



Universiteit Utrecht



Copernicus Institute for
Sustainable Development and
Innovation



The impacts of CO₂ capture technologies in power generation and industry on greenhouse gases emissions and air pollutants in the Netherlands

Date	8 July 2009
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Keywords	Capture CO ₂ Greenhouse gas Transboundary air pollution
Customer	Ministry of VROM Milieu- en Natuur Planbureau
Reference number	BOLK
Number of pages	164 (incl. appendices)
Number of appendices	8

Preface

This study has been performed for the Netherlands Environmental Assessment Agency / Planbureau voor de Leefomgeving (contact: Pieter Hammingh) within Dutch programme entitled Policy Research Programme on Air and Climate / Beleidgericht Onderzoeksprogramma Lucht en Klimaat (BOLK) for the Dutch Ministry of Housing, Spatial Planning and Environment and Environment / Ministerie van Volkshuisvesting, Ruimtelijke Ordening en Milieubeheer (VROM, contact: Jan Wijmenga). The report presents the final results of a second research phase of one out of four projects conducted within the framework. The first phase report 'The impacts of CO₂ capture technologies on transboundary air pollution in the Netherlands' by Toon van Harmelen (TNO), Joris Koornneef (UU), Arjan van Horssen (TNO), Andrea Ramírez Ramírez (UU) and René van Gijlswijk (TNO) was published in May 2008.

Executive summary

Main conclusions

- Changes in the level of NEC emissions (National Emission Ceiling Directive, being SO₂, NO_x, Particulate Matter, NMVOC and NH₃) are not a bottleneck for CCS implementation. Even for those substances that could increase significantly at the plant level as a consequence of CO₂ capture (e.g. NH₃), mitigation measures can be applied using current available technology without significantly changing the economic feasibility of the options.
- At the national level, PM₁₀, SO₂ and NO_x are the most relevant substances that may be affected by the large scale deployment of CCS. The level of SO₂ emission will most likely decrease (compared to coal fired plants without CCS) while changes in the emission of NO_x strongly depend on the capture and conversion technology applied and on any additionally installed NO_x mitigation measure.
- At the moment, there is no clear winning capture technology; Different types of carbon capture technologies have different development phases and pro's and con's (economically, CO₂ avoidance costs, fuel use, emissions, waste).
- The effect of CO₂ capture on NEC emissions from the Dutch industrial sector in 2020 is largely dependent on the CO₂ capture technology applied at the Corus IJmuiden iron and steel plant. There is a large uncertainty on NO_x emissions. SO₂ emissions will most likely decrease and NH₃ and particulate matter emissions will likely be unaffected.

Introduction

The European Union has committed itself to reducing its GHG emissions by 20% by 2020. In January 2009, the European Parliament called on the EU and other industrialised countries to reduce GHG emissions by between 25% and 40% by 2020 with a reduction of at least 80% to be achieved by 2050 (all compared to 1990 levels).

Carbon Capture and Storage (CCS) is a technological concept to reduce the atmospheric emissions of CO₂ that result from various industrial processes, in particular from the combustion of fossil fuels (mainly coal and natural gas) in power generation. The Intergovernmental Panel on Climate Change (IPCC) regards CCS as “an option in the portfolio of mitigation actions” to combat climate change (IPCC, 2005). Furthermore, the IPCC states in its Special Report on CCS that confidence is required on the environmental performance of full scale capture facilities. One of the key environmental stressors caused by the industry and energy sector that may be affected by deployment of CO₂ capture units is the emission of atmospheric pollutants.

The inclusion of GHG mitigation options in general and of CCS in particular, could have large impacts on transboundary air pollution¹ by a change in (fossil) fuel supply and demand and by the emissions from CCS itself. Therefore, the Dutch Ministry of Housing, Spatial Planning and the Environment (VROM) requires more detailed information on the synergy and/or trade-offs of CCS as well as of other technologies which could be used together with CCS for GHG mitigation and transboundary air pollution (AP) policies. This request has translated into the CCS research being done as part of the BOLK project.

¹ sulphur dioxide (SO₂), nitrogen oxides (NO_x), ammonia (NH₃), particulate matter (PM) and volatile organic compound (VOC).

CCS is one of four projects addressed in the BOLK research. In phase I an inventory of the impacts of different CO₂ capture technologies in the power sector on transboundary air pollution in the Netherlands in 2020 were assessed. Other possible environmental impacts such as toxic emissions and safety were also considered. Recommendations for further research were provided in order to address the current knowledge gaps found on this subject. Phase 2 focuses on the knowledge gaps identified in the first phase of BOLK.

What has been done?

The general aim of the second phase of the project was to generate a more detailed analysis of the effects of different CO₂ capture technologies on transboundary air pollution in the Netherlands in 2020 and 2050. To reach this aim the following activities have been carried out:

- Update existing information on the performance of CO₂ capture technologies, developments in solvents, biomass and CCS and effects on NEC emission factors. Also, the possibilities for deploying CO₂ capture technologies in the Dutch industry were examined. This was done by reviewing international and national literature and also by interviewing international and national CCS and biomass experts.
- Characterization, harmonisation and evaluation of technologies. Parameter standardisation was performed with respect to year, type of plant, costs (OPEX, CAPEX, O&M), interest rates, lifetime, reference technologies, fuel quality (sulphur content) and fuel prices, and CO₂ compression pressure. The standardization of parameters was performed using parameter values representing the Dutch situation.
- Assessment of the effect of implementing CO₂ capture technologies in the Dutch power sector on the emission levels of NEC substances in 2020 and 2050 and in the Dutch industry in 2020. Assessment of effects and costs of additional mitigation measures for NEC emissions.

Effects on air pollutants of CO₂ capture technologies in the power sector

The effects on air pollutant emissions of three types of CO₂ capture technologies have been investigated, viz. post combustion, pre combustion and oxyfuel combustion. All three CO₂ capture technologies are likely to be ready for large(r) scale demonstration before 2020.

For all coal firing conversion technologies, the application of CO₂ capture results in a decrease of **SO₂ emissions** per kWh. Standardisation of the sulphur content of the coal resulted in even lower SO₂ emissions from coal fired power plants with CO₂ capture than indicated in phase 1. It was found that the implementation of all capture technologies will result in very low SO₂ emissions, below the BAT level for power plants.

Standardisation of parameters to assess changes on **NO_x emissions** was not possible due to lack of supporting information in the relevant literature and the amount of factors affecting the end-of-pipe NO_x emission level. Data, as taken from the literature, point out that for facilities equipped with pre- and post combustion capture NO_x emissions seem to increase per kWh almost proportionally with the increase in primary energy demand due to the energy penalty induced by CO₂ capture. In general, NO_x emissions from oxyfuel concepts are expected to be very low, particularly for gas fired concepts.

In this study we have added data sources on **NH₃ emissions** from power plants with post combustion capture resulting in wider range of emission estimates. NH₃ emissions are estimated to significantly increase up to a factor 45 (average 14) compared to coal-fired power plants without capture. NH₃ emissions are also expected to increase at gas fired plants with CCS, although lower rates are expected compared to coal fired plants with CCS. NH₃ emissions are caused by the slip of ammonia (in the case of the chilled ammonia concept) or by the degradation of an amine based solvent that may be used in post-combustion capture. However, NH₃ emissions can be mitigated by implementing additional equipment or by solvent selection. All in all, the uncertainty regarding the estimates is considered to be high but their effect in the national NEC levels is estimated to be low.

The emission of **particulate matter** (PM) from natural gas fired cycles can be considered negligible. For coal fired power plants equipped with post-combustion capture, PM emissions are expected to decrease per MJ primary energy. On a kWh basis, however, PM emissions may also slightly increase due the efficiency penalty. For coal fired oxyfuel concepts PM emissions are estimated in literature to be lower per kWh, compared to conventional pulverized coal fired power plants. The already low PM emissions for IGCC power plants are not expected to be significantly affected due to the application of pre-combustion capture and thus will result in an increase per kWh due to the efficiency penalty. CO₂ capture may lower PM_{2,5} emissions from an IGCC, quantitative estimates are however not available.

It is largely unknown whether and to what extent **NM VOC** emissions are affected by the CO₂ capture concepts.

The costs of CO₂ capture technologies for the power sector

The range of **CO₂ avoidance cost** reported in the literature narrowed significantly due to the parameter standardisation. The obtained results enable the drawing of (more) robust estimates on cost performance of CO₂ capture.

Our results show that an Integrated Gasification Combined Cycle (IGCC) power plant with pre combustion capture could offer the lowest costs in 2020, (between 18 and 27 Euro/tonne CO₂ avoided; results do not include transport and storage costs). This is followed by post combustion capture and oxyfuel combustion capture from coal fired power plants. It should, however, be noted that most of the cost figures reported in the literature are based on the assumption that the technologies are mature. The results therefore do not necessarily imply that in the short and mid term future IGCC with pre-combustion CO₂ capture would be the cheapest.

Biomass and CCS

In principle, all three CCS technological approaches being considered for fossil fuels systems could be applied to bio-energy systems. Biomass is not expected to affect the performance of the CO₂ capture unit significantly. However, the efficiency of co-firing biomass is, on average, 0-10% points lower than the efficiency of coal combustion in a pulverised coal plant due to the lower energy content of biomass. This decrease combined with the energy loss due to the energy penalty caused by the CO₂ capture process constitutes the main drawback of (co-) firing biomass in combination with CCS. In general, co-firing biomass with coal (compared to pure coal firing) provides means to reduce SO₂, PM, NMVOCs and it may reduce NO_x emissions. There is not enough data to make any conclusion about possible effect on NH₃ emissions.

Effects on air pollutant emissions of CO₂ capture technologies in industry

In the **Dutch industrial sector**, cost-effective CO₂ capture may be possible in the year 2020 for the hydrogen production process and iron and steel making process. Additional potential lies in the cement sector. Amine-based CO₂ capture from industrial processes such as cement production, ethylene production and petroleum refineries were found to be expensive. Amine-based CO₂ capture, however, will significantly reduce SO₂ and dust emissions and the co-benefits may be significant. The effect of CO₂ capture on NEC emissions from the Dutch industrial sector in the year 2020 is largely dependent on the type of CO₂ capture that is assumed for the Corus IJmuiden iron and steel plant. CO₂ capture using an oxygen blast furnace may reduce various NEC emissions because such a furnace consumes significantly less coke and coal compared to a conventional blast furnace. Emissions of NO_x are likely to decrease when an oxygen blast furnace is applied, and increase when a conventional blast furnace is applied.

Updated information on solvents and oxyfuel combustion

In this study information is updated compared to BOLK I on the performance of solvents and oxyfuel combustion. The latest information confirms that the development of solvents and its application in post combustion capture is aiming at reducing energy and solvent consumption (e.g. due to degradation) and reducing negative environmental consequences of CO₂ capture. Post combustion concepts using amines can be a source of ammonia emissions when no additional measures are taken. It is possible to reduce the NH₃ emission with (acid) scrubbers, but this will lead to additional costs. The use of other solvents such as potassium carbonate and amine salts, new but still expensive alternatives, will not emit any NH₃ during the capture process. Another possibility being considered is the use of chilled ammonia. However, first results from this process show some increases in ammonia slip.

Updated information on oxyfuel combustion partly comes from experiences with pilot plants. The results suggest that oxyfuel CO₂ capture from coal-fired plants can achieve more than 90% reduction in NO_x, SO_x and dust emissions per unit output compared to emissions from conventional coal-fired plants without CO₂ capture. One of the reasons is that additional removal of these substances is expected in the CO₂ purification and compression process.

Scenario analysis: air pollutants impacts of CCS in the Power sector in 2020

The **power generating** capacity of large scale power plants in the Netherlands is expected to increase from 13.5 GW in 2006 to 18 GW in 2020. CO₂ emissions from this sector will increase from 38 in 2006 to 62 Mtonne in 2020, without the introduction of CCS. In 2020, up to 24 Mtonne CO₂ could be avoided when equipping four new coal fired power plants with CO₂ capture (see Figure 1.1).

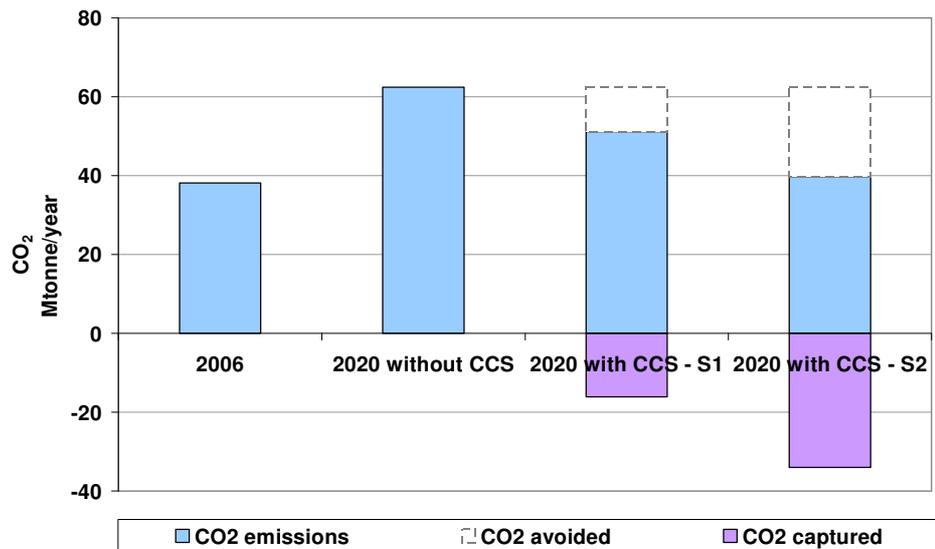


Figure 1.1 Emissions of CO₂ in 2006 and three 2020 scenarios and the avoided and captured CO₂.

Emissions of NO_x, SO₂, PM₁₀ and NH₃ increase in the reference scenario for the year 2020, due to the increase in coal fired capacity without CCS. The introduction of CCS (only post- and pre combustion) is expected to lead to a further increase of NO_x (up to 1.5 ktonne), PM (up to 70 tonne) and NH₃ emissions (up to 0.7 ktonne), see Figure 1.2. SO₂ emissions decrease below the 2006 level. The introduction of CCS leads to a relative large increase (from 0.1 ktonne to up to 0.8 ktonne) in the contribution of the power generation sector to the NH₃ emissions. However, the contribution of the power sector to the national total ammonia emissions stays small compared to the contribution of agricultural sources (more than 100 ktonne).

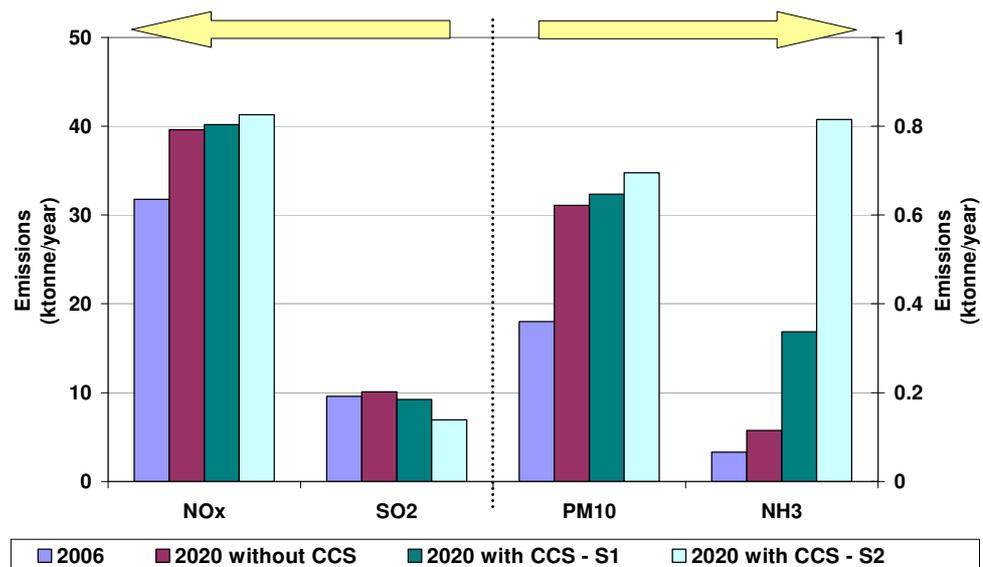


Figure 1.2 Emissions of NO₂, SO₂ (ktonne/year) on left axis and of PM₁₀, NH₃ (ktonne/yr) on right axis, in the Dutch power plant sector in 2020.

The increased cost of mitigating NEC emissions in 2020, compared to the 2006 situation, mainly consist out of the increased costs for air pollution control needed to counteract the projected capacity increase of the power plant sector. The additional mitigation costs due to CCS are small compared to those costs. The SO₂ reduction, needed for post combustion capture with amines, contributes for only a small part to the total costs of CCS (1%).

Scenario analysis: air pollutants impacts of CCS in the Power sector in 2050

Five scenarios with different combinations of combustion technologies with CCS have been constructed for 2050 to examine the effects on air pollutant emissions. Three scenarios are developed with the MARKAL model assuming different CO₂ reductions targets and timing of action. The scenarios consist of:

- *The Business as usual (BAU) scenario* where no climate policy is in place. This means that no CO₂ reduction target is defined for the power and heat sector.
- *In the Postponed Action (PA) scenario* a 15% CO₂ reduction in 2020 and 50% reduction in 2050 in the power and heat sector compared to the CO₂ emission level in 1990 is assumed. This scenario incorporates CO₂ reduction targets from 2020 onwards.
- *In the Direct Action (DA) scenario* a 15% CO₂ reduction in 2020 and 50% reduction in 2050 in the power and heat sector compared to the CO₂ emission level in 1990 is assumed. This scenario incorporates CO₂ reduction targets from 2010 onwards.

For the Direct Action scenario two additional variants are developed focusing on post- and oxyfuel combustion CO₂ capture. These variants are developed to show the effect of the extreme implementation of both technologies.

- In the *Direct Action- post combustion* gas variant (DA-Post) all gas fired power plants in the power and heat sector are equipped with post combustion CO₂ capture. The coal-fired power plants are unaltered in this scenario. This means that all gas-fired power plants are directly equipped or retrofitted with CO₂ capture in the year 2050.
- In the *Direct Action – oxyfuel variant* (DA-Oxy) all new built gas and coal fired power plants from 2010 onwards are assumed to be equipped with the oxyfuel combustion concept. The existing coal power plants are retrofitted with oxyfuel technology.

In the BAU scenario, CO₂ emissions rise from 73 Mtonne in 2030 to 84 Mtonne in 2050 assuming that electricity demand rises until 2020 with 1.6%/yr and between 2020 and 2050 with 0.8%/yr. Also, SO₂, NH₃, NMVOC and particulate matter emissions increase with the increase in generating capacity in this scenario. NO_x emissions however, decrease in the baseline scenario because of the assumed replacement of old pulverized coal power plants by new power plants that emit less NO_x per unit energy output. The most extreme scenario shows a CO₂ avoidance of 79 Mtonne in the year **2050**. It is concluded that NO_x emissions will decrease moderately in most scenarios and that SO₂ emissions decrease considerably in all scenarios, compared to the coal based baseline. Particulate matter emissions will also decrease though to a lesser extent. Only for the scenario with a Pulverized Coal (PC) power plant park equipped with oxyfuel combustion CO₂ capture there was a considerable decrease in PM. Results for NMVOC emissions are uncertain and mainly dependent on the energy conversion technology implemented (PC vs. IGCC). An increase in NH₃ emissions is expected due to the use of amine based solvents in post combustion capture technologies. The more expensive

post combustion is, however expected to have a limited share compared to IGCC power plants with CCS in 2050. Furthermore, the NH₃ emissions from post combustion technologies may prove to be insignificant in the year 2050 due to the development of new solvents and mitigation technologies for NH₃ emissions.

When comparing all scenarios and substances the results suggest that the scenario with the oxyfuel combustion technology widely implemented shows relatively higher emission levels for SO₂, NO_x and NMVOC compared to the other scenarios. However, when taking the results of the pilot projects into account, oxyfuel has the lowest SO₂ and NO_x emissions. Clearly, this indicates that emission estimates suggested in literature are uncertain and possibly too conservative.

A large part of the results is determined by the fact that in the scenarios IGCC power plants equipped with CCS is the dominant technology applied in 2050. The results show a replacement of gas fired capacity by coal fired capacity. The replacement of old plants and an increase in demand is met by IGCC power plants with CO₂ capture. This also means that in our scenarios post combustion capture gradually phases out towards 2050, which has consequences for NEC emissions. Dominant are, for instance, the effects on NH₃ and NO_x emissions. In one variant, 'Direct action post combustion', the NH₃ emissions in 2030 is estimated to be more than a factor 5 higher compared to the reference scenario without CCS.

Scenario analysis: air pollutants impacts of CCS in industry in 2020

The CO₂ emission reduction potential, with costs lower than 50 Euro/tonne avoided CO₂, from the **industrial sector** in the year **2020** was estimated to be up to 8 million tonnes per year. The sources will likely be the pure CO₂ streams and the Corus IJmuiden iron and steel plant. The CO₂ emission reduction potential, however, largely depends on which CO₂ capture technique will be applied to the Corus IJmuiden site. The increase in primary energy consumption due to CO₂ capture and storage from industrial sector will be at least 4 PJ per year, largely dependent on the CO₂ capture technique applied to the Corus IJmuiden site.

With regard to the grand total effect of implementing CO₂ capture in the industrial sector on NEC emissions, it can be concluded from our results that the SO₂ emissions will decrease and NH₃ and dust emissions will remain comparable to the reference case regardless of the CO₂ capture technique applied at the Corus IJmuiden site.

Recommendations for further research

Four research activities are recommended to address the knowledge gaps which were revealed in the present analysis:

- **Improve inventory** on transboundary air pollutants from CO₂ capture technologies by including values taken from *measurements in pilots and demonstration plants*, particularly SO₂, NO_x, PM, NH₃, NMVOC and (other) degradation products of amines, preferably on existing coal and gas fired power plants.
- **Improve application** for the Dutch situation by clarifying the role of European and Dutch legislation, particularly on e.g. CO₂ accounting in emission trading, combustion of waste and storage of other pollutants than CO₂.

- **Refine the analysis** by providing continuous attention to:
 - Novel technologies, including new solvent which are under development
 - Other environmental aspects such as waste and emissions to water
 - Co-firing biomass: impact on NEC emissions of different forms and qualities of biomass, based upon experiences in power plants.
 - Economic and environmental (NEC-emissions) impacts of possible strategies for utilities and industry to mitigate CO₂ emissions by using biomass co-firing and/or CO₂ capture separately or in combination.
- **Improve scenarios** for the Netherlands:
 - policy analysis of both greenhouse gases and transboundary air pollution for 2020 (ECN / PBL)
 - cost-effectiveness analysis of both greenhouse gases and transboundary air pollution for the long term using the energy model MARKAL (UU)

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1 Introduction

1.1 Background

Climate change is a global, long-term problem that involves complex interactions between physical climatic, environmental, economic, political institutional, social and technological processes. Climate change is already happening and represents one of the greatest environmental, social and economic threats facing the planet. To address this threat, the United Nations Framework Convention on Climate Change (UNFCCC) commits all Parties to formulate, implement, publish and regularly update national, and where appropriate, regional programmes containing measures to mitigate climate change by addressing anthropogenic emissions by sources and removals by sinks of all greenhouse gases (GHG). The European Union has committed itself to reducing its GHG emissions by 20% by 2020. In January 2009, the European Parliament called on the EU and other industrialised countries to reduce GHG emissions by between 25% and 40% by 2020 with a reduction of at least 80% to be achieved by 2050 (all compared to 1990 levels). This means that significant changes in the energy and industrial sectors are indispensable.

Carbon Capture and Storage (CCS) is a technological concept to reduce the atmospheric emissions of CO₂ that result from various industrial processes, in particular from the use of fossil fuels (mainly coal and natural gas) in power generation. The Intergovernmental Panel on Climate Change (IPCC) regards CCS as “an option in the portfolio of mitigation actions” to combat climate change (IPCC, 2005). CCS, as the name suggests, comprehends capturing CO₂ from flue gases, transporting and storing it in geological formations instead of releasing it into the atmosphere.

Technology for large-scale capture of CO₂ is to some extent already commercially available (e.g. for some industrial processes such as ammonia) and fairly well developed. However, up to now there are no large-scale power plants operating with a full carbon capture and storage system. Furthermore, the IPCC states in its Special Report on Carbon Capture and Storage that confidence is required on the environmental performance of such full scale capture facilities. One of the key environmental stressors caused by the industry and energy sector that may be affected when implementing CO₂ capture in these sectors is the emission of atmospheric pollutants.

The Directive 2001/81/EC of the European Parliament and the Council on National Emission Ceilings for certain pollutants (NEC Directive) sets upper limits for each Member State for the total emissions in 2010 of the four pollutants: sulphur dioxide (SO₂), nitrogen oxides (NO_x), volatile organic compounds (VOCs) and ammonia (NH₃). Parallel to the development of the EU NEC Directive, the EU Member States are parties of the Gothenburg protocol. Both the NEC Directive and the Gothenburg Protocol are currently under revision, setting emission ceilings to be respected by 2020 for the four already regulated substances and for the primary emissions of particular matter (PM_{2.5}) as well. These targets are being negotiated on the basis of scenarios in which the energy supply and demand systems are a starting point for the discussion on the abatement options and emission reduction targets of a country.

In the period 2008-2011, important policy developments are taking place in the European Union, in the field of climate change mitigation and air quality improvement. While developing new policies and setting new targets, the European Commission attempts to take into account the synergies and trade-offs between climate change mitigation measures and air pollution.

In this context, the inclusion of GHG mitigation plans in general and of CCS in particular could have large impact on transboundary air pollution² by a change in (fossil) fuel supply and demand but also by the emissions from CCS itself. Therefore, the Dutch Ministry of Housing, Spatial Planning and the Environment (VROM) requires more detailed information on the synergy and/or trade-offs of CCS as well as of other technologies which possibly could be used together with CCS for GHG and transboundary air pollution (AP) policies. This request has translated into the CCS research being done as part of the BOLK project.

1.2 BOLK

BOLK stands for the Dutch Policy Research Programme on Air and Climate (Begeleidsricht Onderzoeksprogramma Lucht en Klimaat). It aims to identify gaps in the knowledge on synergies and trade-offs between climate measures and emissions of air pollutants, and attempts to fill these gaps. The programme runs from January 2008 until December 2009 and is split into two phases: Detailed inventory (literature survey, expert interviews) of existing knowledge (BOLK-I) and in depth studies assessing the knowledge gaps identified in the inventory (BOLK-II). In the two phases the following cases are addressed:

- Carbon dioxide and air polluting emissions of biofuels and biomass from production to distribution
- Impacts on air pollution of biofuel use in road vehicles
- Impacts on air pollution of biomass and biofuel use at stationary installations
- Impact on air pollution of carbon dioxide capture technologies
- Integration of the above mentioned projects

For additional information on the BOLK projects and detailed reports on the results of the other cases we refer to:

http://www.pbl.nl/en/dossiers/Transboundaryairpollution/content/Dutch_Policy_Research_Programme_on_Air_and_Climate.html

1.3 CCS in BOLK

Carbon capture and storage is one of the four projects addressed in the BOLK research. The results presented in this study correspond to the second phase of research. In this section we present a brief overview of the main results obtained during the first phase (inventory of existing knowledge and identification of gaps). For detailed results we refer to Harmelen et al. (2008). The objectives of the CCS work in BOLK I were:

² sulphur dioxide (SO₂), nitrogen oxides (NO_x), ammonia (NH₃), particulate matter (PM) and volatile organic compound (VOC).

- To assess the impacts of different CO₂ capture technologies on transboundary air pollution in the Netherlands in 2020. Other possible environmental impacts such as toxic emissions and safety are considered qualitatively.
- To provide recommendations for further research in the in-depth phase 2 in order to address the current knowledge gaps found in this area.

The research was conducted in three steps: Inventory, Evaluation and Impact analysis. Though the industrial sector was somehow analysed, the focus on BOLK-I was on the power generation sector. In terms of technologies, three types of CO₂ capture technologies were investigated, viz. post combustion, pre combustion and oxyfuel.

Key results found in BOLK-I for the power sector are:

- SO₂ emissions are very low for scenarios that include large-scale CCS implementation in 2020, viz. in the order of 1 ktonne SO₂.
- Large scale implementation of the post combustion technology on existing coal fired plants in 2020 may result in (slightly) higher NO_x emissions compared to the implementation of the other CO₂ capture technologies or no capture.
- Large-scale implementation of the post combustion technology in 2020 may result in more than 5 times higher NH₃ emissions compared to scenarios without CCS and with other CO₂ capture options, if the issue of NH₃ emission control is not addressed.
- Particulate Matter emissions are equal or higher than in the NEC5 scenario. In the latter case, retrofitting pulverized coal plants with post combustion capture results in higher PM emissions than from pre combustion on IGCC. The scenario with large-scale implementation of the oxyfuel technology shows the lowest emissions of particulate matter.
- NMVOC emissions from capture technologies are less well known than emissions from other pollutants.
- The effect of biomass (co-)firing in power plants with pre or post combustion CO₂ capture is not well researched, although it seems likely that both SO₂ and NO_x emissions will be lower, since the sulphur content and the flame temperature will be lower for biomass than for coal. For other emissions was not possible to make an educated guess.
- The indirect emissions of CCS (upstream flows) exceed the direct emissions in most cases for all NEC substances. The major part of these indirect emissions is caused by mining, preparation and transport of coal. In general CO₂ capture is likely to increase emissions of transboundary air pollutants over the lifecycle due to increased fuel consumption in the order of 15% to 25% depending on the capture technology type. The geographical location of emissions due to fuel preparation is outside the Netherlands and therefore do not influence the Dutch national emission ceilings and standards.

The results however show some caveats and gaps in knowledge, namely:

- NEC emissions have been estimated by applying simple CO₂ capture correction factors on the IIASA's NEC emission factors. These correction factors were calculated by the emission ratio of plants without and with CO₂ capture from the literature inventory. These factors *do not take into account country specific* situations with respect to plants and fuel quality.
- There are uncertainties in the cost estimates of capture technologies. Though some standardization efforts were conducted, important differences between studies remain with regard to the energetic performance and important cost parameters (capital cost, project lifetime, interest rate, O&M cost and fuel cost). A *harmonization* of these kinds of parameters would allow for a better assessment of the potential of each technology.
- The technology descriptions of CO₂ capture technologies indicated that a number of opportunities exist for capture of CO₂ emissions from the industry. The total CO₂ emissions from the large industrial sources interesting for CO₂ capture were estimated at about 20 Mt per year (c.a. 10% of the national CO₂ emissions). However, the costs of applying a CO₂ capture technology in an industrial process highly depends on the situation, e.g. can it be fitted in taking into account the availability and security of the plant and its production? Further research into the *industrial sector*.
- A combination of *biomass and CCS* could provide extra opportunities in terms of CO₂ mitigation options (i.e. by achieving negative emission). This option needed to be analysed in more detail.
- The level of net emissions identified in BOLK-I assumes that non-additional *mitigation measures* (e.g. de-NO_x equipment) are deployed. It remains a question the costs that such mitigation measures would imply.

