. The original intention was to select 3 or 4 of the processes which emerged as front runners with good zero emission potential for a more detailed analysis. However as the study progressed no obvious front runners were identified and it was deemed more appropriate to examine and compare in some more detail the main competing pre, post and oxy-combustion alternatives.

Having evaluated the prospects for adapting capture processes to deliver zero emissions the study went on to consider the emissions of the complete energy chain, including mining/production/transport of the fuels, construction and decommissioning. This was done on the basis of a literature review as a full LCA (Life Cycle Analysis) was beyond the scope of this study.

Results and Discussion

Ranking of processes on basis of zero emission potential

The selection of post, pre or oxy-combustion is the main determinant of the ease with which power generation processes can approach "zero emissions". The type of processes used for CO_2 separation within these overall concepts appeared to be less important. The reasons can be summed up as follows;

Pre-combustion capture relies ultimately on performing the shift reaction to convert all carbon species to CO_2. The shift reaction equilibrium makes it increasingly expensive and difficult to reach high levels of conversion. Loss of recovery is due partly to residual CO but can also be due to the amount of unconverted methane which depends largely on the temperature reached in the gasification step. The shift reaction equilibrium limits achievable capture unless devices such as membrane reactors are used to affect the equilibrium. Other alternatives are possible but would involve separation and recycling of residual CO and methane in the hydrogen stream as well as a system to remove inert gases such as Ar and N_2 which would build up. Such systems were not considered in this report because of their obvious complexity and cost.

Post combustion capture relies on removal from dilute low pressure flue gas. Removal systems can be designed to achieve high levels of capture but the driving force for whatever technology is employed becomes extremely low necessitating additional stages of large equipment. Both the cost and energy consumption of the extra equipment are high but in principle virtually all of the CO_2 in flue gas could be captured.

Oxy-combustion processes deliver a concentrated stream of CO_2 which after basic compression and separation of the bulk of the CO_2 leaves a small pressurised stream of CO_2 mixed with incondensibles (mainly N_2, Ar and O_2). This stream can be processed to capture the remaining CO_2 with relatively small equipment and at low cost and energy consumption. Thus oxy-combustion is intrinsically suited to reaching near-complete CO_2 capture at the power plant.

Economic considerations

The estimated cost of capturing increased portions of CO_2 emitted at power stations can be viewed either for the effect on total cost of CO_2 capture or cost of electricity generation. The graphs of these cost trends shown in Fig 1 for conventional processes and Fig 2 for advanced processes below indicate significant but apparently affordable increases. (Note that the absolute values of the costs are order of magnitude estimates based on results of a range of previous studies. As such no particular conclusions should be drawn from any relative cost differences ***between*** technologies.) However if the incremental costs of the extra capture are considered a quite different picture emerges. The incremental costs range from moderate for oxy-combustion to extremely high in the case of post combustion processes. This is represented graphically for conventional processes only in fig 3 below. It should be noted that the cost scale on this chart is logarithmic. From a purely economic point of view it would be far better to invest in more power stations with optimum capture than fewer of near zero emission performance. The precise level of capture which would be optimum, in other words gives minimum electricity price, will depend on the parameters which are used in economic analysis. Other considerations such as local public perception and how this translates into easier permitting could also influence the chosen level of capture. However if the full chain performance is considered this could undermine the validity of promises of 100% capture and zero emissions.

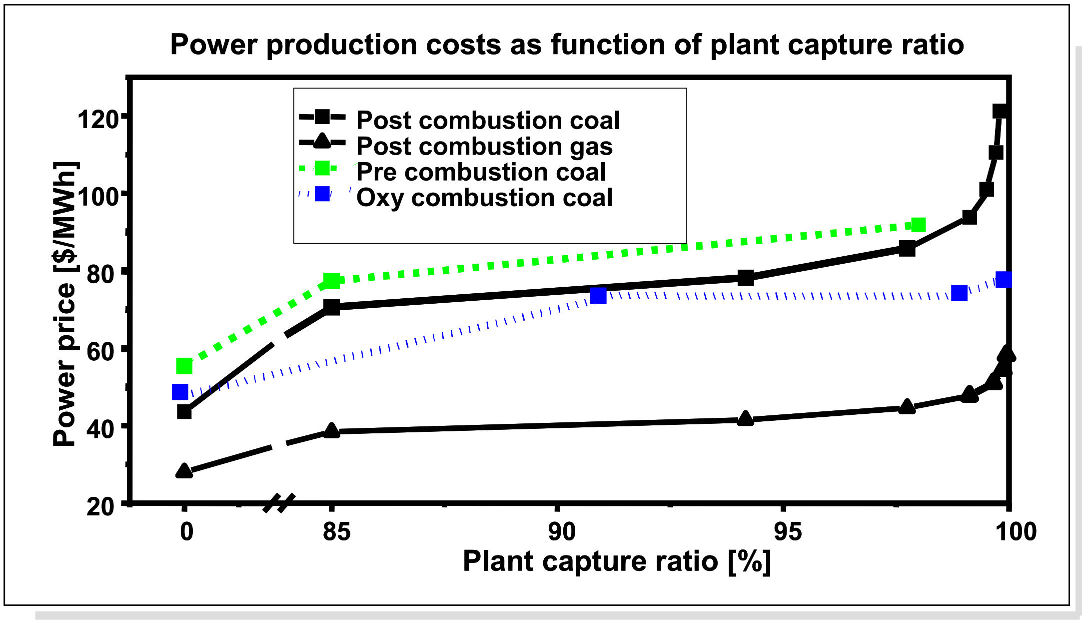

Fig 1 Conventional capture processes – power cost as function of capture ratio

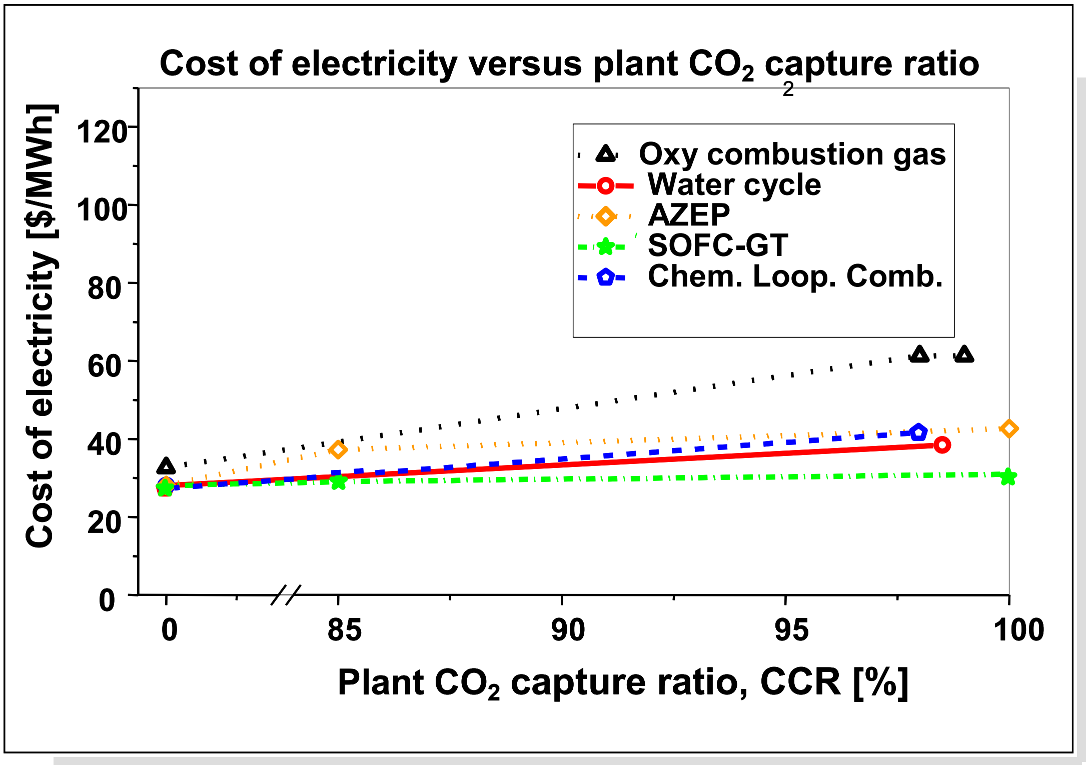

Fig 2 Advanced capture processes – power cost as function of capture ratio

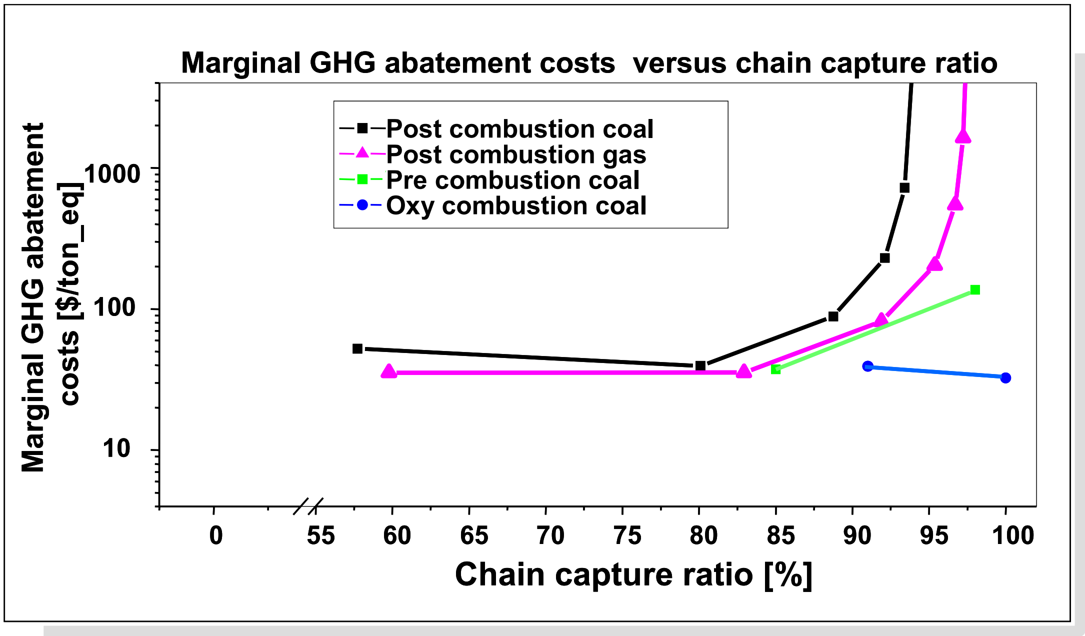

Fig 3 Marginal GHG abatement costs – conventional processes – Logarithmic scale

Other pollutants

In general all of the processes which capture high percentages of CO_2 eliminate emissions of other toxic materials. These either have to be removed to protect the CO_2 capture process or are concentrated into the captured CO_2 from which they can be separated easily if necessary. Effects on removal of other contaminants were assessed qualitatively in the first screening and thumbnail process descriptions. Increasing CO_2 capture in all cases leaves these other emissions and wastes at similar or lower levels than for the base case capture processes.

Life cycle considerations

Estimates of the CO_2 and other GHG emissions from mining and gas production, coal and gas transport and power plant construction and decommissioning were found in the literature. These were converted to CO_2 equivalent using the standard global warming potential GWP. Inspection of the data showed that construction and decommissioning emissions were not significant. Emissions from the other activities in the chain are however quite significant and for long transport distances are estimated to limit the percentage of CO_2 and other greenhouse gas emissions which can be captured in the complete energy chain to 93% for coal and 96% for gas. It should be noted that these extra chain emissions are strongly dependent on the transport distance and further details of this dependency are in the main report. The losses from gas transport systems are typical of well maintained systems. Losses from the existing pipeline system transporting Russian gas are significantly higher and limit the maximum effective energy chain greenhouse gas capture efficiency to about 85%.Chain emissions for LNG based systems have not been developed but will generally be higher than those for pipeline systems since the LNG transport chain typically consumes 8-10% of the feed gas. These results are plotted in fig 4 below which is similar in form to fig 1 but now the horizontal axis represents the overall energy chain capture ratio rather than the capture ratio within the power plant. This illustrates the limitations of the zero emission concept when life cycle effects are taken into account.

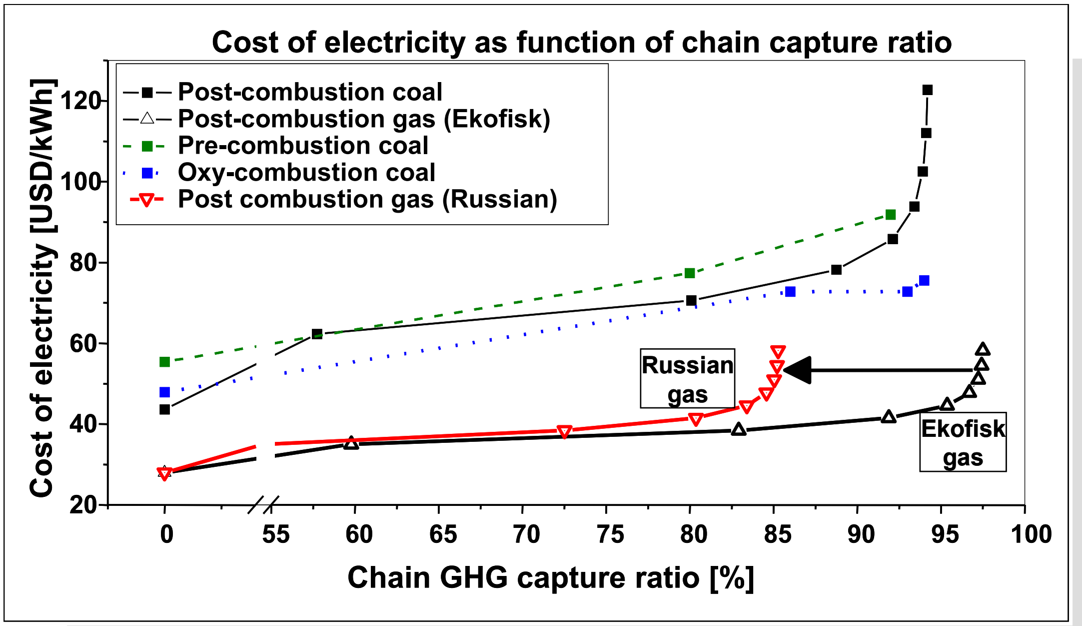

Fig 4 Conventional capture plant –Power cost as function of energy chain capture ratio

These figures are based on historical emissions and there are possibilities to reduce them. In particular technologies are available to reduce emissions of methane during mining and better design and management of gas pipeline systems is also reducing fugitive emissions from this source. There remain however emissions from the ships which transport coal and the booster compressors in gas pipeline systems. The latter could in principle be run with power from low emissions sources such as electricity from a CO_2 capturing power station but as they are often in isolated places this does not seem to be likely in the short term. Emissions from the engines of ships carrying coal or LNG are unlikely to be eliminated in the short or medium term.

Thus although some types of fossil fuelled capture plant can be adapted to capture practically all of their produced CO_2 it is not practicable to do this for the complete energy chain.

Expert Reviewers' Comments

Some comments were made with regard to the level of detail and basis of cost estimates. Initially the intention was to evaluate 4 selected processes to a significantly greater level of detail than performed in the order of magnitude estimates. However the effort and cost of doing this was not considered justified and in the event the 4 selected processes were subjected only to a slightly more refined review. More details about the scaling methods used to estimate cost increases were included in the final report.

Reveiwers felt that the chain emission data for gas did not take account of leakage amounts in the existing Russian gas systems which were expected to be higher than the quoted data. The report was modified to reflect data on Russian gas system emissions. Although the literature figures indicate that historically there have been high rates of loss, successful efforts are now being made to reduce them.

Some reviewers wondered about the value of looking at zero emissions capability in this way on the basis that it was perhaps obvious that each process has an economic optimum and zero emissions was not a sensible design goal. However the zero emissions promise definitely has an allure which transcends the basic economics and it is considered legitimate to assess the cost and capability of providing such a solution.

Major Conclusions

Oxy-combustion processes can be adapted to provide near zero emission performance of CO_2 capturing power plant without significantly increasing cost of electricity. Pre and post combustion processes can be adapted but at marginal costs which are excessive and cannot easily reach the close to 100% possible with oxy-combustion.

Life cycle considerations limit the overall reduction of emissions in the full fossil fuel to electricity energy chain because of emissions caused by transport and production. These are sufficient to question the wisdom of increasing capture of CO_2 emissions at power plants beyond the economic optimum even for oxy-combustion. Also the “zero emission” advantage of oxy-combustion is significantly diminished as a result of these additional emissions.

Capture processes already eliminate many of the toxic emissions and further increases in CO_2 capture percentage would yield little or no further advantage with respect to SOx, NOx, particulate or mercury emissions.

Recommendations

The better zero emission capability of oxy-combustion processes should not be considered to disadvantage other capture processes and all should continue to be assesses on the full range of cost, performance, operational and maintainability attributes.

The extra processing required to increase the amount of CO_2 captured from oxy-combustion processes should be further studied and optimised as it may provide a low cost opportunity to capture more CO_2.

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Near zero emission technology for CO_2 capture from power plants

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ECN-X--06-098

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August 2006

Acknowledgement/Preface

This report presents the results of the project "Zero emission technologies for power generation". This study has been carried out by the Energy research Centre of the Netherlands, ECN and Jacobs Consultancy for the International Energy Agency, Greenhouse Gas R&D programme. Project manager at IEA GHG was M. Haines. Contributions to this study have also been made by A.C.B den Ouden, L. Verbeek (Jacobs Consultancy), D. Jansen and M. Weeda.

Abstract

A study has been performed to assess which of the various power plant CO_2 capture technologies are capable of delivering "near zero"-emissions, what is the cost of doing so and how close to zero emission the most promising systems can come. Firstly a qualitative analysis of around twenty processes has been made and the nature of the limitations to their emissions performance described. Then 10 processes were selected for a qualitative analysis, which included an order of magnitude estimation of the maximum CO_2 capture ratio, the efficiency penalty and the cost of electricity. This information is used to examine life cycle aspects in an energy chain analysis, which compares the emissions during operation with those during mining, fuel transport and plant construction and decommissioning. With these results, the overall fuel chain capture ratio is calculated and conclusions are drawn about the achievable capture ratio for power plants using the different CO_2 capture technologies. Oxy-combustion appears to be the preferred technology when aiming at near zero emissions.

Keywords

CO_2 capture, power generation, CO_2 capture ratio, process analysis, pre-combustion, post-combustion, oxy-combustion conversion, energy chain analysis, life cycle analysis, emission reduction.

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Executive summary

The notion "zero emission process" is often used while referring to power production with CO_2 capture. This suggests that no emissions whatsoever remain during power generation after these technologies have been implemented. The relative amount of CO_2 captured is not 100% for all processes at the "normal" design point, but possibilities for increasing the amount of capture often exist. For some processes however there is an economic or practical limit with regard to the percentage of the CO_2 that can be captured. Furthermore, there are emissions of various kinds elsewhere in the full power generation chain (including notably the stages of resource mining and transport, as well as construction and decommissioning of power plants). These emissions will still be present after implementation of capture technology and may even increase as a result of increased fuel use. This study aims to address to which extent "zero emission" can be accomplished. The overall objective of this study is to assess which of the various capture technologies that could be employed are capable of delivering "near zero"-emissions, what is the cost of doing so and what is the best overall emissions performance which can be expected.

Three main types of CO_2 capture can be employed in power production processes: pre-combustion capture, post-combustion capture, and oxy-combustion. This study shows that some processes can easily come close to 100% capture of CO_2 and other polluting gaseous emissions at the power plant itself. However, overall life cycle GHG (CO_2, CH_4 & N_2O) emissions will be reduced to lower values. Of the three types, oxy-combustion can most easily approach high CO_2 capture ratios. Post-combustion capture technologies can deliver the same near zero emission performance but at a large increase in costs at high capture ratios. Pre-combustion capture has the lowest amount of CO_2 captured with a moderate increase in cost. The findings of this study are that it is considered to be more appropriate to use the notion "near zero emissions processes" instead of "zero emission process" since thermodynamic limitations make complete capture inappropriate for some of the contending processes and life cycle and chain effects emissions remain even while applying capture technology.

The concept of "near zero emissions" corresponds, on a power plant level, to a CO_2 capture ratio (CCR) close to 100%. The CCR is defined as the ratio between the amount of CO_2 captured and the CO_2 produced at complete combustion of the fossil fuel employed. Additionally, other emissions (including NOx, SOx, and particulate matter) are taken into account, taking the Best Available Technology (BAT) without CO_2 capture as a reference. Besides emissions at the power plant itself, also emissions in the other stages of the fuel chain and during construction/decommissioning of the power plant are addressed. The reason is not only to put the total power plant emissions into a broader perspective, but also to provide the overall chain emissions when CO_2 capture is applied.

In the study a staged approach has been used in which a "longlist" of processes is assessed qualitatively. Then, for a selection of processes a quantitative analysis has been performed. Separately, an energy chain analysis including life cycle effects has been carried out, and the results have been incorporated into the quantitative analysis.

Qualitative analysis

First a "longlist" of 24 different types of capture processes has been established (Table 2 in this report). All important processes and separation principles are represented in this list. Based on the block schemes and descriptions of these processes, and through an analysis of the principle of separation used in each of them, all processes have been assessed qualitatively, in terms of their "normal" capture ratio (as generally used in literature, usually determined by some form of economic optimisation or by design rules), the possibilities available to increase their capture ratio from both the technical and economic standpoint, as well as the efficiency impacts. In addition the broad impact of CO_2 capture on other emissions was assessed, i.e. would they be worse, better or roughly the same.

The qualitative analysis revealed that there is no significant difference between natural gas and coal fed options with respect to the CCR and possibilities for increasing this. Also there is no clear impact of the principle of separation (liquid absorption, membranes, solid absorbents, cryogenic separation). What is most determining is the main capture process type (i.e. capture route: pre-, post- or oxy-combustion).

Quantitative analysis

For a shortlist of 10 processes, a quantitative analysis has been performed to assess the power production costs associated with increasing the capture ratio beyond the "normal" design point. The processes were selected to include all those having some prospects of approaching near zero emissions and to exclude processes that had very similar characteristics. Based on design rules, in-house and literature data, the costs have been estimated using efficiency estimates, relative investments and relative contributions of investments and fuel costs.

The emphasis of the study has been on the magnitude of the cost increase associated with increasing the relative amount of CO_2 captured rather than on the absolute value of the costs of electricity. Especially the difference between the gas and coal fired options is subject to significant impact of the assumptions used, especially for fuel prices. The standard IEA GHG assumptions used for coal and gas prices make the cost of electricity of coal-fired options relatively cheap compared to gas-fired options. However, this could be different following recent fuel price developments. The choice between gas and coal is also a strategic choice.

In the presentation of the results a distinction is made between conventional and advanced processes. The conventional processes assessed are:
- Post-combustion capture using MEA absorption for a pulverised coal boiler (PC)
- Post-combustion capture using MEA absorption for a natural gas combined cycle (NGCC)
- Pre-combustion capture for an integrated coal gasification combined cycle (IGCC) using shift and Selexol absorption
- Pre-combustion capture in a NGCC using ATR, shift and Selexol absorption
- Oxy-combustion for a pulverized coal (PC) boiler with a CO_2 recycle.

The advanced options selected are:
- Oxy-combustion gas: oxy-combustion NGCC with CO_2 recycle
- Water cycle: oxy-combustion gas cycle with a water injected combustion
- AZEP (Advanced Zero Emission Process): NGCC with integrated oxygen conducting membrane
- SOFC-GT (Solid Oxide Fuel Cell - Gas Turbine hybrid) with an afterburner based on oxygen conducting membranes
- NGCC with Chemical Looping Combustion (CLC).

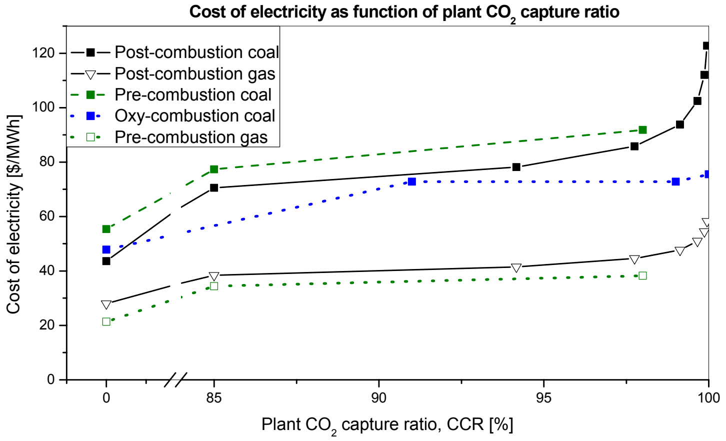


Figure 1: *Effect of increasing the amount of CO_2 captured on COE, conventional processes.*

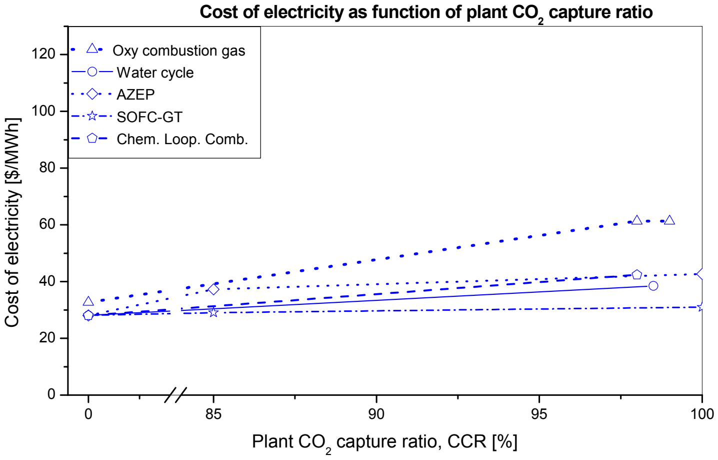


Figure 2: *Effect of increasing the amount of CO_2 captured on COE, advanced processes.*

Figure 1 and Figure 2 present the results of the qualitative estimation of the power production costs (cost of electricity) as a function of the CCR. The lines are only drawn to connect points of one process, and do not represent the actual shape of the curve. For the conventional processes in Figure 1 it can be concluded that post-combustion capture for coal and gas fired plants will have the largest increase in power production costs with increasing CCR. Especially at very high capture ratios the costs become extremely high. Pre-combustion capture has costs similar to post-combustion capture, but cannot be readily adapted to a very high capture ratio. Oxy-combustion coal technology is the best suitable for "zero emission". The oxy-combustion coal process also inherently offer lowers emissions of other gaseous pollutants such as NO_x. The advanced processes, as presented in Figure 2 (water cycle, AZEP, SOFC-GT and chemical looping combustion), are subject to a large uncertainty in the costs of electricity. They do however all offer the prospects of near 100% CO_2 emission reduction with a limited increase in costs. For the water cycle and chemical looping no moderate capture case was found to be relevant, these processes inherently offer very high capture ratios.

Chain analysis

An inventory of the literature on energy chain emissions (including life cycle aspects) has been performed. Of the various contributions considered (fuel "mining", fuel transport, power generation, plant construction and decommissioning) emissions in the construction and decommissioning phases are negligible compared to those occurring during the fuel "mining", fuel transport and power plant operation. It was found that the fuel transport distance is important for the overall chain emissions, especially for coal. Depending on the capture technology used, overall chain emissions other than CO_2 (i.e. CH_4, CO, N_2O) can both decrease as well as increase when applying CCS. The decrease can be partially or total, the increase can amount to a maximum of 30% for coal, 20% for gas, specifically as a result of those emissions occurring in fuel mining and/or transport, such as NO_x.

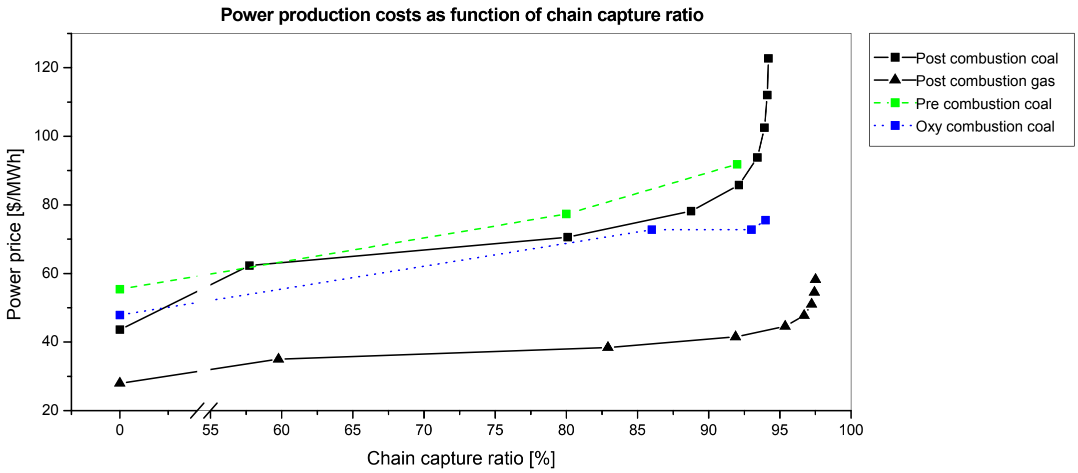


Figure 3: *Power production costs as a function of the chain GHG capture ratio.*

CO_2 capture processes cause an increase in fuel consumption, which in turn will increase greenhouse gas (GHG) emissions from fuel production and transport. In theory, at some point increasing the chain GHG CCR can be rendered pointless because of increasing emissions elsewhere in the chain.

Based on the data obtained from the literature study, the overall energy chain effects have been incorporated accounting for all relevant greenhouse gasses (CO_2, N_2O and CH_4), and the overall chain capture ratio of the processes has been calculated. The chain GHG abatement curve in Figure 3 shows the same trends for each of the capture processes as the corresponding abatement curve without chain effects in Figure 3. It can however be seen that the maximum achievable chain capture ratio is less than 100%, caused by the emissions in the fuel chain. For coal-fired options the maximum chain capture ratio found is 93% (for oxy-combustion coal) and for the gas fired option the maximum chain capture ratio is higher, 96%. The differences in maximum achievable plant CCR between the three coal-fired options considered are not very relevant when taking these chain effects into account. The secondary effects on the emissions from extra fuel consumption at increasing capture ratio are most significant for the post-combustion processes, however even here the CCR of the plants can be pushed to around 99% without further increases becoming self defeating.

Following recent reports on the emissions from long distance gas transport from e.g. Russian pipelines, the Russian gas case has been assessed in more detail. It is concluded that for the case of Russian gas, transport emissions are much more significant than for the cases assumed in the rest of this report. This will have a significant effect on the maximum GHG capture ratio which for post-combustion gas will drop from 96% to 85% typically, as well as the on the cost per ton CO_2 avoided, which will be higher. Given the magnitude of the emissions, future measures for emission reduction could very well be justified.

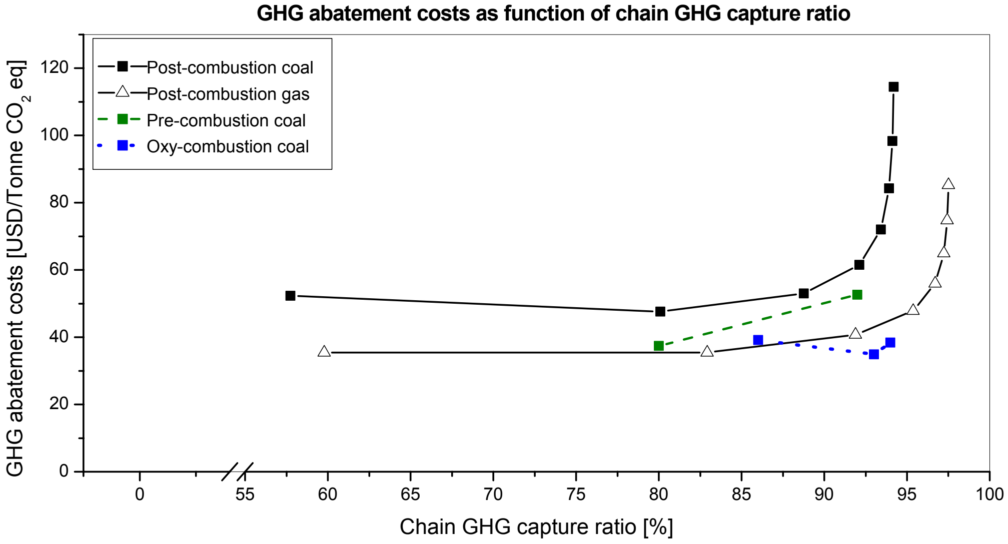


Figure 4: *Chain GHG abatement costs as function of the chain GHG capture ratio*

Figure 4 gives the chain GHG abatement costs (USD/ton CO_2 equivalent) as the function of the chain capture ratio for a selection of processes. Again, the abatement costs for both the coal and natural gas post-combustion options are increasing rapidly at high chain capture values. Pre-combustion coal has a comparable increase in cost, but cannot reach high capture ratios, so it does not have the high cost-high capture part of the curve. The oxy-combustion coal option CO_2 costs do not change significantly with increasing chain capture ratio. Even a small decrease is observed because of the relative ease with which final traces of CO_2 can be captured from the pressurised incondensable gases vent by adding a simple amine absorption process.

The marginal costs of GHG abatement are increasing even more dramatically as is shown in Figure 5. The marginal costs of capture can surpass 1000 USD/ton for both coal and gas post-combustion. Pre-combustion and oxy-combustion coal marginal GHG abatement costs do not show the dramatic increase at high chain CCR values.

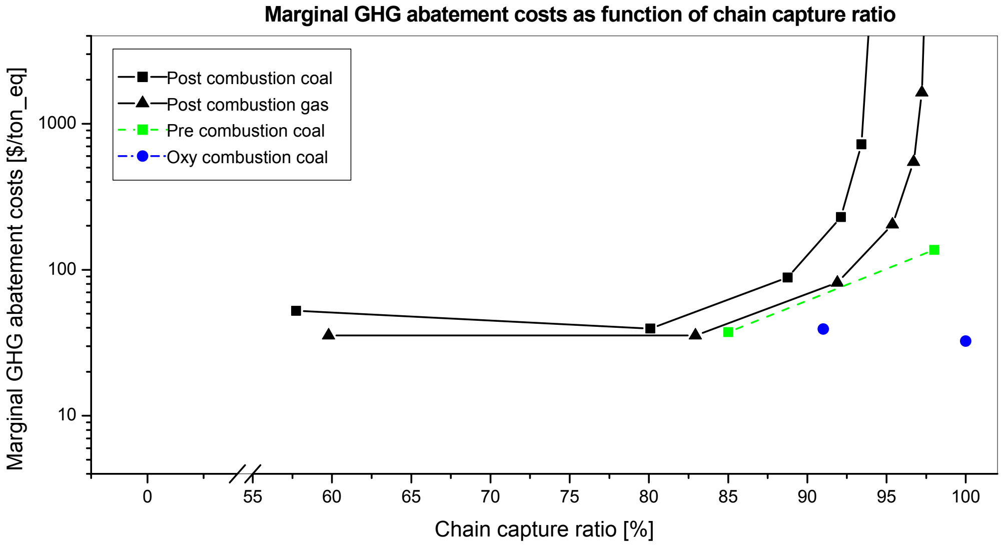


Figure 5: *Marginal GHG abatement costs as function of the chain GHG capture ratio.*

Conclusions

A central finding of this study is that the notion "near zero emission power plant" is more appropriate than "zero emission power plant" when life cycle aspects of the entire fuel chain are taken into account. These life cycle effects (in the full chain of fuel supply and power production) limit the maximum reduction of emissions to about 93% for coal and 96% for gas. To achieve this performance the power plant process has to operate at close to 100% capture. Oxy-combustion coal processes are best suited to being adapted to high capture ratios with little extra cost. Post-combustion processes can be modified to approach the near zero emissions performance but only at excessive cost and through installation of large pieces of additional equipment. Pre-combustion processes cannot reach very high capture ratios. However given that true zero emissions in the fuel–power chain are not feasible, both pre- and post-combustion capture remain economically interesting options.