Addressing these aspects constitutes the main core of this study.

1.4 CCS in BOLK II: Objective

The general aim of the second phase of the project is to generate a more detailed analysis of the effect of different CO₂ capture technologies on transboundary air pollution in the Netherlands in 2020 and 2050. To reach this aim several objectives have been formulated:

- To extend and harmonize the data on the environmental, economical and energetic performance of different types of CO₂ capture technologies implemented in the power sector to make a more balanced evaluation of capture technologies possible.
- To assess in more detail the effect of using a variety of solvents during CO₂ capture.
- To assess the impacts on atmospheric emissions when CO₂ capture technologies are implemented at existing facilities in the Dutch industrial sector.
- To assess the effect of co-firing biomass on the environmental, economical and technical performances of power plants equipped with CO₂ capture technologies.
- To assess the additional mitigation measures for atmospheric emissions and assess its impacts in terms of costs and technical configuration of CO₂ capture systems.

- To assess the impact of various implementation scenarios for CO₂ capture technologies on nationwide NEC emissions levels for:
 - The industrial sector in 2020
 - The power sector in 2020
 - The power sector in 2030/2050

With this second phase, the project generates strategic information needed for air quality and climate policy making, specifically with regard to the Dutch National Emission Ceilings and CO₂ target reduction for 2020 and 2050. The inventory summarises all (public) available information that is relevant for transboundary air pollution and presents it in understandable terms for environmental experts and policymakers who are not CCS experts.

The project reviews the present, scientific and available literature and interviews the national and international experts in the carbon capture and biomass community aiming to present the most up-to-date insights on CO₂ capture technologies, particularly with respect to transboundary air pollution. The gathered information is combined with scenario information on the implementation of carbon capture technologies in the Dutch power and industrial sector to provide insight into possible effects of wide scale implementation of this technology on transboundary air pollution in 2020. It further provides a concise panorama for the longer term (2030-2050).

1.5 Reading instruction

The structure of this report is as follows:

Chapter 2 explains in detail the methodology used and the research process followed in the project. Chapter 3 describes the results from the parameters standardization. Chapter 4 updates the technology Assessment carried out in the first phase of Bolk, introduces novel solvents and co-firing biomass with CCS. In this chapter the possibilities to deploy CO₂ capture in the Dutch industrial sector are also presented as well as a general description of air pollution mitigation options. Chapter 5 presents a comparative analysis, a what-if emission scenario analysis for the impact of CO₂ in the Dutch power generation and industrial sector for 2020, 2030 and 2050. Finally, Chapter 6 shows the main conclusions of the work conducted in the both phases of BOLK and provides recommendation for further research.

2 Approach

2.1 Overall methodology

The impact of the deployment of CO₂ capture on the national emission ceilings of transboundary air pollution are assessed in this report for the Netherlands in 2020 and 2050. Out of the whole CCS chain, the focus of this project remains on CO₂ capture technologies (transport and storage of CO₂ are not analysed). This report tackles two main sectors: the power sector and industry with (almost) pure CO₂ streams. Additionally, special attention has been placed to the impacts of co firing biomass when combined with CCS. Also an in-depth review of the solvent that could be used in post-combustion capture has been performed. The focus is on first generation, i.e. the most mature capture technologies that are expected to be ready for implementation in 2020. Second generation technologies (e.g. direct chilling, membranes etc.) are not analysed in detail due to the lack of available data on their environmental performance and cost. Moreover, the focus of this report is mainly on transboundary air pollution and national emission ceilings; hence, other environmental issues including indirect emissions (from the up-or downstream parts of the life cycle) are not included in the scenario analysis. Life cycle analysis on CCS was already reported in the first phase of BOLK (Harmelen et al., 2008).

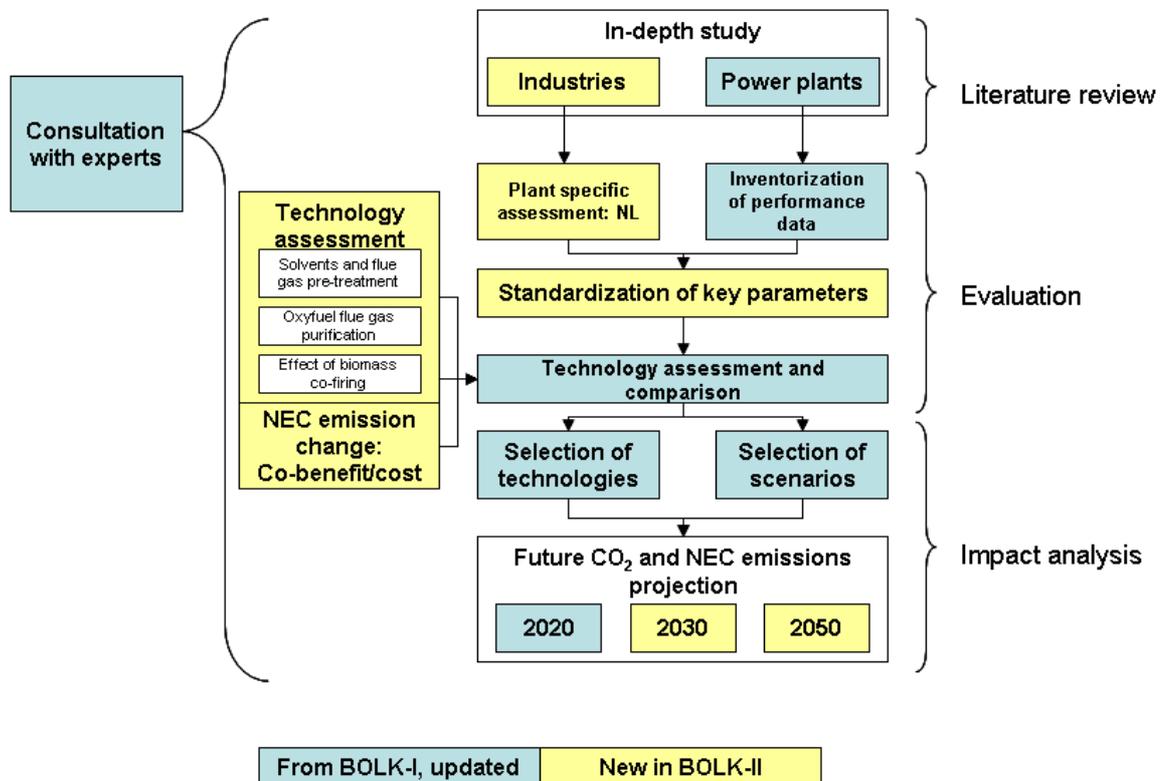


Figure 2.1 Sketch of the methodology followed in this project.

The methodological approach can be schematised in three main steps (see Figure 2.1):

- 1) *Inventory*, based on in-depth literature review and consultations with national and international experts (the list of experts is presented in the next section).
- 2) *Evaluation*, including the characterization of CO₂ capture technologies, associated costs, harmonization and assessment of the available data and finally comparison and assessment of technologies.
- 3) *Impact analysis*, with specific attention to the effects of CO₂ capture in the Dutch public electricity sector (2020, 2030 and 2050) and industrial sectors in the Netherlands (2020). The selected technologies are end-of-pipe technologies.

Moreover, the same steps are also applied for two aspects: co-firing biomass with CCS as well as for the analysis of a variety of solvents used for post combustion capture. In this way the project generates strategic information needed for air quality and climate policy making.

2.2 Literature review and interviews

The first step in the project was to gather existing information on CO₂ capture technologies and NEC emission factors. This was done by reviewing international and national literature and also by interviewing international and national CCS and biomass experts. Since CCS is considered as an important option for mitigation climate change there is a relatively large quantity of available information. A structured approach using explicitly defined criteria is applied to collect, aggregate and present the information. It should be mentioned that despite efforts made to harmonize the data collected essential differences remain, especially in the methodologies used, scales considered, assumptions made on technical performance and economic factors present in the studied literature. This is explained in more detail in the next section.

As part of the approach taken, interviews with (inter)national experts were conducted. A main condition was that besides knowledge in the area, the national experts would have an understanding of the Dutch context and application of CCS in the Netherlands and are active players of the international CCS community. The expert panel consisted of:

- Jean Pierre Birat (Arcelor Mittal)
- Arjen Boersma (ECN, Unit Biomass, Coal and Environmental Research, Department Heat and Power)
- Kay Damen (NUON)
- Earl Goetheer (TNO, Post Combustion/Solvents expert)
- Gerard Jägers (Corus Steel)
- Ton Pereboom (ENCI)
- Pierre Ploumen (KEMA, Plant configuration expert)
- Jiri van Straelen (Shell)

Even though the topic of biomass with CO₂ capture (BECS) is a promising one, available literature and research attention is very limited and is mainly based on process modelling and economic evaluations. In order to obtain deeper insights the following international experts were interviewed:

- Noim Uddin (Lead Climate Change Verifier, Det Norske Veritas Australia and New Zealand)
- Kenneth Möllersten (Swedish Energy Agency)

- James S. Rhodes (Carnegie Mellon University, Department of Engineering and Public Policy)

The consultation resulted in valuable insights into the limitations, strengths and weakness of the published knowledge and available data.

2.3 Characterization, harmonisation and evaluation of technologies

2.3.1 CO₂ capture technologies

Large carbon dioxide point sources will be the main application for carbon capture. They include fossil fuel power plants, fuel processing plants and other industrial plants, such as iron, steel, cement and bulk chemical plants. Capturing from small and mobile sources is expected to be more difficult and expensive. There are four basic systems for capturing CO₂ from use of fossil fuels and/or biomass, schematically drawn in Figure 2-2.

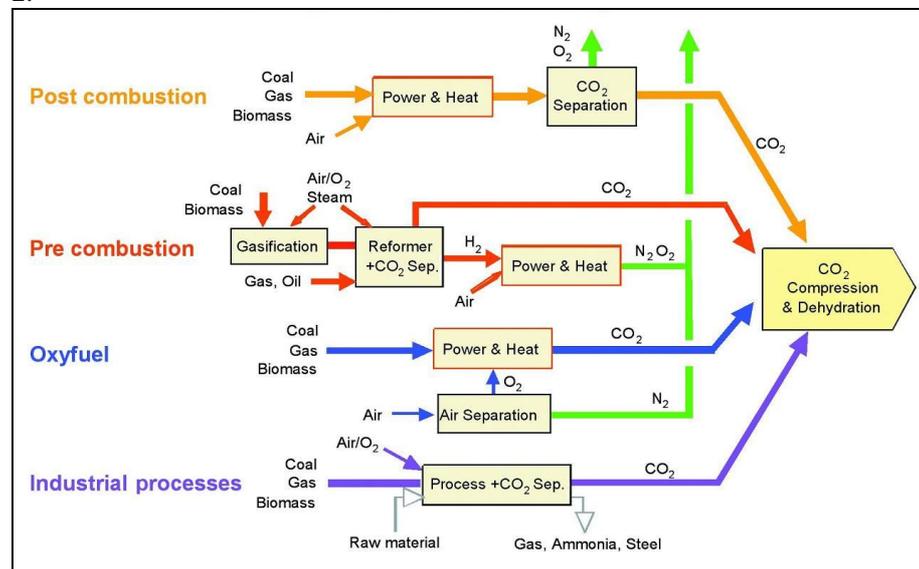


Figure 2-2 Carbon Capture Technologies (IPCC, 2005b).

Post combustion capture

Capturing the CO₂ from the flue gas, produced by a combustion process is called post combustion capture. The flue gas is passed through separation equipment, which separates the CO₂. The CO₂ can be then transported and stored underground; the remaining gas is discharged into the atmosphere.

Pre combustion capture

Syngas, containing carbon monoxide (CO) and hydrogen (H₂), is produced by the reaction of a fuel and oxygen or air and/or steam. The CO is shifted to CO₂ with steam in a catalytic reactor. The CO₂ is separated from the H₂ rich gas, which can be used in other applications (e.g. as bulk product or for power generation).

Oxyfuel combustion capture

In the oxyfuel combustion process, nearly pure oxygen is used for the combustion instead of air. The resulting flue gas contains mainly CO₂ and H₂O, which can be easily separated.

Capture from industrial processes

CO₂ has been captured from industrial process streams for decades. Examples are the purification of natural gas, and the production of hydrogen containing synthesis gas for the manufacturing of ammonia, alcohols and synthetic liquid fuels. Other CO₂ emitting industries are cement, iron and steel production (IPCC, 2005b).

The technologies for capturing CO₂ using the first three routes are described in detail in (Harmelen et al., 2008); IPCC, 2005).

2.3.2 Standardisation of parameters: a fairer comparison of different CO₂ capture technologies

This report departed from the inventory on transboundary air pollutants from CO₂ capture technologies developed in BOLK-I. The collected data contained specific parameter assumptions that were not further processed in BOLK-I. To compare data from various literatures on an equal footing, standardisation of some, if not all, important parameter values is necessary.

The parameter standardisation is performed with respect to year, type of plant, costs (OPEX, CAPEX, O&M), interest rates, lifetime, reference technologies, fuel quality and fuel prices, and CO₂ compression pressure. The standardization of parameters was performed using parameter values representing the Dutch situation.

Moreover, new publications in the last 12 months have also been added to the inventory. Many of these publications are from the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9) held in Washington D.C. in November 2008.

In addition, it was found in the inventory that some research results were doubly reported in forms of, e.g. peer-reviewed article, conference proceedings or a general project report. These doubly reported research results have been filtered in BOLK-II.

It is worthwhile to note in advance that a number of studies reviewed in BOLK-I and II provide emission figures based on the assumption that the power plant in question meets the local environmental regulations. These figures therefore do not represent realistic emissions performance of the power plant.

CO₂ compression pressure

The CO₂ compression pressure values found in the literature ranged between 80 and 200 bar. In BOLK-II, the CO₂ compression pressure is standardized to 110 bar. Net power output and capital investment costs of each power plant are adjusted accordingly. The adjustment methodology is described in Appendix A.

Sulphur emission: standardised sulphur content in coal

The sulphur (SO₂) emission data was adjusted by standardizing the sulphur content in the coal to the current coal mix used in Dutch power plants. SO₂ removal efficiencies of Flue Gas Desulphurisation (FGD), Acid Gas Removal (AGR) and CO₂ capture units were assumed to remain constant. The standardized parameter values are presented in Table 2.1 together with the range of values found in the literature.

Table 2.1 Coal specification parameters (Standardised value based on the 2007 data from Electrabel, 2008).

Parameter	Unit	Value	Literature value
Average S content (assumed wt% dry)		0.78%	0.22% - 2.98%
Heat content (as received, LHV)	MJ/kg	24.8	10.5 – 32.1
Sulphur emission factor per heat content (LHV)	g/MJ	0.31	0.12 - 0.97

The assumptions shown in Table 2.1 may seem unfair for power plants using low-sulphur coal, because their aim is to meet the environmental regulations, not the SO_x removal efficiency *per se*. Nevertheless in the future, under more stringent environmental regulations, it can be expected that power plants will have to install a state-of-the-art de-SO_x unit.

For oxyfuel PC plants, SO_x emissions largely depends on whether or how the CO₂-rich gas is treated before being compressed and transported to the storage site. Some reports do not include CO₂-rich gas purification units within the system boundary (Andersson, 2007; one case in Davison, 2007; four cases in DOE and NETL, 2007), while other reports do. It has been suggested that SO_x should be removed to meet the CO₂ transport pipeline specifications (e.g., de Visser et al., 2008). Co-storage of SO_x is unlikely to happen in the Netherlands not only because of CO₂ transport pipeline specifications to avoid corrosion, but also because of the CO₂-purity requirements for CO₂ storage, i.e. co-storage will probably not be allowed (EU, 2009).

Regarding the emissions for the systems without CO₂-rich gas purification, the data are omitted from the analysis since co-storage will most probably not be allowed in the EU. Although we wish to estimate pollutant emission levels after the purification process, the pollutant removal rates are dependent on the type of purification process installed.

For the literature data with CO₂-purification process taken into account, the sulphur content of the coal is standardised to the level of a coal mix used in Dutch power plants (see Table 2.2), it was assumed that the overall system SO_x removal rate remain constant after the standardisation.

NO_x: no standardization applied

End-of-pipe NO_x emissions are influenced by both the NO_x generation levels and the NO_x removal efficiency. The former is influenced by, e.g. combustion temperature, fuel burner type and excess oxygen rate. The latter is influenced by, e.g. selective catalytic reduction (SCR) and acid gas removal (AGR) efficiencies. The combination of technologies strongly depends on factors such as environmental regulations and total costs. Consequently, it is not surprising to find a wide range of end-of-pipe NO_x

emissions in the literature. Standardisation of NO_x emission is however not possible due to lack of supporting information in the relevant literature.

NH₃: Calculated with available data

In BOLK-I, information on NH₃ emissions from power plants with and without CO₂ capture was scarce. However, an in-depth analysis of the inventory has found that it is possible to generate estimates of NH₃ emissions using available data and a number of assumptions. The methodology used is described in Appendix B.

Dust (particulate matter): no standardisation applied

Amount of data available in the literature on dust removal performance in power plants with and without CO₂ capture was insufficient to perform standardisation of any parameter value.

Standardisation of parameters for economic performance evaluation

The parameters and their standardized values for a fair comparison of economic performance of CO₂ capture technologies are presented in Table 2.2. For both coal and natural gas, higher prices were assumed for the year 2020 compared to current prices.

Table 2.2 Parameter values standardised for economic performance calculations in this study.

Parameters	Unit	Value	Literature value range and notes
Currency and year		2008 Euro	
Adjustment factors for inflation and material price increase for power plants			Chemical Engineering Plant Cost Index (CEPCI, 2009)
Conversion rate	\$/Euro	1.47	From (OANDA, 2009)
Coal price	Euro/GJ	2.77 (IEA, 2008)	0.78-2.56 (in 2008 Euro)
Natural gas price	Euro/GJ	8.38 (IEA, 2008)	2.47-6.52 (in 2008 Euro)
Total capital requirement / total plant cost *		110%	6.4% - 12.0%
Total plant cost / process plant cost *		130%	21.4% - 33.1%
O&M cost	% TPC	4%	1.2% - 5.5%
Capacity factor: coal power plants		75%	65% - 91.3%
Capacity factor: NGCC		75%	65% - 95%
Discount rate: utilities		10%	8% -10%
Economic lifetime: coal power plants	years	30	20-30
Economic lifetime: natural gas power plants	years	25	25-30
Capacity factor: coal power plants		75%	65% - 91.3%
Capacity factor: NGCC		75%	65% - 95%

* Process plant cost (PPC) comprises equipment cost and installation costs. Total plant cost (TPC) comprises PPC and engineering fees and contingencies. Total capital requirement (TCR) comprises TPC, owner costs and interests during construction.

2.3.3 *Solvents in absorption and adsorption processes (Section 4.1)*

Solvents play an important role in both post and pre combustion CO₂ capture processes. The focus in this report is on post combustion capture, because solvent related emissions from this technology could be emitted into the atmosphere. In the case of pre-combustion capture, solvent related emissions are burned or end up in the CO₂ stream and are not emitted to the air. The inventory made in BOLK -I pointed out CO₂ capture (amine based) solvent in post combustion processes as responsible for a large increase in NH₃ emissions at the plant level. In BOLK-II various solvents are assessed in more detail. With this aim, the concept behind the solvent capture process is briefly described, as well as key solvents which are currently being investigated as promising for capture processes. Examples of pilots are given to indicate at which scale the capture process is available. Trends in solvent development are mentioned, which describe the main bottlenecks to be solved in using solvents. Finally the solvent related emissions from the inventory are summarized.

2.3.4 *CO₂ capture from industrial processes (Section 4.4)*

The industrial sector is one of the largest CO₂ emitters in the Netherlands. In 2006, the Dutch industrial³ and petroleum refining sectors accounted for about 35 million tonnes and 10 million tonnes of CO₂ emissions, respectively (MNP, 2008). In BOLK-I, only CO₂ capture from iron and steel process was investigated as a part of pre-combustion capture technology assessment. In BOLK-II the scope is broadened. Economic and environmental performances of CO₂ capture from various industrial sectors are investigated. With regard to timeframe, the implementation of CO₂ capture in the mid-term future (2020-2025) was considered. All the economic data are compared on the basis of standardized key parameter values as presented in 2.3.2.

2.4 Scenario analysis and assessment of impacts

The main goal of the scenario analysis is to assess the effect of implementing CO₂ capture technologies in the Dutch power sector on the emission levels of NEC substances in 2020 and 2050. In the rest of this section the methodology used to develop the scenarios is explained in detail.

2.4.1 *Power generation*

To analyze the effect of CCS implementation on the power sector two scenarios have been developed: 2020 and 2030-2050. A key difference between the two scenarios is that in the former case (i.e. 2020) emission levels have been calculated based on the maximum emission loads allowed in the environmental permits, while in the scenarios 2030-2050 emissions factors based on IASA data have been used (this was the approach taken in BOLK-1). The reason behind using maximum loads for the 2020 scenario is that this allows taking into account specific conditions of the current plants and of the plants being built in the Netherlands. A complete overview of the differences between the methodologies used in BOLK-I and BOLK-II is shown in Table 2.4.1. Box 1 summarizes main aspects of the methodology used in BOLK-I. For a more detailed overview we refer to Harmelen et al. (2008).

³ Includes the following sectors: "Manufacturing industries and construction" and "Industrial Processes".

Box 1. Summary of the methodology used in BOLK-I for scenario analysis.

In order to illustrate the impact of different types of CO₂ capture options, in BOLK-I a baseline scenario without climate policy measures and two CO₂ mitigation scenarios stemming from van den Broek et al., (2008) were used. Furthermore, two variants were added to illustrate the impacts of several other CO₂ capture technologies which were not present in the technology mix of the scenarios of van den Broek.

For the scenarios, transboundary air pollution of technologies without capture was calculated using emission factors from the Dutch part of the GAINS model run by IIASA for the update of the NEC directive (June 2007). This scenario defined emission factors for the power production technologies installed in the year 2020 in the Netherlands. However, no emission factors are defined for technologies that are equipped with CO₂ capture technologies. Therefore, a simple approach was used to estimate the emission factors for technologies equipped with CO₂ capture in the year 2020. The emission factors for air pollution from power plants with CO₂ capture were calculated by multiplying the technologies without CO₂ capture with a Relative Factor derived from the technology assessment. This factor is the ratio of emissions in a plant with and a plant without CO₂ capture as calculated in a literature source. This ratio includes both the emissions due to the new capture technology and the change in emissions from the power plant due to increasing fuel consumption caused by the capture technology. When possible, the factors were calculated for each individual case in the gathered literature.

The emission factors from the GAINS model are then multiplied with the Relative Factor to acquire an emission factor (per PJ fuel input) that is differentiated for power production technology, new or existing power plant, and CO₂ capture technology. The estimated fuel requirements in each scenario are then multiplied with the emission factors to estimate the emission levels for NEC substance in 2020 from large-scale electricity production.

Table 2.3 Characteristics of scenario analyses applied in BOLK I and BOLK II.

Project	BOLK I	BOLK II	
	2020	2020	2030/2050
Target year scenario analysis	2020	2020	2030/2050
Composition power sector target year	MARKAL model scenarios based on cost optimization	As planned by companies – expert opinion	MARKAL model scenarios based on cost optimization
GDP growth annually	1.6 %	-	1.6 %
Electricity demand growth annually	2005–2020: 1.5%	-	2005–2020: 1.5% 2020–2050: 0.8 %
Electricity demand (TWh)	2020: 138	-	2030: 149 2050: 175
Scenarios	1. Business as usual (BAU) 2. Postponed Action 3. Direct Action 4. Direct Action- post combustion gas	1. Without CCS (BAU) 2. With CCS -S1 (2 coal fired power plants) 3. With CCS -S2	1. Business as usual (BAU) 2. Postponed Action 3. Direct Action 4. Direct Action- post combustion gas

Project	BOLK I	BOLK II	
Target year scenario analysis	2020	2020	2030/2050
	5. Direct Action – oxyfuel 6. IIASA NEC5 2020	(all coal fired power plants)	5. Direct Action – oxyfuel (6. Oxyfuel demo)
Emission data – no CCS	IIASA emission factors year 2020	As permitted/reported	-NH ₃ and SO ₂ standardized emission factors -Remaining: IIASA emission factors year 2030
Emission data – with CCS	Emission factors IIASA 2020 adapted with relative factors	Permitted/reported data adapted with relative factors	-NH ₃ and SO ₂ standardized emission factors -Remaining substances: Emission factors IIASA 2030 adapted with updated relative factors

BOLK II: Power generation 2020

The scenario analysis for the power generation sector in 2020 are based on the current and planned public electricity sector development in the Netherlands and the opinion of experts on the introduction of CCS.

The impact analysis for applying CCS to the Dutch power plant sector in 2020 is based on three scenarios:

- **2020 without CCS:** No CCS is applied to the power plant sector in 2020
- **2020 with CCS -S1:** CCS is applied to two new coal fired power plants:
 - Integrated Gasification Combined Cycle (IGCC) – NUON (Eemshaven) equipped with pre combustion CO₂ capture.
 - Pulverized Coal (PC) – EON (Maasvlakte) equipped with post combustion CO₂ capture.
- **2020 with CCS -S2:** CCS is applied to all new coal fired power plants:
 - IGCC – NUON (Eemshaven) (pre combustion)
 - PC – EON (Maasvlakte) (post combustion)
 - PC – Electrabel (Maasvlakte) (post combustion)
 - PC – RWE (Eemshaven) (post combustion)

These CO₂ capture technologies are chosen as these are expected to be commercially available by 2020 and most likely be applied on those energy conversion concepts. The NUON IGCC is currently being designed with pre combustion capture implementation in mind. The PC power plants are most likely equipped with post combustion capture as retrofitting with this technology is considered to be easier compared to retrofitting with oxyfuel combustion technology.

As noted in the previous section, the emission factors for the plants without CCS are, in this scenario, based on the maximum loads, which the power plants are allowed to emit

by their permits. The emissions of the power plants with CO₂ capture are estimated by the use of the relative factors quantifying the relative change in the emission factor caused by the implementation of a certain CO₂ capture technology (see Box 1). For a detailed description of the methodology for deriving the relative factors see (Harmelen et al., 2008).

Power generation 2030 and 2050

For the scenario analysis for 2050 basically the same approach as presented earlier in (Harmelen et al., 2008) is followed. Three of the scenarios used in that study are being used here though the time horizon has been extended from 2030 to 2050:

- *The Business as usual (BAU) scenario* where no climate policy is in place. This means that no CO₂ reduction target is defined for the power and heat sector.
- *In the Postponed Action (PA) scenario* a 15% CO₂ reduction in 2020 and 50% reduction in 2050 in the power and heat sector compared to the CO₂ emission level in 1990 is assumed. This scenario incorporates CO₂ reduction targets from 2020 onwards.
- *In the Direct Action (DA) scenario* a 15% CO₂ reduction in 2020 and 50% reduction in 2050 in the power and heat sector compared to the CO₂ emission level in 1990 is assumed. This scenario incorporates CO₂ reduction targets from 2010 onwards.

For the Direct Action scenario two additional variants are developed focusing on post- and oxyfuel combustion CO₂ capture. These variants are developed to show the effect of the extreme implementation of both technologies.

- In the *Direct Action- post combustion gas variant (DA-Post)* all gas fired power plants in the power and heat sector are equipped with post combustion CO₂ capture. The coal-fired power plants are unaltered in this scenario. This means that all gas-fired power plants are directly equipped or retrofitted with CO₂ capture in the year 2050.
- In the *Direct Action – oxyfuel variant (DA-Oxy)* all new built gas and coal fired power plants from 2010 onwards are assumed to be equipped with the oxyfuel combustion concept. The existing coal power plants are retrofitted with oxyfuel technology.

Following (Broek, 2008), in this study second and third generation CO₂ capture concepts are not taken into account in the scenario analysis for 2030 and 2050. Advances in energy conversion technologies are taken into account in the analysis. New conversion and CO₂ capture technologies may emerge and become commercially attractive before 2050. However, since these technologies are currently at best in the lab phase, detailed quantitative data on emissions from these technologies are not available. This is the main reason for exclusion.

Use of emission factors and relative factors

For the substances SO₂ and NH₃, the standardized emission factors gathered in the database have been used to calculate the emission level in 2050. This was not possible for the other substances due to lack of data. In BOLK-I (Harmelen et al., 2008) emission factors from the GAINS database, see (IIASA, 2008), for the Netherlands in the year 2020 were used. These emission factors were adapted with the relative factors obtained from the inventory. This approach was applied for all NECD emissions in that study.

In this study that approach is applied for the substances PM₁₀, PM_{2.5}, VOC and NO_x with the use of emission factors from the GAINS database for the Netherlands in the year 2030. The relative factors have been updated whenever data permitted. An important update is that emission factors for power plants with oxyfuel combustion that allow co-sequestration have been excluded when calculating the relative factor. The reason is that co-sequestration will very likely not be allowed in the Netherlands. This results in a change on the emission factors used in this scenario analysis. New emission factors and the relative change compared to the emission factors used in the BOLK I report are presented and discussed in section 5.3.3.

Shadow prices

Mitigation costs of NO_x, SO₂ or other pollutants depend on many factors, among which important ones relate to plant configuration, e.g. plant size, operation hours, lifetime, exact fuel quality, production volume, the required emission limits etc. In addition, CO₂ capture highly influences the plant configuration, for instance the net electricity production but also the flue gas composition. This will result in some cases in higher emissions (e.g. NO_x), in other cases lower emissions (e.g. SO₂) for the plant. Without a detailed, very specific assessment, it is not possible to estimate the additional mitigation costs for transboundary air pollutants of a specific plant.

Nevertheless, it is valuable to assess the order of magnitude of the change in air pollutant emissions due to the application of CCS and to relate this value to the costs of capturing CO₂. Are these costs significant or not? To this end, in this report the shadow price method is used. The shadow price is the value that government as a representative of society attaches to the reduction of pollutants (see Box 2). Though the shadow price is not the marginal emission reduction costs needed to meet a certain emission limit in a specific situation, it indicates the value according to the government that within the power generation should be attached to a certain emission change. This value can be related to not only the mitigation costs of CO₂ but also the societal value of the CO₂ mitigation (being around 50 euro per tonne CO₂), which is in itself a perfect example of the shadow price method.

Box 2. The concept of shadow prices

One of the methods used to value environmental impacts, which is operationalised for a number of impact categories in the Netherlands, is known as the shadow price method which uses the highest acceptable costs for mitigation measures as a valuation (Harmelen 2003; KPGM, 2002; Pearce et al, 2000, Wit, 1992). This is based upon the following principles.