1. Introduction

1.1 Background of the study

Human activity is significantly altering the climate system by an increase in the amount of greenhouse gases in the atmosphere and a corresponding rise in the global average atmospheric temperature. This increase is largely occurring through the combustion of fossil fuels and the resulting emissions of CO_2. Various options exist for reducing the rate of release of CO_2, in order to eventually stabilise its concentration in the atmosphere at a specified level. Since recently, an additional method for decreasing CO_2 emissions is being investigated: Carbon Dioxide Capture and Storage (CCS). Emissions from fossil fuels could be reduced by capturing CO_2, particularly at large point sources such as power stations or hydrogen production plants. Subsequently, the CO_2 captured would be injected into storage reservoirs, for example depleted oil and gas fields, deep saline aquifers or unminable coal seams.

The IEA Green House Gas R&D programme has issued reports assessing the cost of CO_2 capture technologies for power generation using all of the three main types of process, i.e. pre-combustion, post-combustion and oxy-combustion capture. In most of the variants of these processes there is an economic or practical limit to the percentage of the CO_2 that can be captured. Furthermore, there are emissions elsewhere in the chain of power generation (including resource recovery (mining), fuel transport and construction/decommissioning of power plants), which will still be present, and may even increase if CO_2 capture is applied. The notion "zero emission process" suggests that no emissions whatever are present during power generation. In this study it is considered to be more appropriate to consider the concept as providing "near zero" emissions to the atmosphere since thermodynamic limitations and chain effects make complete capture inappropriate for some of the contending processes.

In this study, building on the previous work, this concept is explored in more depth. The focus of the study is on the relative amount of CO_2 captured, taking into account efficiency and costs. Near zero emissions corresponds on a power plant level to nearly 100% capture of CO_2. The relative amount of CO_2 captured, or the CO_2 capture ratio (CCR) is defined as:

$$CCR = \frac{Amount\ of\ CO_2\ captured}{Amount\ of\ CO_2\ produced\ when\ combusting\ the\ fuel\ used} * 100\% \quad [\%] \qquad (1)$$

Additionally the emissions of substances other than CO_2 are taken into account (CH_4, NO_x, SO_x, small particulates), taking as a reference the Best Available Technology without CO_2 capture (See Appendix A). Besides emissions at the power plant itself, also emissions in the fuel chain and during construction/decommissioning of the power plant are addressed. Firstly to put the power plant emissions into perspective, and secondly to assess the overall chain emissions when applying CO_2 capture.

1.2 Objective of the study

The overall objective of the study is to assess which of the various capture technologies are capable of delivering "near zero" emissions, what is the cost of doing so and what the residual level of emissions will be.

In finding an answer to these questions first an overview of the various chemical and physical separation processes and their limitations will be made with the objective to assess how closely these processes can approach zero-emissions on-site.

In addition, off-site life cycle feedstock and waste implications will be reviewed with the objective of assessing whether pursuing zero emission targets for power plants just leads to transferring problems to other areas.

1.3 Contents of the report

The structure of the study is illustrated in Figure 6. In Chapter 1 an introduction is provided. In Chapter 2 a "longlist" of processes for CO_2 capture is set up. All processes are described in Appendix A, and a summary is provided in Chapter 2. From the "longlist" 10 processes have been selected for a characterisation in Chapter 3. This includes the construction of CO_2 abatement curves, which give the relation between CO_2 capture ratio and costs. Chapter 4 discusses emissions of CO_2, greenhouse gases and other emissions in processes with CO_2 capture, focussing on the whole chain of mining, fuel transport and construction/decommissioning. The results of the quantitative analysis and chain analysis are combined here. Finally, conclusions are formulated in Chapter 5.

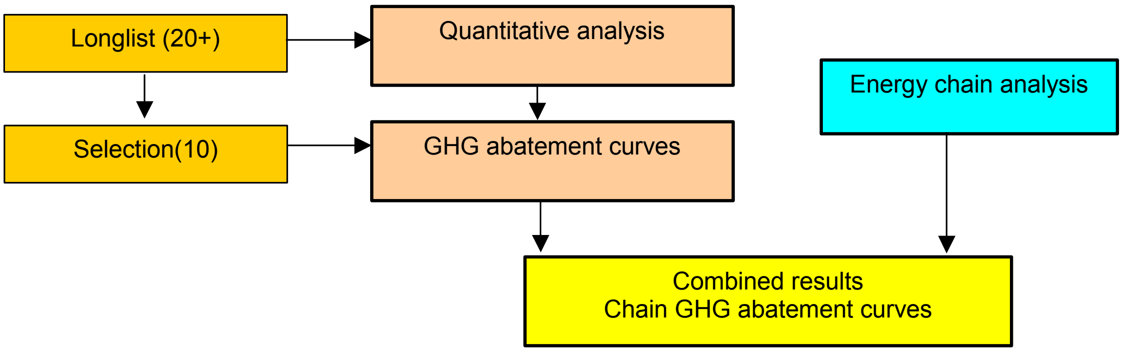


Figure 6: *Structure of study and report.*

2. Description and qualitative characterisation of processes

First in section 2.1 an introduction to the descriptions of Best Available Technologies for power generation without capture is provided. Then, the "longlist" of processes is presented in section 2.2 and in section 2.3 an introduction to the process descriptions is given. In 2.4 the methodology and the results of the qualitative characterisation of the longlist processes are presented.

2.1 Best Available technologies (BAT) without CO_2 capture

As a basis for the description and for reference with the CO_2 capture processes the Best Available Technologies for power generation without CO_2 capture are described in Appendix A. The descriptions are mainly based on (IEA GHG, 2000). The best available technologies for power generation without CO_2 capture are:

- Natural Gas Combined Cycle (NGCC)
- Supercritical Pulverized Coal Plant (PC)
- Integrated Gasification Combined Cycle (IGCC)

2.2 "Longlist" of processes

A "longlist" of processes for power production with CO_2 capture was developed during a joint expert meeting by Jacobs and ECN staff. A structured approach was used, based on Table 1. Both coal and gas fired processes were considered.

Table 1: *Working scheme for "longlist".*

Separation technology	**Capture method**		
	Post-combustion capture *(CO_2/N_2-separation)*	Pre-combustion capture *(CO_2/H_2-separation)*	Oxy-combustion capture *(O_2/N_2-separation)*
Liquid phase absorption	• Chemical solvent scrubbing	• Scrubbing using chemical and physical solvents	• Absorbents for O_2/N_2 separation
Solid sorption	• Post-combustion CO_2 sorbents	• CO_2 sorbents, including sorption enhanced reaction.	• Adsorbents for O_2/N_2 separation • Oxygen chemical looping
Membranes	• Membrane gas assisted gas absorption • Carbon molecular sieve membranes	• CO_2/H_2 separation based on hydrogen and CO_2 separating membranes	• O_2-separating membranes
Cryogenic	• CO_2 separation by liquefaction	• Cryogenic CO_2/H_2 separations	• Cryogenic air separation with oxy-combustion

The resulting "longlist" is presented in Table 2. This "longlist" gives an overview of specific processes for power production with CO_2 capture. Emphasis has been put on processes, which are considered to have the prospects for a high CO_2 capture ratio.

Table 2: *"Longlist" of processes for power generation with CO_2 capture*

Separation technology	**Capture method**		
	Post-combustion capture *(CO_2/N_2-separation)*	Pre-combustion capture *(CO_2/H_2-separation)*	Oxy-combustion capture *(O_2/N_2-separation)*
Liquid phase absorption	• NGCC with MEA absorber	• NGCC with Selexol CO_2 absorber.	
	• PC with MEA absorber	• IGCC with Selexol absorber	
Solid sorption	• CC with flue gas CO_2 sorption	• NGCC with sorption enhanced reforming • NGCC with in situ CO_2 separation	• CC with CLC
	• PC with flue gas CO_2 sorbent	• PC with in situ CO_2 separation • IGCC with sorption enhanced shift	• IGCC with CLC
Membranes	• NGCC with membrane assisted absorption • NGCC with membrane reformer	• NGCC with OCM combustor (AZEP)	• NG fed SOFC (GT) with afterburner • IGCC with SOFC and afterburner
	• PC with membrane assisted absorption	• IGCC with shift membrane reactor	• PC boiler with integrated OCM
Cryogenic			• NGCC oxy-combustion conversion with CO_2 recycle • Matiant cycle • Water cycle
			• PC oxy-combustion boiler with CO_2 recycle

* For a list of abbreviations see page 74

Processes considered but not selected for the "longlist" are:

- Combination of post-combustion liquid phase sorption with solid sorption. The solid sorption step could be used as an additional CO_2 removal step to achieve very high CO_2 capture ratios. This option has not been considered in the literature.
- IGCC with PSA or a combination of Selexol absorption and PSA for CO_2 separation. This is an alternative to liquid absorption.
- Cryogenic separation of CO_2 from flue gases (in post-combustion capture) or reformate gas (in pre-combustion capture). Cryogenic separation of CO_2 from the flue gas would involve refrigeration of the flue gas to liquefy or freeze CO_2. Cryogenic separation of CO_2 is mainly

applied to gas streams with a relatively high CO_2 concentration. For flue gas from a coal-fired boiler or from a gas turbine, it is not economically attractive, because of the very low CO_2 concentration in the flue gas. The total flue gas volume has to be cooled to a very low temperature resulting in a high energy demand. In addition, water vapour in the flue gas may interfere, because of potential blockage in heat exchange equipment due to freeze out, and may need to be removed prior to refrigeration.

- Pressurized fluidised bed coal combustion with O_2/CO_2. Here, coal combustion is carried out in a fluidised bed at high pressure (10-20 bar) and is integrated in a gas turbine with a CO_2 recycle (Smith, 1999).

The use of PSA is thought to be relatively costly for use in CCS. Cryogenic separation also is considered to be unattractive. The pressurized PC boiler has not been pursued because of a low predicted efficiency (Smith, 1999) and lack of recent interest in applications related to CO_2 capture.

2.3 Description of CO_2 capture processes

Process descriptions are provided for all the processes in the "longlist". The descriptions are provided in Appendix B. The focus of these descriptions is on the physical and chemical principles of operating in relation to the CO_2 capture ratio, and on the possibilities for increasing this ratio. In these descriptions the following structure is used:

- Block diagram with process description
- Principle of separation
- Factors determining the CO_2 capture on a system level
- Possibilities for increasing the CO_2 capture ratio
- Non-CO_2 emissions

2.4 Qualitative characterisation

Based on the descriptions, a qualitative characterisation has been made for the processes. This is used to give an overview of the results and is used for selection.

2.4.1 Characterisation methodology

Four criteria have been developed for the characterisation of the processes. Two criteria are for the base case or "normal" CO_2 capture ratio. The "normal" capture is the capture ratio as generally encountered in literature, which is generally related to a design using economic optimisation or design rules therefore. Two criteria address the possibilities for increasing the CO_2 capture ratio above the base case (stretch cases). A three-level scale has been used, which is discussed below. The criteria are limited to near zero emission potential. Important other criteria for a successful technology, such as capture efficiency penalty and costs, are not included since they require a quantitative approach. Options can have a predominantly low score in the near zero emission potential, but be promising from, e.g., a cost perspective.

Criteria for cases with normal CO_2 capture.

Criterion 1. Base case or "normal" CO_2 capture ratio

-	<80%
0	80-90%
+	>90%

Criterion 2. Base case other emissions

-	Increase in other emissions compared to case without capture
0	Emissions in the same range as technology without CO_2 capture
+	Other emissions lower as in case without capture

The other emissions are compared to a reference case of the equivalent technology without CO_2 capture. The effect of increased fuel use on emissions is excluded.

Stretch criteria

Criterion 3. Technical feasibility of CCR stretch to high CO_2 capture ratios

-	Not feasible to stretch CCR to very high values
0	Feasible, but requires changes to equipment or process conditions
+	Increased to 100% with minor changes, or base case already near zero emissions

Criterion 4. Efficiency penalty for increasing the CCR

-	Large efficiency penalty expected associated with increasing the CCR
0	Efficiency penalty present
+	No, or very low efficiency penalty or base case already near zero emissions

2.4.2 Characterisation results

The results of the characterisation against the criteria formulated are summarized in Table 3.

Table 3: *Qualitative characterisation of CO_2 capture processes*

	Base case CCR	Other emissions	Stretch Technical	Stretch-Efficiency
Criterion number	1	2	3	4
NGCC with MEA absorber	0	0	0	-
PC with MEA absorber	0	0	0	-
NGCC with Selexol pre-combustion capture	0	0	0	-
IGCC with Selexol pre-combustion capture	0	0	0	-
Oxy-combustion NGCC with CO_2 recycle	+	+	+	+
Oxy-combustion PC boiler	+	+	+	+
Matiant cycle	+	+	+	+
Water cycle	+	+	+	+
NGCC with post-combustion solid sorption	0	0	+	-
PC with post-combustion solid sorption	0	0	+	-
NGCC with membrane reformer	0	-	-	0
NG with sorption enhanced reforming	0	-	-	0
NGCC with CLC	+	+	+	+
IGCC with CLC	+	+	+	+
NGCC with post-combustion membrane absorber	0	+	0	-
PC with post-combustion membrane absorber	0	+	0	-
AZEP	0	+	+	0
NG SOFC-GT	0	+	+	0
IGCC SOFC	0	+	+	0
PC with CaO	0	0	-	-

From this table it can be observed that there is no significant difference between gas and coal fed options. Also there is no clear impact of the principle of separation. The oxy-combustion type technologies (oxy-combustion NGCC & PC, Matiant, water cycle, chemical looping combustion, AZEP, SOFC) have in general the highest scores. Pre- and post-combustion technologies have in general lower scores. The post-combustion technologies are expected to have a relative large efficiency penalty when increasing the CCR compared to other technologies. Advanced pre-combustion technologies (membrane reformer, sorption enhanced reaction) are expected to have technical difficulties achieving very high capture ratios, unless a combination of technologies is used to overcome this. In situ removal of CO_2 during combustion is not expected to be very attractive from a high CO_2 capture view (See Appendix B.20).

3. Characterisation of processes

In this section a shortlist of processes is set up for which an Order Of Magnitude (OOM) estimation is made of the efficiency and costs for varying CO_2 capture ratios. The assessment discusses efficiency, cost and chain emission effects.

3.1 Shortlist of processes

Based on the process descriptions and characterisations in Chapter 2, a shortlist has been set up. The shortlist was selected by exclusion of processes from the "longlist" based on the following criteria:

- Processes that are very similar to other processes and offer merely cost or efficiency benefits rather than CCR benefits
- Processes that have a very low or uncertain development status and are not applicable to a high CCR requirement
- Processes that are similar to other processes and offer little prospect of increased CCR.

The Matiant cycle is excluded because the water cycle is a similar and simpler option. The options with post-combustion solid adsorption (NGCC and PC) are excluded because of their low development status. The membrane reactor and sorption enhanced reaction options are excluded because they offer more of a cost and efficiency benefit than a CO_2 capture ratio benefit, compared to conventional gas fed pre-combustion capture. IGCC with chemical looping results will be similar to NG fed chemical looping. NGCC and PC with post-combustion membrane contactors are excluded because they are similar to conventional post-combustion. The development status of SOFC-GT is too low for large-scale applications combined with IGCC, for gas fed applications it is selected since it is of interest from a high CCR point of view. The process with CaO has too low a development status. The resulting shortlist of processes is presented in Table 4.

Table 4: *Shortlist of processes for quantitative characterisation.*

Process	Description
Post-combustion coal	PC boiler with post-combustion MEA absorber
Post-combustion gas	NGCC with post-combustion MEA absorber
Pre-combustion coal	Pre-combustion capture IGCC with shift and Selexol absorber
Pre-combustion gas	Pre-combustion NGCC with ATR, shift and Selexol absorber
Oxy-combustion coal	Oxy-combustion PC boiler with CO_2 recycle
Oxy-combustion gas	Oxy-combustion NGCC with CO_2 recycle
Water cycle	Water cycle: oxy-combustion gas turbine with water cooling
AZEP	AZEP: NGCC with integrated oxygen conducting membrane
SOFC-GT	SOFC-GT with afterburner with oxygen conducting membrane
Chemical looping	NGCC with chemical looping combustion

3.2 Characterisation of processes

The processes from Table 4 are analysed quantitatively with a so-called order of magnitude (OOM) estimate. With this OOM estimate the investment costs and efficiency at the upper limit of the capture ratio are determined. The processes have been divided into two groups. The results for the "conventional" processes (first 5 processes from Table 4) and the "advanced" processes (last 5) are treated separately.

3.3 Methodology

The efficiency and investment at the upper limit of the capture ratio "zero emission" of the power generation process is determined relative to data at a "normal" capture ratio. Firstly the extension and/or modification of the capture process to achieve "zero emission" is studied. Then the investment costs relative to "normal capture" are determined, and the efficiency penalty is determined.

An example of this methodology for "process X" is given in *Figure 7*.

- The "no capture" column contains the BAT data
- The "normal capture" column contains the reference data at a certain (normal) capture ratio

The "normal" capture refers to the capture ratio as generally encountered in literature, which is generally related to a design using economic optimisation or design rules therefore.

- The "enhanced capture" column contains the "zero emission" data

Input data for the calculations are printed in a bold font style. Output data are printed in a normal font style.

The "enhanced capture" data follow from the estimate, e.g.:

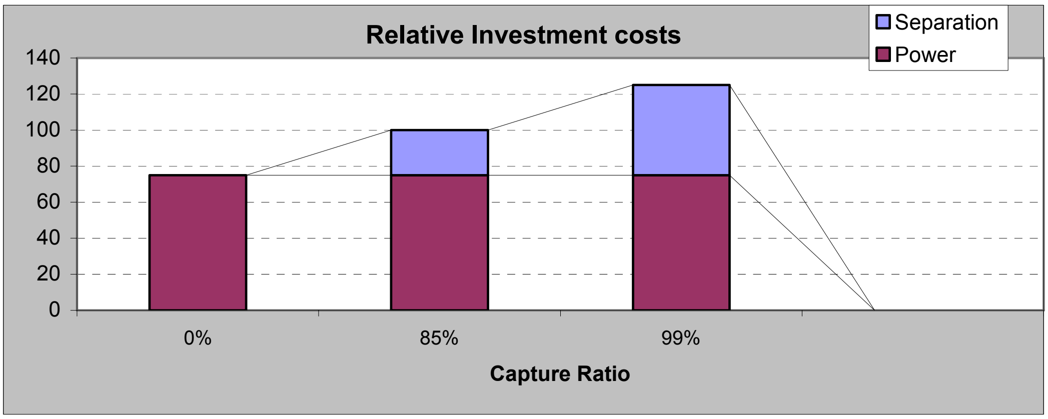
- *Capture ratio*
  99% is estimated as a feasible upper limit of this technology
- *Efficiency*
  The efficiency penalty for going from no capture to 85% capture is 10 %-points. Suppose 7 %-points come from utilities (electricity and steam) and this is doubled to achieve 99% capture. 3 %-points come from CO_2 compression with only limited increase when going to 99% capture. The additional efficiency penalty for going to 99% would then be 8 %-points.
- *Investment costs*
  The split between separation and power at normal capture (25/75) comes from the reference source. Based on the extension and/or modification of the capture process the investment is estimated to be a factor of 2 higher in the enhanced capture case.
- *Power costs*
  The split between investment and fuel at normal capture (67/33) comes from the reference source. The figures in the enhanced capture case follow from the investment data. Note that the ratio of the efficiencies impacts the number for fuel but also for investment because it is the specific investment that is determining the power costs.

CO_2 capture process X

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**50%**	**40%**	**32%**	
Capture ratio	**0%**	**85%**	**99%**	

Investment costs	(relative to state of the art)			
Separation	0	**25**	**50**	
Power	75	75	75	
total	75	100	125	0

Power costs	(relative to state of the art)			
Investment	40	**67**	105	
Fuel	26	33	41	
total	67	100	146	0



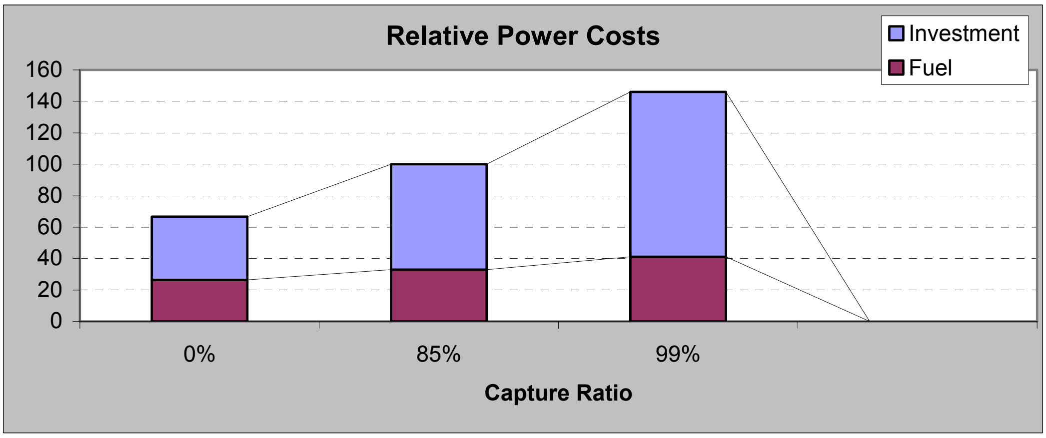


Figure 7: *Example OOM estimate of CO_2 capture process X.*

For the advanced processes (water cycle, AZEP, SOFC-GT and chemical looping combustion) a somewhat different calculation order for the same method has been used since often other input data was available (e.g. 100% capture data available, 85% capture data is estimated from this).

3.4 Results

3.4.1 Post-combustion coal

In this process the CO_2 is removed from the flue gas with an MEA solvent (see more detail in appendix B.3). The reference data for the normal capture case are taken from (IEA GHG, 2000).

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Capture ratio

Amine scrubbing technology using MEA as a solvent is used for capturing flue gas CO_2 to a level of 500 ppm or 0.05 vol%. Whether the MEA solvent is capable of achieving 500 ppm has to be confirmed. With a normal CO_2 concentration of 14% in a pulverized coal power plant, this is equivalent to a capture ratio of over 99%.

Investment costs

With a normal capture ratio of 85%, the CO_2 concentration in the flue gas is reduced from 14% to ±2%. Increasing the capture ratio to 99% gives the following effects:

- The column height for a reduction to 0.05% (H_2) relative to the column height for a reduction to 2% (H1) follows from the equation below.

  $$\frac{H2}{H1} = \frac{\ln(14/0.05)}{\ln(14/0.2)} = 3 \qquad (2)$$

  With three columns in series and a scaling factor of 0.8, the investment costs for the separation increase by a factor of 2 (i.e., $3^{0.8}$).
- The regenerator size increases with a factor 1.5. Applying a factor of 0.8 gives a cost increase of 1.4.
- The sorbent recirculation system increases in size with a factor of 1.3, applying a scaling factor of 0.65 gives a cost increase of a factor 1.1.

The weighted average (based on investment costs of sections) gives a total increase in investments of the capture part with a factor 2. In further analysis a scaling factor of 0.65 (3^0.65 = 2) for the whole capture section will be used for determination of intermediate points. The factor 2 increase in investment of the capture part corresponds with a total plant investment increase of 20%.

Efficiency

The efficiency penalty for going from 0% to 85% capture is roughly 12.5 %-points. The efficiency penalty can be split as follows:

- 9 %-points due to steam consumption in the MEA regenerator
- 3 %-points due to CO_2 compression
- 0.5 %-point due to flue gas pressure drop over the MEA scrubber section

With enhanced capture (99%) the efficiency penalties are:

- 14.4 %-points due to steam consumption in the MEA regenerator. Regeneration steam demand is a factor of 1.6 higher due to higher recirculation and leaner MEA requirements at the top of the scrubber.
- 3.6 %-points due to CO_2 compression
  The amount of CO_2 is roughly 16% higher.
- 1.5 %-points due to flue gas pressure drop over the MEA scrubber section
  The pressure drop over the scrubber section is roughly 3 times as high.

With the above efficiency penalties the overall efficiency of the enhanced capture case is roughly 26%.

Results

Increasing the CCR from 85% to 99% gives:

- a 7 %-points decrease in efficiency,
- a 20% increase in investment costs and
- a 45% increase in power production costs

See *Figure 8*.

Post combustion Coal

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**46%**	**33%**	**26%**	
Capture ratio	**0%**	**85%**	**99%**	

Investment costs (relative to state of the art)

Separation	0	**20**	**40**	
Power	80	80	80	
total	80	100	120	0

Power costs (relative to state of the art)

Investment	41	**70**	107	
Fuel	22	30	38	
total	62	100	145	0

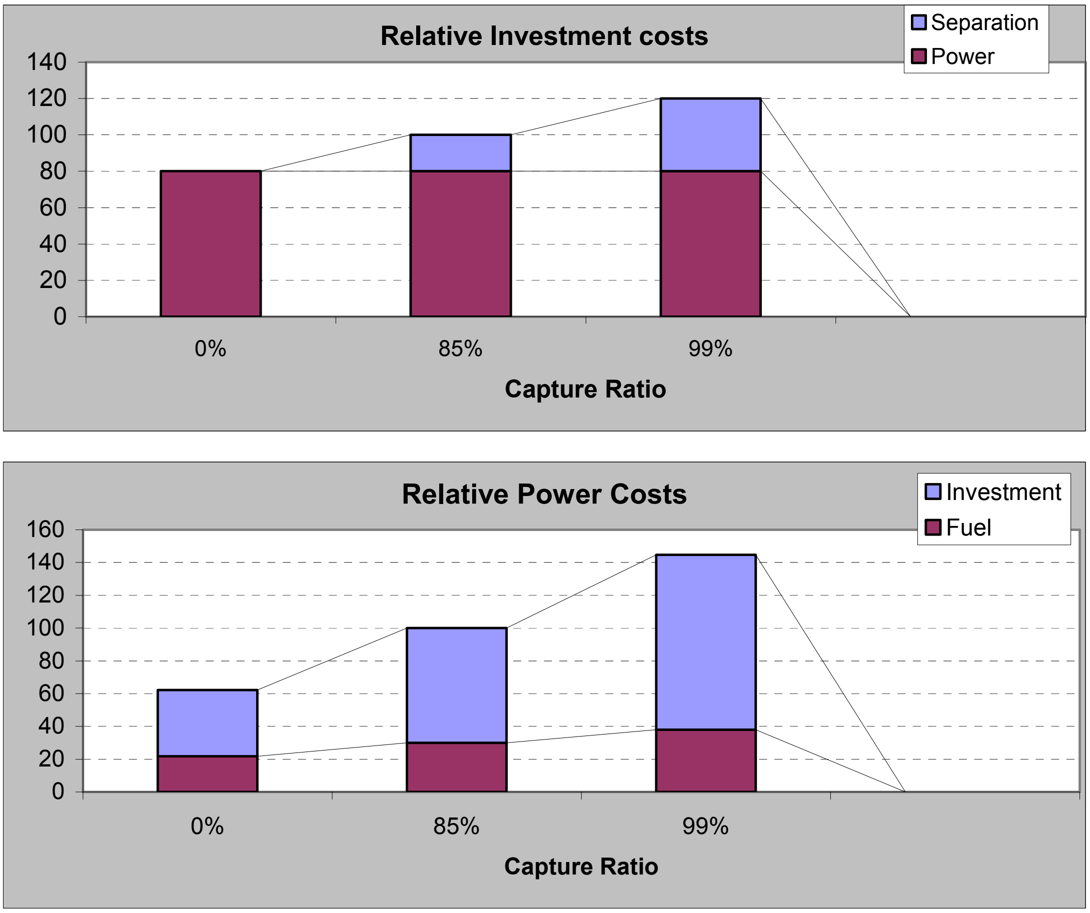


Figure 8: *Results for post-combustion coal.*

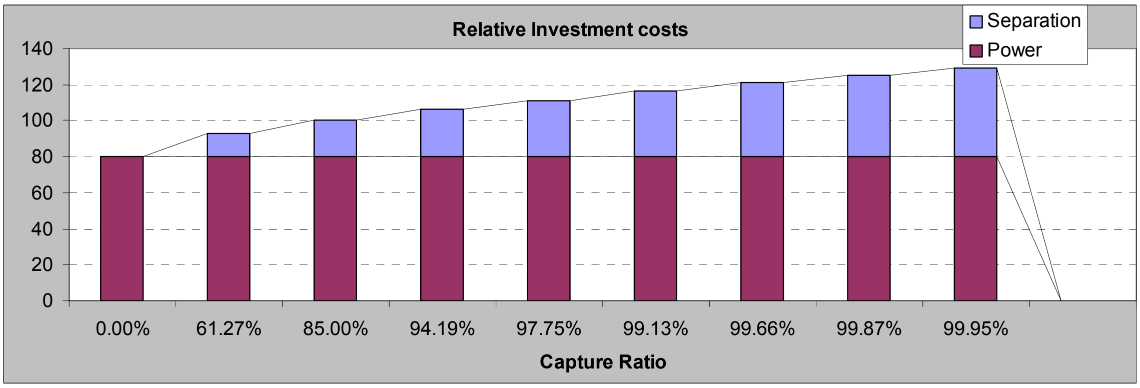
Intermediate points have been generated using a scaling exponent of 0.65 for the whole capture section. This is the overall factor which accords with the 99% capture case. The results are presented in Figure 9.

Post combustion Coal

	No capture	Capture 1	Capture 2	Capture 3	Capture 4	Capture 5	Capture 6	Capture 7	Capture 8
Efficiency	**45.6%**	35.4%	**33.0%**	31.1%	29.4%	27.8%	26.2%	24.6%	23.0%
CO2 concentration	**14.0%**	5.42%	2.1%	0.81%	0.32%	0.12%	0.05%	0.02%	0.01%
Capture ratio	0.00%	61.27%	**85.00%**	94.19%	97.75%	99.13%	99.66%	99.87%	99.95%
steam factor leaner MEA + recirc		0.85	**1**	1.15	1.3	1.45	**1.6**	1.75	1.9

Investment costs		Scaling factor	0.65						
Column height (relative)	**0**	**0.5**	**1**	**1.5**	**2**	**2.5**	**3**	**3.5**	**4**
Separation	0	13	**20**	26	31	36	41	45	49
Power	80	80	80	80	80	80	80	80	80
total	80	93	100	106	111	116	121	125	129
Power costs			(relative to state of the art)						
Investment	41	60	**70**	79	88	97	107	118	130
Fuel	22	28	30	32	34	36	38	40	43
total	62	88	100	111	121	132	144	158	173

Absolute									
Reference investments $/kWe			1856						
Ref power price $/MWh			63.50						
Specific investment $/kWe	1075	1604	1856	2088	2321	2564	2827	3115	3437
Specific investment corr $/kWe	1246	1859	2152	2421	2690	2973	3277	3612	3985
Power price $/MWh	39.52	56.15	63.50	70.23	76.96	84.04	91.71	100.16	109.62
Power price indexed $/MWh	43.62	62.27	70.58	78.19	85.81	93.82	102.49	112.05	122.74



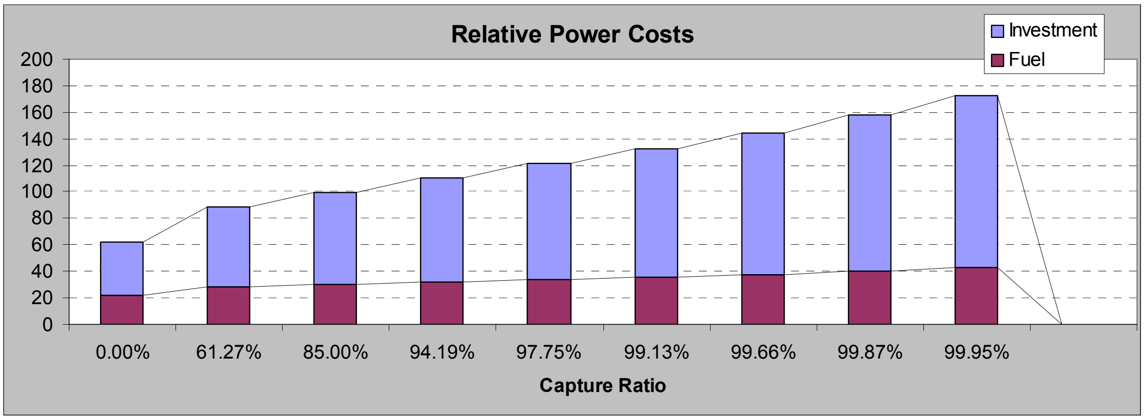


Figure 9: *Results for post-combustion coal at different column heights.*

3.4.2 Post-combustion gas

In this process the CO_2 is removed from the flue gas via MEA solvent scrubbing (see for more detail appendix B.2). The reference data for the normal capture case are taken from (IEA GHG, 2000).

Capture ratio

With the MEA solvent a CO_2 concentration of 500 ppm or 0.05 Vol% is achievable. With a normal CO_2 concentration of 4% in a natural gas combined cycle power plant, this is equivalent to a capture ratio of over 98%.

Investment costs

The effects of increasing the capture ratio from 85% to 98% are as follows:

- With a normal capture ratio of 85% the CO_2 concentration in the flue gas is reduced from 4% to ±0.6%. The column height for a reduction to 0.05% (H_2) relative to the column height for a reduction to 0.6% (H1) follows from the equation below.

  $$\frac{H2}{H1} = \frac{\ln(4/0.0.5)}{\ln(4/0.6)} = 2.3 \qquad (3)$$

  With two slightly higher columns in series and a scaling factor of 0.8 the investment costs for the separation increase by a factor of 1.9 ($2.3^{0.8}$)
- The regenerator size increases with a factor 1.2. Applying a cost exponent of 0.8 gives a cost increase of a factor 1.1.
- The solvent recirculation system increases with a factor 1.3. Applying a cost exponent of 0.65 gives a cost increase of 1.2.

The weighted average (based on investment costs of sections) gives total increase of investments of the capture process part by a factor 1.7. In further analysis a scaling factor of 0.65 (2.3^0.65 = 1.7) for the whole capture section will be used for determination of intermediate points. The factor 1.7 increase in investment of the capture part corresponds with a total plant investment increase with 20%.

Intermediate points have been generated using a scaling exponent of 0.65 (2.3^0.65 = 1.7)for the whole capture section. This is the overall factor which accords with the 99% capture case. The results are presented in Figure 9.

Efficiency

The efficiency penalty for going from 0% to 85% capture is roughly 9 %-points. The efficiency penalty can be split as follows:

- 7.5 %-points due to steam consumption in the MEA regenerator
- 1.0 %-point due to CO_2 compression
- 0.5 %-points due to flue gas pressure drop over the MEA scrubber section

With enhanced capture (98%) the efficiency penalties are:

- 13 %-point due to steam consumption in the MEA regenerator. Regeneration steam demand is a factor of 1.6 higher due to higher recirculation and leaner MEA requirements at the top of the scrubber.
- 2.0 %-point due to CO_2 compression
  The amount of CO_2 is roughly 20% higher.
- 1.0 %-point due to flue gas pressure drop over the MEA scrubber section
  The pressure drop over the scrubber section is roughly 2 times as high.