A demand for environmental quality or damage limitation exists on a virtual market for environmental quality, where the willingness to pay a high price will increase with the emission level of pollution. Also, a supply of emission mitigation measures is available that will cost more per unit of reduction at higher reduction levels. If this market existed, an equilibrium price would arise at the intersection of demand and supply. This is illustrated in the figure below.

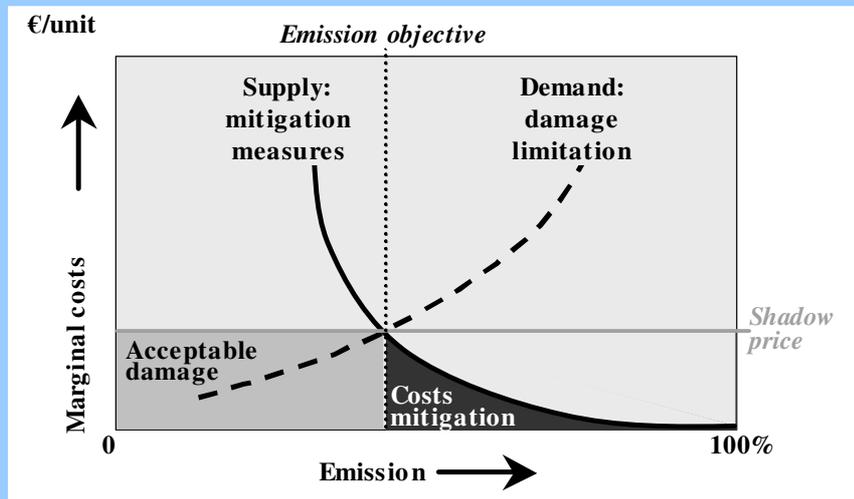


Figure 2-3 In a virtual market, demand for environmental damage limitation and supply of emission mitigation by measures will result in an equilibrium price for environmental quality. If a government's emission objective will cross the equilibrium point, the shadow price is equal to the equilibrium price.

Since the environmental market is a virtual market and the costs of environment are so-called external costs, the government has to set an emission objective to improve the environmental quality. The price level at the crossing of the emission objective and the supply of emission mitigation is called the shadow price, being the highest acceptable price for the government to be paid by society for improving environmental quality. The shadow price is the extent to which total costs change as a result of a change in a limiting factor, in this case an emission objective.

The total environmental costs for society will be the costs of mitigation (the shaded area under the supply curve) plus the damage to the environment, being the remaining emissions multiplied with the price level that society is willing to pay (according to the demand curve). In market equilibrium this is the equilibrium price.

The government will aim its emission objective at the intersection of demand and supply since the virtual environment market is at this point in equilibrium according to society. Under the assumption that the government manages to design a policy of which the shadow price equals the equilibrium price, the shadow price multiplied with the remaining emissions indicate the environmental damage as perceived (and accepted) in society. This principle is used when applying the shadow price method.

The advantage of using shadow prices is that different environmental impacts are translated into (external) costs that can be compared with the internal production costs. Several sets of shadow prices have been assessed mainly for near future targets of well-documented Environmental Impact Categories (EIC) such as climate change,

acidification, ozone depletion, tropospheric ozone formation and eutrophication, e.g. by CE (KPGM. 2002), NIBE (2002) and TME (Jantzen 2000).

2.4.2 *Industrial processes*

The economic potential of CO₂ capture from the Dutch industrial sector in the year 2020 was evaluated based on the economic performance evaluation performed in Section 4.4 and the CO₂ price forecasts reported in the literature. Following this, changes in NEC emissions will be calculated based on the environmental performance evaluation performed in Section 4.4.

2.5 Relation to other BOLK projects

Clear relations exist between the subjects within the BOLK framework. The present project on CO₂ capture technologies is connected with the project on emissions related to the use of biomass in stationary sources (ECN), and the lifecycle analysis of biomass and biofuels (Ecofys).

Finally, the information on capture technologies and their applications with respect to costs, emissions and a lesser extent potentials will be translated into model specifications of energy options to mitigate GHG and / or transboundary air pollution to be used in the national energy modelling framework of ECN. Together with information from the other BOLK projects, an integrated cost-effectiveness analysis will be made for the Dutch energy sector in the year 2020.

3 Standardisation of parameters: results

BOLK-II standardised the values of key parameters that are used in the literature to calculate environmental and economic performance to enable a fair comparison between literature-based values. This chapter presents the range of environmental and economic performance of various CO₂ capture routes for power plants reported in the literature after the standardization of key parameters. There may be cases that CO₂ capture leads to an increase in NEC emissions. In the standardization extra measures and related costs to maintain the NEC emissions to pre-CO₂ capture levels were not considered.

3.1 Environmental performance

As discussed in the methodology section, the requirements on background data needed to standardized environmental performance was lacking for NO_x, PM and VOC emission. The data used reported for these emissions and used in the scenario analysis correspond solely to the ranges found in the updated inventory (see Appendix C).

SO₂ emissions

Figure 3-1 shows the SO₂ emissions per kWh before (BOLK-I) and after parameter standardization for PC and IGCC plants, respectively (overview of the ranges are shown in Appendix C). SO₂ emissions from coal power plants with CO₂ capture were found to be much lower than indicated in the BOLK-I report. The main reason for this is that most studies assumed a sulphur content in the coal that is much higher than the one present in the coal mix used in the Netherlands. Among the three CO₂ capture routes, post combustion capture was found to emit the least SO₂, before and after parameter standardization. The figures also show that in the Dutch context, CO₂ capture will reduce SO₂ emissions of coal-fired power plants to below 30 mg/kWh, regardless of the CO₂ capture route selected.

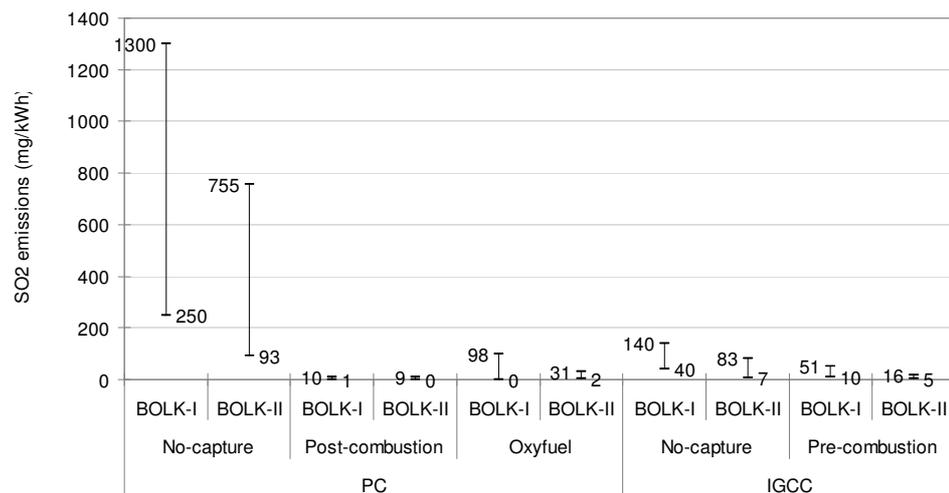


Figure 3.1 SO₂ emission per kWh for coal power plants with and without CO₂ capture.

NH₃ emissions (post combustion capture)

An update of the inventory conducted in BOLK I has resulted in an increase on the number of NH₃ emission data sources (from 1 to 2 for NGCC with post combustion capture and from 1 to 9 for PC). As a result, the range for NH₃ emissions has widened, as shown in Figure 3.2. For all cases, the emission values found in the literature in BOLK-I are within the range of emission values calculated in BOLK-II.

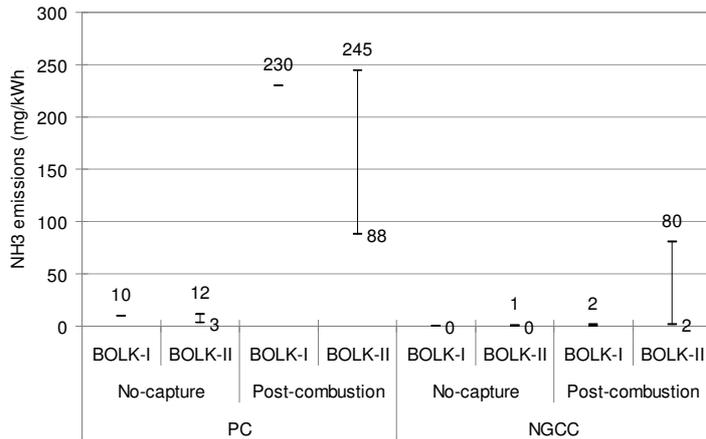


Figure 3.2 Comparison of NH₃ emissions per kWh between BOLK-I and BOLK-II for no CO₂ capture and post combustion capture case.

3.2 Economic performance

Figure 3.3 shows the range of costs of electricity (COE) for various new power plant types with and without CO₂ capture. The values are taken from the literature, before and after the parameter standardization. The results show a significant narrowing on the range of COE for all cases. It is worthwhile to mention that the COE range for IGCCs shifted lower by the parameter standardization, even though future increases in fuel price and material prices have been taken into account. A possible explanation for the COE decrease is that all the literature sources are from the U.S. and that a higher Euro to dollar (€/€) conversion ratio was used compared to BOLK-I. An extensive literature review performed in BOLK-II did not find any economic studies on IGCC with CO₂ capture from Europe. Increases in the COE for NGCC plants, compared to BOLK-I results, are largely due to a high natural gas price expected for 2020.

For coal power plants, on the contrary, the effect of coal price assumption on the COE for 2020 is limited. Two main reasons can explain the limited effect. First, the coal price increase in 2020 compared to today is more modest than the increase expected for natural gas. Secondly, unlike natural gas power plants, the fraction of fuel cost in electricity generation cost is relatively small.

Note that in Figure 3-3 the results of BOLK II show a unique value (no range) for NGCC plants with oxyfuel CO₂ capture. This is because we have corrected for the fact that the two study results inventoried in BOLK-I were from an identical research work, but with different parameter values for cost calculations.

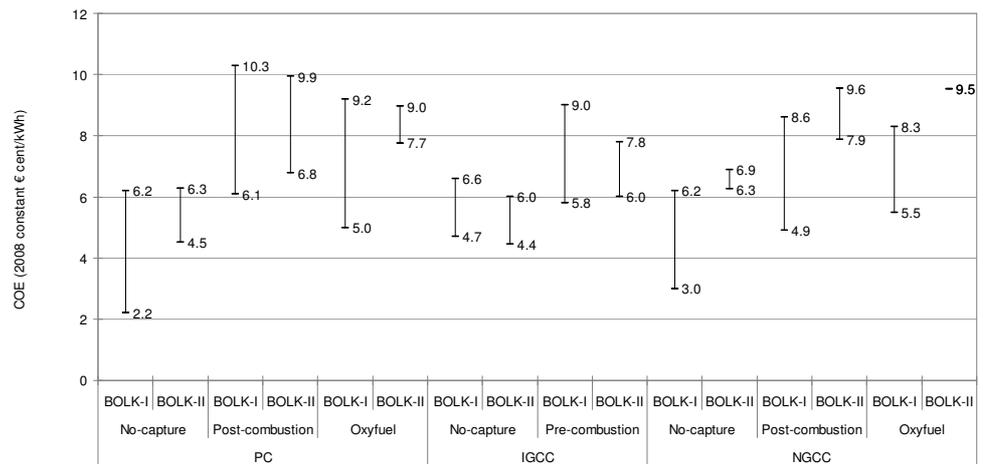


Figure 3.3 Comparison of cost of electricity (COE) between BOLK-I and BOLK-II for various newly built power plants and CO₂ capture routes.

Figure 3.4 shows the range of CO₂ avoidance costs for the year 2020, before and after the parameter standardization. For PC with post-combustion CO₂ capture, the cost range for retrofitting is also presented. The readers should keep in mind that the cost estimates found in the literature are based on the assumption that the CO₂ capture technology in question is mature. The CO₂ avoidance costs in the early stage of CCS deployment is likely to be significantly higher than shown in the figure.

As is the case for COE, the range of CO₂ avoidance costs has also narrowed significantly for all cases. Figure 3-5 shows that the lowest CO₂ avoidance cost can be achieved by pre combustion from IGCC. This result, however, should be treated carefully. As explained earlier, the economic performance of data collected for IGCC with CO₂ capture were solely from the U.S. studies, meaning that the influence of €/€ conversion factor may be considerable. For PCs, post combustion capture and oxyfuel capture are likely to achieve similar CO₂ avoidance cost. CO₂ capture from NGCC is clearly more expensive than that for coal-fired plants.

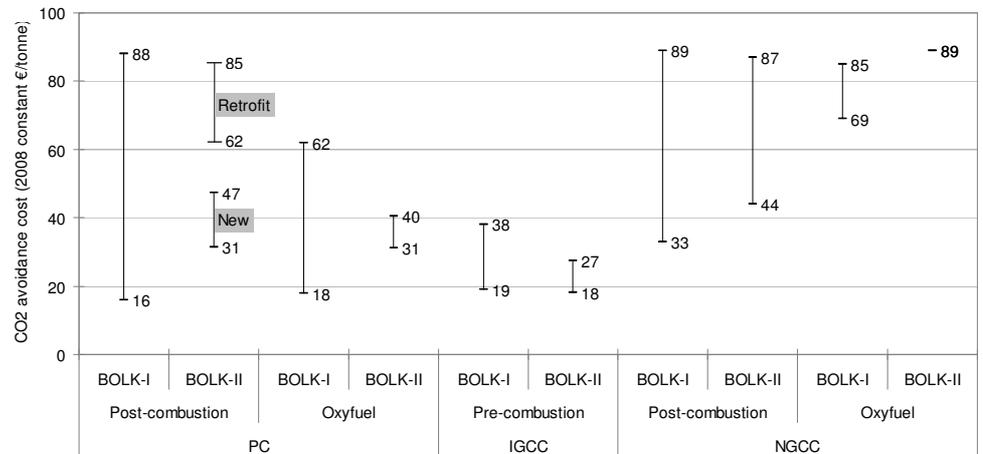


Figure 3.4 Comparison of CO₂ avoidance costs between BOLK-I and BOLK-II for different power plant types and CO₂ capture routes.

It should, however, be noted that most of the cost figures reported in the literature assume that the technology is mature. The results presented in the figures therefore do not signify that IGCC with pre-combustion CO₂ capture would be the cheapest in the short-mid term future.

Comparative evaluation

Table 3-2-1 shows an updated summary of the characterization of various CO₂ capture technologies and their reference cases. The values represent the average of the values reported in the literature. The green, yellow and red shades indicate that the value is in the top, middle and bottom one-third of all the values found for each criterion (column), respectively. For reference, the same table developed for BOLK-I report is presented in Appendix D.

Note that CO₂ avoidance cost figures in the table did not change significantly from the one in the BOLK-I report. This is mainly because the figures are an average of all the collected cost data. It can, however, be said that the cost figures presented in this report are more robust and reliable than those in the previous report as the cost estimate ranges have narrowed after parameter standardization. The presented figures can now be better used for comparing the various capture alternatives.

Conclusions

To compare data from various literatures on an equal footing, standardisation of some important parameter values were performed using parameter values representing the Dutch situation. Standardization of key parameters resulted in narrower ranges than those found in BOLK-I. Narrower ranges allow for more robust comparison on the environmental and costs performance of power plants with CO₂ capture technologies.

An important finding on NEC emissions is that SO₂ emissions from coal power plants with CO₂ capture were found to be much lower than indicated in the BOLK-I report. This is mainly because now it has been taken into account that the average sulphur content in the Dutch coal mix is considerably lower than that assumed in most studies. The range of SO₂ emissions reported in the literature also narrowed after parameter standardisation. All CO₂ capture routes result in a significant reduction on SO₂ emissions.

For NO_x emissions, standardisation of the relevant parameters was not possible. There are many factors that influence NO_x emissions, which requires significant amount of data to perform the standardisation. Currently, there were not enough data available in the relevant literature.

Our results show that for the year 2020 IGCC with pre combustion capture was found to offer the lowest CO₂ avoidance costs ranging between 18 and 27 Euro/tonne CO₂ avoided. This is followed by post combustion capture and oxyfuel capture from coal power plants. Absolute values for the cost figures for some CO₂ capture routes have decreased after parameter standardization. The influential parameters are, e.g., annual operation time, economic lifetime of a plant, interest rate.

It should, however, be noted that most of the cost figures reported in the literature are calculated under the assumption that the technology is mature. The results presented in

the figures therefore do not signify that IGCC with pre-combustion CO₂ capture would be the cheapest in the short-mid term future. “First-of-a-kind” plants are likely to be significantly more expensive than the results presented in this report.

Moreover, the cost figures presented in this study do not include CO₂ transport and storage costs, which may add up another 5-10 €/tCO₂ avoided, depending on the amount of CO₂ and the maturity of CO₂ transport infrastructure.

Table 3.1 Overview of aspects and criteria to characterise several CO₂ capture technologies and their reference technologies based on the improved inventory developed in BOLK-II. N.D.= No data, PC = pulverised coal, NGCC = natural gas combined cycle, IGCC = integrated gasification combined cycle, GC = gas cycle. All cost figures are for newly built plants and they do not include extra expenses for being “first-of-a-kind”. Also, the cost figures do not include CO₂ transport and storage, which may add another 5-7 €/tCO₂.

Capture Technology	Application	Development phase	Application retrofit/robust/process industry	Economic performance			Environmental performance						
				electrical efficiency (%)	COE €/cst/kWh (constant 2008)	€ per tonne avoided (constant 2008)	efficiency penalty (% pts)	CO ₂ emissions (g/kWh)	NOx emissions (g/kWh)	SO ₂ emissions (g/kWh)	PM10 emissions (g/kWh)	NH ₃ emissions (g/kWh)	Other impacts
no capture	PC	commercial		40%	5,4	-	0	786	0,37	0,25	0,042	0,0058	
	NGCC	commercial		57%	6,6	-	0	366	0,09	0	-	0,00037	
	IGCC	commercial		42%	5,4	-	0	761	0,23	0,036	0,028	0	
Post	Amine	pre-commercial	yyy	31%	8,3	42	9	106	0,56	0,006	0,048	0,17	Toxic waste
	Amine	pre-commercial	yyy	49%	8,6	63	8	40	0,06	0	-	0,041	Toxic waste
	Chilled ammonia	pilot	yyy	39%	N.D.	16	N.D.	N.D.	N.D.	(estimated in order of Amine)	-	0,12	
	Membranes	lab scale	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	
Pre	GC	demonstration	nyy	49%	N.D.	N.D.	8	21	n.a. (estimated in order of Amine NGCC)	-	-	-	
	IGCC	demonstration	nyy	35%	6,8	23	7	97	0,21	0,0099	0,034	0	
Oxyfuel	PC	pilot	y?ny	33%	8,3	36	7	51	0,27	0,016	0,006	-	
	GC	pilot	y?ny	53%	N.D.	N.D.	4	10	-	-	-	-	
	NGCC	pilot	y?ny	46%	9,5	89	11	6	0	0	-	-	

4 Technology assessment

The choice of a suitable CO₂ capture technology depends on the characteristics of the gas stream from which CO₂ needs to be separated, which mainly depends on the power plant technology. A wide range of technologies exists for the separation and capture of CO₂ from gas streams. These technologies, however, have not been designed yet for operation on the scale of a commercial size power plant. The idea of CO₂ capture is to produce a stream of pure CO₂ gas from a mixture of CO₂ and other gas components. There are many ways to perform this operation: absorption or adsorption (separating CO₂ by using solvents or sorbents for absorption), membranes, and thermal processes such as cryogenics or mineralization. Figure 4.1 briefly summarizes technology options which are based on different physical and chemical processes (Wilson and Gerard, 2007).

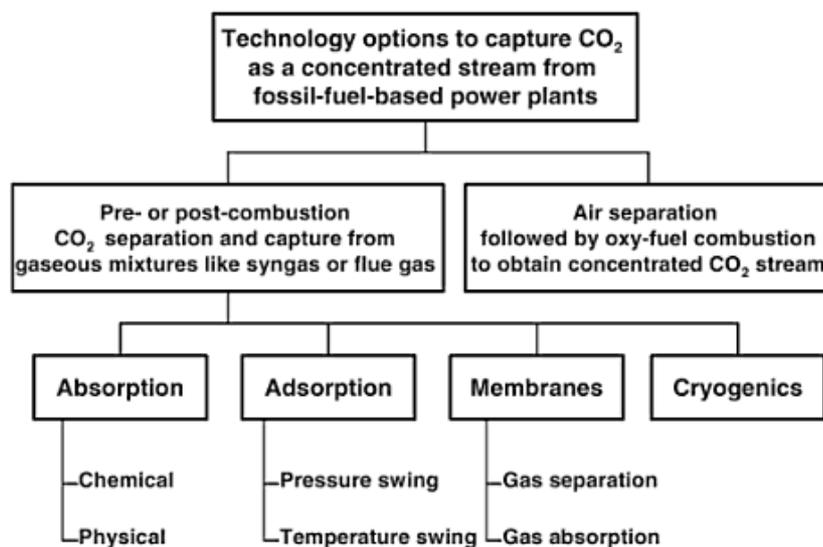


Figure 4.1 Technology options for CO₂ separation and capture (Wilson and Gerard, 2007).

As Figure 4.1 shows, four main technology options exist for pre- or post-combustion CO₂ separation and capture. These technologies were assessed in detail in BOLK I. It was concluded that currently the CO₂ separation process based on chemical absorption, using an amine based solvent (e.g., MEA), is the most developed process for post combustion capture. However, one drawback is that it can lead to an increase of NH₃ emissions. For this reason, in the second phase of BOLK solvent-based technologies are analyzed in more details later. To be more specific, in this report the following processes are assessed in detail:

- Chemical solvents
- Physical solvents (to a lower extent) and
- Chilled ammonia process

Furthermore, in this report we assess the economic and environmental performance of capturing CO₂ in industrial processes in the Netherlands. Also a first assessment is made of a relatively new topic: co-firing of biomass with CO₂ capture.

4.1 Solvents in absorption and adsorption processes

Absorption is a common process for post-combustion CO₂ capture, which has the aim of separating CO₂ from the flue gases (see Figure 4.2). The mixture of CO₂ and other gas components, such as nitrogen, is mixed with a liquid solvent in an absorption column. The solvent must be able to react with CO₂ but not with the other gas components. Using this method produces different streams coming out of the absorption column; one being a mixture of solvent and CO₂ and the other one a mixture of all of the other gas components (IPCC, 2005). Adsorption is very similar to absorption. The difference being that in adsorption the CO₂ binds to the surface of the solvent, while in absorption there is chemical binding between the CO₂ molecules and the solvent molecules.

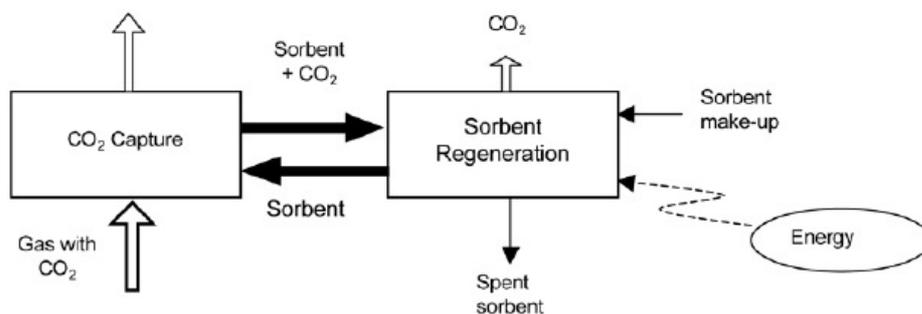


Figure 4.2 General scheme of CO₂ separation with sorbents/solvents (IPCC, 2005).

Solvents are used for scrubbing CO₂ from a flue gas. The technology is based on the affinity of the solvent for CO₂ relative to other gases. This affinity is dependent on the temperature and pressure, and hence the solvents can be regenerated by raising the temperature and/or reducing the pressure. Solvent processes are widely used in the (petro-) chemical industry and the oil and gas industry.

There are two types of solvents: physical and chemical solvents. In physical solvents, the CO₂ dissolves in the solvent liquid. Henry's law determines the equilibrium between the gas and the liquid phase. The solvent loading is more or less linear with the CO₂ partial pressure. Chemical solvents show a non-linear relation. The CO₂ reacts with specific components in the liquid phase, and increased solvent loadings are observed at low partial pressures (Figure 4-3). The main determinant of the type of solvent to be used is the partial CO₂ pressure in the flue gas. In general, chemical solvents can be regenerated by a thermal process, whereas physical solvents require a pressure swing. It is also possible to use a mixture of physical and chemical solvents. In the power generation sector, the exhaust flue gas has a low CO₂ partial pressure (approximately 5 – 15 vol.%). Due to the low partial CO₂ pressure, the use of chemical solvents is preferred in post combustion capture.

In pre combustion capture, CO₂ is captured from the high pressure feed gas stream. The feed gas is obtained from a gasification (coal) or a reforming process (natural gas), which generates a synthesis mixture of mainly CO and H₂. The CO gas is shifted to CO₂ and H₂ by introducing steam. The partial CO₂ pressures are much higher than in the post combustion process and therefore CO₂ can be captured by a chemical or a physical solvent. An overview of some physical and chemical solvents is given in Table 4.1. Chemical solvents have the advantages that the removal of CO₂ to low levels is feasible

at low partial pressures. Physical solvents have the advantages that the absorption is not limited by the stoichiometry and they are less energy consuming. Since in this project the main focus remains on the short-term options, mainly chemical solvents will be discussed in detail in the following section.

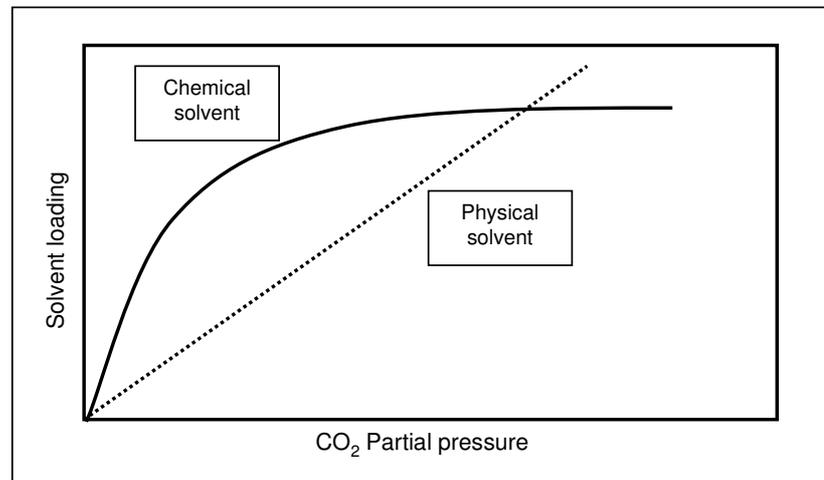


Figure 4-3 CO₂ equilibrium partial pressure for a chemical and a physical solvent after (Gijlswijk et al., 2006).

Table 4.1 Commercial CO₂ Scrubbing solvents used in industry (IEA, 2008a).

	Solvent name	Solvent type	Process conditions
Chemical solvents	MEA	2,5n monoethanolamine and inhibitor	40 °C, ambient-intermediate pressures
	Amine guard	5n monoethanolamine and inhibitor	40 °C, ambient-intermediate pressures
	Econamine	6n diglycolamine*)	80-120 °C, 6.3 MPa
	ADIP	2,4n diisopropanolamine 2n methyldiethanolamine	35-40 °, >0.1 MPa
	MDEA	2n methyldiethanolamine	
	Flexorb, KS-1, KS-2, KS-3	Hindered amine	
	Benfield and versions	Potassium carbonate and catalysts. Lurgi & catacarb processes with arsenic trioxide	70-120 °C, 2-2.7MPa
Physical solvents	Rectisol	Methanol	-10/-70 °C, > 2 MPa
	Purisol	n-2-methyl-2-pyrrolidone	-20/+40 °C, >2 MPa
	Selexol	Dimethyl ethers of polyethyleneglycol	-40 °C, 2-3 MPa
	Fluor solvent	Propylene carbonate	Below ambient temperatures, 3.1-6.9 MPa
Physical/chemical solvents	Sulfinol-D, Sulfinol-M	Mixture of DIPA or MDEA, water and tetrahydrothiopenone (DIPAM) or diethylamine	>0.5 MPa
	Amisol	Mixture of methanol and MEA, DEA, diisopropylamine (DIPAM) or diethylamine	5-40 °C, >1 MPa

*) MEA 30% solution according to (Goetheer, 2009).

4.1.1 Chemical solvents

Amine based solvents

The most successful and well-known processes to remove CO₂ from a gas stream are amine based. An exothermic reaction of CO₂ with the amine functionality of an alkanolamine takes place in the solvent.



Reaction (5) takes place with primary and secondary amines, which contain at least one hydrogen atom at the amino group. This carbamate formation is usually fast and is the reason for the higher reactivity of the primary and secondary amines. Next to the difference in reaction rate there is a variation in equilibrium absorption characteristics, sensitivities with respect to solvent stability and corrosion factors.

Alkanolamines can be divided into three groups: primary, secondary and tertiary amines. Primary amines, like MEA, have the advantage of a high reaction rate, resulting in small capture equipment and a high recovery rate. A main disadvantage however, is the high-energy consumption needed for the regeneration of the solvent. By adding a bulky molecule to the chain of primary or secondary amines a so-called sterically hindered amine can be created. An example of a sterically hindered amine is KS-1 (manufactured by MHI). Contrary to primary amines, tertiary amines combine a low reaction rate with a low energy demand for regeneration.

Table 4.2 Advantages of different groups of amines.

	Reactivity rate	Regeneration energy
Primary amines	High	High
Secondary amines	Medium	Medium
Tertiary amines	Low	Low

Alkanolamines were developed and mostly used for removing acidic gases (CO₂, H₂S) from natural gas streams. Main difference with a flue gas from a power plant is the very low oxygen concentration (< 0.1vol%). The flue gas from a power plant contains 5-15 vol% oxygen, which will degrade most of the amine solvents and lead to high solvent losses or expensive reclaiming processes. Oxygen can also cause corrosion problems in the process equipment, which set a demand for more expensive construction materials. Adding corrosion inhibitors to the solvent could solve this problem. Contrary to post combustion, in pre combustion capture oxygen is absent and therefore degradation by oxidation will be absent.

Another point to take into consideration is that NO₂ and SO₂ react with alkanolamines (e.g., MEA) to form heat stable salts (HSS). SO₂ can be removed from the flue gas by

installing a flue gas desulphurization unit upstream the absorber. SO₂ should be removed to a concentration level of 10 ppm for MEA or even < 2 ppm for KS-1. The NO_x in a flue gas consists of NO (90-95%) and NO₂ (5-10%). The first is inert, the second reacts with MEA to form HSS. Reduction of NO_x to a level of 20-30 ppm is indicated in the literature. In general a trade-off between solvent degradation and costs of extra purification of the flue gas have to be accepted. Solvent consumption is generally in the order of 1-2 kg/tonne CO₂ (Ploumen, 2009;Goetheer, 2009). In summary:

The advantages of the amine technology are (Wilson and Gerard, 2007;Harmelen et al., 2008):

- Easy retrofitting (end-of-pipe treatment)
- Most mature CO₂ capture technology for power plants (commercially available at industrial scale, not implemented at the scale needed for power plants)
- High CO₂ reduction is possible
- Effective for dilute CO₂ streams (3-15 % CO₂ v/v)
- Ordinary operation conditions (temperature and pressure)
- High-purity product (98%+)
- Ongoing research and development

The disadvantages of the amine technology are:

- High costs for energy (energy penalty) and equipment
- Large volume of gas have to be handled
- Degradation and loss of amines
- Harmful and corrosive solvents
- Emission of organic components (VOC)
- Emissions of ammonia
- Plot space requirements
- Water and cooling requirements

Case studies of CO₂ capture processes

At the moment there are few industrial CO₂ capture processes which can be applied to power plants. There are also few demonstration plants where new solvents are being tested. Table 4.3 presents an overview of existing and planned projects with solvents being used for CO₂ separation.

Table 4.3 An overview of projects/processes and used solvents for CO₂ separation from flue gas for industry as well as for planned pilot power plants (Reddy et al., 2008;Knudsen et al., 2008;Hetland and Christensen, 2008;Bak, 2009;Kishimoto et al., 2009c).

Project	Solvent	Capacity	Location	Country
MITSUBISHI HEAVY INDUSTRY ¹⁾ <i>KM-CDR process</i>	Amine KS-1 KS-2 KS-3	10 tCO ₂ /day via a slip stream from a 500 MW unit	Matsushima	Japan
FLUOR ²⁾ Fluor Daniel @ ECONAMINE™ Process	Econamine	331 tCO ₂ /day	Bellingham	USA
CB&I (former ABB) <i>Kerr-McGee/ABB Lummus absorption/stripping technology</i>	Amine	(150-800 tCO ₂ /day)	Houston	USA
SARGAS ABB Carbon P200 PFBC power cycle technology CASTOR	K ₂ CO ₃ ³⁾ Amine (CASTOR-1, CASTOR-2)	24 tCO ₂ /day	Esbjerg	Denmark
Examples of pilot power plants				
CATO	Amine ³⁾		Limburg	Netherlands
CATO (2011)	Amines Amine Salts ⁵⁾	0.4 MW 6 tCO ₂ /day	Maasvlakte	Netherlands
ALSTOM (2009)	Chilled Amonia	5 MW	Karlshamn	Sweden
HITACHI (2009)	Amine	1.5 MW	Datteln	Germany
SIEMENS (2009)	Amine Salts	<1 MW	Staudinger	Germany
CANSOLV (2010)	Amine	5 MW	Heyden	Germany

¹⁾ MHI has multiple commercial CO₂ recovery plants in chemical and fertilizer industries, which recover CO₂ from natural gas fired flue gas with 4 commercial plants in operation and another 4 under construction, which are expected to be under operation within the next few years (2010 in Germany);

²⁾ This pilot plant is expected to start operation in 2010 at E.ON's coal-fired power plant in Wilhelmshaven, Germany. ³⁾ Hot potassium carbonate. ⁴⁾ New solvents will be tested. ⁵⁾ CATO tested amines and amino salts at the Maasvlakte. In CATO II probably more solvents (sorbents) will be tested also with use of membranes.

The first three processes are considered to be commercially available for CO₂ capture in post-combustion systems for industry. A brief explanation is provided below. Note however that none of these processes have been used on coal-fired power plants at the scale needed for CCS.

Mitsubishi Heavy Industries

MHI has been involved in R&D relating to CO₂ capture from flue-gas streams of fossil fuel-fired power stations since 1990, undertaken jointly with Kansai Electric Power Co., the second largest electric utility in Japan. These efforts led to the development of advanced PCC proprietary equipment and processes and the deployment of four CO₂ capture plants (Figure 4.3). MHI has also been awarded a further four commercial

license contracts for CO₂ capture plants in the chemical and fertilizer industries expected to be under operation within the next few years. MHI claims to be ready to deliver large, single train PCC (post combustion capture) plants for natural gas fired application.

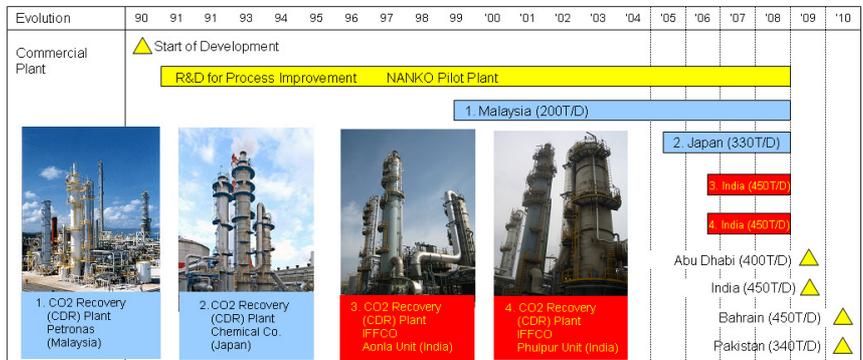


Figure 4.3 MHI's commercial CO₂ capture plant experience (Kishimoto et al., 2009b).

For coal fired flue gas application, MHI has undertaken a long term demonstration test at the Matsushima Power Station in southern Japan and has operational experience of more than 5,000 hours, at 10 tonne/day capacity, applying the KM-CDR Process on coal fired flue gas streams. Results of the pilot show that effective removal of coal based flue gas impurities at the pre-treatment section is very important to achieve stable and reliable operation of the CO₂ recovery plant (Kishimoto et al., 2009a).

Fluor

Fluor has designed and built more than 20 commercial plants (up to 320 tonne CO₂/day). The patented process, Econamine FG PlusSM, is a development of the Econamine process, originally developed by Dow. The technology uses MEA as basis for the solvent (30-35% aqueous solution). An inhibitor is added to protect the equipment against corrosion, and allows the use of conventional materials of construction as carbon steel. Improvements in the solvent formulation and the process are claimed to reduce thermal energy requirement for solvent regeneration from 4.2 to 3.24 GJ/tonne CO₂. Fluor has developed innovative strategies to prevent amine degradation and corrosion. Figure 4-8 shows an aerial view of the Bellingham Econamine FGSM plant (Reddy et al., 2003;Ploumen, 2007;Reddy et al., 2008).

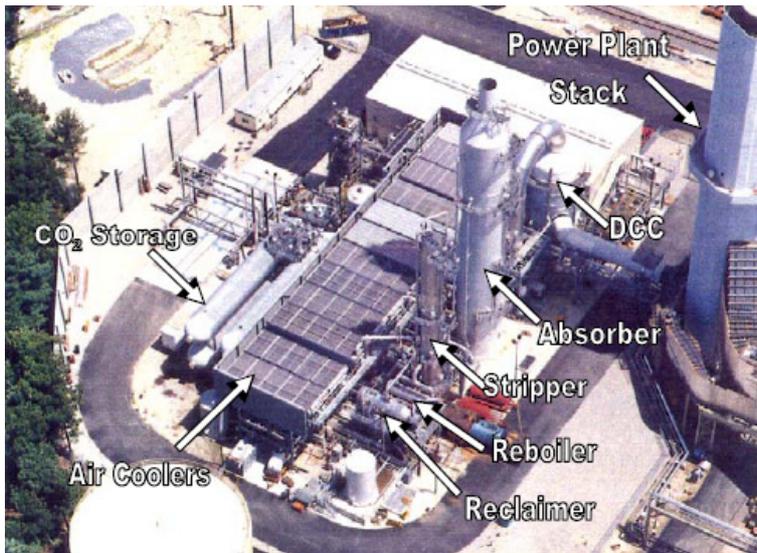


Figure 4.4 Bellingham Plant Aerial View (Reddy et al., 2008).

CB&I (former ABB)

In this case, commercially proven Kerr-McGee/ABB MEA-based CO₂ recovery process, installed downstream of the flue gas desulphurization unit, is integrated into the power plant to strip CO₂ from the effluent gas stream (containing about 15% CO₂ by volume). The Kerr-McGee/ABB Lummus Crest Process (Barchas and Davis, 1992) uses a 15 to 20% by weight aqueous MEA (Mono-Ethanolamine) solution. The CO₂ is recovered from coke and coal-fired boilers, delivering CO₂ for soda ash and liquid CO₂ preparations. The largest capacity experienced for this process is 800 tonne CO₂/day utilizing two parallel trains.

Esbjerg power station in Denmark

In this power plant, an absorption pilot plant (1 t/h CO₂) has been used to test the performance of (new) solvents in real conditions (flue gases from a coal-fired power station). The tests carried out until now with both conventional (30% MEA) and novel amine solvents (CASTOR 1 and 2) have confirmed that it is possible to maintain stable and reliable operation of a post combustion capture unit on coal flue gas for extended periods of time achieving around 90% CO₂ capture. The tests with the novel solvent CASTOR 2 indicated that it is possible to develop amine solvents with lower regeneration energies than MEA while having increased stability towards degradation (Knudsen et al., 2008).

SARGAS

SARGAS constitutes a new energy technology characterised by pressurised post-combustion capture. It is a complete system that can only be used in connection with a PFBC (Pressurized Fluidized Bed Combustion). The capture part is made up by hot potassium carbonate processes, such as the Benfield process. The hot potassium carbonate process is a chemical absorption, thermally regenerated cyclical solvent process that uses an activated hot potassium carbonate solution for removing the CO₂. The capture rate may be as high as 98% for CO₂ capture compared with 85–90% for

MEA in combined cycles using post-combustion schemes. The practical capture rate will be however, determined on commercial terms. Furthermore, in contrast to MEA or other amine-based or organic solvents, potassium carbonate is stable and does not degrade in the presence of oxygen. However, the direct employment of the CO₂ capture unit is only possible on a limited number of plants because the technology can neither be used in existing plants nor in coal fired plants that are currently planned (Hetland and Christensen, 2008).

From amines to amino salts

Main disadvantages of using amine based solvents such as MEA, is thermal degradation and emission of degradation products such as ammonia. These problems can be reduced or even avoided by the use of amino acid salts. Siemens and also TNO (Coral – CO₂ Removal Absorption Liquid) are both developing these solvents. Details of the first results of testing CORAL at the CATO pilot plant are confidential, but the public summary mentions the following findings (Jaspers and Allaie, 2008):

- High capture rates proven (over 90%)
- Solvent stability, no degradation found
- Lower emissions, no ammonia formation, no evaporation losses
- Comparable energy consumption to MEA standard
- Low temperatures possible which broadens application of waste heat
- Membrane application showed feasibility of ultra-compact absorption

The advantages of the Siemens' process rely on the use of an amino-acid salt solution as a solvent that has been optimized for high selectivity, high absorption capacity, low chemical and thermal degradation, low energy demand for solvent regeneration and near-zero solvent slip (Jockenhoevel et al., 2009).

The main disadvantage of these amino salts is the high cost compared with MEA. Lowering the costs is a main point of the R&D currently being carried out by Siemens Energy and TNO (though a higher CO₂ absorption capacity may be favourable over lower regeneration energy). A cooperation agreement between both parties has been signed aiming to have a full-scale demonstration plant by 2014.

Chemical waste

By reclaiming the solvent degradation products (MEA process) approximately 1.5 kg of solid waste per tonne of CO₂ is created. An average power plant emits c.a.700 tonne of CO₂ per hour. As a result, approximately one tonne of toxic waste is produced per hour. The preferred option is to prevent the degradation of the product. An alternative option is to reintroduce the waste together with the fuel in the combustion process. From a technological point of view, no problems are expected, but current legislation may put barriers to this.

Other developments

Other issues under development are increased attention to the off-gases, the emissions of the power plant, and the integration of CO₂ and SO₂ capture. The composition of the off-gases influences the capture efficiency. In practice a trade-off will be made between the costs of off-gas treatment on the one hand, and the costs of the efficiency reduction of the capture process and the cost of discharging waste on the other hand.

Integrating CO₂ and SO₂ capture could however result in reduction of emissions and costs.

Chilled ammonia

Chilled ammonia process is a promising way to reduce the efficiency penalty of the capture process to approximately 6% points. A decrease in the efficiency penalty would imply a reduction on the level of emissions. A main reason for the relatively low efficiency penalty is that the CO₂ is released at 30 bar after the capture process. This prevents the high cost compression from 1 to 30 bars after the regular capture process. On the one hand, the chilled ammonia process is considered to be a difficult process compared to the regular solvent process (Goetheer, 2009). On the other hand, it is a very promising process and large investments are done by companies such as Alstom (Ploumen, 2009).

At the WE Energy power plant in Pleasant Prairie (USA), a pilot plant is in operation since June 2008 for over 4000 hours. The pilot plant is designed for 35 tonnes CO₂/day. First results of the pilot plant show that the CO₂ capture efficiencies are below the designed 90%. Also, the NH₃ slip was higher than expected as a function of unstable regenerator/stripper system operations. After resolving the problem, the NH₃ slip is reduced to lower levels. The objective is to control the ammonia slip to acceptable environmental standards (Kozak et al., 2009a).



Figure 4.5 CO₂ Field pilot at Pleasant Prairie (Kozak et al., 2009b).

4.1.2 Physical solvents

There are several physical solvents that could be used for CO₂ separation from flue gases. The Rectisol[®] Process uses refrigerated methanol as the solvent for physical absorption. Components of the flue gas, such as CO₂, H₂S and the remaining sulfur compounds, HCN, NH₃ as well as nickel and iron carbonyls are physically absorbed from the flue gas by the solvent. In the COORIVA project a consortium of leading German utilities and engineering companies develops a German IGCC fuelled with lignite or hard coal that uses physical solvents for the CO₂ separation (LURGI, 2009).

Selexol is another physical solvent that can be used for CO₂ sequestration. Klara (2009) reports some results from the process engineering program used for new technology evaluation. Selexol physical solvent process is used at IGCC plant, using Conoco-Phillips E-GasTM gasification technology in USA. Net power output is 518 MWe and CO₂ is removed with the two-stage Selexol physical solvent process (Klara, 2009).

4.1.3 Overview of fuel penalty

It is known that when CO₂ capture technologies are applied to coal-based power generation plants, these plants will require 20-40% more fuel in order to deliver the same amount of electric energy. The energy penalty may depend on technology and level of technology maturity, as shown in Table 4.4. Current literature suggests that for coal-based power plant the state-of-the-art efficiency without CCS would be 47% and at least 9% lower if CO₂ capture is deployed, 38% (at best) (Hetland and Christensen, 2008).

Table 4.4 Fuel penalty by technology and solvent and assumed by Hetland et al. (2008) state-of-the-art efficiency (Hetland and Christensen, 2008).

Technology	Solvent	% – Points efficiency drop	Efficiency with CO ₂ capture (%)
Pulverised hard coal	Chemical MEA	9	38
Pulverised lignite	Chemical MEA	12	33
IGCC, hard coal	Rectisol/selexol	8	31–33
IGCC, lignite	Rectisol/selexol (80% capture rate)		35–38
NGCC	Chemical MEA	9	49

Less energy consuming solvents

The regeneration of chemical solvents is a highly energy consuming process. Focus of the development of new solvents is on the reduction of the energy needed for recovery by reducing the bonding strength between the CO₂ and the solvent. Table 4.5 shows results of a study made by Peeters et al. (2009). This study shows an expected reduction in the regeneration energy from 4.4 to 1.6 MJ/kg CO₂. In combination with an improvement in the efficiency in the power generation, the energy penalty could be reduced from 7.9 to 3.7 in the time period of 2010-2030.

Table 4.5 Expected trends and solvent energy regeneration (Peeters et al., 2007).

	2010	2020	2030
Regeneration energy [MJ/kg CO ₂]	4.4	2.6	1.6
Net efficiency [%LHV]	49	55.1	58.3
Energy penalty [%point LHV]	7.9	4.9	3.7

Several ways are currently under investigation to achieve significant reduction on the energy penalty. One way is the use of sterically hindered amines as described in section 4.1-1. Another way is the use of a new solvent system consisting of two liquid phases. One phase has a high CO₂ absorption capacity; the other has a low CO₂ absorption capacity. During the capturing process the liquids are mixed, after the capturing process the liquids are separated. Only the CO₂ rich phase has to be regenerated, resulting in a

reduced amount of energy needed for regeneration. In addition, after separation the CO₂ rich phase is outside the zone of thermodynamic equilibrium and, as a result, releases some of the CO₂ it captures. This natural effect further reduces the quantity of heat required for regeneration (Goetheer, 2009).

4.1.4 Emissions directly related to solvents

Currently, available information on solvent related emissions is scarce. Table 4.6 presents the harmonised emission data from post combustion CO₂ capture using amines, assigned to the various solvents as described in literature. Key findings can be summarized as follows. Net emissions (in g/kWh) will increase for NO_x en NH₃. The emissions of NO_x increase because of the fuel penalty. The solvent washing process will only remove a part of the NO_x. NO₂ reacts with the solvent, but is only a minor part (~10%) of the total NO_x. NH₃ emissions are caused by the degradation of the amine-based solvents (MEA). The emissions of SO₂ and PM₁₀ emissions will decrease because of the solvent scrubbing step. They react (SO₂) with or are simply washed out by the wet scrubbing step. Though it is known that MEA itself can evaporate from the process (Gijlswijk et al., 2006) and that degradation of MEA can also lead to other emissions of volatile organic compounds⁴, there is not information publicly available on the level of NMVOC emissions that could be generated.

Table 4.6 Harmonised emissions from CO₂ post combustion capture using amines (g/kWh).

		CO ₂	NO _x	SO ₂	PM ₁₀	NH ₃
PC	No capture	786	0.37	0.25	0.042	0.0058
	Fluor Econamine	114	0.45	0.009	0.072	
	FG+ ^{1, 2)}					
	MEA ^{3, 4, 5, 6)}	98	0.65	0.0004	0.031	0.125
	Amines (overall)	105	0.55	0.0046	0.055	0.125
NGCC	No capture	366	0.09	-	-	0.00037
	Fluor Econamine	54	0.11	-	-	0.080
	FG+ ^{1, 2)}					
	KS1 ²⁾	63	0.18	-	-	-
	MEA ^{3, 4, 5, 6)}	45	0.11	-	-	0.002
	Amines (overall) ⁷⁾	49	0.12	-	-	0.041

¹⁾ (IEA GHG, 2004); ²⁾ (IEA GHG, 2004;ER, 2006); ³⁾ (EPRI, 2000;EPRI, 2002); ⁴⁾ (Rubin and Rao, 2002); ⁵⁾ (Rubin et al., 2007); ⁶⁾ (Stobbs and Clark, 2005); ⁷⁾ (Kvamsdal et al., 2007)

Experts expect that NH₃ emissions can be prevented, for example by adding an additional acid based wash section after the absorber. Next to the capture process NH₃ emissions are produced by the de-NO_x SCR unit (Koornneef et al., 2008). Prevention of NH₃ emissions can also be achieved by solvent selection (e.g. TNO Coral process I (Jaspers and Allaie, 2008)).

⁴ One possible class of degradation product from the amine based CO₂ capture processes are nitrosoamines (Knudsen et al., 2009). These products are carcinogenic and the possible formation can not be neglected, although the risk of formation is expected to be very small.

Post combustion capture, using amine-based solvents is considered as the first available CO₂ capture technology applicable for large-scale applications as power plants. However, industrial CO₂ capture plants have a capacity of up to 500 tonne CO₂/day at this moment. This is still a 25 factor smaller than needed for an average power plant.

The most important trends in solvent development are: the development of solvents with a reduced energy consumption and the development of amine based salts. Related to the first trend is the development of the chilled ammonia process, which is a promising technology, which potentially could strongly reduce the energy penalty. Nevertheless it is a more complex technology and significant R&D efforts need to be conducted for its commercial application on the medium term.

In terms of emissions, due to the efficiency drop by the CO₂ capture process fuel consumption will increase, which will result in an increase of the combustion related emissions of NO_x, SO₂ and PM₁₀. The capture process itself demands low concentrations of these emissions. Especially for SO₂, additional measures will be applied to reduce its concentration. The SO₂ capture process, a washing step, will also capture NO₂ and PM₁₀. Consequently, the current consensus is that the emission (per kWh) of NO_x will increase and of SO₂ and PM₁₀ will decrease.

The introduction of the solvents themselves can constitute an additional source of emissions, e.g. NH₃ which can be emitted by the MEA based solvents when no additional measures are taken and first results from the chilled ammonia process show some problems with ammonia slip, which result in unwanted emissions. It is possible to reduce the NH₃ emission with (acid) scrubbers, but this will lead to additional costs. Amine salts, on the other hand, will not emit any NH₃ during the capture process. However they are still on a development phase.

4.2 Oxyfuel combustion CO₂ capture: assessment of purification technologies

The status of R&D on oxyfuel CO₂ capture has been described in detail in the BOLK-I report (van Harmelen et al., 2008). As shown in Table 4.7, a number of oxyfuel combustion pilot projects have been proposed and started up recently. Since the BOLK-I report was published, new test results from pilot plants have been presented in international conferences, e.g. 9th International Conference on Greenhouse Gas Control Technologies (November 2008) and the 1st Oxyfuel Combustion Conference (September 2009). In this section we provide a brief overview of the new insights.

Note that co-storage of acid gases such as SO₂ and NO_x is unlikely to be practised. The presence of these gases will increase the specifications and costs of CO₂ transport pipelines in order to avoid corrosion. Moreover, health and safety criteria may recommend maximum concentrations of impurities in the CCS chain. Hence, flue gas purification is expected to play an important role in the oxyfuel CO₂ capture and storage chain. The emission level of NEC emissions for oxyfuel plants largely depends on how the CO₂-rich gas is treated before being compressed and transported to the storage site.

Table 4.7 Proposed pilot projects for oxyfuel combustion with non-gaseous fuels (van Harmelen et al., 2008).

Project Name	Location	Feedstock	Size MW	CO ₂ Fate	Start-up
Total Lacq	France	Oil	35	Sequestration	2008
Vattenfall oxyfuel	Germany	Coal	30/300/1000*	Undecided	2008
Callide-A	Australia	Coal	30	Sequestration	2009
Oxy Fuel Doosan Babcock Energy	United Kingdom	Coal	40	Vented	2009
SaskPower Clean Coal	Canada	Coal	450	Undecided	Cancelled

*pilot scale 30 MW, demonstration scale 300 MW and full commercial scale 1000 MW

This section presents the new test results on some of the oxyfuel combustion pilot projects with a special focus on the purification of oxyfuel combustion flue gas and its environmental performance.

Pilot plant test results

Flue gas clean up

Figure 4.6 shows a simplified diagram of a flue gas cleaning system for oxyfuel combustion plants tested at the Schwarze Pumpe pilot plant in Germany (Wang et al., 2009). This system has de-NO_x and de-SO_x units separate from the compression unit. Flue gas from the oxyfuel boiler flows first through a Selective Catalytic Reduction unit (SCR) to remove NO_x and then through an electrostatic precipitator (ESP) to remove particulates. Following this, sulphur content in the flue gas is removed in a Flue Gas Desulfurization unit (FGD). Water content in the flue gas is condensed and removed in a Flue Gas Condenser unit (FGC). Further NO_x and SO_x removal is achieved by FGC as the condensed water absorbs some SO_x and NO_x in the form of H₂SO₄ and HNO₃, respectively.

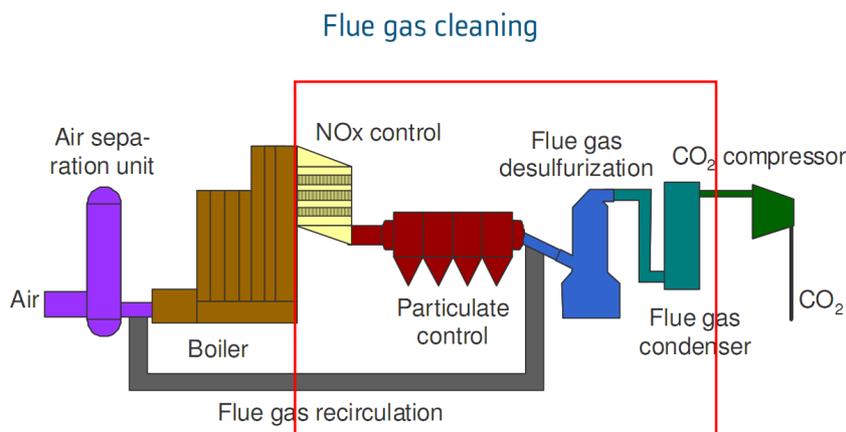


Figure 4.6 Flue gas cleaning system for oxyfuel combustion plants (Wang et al., 2009).

Figure 4.7, which integrates gas clean-up, purification and compression (e.g. Sarofim, 2007; White et al., In Press, Corrected Proof). This flue gas clean-up system has been

tested in the Doosan Babcock pilot project. In sour compression process, NO_x and SO_x are removed by water washing. Flue gas is compressed to 15 bar and cooled down, where most of the NO is oxidised to NO₂. Flue gas then contacts water, where SO₂ converts into sulphuric acid (H₂SO₄) and NO_x is converted into HNO₃, and dissolves into the washing water. Flue gas is further compressed to 30 bar and more NO_x is removed by water washing in the form of HNO₃. Experimental results show that the SO₂ conversion to H₂SO₄ decreases as the SO₂/NO_x ratio increases, which may agree with the theory that NO_x acts as a catalyst for the SO₂ oxidation to H₂SO₄ (White et al., In Press, Corrected Proof).

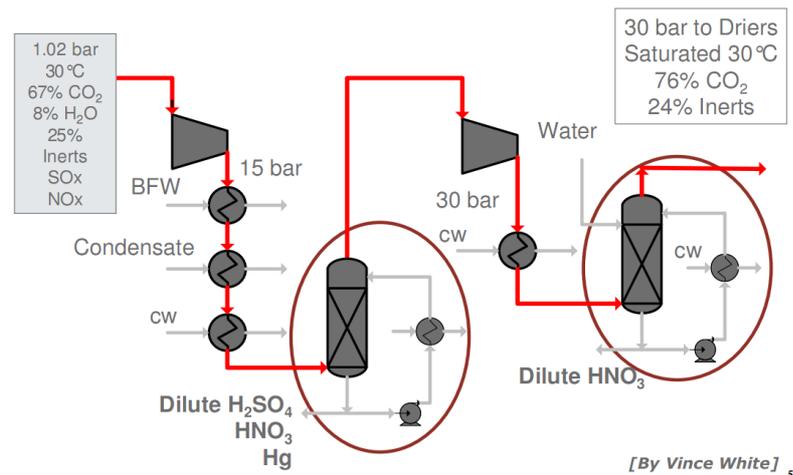


Figure 4.7 Simplified process flow diagram of sour compression process (Murciano et al., 2009).

Table 4.8 shows the performance observed during the pilot plant tests of two different oxyfuel combustion flue gas clean-up systems, alongside with the emission ranges found in the literature for a PC plant without CO₂ capture. The flue gas clean-up system is comprised of separate SCR, FGD and FGC units shows significantly better emissions control performance for SO₂ and dust compared to a PC without CO₂ capture. NO_x and NH₃ emission levels are dependent on whether or not a SCR is installed and how well it performs. Sour compression process also shows good emissions control performance.

CO₂ purification and compression

After the flue gas clean-up, the cleaned flue gas is compressed for transport. The cleaned-up flue gas still contains a large amount of impurities such as N₂, O₂, Ar and CO. The fraction of these impurities ranges widely, depending on factors such as the purity of oxygen for combustion, amount of air leakage and fuel specifications. These gases, together with the remaining NO_x and SO_x, can be removed during the compression process as presented in Figure 4.8. Sulphur contents are first removed by activated carbon filter and then further reduced in the compression process by being absorbed, together with NO_x, by water/condensate. A large fraction of the CO₂ is separated from other gases in the adsorber. As a result, up to more than 10% of the CO₂ will be vented together with impurities.

Table 4.8 de-NO_x and de-SO_x performance of two different oxyfuel combustion flue gas clean-up systems. Standardization between both systems is performed assuming a flue gas CO₂ concentration of 85 vol.% (dry).

		Separate SCR, FGD and FGC (Burchhardt, 2009)	Sour compression process (integrated) (White et al., In Press, Corrected Proof)	PC plant without CO ₂ capture (data found in the literature (see Appendix C))
SO ₂	Emission level (mg/MJ LHV)	<1.1	14	12-70
	Removal rate	> 99.8 % ^a	98%	---
NO _x	Emission level (mg/MJ LHV)	< 24 ^b	6 ^c	20-98
	Removal rate		> 90% ^c	---
NH ₃	Emission level (mg/MJ LHV)	Dependent on SCR performance	0	0.4-1.3
Dust	Emission level (mg/MJ LHV)	< 0.06	N.D.	0.83-5.9
	Removal rate	> 99%		---
CO ₂ -rich gas outlet pressure		0.3 bar (after FGC)	30 bar	---
Mercury removal		N.D.	~100% ^d	---

a: FGD removes around 97% of inlet SO₂ (7500 mg/Nm³ inlet concentration) and FGC removes 93-97% of SO₂ at an inlet concentration of approximately 135 mg/Nm³ (Yan et al., 2009). FGC also removes 58-78% of SO₃ (Yan et al., 2009). The SO₃ removal efficiency of FGD is not presented in the literature. b) No SCR is used. FGD reduces NO₂ by around 70% (from 170 to 51 mg/Nm³), but does not remove NO (Yan et al., 2009). FGC does not remove much NO_x either. The pilot plant results show a slight decrease in NO (from 372 to 356 mg/Nm³) and a slight increase in NO₂ (due to oxidation of NO: from 51 to 65 mg/Nm³) with comparable total NO_x concentration in terms of mg/Nm³ (Yan et al., 2009). c) Emission levels expressed in NO₂ terms. 90% reduction of NO_x is achieved only by the first washing process (see Figure 4.7) at 14 bar during the pilot plant experiments. Higher NO_x removal rates were observed at higher gas pressures. NO_x is expected to decrease further after the second washing process at higher pressure. d) Experimental results indicate that any mercury present is removed from the gas phase with the first acidic condensate stream.