With the above efficiency penalties the overall efficiency of the enhanced capture case is roughly 40%.

Result

The result of the estimate is that for enhanced capture (98%) the result is:

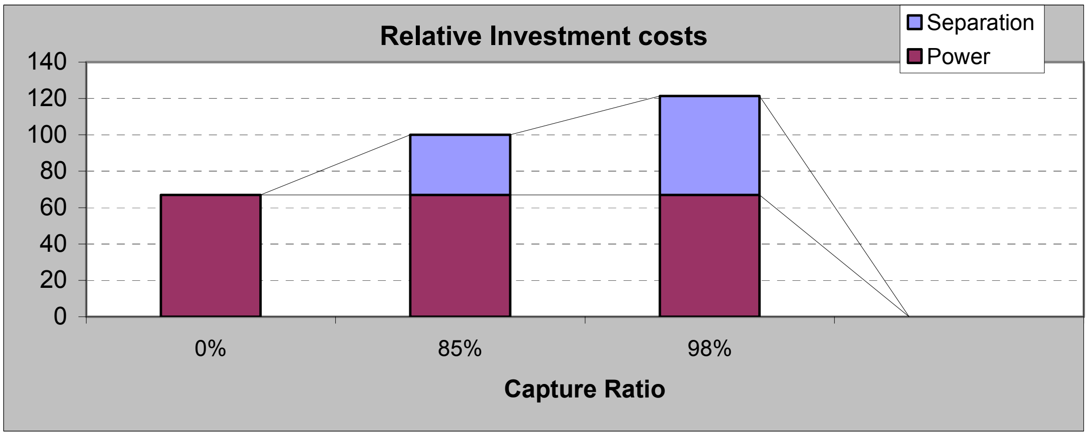
- a 7 %-points decrease in efficiency,
- a 21% increase in investment costs and
- a 30% increase in power production costs

See Figure 10.

Post combustion Gas

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**56%**	**47%**	**40%**	
Capture ratio	**0%**	**85%**	**98%**	

Investment costs		(relative to state of the art)		
Separation	0	**33**	**54**	
Power	67	67	67	
total	67	100	121	0
Power costs		(relative to state of the art)		
Investment	28	**50**	71	
Fuel	42	50	59	
total	70	100	130	0



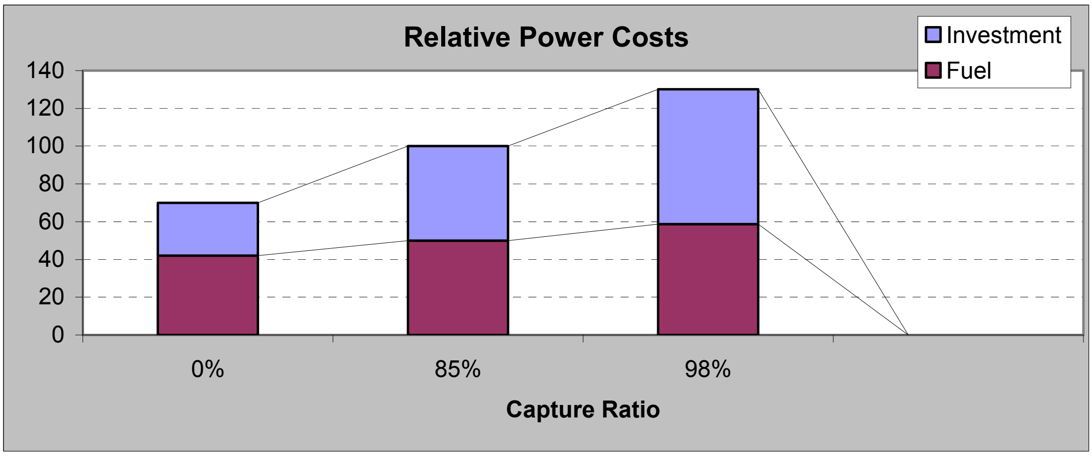


Figure 10: *Results post-combustion gas.*

Intermediate points have been generated using a scaling exponent of 0.65 for the whole capture section. This gives a good accordance for the 99% capture case. The results are presented in Figure 11.

Post combustion Gas

	No capture	Capture 1	Capture 2	Capture 3	Capture 4	Capture 5	Capture 6	Capture 7	Capture 8
Efficiency	**56.0%**	49.0%	**47.0%**	45.2%	43.5%	41.9%	40.2%	38.6%	36.9%
CO2 concentration	**4.0%**	1.5%	0.6%	0.23%	0.09%	0.035%	0.014%	0.005%	0.002%
Capture ratio	0.00%	61.27%	**85.00%**	94.19%	97.75%	99.13%	99.66%	99.87%	99.95%
Steam factor leaner MEA		0.8	**1**	1.2	1.4	**1.6**	1.8	2	2.2
Investment costs		Schaalfactor	0.65						
Column height (relative)	**0**	**0.5**	**1**	**1.5**	**2**	**2.5**	**3**	**3.5**	**4**
Separation	0	21	**33**	43	52	60	67	75	81
Power	67	67	67	67	67	67	67	67	67
total	67	88	100	110	119	127	134	142	148
Power costs			(relative to state of the art)						
Investment	28	42	**50**	57	64	71	79	86	94
Fuel	42	48	50	52	54	56	58	61	64
total	70	90	100	109	118	127	137	147	158

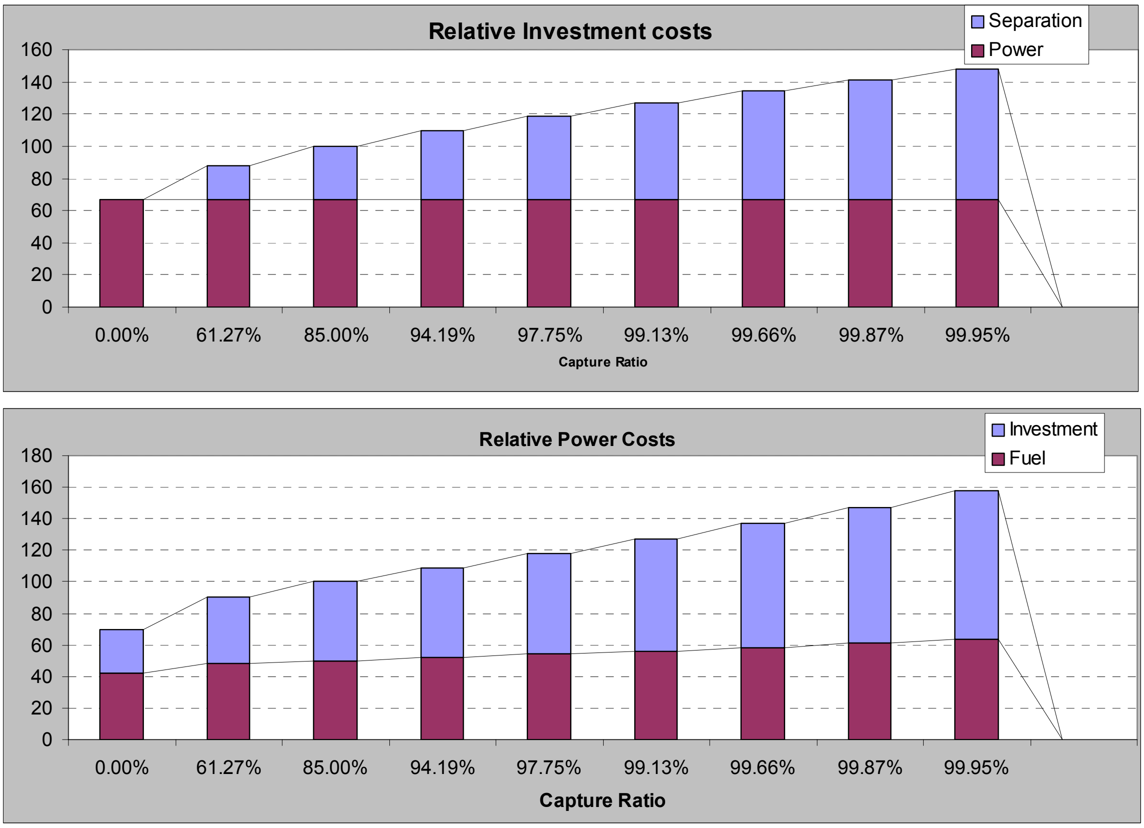


Figure 11: *Results for post-combustion gas at different column heights*

3.4.3 Pre-combustion coal (IGCC)

In this process the CO_2 is removed from the coal gasification syngas using Selexol solvent (see more detail in Appendix B.5). The reference data for the normal capture case is taken from (IEA GHG, 2000). .

A simplified mass and heat balance for the process has been made, see Figure 63 and Figure 64 in Appendix C that give the block diagram and stream data of the two phase shift and Selexol CO_2 capture of the normal capture case, with a capture ratio of 85%, and of the four phase shift and Selexol CO_2 capture, with a capture ratio of 98%. The inlet conditions to the CO_2 capture section are based on (IEA GHG, 2000). *Leading Options for the Capture of CO_2 emissions at power stations*, International Energy Agency, Paris (France), *Greenhouse Gas R&D Programme*, Report Number PH3/14). Shift and CO_2 wash performance are based on typical design of these components.

Description

For the 85% capture case, a two-stage CO shift conversion with high temperature shift catalyst is adequate. Cooling between the stages, by preheating the feed gas to the first shift reactor, is applied to remove the reaction heat. The exit temperature of the second shift reactor is approximately 440°C. Further heat recovery is applied, including a desaturator/saturator system, to generate steam for the shift reaction. The resulting CO concentration after shift conversion is approximately 5 mol%. The overall carbon conversion to CO_2 (on the basis of the original carbon in the fuel) is approximately 87%. Removal of CO_2 from the gas is accomplished with Selexol absorber with a two-stage flash to recover the CO_2 from the solvent. With this setup approximately 98% of the CO_2 is removed from the gas, resulting in an overall CO_2 capture ratio of 85%.

For the 98 % capture case, three stages of high temperature shift catalyst and a last stage with low temperature shift catalyst are required to achieve a sufficiently low CO concentration in the product gas. The last shift reactor is designed for an exit temperature of approximately 230°C to achieve favourable reaction equilibrium. The concentration of remaining CO in the product gas is approximately 0.05 mol%, resulting in an overall carbon conversion of almost 99%.

The Selexol treater removes CO_2 from the gas to approximately 500 ppm. For this duty, the absorber is approximately twice as high, the solvent circulation flow is higher and an additional steam stripper down-stream of the two-stage flash is required.

The effect of the extended shift conversion unit and extended Selexol treater is a 90% higher investment in the separation section (i.e. shift reactors and Selexol treater).

The reduction of approximately 2% points in overall efficiency, due to the higher capture ratio, results from:

- Higher steam consumption in the CO shift: 0.1 %-point
- Higher solvent circulation (Selexol treater: 0.5 %-point)
- Steam consumption by the Selexol stripper: 1 %-point
- Higher CO_2 compression power: 0.4 %-point

Results

The result of increasing the CCR from 85% to an enhanced capture ratio of 98%:

- a 2 %-points decrease in efficiency,
- a 15% increase in investment and
- a 18% increase in power production costs

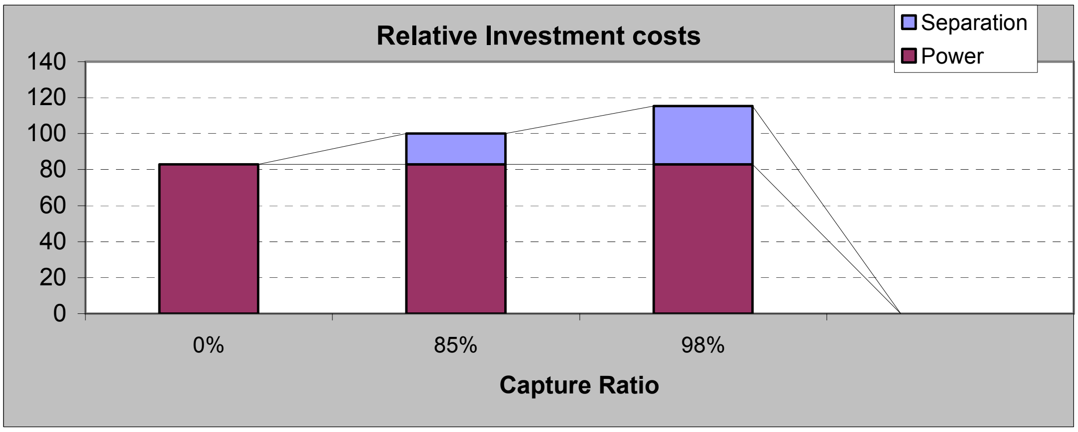
The results of the analysis are presented in Figure 12.

Pre combustion Coal

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**46%**	**38%**	**36%**	
Carbon conversion		**89%**	**98%**	
Carbon capture		**96%**	**100%**	
Overal Carbon capture	**0%**	85%	98%	

Investment costs		(relative to state of the art)		
Separation	0	**17**	**32**	
Power	83	83	83	
total	83	100	115	0

Power costs		(relative to state of the art)		
Investment	51	**75**	92	
Fuel	21	25	27	
total	72	100	118	0



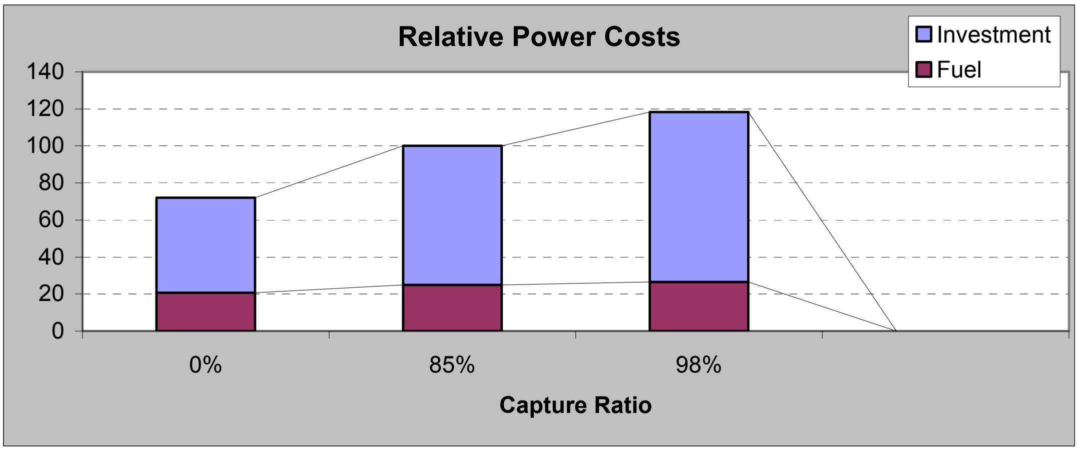


Figure 12: R*esults pre-combustion IGCC*

3.4.4 Pre-combustion gas

In this process the CO_2 is removed from the syngas, from reforming natural gas, using Selexol solvent (see more detail in Appendix B.4). The reference data for the normal capture case is taken from (IEA GHG, 2000). .

Capture ratio

With a four stage shift instead of a two stage shift a CO concentration in the syngas of 500 ppm or 0.05 vol% is achievable. With Selexol removal a CO_2 concentration in the syngas of 500 ppm or 0.05 Vol% is achievable. This results in an overall CO_2 capture ratio of over 98%.

Investment costs

The investment costs for the shift section increase by a factor of 3. The investment costs for the Selexol removal section increase by a factor of 1.65. The total CO_2 separation costs increase by a factor of 1.2. Note that the factor is not 1.9 as with pre-combustion coal because the reformer is part of the separation investment contrary to situation for the coal gasifier, where it is considered part of the power plant.

Efficiency

The 8 %-points efficiency penalty between no capture and normal capture is mainly caused by the steam injection for the shift and the recirculation of the Selexol solvent. Because the additional steam injection and recirculation is very limited the additional efficiency penalty for enhanced capture is limited to 2 %-points.

Result

The result of the estimate is:

- a 2 %-points decrease in efficiency,
- a 10% increase in investment and
- a 11% increase in power production costs

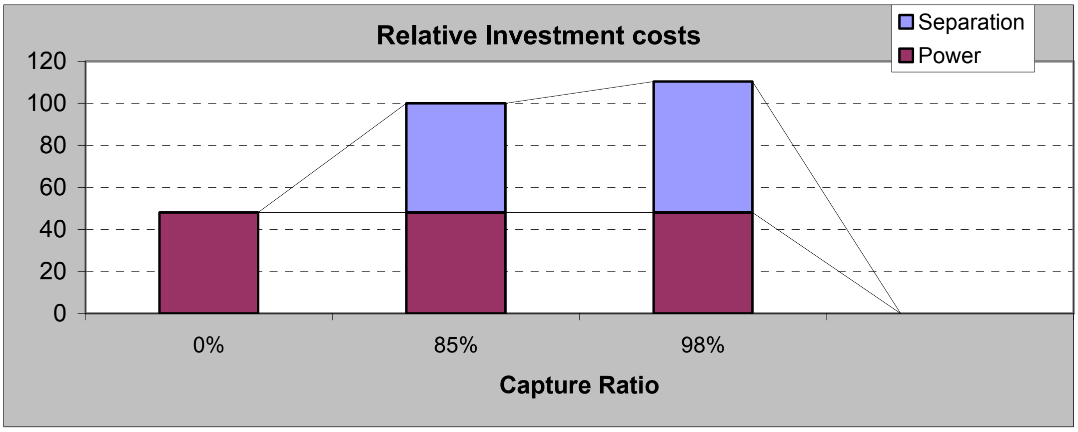
See Figure 13.

Pre combustion Gas

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**56%**	**47%**	**45%**	
		88%	**99%**	
		97%	**100%**	
	0%	85%	98%	

Investment costs		(relative to state of the art)		
Separation	0	**52**	**62**	
Power	48	48	48	
total	48	100	110	0

Power costs		(relative to state of the art)		
Investment	20	**50**	58	
Fuel	42	50	53	
total	62	100	111	0



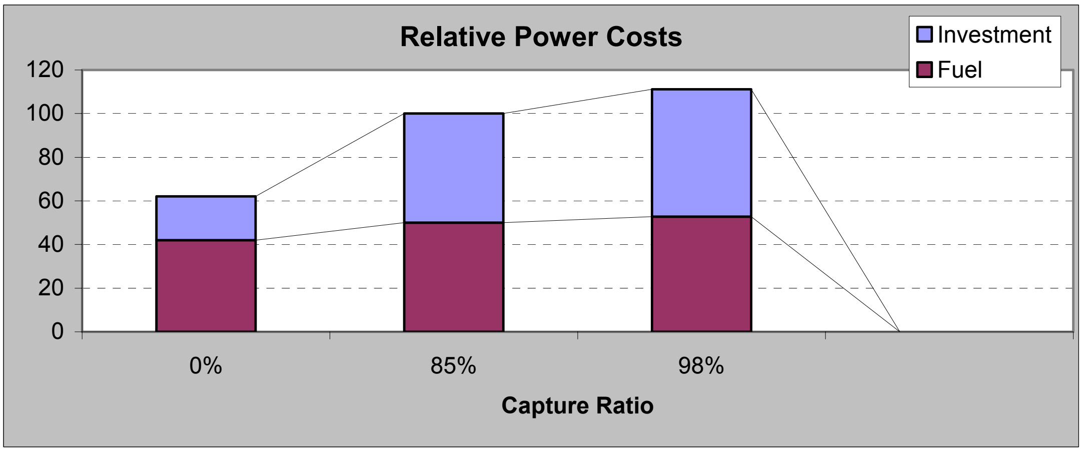


Figure 13: *Results pre-combustion gas.*

3.4.5 Oxy-combustion coal

General

In this process the coal boiler is fired with 95% pure oxygen, resulting in a highly concentrated CO_2 flue gas stream (see more detail in Appendix B.7). The reference data for the normal capture case is taken from (IEA GHG, 2000). .

Capture ratio

In principle, 100% of the CO_2 is captured in the flue gas; however the final flue gas stream contains about 25% non-CO_2 components like O_2, N_2 and Ar. This is caused by air in-leakage in the boiler, excess combustion oxygen, and use of 95% pure oxygen. In a cryogenic purification step the flue gas is enriched to 95% CO_2. The vent stream with most of the non-CO_2 components also contains 25% CO_2, resulting in a capture ratio of 91% for the normal capture case. The capture ratio can be increased to nearly 100% by eliminating the flue gas purification step and storage of the entire flue gas stream including the non-CO_2 components. Further study may be required to determine whether the transport and storage of these non-CO_2 components interfere with the pipeline and injection requirements.

An alternative option that is considered is to treat the vent stream separately with Selexol scrubbing. Figure 65 in Appendix D gives the block diagram and stream data of the Selexol CO_2 capture system for the vent stream from the oxy-combustion coal fired boiler. With the additional Selexol treater the normal capture ratio of 90.8% from the Mitsui Babcock IEA report (IEA GHG, 2005a) can be increased to 99.7%. In principle three cases can be distinguished:

- Normal capture case: 90.8% capture ratio; IEA Mitsui Babcock case with cryogenic separation of inerts.
- Inert storage case: 100% capture ratio, this is the IEA Mitsui Babcock case with direct storage of CO_2 flue gas including all inerts, provided that this is technically feasible. For technical and/or political reasons, CO_2 quality constraints may be set for specific storage and transport cases, which may affect their feasibility.
- Vent stream scrubbing case: 99.7% capture ratio; analysis case: this is the IEA Mitsui Babcock case with cryogenic separation and treatment of the vent stream with Selexol scrubbing.

For the development potential case a Selexol treater at elevated pressure (upstream of the expander) has been selected because of the relatively high oxygen content of the waste stream. Treating of the waste stream downstream of the expander would have required an amine solvent because of the low pressure. However, the high oxygen content is prohibitive for the application of amine solvents because of solvent degradation. Currently oxygen tolerant amine systems up to 14% O_2 are proven. Because the oxygen concentration in this stream is 20%, Selexol treatment is selected as the first choice.

Investment costs

Inert storage case: The investment costs for the purification step are assumed to be comparable to the investment costs for additional compression power. As a result of this assumption, the additional investment costs are zero.

Vent stream scrubbing case: The investment of USD 16.4 mln has been scaled from the cost of similar treating units with comparable duty.

Efficiency

Inert storage case: The extra compression power is assumed to be comparable to the energy required for cryogenic removal of the inerts. Therefore, the efficiency penalty compared to the normal capture case is zero.

Vent stream scrubbing case: The efficiency penalty for enhancing the capture ratio by additional treating of the vent stream and compression of the additional CO_2 results from:

- Additional pumping power for recirculation: 1 MW_e
- Additional steam consumption for the absorption cooling of solvent: 1 MW_e
- Additional compression power due to 10% larger CO_2 steam: 3 MW_e

The total efficiency penalty is 5 MW_e or almost 1 %-point.

Result

The results are presented in Figure 14, where the 'enhanced capture' case is the result of direct storage of CO_2 with all inerts and the 'development potential' case is the result of the analysis of Selexol scrubbing of the vent stream.

The result for the inert storage case (100% capture) is:

- no decrease in efficiency,
- no increase in investment and
- no increase in power production costs

as said, further research may be required whether this options is technically feasible.

The result for the vent stream scrubbing case (99.7% capture) is:

- 0.9%-points decrease inn efficiency,
- 1.3% increase in investment and
- 3.8% increase in power production costs

Oxy fuel Coal

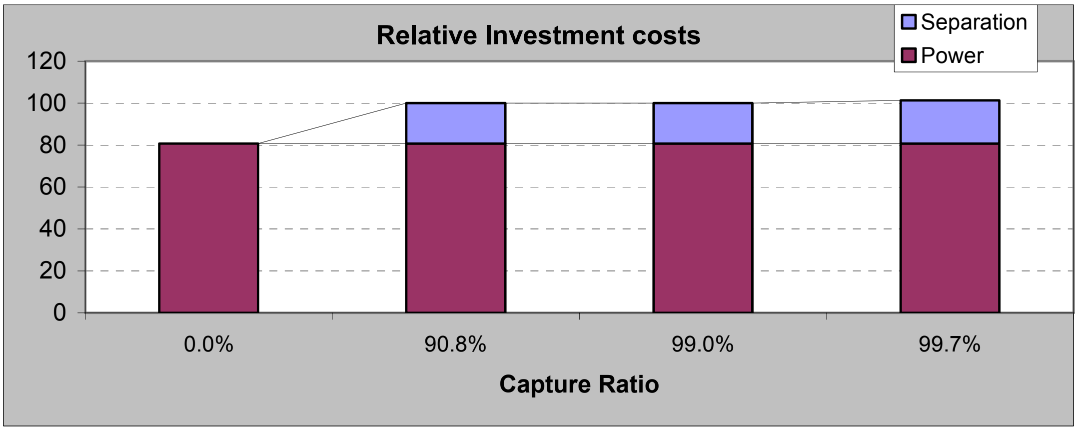
	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**45.6%**	**35.4%**	**35.4%**	**34.5%**
Overal Carbon capture	**0.0%**	**90.8%**	**99.0%**	**99.7%**

Investment costs (relative to state of the art)

Separation	0	**19.3**	**19.3**	**20.6**
Power	81	80.7	80.7	80.7
total	80.7	100.0	100.0	101.3

Power costs (relative to state of the art)

Investment	49.5	**79.0**	79.0	82.2
Fuel	16.3	21.0	21.0	21.5
total	65.8	100.0	100.0	103.8



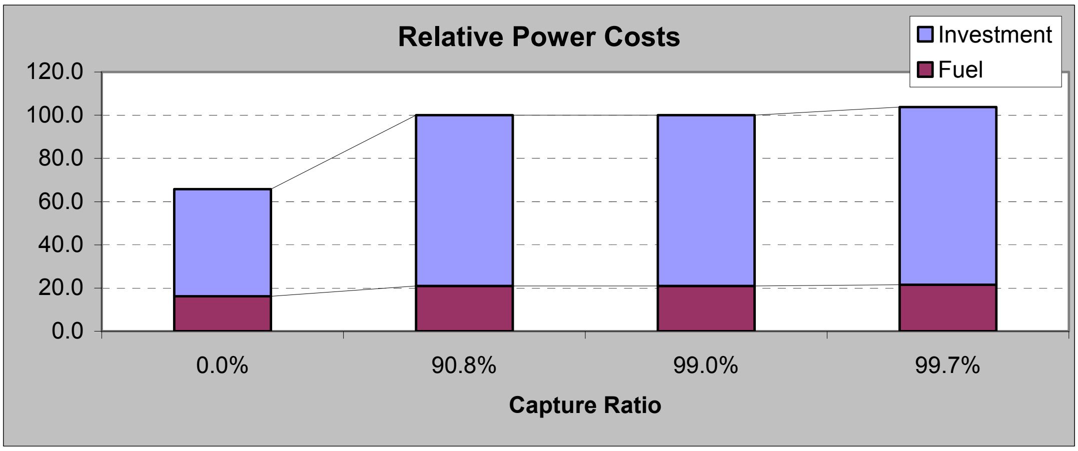


Figure 14: *Results oxy-combustion coal*

3.4.6 Oxy-combustion gas

General

In this process, the gas turbine is fired with nearly pure oxygen resulting in a highly concentrated CO_2 flue gas stream (see for more detail Appendix B.6). The reference data for the normal capture case is taken from (IEA GHG, 2000).

Capture ratio

In principle 100% of the CO_2 is captured in the flue gas; however the final flue gas stream contains about 12% inerts (O_2, N_2 and Ar). This is caused by excess oxygen and because of the use of 95% pure oxygen. In the cryogenic purification step the flue gas is enriched to 95% CO_2. The vent stream with most of the inerts also contains 25% CO_2, resulting in a capture ratio of 98% for the normal capture case. The capture ratio can be increased to nearly 100% by eliminating the flue gas purification step and storing the entire flue gas stream, including the inerts, provided that this is feasible. An alternative may be to treat the vent stream separately with amine or Selexol scrubbing.

Investment costs

The investment costs for the purification step are assumed to be comparable to the investment costs for additional compression power. As a result of this assumption, the additional investment costs are zero.

Efficiency

In a first order estimate the extra compression power is assumed to be comparable to the energy required for cryogenic removal of the inerts. Therefore, the efficiency penalty compared to the normal capture case is assumed to be zero.

Result

The result of the estimate is:

- no decrease in efficiency,
- no increase in investment and
- no increase in power production costs

See Figure 15.

Oxy fuel Gas

	No capture	Normal capture	Enhanced capture	Development potential
Efficiency	**56%**	**45%**	**45%**	
Capture ratio	**0%**	**98%**	**99%**	

Investment costs (relative to state of the art)

Separation	0	**55**	**55**	
Power	45	45	45	
total	45	100	100	0

Power costs (relative to state of the art)

Investment	22	**61**	61	
Fuel	31	39	39	
total	53	100	100	0

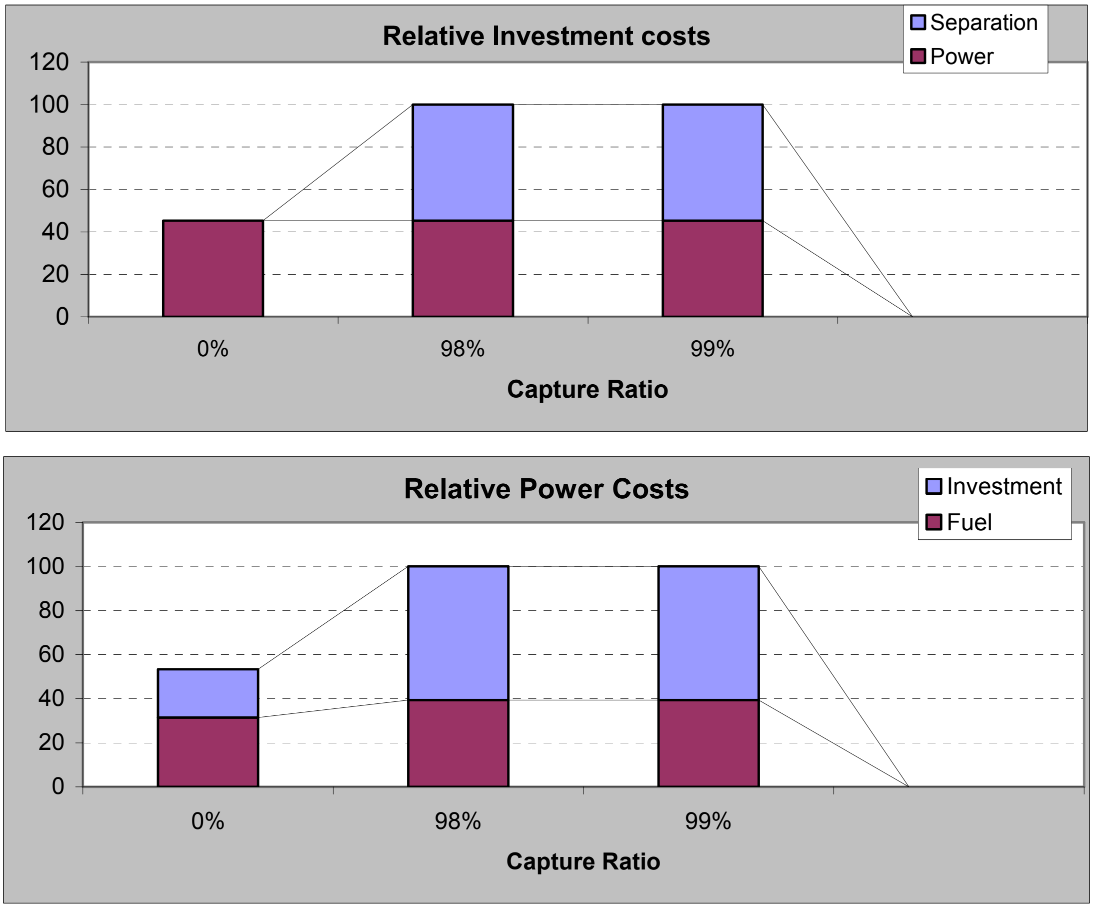


Figure 15: *Results estimate oxy-combustion gas.*

3.4.7 Water cycle

General

In this process natural gas is combusted with oxygen (from an ASU) in a semi-closed gas turbine cycle. During combustion water injection is used to limit the temperature level. For a detailed description, see appendix B.9.

Capture ratio

The CCR of this cycle is taken from (Bolland, Kvamsdal& Boden, 2005). They conclude that the CO_2 emission is 4 g CO_2/kWh as a result of CO_2 dissolved in the wastewater stream. This corresponds to 98-99% capture. It must be noticed that the authors assume the use of 100% pure oxygen. Using less pure oxygen will result in a lower CCR, in the same way as described for the oxy fuel NGCC in section 3.4.6. This will lower the CCR with an additional 2% points. A value of 98.5% is used in this analysis. A case with lower CO_2 capture has not been found.

Investment costs

There is a large uncertainty in the investment costs because of the large difference of the values reported in the literature. In literature the following investments have been reported for the normal capture case:

- (Anderson, 1999) reports a value of 290 USD/kWe. If we apply a correction for the gross/net efficiency difference, and if the investments for oxygen generation and CO_2 compression are added, the resulting investments are 490 USD/kWe. Following these investments the water cycle would be the most attractive option for power production with CO_2 capture.
- (IEA GHG, 1998)[1]. reports investments of 1770 USD/kWe (all included costs). Following these investments, the power generation costs would be far higher than competing technologies. The contribution of the investments to the electricity price is been estimated to be 50%, in the same range as NGCC.
- (IEA GHG, 2005b) reports a value of 1419 USD/kWe.

This latter value of 1419 USD/kWe is the middle of the three values and will be used for the calculations. Furthermore it is estimated that the share of the investment costs in the total power cost is 50%, which is in the same range as NGCC.

Efficiency

The performance of the water cycle with respect to efficiency is very much dependent on the process conditions used, especially inlet temperature and pressure. These are related to the development status of the concept. Further development will allow for more beneficial process conditions. Efficiency differences, expressed as the difference between the water cycle efficiency and a reference no-capture NGCC efficiency of 56%, are.

- A penalty of 3.4%-points reported by (Anderson, 1999).
- A best-case penalty of 12%-points reported by (Bolland, Kvamsdal& Boden, 2005).
- (IEA GHG, 2005b) reports a an efficiency of 45.4% which corresponds to penalty of 10.5%-points

Based on this a penalty of 8%-points has been assumed, which results in a system efficiency of 48%.

Result

The result of the estimate is that for the water cycle there is only one case with a 98.5% capture, no stretch case relevant. Compared to the no-capture case this gives:

- 18% increase in investments
- 18% increase in power production costs

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[1] this report is prepared for IEA by Bolland et al.

See Figure 16.