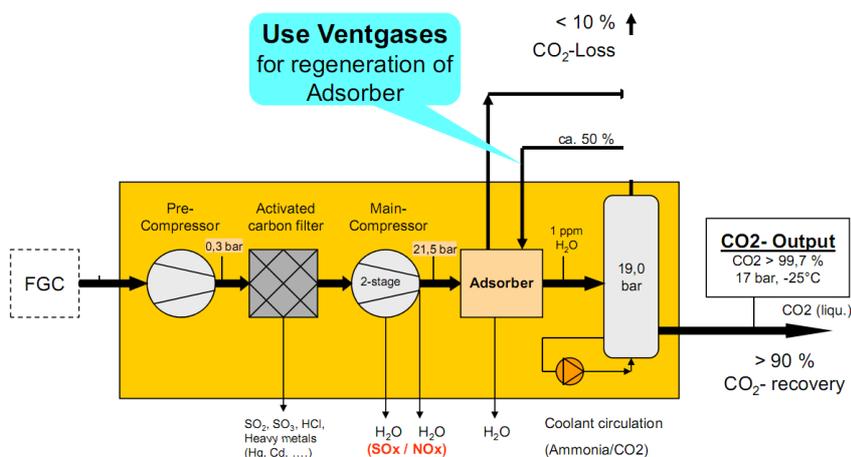


Figure 4.8 A detailed flow diagram of the CO₂ compression unit (Burchhardt, 2009).

Table 4.9 presents the NO_x and SO_x emission reduction performance of the compression process observed during the pilot plant tests. The results show that oxyfuel with CO₂ capture can achieve very low NO_x and SO_x emissions even when the pollutants are not sequestered together with the CO₂.

Table 4.9 NO_x and SO_x removal performance in the CO₂ compression process. (Burchhardt, 2009). CO₂ recovery rate is assumed to be 90% for the calculation of NO_x and SO_x emissions.

NO _x		SO _x	
Emission level (mg/MJ LHV)	Removal+co-sequestration rate	Emission level (mg/MJ LHV)	Removal+co-sequestration rate
~0.12	~99.7%	~0.12	~90%

Energy requirement for oxyfuel flue gas clean-up, purification and compression

The energy requirement for the CO₂ compression process depends largely on the following factors (Ritter et al., 2009):

- Content of raw gas composition (especially CO₂ content);
- Required product quality (especially O₂ content);
- Required CO₂ recovery rate;
- Arrangement of process equipment, variation of process designs.

Figure 4.9 presents the influence of the flue gas composition on the specific energy consumption as calculated by (Ritter et al., 2009). The figure shows that the higher the CO₂ concentration in the flue gas, the lower the specific energy consumption. Similar results were presented in another modelling study on the oxyfuel combustion gas purification using two different phase separation techniques (Pipitone and Bolland, 2009). The specific energy consumption were found to be around 125 kWh/tCO₂ at 95-96% recovery for natural gas fired flue gas (75.1 % CO₂) and 163-168 kWh/tCO₂ at 87-88% recovery for coal fired flue gas (62.6 % CO₂).

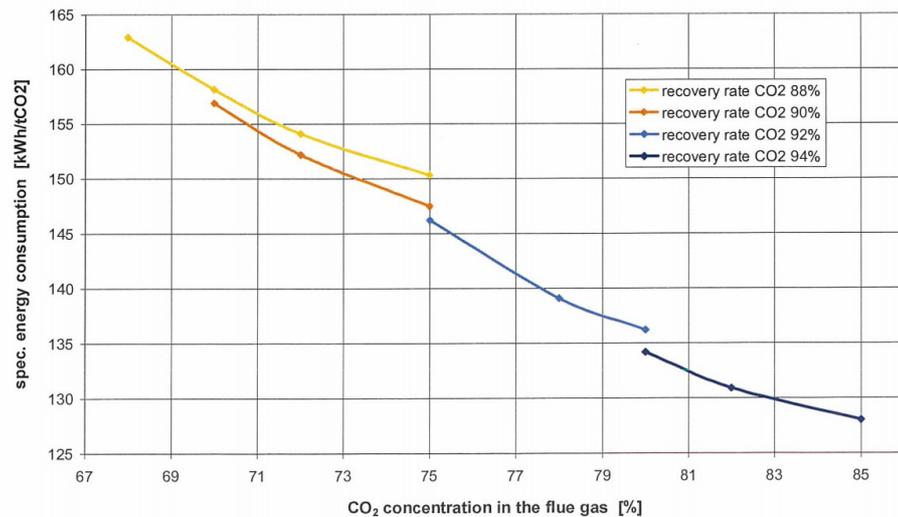


Figure 4.9 Influence of the flue gas composition (to 100 bar) on the specific energy consumption (Ritter et al., 2009).

Economic costs for oxyfuel flue gas clean-up, purification and compression

At the moment there are no cost estimates publicly available on the clean-up, purification and compression of oxyfuel combustion flue gas.

Conclusions

A number of pilot plants have been testing the clean-up, purification and compression of CO₂-rich oxyfuel combustion flue gas. For flue gas clean-up, two systems have been studied. The first system comprises of a separate de-NO_x, de-SO_x units and a flue gas condenser. The second system is an integrated system in which flue gas is washed in water at higher pressures up to 30 bar. Pilot plant test results show that both systems would maintain the concentration of most NEC pollutants in the flue gas significantly lower than those for conventional coal-fired plants without CO₂ capture.

Moreover, the pilot plant test results show that NEC pollutants will be further reduced in the CO₂ purification and compression process, in which impurities such as N₂, O₂, Ar and CO are removed. The amount of NO_x and SO_x vented to the atmosphere per MJ fuel input will likely be well below 10% of those contained in the flue gas after clean-up.

Overall, it is safe to say that oxyfuel CO₂ capture from coal-fired plants can achieve more than 90% reduction for NO_x, SO_x and dust emissions per MJ fuel input compared to those emissions from conventional coal-fired plants without CO₂ capture.

However, the flue gas purification, will reduce the amount of captured CO₂ by up to 10%, increase the specific energy consumption for CO₂ compression, and most likely will increase the costs as well.

4.3 Co-firing biomass with CO₂ capture (BECS)

CO₂ capture and storage has increasingly gained attention as a means to combat climate change. Likewise, significant attention is being given to the use of biomass for energy purposes. Because CO₂ capture and storage is also possible for biomass based power generation, the concept of BECS is becoming a very promising one. The ability of such integrated systems to produce energy products with negative⁵ net atmospheric carbon emissions could have important implications for mitigating anthropogenic climate change. In this section a first assessment is conducted on first, the technical feasibility of combining biomass energy systems with CO₂ capture technology; and secondly, on possible barriers and opportunities for BECS deployment and its impacts on NEC emissions.

Even though (co)firing biomass with CO₂ capture seems to be a promising option to reduce CO₂ emissions, available literature/data is very limited. The information presented in this section has been gathered from national and international literature and from interviews with experts on both issues.

⁵ There is ongoing discussion if BECS deliver the negative CO₂ energy. The principle is that during their growing process, plants capture CO₂ by photosynthesis, thus reducing the level of CO₂ in the atmosphere. When plant matter (biomass) is burned, the CO₂ is released into the atmosphere again. However, if it is captured and stored by CCS, the CO₂ can be kept out of the atmosphere.

4.3.1 Co-firing biomass

As the name suggests, co-firing refers to the simultaneous combustion of different types of material. From a technical perspective, there are three different concepts of co-firing biomass (see Figure 4.10. (Baxter and Koppejan, 2006)):

- **Direct co-firing** is the most straightforward, most commonly applied and low-cost of all three options. Biomass fuel and coal are burned together in the same furnace, using the same or separate mills and burners depending on the biomass fuel characteristics.
- **Indirect co-firing** can use a biomass gasifier to convert solid biomass raw materials into a clean fuel gas form, which can be burnt in the same furnace as coal. The advantage of this method is that a wider range of biomass fuels can be used and the fuel gas can eventually be cleaned and filtered to remove impurities before it is burned.
- **Parallel co-firing** requires at least two boilers as biomass is burned in one and fossil fuel in another.

The complexity of the co-firing process is installation specific. Each co-fire process has unique operational requirements, constraints and demands on the fuel quality, resulting in various co-firing percentages.

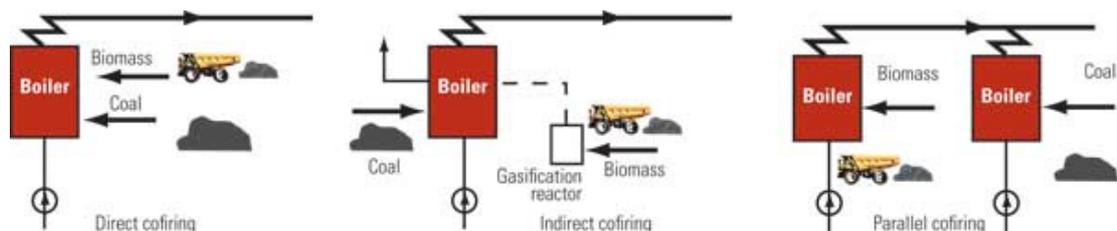


Figure 4.10 Three co-firing options (Eisenstat et al., 2009).

Effects on emissions

In general, co-firing biomass with fossil fuels provides means to reduce SO₂, CO₂ and Particulate Matter (PM) emissions and it may also reduce NO_x emissions of the plant. However, the amount of emitted pollutants strongly depends on the type of biomass, the used combustion technology, the applied process conditions and, the used emission reduction measures (Boersma et al., 2008). The characteristics of biomass are very different from those of coal. The carbon content in coal can reach 87%, with 80% as average while for biomass it is around 50%. The content of volatile matter in wood-based biomass is generally close to 80%, whereas in coal it is around 30%. In general biomass fuels are lower in sulphur and nitrogen compared to coal, with exception of specific waste streams. This implies that blending wood biomass with coal lowers emissions simply because of dilution. A very important difference between both fuels is the net calorific value. Biomass fuels often have high moisture content which results in relatively low net calorific value (European Bioenergy Network, 2004). Appendix E presents typical properties of different fuels.

Carbon dioxide (CO₂)

CO₂ is a major combustion product from all biomass fuels, originating from the carbon content in the fuel. However, CO₂ emissions from biomass combustion are regarded not to contribute to the greenhouse gas effect. Biomass is considered to be a (nearly) CO₂ neutral substitute for fossil fuels and as a mean for sequestering carbon in terrestrial ecosystems (Rhodes and Keith, 2008). Consequently, biomass has an emission factor of zero in the EU Emission Trading Scheme. This means that the combustion of every tonne of biomass is considered as non-emitted CO₂. The rationale behind, and major benefit of biomass combustion, lies on the assumption that the net emission of CO₂ from biomass combustion is zero as plants use the same amount of CO₂ during growth that is released during combustion. The IPCC default CO₂ emission factors for stationary combustion in the energy industries are within the same range for both solid biomass and coal ~100 (96-112) (tonne/TJ) based on a net calorific value (IPCC, 2006). This means that for biomass as well as for coal the same volume of CO₂ is expected. Moreover, the same concentration of CO₂ in the flue gas is expected since solid biomass has almost the same characteristics as brown coal. Note that due to the lower heating value of biomass (compared to coal), more biomass will be combusted to obtain the same energy output. However, less air will be added during the combustion process because of the lower carbon content.

A final point should be noted regarding the use of biomass for biofuels production (liquid or gaseous fuels used for transport and produced from biomass, i.e. biodegradable waste and residues). Though biofuels are not within the scope of this analysis, it should be mentioned that biofuel crops vary considerably in their environmental impact and while they may offer advantages in terms of CO₂ emissions compared with their fossil based alternatives (petrol or diesel), their wider environmental impacts are still debated (VIEWLS, 2005). Taking the entire production and application chains into account, current biofuels lead to lower CO₂ emissions, but in most cases they are not carbon neutral.

NEC pollutants: SO_x, NO_x, NH₃, NMVOC and Particulates

A life cycle assessment⁶ made by the National Renewable Energy Laboratory in USA examined five energy systems: biomass IGCC, average coal, co-firing biomass and coal (5 and 15% on energy basis), direct-fired biomass and natural gas (Mann and Spath, 1997; Mann and Spath, 2009). The results are presented in Figure 4.11. Co-firing was found to significantly reduce the environmental footprint of the average coal-fired power plant. Changing from coal to co-fired biomass gives better environmental performances for all NEC substances. Additionally, at rates of 5% and 15% by heat input, co-firing reduces greenhouse gas emissions on a CO₂-equivalent basis by 5.4% and 18.2%, respectively (Mann and Spath, 2001).

⁶ This means that it was a cradle-to-grave manner of the assessment to cover all processes necessary for the operation of the power plant, including raw material extraction, feed preparation, transportation, and waste disposal and recycling.

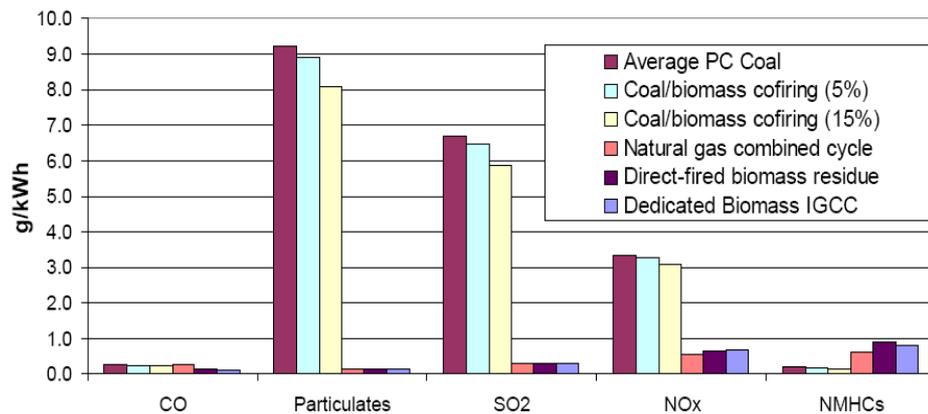


Figure 4.11 Life cycle analysis of NEC pollutants for various power systems (Mann and Spath, 2009).

The net effect on emission levels of co-firing biomass in Dutch coal power plants is expected to be limited due to the low share of biomass (up to 15% on energy base), the composition of the fuel (low in sulphur and nitrogen compared to coal) and the extensive flue gas cleaning that is currently installed. Moreover, some of the positive environmental effects of co-fired biomass (compared to coal) are reduced by emissions occurring upstream (biomass production) as well as by the loss in power plant efficiency. Power plant efficiency was respectively 1.5 and 3% lower for 5 and 15% biomass co-firing compared to no co-firing (Mann and Spath, 2001; Mann and Spath, 2009).

SO_x

According to various studies, the use of biomass in coal fired power plants will reduce emissions of SO_x (Leckner and Karlsson, 1993; Loo and Koppejan, 2003). Due to the relatively low sulphur content of most biomass fuels⁷ relatively low emissions of SO_x are expected compared to coal firing (Boersma et al., 2008). Smaller quantities of sulfur in the feed also result in a reduction in the amount of lime and limestone required for flue gas clean up. Actual reduction in SO₂ will depend on the quantity of sulphur in the coal being used and the amount of scrubbing that is practiced at a given power plant (Mann and Spath, 2001).

NO_x

Contradictions exist in the literature about the effect on nitric oxides emissions (NO_x). Possible gas-phase reaction mechanisms for NO_x formation in biomass combustion applications are: the fuel NO_x, the thermal NO_x and the prompt NO_x mechanisms (Loo and Koppejan, 2003). The “thermal NO_x” is very dependent on the flame temperature. Adding biomass can reduce flame temperatures, leading to lower levels of “thermal NO_x”. However, NO_x emissions vary significantly among combustion facilities depending on their design and controls. Initially, NO_x emission reductions (“fuel NO_x”) can be observed and can be attributed to changing (lowering) the amount of nitrogen in the fuel blend. However, this may not be the case in full-scale biomass and coal co-

⁷ Most biomass fuels are lower in sulphur content but it should be noted that it depends on the biomass type e.g. straw can have a relatively high sulphur content compared to the woody materials.

firing applications. In that situation many other engineering factors contribute to NO_x formation. For instance, some biomass power plants show a relatively high NO_x emission rate per kWh compared to other combustion technologies. Utility boilers are far from isothermal, and adding biomass to a pulverised coal-fired boiler can significantly change the flame structure and characteristics. The high volatiles content of biomass can effectively establish a fuel-rich zone early in the flame that can reduce NO_x emissions. On the other hand, N₂O emissions seem to be higher. The high moisture content of some biomass may also be effective for NO_x reduction at full-scale (Leckner and Karlsson, 1993).

NH₃

Currently, there is no consensus in the level of NH₃ emissions as a consequence of co-firing biomass and many contradictions exist. Available data on NH₃ emission is very limited. In general, when biomass is combusted, NH₃ emissions are generally very low (a few ppm for fluidized bed combustion). This occurs as a result of incomplete conversion of ammonia, formed during pyrolysis or gasification, into NO_x. However, when a de-NO_x installation with addition of urea or ammonia is installed (ammonia slip), the NH₃ emissions can be even higher than for a coal-fired installation (Boersma et al., 2008). The reported range of NH₃ emission factors found in the literature for biomass is 1-21 mg/MJ (see Appendix F).

Non-methane hydrocarbon emissions (NMVOC)⁸

The NMVOC group includes all hydrocarbons except CH₄, PAH and other heavy hydrocarbons. As shown in Figure 4.11, changing from only coal combustion to 5- 15% biomass co-firing slightly reduce NMHCs emissions. Appendix F presents the summary of reported emission factors.

PM

Report measurements of specific dust emissions are often missing in the literature. In general however biomass fuels have a low ash content (Boersma et al., 2008). For typical properties (contents) of solid fuels (coal as well as biomass) please see Appendix E.

Effects on plant operation

There are a number of technical problems, constraints and issues associated with co-firing biomass that need to be considered. Figure 4.12 gives an overview of the main effects of co-firing in a coal-fired boiler.

⁸ Non-methane hydrocarbons (NMHC) and non-methane volatile organic compounds (NMVOCs) are used interchangeably in the literature.

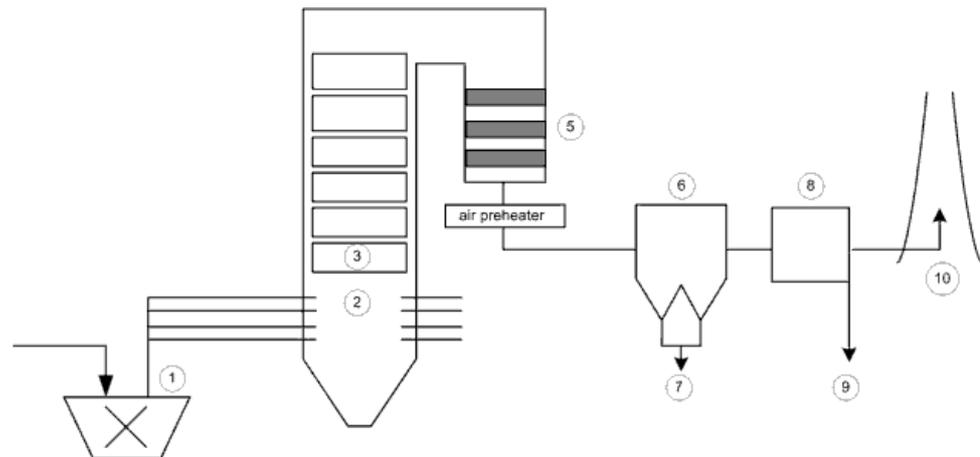


Figure 4.12 Effects of biomass co-firing on a coal-fired power station (Spliethoff et al., 1996). 1: grinding equipment: reduced capacity and lifetime of; 2: combustion chamber: slagging, 3: superheater: high temperature corrosion, 4: heat exchanger: depositions and erosion, 5: deNO_x installation: capacity, poisoning, 6: Electric precipitator: capacity, 7: ash: utilisation, 8: deSO_x installation: capacity, 9: utilization of residues from desulphurisation, 10: flue gas: emissions.

The use of biomass in power plants is affected by the quantity and quality of the feedstock available, location of the consumers, type and value of energy services required. The collection, transport, storage and handling of biomass are still more costly per unit of energy than fossil fuels because prior to conversion, biomass feedstocks have a lower energy density per volume or mass compared with equivalent fossil fuels (IPCC, 2007). Different technical barriers occur at all steps of biomass co-firing (from preparation to ash utilization) (SLU, 2006). Furthermore, the use of many different kinds of biomass material⁹ together with the variety on the kinds of coal used in co-firing plants (peat, lignite, bituminous coals, anthracite etc) will result in a vast diversification of technical problems when co-firing is practiced (Sami et al., 2001).

Low moisture and low volatile matter content biomass would be better for co-firing with coal, since dry wood has a higher net heating value and dirt in the wood may cause boiler damage and increase the amount of disposed ash. Moreover, biomass with high moisture content may need dewatering or drying prior to combustion. Higher volatile matter content means that biomass materials are more reactive to combustion processes than are most coals. Summarizing, the most important technical barriers found in the literature include (Spliethoff et al., 1996; Sami et al., 2001; Loo and Koppejan, 2003; SLU, 2006):

- Fuel flexibility/availability (quality and quantity)
- Lack of appropriate infrastructure for transport / logistic / storage / cleaning / pulverization
- Higher risks (spark ignition, explosion or fire)
- Pre-treatment issues (milling / drying)
- Thermal behaviour and efficiency (lower heating value)
- Complete combustion and well mixing in boiler (flammability)
- Fouling, clogging, slagging and corrosion of the boiler (alkalis, chlorine)

⁹ Wood waste as sawdust, planer savings, chips, bark, firewood plantations, forestry residues, urban wood waste, short rotation woody crops as willows, poplars, black locust, agricultural wastes as rice hulls, straws, orchard and vineyard prunings, animal waste, sewage sludge, and a range of other materials.

- Negative impact on flue gas cleaning system (SCR, FGD, ESP)
- Aging and deactivation of catalytic deNO_x
- Ash quality
- Ash utilization (unburned carbon, contamination)
- Possible increase of deposition rates
- Additional investments costs for biomass pre-treatment and boiler retrofitting
- Higher operational costs due to increased corrosion and maintenance
- Other operational challenges

Moreover, there are many non-technical barriers related to economic, social, environmental and political aspects, which stimulate currently ongoing discussion about the use of biomass. These problems are beyond the scope of this project and are not further discussed in this report.

Electric efficiency of biomass based power plants

Biomass is often combusted in relatively small installations. Most current biomass conversion is based on direct combustion in small, biomass-only plants (~20MW_e) with a relatively low electric efficiency of about 20% (LHV)¹⁰. The steam pressure and temperature are much lower than with the advanced coal-fired power plants. According to BAT¹¹ levels, new coal plants can achieve net electrical efficiencies in the range of 43-47% (PC) and more than 41% (FBC), while biomass-only power plants can achieve efficiencies of 20-30% (depending on the technique: grate-firing, spreader-stoker, FBC). Note however that the BAT levels of possible electric efficiency are often higher than the ones observed in practice.

Co-firing of woody biomass can result in boiler efficiency reductions, typically of about 1% (with a 10% biomass fuel in the co-firing). This is caused by biomass having a lower energy density and higher moisture content than coal. Thus the combustion efficiency for biomass (100%) is 10% lower than for coal when fired in the same installation (IEA, 2008b)¹².

The electric efficiency of PC plants with co-firing can decrease as a result of substituting coal by biomass. The main reported reasons for decreased efficiency are (Damen and Faaij, 2003):

- Energy requirement of the coal mills might increase when biomass is added as a result of the biomass structure;
- Decreased boiler efficiency as a result of biomass properties (e.g. chemical composition and moisture content) and related gas stream properties (heat exchange coefficient);
- A decrease in carbon burnout might occur;

¹⁰ Generally, biomass based power plants produce electricity with relative low efficiency (18-22%) comparing to large-scale coal fired power plants (32-38%).

Best Available Technologies are a key concept of the IPCC Directive (96/61/EC). BAT is defined in Section 5 of Environmental Protection Agency Acts, 1992 and 2003, and Section 5(2) of the Waste Management Acts 1996 to 2005, as the “most effective and advanced stage in the development of an activity and its methods of operation, which indicate the practical suitability of particular techniques for providing, in principle, the basis for emission limit values designed to prevent or eliminate or, where that is not practicable, generally to reduce an emission and its impact on the environment as a whole”.

¹² In the literature, efficiency of co-firing biomass is reported on average, 0-10% points lower than the efficiency of coal combustion in a PC plant. However, it should be noted that the efficiency penalty depends on the biomass type and the combustion process characteristics.

- Biomass has a lower calorific value than coal. The volume flow of fuel, air and resulting flue gas increases for similar boiler and turbine capacity of a PC plant without co-firing.

Co-firing of biomass with coal can increase overall biomass-to-electricity conversion efficiency. In general, small to medium-sized installations (up to several megawatt thermal [MWth]), including those using biomass, biofuels or biogas, emit relatively high amounts of air pollutants (per unit of heat or electricity), compared to large-size power plants. The main reason is that small-sized installation use less advanced combustion technologies and flue gas cleaning systems. Furthermore, the emission limit values for small-sized installation are less strict. However, the Dutch Government is reviewing its decree on emission limits for smaller combustion plants (BEES-B) and those limits are expected to be tightened (Netherlands Environmental Assessment Agency, 2008a; Kroon and Wetzels, 2009).

4.3.2 Cofiring Biomass in combination with Carbon dioxide Capture and Storage
CCS in a conventional power plant is seen by many as a key technological option to reduce CO₂ emissions. However, the carbon releases from biomass conversion can also be captured and stored. If that is done, biomass energy with CO₂ capture and storage (BECS) would become a technology that removes CO₂ from the atmosphere and at the same time deliver energy carriers (heat, electricity or hydrogen) to society as shown in Figure 4.13 (Azar et al., 2006).

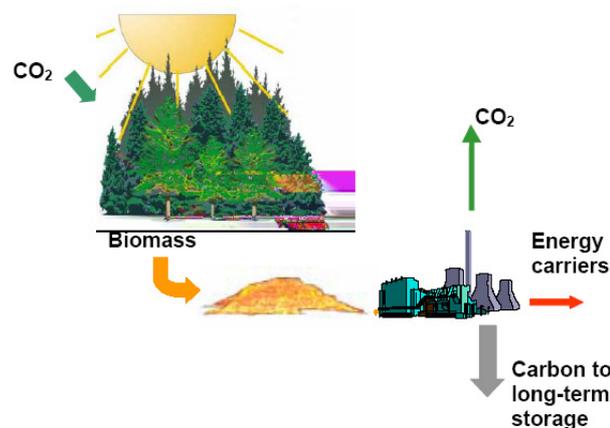


Figure 4.13 The principle of bioenergy with CO₂ capture and storage (BECS) (Möllersten et al., 2007) .

Technology processes for BECS

Large-scale implementation of biomass with CO₂ capture technologies is, technically speaking, a straightforward concept. The first step consists on replacing (part of) fossil feedstocks with biomass in large-scale plants, such as power plants or process industries such as cement factories and steel mills. Biomass combustion is already happening at the industrial level, either through co-firing biomass with coal or by using solely biomass. Vattenfall, for example, is investing in a program to use co-firing on three power plants in Denmark. The plan is to replace 0.75 million tonnes of coal with 1.2 million tonnes of biomass by 2013. Similarly, Drax has announced plans to build three dedicated (300MW) biomass power plants and a 400 MW biomass co-firing plant in the UK. The second step is to add CO₂ capture technologies to the facility. Vattenfall's first

commercial-scale CCS demonstration plant is being built at Nordjyllandsværket in Denmark. This is one of the plants which Vattenfall plans to co-fire with 30% biomass (Bellona, 2009a; Bellona, 2009b).

Biomass-based energy conversion with CO₂ capture can be divided into four main process groups (see Figure 4.14) (Möllersten et al., 2003). As discussed in the previous section, biomass has important similarities with coal, including conversion technologies and the range of energy products that can be generated. In principle, all three CO₂ capture technological approaches designed for fossil fuels systems (such as gasification and oxy-fuel) could theoretically be applied to bio-energy systems. Biological processes provide a fourth additional CO₂ capture opportunity. CO₂ can be recovered from the process of fermenting sucrose to produce ethanol. Nevertheless, the technical performance of such pathways remains uncertain (Rhodes and Keith, 2005; Rhodes and Keith, 2008).

In processes within the **pre combustion** group, biomass is gasified and CO₂ is captured before the fuel gas is combusted or converted to refined liquid or gaseous fuel such as methanol. **Oxygen combustion** capture covers processes based on air separation with the subsequent combustion of biomass in oxygen instead of air. There is almost only CO₂ in the flue gas because the water is condensed. This technology has not been demonstrated and should be regarded as long-term. Technically mature biomass combustion systems with CO₂ capture from flue gases are represented by the **post combustion** group. It is a conventional approach for CO₂ capture and it has achieved widespread industrial application. Finally, the last group is the collection of CO₂ produced during biomass conversion to secondary fuels. The processes from the last two groups are technologically mature in industrial applications. They are applied in pulp and paper (Kraft pulp mills) and cane sugar sectors. An example is sugar fermentation process to yield ethanol. The CO₂ conversion process is carried out as the final stage of ethanol production from biomass, either from corn, sugar cane, sugar beet, or even cellulose.

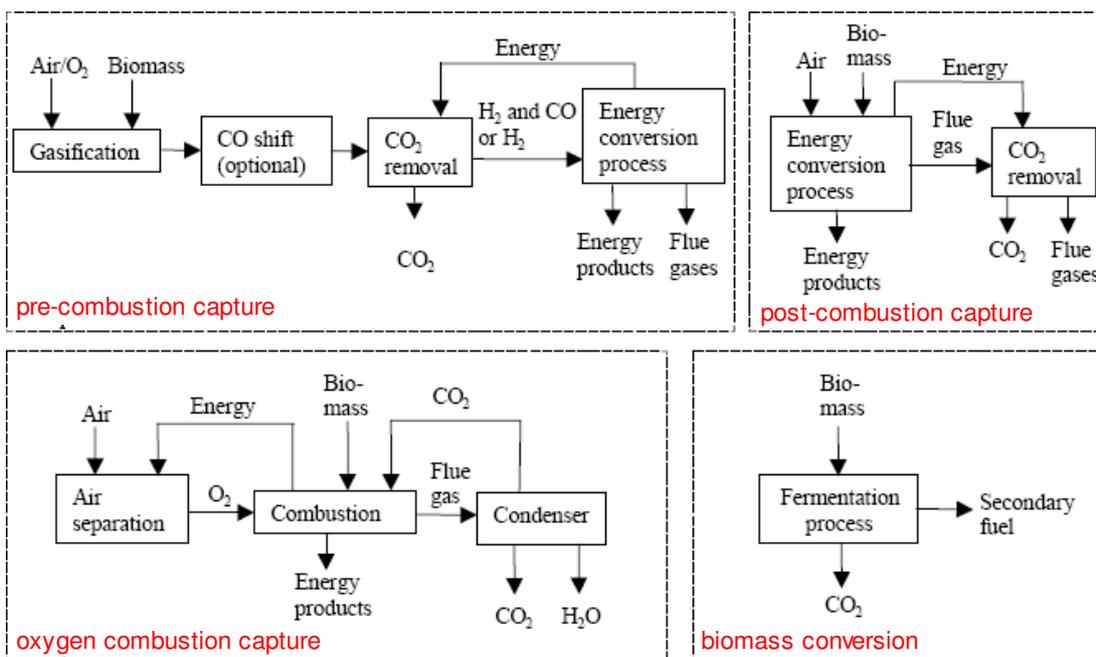


Figure 4.14 Main process groups for biomass-energy conversion with CO₂ capture (Möllersten et al., 2003).

Even though a broad variety of BECS “technology chains” can be envisaged, linking different biomass feedstock sources, biomass pre-treatment and transportation systems, and co-firing technologies, only a few BECS “technology chains” have been studied in detail (Möllersten et al., 2007). Since the available literature is very scarce, the (possible) effects of BECS on emissions and plant operation reported in this study are based on interviews carried out with (inter)national experts in the field of biomass and or CO₂ capture.

Effects on emissions

Though an exact range is unknown, experts expect that almost the same effects on NEC emissions¹³ will occur as for co-firing biomass (section 4.3.1).

Effects on plant operation

All experts agreed that, in theory, all three main capture technological routes (post-, pre- and oxyfuel combustion) are possible with co-firing biomass. Some experts pointed out the post combustion route as the most feasible for BECS because it is the most developed technology. On the other hand, post combustion can be considered as difficult and not efficient, because a large amount of inert gas has to be treated. Further the efficiency penalty is significant. For some experts, the effect of co-fire biomass (10-15% on energy basis) with post combustion CCS is expected to be limited. The effect of co-firing higher percentages remains unknown.

Some experts also claim that post combustion capture can be considered to be problematic because some components of biomass may possibly interact with the SCR catalyst in such a way that the activity of the catalyst may decrease. It was also noted that it is still too early for co-feeding oxyfuel. This technology is not ready yet.

According to experts, there are no obvious technological barriers to co-fire biomass together with CO₂ capture. It is expected that the (possible) problems that may occur when biomass is co-fired will remain at the same level when CO₂ capture technologies are also deployed (see section 4.3.1). Biomass has a higher flammability resulting on an increase in the “spot” flame temperature, which can lead to damages on the equipment. Very important, and a main drawback, is the lower heating value of biomass which will probably result in a lower energetic input and thus a lower energetic output. This restriction is important for gasifiers because the produced gas volume is limited. Also a lower efficiency due to the cofiring will be made more problematic by the energy penalty induced by the CO₂ capture process. Ash fouling can also be a problem due to different composition and melting temperature of biomass ash compared to coal ash. However, when appropriate investments and improvements have been done to co-fire biomass with coal, experts do not perceive further obstacles. The experts believe that the flue gas cleaning facilities (FGD, SCR and ESP) working for coal-fired power plants would also be enough when biomass is co-fired (up to 15-20%). This is due to the nature of the combusted coal and the combustion conditions.

¹³ SO_x, NO_x, PM, NMVOC.

Scale effect

The cost of CO₂ removal depends strongly on the plant size. CO₂ capture is more effective and less costly when carried out in large plants. Coal fired power plants ranges in size from 500 to over 1000 MWe are common in the world and natural gas-fired power plants with unit sizes of several hundred MWe are abundant. Pulp and paper mills, along with sugar cane based ethanol mills, are among the few industries where large-scale bioenergy conversion takes place. The fact remains, however, that most of the biomass in the world is currently used at small scales. Therefore, the costs of removing CO₂ in small biomass plants are expected to be significantly higher than those of fossil fuel based only power plants. Larger biomass plants could potentially benefit from economies of scale, decreasing the capture costs. However since larger amounts of biomass would be required, fuel transportation costs are also expected to increase. This mismatch between the scales of economically viable bio-energy deployments and CO₂ capture could be a challenge for BECS. However, co-firing smaller amounts of biomass in large-scale power plants seems to be a good alternative. Co-combusted biomass benefits from the scale effects of coal in terms of higher efficiency and lower costs. BECS remains a possible key technology for the medium and longer term. As stated by the IPCC report “it is perfectly conceivable that BECS technologies might play a significant role by 2050 and produce negative emissions across the full technology chain” (IPCC, 2005). This would require a major increase in large-scale biomass energy conversion on a global scale compared to the current situation (Möllersten et al., 2007).

Co-firing biomass and BECS in the Netherlands

In the Netherlands, biomass covers about 2% of the energy demand. It is estimated that it could make a much larger contribution. For instance The Dutch Platform Groene Grondstoffen¹⁴ estimated that biomass could supply 60% of transport fuels, 25% of chemicals and materials, 17% of heating requirements and 25% of the electricity demand by 2030. Since the Netherlands have a limited agricultural area, 60 - 80% of the needed biomass raw materials will have to be imported to achieve these goals.

Biological Routes in the Netherlands

Some of the biological routes (e.g. digestion of manure and other wet streams) are widely applied in the Netherlands. The produced gas is mainly combusted in gas engines to produce power and low temperature heat. There are possibilities to upgrade the gas to natural gas quality. The theoretical maximal potential in the Netherlands is estimated to be 50-60 PJ/yr (the total annual gas consumption is around 1500 PJ/yr) (Lenstra et al., 2009). Next to digestion there is a potential for ethanol produced from biomass by fermentation. It is estimated that at the moment there is 790 kt/a bio-ethanol from wheat/potatoes production capacity planned to be operational in 2011 (Milieudefensie, 2008). An example is the Bio-ethanol Rotterdam BV facility (BER). The primary goal of BER BV is the production of two different bio fuels: bioethanol and SuBERgas[®]. The production will be carried out without using fossil fuels and with capture of all CO₂ from the production process. BER BV will produce 110 kt/a of bio-ethanol from approximately 350 kt of wheat (Bio-Ethanol Rotterdam BV, 2009).

¹⁴ For more information we refer to <http://www.senternovem.nl/energietransitiegg/Index.asp>

Gasification Routes in the Netherlands

There are some projects being considered on bio-SNG, which is a substitute of natural gas made from biomass. A study made by by NUON present some power plants based on gasification technology that can be fired on coal, gas and biomass as CCS ready. (NUON, 2009b). These plants are also presented as opportunities for the combination of biomass and CCS. The potential will depend on the amount of biomass that can and will be co-fired.

Combustion Routes in the Netherlands

Co-firing of biomass in pulverized coal fired power plants in the Netherlands is not a new technology and it occurs quite extensively in the Netherlands (see Figure 4.15).

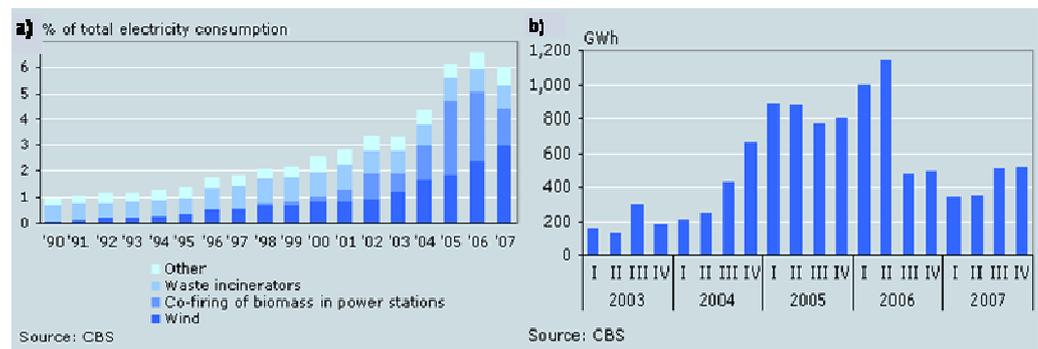


Figure 4.15 a) Renewable electricity from domestic energy sources (CBS, 2009). b) Electricity generated by co-firing of biomass in power stations (CBS, 2009).

Biomass combustion and co-firing played an important role in the total sustainable energy production, especially in the period 2000-2006. The electricity production from biomass as co-firing fuel has reduced significantly from 2.5% to 1.3% in 2007 as a result of change in the subsidy programme. Nowadays, the Netherlands has 7 coal-fired units in 5 locations. Out of these, 6 units are co-firing on a commercial basis. The biomass is milled separately, often by equipment on-site. The pulverized biomass is either injected in the coal lines, or injected in separate feeding lines. Table 4.10 (KEMA, 2009) presents the Dutch existing biomass co-firing power stations and the co-firing percentage. It is important to mention that the co-firing percentages shown in the table correspond to what is possible and not what is currently co-fired.

Table 4.10 Biomass co-firing power stations in the Netherlands (Cremers et al., 2009).

Power station	Owner	Plant output (MWe)	Plant output (MWth)	Direct co-firing percentage (energy basis)
Amer Centrale	Essent	645	250	10 – 12%
Amer Centrale	Essent	600	350	27 (+ 5%)*
Borssele	EPZ	403	-	10 – 15%
Gelderland	Electrabel	602	-	5 – 8%
Maasvlakte	E.ON	2 x 531	-	6%
Buggenum	NUON	253	-	Unknown

* 27% direct co-firing and 5% indirect co-firing.

There are also cofiring power plants that are being planned or are under construction. Table 4.11 presents initiatives in the Netherlands for new-to-build coal fired units. All units are in the process of acquiring a permit for co-firing up to a certain percentage of biomass fuels.

Table 4.11 New-to-build initiatives in the Netherlands with application for co-firing. Status: first half 2009. (KEMA, 2009).

Initiative	Location	Fuel ^{a)}	Type ^{b)}	Power [MW _e] ^{c)}	Year into operation	Co-firing ^{d)}	Status / background
Nuon / Magnum	Eemshaven	Coal / petcoke / biomass / natural gas	IGCC	1200	2012 (gas) 2014 (coal)	30% m/m	Permit application
Electrabel	Maasvlakte	Coal / biomass	USC	800	2013	60 % e/e ^{e)}	None irrevocable permits
E.ON / MPP3	Maasvlakte	Coal / sec. fuels (incl. biomass)	USC	1100	2012	20% m/m	None irrevocable permits
RWE	Eemshaven	Coal / biomass	USC	2 x 800	2013	10% e/e	None irrevocable permits
C.gen	Europoort Rotterdam	Coal / petcoke / biomass / natural gas	IGCC	450	2014	30% e/e	Notification of intent, September 2008

^{a)} As a guideline with biomass is meant wood pellets and wood derived fuels, while secondary fuels also incorporate other derived fuels; ^{b)} IGCC: Integrated Gasification Combined Cycle power plants / USC: direct injection ultra supercritical boiler; ^{c)} Gross; ^{d)} m/m: mass based; e/e: energy based; ^{e)} This is the upper co-firing percentage from the Environmental Impact Assessment done by the Electrabel. It is doubtful that this percentage will be co-fired.

According to the Dutch Central Bureau of Statistics (CBS) in 2008 the net production of electricity from biomass was 2.2 TWh which resulted in 19.7 PJ production of renewable energy in terms of avoided use of primary energy and 1.7 Mt avoided CO₂ emissions. Electricity plants used 8.2 Mt coal in 2008. This is equivalent to an emission of 20.2 Mt¹⁵ of CO₂. Assuming that if coal is substituted by biomass almost no CO₂ is emitted per MJ compared to coal over the whole process chain. Thus 10-20% biomass co-firing on mass basis can give around 2-4 Mtonne/year CO₂ emission reductions without CCS. However, 16-18 Mtonne of CO₂ would still be emitted.

Another issue is the treatment of BECS under the EU Emission Trading Scheme (ETS). Although the role of CCS under the EU ETS has been addressed in the review of the EU ETS post-2012 by crediting CO₂ emissions captured by the use of CCS technologies as 'not emitted', there are uncertainties on how BECS can comply with the EU ETS. There is ongoing a very complex revision policy-making process relating to adaptation of guidelines for the monitoring and reporting of greenhouse gas emission under the ETS (MRG).

¹⁵ Based on a emission factor of 2.47 tonne CO₂/tonne coal for coal bituminous.

4.3.3 Conclusion

Substituting coal in large power plants with biomass can have neutral to positive effects on air pollution. In general, co-firing biomass with coal provides means to reduce SO₂, PM, NMVOCs and it may reduce NO_x emissions. There is not enough data to make any conclusion about possible effect on NH₃ emissions. However, use of biomass or biofuels in gas-fired power plants may increase air pollution, mainly emissions of SO_x and PM compared to natural gas.

It is expected that emissions of NEC pollutants will not be a problem due to BECS introduction. Large-scale implementation of biomass with CO₂ capture is technically speaking a straightforward concept. For low co-firing ratios there are no main problems expected, but there are poor combinations of fuel, boiler and operation process. Replacing a substantial share of fossil fuel by biomass requires intensive redesign of processes and installations.

Although biomass combustion and co-firing technologies can already be considered as proven, there is a continuous demand for equipment with lower investment and operational costs; increased fuel flexibility; lower emissions; increased reliability and efficiency.

The technology for capturing CO₂ would work on concentrated point sources from many fuels, including biomass. In principle, all three CCS technological approaches being advanced for fossil fuels systems (such as gasification and oxy-fuel) combustion could be applied to bio-energy systems.

For solid biomass as well as for coal the same volume of CO₂ is expected in the flue gases. Moreover, due to similar characteristics of solid biomass and brown coal, similar CO₂ concentrations are also expected in the flue gases. However, biomass could lead to an increase in the “spot” flame temperature occasioning damages on the equipment, and there are some concerns regarding ash fouling. The main drawback of BECS is the additional energy loss (reduction in output) when applying CO₂ capture due to double energy penalty, from both CCS (the average efficiency penalty for CCS is 10%) and biomass co-firing (in the range of 0-10%).

BECS will be implemented only if it is cost-effective. The treatment of BECS under EU ETS is still unknown and under discussion. Only if allowances are given to the negative emissions from biomass with CCS, BECS will become an attractive option. The status at the moment is that the CO₂ emissions from biomass count as 0 and no additional reward is planned for the combination of biomass and CCS, i.e., negative emissions are currently not acknowledged.

Commercial BECS options are currently limited for the short term and additional knowledge and research are needed on the techno-economic and environmental implications of BECS. In order to avoid technological uncertainties, it is at this moment recommended to keep both options (biomass cofiring and CO₂ capture at power plants) separate as long as enough coal-fired power plants are available in the power sector. It will help to avoid the double fuel penalty and possible technical complications, especially if shares above 10-20 % of biomass are desired.

4.4 CO₂ capture from industrial plants in the Netherlands

The industrial sector is one of the largest CO₂ emitters in the Netherlands. In 2006, the Dutch industrial¹⁶ and petroleum refining sectors accounted for about 35 million tonnes and 10 million tonnes of CO₂ emissions, respectively (PBL, 2008). As shown in Figure 4.16, these two sectors together emit an amount of CO₂ comparable to the public electricity and heat production sector.

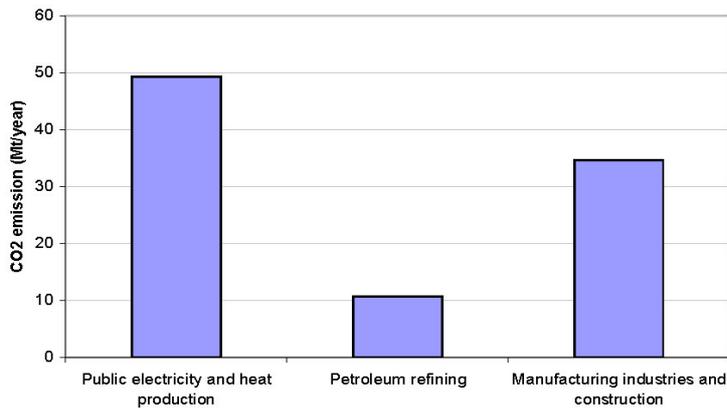


Figure 4.16 CO₂ emissions from various sectors in the Netherlands in 2006 (PBL, 2008).

CO₂ capture from industrial emission sources was briefly investigated in BOLK-I. In this report, an in-depth analysis on the feasibility and potential environmental effects of CO₂ capture from the industrial sector and the petroleum refining sector has been performed. Among various industries, the following were considered:

- Cement;
- Iron and steel;
- Petrochemical industries
 - Ammonia
 - High-purity hydrogen
 - Ethylene

The selected industries are generally considered to be the largest emitters among all industries (Table 4.12). For the analysis various CO₂ capture options proposed in the literature were considered. With regard to timeframe, the focus was on the implementation of CO₂ capture in the mid-term future (2020-2025).

¹⁶ Includes the following sectors and subsectors: “Manufacturing industries and construction” and “Industrial Processes”.

Table 4.12 Profile by process or industrial activity of worldwide large stationary CO₂ sources with emissions of more than 0.1 million tonnes of CO₂ (MtCO₂) per year (IPCC, 2005).

Process	Number of sources	Emissions (Mt CO ₂ per year)
<i>Fossil fuels</i>		
Power	4492	10539
Cement production	1175	932
Refineries	639	798
Iron and steel industry	269	646
Petrochemical industry	470	379
Oil and gas processing	Not available	50
Other sources	90	33
<i>Biomass</i>		
Bioethanol and bioenergy	303	91
Total	7887	13466

4.4.1 Pure CO₂ emission sources

There are a number of processes in the industrial sector that produces (almost) pure CO₂ streams, e.g. ammonia, ethylene oxide and hydrogen production. These CO₂ streams can be compressed and transported to the storage site without any additional gas treatment. Due to this, they are generally considered as an early opportunity for CCS. Table 4.13 shows the pure CO₂ streams available from industrial sites for storage in the Netherlands. The pure CO₂ streams altogether account for 2.6 million tonnes per year.

Table 4.13 Overview of industrial sites with pure CO₂ streams in the Netherlands (Adapted from (Damen et al., 2009)).

Sector	Plant name	City	Status	CO ₂ available for storage (kt/yr)	CO ₂ compression, transport and storage cost (€/tCO ₂)
Existing plants					
Ammonia	DSM/SABIC NH ₃	Geleen	operating	500 ¹	10
	Hydro Agri /YARA NH ₃	Sluiskil	operating	800 ¹	8
Ethylene oxide	Shell EO	Moerdijk	operating	130 ¹	17
	Dow EO	Terneuzen	operating	60 ¹	25
Hydrogen	Shell H ₂	Rotterdam	operating	600 ¹	9
	Esso H ₂	Rotterdam	operating	100 ¹	19
Plants to be built in the near future					
Bioethanol	Abengoa	Rotterdam	2010	350 ²	11
	BER	Rotterdam	After 2010 (?)	100 ³	19

¹ Damen et al. (Damen et al., 2009); RCI (Rotterdam Climate Initiative, 2008)
BER (Bio-ethanol Rotterdam, 2009)

4.4.2 Iron and steel industry in the Netherlands

The Corus IJmuiden plant is the only integrated iron and steel plant in the Netherlands (PBL, 2008) and by far the largest point CO₂ emission source, accounting for more than 10 million tonnes per year. General information on the Corus IJmuiden plant is given in Table 4.14. A literature review in the BOLK-1 report suggested that for Corus IJmuiden plant, pre-combustion CO₂ capture by shifting the CO-rich gas may be an option. It was also suggested that the CO₂ capture may become feasible on the medium to longer term, e.g. around 2020 (van Harmelen et al., 2008). In this report, we take a further look into the CO₂ capture possibilities for this plant.

Table 4.14 General data on Corus IJmuiden plant.

Annual steel production (ktonne/year)	Annual CO ₂ emissions (ktonne/year)	CO ₂ concentration (v/v)
7364	10,000 *	25% **

* The figure includes all carbon in blast furnace gas that is sold to NUON (Corus, 2007); ** Damen et al.(2009).

Case study: Corus IJmuiden plant

Figure 4.17 shows a simplified flow diagram of the Corus IJmuiden site. A general description of carbon flows in the iron and steel production process can be found in (Farla et al., 1995) and elsewhere.

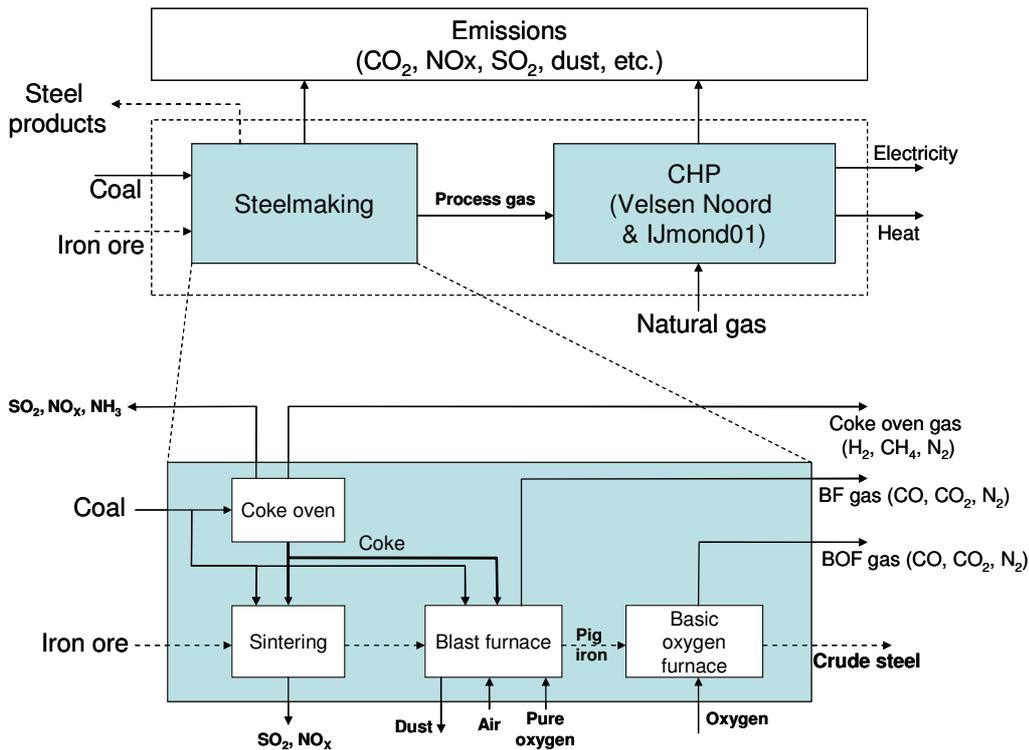


Figure 4.17 Simplified flow diagram of iron and steel production process.

At Corus IJmuiden, a significant amount of process gas from the steel making process is used in two CHP plants of NUON (Velsen Noord and IJmond01). With regard to carbon flows, generally around 85% of the carbon introduced into the process is present at one time in three gas flows; approximately 70% in the blast furnace (BF) gas, 9% in

the coke oven gas and 7% in the blast oxygen furnace gas (Farla et al., 1995). Because around 70% of the total carbon input emerges as either CO or CO₂ in the blast furnace gas, CO₂ capture from the blast furnace has been attracting much attention. The figures presented above indicate that for the Corus IJmuiden plant, total carbon of around 7 million tonnes of CO₂-equivalent flows out of the blast furnace each year.

CO₂ capture options

In a blast furnace (BF), pig iron and blast furnace gas is yielded by reducing iron ore with coal and cokes. BF gas contains CO₂ (17-25%), CO (20-28%), H₂ (1-5%), N₂ (50-55%), NH₃, hydrocarbons, PAH, sulphur and cyanide compounds (IPPC, 2001). The BF gas at the Corus IJmuiden plant contains very little hydrocarbon and no NH₃, cyanide compounds and PAH (Treadgold, 2009). Currently, most of the generated BF gas is exported to the neighbouring NUON CHP plants.

There are several ways to remove carbon from BF gas. It is an important choice whether or not to shift CO to CO₂ and capture it, because BF gas contains large amount of CO. Gielen (2003) proposed to capture CO₂ with a physical solvent (Selexol) after CO is converted to CO₂ via shift reaction. The main advantage of this method is high carbon removal rate (85-99.5% of the carbon contained in the BF gas can be captured). The main drawback of this method in the case of Corus IJmuiden is that the CHP plants may have to be re-designed or largely modified. The BF gas after shift reaction and CO₂ removal becomes hydrogen rich and thus, the existing gas turbines probably cannot bear the high combustion temperature (van Harmelen et al., 2008).

Gielen (2003) argues that this CO₂ capture technique can also be applied to oxygen blown blast furnaces. Such an option, however, is technically very difficult for at least retrofitting the existing iron and steel plants (Treadgold, 2009). A modern blast furnace has a large diameter, usually over 10 m, and the gas that is injected low down at the tuyeres¹⁷ must penetrate to the centre of the furnace. To enable the gas to penetrate, there are cavities in the coke bed behind each tuyere, which is often referred to as raceways. Using oxygen instead of air reduces the gas volume at the tuyeres and thus reduces or even collapses the raceways. Moreover, the flame temperature in the raceways must be controlled, as it would become too high in an oxygen blast furnace. It is therefore necessary to maintain the gas injection rate from the tuyeres to the blast furnace.

The injection gas can either be inert like N₂ or reducing (e.g. H₂ and CO) but it cannot be oxidising (CO₂ or H₂O). Using shift reaction hence requires the recycling of H₂, which is a useful reductant but the kinetics are different from those of CO. It might be possible to operate at blast furnace with a high H₂ concentration, but that is another process development which would take major R&D efforts. Taking these arguments into account, CO₂ capture using shift reaction and oxygen blast furnace is not investigated further in this report.

Other authors have proposed to capture CO₂ directly from BF gas without shift reaction. The CO₂ can be captured via vacuum pressure swing adsorption (VPSA: (Danloy et al., 2009)), physical absorption (Lampert and Ziebig, 2007), or chemical absorption such as MEA, MEA/piperazine mix and AMP (2-adenosine 2-amino-2-methyl-1-propanol)

¹⁷ A tuyere is a nozzle through which gases are blown into the blast furnace.

(Tobiesen et al., 2007; Torp, 2005). Blast furnace can be either air blown or oxygen blown. An advantage of using air blown blast furnace is that it does not require major modification on the blast furnace. The main disadvantage is the lower carbon removal rate compared to cases with shift reaction, because the carbon from CO will not be removed. An advantage for using oxygen blown blast furnace is that the BF gas after CO₂ removal is CO-rich, thus it can be used as a reducing agent when its recycled, improving the BF performance. Danloy et al. (2009) suggests that coke consumption can be reduced by up to 24% due to improved BF performance. The overall energy consumption reduction will be somewhat smaller because the reduced BF gas export needs to be compensated. The main disadvantage of using oxygen blown blast furnace is that a major modification to the conventional blast furnace will be required, although it is possible to retrofit.

An issue specific for the Corus IJmuiden plant is that if it chooses to capture CO₂ using chemical solvents, a steam generator has to be newly built to meet large solvent regeneration heat demand because there is no extra steam generation capacity available in the vicinity (Treadgold, 2009).

Energy and CO₂ performance

Table 4.15 shows the energy, CO₂ and economic performance of various CO₂ capture options for blast furnace reported in the literature. Note that a) some of the important parameters (e.g. interest rate, plant lifetime, fuel price, CO₂ compression) are not standardized due to lack of background information; and b) the table only presents CO₂ capture options that have been investigated in the open literature. There are other CO₂ capture options, e.g. oxygen blast furnace with VPSA without shift reaction, or CO₂ capture after BF gas combustion, that are technically feasible.

Table 4.15 Energy and economic performance for various CO₂ capture routes from blast furnace gas. CO₂ compression is included for all cases at pressures between 80 bar and 115 bar.

Plant configuration			Specific energy consumption (GJ/tCO ₂)		Carbon removal rate (%-carbon in BF gas)	CO ₂ capture cost (2008 €/tCO ₂)
Shift reaction?	Blast furnace type	CO ₂ capture method	Power	Heat		
With shift ⁽¹⁾	Oxygen blown	Selexol	0.59	0 ⁽²⁾	85-99.5% ⁽³⁾	18
	Air blown		0.34-0.62	0 ⁽²⁾		
Without shift	Oxygen blown	VPSA + cryogenic purification	0.94 ⁽⁴⁾	24% decrease in coke consumption ⁽⁴⁾	68% ⁽⁵⁾	28 ⁽⁴⁾
		MEA/ piperazine ⁽⁶⁾	N.D.	2.3-2.4	42%	N.D.
	Air blown	Selexol	0.51 ⁽⁷⁾	0 ⁽⁷⁾	33% ⁽⁷⁾	33 ⁽⁴⁾
		AMP ⁽⁶⁾	N.D.	2.2	43%	N.D.
		MEA	0.62 ⁽⁴⁾	3.2-4.1 ^(4,6)	40-43% ⁽⁶⁾	45 ⁽⁴⁾
		MEA/ piperazine ⁽⁶⁾	N.D.	2.4-2.9	39-44%	N.D.

Data for the row from Gielen (2003), unless otherwise stated. Captured CO₂ is compressed to 100 bar; ⁽²⁾ Shift reaction is exothermic. Surplus steam may be available for other uses, but such use of surplus steam was neglected in the study (Gielen, 2003); ⁽³⁾ Based on the assumption that all CO in the blast furnace gas is shifted to CO₂. ⁽⁴⁾ Torp, (2005). CO₂ compression pressure is not stated and the cost figure may not include the oxygen production cost. ⁽⁵⁾ Danloy et al., (2009). ⁽⁶⁾ Data for the row from Tobiesen et al., (2007), unless otherwise stated. AMP stands for 2-adenosine 2-amino-2-methyl-1-propanol. ⁽⁷⁾ Lampert and Ziebig, (2007). Captured CO₂ is compressed to 80 bar.

Figure 4.18 shows the CO₂ emission reduction potential for Corus IJmuiden site by CO₂ capture technique. To enable a fair comparison between different CO₂ capture options investigated in the literature, we assumed the following:

1. Modifying the blast furnace only affects the energy consumption and emissions from the blast furnace itself and the coking process (due to change in coke consumption). Other processes such as sintering and pelletization are unaffected.
2. Extra electricity and heat requirement for CO₂ capture and compression is met by a gas-fired CHP with an efficiency of 85%.
3. Loss of blast furnace gas export due to CO₂ capture is compensated by natural gas.

Please note that the changes in NEC emissions strongly depend on factors such as:

- Fuel type used to meet the extra heat and power consumption for CO₂ capture (coal or natural gas)
- Configuration of pollutant control measures installed at each iron and steel plant

For CO₂ capture options using conventional blast furnace, no modification to the steel making process was assumed. Gas-fired installations with a low-NO_x burner (no SCR required) are assumed to meet the heat and electricity demand for CO₂ capture.

It is clear from the figure that more CO₂ emission is avoided when CO in the blast furnace gas is converted into CO₂. CO₂ capture using oxygen blast furnace also reduces CO₂ emission significantly, partly due to improved blast furnace efficiency. When the oxygen blast furnace is used, VPSA reduces much more CO₂ emissions than chemical absorption (MDEA/piperazine mix solvent) due to a lower energy requirement. CO₂ capture from conventional blast furnace without CO-shift is not an attractive option when significant CO₂ emission reduction from the site is required.