Water cycle

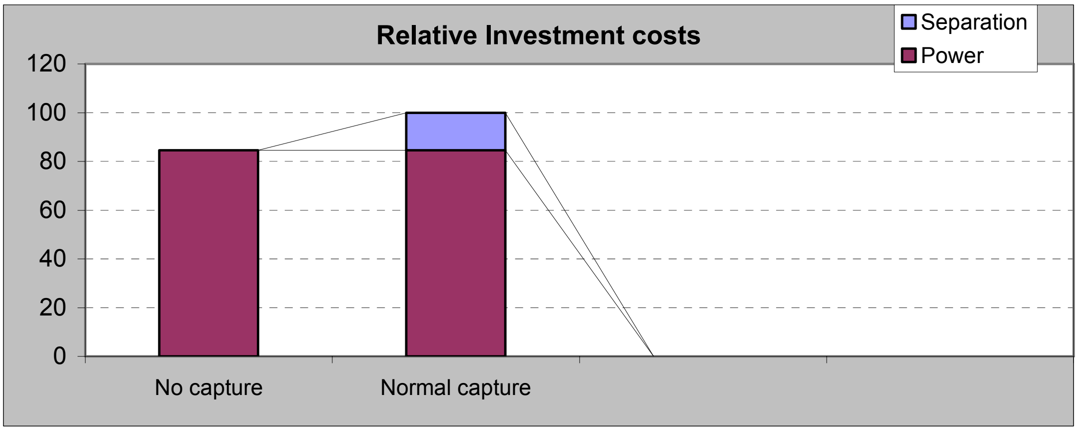
	No capture	Normal capture
Efficiency	**56%**	**48%**
CO2 capture %	**0%**	**98.5%**

Investment costs (relative to state of the art)

Separation	0	15	
Power	84.6	84.6	
total	**84.6**	**100**	0

Power costs (relative to state of the art)

Investment	42	**50**	
Fuel	43	50	
total	85	100	0



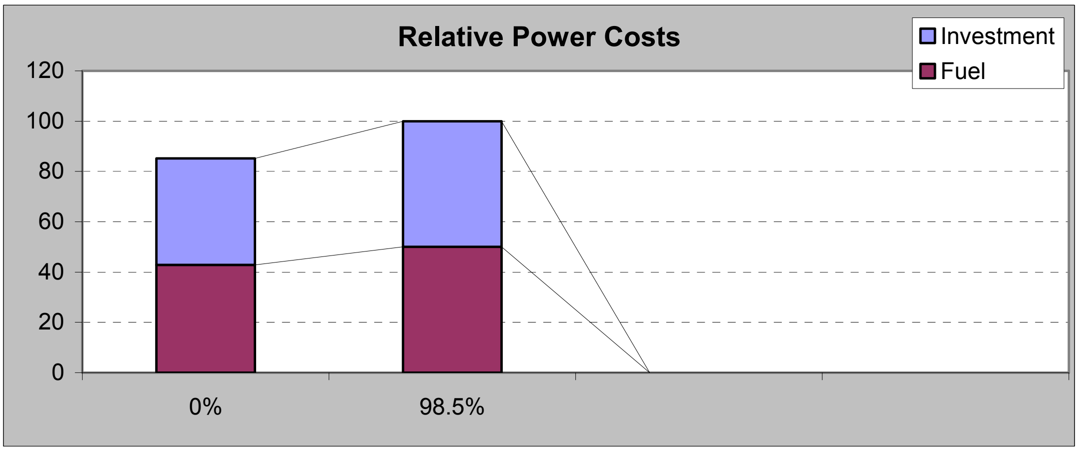


Figure 16: *Results water cycle*

3.4.8 NGCC with oxygen conducting membrane (AZEP)

General

In this process natural gas is combusted using oxygen separated from air using an oxygen conducting membrane integrated with the gas turbine. (See for more detail Appendix B.17).

Capture ratio

The normal capture ratio is 85%. This is due to the additional combustion in the gas turbine with natural gas in order to increase the turbine inlet temperature and, thus, the cycle efficiency. The CCR can simply be increased to nearly 100% by omitting the additional firing. No detailed information is available about the extent to which the 100% figure can be approached in practice.

Investment costs

Investment data have been taken from (Bückner, Holmberg& Griffin, 2005). The process presented there is, however, a simple cycle process, so without a HRSG. The additional costs for a HRSG have been estimated from (Gas Turbine World, 2001).

Efficiency

The efficiency penalty data for the AZEP process compared to NGCC without capture is taken from (Sundkvist, 2005). Because all data in this report are for large-scale applications, the data from the large-scale process (400 MW) is taken, though the efficiency penalty going from 85% to 100% capture of the small-scale case (50 MW) is considerably lower (1.8%) than that of the large-scale case (3.5%).

Result

The result of the estimate is:

- a 3.5%-point decrease in efficiency,
- a 6% increase in investment and
- a 7% increase in power production costs

See Figure 17.

AZEP

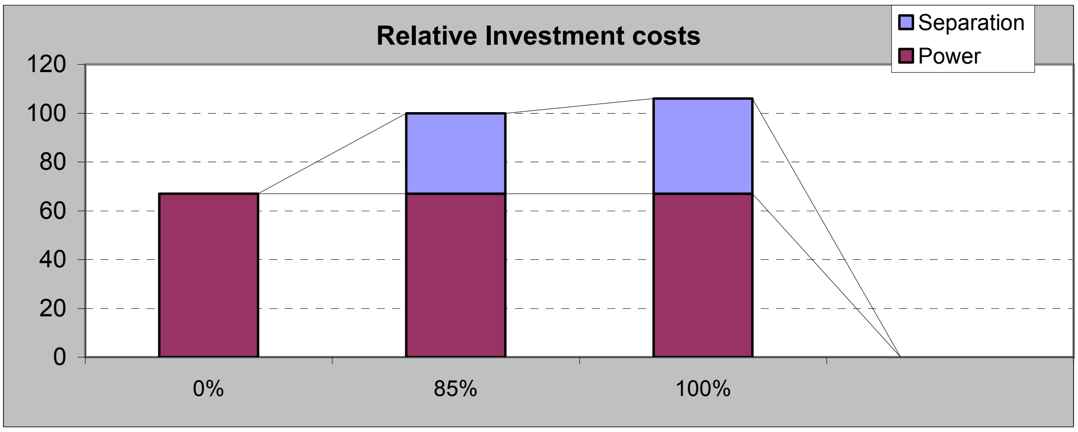
	No capture	Additional firing	Max capture	
Efficiency	**56%**	**52%**	**48%**	
CO2 capture %	**0%**	**85%**	**100%**	

Investment costs (relative to state of the art)

Separation	0	**33**	**39**	
Power	67	67	67	
total	67	100	106	0

Power costs (relative to state of the art)

Investment	34	**50**	53	
Fuel	46	50	54	
total	79	100	107	0



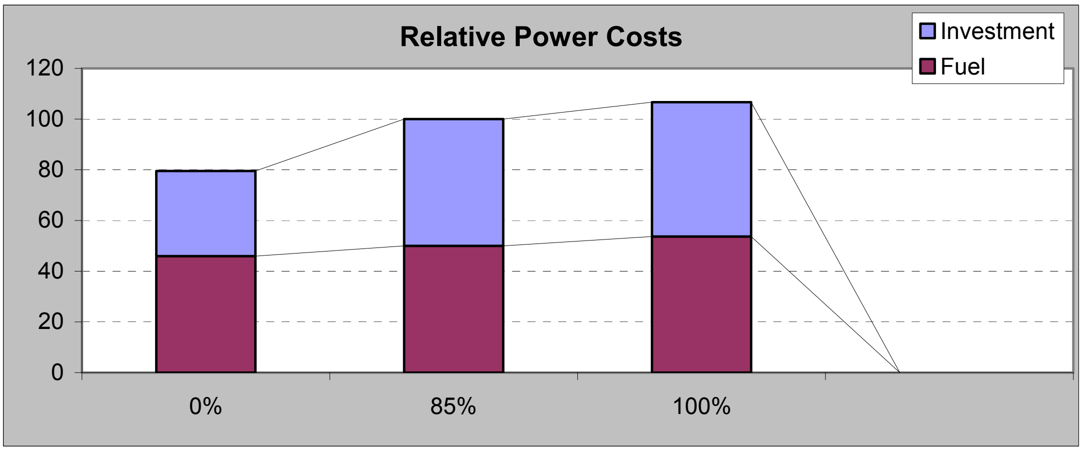


Figure 17: *Results AZEP*

3.4.9 SOFC-GT with CO_2 capture

General

In this process, natural gas is converted in a solid oxide fuel cell (SOFC) equipped with an afterburner and integrated into a gas turbine cycle. Air and fuel are kept separate resulting in a concentrated CO_2 stream. For more detail see appendix B.18.

Capture ratio

The normal capture ratio is 85%. This is due to the supplementary firing of the gas turbine with natural gas used in the base case to increase the turbine inlet temperature and thus the cycle efficiency.
The CCR can simply be increased to near 100% by omitting the additional firing. No detailed information is available about the extent to which the 100% figure can be approached in practice.

Investment costs

The investment costs have been taken from literature (Gielen, 2003). The costs for the reference NGCC have been based on (IEA GHG, 2000).

Efficiency

For the reference cases without capture SOFC-GT without capture is used, as well as an NGCC without capture. The calculation procedure requires that an NGCC without capture should be considered. However, these data are not reported in Figure 18. The efficiency has been derived from literature (IEA GHG, 2005b) for the 0% and 100% capture case. The data here is for an SOFC-GT with an oxygen membrane afterburner type, but other afterburner types will perform quite similarly. The 85% capture case efficiency has been estimated using an ECN in-house model (Jansen, Dijkstra, 2003). Only a small efficiency difference of 1%-point between the 85% and 100% capture cases has been found. This is due to the relatively low amount of power produced by the gas turbine, compared to that of the SOFC. Increasing the CCR requires very little additional investment, so the increase in specific investment costs is very small.

The uncertainty in SOFC-GT cost is very high. Current SOFC costs are very high, and there is a large uncertainty as to what level SOFC costs will eventually drop. Also there are no detailed estimates of the magnitude of additional costs of CO_2 capture. As an indication of the range, Table 5 gives an overview of the various cost estimates and target values cited in literature. For the investment cost the data from literature (IEA GHG, 2005b) have been adopted.

Table 5: *Overview of SOFC (-GT) costs in literature*

Source	**Case**	**0% capture**	**100% capture**
This study	*Gas CC-SOFC*	*800 €/kWe*	*1200 €/kWe*
(Gielen, 2003)	Gas CC-SOFC	800 €/kWe	1200 €/kWe
(IEA GHG, 2005b)	Gas CC-SOFC		2850 €/kWe
(Blesl, 2004)	Gas SOFC@2MWe target costs	1250 €/kWe	-
(TIAX, 2003)	SOFC-GT installed costs (Planar SOFC)	513 $/kWe	-
(NETL, 2005)	SOFC small scale target costs, (SECA program, 3-10 kWe)	400 $/kWe	-
(Biasi, 1999)	Small SOFC-GT	1000-1500 $/kWe	-
(Lundberg, Veyo, 2002)	300 MW LNG SOFC-GT (tubular SOFC)	1320 $/kWe	-

Results

The result of the increasing the capture from the normal capture (85%) to enhanced capture (100%) the effects are:

- a 2%-points decrease in efficiency
- a 4% increase in investment and
- a 4% increase in power production costs

See Figure 18. Note that both the SOFC-GT without capture and NGCC without capture reference cases are listed.

SOFC-GT

	Ref NGCC	Additional firing	Max. capture	Ref SOFC GT no cap
Efficiency	**56%**	**66%**	**64%**	**70%**
Overal Carbon capture	**0%**	**85%**	**100%**	**0%**

Investment costs		(relative to state of the art)		
Separation	**0**	33	38	0
Power	36	67	67	70
total	36	**100**	**104**	**70**
Power costs		(relative to state of the art)		
Investment	25	**70**	73	49
Fuel	35	30	31	28
total	61	100	104	77

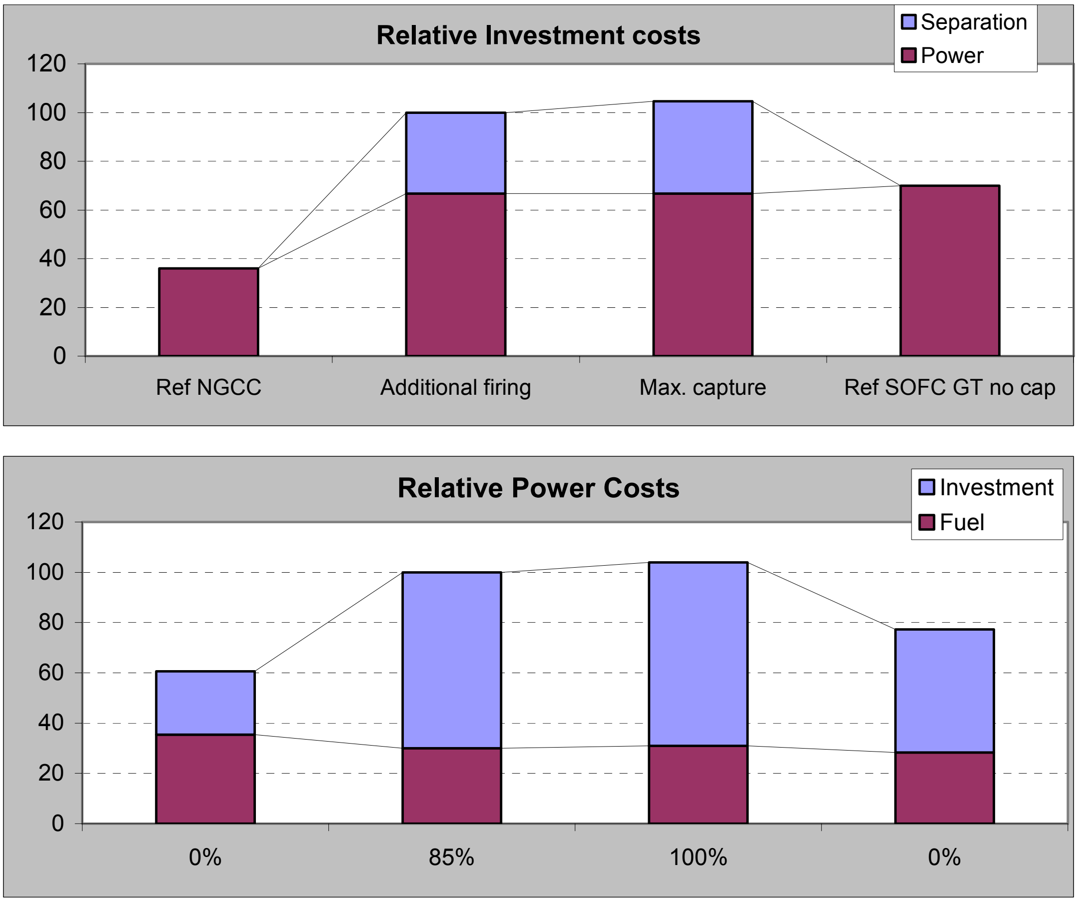


Figure 18: *Results SOFC-GT*

3.4.10 NGCC with Chemical looping combustion

General

In this oxy-combustion type process, natural gas is combusted using oxygen from circulating metal oxide particles that undergo a reduction/oxidation cycle. The working principle is described in appendix B.13. As opposed to the Appendix B.13, the data used are those of a scheme in which no integration with a gas turbine has been applied. Both reactors are operated at atmospheric pressure, and the heat is converted into power by a steam cycle. This variant is chosen because this was the only arrangement for which economic data was found in literature (IEA GHG, 2005b). The choice of this scheme has some consequences for the absolute value of the efficiencies and costs, but the effect of increasing the capture ratio can be expected to be similar for both schemes.

Capture ratio

The source mainly used for the data of this process (IEA GHG, 2005b) reports 100% capture. However, (Wolf, Anheden& Yan, 2005) report that probably 98% can be captured due to leakage between the oxidation and reduction reactor.

Investment costs

The investment data for chemical looping are taken from (IEA GHG, 2005b). The case taken is that using CuO as an oxygen carrier.

Efficiency

The base case efficiency data is taken from (IEA GHG, 2005b).

Results

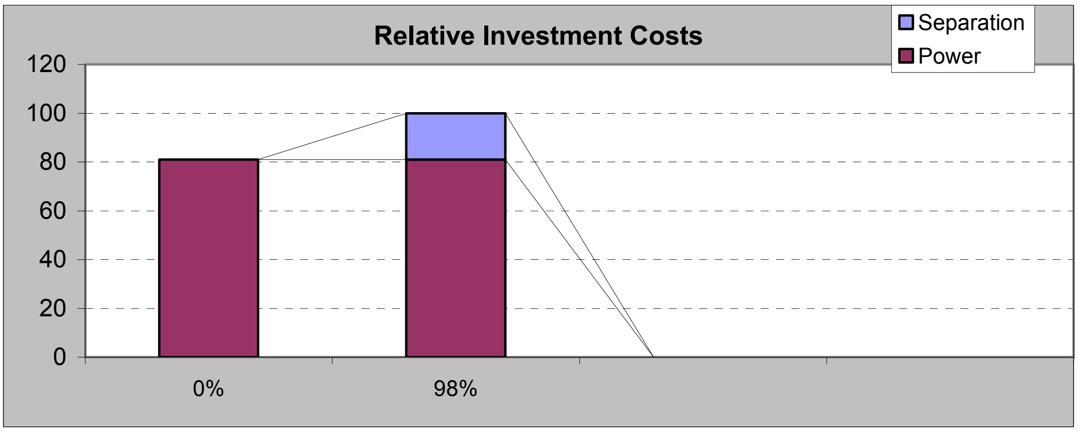
The result of the is that only one case with 98% capture is found, no stretch case relevant which gives compared to the no-capture reference case. See Figure 19.

Chemical looping combustion

	No capture	Normal capture	
Efficiency	**56%**	**46%**	
CO2 capture %	**0%**	**98%**	

Investment costs		(relative to state of the art)	
Separation	0	**19**	
Power	81	81	
total	81	100	0

Power costs		(relative to state of the art)	
Investment	41	**50**	
Fuel	41	50	
total	81	100	0



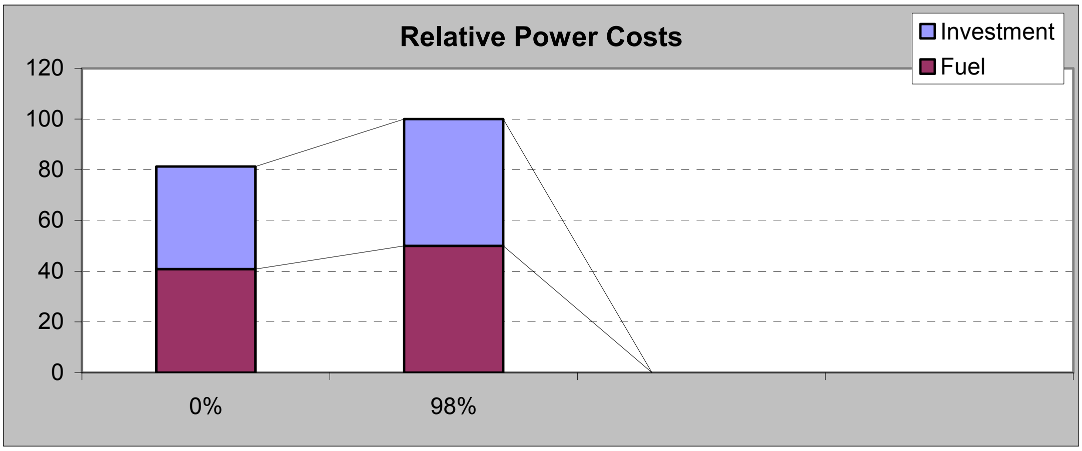


Figure 19: *Results chemical looping combustion*

3.5 Combined results

The relative data can be made absolute by using the specific investment costs and power price from the various literature sources. The data for post- and pre-combustion coal and gas is taken from the IEA leading options report (IEA GHG, 2000). The data for oxy-combustion coal and gas are taken from the Mitsui Babcock report for IEA (IEA GHG, 2005a). Because the IEA leading options report is from 2000 an escalation of 3% has been taken for coal fired power plants. Recent data show that there is no or very limited increase in prices of gas fired power plants. In the IEA leading options report fuel prices of 1.5 and 2 Euro/GJ have been used for coal and gas respectively. For this study updated costs of 1.5 and 3 Euro/GJ are be used for coal and gas respectively. Therefore an index factor of 1.5 on the gas price has been used. The Mitsui Babcock IEA report is from 2005 and no index on investment or fuel price is necessary. See Table 6 for investment data and indexing. For the advanced processes the investment level is taken as discussed in the corresponding paragraphs of section 3.4.

Table 6: *Investment data summary*

	Reference investments (normal capture) [USD$/kWe]	Ref power price [US$/MWh]	Fuel price index [-]	Investment escalation [%/yr]	Investment index [-]
Post coal	1856	63.5	1	3	1.16
Post gas	716	30.7	1.5	0	1
Pre coal	2201	69.1	1	3	1.16
Pre gas	906	34.4	1.5	0	1
Oxy Coal	2342	72.8	1	0	1
Oxy Gas	1144	38.5	1	0	1
Water Cycle	1419	38.5	1	0	1
AZEP	1216	29.8	1	0	1
SOFC	1150	39.4	1	0	1
Chem. Loop comb.	664	42.4	1	0	1

With the investment data and indexing of Table 6 the relative data can be made absolute. The resulting cost of electricity (COE) are presented in Figure 20 (conventional technologies) and Figure 21 (advanced technologies). See Table 4 for a short description of the cases. **The lines between the points in the next graphs are only to connect points of one process and do NOT reflect the actual shape of the curve.**

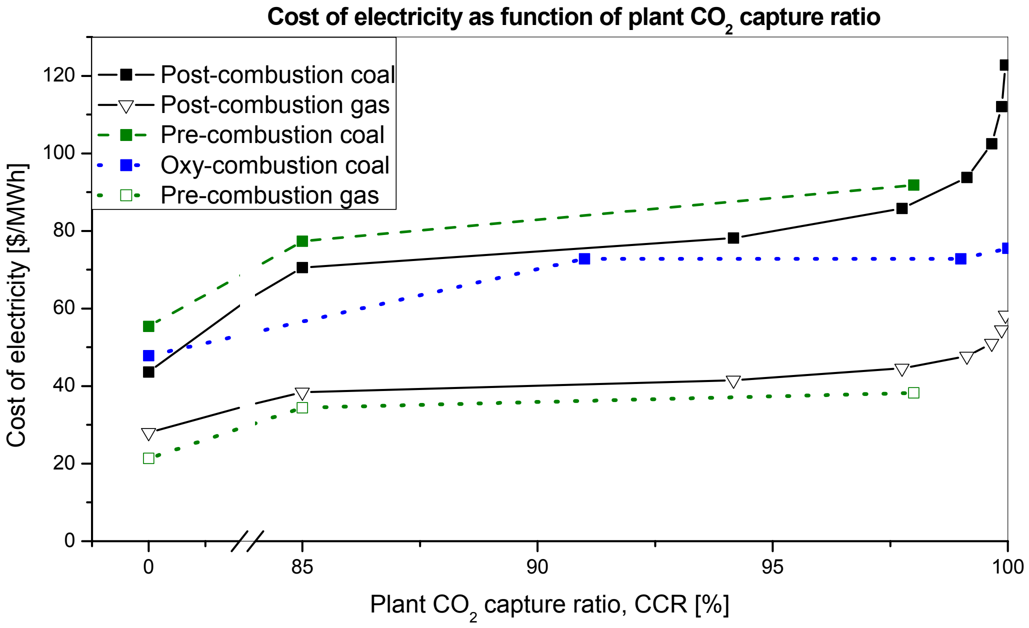


Figure 20: *Effect of increasing the amount of CO_2 captured on COE, conventional processes*.

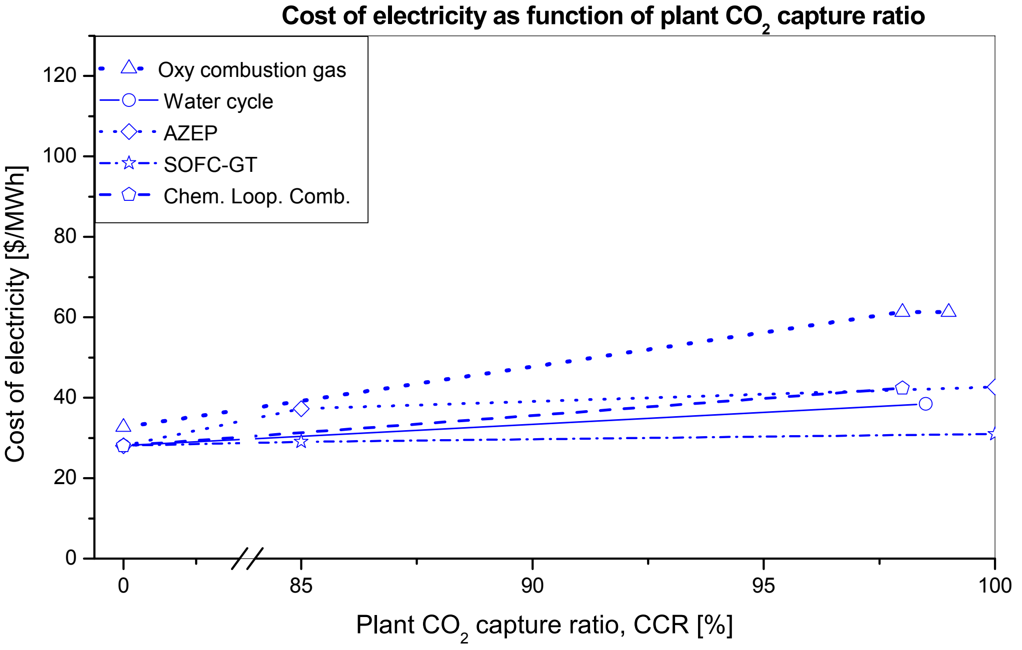


Figure 21: *Effect of increasing the amount of CO_2 captured on COE, advanced processes*.

In Figure 20 and Figure 21 it can be seen that:

- Post-combustion capture has a large increase in power production costs when increasing the CCR to very high capture ratios. At normal capture ratios of 85% to 90% the post-combustion technology is the most competitive by a small margin.
- Pre-combustion technology cannot reach very high capture ratios. The part of the curve that is present shows the same cost levels as post-combustion.
- The CCR of coal oxy-combustion technology can be increased with only a small effect on the cost of electricity. Therefore this technology is very suitable for "near-zero emission".
- The advanced processes (oxy-combustion gas, water cycle, AZEP, SOFC-GT and chemical looping) are all subject to a high uncertainty in the investment costs and cost of electricity. All offer the prospect of near 100% emissions with limited increase in costs. SOFC-GT offers the best overall prospects, but also here the costs are subject to a large uncertainty. For the oxy-combustion gas, water cycle and chemical looping, no moderate capture case is relevant.

Comparing the gas with the coal fed options in Figure 20 shows that the COE of the gas-fired options is lower. Comparing these to collected literature data in (Metz, 2005) gives a different ranking: the coal options there are less expensive than the gas options. This can be explained by differences in assumptions on fuel price. Following recent fuel price developments, the coal price assumed by (Metz, 2005) is lower (1.0-1.5) and the gas price assumed is considerably higher than the IEA standard assumptions used in this report. It must be emphasized that the objective of this study is to assess the impact of increasing CCR rather than giving a comparison between the various COE of the various options on an absolute basis. It is expected that changes in fuel prices will not have a effect on the main conclusions when comparing the effect of increase in CCR between various processes. This would only be the case if there is a large difference in the contribution of efficiency penalty an additional investment to the costs of CO_2 capture between two processes.

4. Energy chain analysis of zero emission processes

4.1 Introduction

In this chapter, the emissions during the power production stage are put into perspective with the emissions in the full energy supply chain. In addition to CO_2, total GHG and other emissions will also be discussed. The energy chain analysis methodology used includes the life cycle effects of construction and decommissioning of equipment. However, the term energy chain analysis will be used, rather than life cycle analysis, since the results are not combined into ecologic themes such as global warming impact and acidification, as is done in life cycle analysis.

4.2 Comparison of literature data

Before starting the analysis several literature sources were compared. (Ruether, Ramezan& Balash, 2004) use an economic input/output based method (using emissions of economic sectors rather than those of technologies used). This makes the total emissions higher than those calculated by other authors. (Muramatsu, Iijima, 2002) report emissions that are too low to be in accordance with emission data from all the other references. (Sundkvist, 2005), (Clerici, 2005) and all list data that give similar results, though the emission data can differ several percent due to differences in technologies used, assumptions, basic data and methodology. For the rest of this study data from (IEA GHG, 1994) will be used, unless stated otherwise.

4.3 Relative contribution of stages

Methodology

In the literature, different methods of subdivision of the energy supply chain are used (See Figure 22). All authors distinguish construction, decommissioning and power generation, which is often referred to as operation. Some authors make, however, a subdivision in fuel mining, transport and operation (thus actual power generation). Thus the term operation could refer to both power generation as well as power generation including fuel mining and transport. In this study operation will refer to power generation only. Emissions resulting from storage are not accounted for.

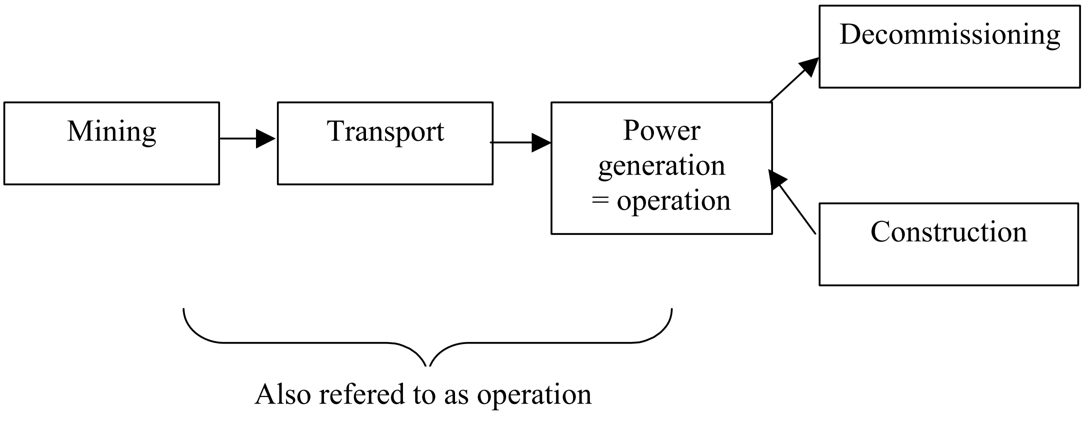


Figure 22: *Energy supply chain*

As for the energy chain analysis, we have focussed on three power generation technologies: IGCC, PC and NGCC. Several assumptions, for example regarding the energy content and combustion CO_2 emission values for coal and natural gas, by using various sources such as IEA statistics (IEA, 1999) are made. For the CO_2 capture ratio and thermal efficiency assumptions are based on the analysis in Chapter 2, though the exact figures differ slightly.

When considering all greenhouse gas (GHG) emissions apart from CO_2 also the greenhouse gas effect of CH_4 and N_2O are accounted for, using a global warming potential of 23 and 296 respectively.

After operational emissions, those generated during fuel (coal or natural gas) transportation constitute the 2nd largest source of emissions of the entire fuel chain when the fuel needs to be transported over a long distance, especially when all GHG emissions are considered. More mining and fuel transportation is needed to produce a given amount of electricity when the efficiency of a power plant decreases, in this case the result of the application of CO_2 capture. The total emissions incorporating both the decrease during operation as a result of capture and the increase of emissions in transport and mining due to increased fuel use is calculated and inventoried.

For coal, two transport distances, long and short, were assumed. The long-distance coal corresponds to coal mined in Australia, while short-distance coal is assumed to come from the USA (as done in the IEA study from which our data were obtained (IEA GHG, 1994)). Equally, for natural gas two (long and short) transport distances were assumed. The power plant is assumed to be located in Western Europe, the first one is assumed to use natural gas from Russia, while the second one consumes natural gas produced in the Netherlands or Scandinavia. The LHV energy content of coal is 26 MJ/kg, while for natural gas an average is taken between the Dutch energy content of natural gas (about 33 MJ/m^3, LHV) and that of natural gas produced in Algeria (about 42 MJ/m^3, LHV) (m^3 at normal conditions) These two values are probably both at the extremes (lower and higher, respectively) of an overall range of energy content, the average of which results in about 38 MJ/m^3.

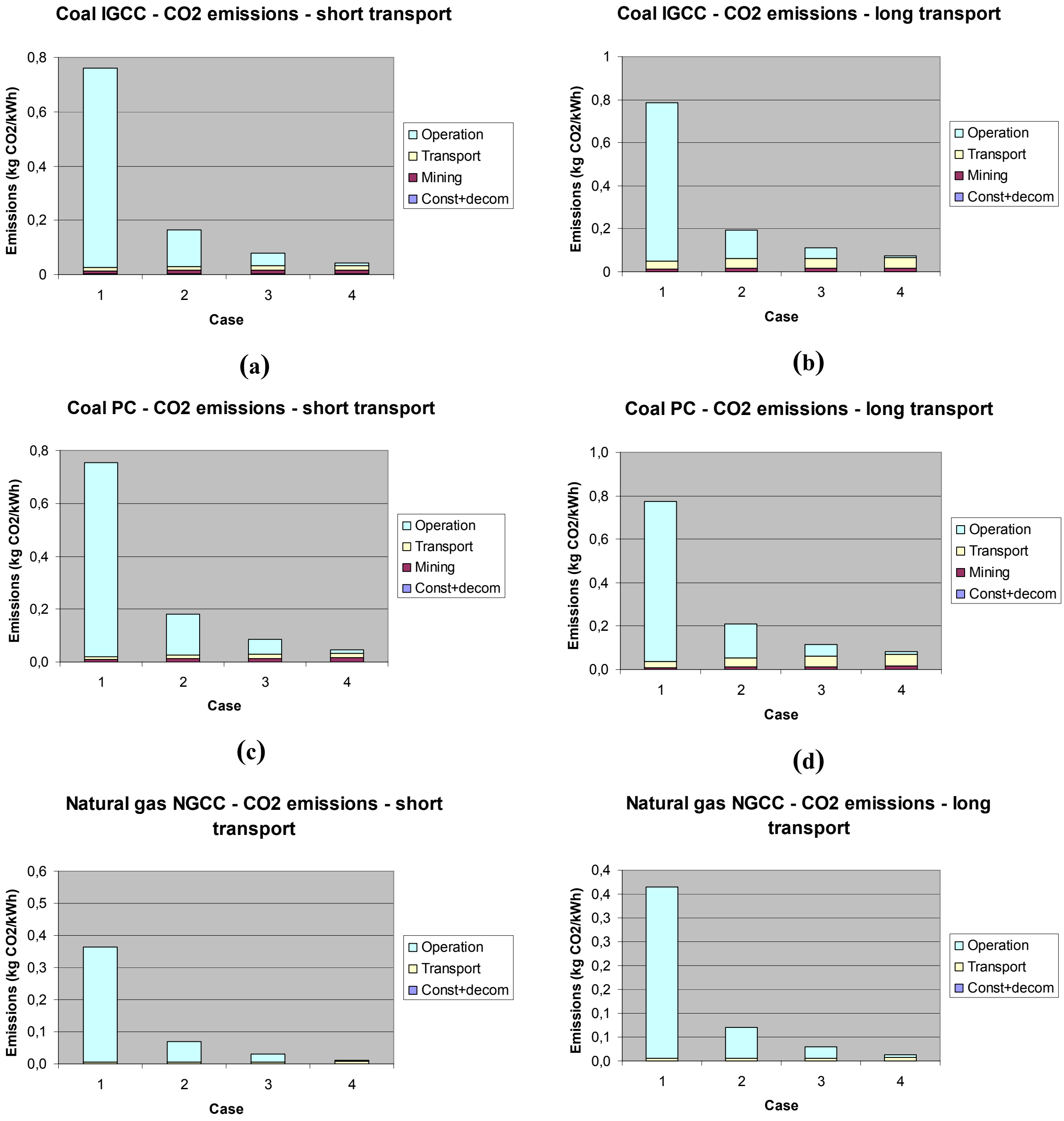
Results: CO_2 and GHG emissions

The results of the analysis are presented in Figure 23 (CO_2 emissions) and Figure 24 (GHG emissions). The first observation is that the emissions related to plant construction and plant decommissioning are in most cases negligible. Typically, mining and transport emissions are in the range of a few percents of the total CO_2 emissions when no CO_2 capture is applied. Including all the GHG emissions of the mining stage does not significantly affect the pattern of results from the study. At high capture ratios, mining and transport emissions become the dominant contributors to the total emissions of the chain.