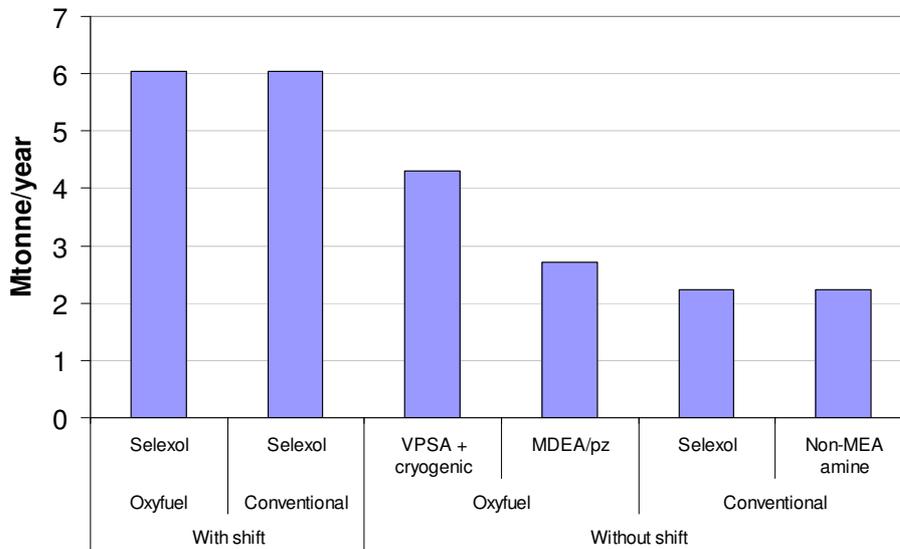


Figure 4.18 CO₂ emission reduction potential for Corus IJmuiden site by CO₂ capture technique.

Figure 4.19 shows extra primary energy consumption due to CO₂ capture from Corus IJmuiden site for various CO₂ capture techniques. Depending on the CO₂ capture technique, CO₂ capture and storage from the Corus IJmuiden site is likely to cost extra primary energy consumption in the range of 2-12 PJ per year. CO₂ capture options using oxygen blast furnace show better energy performance due to reduced coke and coal consumption compared to conventional blast furnace.

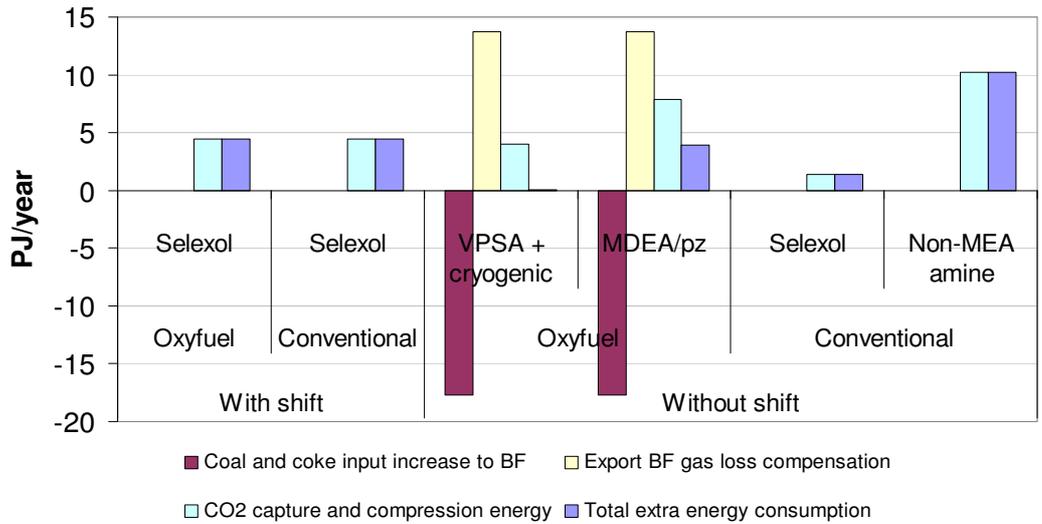


Figure 4.19 Extra primary energy consumption due to CO₂ capture from Corus IJmuiden site by CO₂ capture technique.

Environmental performance

Figure 4.20 shows the breakdown of annual NEC emissions from Corus IJmuiden site in 2008 by process. A significant fraction of NEC emissions come from processes that are independent of blast furnace operation, e.g. pelletizing and sintering, hot strip mill and open source. Note that the figures do not include the pollutants contained in the BF gas that is exported to the NUON CHPs.

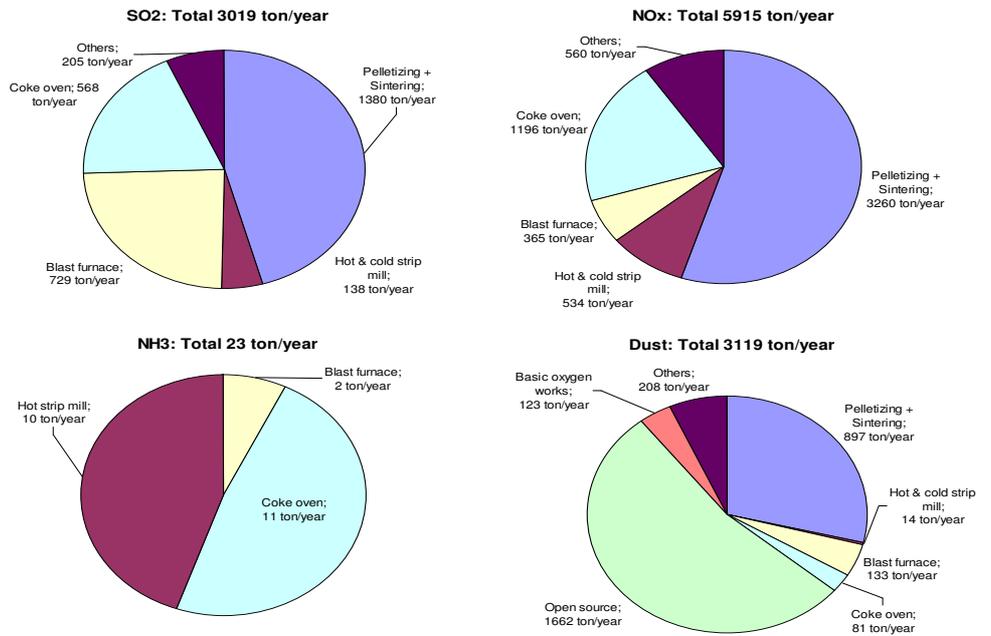


Figure 4.20 Breakdown of annual NEC emissions from Corus IJmuiden site in 2008 by process (Corus, 2009).

Figure 4.21 shows NEC emissions from Corus IJmuiden site when CO₂ is captured from the blast furnace. For the calculation of the emissions, it was assumed that CO₂ capture from blast furnace only influences the emissions from blast furnace and coking process. The NO_x formation rate per MJ input for oxygen blast furnace was assumed to be 50% of that for conventional blast furnace, based on the values indicated in the literature (discussed in detail in Harmelen et al., 2008).

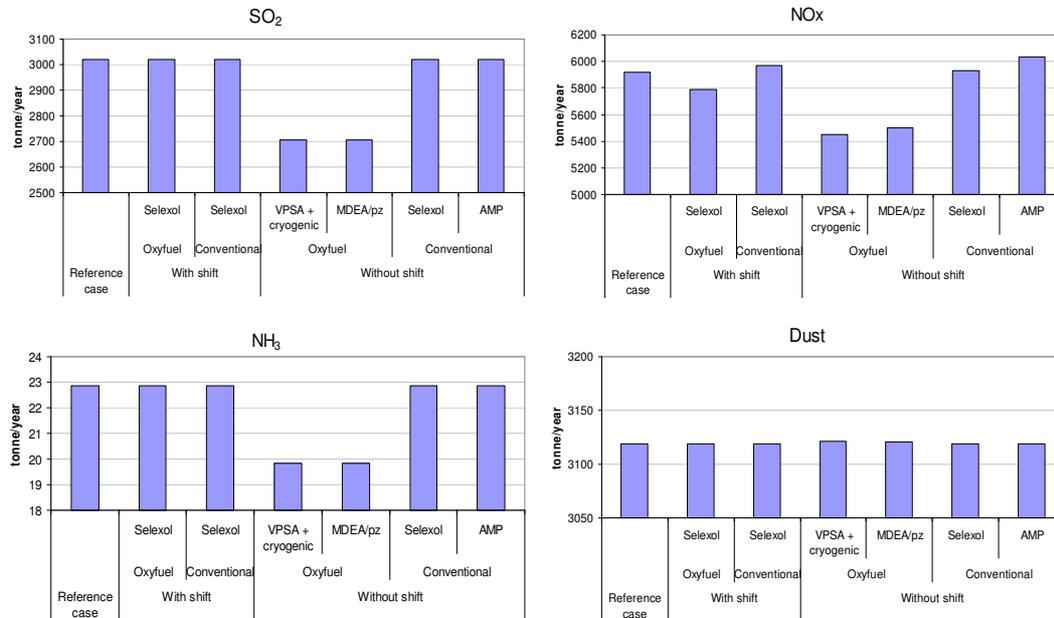


Figure 4.21 NEC emissions from Corus IJmuiden site when equipped with CO₂ capture.

For SO₂, NH₃ and dust emissions, changes occur largely by the change in coke and coal consumption in the blast furnace. Extra energy consumption for CO₂ capture and compression does not affect these emissions because it is met by natural gas fed installations, which emits virtually no SO₂, NH₃ and dust. Total emission for each pollutant, therefore, decreases for CO₂ capture techniques using oxygen blast furnace and increases for those using conventional blast furnace because oxygen blast furnace is more energy efficient than conventional blast furnace. For SO₂ and NH₃, modification of blast furnace to oxygen blowing reduces the emissions by around 10%. For dust emissions, the effect is minimal because blast furnace and coke production emit account for very small fraction of total dust emission as seen in Figure 4.20.

As mentioned earlier, the emissions contained in the exported BF gas are not counted in the calculations. Some CO₂ capture techniques may lead to a significant reduction in sulphur in the BF gas. When shift reaction takes place, large part of SO₂ in the BF gas will be converted to H₂S, which can be captured by Selexol. The sulphur content in the exported BF gas will be more than 90% lower than in the case without CO₂ capture.

Unlike other NEC emissions, NO_x emissions are influenced not only by the coke and coal consumption in the blast furnace, but also by the type of blast furnace and the CO₂ capture technique applied. The figure clearly shows that the CO₂ capture options with oxygen blast furnace reduce NO_x emission by nearly 600 tonnes/year. Extra energy

consumption for CO₂ capture and compression accompanies additional NO_x emission from natural gas fed installations. The effect of this additional NO_x emission is, however, limited.

It should be stress that there is a large uncertainty regarding NO_x emission when CO₂ capture incorporates shift reaction ($\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$). As described earlier, blast furnace gas from Corus IJmuiden plant is exported to the neighbouring two NUON CHP plants. Because of the shift reaction, the blast furnace gas becomes H₂-rich. The gas turbines of NUON CHP plants are not designed to fire H₂-rich fuels, requiring the gas turbines of the CHP to be either re-designed or replaced. In such cases, it is unclear how the NO_x emissions may change.

Fraction of SO₂ and NO_x mitigation in CO₂ mitigation costs

The effect of CO₂ capture from blast furnace on SO₂ and NO_x emissions from the Corus IJmuiden site is limited. Assuming a shadow price of 1000 €/tonne, the co-reduction of SO₂ emission accounts for, at highest, only 0.11 €/tCO₂ avoided (oxygen blast furnace – VPSA case). Assuming a shadow price of 4000 €/tonne, similar results were found for costs attributable to NO_x emission reduction/increase.

4.4.3 Cement industry

Cement industry in the Netherlands

A general description on cement production process can be found in Appendix G. There are three cement production plants in the Netherlands (Rotterdam, IJmuiden and Maastricht). Among them, the ENCI plant in Maastricht is not only the largest but also the plant that produces clinker, which emits considerable amount of CO₂ from the raw material (see Table 4.16). ENCI Maastricht produces around 1 million tonnes of clinker per year (Heidelberg Cement, 2007). It has a dry kiln, but unlike many other dry process plants, it does not have pre-calcination and midkiln firing processes (Heidelberg Cement, 2007). Another unique aspect of this ENCI Maastricht plant is that more than 90% of the consumed fuel is non-fossil. The non-fossil fuels used are mainly sewage sludge, together with other energy sources such as glycolbottom, rubber granulate and animal meal. There are two dried sewage sludge milling plants at ENCI, which together processes 11 tonnes of dried sewage sludge per hour (Heidelberg Cement, 2007).

Table 4.16 General data on ENCI Maastricht plant for year 2007 (ENCI, 2008).

Annual cement production (ktonne/year)	Annual CO ₂ emissions (ktonne/year)	CO ₂ concentration and process gas pressure
1400	620 ¹⁸	13.3%, 1 bar

4.4.4 Case study: CO₂ capture from ENCI Maastricht plant

The ENCI Maastricht plant is expected to shut down within the next ten years and currently there is no plan for building a new plant (Pereboom, 2009). Retrofitting CO₂ capture unit to the operating plant is, therefore, not an option. Nevertheless, in this section we assess the performance of CO₂ capture for a possible new cement plant that might be built after 2020.

¹⁸ 3650 ktonne emitted at CORUS site + CO₂ in blast furnace gas that is sold to NUON.

For cement production process, two CO₂ capture routes have been proposed: post combustion capture and oxyfuel combustion capture. The IEA-GHG has performed a techno-economic feasibility study on CO₂ capture from cement production plants (IEA GHG, 2008). In this report, two CO₂ capture routes were assessed for a typical dry process plant with a pre-calciner. The report suggests that the post combustion CO₂ capture is the option that can be implemented with a low technical risk and enables retrofitting in the short- to mid-term.

However, when the CO₂ avoidance cost is considered, oxyfuel combustion capture is much cheaper than post combustion capture. For oxy-combustion capture, this IEA-GHG study compared four different plant configurations. The study suggested that oxy-combustion capture only from precalciner has the lowest technical risk, although the risk is still higher than that for post combustion capture. The ENCI Maastricht plant, however, does not have a precalciner. The technical risk for capturing CO₂ from the kiln is high, because the kiln operation in a CO₂-rich atmosphere is not proven to date (IEA GHG, 2008).

In this study, post combustion capture was selected for the assessment. Although economically more attractive, we concluded that an oxyfuel kiln is unlikely to be installed in the coming 10-15 years. Figure 4.22 shows a simplified scheme of a cement plant with post combustion CO₂ capture. The gray color stands for the process units that will be newly installed for CO₂ capture. Since the ENCI Maastricht does not have a CHP, a new CHP is needed to supply steam and power for CO₂ capture. CO₂ from the CHP is co-captured in the same CO₂ capture unit. For this study, we considered a gas-fired CHP.

SCR for the CHP is optional, depending on the NO₂ emissions generated by the CHP type and the NO₂ concentration limit for the CO₂ scrubber. Additional de-NO_x and desulfurization units are also required for the exhaust gases from the cement plant because the emission levels are higher than those required for the operation of CO₂ scrubber (Figure 4.22). With regard to the co generated electricity, part of it is used for the operation of CO₂ capture and compression, and the cement production plant. The excess electricity, if any, was assumed to be exported to the grid.

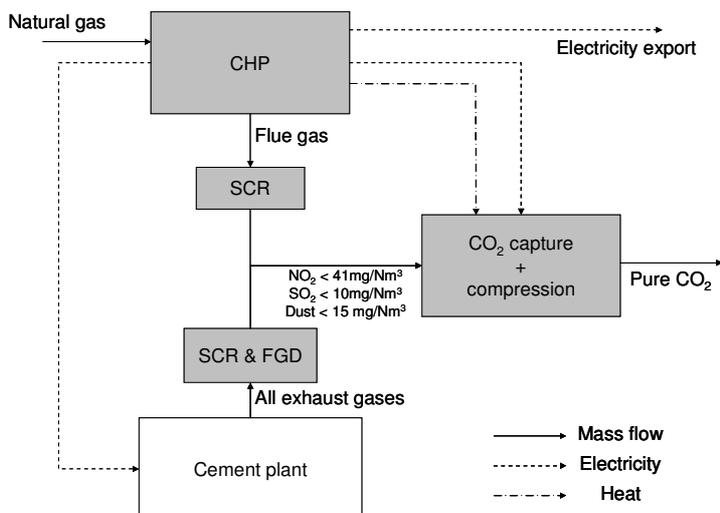


Figure 4.22 Schematic of a cement plant with post combustion CO₂ capture.

Energy, CO₂ and economic performance

The calculated energy performance of the CO₂ capture from ENCI Maastricht plant is presented in Table 4.17. The gas turbine CHP for heat supply was assumed to operate at 25% electrical efficiency and 60% steam efficiency, respectively. Other underlying assumptions for the calculations can be found in Appendix G.

Table 4.17 Energy performance of post combustion CO₂ capture from ENCI Maastricht cement plant (unit: MW). GT-CHP was assumed to operate with 25% electrical efficiency and 60% steam efficiency, respectively.

Energy performance		
Heat requirement for CO₂ capture (MW)	Onsite power generation (MW)	Total extra fuel consumption (MW)
92	10	121
CO₂ emission reduction performance		
CO₂ concentration at the CO₂ scrubber inlet (v/v)	CO₂ avoided (ktonne/year)	CO₂ avoidance rate (v/v)
9.3 %	497	80%

The economic performance data were obtained from the literature (Hassan, 2005; IEA GHG, 2008) and presented in Table 4.18. Data for chemical absorption as well as for advanced oxyfuel kiln concept are also presented in the table.

Table 4.18 CO₂ Economic costs for CO₂ capture from cement production plants indicated in the literature. CO₂ compression and purification are included.

Source	Cement production	CO₂ emitted	CO₂ captured	Flue gas CO₂ concentration	CO₂ capture cost			CO₂ avoidance cost
					Total	deSO_x related	deNO_x related	
					ktonnes/year		v/v	
Chemical absorption (MEA)								
Hassan (Hassan, 2005)*	680	546	N.D.	31.8%	44	5	0	---
IEA-GHG (2008)**	1000	188	1068	26.4%	67	9	3	132
Oxyfuel kiln (advanced)								
IEA-GHG (2008)	1000	283	465	N.D.	39	0 ***	0 ***	41

* Steam for solvent regeneration is purchased; ** steam for solvent regeneration is supplied by coal-fired CHP. CO₂ from the CHP is co-captured.; *** SO_x emission is assumed to be co-sequestered.

Environmental performance (chemical absorption capture)

The environmental performance of chemical absorption CO₂ capture from the ENCI Maastricht plant was calculated based on the assumptions given in Appendix G in a similar manner as for CO₂ emission. It was found that an additional FGD would be required because of high SO₂ emission intensity in the cement process gas (Figure 4.23). Additional SCR and dust removal units will not be necessary.

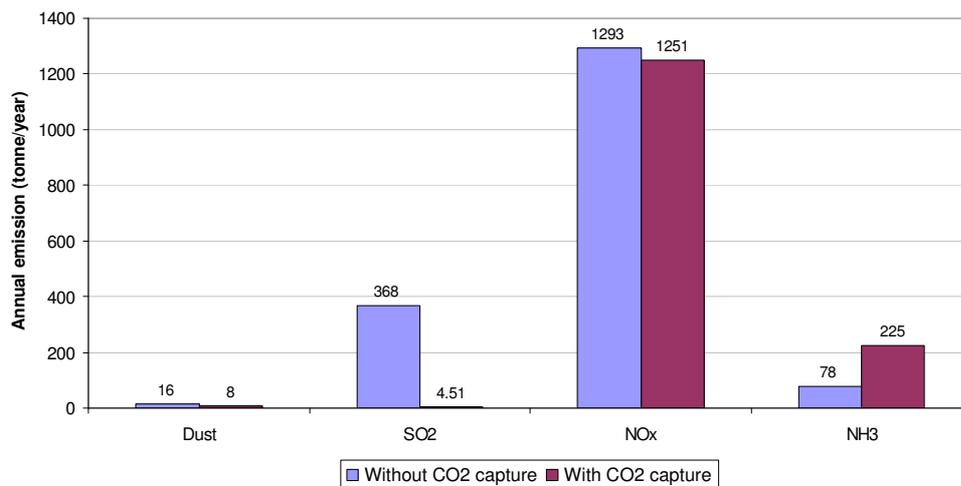


Figure 4.23 Changes in annual NEC emissions from ENCI Maastricht plant due to post-combustion CO₂ capture.

Main conclusions regarding the environmental performance are:

SO₂: large decrease. Because the SO₂ concentration in the cement process gas is higher than the level CO₂ capture solvent can tolerate (75 mg/Nm³ compared to 10 mg/Nm³), the desulphurization unit has to be upgraded. In addition, a large fraction of SO₂ can be captured in the CO₂ capture unit (90%), resulting in a significant emission reduction.

- *NO_x: no significant change.* No significant changes in NO_x emission are expected for a number of reasons. First, no additional de-NO_x unit before the CO₂ scrubber is installed because the NO₂ concentration in the process gas is sufficiently low for the CO₂ capture solvent. The low NO₂ concentration is partly due to the co-capture of CO₂ from the GT-CHP flue gas, which has a lower NO_x concentration compared to cement process gas due to low-NO_x burner. We expect that a low-NO_x burner (15 ppmv at 15% O₂) is installed for the GT-CHP in year 2020. Second, amine solvent only captures NO₂ and not NO. NO₂ accounts only for less than 10%, possibly as low as 2%, of the total NO_x emissions from a kiln system (IEA GHG, 2008).
- *NH₃: large increase.* The significant increase in NH₃ emission is principally because of the degradation of amine solvent. No additional NH₃ emission is expected from SCR, as additional de-NO_x was found to be unnecessary. Nevertheless, if an additional de-NO_x is required to meet the flue gas specification, even higher NH₃ emission will likely be observed.
- *PM (dust): decrease.* In a CO₂ capture unit, amine solvent is expected to capture some PM as well as CO₂.

4.4.5 Ethylene production

Ethylene production in the Netherlands

Table 4.19 presents an overview of ethylene production plants currently operating in the Netherlands. Ethylene is produced via steam cracking of light hydrocarbons, e.g.

naphtha, LPG and ethane. The ethylene sector alone accounts for nearly 6 million tonnes of CO₂ emissions per year.

CO₂ emissions from ethylene production are predominantly attributable to fuel combustion to supply heat for endothermic cracker reactions. In the steam cracking process, not only high value basis petrochemicals are generated but also low value by-products, part of which is used as a fuel.

Table 4.19 Overview of existing ethylene production plants in the Netherlands.

Plant name	City	CO ₂ available for storage (ktonnes/yr)	CO ₂ concentration (v/v) and process gas pressure (Damen et al., 2009; IPCC, 2005b)
DSM/SABIC	Geleen	1700	12%, 1 bar process gas pressure
Shell	Moerdijk	1400	
Dow	Terneuzen	2600	

CO₂ capture from ethylene production plants: case of Dow Terneuzen site

Because of low CO₂ partial pressure in the process gas, chemical absorption is considered to be the only feasible option (IEA, 2004). The post combustion CO₂ capture system configuration defined for this study is likely to be identical to that for cement process, which is described in the previous section. MEA was assumed to be the CO₂ capture solvent and CO₂ in the flue gas from GT-CHP that meets electricity and heat demand for CO₂ capture was assumed to be co-captured.

Energy, CO₂ and economic performance

As a case study, we used the emissions data from Dow Terneuzen site to assess the performance of CO₂ capture (Benelux, 2007). Although there are productions of chemicals other than ethylene, it was assumed that all emissions from the site are attributable to ethylene production to simplify the calculations. Table 4.20 presents the calculated energy and CO₂ emission reduction performance of post combustion CO₂ capture from Dow Terneuzen site. The methodology and assumptions for the calculations are presented in Appendix G. The CO₂ concentration in the process gas at the CO₂ scrubber inlet was found to be lower than that of ethylene process gas, because it is diluted by the flue gas from GT-CHP that generates heat and power required for CO₂ capture. The table also shows that nearly 300 MW of heat is required to operate CO₂ capture. It is questionable whether an existing onsite CHP can meet such a large heat demand.

There were no economic performance data on post combustion CO₂ capture from ethylene production. The economic performance is likely to be largely influenced by factors such as the need for an FGD for desulphurization or an additional CHP to generate regeneration heat for CO₂ capture.

Table 4.20 Energy and CO₂ emission reduction performance of post combustion CO₂ capture from Dow Terneuzen site.

Energy performance			CO ₂ emission reduction performance		
Heat requirement for CO ₂ capture (MW)	Onsite power generation (MW)	Total extra fuel consumption (MW)	CO ₂ concentration at the CO ₂ scrubber inlet (v/v)	CO ₂ avoided (ktonne/year)	CO ₂ avoidance rate (v/v)
298	33	389	8.8 %	2080	80%

Environmental performance (chemical absorption capture)

Figure 4.24 presents the annual NEC emissions and its relative attributable to CO₂ capture for ethylene production plants. The results show that no additional gas pre-treatment was required prior to CO₂ capture. Main conclusions regarding the environmental performance are:

- *SO₂*: 90% decrease (though negligibly small). SO₂ emission data used for the calculation is from Dow Chemicals Terneuzen plant (Dow Benelux, 2009), the SO₂ emission of which is low. Thus the effect of CO₂ capture on SO₂ emission is minimal. The negative SO₂ emission is primarily due to the export of electricity generated by the GT-CHP to the grid, which has a significantly lower SO₂ emission factor compared to the electricity produced in centralised power plants.

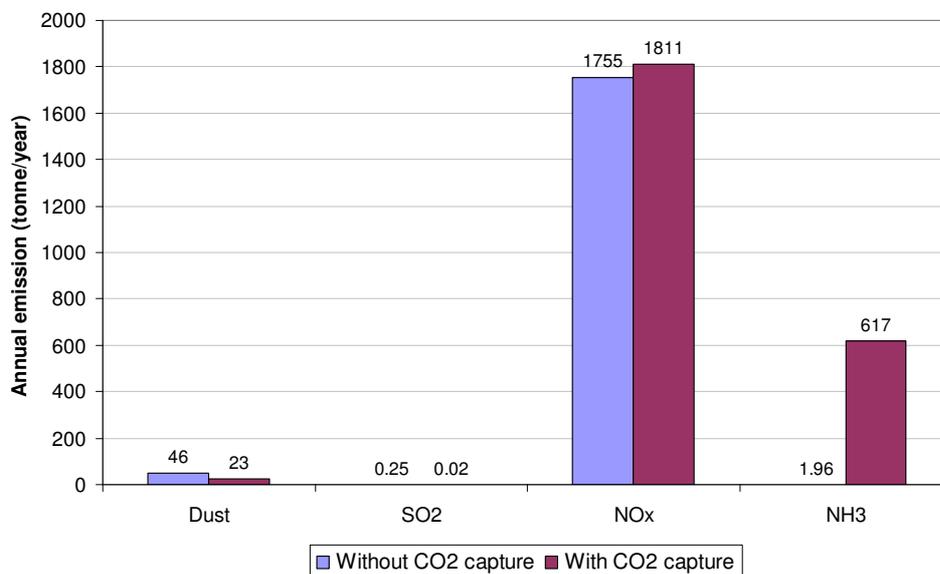


Figure 4.24 Changes in annual NEC emissions from Dow Terneuzen site due to CO₂ capture.

- *NO_x*: no significant change. No major change in NO_x emission is expected for similar reasons described for CO₂ capture, as no additional de-NO_x unit is required before the CO₂ capture unit. The negative NO_x emission value in the table is principally due to the export of the electricity generated by the GT-CHP to the grid, which has a significantly lower SO₂ emission factor compared to the electricity produced in centralised power plants.

- *NH₃: large increase.* The significant increase in NH₃ emission is largely because of the degradation of amine solvent. No additional NH₃ emission is expected from SCR, as additional de-NO_x was found to be unnecessary. Nevertheless, if an additional de-NO_x is required to meet the flue gas specification, even higher NH₃ emission will likely be observed.
- *PM: large decrease.* PM emissions are expected to decrease significantly, as an extra dust filter must be installed to control the PM content (from 51 mg/Nm³ to 15 mg/Nm³) in the ethylene process gas before entering the CO₂ scrubber.

4.4.6 High-purity hydrogen production from natural gas reforming

Hydrogen production from steam methane reforming in the Netherlands

In the Netherlands, a significant amount of hydrogen is produced via steam reforming of natural gas (steam methane reforming; hereafter SMR). After generation of hydrogen via steam methane reforming and water-gas-shift (WGS), impurities such as CO, CH₄ and CO₂ must be removed. Hydrogen purification can be performed in several ways. Older plants remove CO₂ by way of chemical absorption using amine solvent. With chemical absorption, a hydrogen purity of 95-98% can be reached and a pure CO₂ stream is generated. With regard to the hydrogen plants with pure CO₂ streams presented in Table 4.13, the Esso plant is a natural gas fed SMR plant and uses chemical absorption for CO₂ removal. The Shell plant gasifies heavy oil residue and the CO₂ is removed by Rectisol.

Modern plants use pressure swing adsorption (PSA) to separate H₂ from other components and achieve higher hydrogen purity, e.g. 99.99% (NYSERDA, 2009). This method, however, does not generate pure CO₂ streams. The main focus of this section is therefore on CO₂ capture from high purity hydrogen production plants. An overview of newly built hydrogen production plants is presented in Table 4.21 (existing hydrogen plants with pure CO₂ streams can be found in Table 4.13).

Table 4.21 Overview of high-purity hydrogen production plants in the Netherlands (partially from (Damen et al., 2009)).

Plant name	City	Start year	CO ₂ available for storage (ktonnes/yr)	CO ₂ purity (v/v) and process gas pressure (Sircar et al., 1999)
Air Liquide	Rotterdam	2011	560	15 - 35%, 20-31 bar
Total	Vlissingen	2008	94	
FMC industrial chemicals	Farmsum	2007	297	

CO₂ capture from high purity hydrogen production plants

For hydrogen production plants using PSA for purification, CO₂ can be captured either before or after PSA. The hydrogen-rich gas before PSA contains 15-35 mol.% CO₂ at gas stream pressures around 20-31 bar (Sircar et al., 1999). When CO₂ is captured after PSA, it can be done either directly from the PSA tail-gas (waste stream; location 1 in Figure 4.25) or after the combustion of the tail gas in the reformer furnace (location 1 in Figure 4.25). The PSA tail-gas contains 30-60 mol.% CO₂ at low partial pressures around 0.14-2 bar. (Meerman et al., In preparation) and (Damen et al., 2006) argue that

it is more economical to capture CO₂ before PSA because the CO₂ partial pressure is higher. The authors suggest chemical absorption as the best CO₂ capture technique and MDEA-based solvents have been proposed by several authors (IEA GHG, 1996; Meerman et al., In preparation; Molburg and Doctor, 2003; Mueller-Langer et al., 2007). Flue gas of the heat supplying unit, boiler or CHP, is not mixed with SMR exhaust gas for CO₂ capture in order to avoid major modifications on the hydrogen purification process.