The four cases presented here correspond to plant CO_2 capture ratios of 0, 85, 95, and 99%, while the corresponding efficiencies values are assumed, respectively, to be 46, 38, 37, and 36% for coal IGCC, 46, 33, 30, and 26% for coal PC, and 56, 47, 44, and 40% for natural gas NGCC. Furthermore a distinction has been made between short and long fuel transport distances.

Whether transport distances are short (USA coal or Dutch / Scandinavian natural gas in our case) or long (Australian coal or Norwegian natural gas in our case), a chain analysis tells us that the CO_2 capture ratio could be brought to high values, possibly as high as 99%, both when CO_2 only is considered and when total GHG emissions are taken into account. If no other factors, like capture costs, are taken into account, and if maximum CO_2 emission reduction is the sole objective all plots in Figure 23 and Figure 24 indicate that it may be worthwhile capturing CO_2 to a level higher than the usual 90% for IGCC/PC and 85% for NGCC, as overall emission levels are lowest in the case when a capture ratio of 99% is applied. As there are no minima observed in the plots of Figure 23 and Figure 24, other than those at the 99% capture ratio cases, our chain analysis tells that there are no cases in which the CO_2 capture ratio should probably not be increased to values as high as 99% when minimisation of chain CO_2 emissions is the sole objective, and cost considerations are not taken into account.

Overall we may conclude that, from an energy chain perspective, there are essentially no differences between IGCC and PC. However, we do find different conclusions for the use of coal versus that of natural gas, in the sense that, the chain emissions of natural gas are much lower than for coal. For short transport natural gas the emissions are virtually negligible, for long transport they are present but low. For coal, on the other hand, even if one goes as far as capture ratios of 99%, there are still substantial emissions occurring during the mining and transport stages even for short transport distances.



(a) (b) (c) (d) (e) (f)

Figure 23: CO_2 *emissions for coal IGCC, coal PC and natural gas NGCC, when fossil fuel transport distances are short (left) and long (right), respectively.*

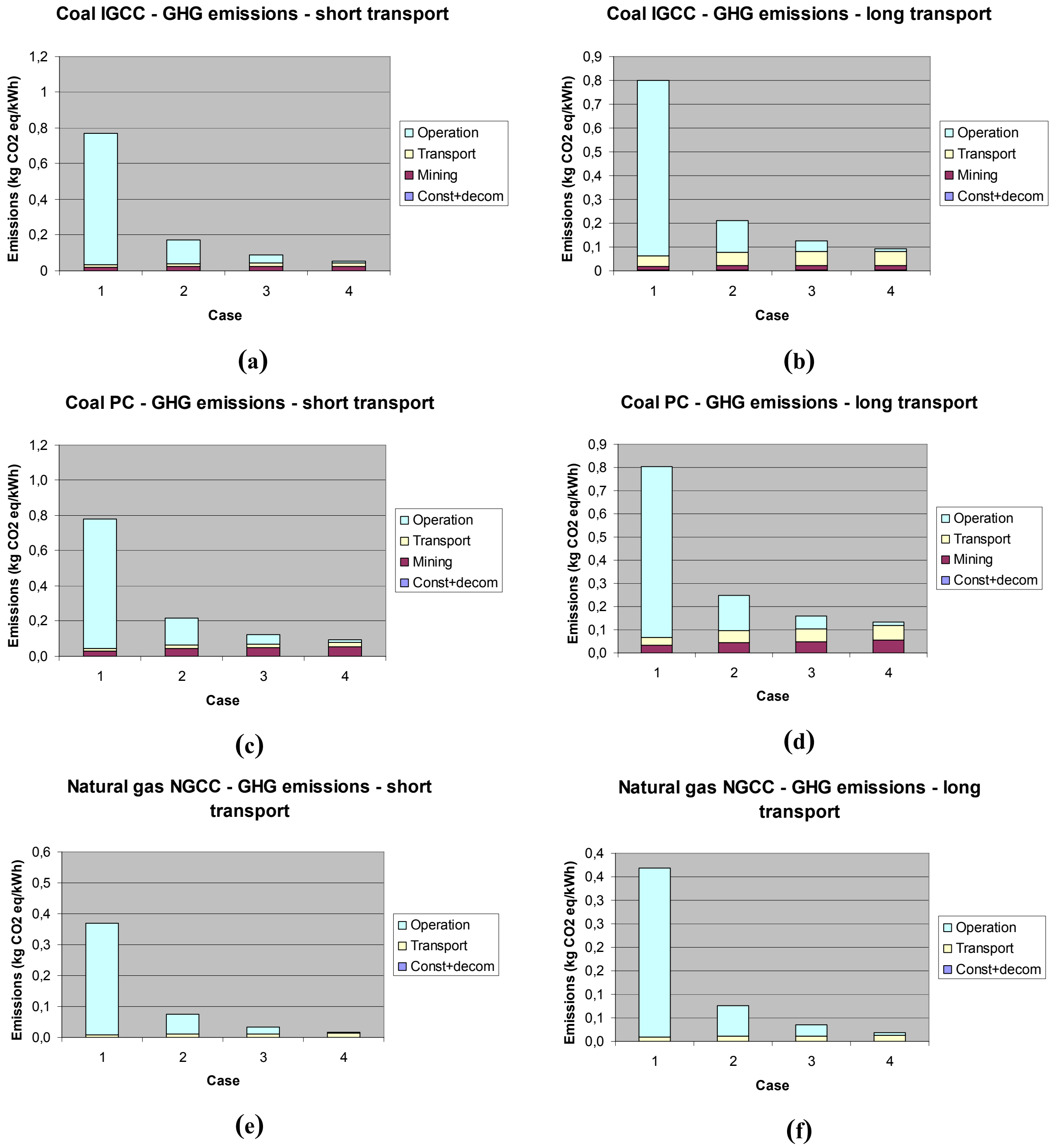


Figure 24: *Total GHG emissions (in CO_2 equivalent) for coal IGCC, coal PC and natural gas NGCC, when fossil fuel transport distances are short (left) and long (right), respectively.*

4.4 Other emissions

The above analysis provides essentially the energy chain part of the information that one needs in order to make a balanced choice among the various available options that allow reducing the intensity of CO_2 emissions through the application of CO_2 capture technologies. This energy chain study complements the other main input required for such decisions, that is, arguments in terms of capture technology costs, which in any case should be investigated to enable the best choice of appropriate zero-emission power technology to be made. Still, the above analysis only presents an energy chain investigation in terms of CO_2 and other GHG gases. To get the complete picture, also other emissions and environmental effects of capture technology application ought to be considered. Other sources of pollution that should be accounted for are such pollutants as particulates, sulphur dioxide (SO_2), oxides of nitrogen (NO_x, N_2O), carbon monoxide (CO), methane (CH_4), volatile organic compounds (VOC), polyaromatic hydrocarbons (PAH), mercury (Hg) and small particulates (PM10 or C-part).

The question is whether the application of a CO_2 capture technology simultaneously reduces the emissions of these other substances, or perhaps increases them. While there are limits to the extent to which a fully-fledged analysis of the corresponding additional environmental impacts can be done in the context of this research project, in principle the kind of analysis performed for CO_2 and the other GHG gases should be extendable to also include these other pollutants.

It is only relatively recently that concepts of integrated environmental control have been developed to ensure that individual pollutants or waste streams are not considered in isolation, with a move towards a broader approach (Henderson, 2005). There will be a continued downward pressure on allowable emissions of all pollutants to the atmosphere. Tightening SO_2, NO_x and particulate emissions limits look set to be joined by mercury emissions limits or degree of removal requirements. This process has now started in various countries and is expected to become more widespread over time. CO_2-capture plants have a different dry flue gas volume flow per quantity of fuel consumed in comparison to non-capture plants. Hence, changes are needed in the way emission concentrations are reported. CO_2 capture is still to be included in the broad all-encompassing approach that needs to be adopted towards emissions control. There could be feasible storage options for CO_2 streams containing impurities of other pollutants. Many of the implications of emission control of other pollutants, such as mercury, on the CO_2-capture process have yet to be examined.

While a full Life Cycle Analysis study is often resource-intensive and time consuming, there is little doubt that life cycle analysis can be an effective tool and that it can play a useful role in assessing the environmental impacts of different processes (Mills, 2005). What is needed for the present study is information on how emission control technologies for different pollutants affect each other when they are simultaneously applied.

Figure 25 gives the emissions of three natural gas fired technologies as published by (Sundkvist, 2005). The GHG emissions account for CO_2 as well as other greenhouse gases, using appropriate global warming factor of each component. MEA post-combustion and AZEP have been compared to NGCC without CO_2 capture. The emissions are presented relative to the emissions of each of the specific components for the reference NGCC without capture, and are expressed per unit of electricity produced. CO_2, NO_x and GHG are decreased when applying capture. CO, and CH_4 increase because these emissions occur mostly during the mining and transport phase of the chain. SO_x emissions are very low, since the natural gas is virtually sulphur free.

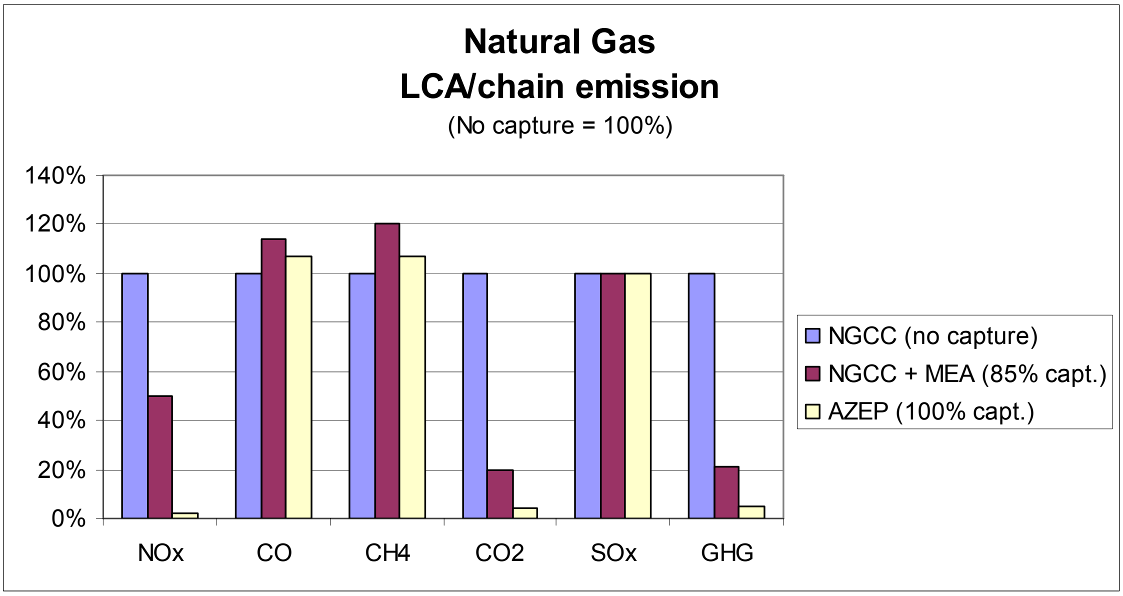


Figure 25: *Emissions for natural gas fired technologies: overall LCA/chain analysis emissions relative to the emissions of NGCC=100%. Based on (Sundkvist, 2005)*

Figure 26 and Figure 27 depict the operation and chain emissions for coal processes. Note that the PC without CO_2 capture (with flue gas desulphurisation FGD and selective catalytic NO_x reduction SCR) is compared to IGCC with CO_2 capture. The effects depicted, therefore, not only reflect the impact of CO_2 capture, but also the effects of IGCC versus PC. For Figure 26 some emissions are constant because they are zero for both cases.

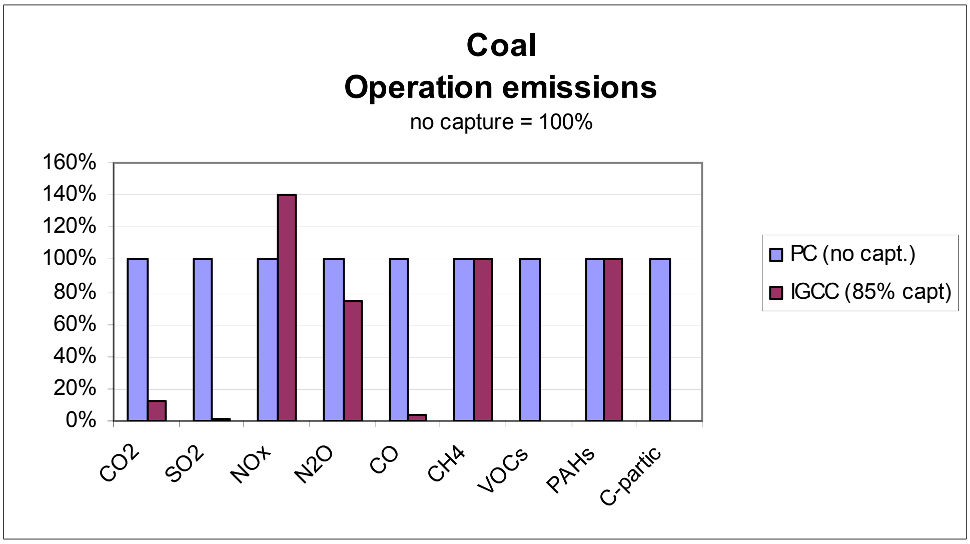


Figure 26: *Operation emissions coal PC (with FGD and SCR) versus IGCC with CO_2 capture. (IEA GHG, 1994).*

Compared to PC, in IGCC pre-combustion capture, the emissions of CO_2, CH_4, SO_x and particulate are strongly reduced, while the emissions NO_x, VOC and PAH (which occur mainly during transport and mining) are increased by about 30%. The decrease in SO_x is most likely related to the IGCC technology and not to CO_2 capture.

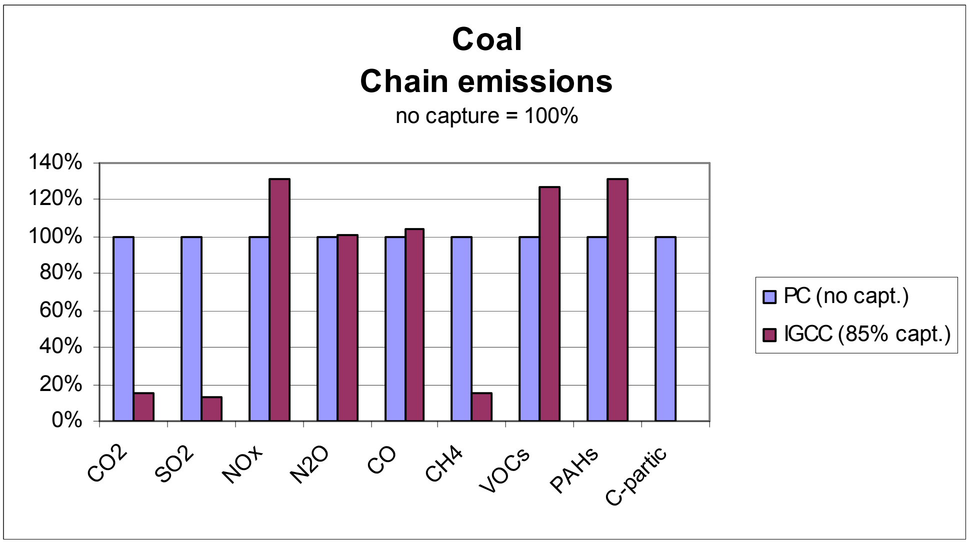


Figure 27: *Chain emissions (LCA) coal PC versus IGCC with CO_2 capture. Based on (IEA GHG, 1994).*

4.5 Combining chain analysis and plant analysis results

In this section the effect of increasing the plant CO_2 capture ratio is addressed taking into account all GHG emissions in the energy chain; which include GHG gas emissions during fuel mining, fuel transport, operation and decommissioning of the power plant, and including life cycle aspects. When increasing the capture ratio at a power plant level the emissions in the rest of the energy chain become more and more relevant. With decreasing power plant efficiency the emissions per MWh in the rest of the chain increase accordingly. This "chain effect" can be brought into the analysis by introducing GHG emissions (in terms of CO_2eq emissions per MWh of fuel) for mining transport and construction/decommissioning (see Table 7). The data used are for long fuel transport (Australian coal and Ekofisk gas to a power plant located in the Eemshaven, in the north of the Netherlands) and are taken from (IEA GHG, 1994).

Table 7: *Chain emission data per kWh of fuel input (kWh$_F$) used for chain analysis*

Chain impact	**coal** (kg CO_2eq/kWh$_F$)	**gas** (kg CO_2eq/kWh$_F$)
CO_2 emission rate plant	0.336	0.202
CO_2 emission rate transport	0.011	0.005
CO_2eq emission rate construction & decommissioning	0.001	0.000
CO_2eq emission rate mining	0.009	0.000

From Table 7 it can be concluded that the specific emissions for construction and decommissioning are not relevant. The same conclusion has already been drawn in section 4.3.

Figure 28 presents the split-up of the total chain GHG emissions between operation, mining and transport with an increasing plant capture ratio. From the figure it can be concluded that for this fictional case the chain CO_2 emission will never be lower that ~0.10 ton CO_2eq/MWh regardless of how high the plant capture ratio may be. Therefore it is useful to introduce the chain capture ratio: the percentage of CO_2 captured over the entire chain of mining, transport and operation. With increasing capture at a plant level, power production costs also increase, while efficiency decreases. In extreme situations this may even lead to increasing chain CO_2 emissions. The theoretical shape of the curve is shown in Figure 29.

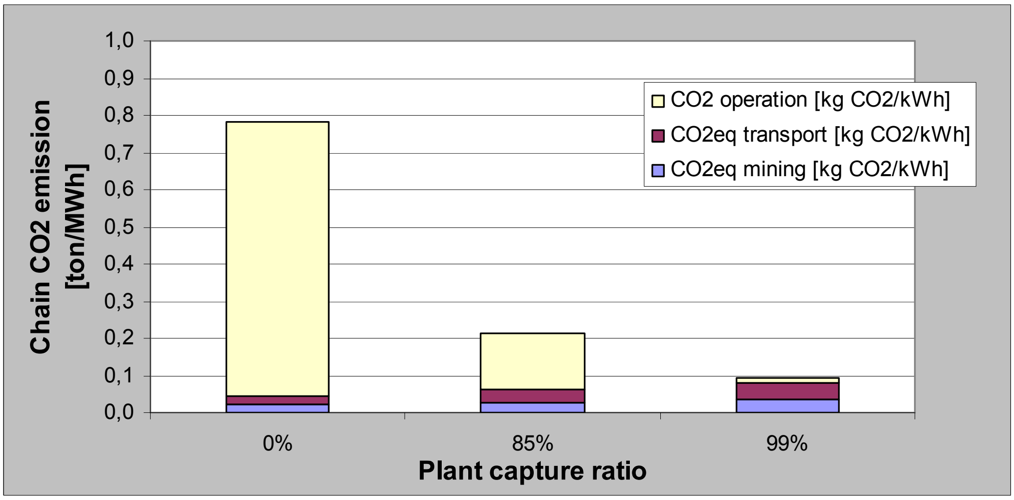


Figure 28: *Chain CO_2eq emission (ton CO_{2eq}/MWh electric) as a function of plant CO_2 capture ratio, typical example.*

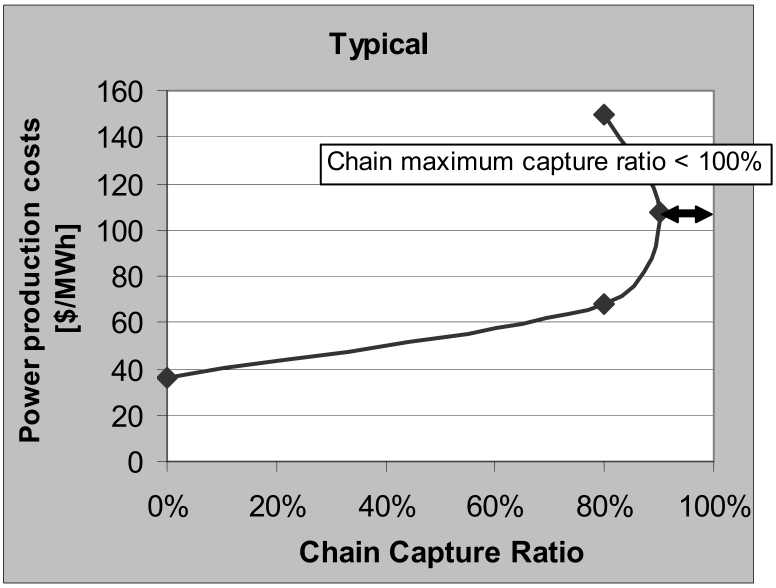


Figure 29: *Maximum chain GHG capture ratio, typical/theoretical shape of curve.*

Thus the CCR from (1) is here modified to the chain GHG capture ratio:

$$\text{Chain GHG capture ratio} = \frac{\text{Amount of GHG } (CO_2 \text{ eq}) \text{ captured}}{\text{Amount of GHG } (CO_2 \text{ eq}) \text{produced in total chain}} * 100\% \quad [\%] \qquad (4)$$

The cost data from the quantitative analysis from section 3.5 and the chain data from Table 7 can be combined to give the overall relation between chain capture ratio and costs. This has only been done for a selection of processes. The processes selected are listed in Table 8. The results are presented in Figure 31.

Table 8: *Selection of processes*

Post-combustion coal	PC boiler with post-combustion MEA absorber
Post-combustion gas	NGCC with post-combustion MEA absorber
Pre-combustion coal	Pre-combustion capture IGCC with shift and Selexol absorber
Pre-combustion gas	Pre-combustion NGCC with ATR, shift and Selexol absorber
Oxy-combustion coal	Oxy-combustion PC boiler with CO_2 recycle

The post-combustion gas fired option has the best overall chain capture ratio. Though the COE is increasing rapidly at increasing capture ratio, the overall costs are still the lowest of the options presented. PC+MEA post-combustion capture shows the same trends, but is shifted to higher costs. Pre-combustion capture at IGCC is always more expensive than post-combustion, though the increase in costs when increasing the CCR is less than with post-combustion. At high capture ratios the two are very close. Oxy-combustion PC is the best option for high capture ratios and has a low penalty for increasing the CO_2 capture ratio to the maximum value.

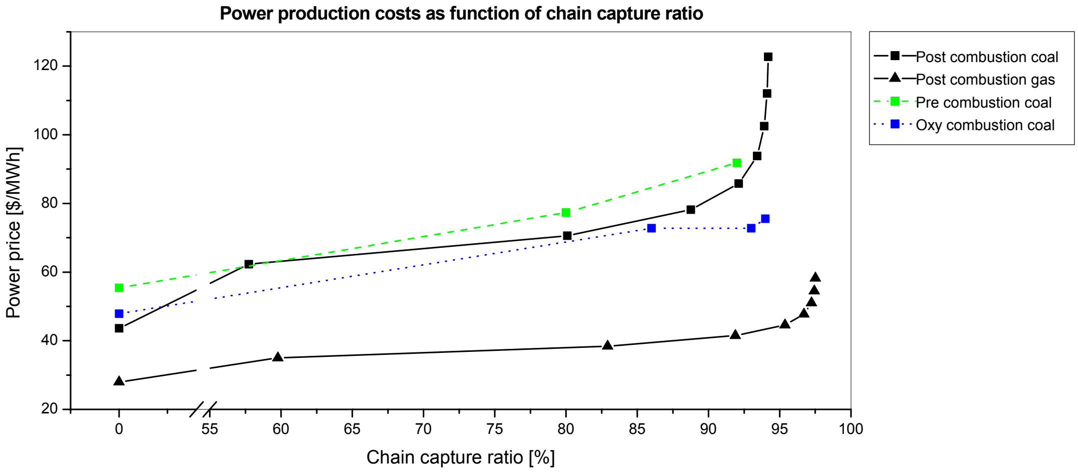


Figure 30: *Power production costs as a function the chain GHG capture ratio*

For the post-combustion case for coal, from Figure 31 it can be concluded that with increasing CO_2 capture at plant level the specific GHG emission decreases rapidly until the emissions in mining and transportation become dominant. When emissions in mining and transportation are dominant, a further increase in plant capture ratio, accompanied by a decrease in efficiency, will increase the specific CO_2 emissions.

The same analysis can be made for gas. The data for this case are provided in Figure 31. The curve is similar, though the point of net increase of emissions at increasing costs is not encountered.

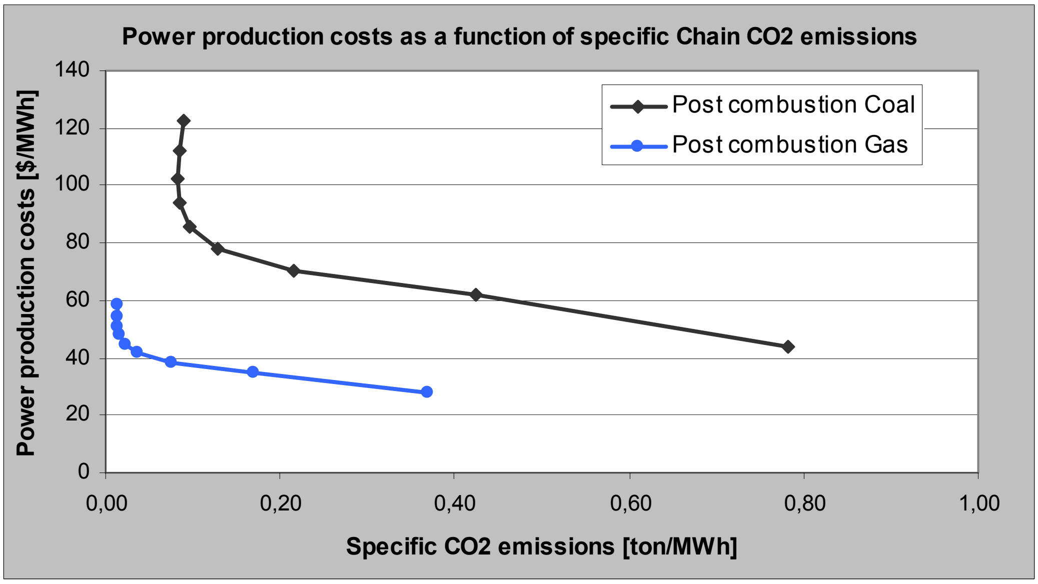


Figure 31: *Power production costs for post-combustion coal and gas as a function of specific chain GHG emissions [ton CO_{2eq}/MWh]. .*

In Figure 32 the pre-combustion and oxy-combustion quantitative analysis results have been included. Gas fired post-combustion has lower specific GHG emissions at lower specific costs. Oxy-combustion offers the best option for the coal fired cases when stretching the technology to near zero emissions. Pre-combustion surpasses post-combustion at decreasing specific emissions.

In Figure 32 there is an optimum with respect to the amount of CO_2 emitted. The optimum is present when emissions are expressed in terms of chain GHG emissions per unit of electricity produced (kg CO_2eq/MWh). The optimum is observed for both the post-combustion coal case, as well as the post-combustion gas case.

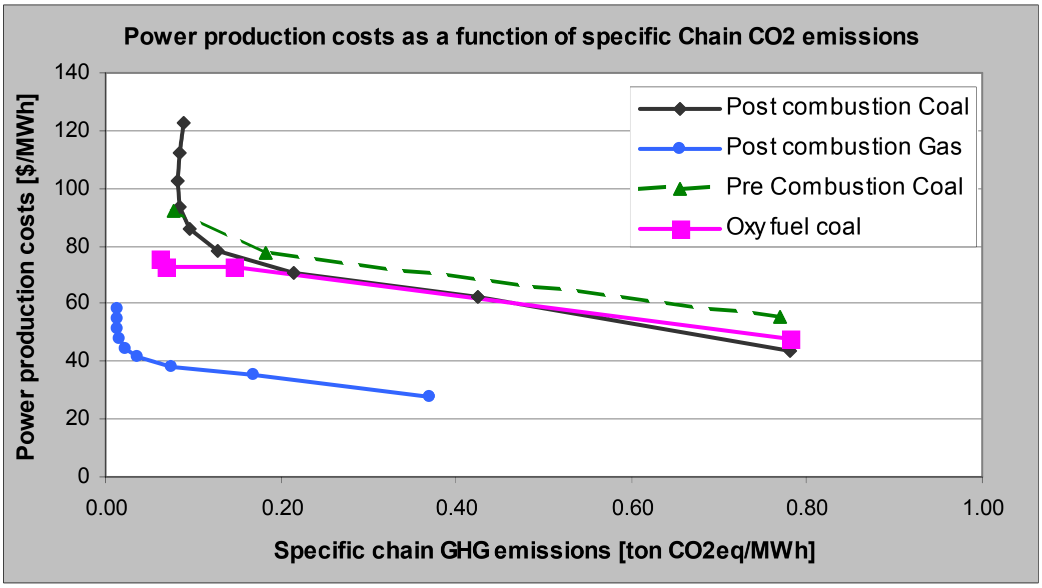


Figure 32: *Power production costs for post-combustion coal and gas, pre-combustion coal and oxy-combustion coal as a function of specific chain GHG emissions [ton* CO_2*eq/MWh].*

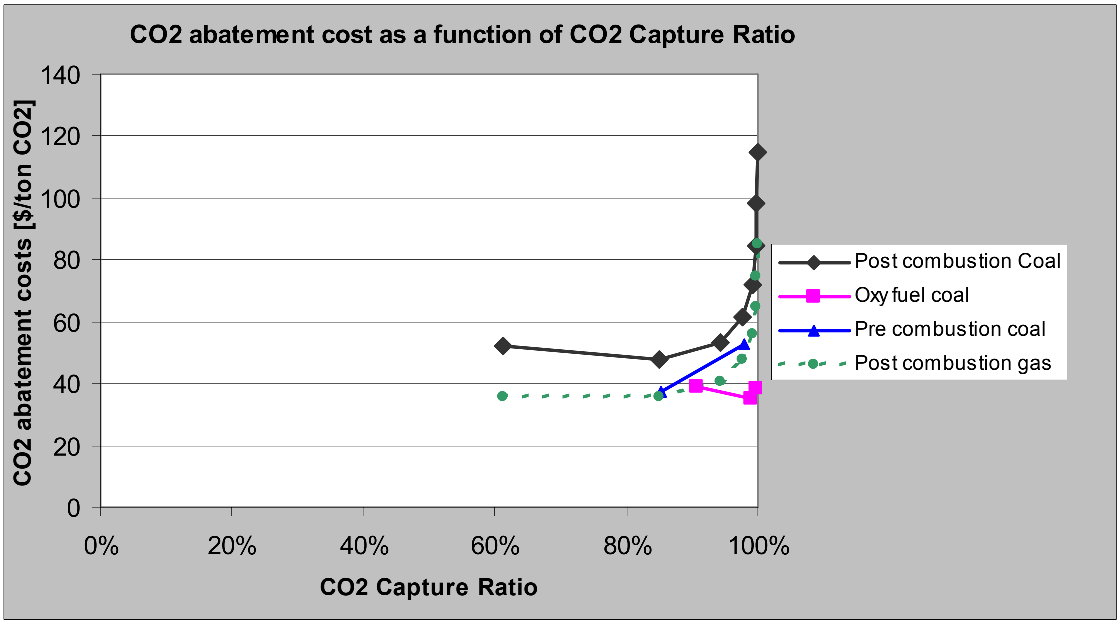


Figure 33: CO_2 *abatement costs as function of CCR*

Figure 33 gives the GHG abatement costs (USD/ton CO_2eq) as a function of the plant CO_2 capture ratio. The cost of both the coal and natural gas post-combustion options is increasing rapidly at high CCR values. The coal pre-combustion option is less expensive than the post-combustion coal option; and, furthermore, the very high costs at high CCR values are not reached. The oxy-combustion coal option CO_2 costs do not change significantly with increasing CCR. Even a small decrease is observed.

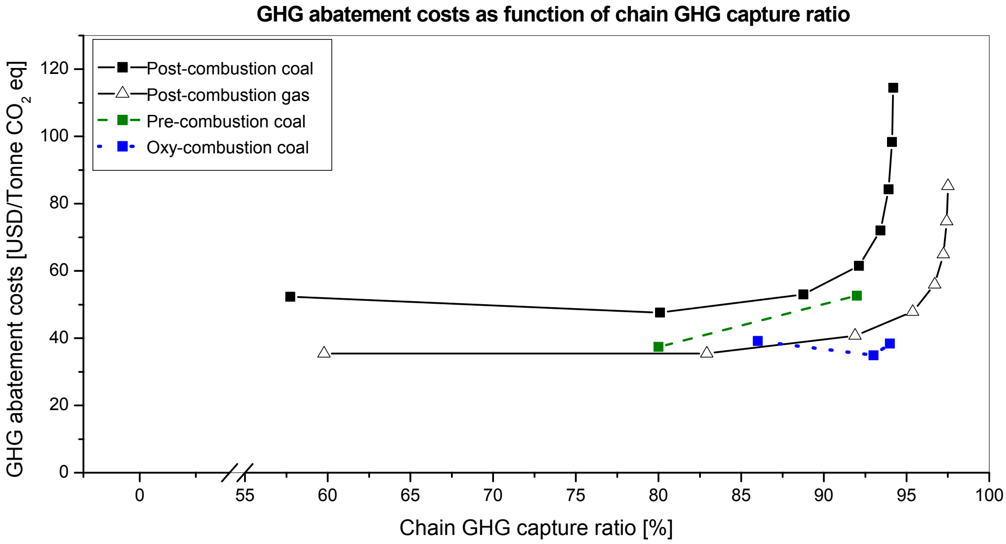


Figure 34: *GHG abatement costs as function of the chain GHG capture ratio*

Figure 34 gives the chain GHG abatement costs (USD/ton CO_2eq) as the function of the chain GHG capture ratio. The figure is quite similar to Figure 33. The curves are however, shifted to lower ratios as a result of including chain effects. The shift is different for the coal and gas cases. The cost of both the coal and natural gas post-combustion options is increasing rapidly at high chain capture values. The coal pre-combustion option is less expensive than the post-combustion coal option; and, furthermore, the very high costs at high chain CCR values are not reached. The oxy-combustion coal option CO_2 costs do not change significantly with increasing chain capture ratio.

4.6 Sensitivity towards gas transport emissions data

The above results may be sensitive towards the assumption of emissions in the fuel chain. Especially for natural gas high leakage rates have been suggested in the past for Russian gas, which were attributed to leakage from pipelines (including compressor stations, valve knots, etc) and could be related to the design and maintenance standards in Russia. Recent extensive measurements on emissions of pipelines indicated that leakage rates are not as high as previously reported, but that they are still significant. The results indicated that methane emissions during transport are in the order of 0.7% for Russian gas (range 0.4-1.6%) (Leliveld, 2005). To assess the impact of emissions data for gas processes a modified case has for Russian gas has been calculated. So for post-combustion gas there are two cases that can be compared:

- Base case: equal to data presented in all other parts of this report. Natural gas from the Norwegian Ekofisk field is used in a post-combustion capture process. Data is taken from (IEA GHG, 1994). Transport emissions amount to 0.005 kg CO_2eq/kWh$_F$
- Additional case: Natural gas from Russian gas fields. Leakage in Russia itself is assumed to be 0.7%, and a global warming factor for methane of 21 is applied. Additional emissions from Russia to the site in the Netherlands are assumed equal to Ekofisk and are added to the emissions within Russia. The total resulting transport emissions amount to 0.035 kg CO_2eq/kWh$_F$.

Of course next to the fact that the emissions from natural gas could be higher because of higher actual leakage rates, the difference in emission data could also be (partly) due to different methods of determining these assessments.

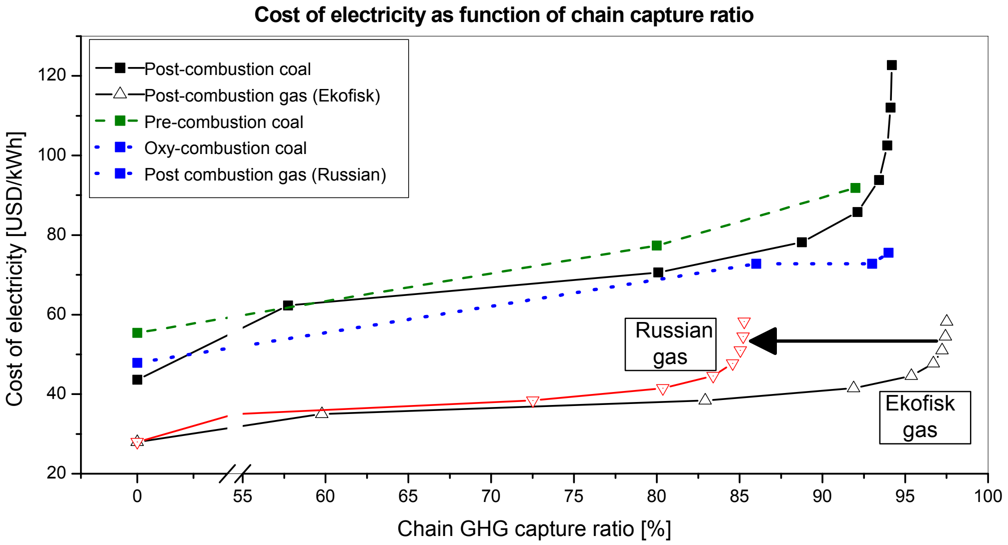


Figure 35: *Impact of emissions natural gas transport emissions on cost of electricity and on chain GHG capture ratio. Impact of using data for Russian gas pipelines compared to data used elsewhere in this report.*

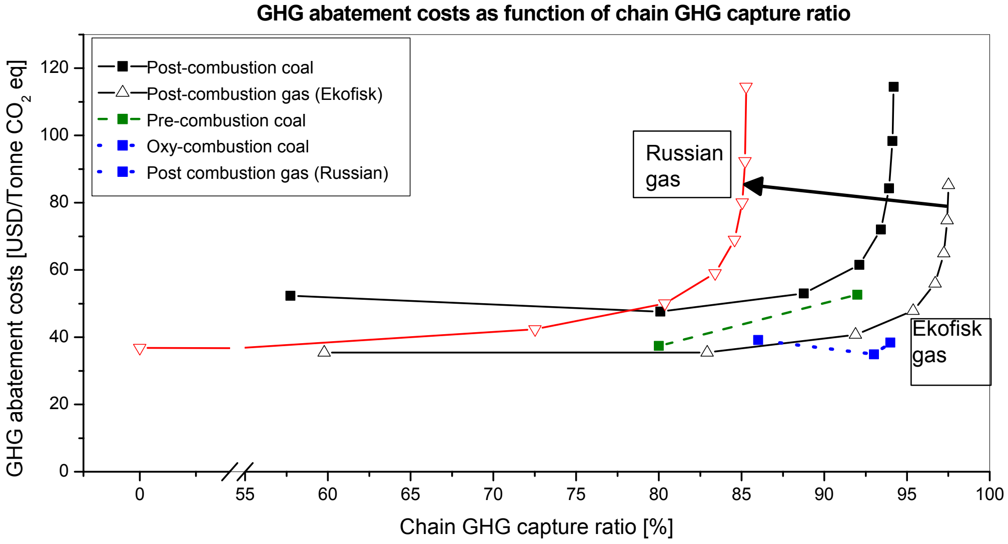


Figure 36: *Impact of emissions natural gas transport emissions on chain GHG abatement costs and on chain GHG capture ratio. Impact of using data for Russian gas pipelines compared to data used elsewhere in this report.*

Figure 35 presents the Russian gas case next to the cases as presented elsewhere in this report. The maximum achievable chain GHG capture ratio drops from 96% for Ekofisk gas to 85% for Russian gas. The maximum achievable capture ratio is less than that of coal-fired options. The COE is not affected. Figure 36 shows again the effect on the chain GHG capture ratio, as well as on the chain GHG abatement costs. The latter are increased compared to the reference case.

It is concluded that for the case of Russian gas transport emissions are much more significant than the cases assumed in the rest of this report. This will have a significant effect on the maximum GHG capture ratio, which will be lower, as well as the on the cost per ton CO_2 avoided, which will be higher. Given the magnitude of the emissions, future measures for emission reduction could very well be justified.

4.7 Marginal GHG abatement costs

Until now, greenhouse gas abatement costs have been expressed as the total abatement costs divided by the total abatement realized:

$$\begin{aligned} GHG\ abatement\ costs &= \frac{Total\ costs}{Total\ GHG\ reduction} \left[\frac{USD}{tonCO_{2_{eq}}}\right] \\ &= \frac{Costs\ (capture\ case) - Costs\ (no\ capture\ case)}{Chain\ emissions\ (no\ capture\ case) - Chain\ emissions\ (capture\ case)} \end{aligned} \qquad (5)$$

Also very relevant are the marginal GHG abatement costs. These are the costs associated with an increase in CO_2 capture along the GHG abatement costs curve and are directly related to the slope of the curve. For two consecutive points on the GHG abatement curve with increasing CO_2 capture ratio, X_1 and X_2, the marginal CO_2 abatement cost for X_2 is defined as:

$$\begin{aligned} Marginal\ GHG\ abatement\ costs\ (case\ X_2) &= \frac{\Delta Total\ costs}{\Delta Total\ GHG\ reduction} \left[\frac{USD}{tonCO_{2_{eq}}}\right] \\ &= \frac{Costs\ (case\ X_2) - Costs\ (case\ X_1)}{Chain\ emissions\ (case\ X_2) - Chain\ emissions\ (case\ X_1)} \left[\frac{USD/MWh}{kgCO_{2_{eq}}/MWh}\right] \end{aligned} \qquad (6)$$

Figure 37 gives the marginal GHG abatement cost curve. Note that the vertical axis is a logarithmic scale. For post-combustion capture (both gas and coal) the marginal costs of capture are quite constant at low capture ratios, even a small decrease can be seen. At high capture ratios the marginal costs increase very rapidly. Marginal costs above 1000 USD/ton are observed. For pre-combustion and oxy fuel capture with coal, the marginal cost increase is far less pronounced. For oxy fuel combustion the marginal costs are more or less constant. Here an increase in CO_2 capture does not lead to an increase in costs per ton CO_2 eq.

It must be noted that in Figure 37 some of the points are not shown. Those points with negative or zero marginal GHG abatement costs cannot be represented on the logarithmic scale. The negative or zero marginal GHG abatement costs are caused by negative or zero increase in specific chain emissions (ton CO_{2eq}/MWh) as observed in Figure 32.

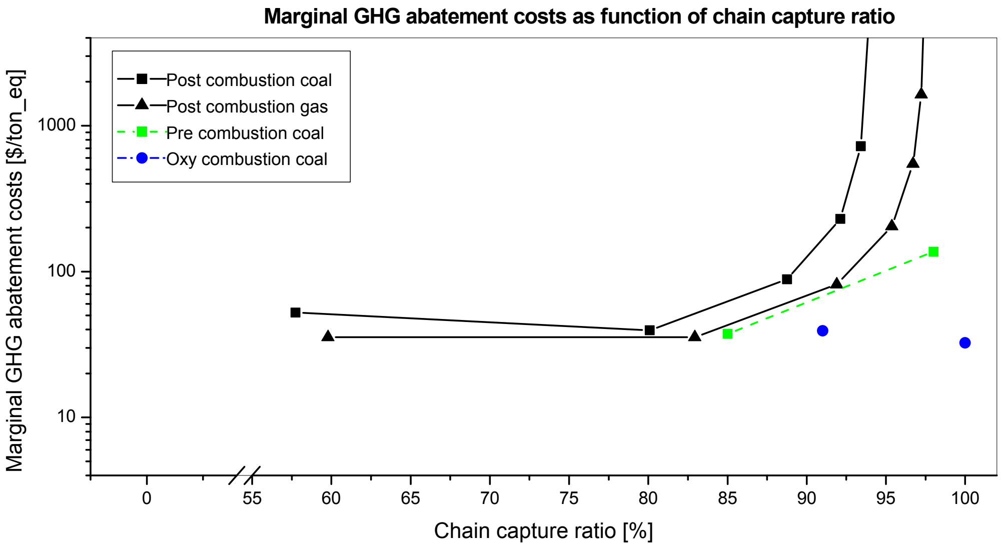


Figure 37: *Marginal GHG abatement costs as function of the chain capture ratio.*

5. Conclusions

Power production plants with capture of CO_2 are sometimes referred to as "zero emission power plants". In this study the zero concept of zero emission has been put into perspective by focussing on the extent to which the zero emission target can actually be reached. Therefore, technologies have been analysed qualitatively, a selection thereof with an order of magnitude approach and four technologies in more detail. Finally, emissions during the fuel supply chain and construction/decommissioning have been compared to those during operation of the plant, thus putting the residual emissions from the plant into perspective with those from the overall fuel chain.

Qualitative analysis

A qualitative inventory of a "longlist" covering a large variety of power production technologies has been made. The inventory focuses on the near zero emission potential and the impact of increasing the CO_2 capture ratio beyond the normal value. This revealed that there is no significant difference between gas and coal fed options. Also, there is no clear impact of the principle of separation (liquid absorbents, membranes, solid absorbents, cryogenic). What is most determining is the capture type (pre-combustion, post-combustion or oxy-combustion). The oxy-combustion type technologies (oxy-combustion NGCC & PC, Matiant, water cycle, chemical looping combustion, AZEP, SOFC-GT) have in general a nearly 100% capture ratio in the normal case, or it is possible to increase the capture ratio with a relatively small impact on efficiency and costs. Post-combustion technologies are expected to have a large efficiency and cost penalty when increasing the CCR. Conventional pre-combustion technologies (with e.g. Selexol absorption) can be modified for somewhat higher CCR with moderate effects on efficiency and costs. Advanced pre-combustion technologies (membrane reformer, sorption enhanced reaction) will require substantial technical changes and a large cost and efficiency penalty for very high capture ratios. In situ removal of CO_2 during combustion is expected to be not very attractive from a high CO_2 capture point of view.

Quantitative analysis

The analysis shows for both post-combustion options a very large increase in power production cost at high CCR values. Pre-combustion cannot reach the very high capture ratios of post-combustion and therefore does not have a high capture part to its cost curve. Oxy-combustion PC is the option with the lowest power production costs for high capture ratios and has a low penalty for increasing the CO_2 capture ratio to the maximum value.

The advanced processes (oxy fuel gas, water cycle, AZEP, SOFC-GT and chemical looping combustion) all offer the prospects of near 100% emission reduction with limited increase in costs. SOFC offers the overall best prospects. For the water cycle and chemical looping combustion, no moderate capture case was found relevant. It must be noted that there is a significant uncertainty in the cost of the advanced processes.

Chain analysis/life cycle analysis

Life cycle aspects in the construction and decommissioning phase are negligible compared to the fuel mining, fuel transport and power plant operation portion of the fuel chain. Other emissions may increase with at a maximum 30% for coal or 20% for gas, specifically for those emissions related to mining and/or transport, such as NO_x. Next to CO_2 and GHG emissions, other emissions can also be reduced, depending on the technology.

If maximum CO_2 emission reduction is the sole objective (if no other factors, like capture costs, are taken into account), the results of the chain emissions for various capture ratios indicate that it may be worthwhile capturing CO_2 to a level higher than the usual level. As there are no minima, other than those at the 99% capture ratio cases, our chain analysis tells us that there are no cases in which the CO_2 capture ratio would not be worth raising to values as high as 99% to minimize only CO_2 emissions when costs are not considered. If data for leakage during transport from Russian gas fields are used a significant impact is found, which reduced the maximum chain GHG capture ratio to 85% for post-combustion gas.

The post-combustion gas fired option has the best overall chain capture ratio, though the power production costs are increasing rapidly at increasing capture ratio. PC+MEA post-combustion capture shows the same trends, but is shifted to higher costs. Pre-combustion capture at IGCC is always more expensive than post-combustion, although the increase in costs when increasing the CCR is far less than with post-combustion. At high capture ratios the two are very close. Oxy-combustion PC is the best option for high capture ratios and has a low penalty for increasing the CO_2 capture to the maximum value.

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Abbreviations

ASU	Air separation unit
ATR	Autothermal reformer
AZEP	Advanced zero emission power plant
BAT	Best Available Technologies
$CaCO_3$	Calcium Carbonate
CaO	Calcium Oxide
CC	Combined cycle
CCR	CO_2 Capture ratio, see page 11
CCS	CO_2 capture and storage
CLC	Chemical looping combustion
CO	Carbon monoxide
COE	Cost of electricity
CO_2	Carbon dioxide
CO_2eq	Green house gas emissions expressed as CO_2 equivalent emissions
C-partic	Carbon particulate matter
CRYO	Cryogenic
CuO	Copper Oxide
$DeNO_x$	NOx removal
ECN	Energy research Centre of the Netherlands
Efficiency	LHV electrical efficiency
ESP	Electrostatic precipitator
Eur	Euro
FGD	Flue gas desulfurisation
GT	Gas turbine
H_2	Hydrogen
H_2O	Water/steam
H_2S	Hydrogen Sulfide
Hg	Mercury
HHV	Higher heating value
HP steam	High pressure steam
HRSG	Heat recovery steam generator
HT shift	High temperature shift
IEA	International Energy Agency
IEA GHG	International Energy Agency Greenhouse gas R&D programme
IGCC	Integrated gasification combined cycle
JC	Jacobs Consultancy
kWhF	kWh fuel
LT shift	Low temperature shift
LHV	Lower heating value
LP steam	Low pressure steam
Me	A metal atom
MEA	MonoEthanol Amine (absorber), a liquid phase chemical CO_2 absorbent
MeO	A metal oxide
MHI	Mitsubishi Heavy Industries
N_2	Nitrogen
N_2O	Dinitrogen oxide, nitrous oxide
NG	Natural gas
NGCC	Natural gas fired combined cycle
NO_x	Nitrogen Oxides

O_2	Oxygen
OCM	Oxygen conducting membrane
OOM	Order of Magnitude
PC	Pulverized coal boiler
PM10	Small particulate matter, less than 10 microns in diameters
PSA	Pressure swing adsorption
R& D	Research and Development
SCR	Selective catalytic reduction
Selexol	A liquid phase physical CO_2 absorption agent
SERP	Sorption enhanced reaction process
SE-WGS	Sorption enhanced water gas shift
SOFC	Solid Oxide Fuel Cell
SOFC-GT	Solid Oxide Fuel Cell - Gas Turbine combination
SO_x	Sulfur Oxides
TSA	Temperature swing adsorption
USD	US dollars
VOC	Volatile organic compounds
WGS	Water gas shift

Appendix A Process descriptions: BAT without CO_2 capture

A.1 Introduction

As a basis for descriptions and for reference for the CO_2 capture processes the Best Available Technologies are described in this appendix. The best available technologies for power generation without CO_2 capture are:

- Natural Gas Combined Cycle (NGCC)
- Supercritical Pulverized Coal Plant (PC)
- Integrated Gasification Combined Cycle (IGCC)

The descriptions are mainly based on the IEA-GHG report: "Leading options for the capture of CO_2 emissions at power stations"; PH3/14 (IEA GHG, 2000). .

A.2 BAT Natural gas combined cycle (NGCC)

Block scheme

The process is a conventional natural gas fired combined cycle. The components are as depicted in Figure 38. The system is based on a state of the art gas turbine (GE Frame 9FA) with a dry low NO_x combustion system. Steam is raised from the gas turbine's exhaust gas in a heat recovery steam generator (HRSG). Approximately 2/3 of the power is produced in the gas turbine and 1/3 in the steam turbine. The CO_2 leaves the system in the flue gas.

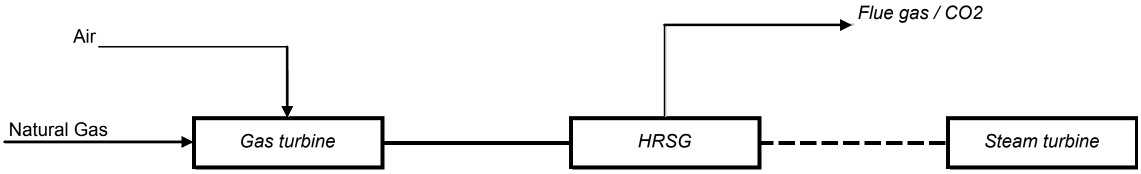


Figure 38: *System configuration for NGCC*

Non-CO_2 emissions

- Sulphur components present in the natural gas will be emitted in the form of SO_x with the flue gas
- NO_x is formed during combustion of natural gas. This will be emitted with the flue gas
- Unconverted fuel emissions are negligible in the case of a natural gas fired combined cycle

System characteristics

The system characteristics are listed in *Table 9*.

Table 9: *Characteristics of NGCC*

	Reference Case NGCC	
Net efficiency	56.2	%
Net power	790	MW_e
Total plant investment	327	MUSD
Specific plant investment	414	USD/kW_e
kWh production cost (@3 $/GJ)	0.0281	USD/kWh
CO_2 emitted	81.2	kg/s
CO_2 emitted	370	kg/MWh
SO_2	0.268	mg/Nm^3
(from 4 mg/Nm^3 H_2S in the fuel)	193	mg/GJ
NO_x	≈ 10	ppm

Currently the GE Frame 9FB, an evolution of the GE 9FA, is also available; however the 9FA can still be considered state of the art. The H-type Frame 9 gas turbine is currently under development but not yet fully commercially available. A system using the GE Frame 9FB gas turbines will generate roughly 5% more power at a 1 %-point higher efficiency.

The plant investment is taken from the IEA "leading options" study using the price level of 1999. Despite escalation, more recent information indicates a decrease of prices rather than an increase. For the study the price level is kept the same.

A.3 BAT Supercritical Pulverized Coal Plant (PC)

Block scheme

In this process pulverized coal is fired in a once through boiler. The components are as shown in Figure 39. Steam, raised in a double-reheat supercritical cycle (310bar/593°C/593°C/593°C) is used to generate electricity. The processing scheme includes flue gas treatment for SO_2 removal and NO_x reduction. The CO_2 leaves the system in the flue gas.

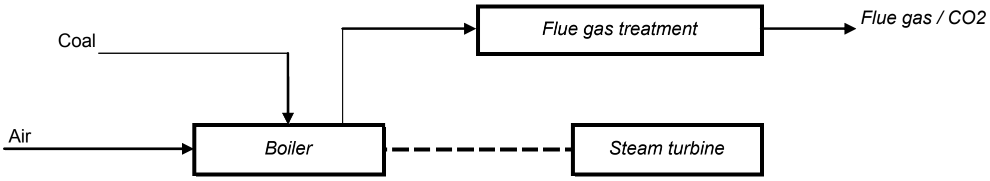


Figure 39: *System configuration for PC*

Non-CO_2 emissions

- SO_2 in the flue gas resulting from sulphur present in the coal will be removed by wet scrubbing
- NO_x formed during combustion of coal is reduced by use of low NO_x burners and selective catalytic reduction
- Particulate matter is removed by the electrostatic precipitator (ESP)
- Unconverted fuel emissions in the flue gas are negligible for a pulverized coal fired plant.

- Mercury traces present in the coal are partly emitted with the flue gas and partly removed with the flue gas treatment.

System characteristics

The system characteristics are listed in *Table 10*.

Table 10: *Characteristics of PC*

	Reference Case PC	
Net efficiency	45.6	%
Net power	501	MW_e
Total plant investment	594[1)]	MUSD
Specific plant investment	1185	USD/kW_e
kWh production cost	0.040	USD/kWh
CO_2 emitted	100.5	kg/s
CO_2 emitted	722	kg/MWh
SO_2 regulatory requirement	< 200	mg/m^3
NO_x regulatory requirement	< 200	mg/m^3

1) On the plant investment an escalation of 3% per year has been applied.

A.4 BAT Integrated Gasification Combined Cycle (IGCC)

Block scheme

In this process electricity is produced from coal in an integrated gasification combined cycle (IGCC). The main components of the process are depicted in *Figure 40*. The O_2-blown gasifier is a dry feed unit based on Shell technology operating at 27 bar and 1613°C. The synthesis gas is quenched before cleaning, to remove mainly sulphur compounds and particulates, before being fed to the combined cycle. The gas turbine is based on a suitably modified GE frame 9F. The CO_2 leaves the system in flue gas.

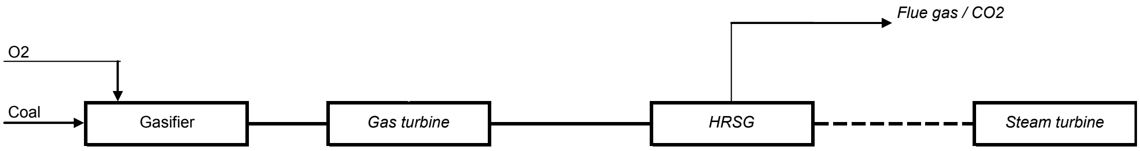


Figure 40: *System configuration for IGCC*

Non-CO_2 emissions

- SO_2 emissions are minimized by sulphur removal from the syngas. Emissions are comparable with emissions of NGCC.
- NO_x formed during combustion of syngas is emitted with the flue gas. NO_x production is likely to be a little higher than with NGCC.
- Unconverted fuel emissions are negligible.
- Mercury traces present in the coal are partly emitted with the flue gas and partly removed with the fuel gas treatment.

System characteristics

The system characteristics are listed in *Table 11*.

Table 11: *Characteristics of IGCC*

Reference Case IGCC		
Net efficiency	46.3	%
Net power	408	MW_e
Total plant investment	696$^{1)}$	MUSD
Specific plant investment	1705	USD/kW_e
kWh production cost	0.059	USD/kWh
CO_2 emitted	80.5	kg/s
CO_2 emitted	710	kg/MWh
SO_2	≈ 0.25$^{2)}$	mg/Nm^3
	≈ 200$^{2)}$	mg/GJ
NO_x	10-20$^{3)}$	ppm

1) On the plant investment an escalation of 3% per year has been applied
2) Comparable with NGCC
3) Most likely slightly higher than NGCC

Appendix B Process descriptions: processes with CO_2 capture

In this appendix a brief and qualitative description is provided for electricity production processes with CO_2 capture. The focus is on the amount of CO_2 captured, possibilities for increasing this, and the effects of CO_2 capture on other emissions. The descriptions are based on the descriptions of the Best Available Technologies without CO_2 capture from Appendix A.

B.1 Introduction

In the paragraphs below a qualitative description of power generation processes with CO_2 capture is presented. The qualitative descriptions include:

- Block diagram
- Principle of separation
- Factors determining the CO_2 capture ratio
- Possibilities for increasing the CO_2 capture ratio
- Non CO_2 emissions

The following processes are discussed:

- Natural Gas Combined Cycle (NGCC) with MEA Absorber
- Pulverized coal plant (PC) with MEA Absorber
- Partial oxidation NGCC with pre-combustion CO_2 capture
- IGCC with pre-combustion CO_2 capture
- NGCC Oxy-combustion conversion with CO_2 recycle
- PC Oxy-combustion boiler
- Matiant Cycle
- Water cycle
- PC/NGCC with solid adsorption of CO_2 from flue gas
- NGCC with membrane reformer
- NGCC with sorption enhanced reforming
- NGCC with CLC
- IGCC with CLC
- NGCC with post-combustion membrane absorber
- PC with post-combustion membrane absorber
- NGCC with oxygen conducting membrane (AZEP)
- SOFC-GT
- IGCC SOFC
- PC with CaO

B.2 Natural gas combined cycle (NGCC) With MEA absorber

Block scheme

The block scheme of this option is depicted in *Figure 41*. Flue gas from the HRSG is treated in the CO_2 capture unit. In this unit, CO_2 is removed from the flue gas by absorption in a monoethanolamine (MEA) solution. CO_2 is recovered from the solvent by heating with low pressure (LP) steam from the HRSG.

Due to the steam used for CO_2 recovery the power output of the steam turbine is reduced by 1/3.

Recycling half the flue gas from the HRSG, shown in figure 2 as "optional", can reduce the volume of gas to be treated in the CO_2 absorber by 50% and has the effect of doubling the concentration of CO_2. The overall result is a small reduction of the overall investment, rather than an improvement of the overall CO_2 capture ratio.

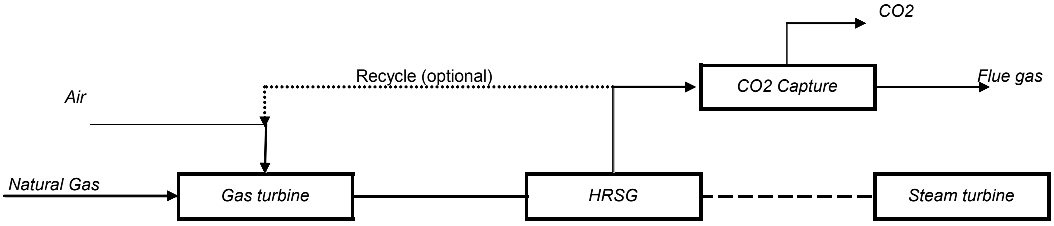


Figure 41: *System configuration for NGCC + CO_2 capture*

Principle of separation

A basic process scheme of the system is shown in Figure 42. Flue gas from the HRSG is first cooled to near ambient temperature, before it enters the absorber. In the absorber, a conventional packed bed column, CO_2 in the cooled flue gas bonds with the solvent. CO_2-lean off-gas is discharged from the absorber to the atmosphere. The CO_2-rich solvent is routed to the regenerator (packed column) where CO_2 is recovered from the solvent by the addition of heat (provided by condensation of LP steam extracted from the HRGS or steam turbine). The lean solvent from the regenerator is cooled in the lean/rich heat exchanger and further cooled in a solvent aftercooler before it is returned to the absorber. Some solvent is lost in both the stripper and regenerator. These losses are compensated for by solvent make-up.

Additional major equipment items in the system (not shown) are a flue gas fan downstream of the flue gas cooler to overcome the pressure drop in the absorber and solvent pumps to circulate the rich and lean solvent.

The CO_2 concentration in the flue gas is approximately 4 vol %. This low concentration (low CO_2 partial pressure) favours a chemical solvent (MEA) instead of a physical solvent. CO_2 is chemically bound to the MEA solvent.

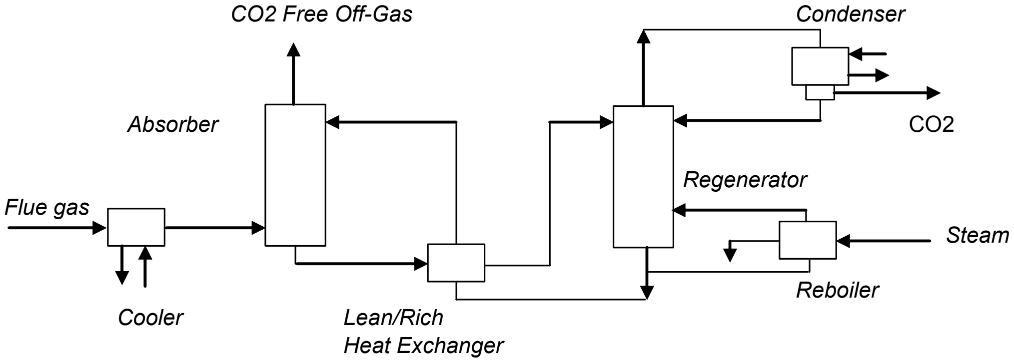


Figure 42*: Working principle for CO_2 absorption in solvent*

Factors determining the CO_2 capture ratio on a system level.

The maximum CO_2 capture ratio is determined by the equilibrium CO_2 concentration in between the exit gas and lean solvent in the absorber. Important parameters are:

- Remaining CO_2 concentration in lean solvent. High purity of the lean solvent favours a low concentration of CO_2 in the off gas from the absorber. A high purity of the solvent demands a large amount of LP steam for regeneration.

- Height of the packed bed in the absorber. A higher packed bed height results in a better approach to equilibrium conditions.
- Solvent temperature. A lower temperature of the solvent in the absorber favours a better absorption of CO_2.

100% CO_2 capture cannot be achieved, as it would demand an infinitely tall column. In practice an economic optimum is used. For the MEA solvent a typical practical CO_2 capture ratio is 85%.

Possibilities for increasing the CO_2 capture ratio

Increasing the CO_2 capture ratio for MEA solvent beyond 85%, could be possible by e.g. tightening lean solvent specification and increasing the absorption capacity. This would require a higher column or more columns in series. Increase of the CO_2 capture ratio beyond 85% could also be achieved by application of an improved solvent: the KS-1 solvent of MHI claims a typical 90% capture ratio at an approximate 15 % higher investment than for MEA solvent.

Non-CO_2 emissions

- SO_x and NO_2 cause degradation of MEA solvent. The minimum requirements with respect to SO_x and NO_2 concentration can be met with current FGD and $DeNO_x$ units. SO_x and NO_x formed during combustion of natural gas will partly be emitted to the atmosphere. Because of co-capture in the amine solvent NO_x and SOx emissions will be lower compared to normal NGCC.
- Unconverted fuel emissions are negligible in the case of a natural gas fired combined cycle
- MEA losses are mostly related to degradation of the solvent, resulting in a waste stream of degraded MEA, rather than MEA emission in the flue gas.

B.3 Pulverized coal (PC) Power Plant with MEA absorber

Block scheme

The block scheme of this option is depicted in *Figure 43*. Flue gas from the boiler is cleaned in the FGD, $DeNO_x$ and ESP and then treated in the CO_2 capture unit. In this unit, CO_2 is removed from the flue gas by absorption a monethanolamine (MEA) solution. CO_2 is recovered from the solvent by boiling the solvent with low pressure (LP) steam. The original power output of the steam turbine is considerably reduced due to the steam demand for solvent regeneration.

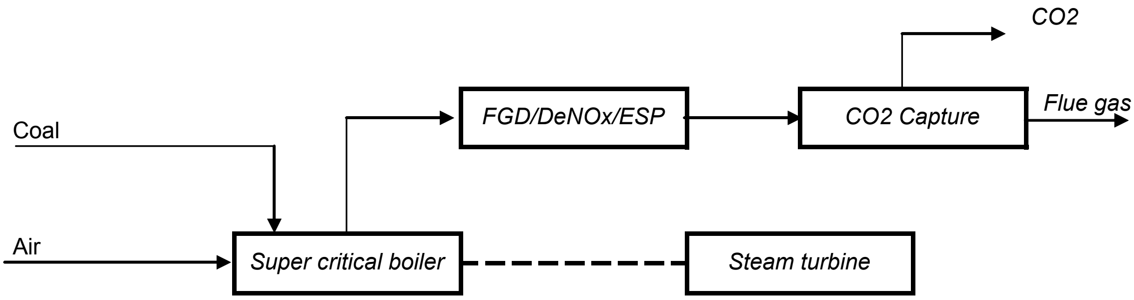


Figure 43: *System configuration of PC + CO_2 capture*

Principle of separation

The relatively low partial pressure of CO_2 in the flue gas from the boiler favours a chemical solvent (MEA) to achieve a high capture ratio. CO_2 is chemically bound to the solvent. The basic process scheme of the system the same as for absorption from a NGCC flue gas stream, see Figure 42.

Factors determining the CO_2 capture ratio on a system level.
See NGCC-MEA

Possibilities for increasing the CO_2 capture ratio
See NGCC-MEA

Non-CO_2 emissions
- SO_x and NO_2 cause degradation of MEA solvent. The minimum requirements with respect to SO_x and NO_2 concentration can be met with current FGD and $DeNO_x$ units. SO_x and NO_x formed during combustion of coal will be partly emitted to the atmosphere. The NO_x and SOx emissions will be lower compared to a normal PC boiler.
- Unconverted fuel emissions are negligible in the case of a PC boiler.
- MEA losses are mostly related to degradation of the solvent, resulting in a waste stream of degraded MEA, rather than the MEA emission in the flue gas.

B.4 NGCC with Selexol pre-combustion capture

Block scheme
The block scheme of this option is depicted in *Figure* 44. In this process, natural gas is converted to a synthesis gas, and subsequently shift converted to a mixture of hydrogen and CO_2. The CO_2 is captured in a physical solvent. The remaining hydrogen rich fuel gas is burned in a gas turbine of a combined cycle.

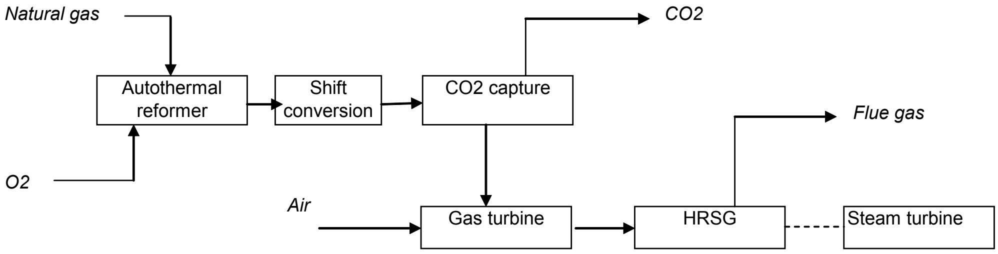


Figure 44: *Combined cycle with Selexol pre-combustion capture*

Principle of separation
A basic process scheme is shown in *Figure 45*. In the auto-thermal reformer, natural gas is converted into syngas (consisting mainly of CO and H_2) using a catalyst. Steam (from a heat recovery unit between the autothermal reformer and shift conversion) and oxygen from an air separation unit are used to enable the conversion. The hot syngas supplies heat to the HRSG, and the gas feed to the reformer, before it enters the two stage shift conversion section. In the two-stage shift reactor CO in the syngas is converted with steam into a mixture of H_2 and CO_2. Steam for the shift reaction is added in the autothermal reformer. As the shift reaction is exothermic, heat can be recovered. The heat recovering system is integrated into the steam and syngas cycle. The H_2/CO_2 mixture then enters an absorption process with a physical solvent (Selexol) where CO_2 is removed from the gas mixture leaving a hydrogen rich fuel gas. The CO_2 is recovered from the solvent by a two-stage pressure reduction step and a final regeneration with LP steam. The H_2 rich fuel gas is mixed with N_2 from the air separation unit and proceeds through the saturator where water is added to enhance gas turbine performance and reduce NO_x emissions.

Oxygen for the gasifier is produced by the air separation unit (ASU). Air side integration is applied between the gas turbine and the ASU to reduce cost. The nitrogen that is produced by the ASU is added to the gas turbine for NOx reduction.

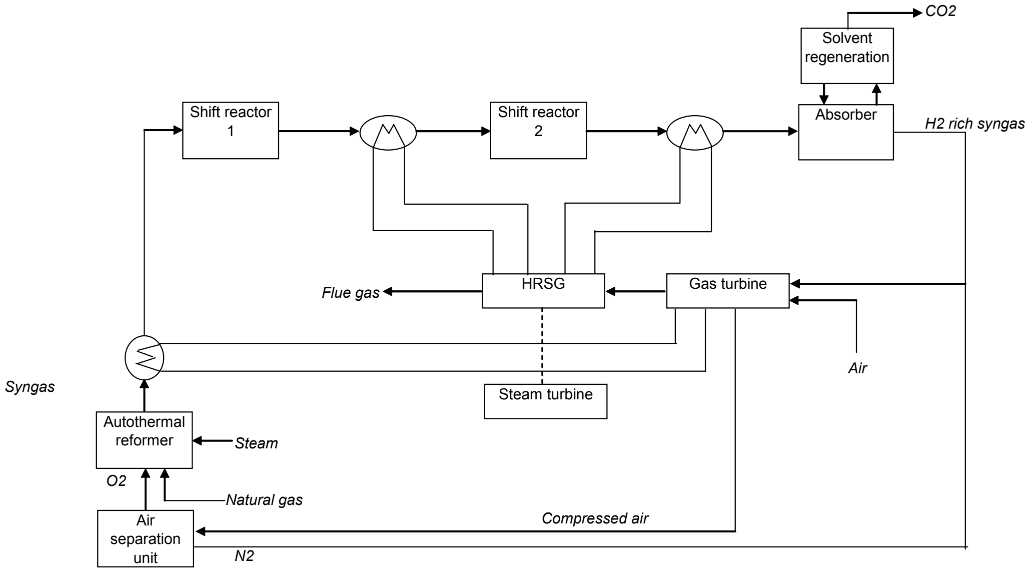


Figure 45: *Working principle of NGCC with Selexol pre-combustion capture*

Factors determining the CO_2 capture ratio on a system level.

The CO_2 capture ratio is determined by the amount of CH_4, CO and CO_2 that are left in the hydrogen rich fuel gas to the gas turbine. This amount depends the type of reformer, on the reaction equilibrium in the shift conversion and the CO_2 removal efficiency in the absorption process. A low exit temperature of the LT shift reactor favours a high equilibrium conversion of CO into CO_2 and thus a low CO content of the fuel gas. A low CO_2 content in the lean Selexol to the top of the absorber, a low solvent temperature and a large packing height in the absorber favour a low residual CO_2 content in the fuel gas. Due to equilibrium considerations, 100% capture cannot be achieved. A typical capture ratio of this system with a two-stage shift conversion is 85%. A lower capture ratio would result if only a one-stage shift conversion (HT shift only) were applied.

Possibilities for increasing the CO_2 capture ratio

The CO conversion can be further enhanced by using a four-stage shift instead of a two-stage shift unit. The CO_2 removal in the absorber can be enhanced by increasing the column height and applying a lower CO_2 content in the lean Selexol at the top of the absorber. An overall capture ratio of 85% is an optimum between performance and cost. Higher capture ratios could be achieved at higher cost.

Non-CO_2 emissions

- Sulphur components present in the natural gas will be removed by the desulphurization unit
- NO_x formation is reduced to <200 mg/m^3. NO_x emissions could be higher than in a reference NGCC without CO_2 capture. This is a result of the firing of the GT with hydrogen. With additional measures to lower the NO_x emission (additional steam or nitrogen injection, selective catalytic reduction) NO_x emission can be kept within allowable limits.
- Unconverted fuel emissions are negligible

B.5 IGCC with SELEXOL pre-combustion CO_2 capture

Block scheme

The block scheme of this option is depicted in *Figure 46*. The process is an integrated coal gasification combined cycle (IGCC) with pre-combustion CO_2 removal by means of shift conversion and subsequent CO_2 removal. The resulting hydrogen rich fuel is burnt in the gas turbine.

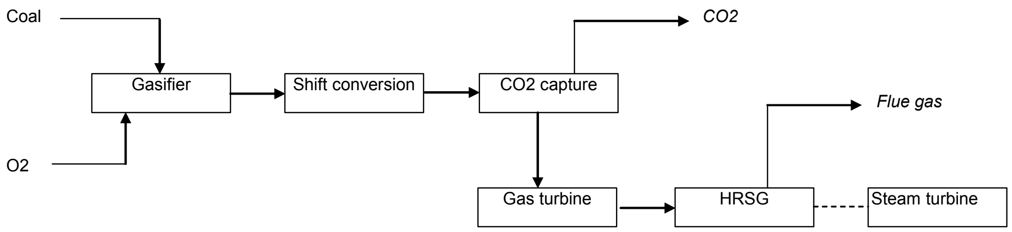


Figure 46: *IGCC + CO_2 capture*

Principle of separation

The basic process scheme is shown in *Figure 47*. Cooled CO-rich syngas produced by the oxygen blown gasifier passes a dust extraction unit and a desulphurisation unit before entering the two-stage shift conversion unit. The first stage is a high temperature (HT) shift reactor and the second stage a low temperature (LT) shift reactor. CO in the syngas produced by the gasifier is converted with steam into H_2 and CO_2. To enable the shift reaction, intermediate pressure (IP) steam is added to the syngas stream entering the first shift reactor and the steam / gas mixture entering is heated up to 350°C. As the processes in the two shift reactors are exothermic, heat can be recovered. The heat recovery system is integrated into the steam and syngas cycle.

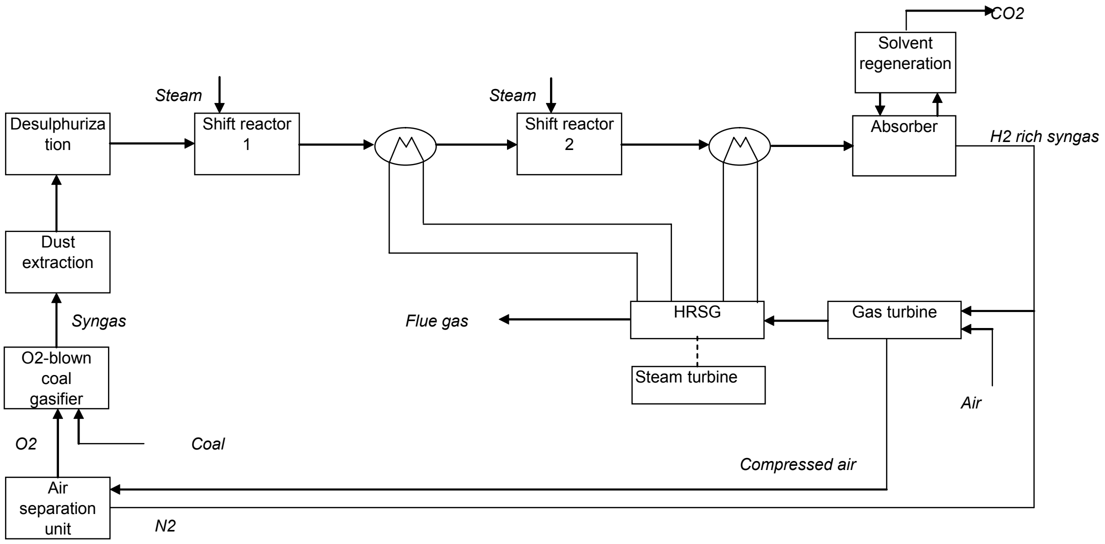


Figure 47*: Working principle of coal gasification with CO_2 capture*

The H_2/CO_2 mixture enters an absorption process with a physical solvent (Selexol) where CO_2 is removed from the gas mixture leaving a hydrogen rich fuel gas. The CO_2 is recovered from the solvent by a two-stage pressure reduction step and a final regeneration with LP steam. The H_2 rich fuel gas proceeds through a fuel gas conditioning section, where the fuel gas is saturated with water (for NO_x emission reduction) and heated. Oxygen for the gasifier is produced by the air separation unit (ASU). Air side integration is applied between the gas turbine and the ASU to enhance overall thermal efficiency. The nitrogen that is produced by the ASU is added to the gas turbine.

Factors determining the CO_2 capture ratio on a system level.

The CO_2 capture ratio is determined by the amount of CO and CO_2 that is left in the hydrogen rich fuel gas to the gas turbine. This amount depends on the reaction equilibrium in the shift conversion and the CO_2 removal efficiency in the absorption process. A low exit temperature of the LT shift reactor favours a high equilibrium conversion of CO into CO_2 and thus a low CO content of the fuel gas. A low CO_2 content in the lean Selexol to the top of the absorber, a low solvent temperature and a large packing height in the absorber, favour a low residual CO_2 content in the fuel gas. Due to equilibrium reactions, 100% capture cannot be achieved. Typical capture ratio of this system with a two stage shift conversion is 85%.

Possibilities for increasing the CO_2 capture ratio

The CO conversion can be further enhanced by using a four-stage shift instead of a two-stage shift unit. The CO_2 removal in the absorber can be enhanced by increasing the column height and applying a lower CO_2 content in the lean Selexol at the top of the absorber. An overall capture ratio of 85% is an optimum between performance and cost. Higher capture ratios could be achieved at high cost.

Non-CO_2 emissions

- Sulphur components present in the coal will be removed by the desulphurization unit
- NO_x formation is reduced to <200 mg/m^3. NO_x emissions could be higher than in a reference IGCC without CO_2 capture. This as a result of the firing of the GT with hydrogen. With additional measures to lower the NO_x emission (additional steam or nitrogen injection, selective catalytic reduction), NO_x emission can be kept within allowable limits.
- Unconverted fuel emissions are negligible as with the reference IGCC.
- Particle emissions are reduced by the dust extraction unit and are comparable to the reference IGCC.

B.6 NGCC Oxy-combustion conversion with CO_2 recycle

Block scheme

The block scheme of this option is depicted in *Figure 48*. Natural gas is combusted with pure oxygen under pressurized conditions. To limit the high temperatures resulting from combustion with pure oxygen, CO_2 rich flue gas is recycled to the compressor inlet and mixed with the oxygen prior to combustion. Oxygen is supplied by an air separation unit. Combustion gas is led to an expander and HRSG for power generation. Flue gas (mainly CO_2 and H_2O) is cooled down and water is separated. This technology requires a re-design of the gas turbine, with as a result a large uncertainty in the investment costs involved.

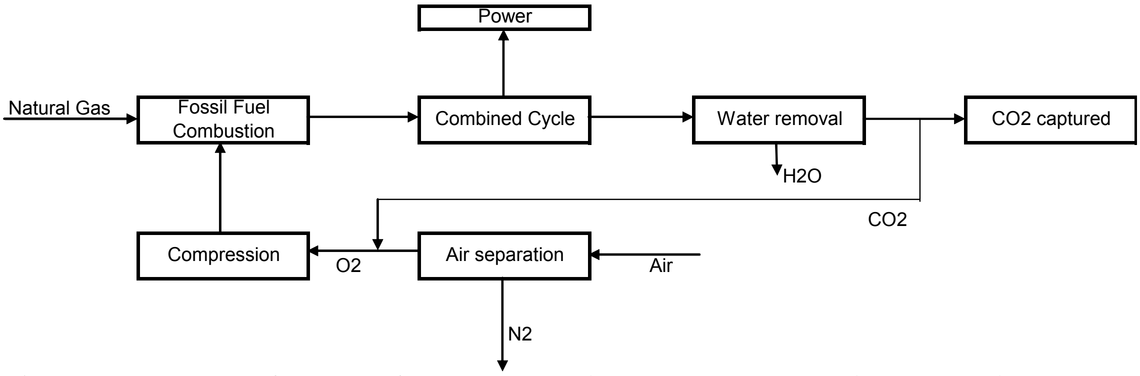


Figure 48: *System configuration for CC Oxy-combustion conversion with CO_2 recycle*

Principle of separation

The key element of this option is combustion with pure (~95%) oxygen, resulting in a flue gas, which mainly consists of CO_2 and H_2O. The water can relatively easily be removed from the flue gas by cooling and knockout.

Oxygen for the combustion is produced in an air separation unit (ASU). In a conventional air separation unit the following process steps are taken:

- Air compression to ~6 bar
- Removal of CO_2, H_2O and hydrocarbons with temperature swing adsorption (TSA)
- Cooling by heat integration with product flows and expansion
- Cryogenic distillation

See also *Figure 49*.

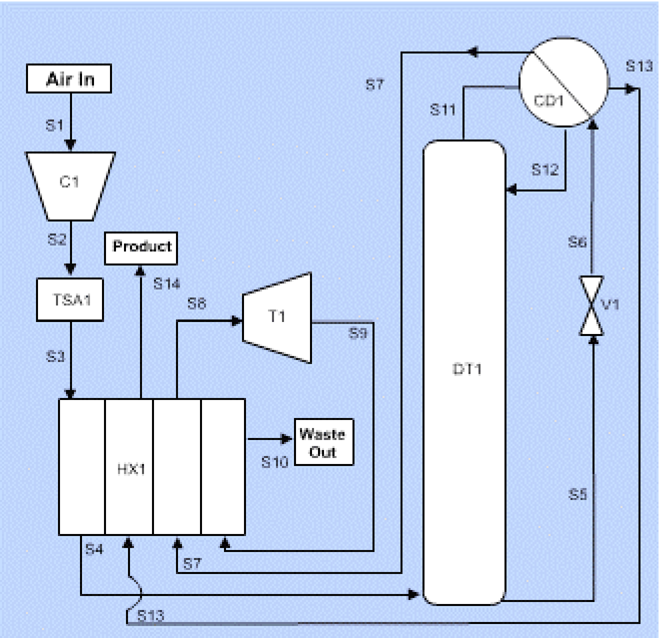


Figure 49: *Cryogenic Air separation unit*

Alternatively, air separation can be done by oxygen selective membranes or pressure swing adsorption (PSA).

The purity of oxygen is an important factor for oxy-combustion conversion. The remaining nitrogen ends up in the CO_2 stream and results in an efficiency penalty when the CO_2 is compressed for storage. Reduction of this efficiency penalty is a trade off with the higher energy requirement for air separation.

Factors determining the CO_2 capture ratio on a system level.

Theoretically the capture ratio is 100%. Although some CO_2 will dissolve in the condensed water. It is possible to recover most of this CO_2 in a degasser and, thus, bring the capture ratio further towards the 100%.

Possibilities for increasing the CO_2 capture ratio

Not applicable.

Non-CO_2 emissions

Sulphur and NO_x emissions are captured in the CO_2 stream. They can be stored together with the CO_2. Alternatively, if transport and/or storage requirements require this, these components can to be removed prior to combustion (SOx) or CO_2 compression (SO_x, NO_x).

B.7 Oxy-combustion PC boiler

Block scheme

The block scheme of this option is depicted in *Figure 50*. The coal is combusted with 95% pure oxygen (supplied by a cryogenic air ASU) under atmospheric conditions. In the boiler steam is generated for power production. Flue gas (mainly CO_2 and H_2O) is cooled and water is separated.

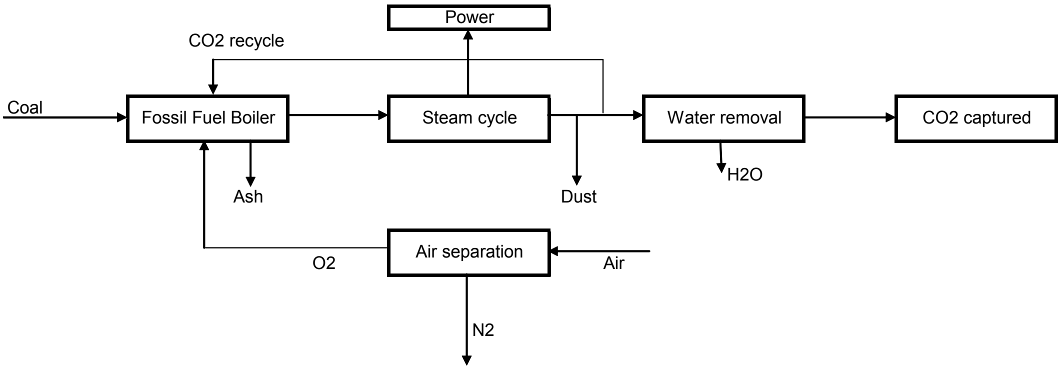


Figure 50*: System configuration for Oxy-combustion PC conversion*

Principle of separation

The principle of separation is based on combustion with pure oxygen giving a CO_2/H_2O mixture as flue gas.

Factors determining the CO_2 capture ratio on a system level.

Theoretically, the capture ratio is 100%. Practically, some CO_2 will dissolve in the condensed water. It is possible to recover most of this CO_2 in a degasser and thus bring the capture ratio towards 100%. Because air in-leakage to the boiler, oxygen purity, and excess oxygen required for coal firing the CO_2 exhaust stream can contain as much as 25% non-CO_2 components like oxygen, nitrogen and argon. In an additional purification step also CO_2 is removed and vented to the air resulting in a normal capture ratio of 90%, see also reference (IEA GHG, 2005a).

Possibilities for increasing the CO_2 capture ratio

With an additional MEA scrubbing step the CO_2 can be removed from the vent stream. Another option is complete capture of the CO_2 stream including inerts and contaminants, provided that this does not interfere with technical and political requirements. See also section 3.4.5.

Non-CO_2 emissions

Sulphur and NO_x emissions are captured in the CO_2 stream. They can be stored together with the CO_2. Alternatively, if transport and/or storage requirements require this, these components can to be removed prior to or during CO_2 compression. Dust will be collected with electrostatic precipitators.

B.8 Matiant cycle

Block scheme

The block scheme of the Matiant cycle is depicted in *Figure 51*. The Matiant cycle is a more sophisticated variation of the combined cycle with oxy-combustion. Natural gas is combusted with oxygen in two stages in a gas turbine producing a flue gas that consists mainly of CO_2 and H_2O. CO_2 and H_2O are recycled thus forming the working fluid of the gas turbine. The Matiant cycle has the potential of higher overall thermal efficiency than oxy-combustion in a combined cycle.

Gas turbines with CO_2/H_2O as working fluid would be different to conventional gas turbines and are currently not available on the market. Potential application of the Matiant cycle is therefore dependent on gas turbine development.

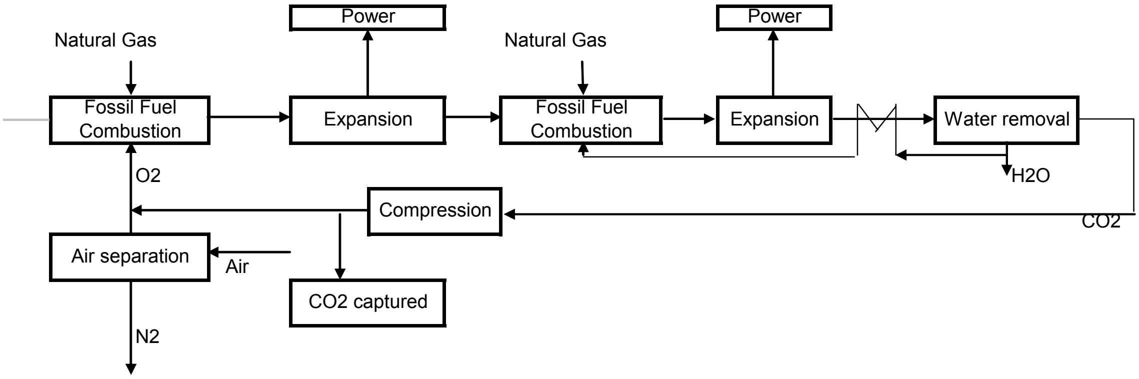


Figure 51: *System configuration for Matiant cycle*

Principle of separation

The principle of separation is based on combustion with pure oxygen giving a CO_2/H_2O mixture as flue gas.

Factors determining the CO_2 capture ratio on a system level.

Theoretically the capture ratio is 100%. Practically, some CO_2 will dissolve in the condensed water. It is possible to recover most of this CO_2 in a degasser and, thus, bring the capture ratio further towards the 100%.

Possibilities for increasing the CO_2 capture ratio

Not applicable.

Non-CO_2 emissions

Sulphur (present at very low levels) and NO_x emissions are captured in the CO_2 stream. They can be stored together with the CO_2. Alternatively, if transport and/or storage requirements require this, these components can to be removed prior to combustion (SOx) or CO_2 compression (SO_x, NO_x).

B.9 Water cycle

Block scheme

The block scheme for this option is depicted in Figure 52. The water cycle is an oxy-combustion cycle using natural gas as a fuel. In a specially designed combustor the temperature is lowered by water injection. The resulting high-temperature gas is used in an expander. An additional steam cycle may be present (not depicted). Optionally there is a CO_2 cycle. After water knock-out a pure CO_2 stream results. This technology requires development of a new expander, suitable for the specific mixture.

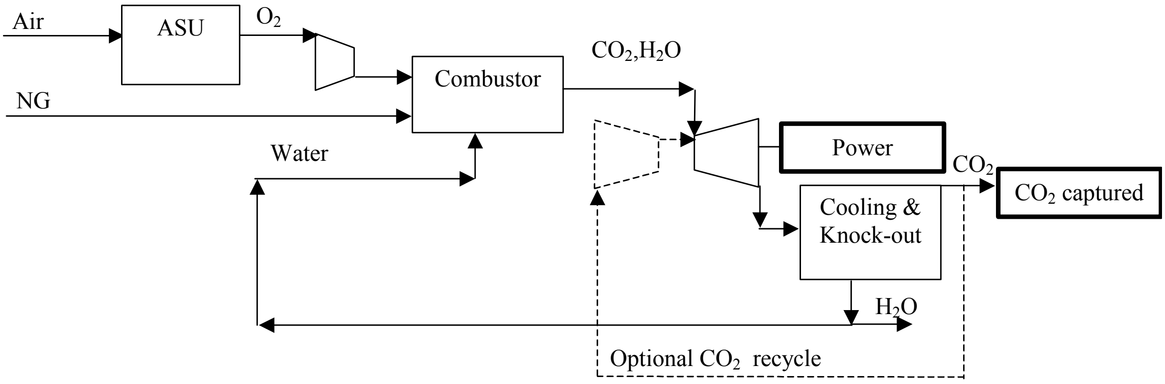


Figure 52: *System configuration for the water cycle*

Principle of separation

The principle of separation is based on combustion with pure oxygen (in small excess quantity compared to stoichiometric) giving a CO_2/H_2O mixture as flue gas.

Factors determining the CO_2 capture ratio on a system level.

Theoretically the capture ratio is always 100%. In practice, some CO_2 will be absorbed in the water stream, but this CO_2 could easily be recovered and sent to CO_2 compression.

Possibilities for increasing the CO_2 capture ratio

Not applicable.

Non-CO_2 emissions

Sulphur (at low levels) and NO_x emissions are captured in the CO_2 stream. They can be stored together with the CO_2. Alternatively, if transport and/or storage requirements require this, these components can to be removed prior to combustion (SOx) or CO_2 compression (SO_x, NO_x).

B.10 NGCC/PC with post-combustion solid adsorption

Block scheme

The block scheme is similar to that of a NGCC or PC plant with post-combustion amine absorption, see *Figure 53*.

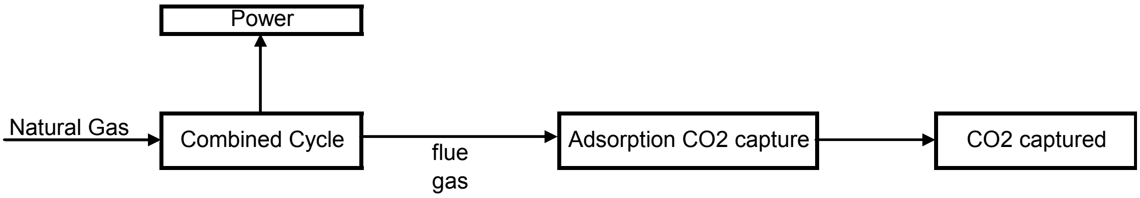


Figure 53: *System configuration for post-combustion solid sorption.*

Principle of separation

An adsorption process consists of two major steps: adsorption and desorption. Adsorption of CO_2 takes place on a solid material with a high surface area and strong affinity for CO_2, such as zeolites or activated carbon. After the sorbent has been loaded to its capacity, it is regenerated, where desorption takes place producing a concentrated CO_2 stream. The sorbent can be regenerated by increasing the temperature; temperature swing adsorption (TSA). The stronger the affinity of the sorbent, the more difficult it is to desorb the adsorbed material and the more energy is consumed in regenerating the adsorbent for reuse in the next cycle. An adsorption unit comprises a series of vessels containing sorbent in packed beds through which the gas flows. The process operates on a repeated cycle of adsorption and regeneration. Depending on the sorbent, it might prove necessary to remove most of the water from the feed gas prior to adsorption. The development of sorbents increased CO2 selectivity could overcome the necessity of this step.

Factors determining the CO_2 capture ratio on a system level.

Important parameters in the adsorption process are temperature, partial pressure of the component to be adsorbed and the characteristics of the sorbent such as pore size and surface area. Adsorption is commercially applied for removing CO_2 from natural gas and removing CO_2 from air prior to liquefaction in an ASU. The process is, however, not yet economically attractive for the large-scale removal of CO_2 from flue gas, because the process requires a low temperature and its capacity and selectivity for CO_2 is low. Water in the flue gas is co-absorbed with CO_2. Therefore development of sorbents that can operate at higher temperatures in the presence of steam with increased capacity and improved selectivity is needed. Pilot plant tests of CO_2 removal from flue gas from a coal/oil fired boiler with modified zeolites report a CO_2 capture ratio of 90(Yokoyama, 2002).

Non-CO_2 emissions

The effect of NO_x and SO_2 is very uncertain since the sorbents are still under development and it is unknown whether they will have to be removed prior to the absorption step, will absorb without causing degradation, or will pass the absorber without being absorbed.

B.11 NGCC with pre-combustion membrane reformer

Block scheme

The block scheme for this option is depicted in Figure 54. The natural gas is fed to a membrane reformer together with steam. In the membrane reformer the steam reforming reaction takes place parallel to separation of hydrogen. The energy content of the natural gas is transferred to the hydrogen. The hydrogen is sent to a conventional combined cycle for power generation. The other product stream of the membrane reformer is a CO_2 stream diluted with steam (of which the bulk content can be removed by condensation and knockout) and unconverted CH_4, CO and H_2. In the clean-up section the CH_4 and unconverted fuel are separated (e.g. by cryogenic distillation during CO_2 compression or by Selexol absorption) or are converted by oxidation. The result is a concentrated CO_2 stream available for storage. The membrane reformer is fired with natural gas and/or a part of the hydrogen product to supply the heat for the steam reforming reaction.

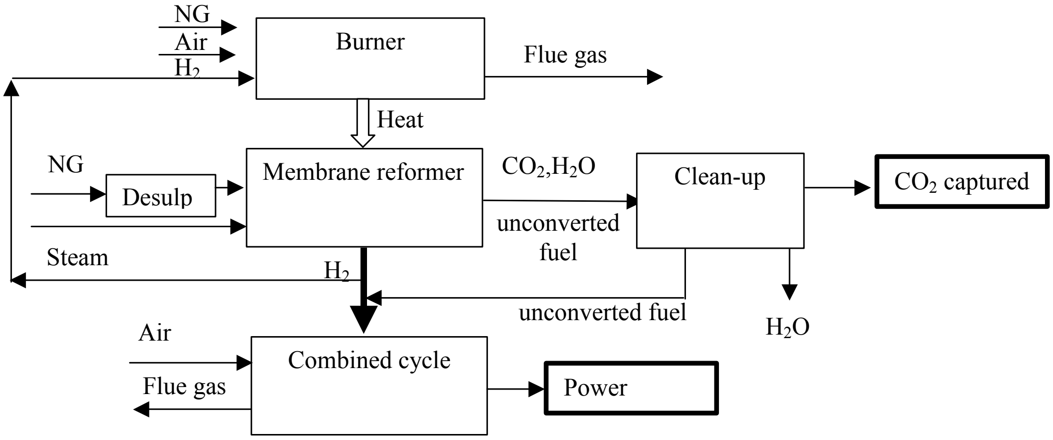


Figure 54: *System configuration for NGCC with membrane reformer*

Principle of separation

The key element of this option is the membrane reformer. A schematic depiction of a membrane reformer is shown in Figure 55. Natural gas and steam are fed to the membrane reformer. The natural gas originates from an adiabatic pre-reformer (not depicted) to convert the higher hydrocarbons and increase the H_2 content of the feed. At the feed side of the membrane reformer, the steam reforming reaction and the shift reaction take place. Here the energy content of the natural gas is transferred to hydrogen. The hydrogen permeates through a hydrogen selective membrane. The retentate (exit at the feed side) is CO_2 , diluted with H_2O and unconverted CH_4, CO and H_2.

At the permeate side a sweep stream of steam (from the combined cycle) is introduced to lower the partial pressure of hydrogen. The permeate stream consists of a mixture of hydrogen and steam.

The removal of hydrogen shifts the reforming equilibrium reactions to the product side. This allows operation at lower temperatures compared to conventional steam reforming with a high CH_4 conversion. The conversion at the feed side is, therefore, linked to the amount of hydrogen that permeates.

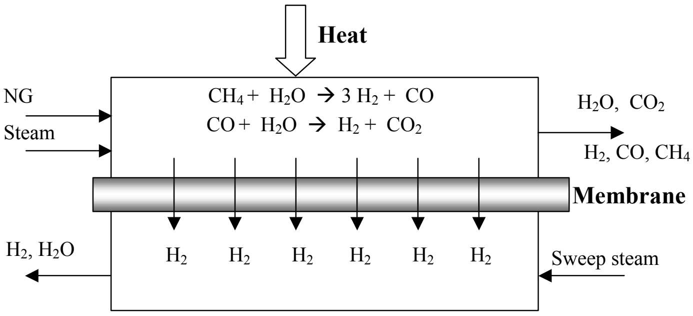


Figure 55: *Working principle of a membrane reformer*

The important factors for membrane reactor performance are:

- Membrane surface area. Increasing the membrane surface area increases the hydrogen recovery (amount of hydrogen permeating) and the CH_4 conversion. It is not possible to achieve 100% conversion. This would require an infinite membrane surface area.
- Membrane permeance. This is the amount of hydrogen permeating per unit of time for a given surface area and pressure differential. A high membrane permeance has a similar effect as a large membrane surface area. It increases the hydrogen recovery and the CH_4 conversion.
- Membrane selectivity. Depending on the membrane type, other components besides hydrogen could also permeate.
- Sweep flow. Increasing the sweep flow increases the hydrogen recovery and thus the conversion in the membrane reactor for a given membrane surface area.
- Permeate side pressure. Decreasing the permeate side pressure increases the hydrogen recovery and, thus, conversion for a given membrane surface area. The feed side pressure is fixed at the available natural gas pressure.

It is not possible to have full 100% conversion in the membrane reactor. In order to have full conversion, the membrane surface area would need to be infinitely large. In practice the membrane surface area will be determined by an economic optimum between membrane investment and system performance.

Factors determining the CO_2 capture ratio on a system level.

The CO_2 capture ratio is mainly determined by the following factors

- Natural gas conversion in the membrane reformer. Unconverted CH_4 or intermediate product CO are combusted in the combined cycle and the carbon content will end up in the flue gas. This will lower the CO_2 capture ratio. Natural gas conversion can be increased by:
    - a. A high membrane surface area.
    - b. A high membrane permeance
    - c. A high sweep flow. However very high sweep flows can lower cycle efficiency considerably.
    - d. Low permeate pressure. However, very low pressures can lower cycle efficiency considerably.
    - e. Selectivity of the membrane. Non-selective permeation of carbon components (CH_4, CO_2, CO) through the membrane leads to a lower CO_2 capture ratio.
- Amount of natural gas used for supplementary firing. If natural gas is used in the burner of the membrane reformer, the CO_2 resulting from this combustion is not captured. It is possible to use part of the hydrogen produced in the membrane reformer in the combustor. This will increase the amount of CO_2 captured, but will lower system efficiency.
- Efficiency of the clean-up section. If the CH4/CO stream from the clean-up section also contains CO_2 this will lower the CO_2 capture ratio.

Possibilities for increasing the CO_2 capture ratio

In this option the following possibilities exist to increase the CO_2 capture ratio:

- Operation at high conversion in the membrane reformer by means of:
    - a. A high membrane surface area and a high membrane permeance.
    - b. A high sweep flow
    - c. A low permeate pressure
- Supplementary firing with hydrogen
- Choice and operation of the clean-up section

It may be possible to achieve near zero CO_2 emissions using 100% hydrogen firing, a very large surface area of a 100% selective membrane and proper choice of the clean-up section. However, the feasibility of this is unclear, since little research has been done on this subject.

Non-CO_2 emissions

- Sulphur components present in the natural gas need to be removed before the pre-reformer because the reforming catalyst and the membrane are probably not resistant to sulphur.
- NO_x formed during combustion of natural gas and/or hydrogen will be emitted to the atmosphere. Special attention is to be paid to the reduction of NO_x formation during hydrogen combustion in both the supplementary firing burner and the gas turbine. NO_x emissions will be in the same range or higher than BAT.
- Unconverted fuel (CH_4) and CO emissions are expected to be negligible.

B.12 NGCC with pre-combustion CO_2 sorption

Block scheme

The block scheme for this option is depicted in Figure 56. Natural gas is fed to an autothermal reformer together with steam and oxygen from an ASU. In the reactor autothermal reforming takes place. The product gas is then cooled and sent to a sorption enhanced water gas shift reactor (SE-WGS). Here the stream is further converted to CO_2 and H_2 by simultaneous adsorption of CO_2 by a solid sorbent. The energy content of the natural gas is by this means transferred to the hydrogen. The hydrogen is sent to a conventional combined cycle for power generation. This stream will also contain some unconverted fuel.

If the sorbent is loaded with CO_2 the sorbent enhanced reactor is switched to regeneration mode. In this mode a purge steam flow is used to desorb CO_2 from the sorbent and produce a mixed CO_2/H_2O stream. After water condensation and knockout, drying and compression this CO_2, stream is ready for storage. The sorption section of the hydrogen product enhanced reformer is fired with hydrogen product and/or natural gas to supply the heat for the steam reforming reaction.

Optionally the ATR and SE-WGS can be integrated. In this case, the autothermal reforming reactions, as well as the shift reaction, are carried out in the presence of a CO_2 sorbent. Integration of the ASU with the gas turbine may be applied but is not required. Another process variant is autothermal reforming with air instead of oxygen. The not integrated case will be taken as this for this most data is available.

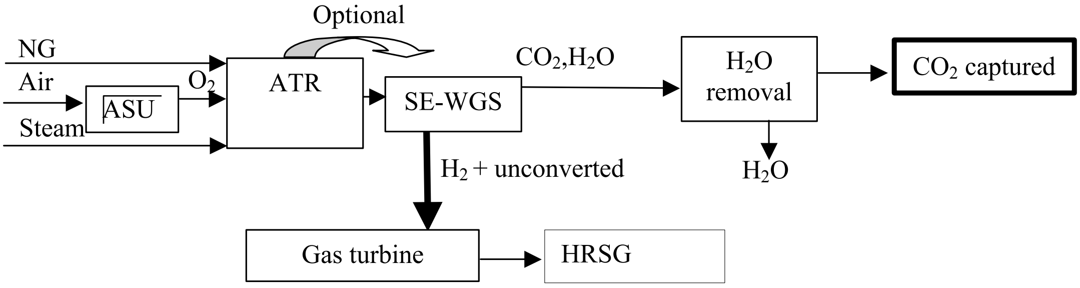


Figure 56: *System configuration for CC with SE-WGS reactor*

Principle of separation

The key element of this option is the sorption enhanced reactor. A schematic depiction of a sorption enhanced reactor is shown in Figure 57. Here the water gas shift reaction takes place simultaneous with absorption of the CO_2. The chemical equilibrium of the reaction is shifted to the right as a result of the absorption of CO_2.

$$CO + H_2O \rightarrow CO_2\,(abs) + H_2$$

Conversion is, therefore, a function of the amount of CO_2 absorbed. By means of the combination of ATR and shift, the energy content of the natural gas is transferred to hydrogen. By-product is mainly CO. Hydrogen, with possibly some unconverted fuel, and excess H_2O leaves the reactor and goes to the combined cycle.

If the sorbent is loaded with CO_2 the reformer is switched to regeneration mode. Then the CO_2 is released by purging with steam, lowering the pressure, increasing the temperature or a combination thereof. The result is a mixed CO_2/H_2O stream. After water condensation and knockout, drying and compression, the CO_2 stream is ready for storage. By having multiple reactors operating in alternating mode, a continuous process can be achieved.

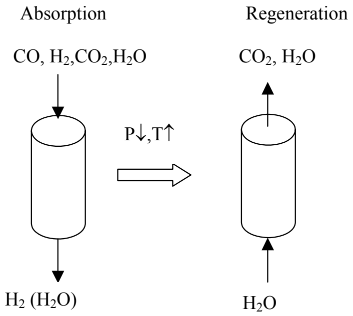


Figure 57: *Working principle of a sorption-enhanced reformer*

Important reactor performance indicators are the CO conversion and the amount of CO_2 captured. The most important factor for reactor performance is the chemical affinity of the sorbent for CO_2. A high affinity will mean a high CO conversion at relatively low temperatures (both will result in a lower efficiency penalty and a higher CCR). However, regeneration will become more difficult and will require lower pressure, higher temperature or a higher amount of purge steam. All of these factors will increase the efficiency penalty and lower the CO_2 capture ratio.

Factors determining the CO_2 capture ratio on a system level.

The CO_2 capture ratio is mainly determined by the relative amount of CO_2 absorbed and the CO conversion in the reactor. In principle the CH_4 conversion in the ATR is also important but, this is normally above 99%. Unconverted CO will be combusted and will end up as CO_2 in the flue gas. This will lower the CO_2 capture ratio. Furthermore, some CO_2 will end up in the flue gas as a result of switching between absorption and desorption mode.

Possibilities for increasing the CO_2 capture ratio

Crucial is the development of a sorbent that has good absorption/desorption characteristics. The sorbent should absorb CO_2 well enough to obtain sufficient CO conversion and a low CO_2 content in the product gas. However, regeneration should not require too much purge steam. Furthermore, the CO_2 shortcut streams during switching should be minimized. The process as well as the sorbents are still under development. Literature (Allam, 2005) reports a typical CO_2 capture ratio of 90% for sorption enhanced reforming with an upstream O_2 or air blown autothermal reformer.

Non-CO_2 emissions

- Sulphur components present in the natural gas need to be removed before the pre-reformer because the reforming catalyst is probably not resistant to sulphur.
- NO_x formed during combustion of natural gas and/or hydrogen will be emitted into the atmosphere. Special attention is to be paid to the reduction of NO_x emissions during hydro-

gen combustion in the gas turbine. NO_x emissions will be in the same range or higher than BAT. With additional measures to lower NO_x (additional steam or nitrogen injection, selective catalytic reduction) NO_x emission can be kept within allowable limits.

- Unconverted fuel (CH_4 and CO) emissions are expected to be lower than in the BAT case.. The flue gas contains less CH_4 and CO as for the replacement of natural gas fuel with hydrogen.

A system designed with a maximum CO_2 emission reduction will reduce most of the CH_4 and CO emissions. NO_x formation will occur and may possibly increase, depending on the measures taken.

B.13 NGCC with chemical looping combustion

Block scheme

The block scheme is depicted in Figure 58. The natural gas (fuel) is fed to a fluidised bed reactor, where it reacts with a metal oxide to form CO_2 and water:

$$CH_4 + 4\ MeO \rightarrow 4Me + CO_2 + 2\ H_2O$$

This reaction is moderately endothermic. Several metal oxides are being considered such as iron or nickel.

The resulting stream contains only CO_2 and water. After water removal a CO_2 stream is available for storage. The spent metal oxide is transported pneumatically to a second reactor, which is part of a gas turbine cycle. The metal is re-oxidized here to a oxide:

$$2Me + O_2 \rightarrow 2MeO$$

This reaction is highly exothermic. The resulting hot air flow drives the gas turbine and is then used to raise steam in a HRSG.

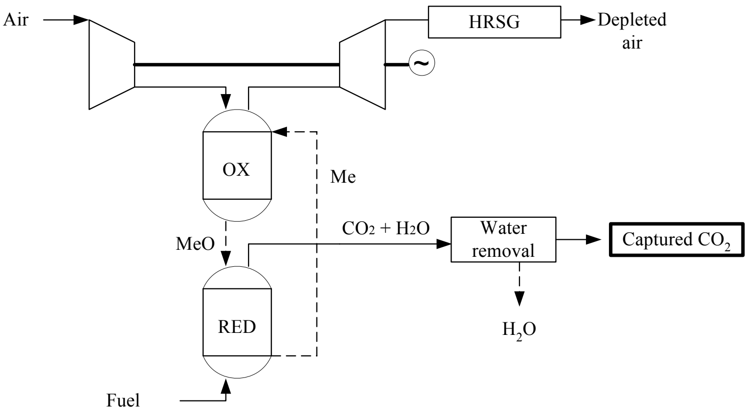


Figure 58: *System configuration for CC with chemical looping combustion*

Principle of separation

The principle of separation that of oxy-combustion. The metal oxide is used as a carrier for oxygen. Dilution with nitrogen from air is prevented. Since the metal and metal oxide are in solid, they can be easily separated from the gaseous phase consisting of a CO_2/H_2O mixture. Water can be removed by conventional means, leaving a CO_2 stream.

Factors determining the CO_2 capture ratio on a system level.

In principle this system has near 100% of CO_2 capture, however some CO_2 will be transported with the metal to the oxidation reactor and will not be captured. (Wolf, Anheden& Yan, 2005) estimate that 98% CO_2 capture can be achieved with natural gas as a fuel.

Possibilities for increasing the CO_2 capture ratio
Minimization of leakage by careful reactor design.

Non-CO_2 emissions
- Sulphur components present in the natural gas and possible small amounts of unconverted fuel (CO, CH_4) will be captured with the CO_2.
- NO_x formed during the fuel conversion step is captured with the CO_2. NO_x formed during oxidation of the metal will be released to the atmosphere with the combined cycle exhaust gases. However, NO_x formation is expected to be lower than in a conventional combined cycle as a result of the much lower peak temperatures in the gas turbine cycle.

B.14 IGCC with chemical looping combustion

Block scheme
The block scheme is similar to that of Figure 58. The chemical looping system is now integrated with the coal gasifier. The fuel is now the fuel gas from the gasifier instead of natural gas. Optionally, the air separation unit may be integrated with the gas turbine, which means that air is withdrawn from the GT compressor and nitrogen is added to the combustion chamber feed.

Principle of separation
Identical to the NG combined cycle with chemical looping.

Factors determining the CO_2 capture ratio on a system level.
In principle this system has nearly 100% of CO_2 capture, However, some CO_2 will be transported with the metal to the oxidation reactor and will not be captured. (Wolf, Anheden& Yan, 2005) estimate that 98% CO_2 capture can be achieved with natural gas as a fuel. For coal gasification the same capture ratio is expected.

Possibilities for increasing the CO_2 capture ratio
Minimization of leakage by careful reactor design.

Non-CO_2 emissions
- It is expected that desulphurisation of the fuel gas will be required, so a sulphur stream will result from the desulphurisation unit.
- Unconverted fuel (CO, H_2) will be captured with the CO_2.
- NO_x formed during the fuel conversion step is captured with the CO_2. NO_x formed during oxidation of the metal will be released to the atmosphere with the combined cycle exhaust gases. However, NO_x formation is expected to be lower than with a conventional combined cycle as a result of the much lower peak temperatures of the gas turbine cycle.

B.15 NGCC with membrane assisted absorption

Block scheme

The block scheme is identical to that of conventional post-combustion NGCC, see appendix B.2 (Figure 41). Except that instead of a packed column a membrane contactor is used. In the membrane contactor, there is no direct contact between the absorption liquid and the gas phase. The absorption liquid flows through a polymer hollow fibre membrane unit with a high mass transfer per unit volume.

Principle of separation

The principle of separation is identical to the combined cycle with MEA absorption. The CO_2 is chemically bonded to the liquid absorbent. Regeneration takes place similar to that for MEA absorption.

Factors determining the CO_2 capture ratio on a system level.

See NGCC-MEA.

Possibilities for increasing the CO_2 capture ratio

Increasing the CO_2 capture could be possible by, e.g., tightening lean solvent specification and increasing the absorption capacity, but would at a higher investment and operational cost. Compared to conventional MEA absorption the equilibrium conditions can be met more easily at lower cost, and lower temperatures allow also for higher CO_2 capture ratios. This means that the basically CO_2 capture rate remains limited by the chemical absorption equilibrium, but this equilibrium can be more closely approached, and by decreasing the temperature the equilibrium can be shifted to conditions more favourable for high CCR values.

Non-CO_2 emissions

See NGCC-MEA. A specific advantage of a membrane contactor is that the emission of the solvent to the flue gas is considerably lower than for typical MEA absorber. Thus, solvent emissions are reduced compared to NGCC-MEA.

B.16 PC with membrane assisted absorption

Block scheme

The block scheme is identical to that of conventional PC with post-combustion CO_2 removal (see appendix B.3, Figure 43). However, instead of a packed column a membrane contactor is used. In the membrane contactor, there is no direct contact between the absorption liquid and the gas phase. The absorption liquid flows through polymer hollow fibre membranes with a high mass transfer per unit volume.

Principle of separation

The principle of separation is identical to the combined cycle with MEA absorption. The CO_2 is chemically bonded to the liquid absorbent. Regeneration takes place in a similar way to that of MEA absorption.

Factors determining the CO_2 capture ratio on a system level.

See PC-MEA.

Possibilities for increasing the CO_2 capture ratio

See PC-MEA. 100% CO_2 capture cannot be achieved, as it would require infinite absorber size. In practice an economic optimum is used. Compared to conventional MEA absorption the equilibrium conditions can be met more easily at lower cost, and lower temperatures allow also for higher CO_2 capture ratios. This means that the basically CO_2 capture rate remains limited by the chemical absorption equilibrium, but this equilibrium can be more closely approached, and by decreasing the temperature the equilibrium can be shifted to conditions more favourable for high CCR values.

Non-CO_2 emissions

See PC-MEA. A specific advantage of a membrane contactor is that emission of the solvent to the flue gas is considerably lower than for a conventional MEA absorber. Thus, solvent emissions are reduced compared to PC-MEA.

B.17 NGCC with oxygen conducting membrane (AZEP)

Block scheme

The block scheme is depicted in Figure 59. Air is compressed by a gas turbine compressor. Then the air is heated further and oxygen withdrawn in a membrane module. The membrane module is equipped with an oxygen selective high-temperature membrane (1075° C (Sundkvist, 2005)). The hot air exhaust is expanded in the gas turbine expander. The off gases from the expander pass through a HRSG.

Natural gas is added to the permeate of the membrane reactor and then fed to a combustor in which the natural gas is combusted. A stream consisting of mainly CO_2 and H_2O results. A large part of this stream is recycled to the permeate side of the membrane module, thus creating a sweep stream and transferring heat to the incoming air. The remaining off-gases are used for heat exchange and steam production. After dewatering a concentrated CO_2 stream results for storage.

Additional firing of natural gas before the GT expander inlet gas may be applied to obtain a significant increase in system efficiency (3.8%-points at 15% additional firing). However, the resulting CO_2 is not captured.

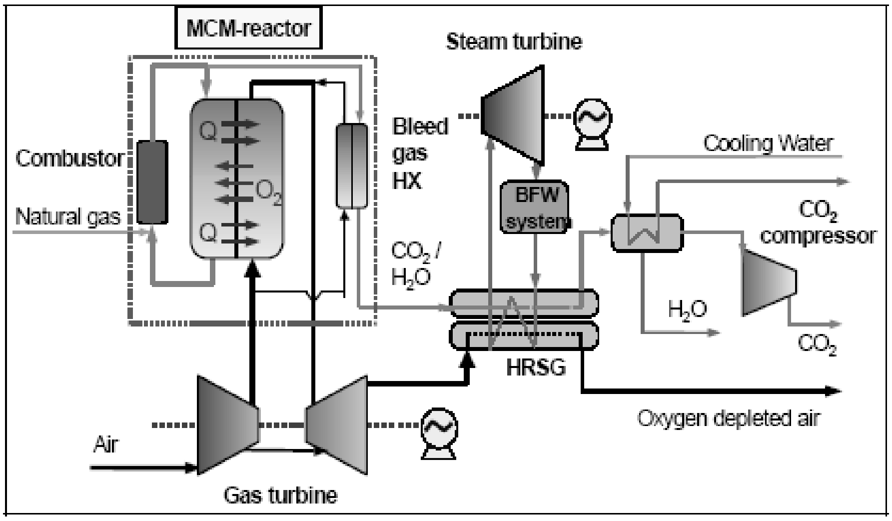


Figure 59: *System configuration for AZEP, (Sundkvist, 2005)*

Principle of separation

The principle of separation is the oxy-combustion principle. The natural gas is combusted in an $O_2/CO_2/H_2O$ atmosphere. After water-knockout a concentrated CO_2 stream results. The membrane module has to perform two tasks: separating oxygen from the air and heat transfer from the permeate side to the feed side. The special combustor is located outside the membrane module, but is an integral part of the concept.

Factors determining the CO_2 capture ratio on a system level.

In principle this system has nearly 100% of CO_2 capture if no additional firing is applied. Additional firing will lower the CO_2 capture ratio. In the 15% additional firing case, the CO_2 capture ratio lowers to 85%. Thus, in this system there is a direct relation between CO_2 capture ratio and system efficiency. No detailed information is available about the extent to which the 100% figure can be approached in practice. Some CO_2 may be absorbed in the condensed water, and some leakage from one side to the other side of the AZEP module may occur.

Possibilities for increasing the CO_2 capture ratio

See the previous paragraph.

Non-CO_2 emissions (Sundkvist, 2005)

- In the 100% capture case NO_x formation will be negligible because of the low temperatures on the air side in the gas turbine cycle. In the case of additional firing, NO_x levels will increase, but will probably be below those of conventional plants.
- Uncombusted fuel (CO, CH_4) will be captured with the CO_2. These components will however be mainly flashed off during liquefaction of the CO_2 stream, together with some N_2 and O_2. Probably 90% of these components can be burned in a catalytic converter and recycled to the CO_2 compression section.

B.18 SOFC-GT with CO_2 capture

Block scheme

The block scheme is depicted in Figure 60. Natural gas is pre-heated, mixed with steam and fed to the SOFC anode. Air is pre-heated and fed to the cathode side of the SOFC. In the SOFC the fuel is converted into electricity. The anode and cathode streams remain separated. Oxygen is transferred through the SOFC membrane. The fuel utilisation in the SOFC has a maximum of about 85%. Larger amounts of fuel converted could damage the SOFC as a result of locally occurring oxidizing conditions at the anode side. The resulting anode off-gas consists of CO_2 and H_2O with unconverted CO and H_2. All CH_4 has been converted into CO and H_2. The unconverted CO and H_2 are converted in an afterburner, so a CO_2/H_2O stream results. After water-knockout a concentrated CO_2 stream results for storage.

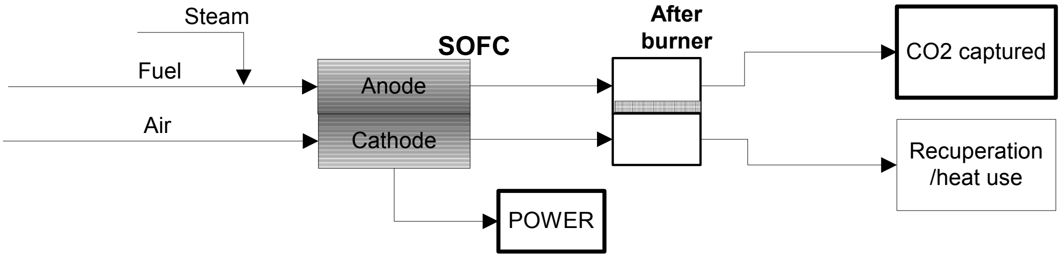


Figure 60: *SOFC with CO_2 capture*

For the afterburner two options exist, see Figure 61. The first type is the OCM afterburner, which uses an oxygen conducting membrane. Oxygen from the air permeates through the membrane and oxidizes the unconverted fuel (CO and H_2). The resulting stream is a CO_2/H_2O mixture.

The second type is the shift membrane burner. The CO is converted to CO_2 and H_2 catalytically, by means of the water gas shift reaction. The resulting H_2 permeates through a hydrogen selective membrane. After permeation, the hydrogen is combusted using oxygen from the air on the other side of the membrane. The retentate CO_2 stream will contain small amounts of H_2 and CO, which can be combusted with air without resulting in a large dilution with air.

Additionally the final oxidation could be done by adding pure oxygen, but this would incur a small efficiency penalty. However this could be compensated to some extent by extra power from the expansion turbine if exit temperatures could thereby be increased.

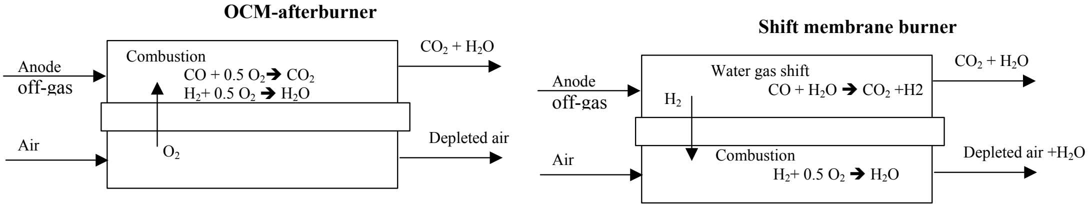


Figure 61: *Working principle of two afterburner types*

The actual system may include integration with a gas turbine. In this case the air originates from a gas turbine compressor, and the cathode exhaust (depleted) air is fed to a gas turbine expander. As with the AZEP system, additional firing may be applied in an additional combustion chamber before the expander. Here natural gas (or anode off-gas) is combusted to raise the turbine inlet temperature and thus increase the system efficiency. The CO_2 resulting from this combustion is not captured.

Principle of separation

The principle of separation is the oxy-combustion principle. The natural gas is converted without dilution with N_2 in the SOFC. The resulting stream is a CO_2/H_2O stream. After waterknockout a concentrated CO_2 stream results.

Factors determining the CO_2 capture ratio on a system level.

In principle this system has near 100% of CO_2 capture. However, in some schemes combustion of natural gas or anode off-gas may be applied on the air side of the system. This may be to heat feed air for the SOFC or for additional firing to raise the expander inlet temperature and to increase efficiency. In this case, the CO_2 capture ratio is significantly below 100%, e.g. 85%. Thus in this system there is a direct relation between CO_2 capture ratio and system efficiency. No detailed information is available about the extent to which the 100% figure can be approached in practice. Some CO_2 may be absorbed in the condensed water, and the streams some leakage from one side to the other side of the SOFC or afterburner module may occur.

Possibilities for increasing the CO_2 capture ratio

The CO_2 capture ratio can be increased by minimizing additional firing, but this will lead to a lower electrical efficiency.

Non-CO_2 emissions

- In the 100% capture case, no NO_x formation is present. In the case of additional firing in GT plants, NO_x will be formed, but levels will be below those of conventional plants.
- Small amounts of unconverted fuel that remain after the afterburner can be flashed off during liquefaction of the CO_2 stream, together with some N_2 and O_2. Probably 90% of these components can be burned in a catalytic converter and recycled to the CO_2 compression

train. Another option is afterburning with air resulting in a limited increase in the nitrogen content of the CO_2.

- The SOFC requires desulphurisation of the natural gas, so SO_x emissions will only result from additional firing and will, therefore, be very small.

B.19 IGCC with SOFC

Block scheme

The block scheme is equal to that of Figure 60, with the difference that the SOFC is integrated with an IGCC; so the fuel is the product gas from a coal gasifier, and integration of the SOFC with the GT integration is used.

Principle of separation

See NG fired SOFC.

Factors determining the CO_2 capture ratio on a system level.

See NG fired SOFC.

Possibilities for increasing the CO_2 capture ratio

See NG fired SOFC.

Non-CO_2 emissions

- SO_x and particulates need to be removed from the fuel gas before it enters the SOFC.
- The other emissions are analogous to the NG fired SOFC.

B.20 PC with CaO for CO_2 capture

Block scheme

The block scheme is depicted in Figure 62. There is little information on the exact lay-out of the process scheme, so the description is limited to the fundamentals of the process. Coal is combusted with air, and the flue gases are led to the carbonator in which at moderate temperature (below 750° C) CO_2 is absorbed with the reaction

$$CaO + CO_2 \rightarrow CaCO_3$$

The $CaCO_3$ is transported to a calciner in which the reverse reaction takes place at high temperature (above 1050° C) producing a hot CO_2 stream. After use of the high temperature heat this CO_2 is available for storage. The heat for the calciner originates from combustion. This heat flux is significant as a result of the large heat of reaction. Constant replacement of CaO is required because of the rapid deactivation of the sorbent.

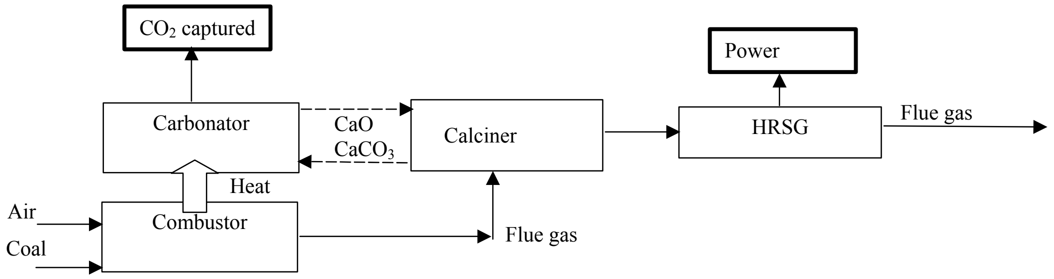


Figure 62: *Block scheme of PC boiler with CaO absorption*

Principle of separation

The principle of separation is that of a gas-solid chemical reaction. The level of CO_2 in the flue gas is limited by the chemical equilibrium composition at the given temperature and pressure. Furthermore the rate of reaction must be sufficiently fast to achieve this chemical equilibrium.

Factors determining the CO_2 capture ratio on a system level.

The CO_2 capture ratio on a system level is determined by the level to which the CO_2 can be removed from the flue gas. This is mainly dependent on the conditions in the calciner. (Marion, 2002) reports that approximately 80% of CO_2 recovery can be achieved with this system. (Abanades, Moliner, 2002) gives a higher figure of above 90%.

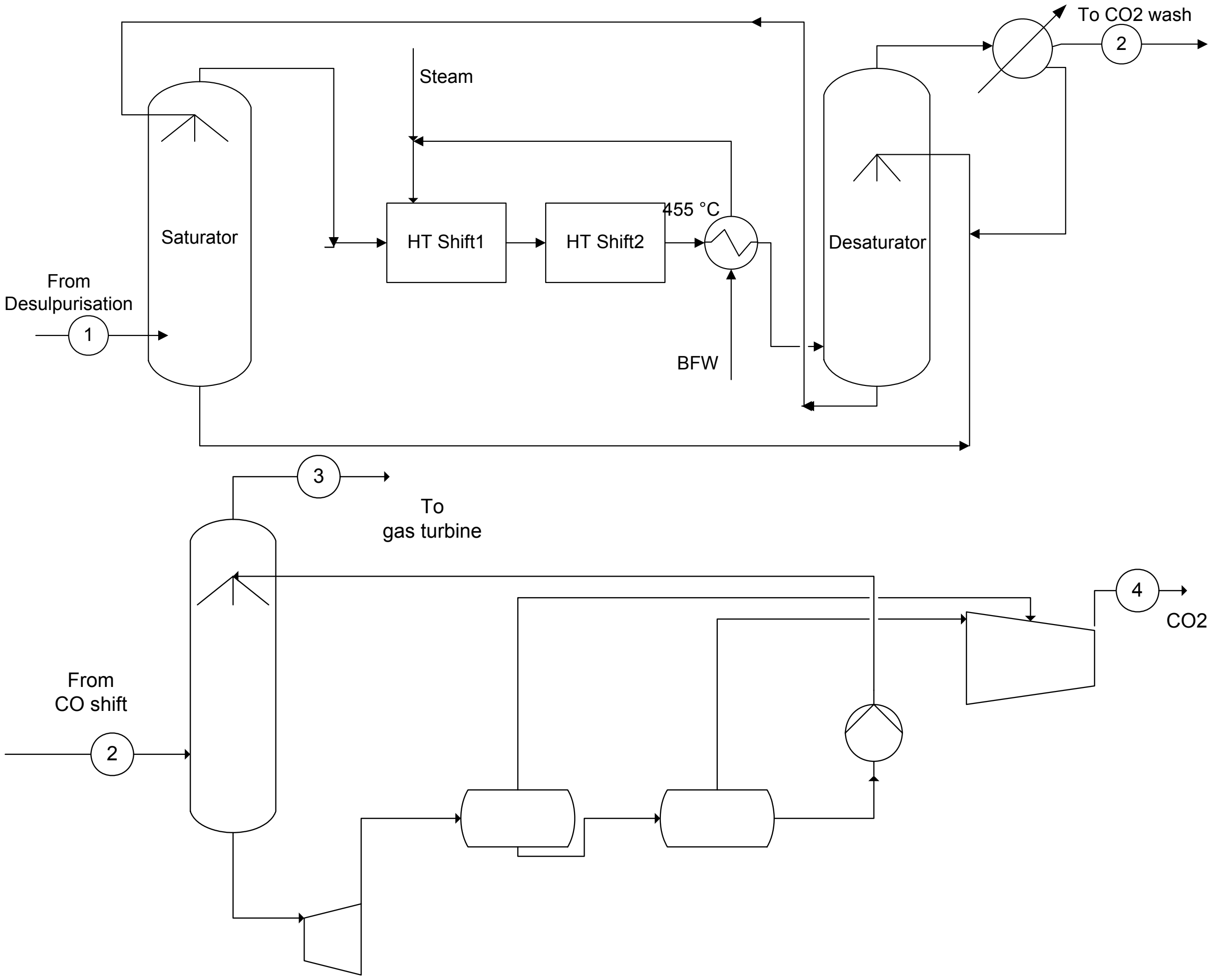
Possibilities for increasing the CO_2 capture ratio

A lower calciner temperature will decrease the flue gas CO_2 content and will therefore increase the amount of CO_2 captured. However a lower calciner temperature will decrease the reaction rate so it will require a larger reactor to reach the equilibrium composition. Furthermore the system efficiency will decrease with lower calciner temperatures. This has indirectly a negative effect on the CO_2 capture ratio. Other improvements could be to use pressurized combustion of coal and also conduct the calcination at elevated pressure. Before the HRSG, expansion of the hot flue gases could be used to gain extra power.

Non-CO_2 emission

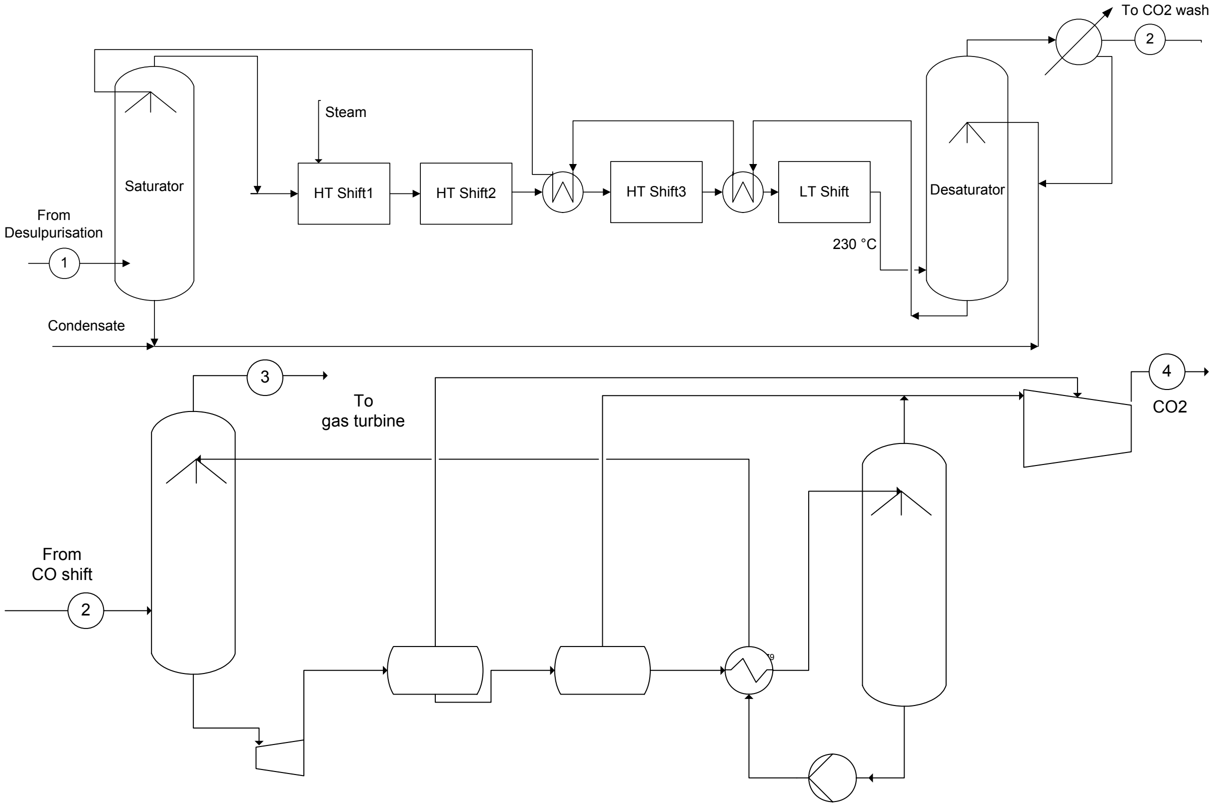
Except for CO_2, the system will have emissions similar to a normal PC boiler, given that the usual technologies for emission reduction are applied. Simultaneous capture of SO_2 and CO_2 in the calciner is also possible as an alternative for conventional sulphur removal options.

Appendix C Pre-combustion capture data



	1	2	3	4	
CO2	1,0	36,4	1,1	99,2	mol%
H2	30,1	55,0	85,8	0,5	mol%
CO	63,9	5,3	8,2	0,2	mol%
CH4	0,0	0,0	0,0	0,0	mol%
Inerts	4,7	3,0	4,6	0,1	mol%
H2O	0,3	0,3	0,3	0,0	mol%
Temp (°C)	0,0	37,0	34,0	35,0	
Press (bar)	0,0	20,0	20,0	110,0	
LHV (MJ)	25474		23108		MJ dry

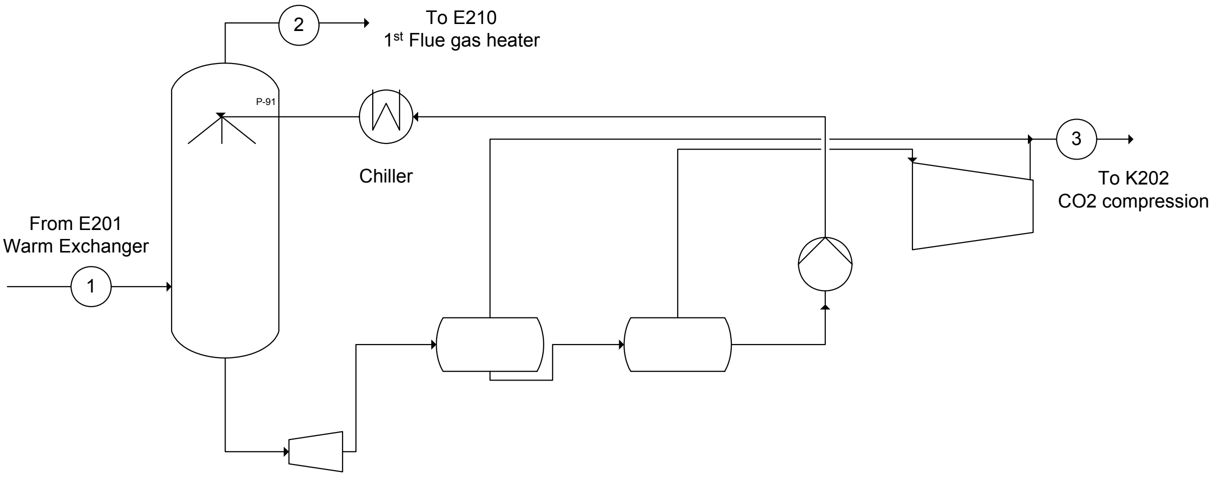
Figure 63*: PFD two-phase shift and* CO_2 *removal*



	1	2	3	4	
CO2	1,0	39,3	0,1	99,4	mol%
H2	30,1	57,1	94,2	0,4	mol%
CO	63,9	0,5	0,8	0,0	mol%
CH4	0,0	0,0	0,0	0,0	mol%
Inerts	4,7	2,9	4,7	0,1	mol%
H2O	0,3	0,3	0,3	0,0	mol%
Temp (°C)	0,0	37,0	34,0	35,0	
Press (bar)	0,0	19,0	19,0	110,0	
LHV (MJ)	25474		22829		MJ dry

Figure 64: *PFD four-phase shift and CO_2 removal*

Appendix D Oxy-combustion PC data



	1	2	3	
CO2	24,6	1,1	94,6	mol%
O2	19,4	25,2	2,3	mol%
Ar	7,1	9,4	0,4	mol%
N2	48,7	64,2	2,7	mol%
NO	0,1	0,2	0,0	mol%
H2O	0,0	0,0	0,0	mol%
Flow	4139	1040	0	kMol/h
Flow	138989	0	0	kgl/h
Temp	7,5	7,5	7,5	°C
Pres	28,9	28,3	9,3	bar

Figure 65: *PFD CO_2 removal from vent stream*