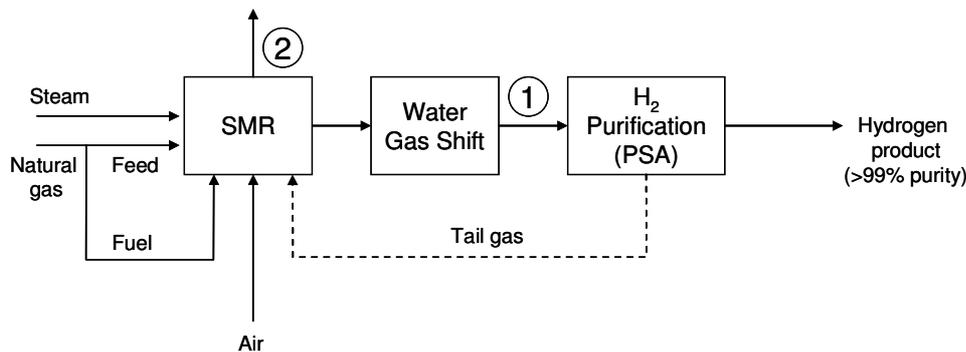


Figure 4.25 Steam reforming of natural gas with CO₂ capture between water-gas shift and H₂ purification (Meerman et al., In preparation; Mueller-Langer et al., 2007).

Energy, CO₂ and economic performance

Table 4.22 presents the energy, CO₂ and economic performance of CO₂ capture from high-purity hydrogen production plants. Each study we reviewed had specific assumptions on by-products from hydrogen generation, i.e. steam, and electricity and/or heat export from the heat supplying unit (boiler or CHP) for CO₂ capture. When there is a loss in heat and/or electricity exports due to CO₂ capture, extra primary energy consumption to compensate the loss was calculated by assuming heat and electrical efficiencies of 50% and 90%, respectively.

Environmental performance

Quantitative analysis of NO_x emissions from hydrogen production process has not been extensively performed to date. Most studies that report emission factors for hydrogen production only used the emission factors for natural gas boilers and somehow scaled them down to compensate for the inclusion of the PSA tail gas in the fuel composition (Contadini et al., 2000).

In addition, no study on the effect of CO₂ capture on NEC emissions has been performed to date. It is however possible to estimate the possible effects to a certain extent based on the literature. The estimates are based on an assumption that extra heat and electricity requirement due to CO₂ capture are supplied by a GT-CHP. Main conclusions regarding the environmental performance are:

- *Sulphur: negligible.* Natural gas intrinsically contains very small amount of sulphur. In addition, natural gas is desulphurised before entering the SMR because the catalysts employed in the SMR are poisoned by even trace amounts of sulphur (Molburg and Doctor, 2003). Thus, the change in sulphur emissions due to CO₂ capture is negligible.

- *NO_x*: strongly dependent on the reformer furnace operating conditions. NO_x is generated only in the reformer furnace, where SMR tail-gas is combusted together with natural gas. NO_x formation is largely influenced by the flame temperature. If CO₂ is removed from SMR tail-gas and the amount of air is unchanged, then the flame temperature is likely to increase and so is the NO_x formation rate. In such a case, however, the fuel consumption in the furnace may decrease due to better furnace efficiency {Mueller-Langer, 2007}. The change in NO_x emission due to CO₂ capture therefore is likely to depend largely on how the reformer furnace operating conditions are changed by the CO₂ removal from SMR tail-gas.
- *NH₃*: dependent on the change in NO_x formation. For hydrogen production plants, CO₂ is likely to be captured by MDEA due to higher partial pressure of CO₂. MDEA, unlike MEA, does not produce NH₃ when it is degraded. This makes SCR the only potential NH₃ emission source. The NH₃ emission from hydrogen production process is therefore largely dependent on the NO_x formation level in the furnace.
- *PM emissions: negligible*. Natural gas combustion generally results in no PM emissions. Assuming that the extra energy requirement for CO₂ capture is met by a GT-CHP, the change in PM emissions due to CO₂ capture is negligible.

Table 4.22 Energy, CO₂ and economic performance data for high purity hydrogen production with CO₂ capture (IEA GHG, 1996; Meerman et al., In preparation; Mueller-Langer et al., 2007). For all cases, CO₂ is captured between water-gas shift reactor and PSA unit using MDEA or MDEA-based solvent. The standardized values for natural gas price, plant lifetime and interest rate are given in Table 2.2.

Reforming method	With or without PSA?	CO ₂ capture location (Figure 4.25) and method	Source	H ₂ purity	H ₂ output (MW LHV)	Primary energy consumption increase	CO ₂ avoidance rate	CO ₂ avoidance cost (2008 €/tonne)
Steam methane reforming (SMR)	With PSA	1; MDEA	(IEA GHG, 1996; Mueller-Langer et al., 2007)	+ 99%	281-450	4-21%	54 - 84%	55-81
		1; MEA	Simbeck (2005)	+ 99%	2087	15%	83%	51
		2; MEA				37%	74%	101
	Without PSA	1; MDEA	(Lindsay et al., 2009)	95%	556	5%	59%	25
		1: MDEA, and 2; MEA				13%	91%	46
Autothermal reforming (ATR)*		1; MDEA				10%	81%	35

* The main difference between ATR and SMR is that ATR uses pure oxygen for producing syngas, while SMR uses steam.

4.4.7 Petroleum refineries (non-hydrogen processes)

Petroleum refineries in the Netherlands

Worldwide CO₂ emissions from petroleum refineries are close to 1 billion tonnes per year, accounting for around 4% of global CO₂ emissions (van Straelen et al., 2008). In the Netherlands, more than 7 million tonnes of CO₂ are emitted annually from petroleum refineries (Table 4.23).

Table 4.23 Overview of petroleum refineries in the Netherlands.

Plant name	City	CO ₂ available for storage (ktonnes/year)	CO ₂ concentration (v/v) and process gas pressure (Damen et al., 2009)
Esso	Rotterdam	1200	8%, 1 bar
Kuwait		480	
Nerefco		2600	
Shell		2400	
Total	Borssele	960	

CO₂ capture from petroleum refineries in the Netherlands

At the refineries, CO₂ are emitted from various sources (besides hydrogen production) such as furnaces and boilers, onsite production of electricity and steam, and fluid catalytic cracker. As is the case with chemical industry, onsite electricity and heat production are responsible for the bulk of the CO₂ emissions from petroleum refineries (Wilkinson et al., 2003). A breakdown of CO₂ emissions from a typical world-class petroleum refinery shows that besides pure CO₂ stream from gasification, a large fraction of CO₂ emissions is attributable to onsite electricity and heat production (van Straelen et al., 2008).

The most feasible CO₂ capture route depends on the processes concerned. (Hurst and Walker, 2005) suggest that oxyfuel capture can be applied to burners and fluid catalytic crackers. Pre combustion capture can be applied to many processes where the fuel is pre-treated, typically forming CO₂ and hydrogen, such as gasifiers. Nevertheless, when the retrofitting of CO₂ capture unit is concerned, most studies focus on post combustion capture.

Energy, CO₂ and economic performance

The literature strongly suggests that retrofitting CO₂ capture to petroleum refineries is not an economically feasible option (Table 4.24). For flue gas CO₂ concentrations between 4% and 12%, and annually captured CO₂ between 0.2 Mtonne and 3 Mtonne per year, retrofitting post combustion capture would cost more than four times the current carbon trading values, which was assumed to be around 25 Euro/tonne CO₂ (van Straelen, 2009; van Straelen et al., 2008).

Table 4.24 Energy, CO₂ and economic performance data for petroleum refineries with CO₂ capture.

Source	CO ₂ emissions (ktonne/year)	Solvent regeneration heat supply unit	Flue gas CO ₂ concentration (v/v)	CO ₂ avoidance rate	CO ₂ capture cost (Euro/tonne CO ₂)	CO ₂ avoidance cost (Euro/tonne CO ₂)
Van Straelen et al. (2008)*	250-2000	Gas-fired steam turbine CHP*	8%	62-66%**	80-110**	110-150**
Hurst and walker (2005)***	3500-4000	Gas-fired steam turbine CHP	N.D.	39%	49-58	69-84

* CO₂ compression is included, but the compression pressure is not given. The solvent regeneration heat supply unit was deduced from the original literature by calculating the CO₂ emission factor of the fuel for operation time of 8300 hours per year. ** The report states that 270ktonne of additional CO₂ is emitted from a CHP to capture 1 MtCO₂. It was therefore assumed that the amount of avoided CO₂ emission is 73% of the amount captured. *** CO₂ compression to 220 bar, CO₂ generated by the CHP is not captured.

Van Straelen et al. (2008) suggests that the costs for retrofitting post combustion CO₂ capture is unlikely to be reduced because the most advanced commercially available CO₂ capture processes are all solvent based. Therefore, the behavior of these costs to the flue gas concentration and CO₂ volume will be similar. The authors also claim that the currently available amine solvents will not reduce costs by more than around 25% compared to a conventional MEA solvent.

Environmental performance

As described earlier, flue gas pre-treatment may be required to reduce NO_x and SO₂ concentration in the flue gas significantly before entering the amine scrubbing process. These emissions will be further reduced in the CO₂ absorber. The estimates on NEC emissions described below were based on an assumption that the extra heat and power consumption for CO₂ capture is supplied by gas-fired installations (boiler, power plant or CHP) and its CO₂ emission is vented. Please note that the overall system emissions depend considerably on the fuel type used.

- *SO₂: large decrease.* SO₂ concentration in the flue gas must be kept below a certain level for cost-effective CO₂ capture operation because SO₂ reacts irreversibly with MEA and degrades it. SO₂ emission is very likely to decrease by either an additional de-SO_x unit preceding the CO₂ capture unit to reduce the SO₂ concentration to an acceptable level for MEA and/or SO₂ removal by MEA.
- *NO_x: dependent on the concentration in the flue gas.* The change in NO_x emission due to CO₂ capture strongly depends on the NO₂ concentration in the flue gas. If the NO₂ concentration is below the acceptable level for MEA, then the total NO_x emission is likely to increase due to extra heat and power generation, which generates additional NO_x. If the NO₂ concentration is above the acceptable level for MEA, then an additional de-NO_x unit needs to be installed and consequently, total NO_x emission is likely to decrease.

- *NH₃: large increase.* The significant increase in NH₃ emission is expected, largely because of the degradation of MEA. Further increase in NH₃ emission can be expected if an additional de-NO_x unit needs to be installed.
- *PM emissions: decrease.* PM emissions are very likely to decrease by either an additional dust filter preceding the CO₂ capture unit to reduce the SO₂ concentration to an acceptable level for MEA and/or removal by MEA.

4.4.8 Summary of results

Table 4.25 shows an overview of industrial emission sources, potentially feasible CO₂ capture technologies and their performances. With regard to emissions, green color indicates better than, yellow indicates as same as, and red indicates worse than the no-capture case, respectively. The table shows that CO₂ capture is likely to reduce most of the NEC emissions, except for NH₃, when it is deployed in the industrial sector.

Table 4.25 Overview of industrial emission sources, potentially feasible CO₂ capture technologies and their performances. Green colour indicates better than, yellow indicates as same as, and red indicates worse than the no-capture case, respectively. Cost figures are for 2020, assuming that the technologies are fully commercialized by then. The cost figures do not take CO₂ transport and storage into account. N.D. s for no data.

Sector	Annual total emissions in NL MtCO ₂ /year	CO ₂ concentration	CO ₂ capture Application	Additional process gas treatment?			Other additional facilities	Application Retrofit?	CO ₂ reduction potential MtCO ₂ /year	Economic performance € per tonne avoided (constant 2008)	Environmental performance					
				de-NOx	de-SOx	Dust filter					Unit	CO ₂ emissions	NOx emissions	SO ₂ emissions	PM10 emissions	NH ₃ emissions
Cement	0.6	13%, 0.13 bar	No capture	-	-	-	-	-	-	-	443	0.92	0.26	0.011	0.056	-
			Chemical abs. (MEA)	No	Yes	No	CHP	y	0.51	110	-60	0.89	0.002	0.004	0.169	Toxic waste
Steel	10.3	25%, 0.25 bar	No capture	-	-	-	-	-	-	-	1.56 x 10 ³	0.83	0.48	0.51	Negligible	-
			Oxyfuel + VPSA	No	No	No	ASU	y	5.2	40	0.78 x 10 ³	N.D.	0.37	N.D.	No change	No change
Hydrogen (high purity)	0.66	15-35%, 3-11 bar	No capture	-	-	-	-	-	-	-	80	0.035	Negligible	Negligible	Negligible	-
			Chemical abs. (MDEA)	No	-	-	-	y	0.37	40	35	N.D.	No change	No change	No change	No change
Ethylene	5.7	12%, 0.12 bar	No capture	-	-	-	-	-	-	-	1560	1.05	1.5 x 10 ⁴	0.67	Negligible	-
			Chemical abs. (MEA)	No	No	Yes	-	y	5.1	110	177	1.03	-0.001	0.36	0.33	Toxic waste
Refineries	7.5	8%, 0.08 bar	No capture	-	-	-	-	-	-	-	-	-	-	-	-	-
			Chemical abs. (MEA)	Yes?	Yes?	Yes?	-	y	4.5	110	60%	-	-	-	N.D.	Toxic waste

4.5 Air pollution mitigation options

Changes in the net NEC emissions of a plant due to deployment of CO₂ capture technologies can be addressed via air pollution mitigation technologies. In this section an overview of such technologies is presented.

4.5.1 Flue gas pre treatment

Flue gases from a coal-fired power plant will contain acid gas components such as NO_x and SO_x. Flue gases from natural gas combustion will normally only contain NO_x. These acidic gas components will, similar to CO₂, have a chemical interaction with the solvent and lead to the formation of heat stable salts (HSS). Pre treatment of the exhaust gas before capturing CO₂ is necessary to remove NO₂ and SO₂. NO_x contains for approximately 10% out of NO₂, the remaining NO does not react with the solvent. The optimal SO₂ content, before the CO₂ absorption process is a cost trade-off between CO₂-solvent consumption and SO₂-removal costs.

SO₂ concentrations in the flue gas are typically around 300-5000 ppm. Commercially available SO₂-removal plants will remove up to 98-99%. For the Kerr-Mcgee/ABB Lummus Crest Technology, SO₂-removal is typically not justified for SO₂ levels below 50 ppm (Barchas and Davis, 1992). For the Fluor Daniel Econamine FG process a maximum of 10 ppm SO₂ content is generally set as the feed gas specification (Sander and Mariz, 1992).

Desulphurization can be done by using alkaline salt solutions in a spray scrubber (Chapel et al., 1999). In the case of CO₂ recovery from a coal-fired boiler flue gas, the plant typically has to be equipped with a deNO_x unit, an electrostatic precipitator or a bag house filter and a deSO_x or flue gas desulphurization unit. In some cases, these environmental protection facilities are not enough to carry out deep SO_x removal up to the 1-2 ppm level sometimes needed to minimize solvent consumption and its reclamation from sticking of solvent wastes on reclaimer tube surfaces (Metz et al., 2005).

Figure 4.26 shows a schematic drawing of a flue gas cleaning system for a coal-fired power plant with CO₂ capture. The flue gas from the power plant is sent to a SCR (selective catalytic reduction) unit to remove ~90% of the NO_x, and an ESP (electrostatic precipitator) with a fabric filter, to remove 99.9% of the dust. SO_x is removed for 98.9% using a FGD (flue gas desulphurisation) unit with and a WESP (wet electrostatic precipitator). After eventually cooling down the gas the CO₂ can be captured (Ploumen, 2008).

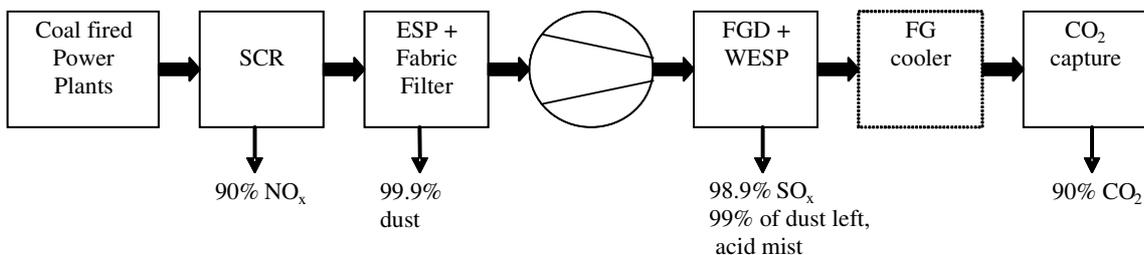


Figure 4.26 Flue gas cleaning system of coal fired power plant with post combustion CO₂ capture.

4.5.2 Technologies for emission reduction

In general there are two ways to reduce the emissions from combustion processes at a power plant:

- Primary measures: integrated measures to reduce the emissions at the source or during the combustion process.
- Secondary measures: End-of-pipe technologies to control the emissions to air water and soil.

Primary measures to reduce emissions

The following primary measures can be applied to reduce the emissions:

- Fuel switch – Switching from solid to liquid to gas can the emissions from the combustion process. The choice for a certain fuel strongly depends on the technical, economic and political feasibility, which are determined by local circumstances. However, using fuels with lower contents of sulphur, ash or mercury are options to consider.
- Combustion modification – A large number of modifications are possible to reduce the emissions of specific components. These are related to capacity derating, burner modifications, in-furnace combustion modifications and air and fuel modifications.

Secondary measures to reduce emissions

In this section (Table 4.26 to Table 4.29) the mostly used end of pipe technologies to reduce emissions at a power plant are mentioned. For more details we refer to the reference BREF documents (EUROPEAN COMMISSION, 2003).

Table 4.26 NO_x mitigation technologies.

Technology	Description
Selective Catalytic Reduction (SCR)	Flue gas is enriched with ammonia or urea and led over a catalyst. NO _x in the flue gas is converted to N ₂ and H ₂ O.
NSCR (Non Selective Catalytic Reduction)	CO, NO _x and VOC are oxidised to CO ₂ , N ₂ and/or H ₂ O over a catalyst, without an additional reagent.

Table 4.27 PM₁₀ mitigation technologies.

Technology	Description
Electrostatic precipitator (ESP)	Particles are charged by applying an electrical to the flue gas stream and withdrawn to a collector electrode.
Fabric filter (FF)	Particles are removed from the flue gas by a fabric filter.
Wet scrubber	Particles are separated by intense mixing of gas stream with water

Table 4.28 SO₂ mitigation technologies.

Technology	Description
Wet scrubber (spray tower)	SO ₂ is removed by a reaction with components in aqueous slurry. Wet limestone scrubbers are the most widely used technology. Other scrubbers are using sea water, ammonia or magnesium.
Spray (semi) dry scrubber	Lime slurry is injected in the gas stream and reacts with the SO ₂ . The liquid evaporates and the solid product is collected in a filter.

Table 4.29 NH₃ mitigation technologies.

Technology	Description
Wet scrubber	Gas stream is intensively exposed to liquid with low pH. NH ₃ reacts with acid (HNO ₃).

5 Impact analysis

In this section we show the results of an impact assessment made to evaluate the effects of CO₂ capture technologies in the Netherlands. The assessment is made separately for the industrial and power generation sector. Though the focus of the report is on 2020 technologies, effects have also been assessed for the longer term for the power sector (2030 and 2050).

5.1 Impact assessment for industry in 2020

CO₂ emission reduction potential: Up to 8 Mtonne/year, depending on the CO₂ capture technique applied to iron and steel industry.

Figure 5.1 shows a simplified cost-supply curve for CCS in the Dutch industrial sector in the mid-term (2020-2025). Colored bands show the CO₂ avoidance cost range indicated in the literature for each industrial process investigated in this report. In the mid-term future (2020-2025), a CO₂ market price of 40-50 €/tonne may well be reached within the considered timeframe (IEA, 2008). The figure shows that with such a CO₂ price, CO₂ capture may reduce up to around 8 million tonnes of CO₂ emissions per year in the Dutch industrial sectors considered in this report. Most of the CO₂ emission reduction is likely to be achieved by the Corus iron and steel plant at IJmuiden.

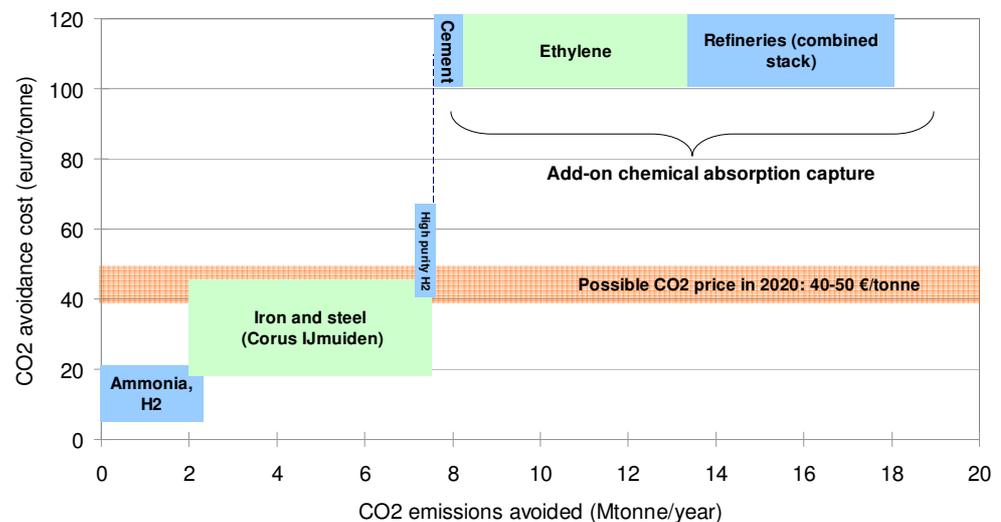


Figure 5.1 Simplified cost-supply curve for CO₂ capture and storage potential in the Dutch industrial sector.

It should be noted that as presented in Figure 4.18, the CO₂ emission reduction potential for the Corus iron and steel plant largely depends on the CO₂ capture technique applied. Moreover, the CO₂ capture technologies for the iron and steel process are still in the pilot testing phase (Danloy et al., 2009). In addition, CO₂ capture from the Corus IJmuiden site will require massive capital investment and it is not expected such decision to be taken in the short term. Furthermore, costs are likely to be much higher

than the literature suggests for the “first-of-a-kind” plants. It is therefore highly questionable if the technology would be ready for commercial use by 2020-2025.

Amine-based CO₂ capture from industrial processes such as cement production, ethylene production and petroleum refineries were found to be expensive (around 100 Euro/tCO₂ avoided). Amine-based CO₂ capture, however, will significantly reduce SO₂ and dust emissions and the co-benefits may be significant. For cement plants, the co-benefit of SO₂ removal can worth up to 9 Euro/tCO₂ captured (CO₂ capture cost: 66 Euro/tCO₂).

The ENCI Maastricht plant, which emits 0.6 MtCO₂/year, will be shut down before 2020 (Pereboom, 2009). If a new cement plant will ever be built in the Netherlands, this might be an opportunity to build a new plant integrated with (possibly oxyfuel) CO₂ capture.

NEC emissions: dependent on CO₂ capture technique applied to iron and steel industry

The effect of CO₂ capture on NEC emissions from the Dutch industrial sector in the year 2020 is largely dependent on the CO₂ capture from Corus IJmuiden iron and steel plant. Figure 5.2 shows the annual NEC emission reductions due to CO₂ capture in the Dutch industrial sector in 2020. The figure shows that SO₂ emission will reduce regardless of CO₂ capture technique applied to the Corus iron and steel plant. NO_x emission is likely to decrease when oxygen blast furnace is used, and is likely to remain comparable to the reference case or even increase when other CO₂ capture techniques are applied. NH₃ and dust emissions are found to be virtually unaffected.

As described earlier, some CO₂ capture options will remove large fraction of SO₂ in the BF gas and consequently lead to a significant SO₂ emission reduction at two NUON CHP sites: Velsen and IJmond. These two CHPs together emit more than 400 tonnes of SO₂ per year. The emissions are likely to be reduced by more than 90% when CO₂ capture using shift reaction and Selexol is applied.

The readers must keep in mind that the CO₂ and NEC emission assessment performed in this section are largely influenced by how the extra electricity and heat demand due to CO₂ capture is met. In our study it was assumed that the CO₂ capture energy requirement was met by a gas-fired CHP and CO₂ in the CHP flue gas was assumed to be co-captured whenever possible. This may not always the case because other electricity and heat supply options such as coal-fired CHP may be more economical.

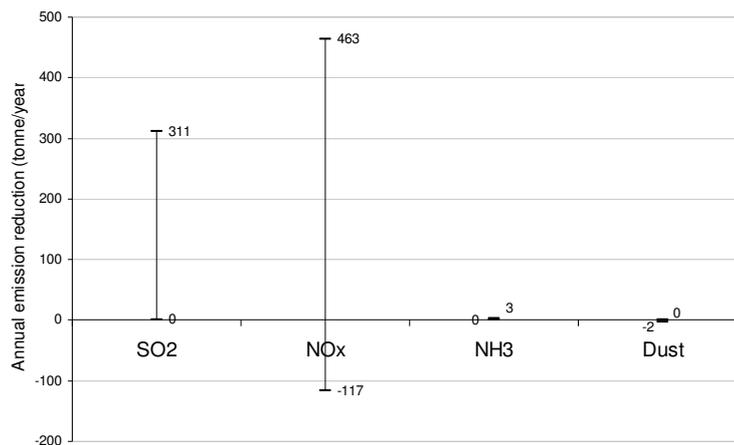


Figure 5.2 Annual NEC emission reductions due to CO₂ capture in the Dutch industrial sector in 2020.

Conclusions

The CO₂ emission reduction potential from the industrial sector in the year 2020 was estimated to be up to 8 million tonnes per year. The sources will likely be the pure CO₂ streams from ammonia and hydrogen production, and the Corus IJmuiden iron and steel plant. The CO₂ emission reduction potential, however, largely depends on which CO₂ capture technique will be applied to the Corus IJmuiden site.

The increase in primary energy consumption due to CO₂ capture and storage from industrial sector will be at least 2.2 PJ per year, largely dependent on the CO₂ capture technique applied to the Corus IJmuiden site.

With regard to the effect of CO₂ capture on NEC emissions, it can be concluded from our results that the SO₂ emissions will decrease and NH₃ and dust emissions will remain comparable to the reference case regardless of the CO₂ capture technique applied at the Corus IJmuiden site. NO_x emission will largely depend on the CO₂ capture technique applied at the Corus IJmuiden site. NO_x emission is likely to decrease when oxygen blast furnace is applied, and increase when conventional blast furnace is applied.

5.2 Power plants in the Netherlands

The public electricity sector in the Netherlands emitted 49.3 million tonnes of CO₂ in 2006, and is responsible for almost a third of the yearly Dutch CO₂ emissions. In Figure 5.3 the CO₂ emissions from fuel combustion processes are specified. Because of being large point sources of CO₂ emissions, power plants are an attractive option for applying CO₂ capture.

In this section the current and future public electricity sector in the Netherlands will be described, as a base for the scenario and impact analysis for 2020. In line with the report, the focus remains on the emissions of the NEC pollutants as NO_x, SO₂, PM₁₀ and NH₃.

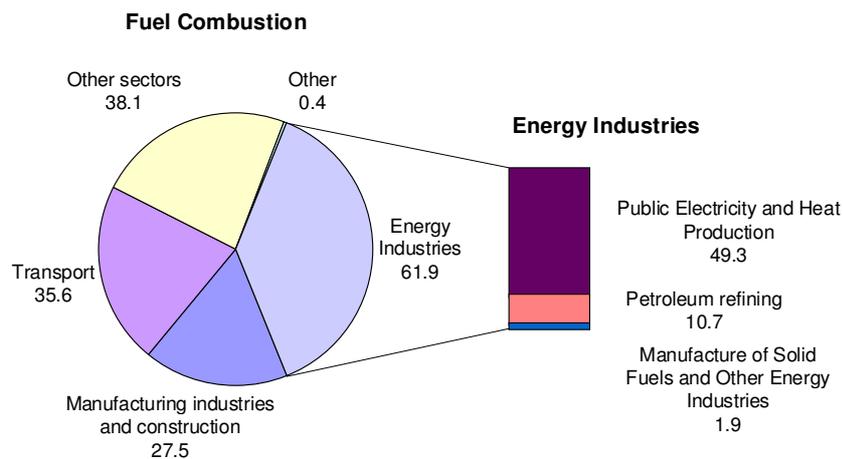


Figure 5.3 CO₂ emissions in millions tonnes for fuel combustion processes in the Netherlands (2006), adapted from (Netherlands Environmental Assessment Agency, 2008b).

5.2.1 Current power plants and emissions

Table 5.1 provides an overview of the current public electricity sector in the Netherlands. The fossil fuel based power sector is a mixture of coal and gas fired power plants, and of new and older plants which will be closed or replaced before 2020. The total capacity of the sector is 13.5 GWatt. The emissions of NO₂, SO₂, PM₁₀ and NH₃ are obtained from the pollutant release and transfer register (ER, 2006). The emission data are for the year 2006; 2007 data are not publicly available at this moment.

Noted that NH₃ emissions for the power generation sector are surrounded by significant uncertainties. The pollutant release and transfer register shows a total of 4 tonne of NH₃ per year. This is the sum of the reported emissions by the individual companies. Because the threshold for reporting NH₃ emissions by the companies is 10 tonne/yr, the value is not usable. A better source is the emission submitted for CLRTAB (EEA, 2009). For 2006 the total emissions for NH₃ from the power generation sector (1A1a) was 65 tonnes.

Table 5.1 Overview of current Dutch power plants, adapted from (Seebregts and Volkers, 2005;ER, 2006).

Producer	Plant	Main Fuel	Power (MWatt)	NO ₂ (kg/year)	SO ₂ (kg/year)	PM ₁₀ (kg/year)	NH ₃ ¹⁾ (kg/year)	CO ₂ (1000 kg/year)
E.ON	Galileistraat	Gas	209	656,098				443,254
E.ON	Maasvlakte	Coal / Gas	1,117	8,717,830	3,869,260	105,729		6,438,010
E.ON	RoCa	Gas	270	314,422				679,349
Electrabel	Gelderland ³⁾	Coal	602	1,527,790	1,566,900	48,000		3,398,930
Electrabel	Harculo	Gas	350	462,892				390,883
Electrabel	Bergum ³⁾	Gas	664	622,928				488,772
Electrabel	Eemscentrale	Gas	2,400	2,276,210				4,528,620,
Electrabel	Flevocentrale	Gas	350	33,711				36,951
Electrabel	Almere	Gas	120	567,653				366,503
EPZ	Borssele	Coal / Gas / Nuclear	873	1,058,010	300,219	14,540		1,342,100
Essent	Clauscentrale	Gas	1,278	2,803,550	19,878	103,840		1,434,680
Essent	Geleen	Gas	190	434,563				740,111
Essent	Amer	Coal	1,245	6,196,610	2,214,810	57,250	7	6,272,850
Essent	Donge ³⁾	Gas	121	181,781				96,950
Essent	Moerdijk	Gas	339	353,562				525,716
NUON	Buggenum	Coal	250	193,022	123,201	10,843	3,847 ⁴⁾	1,147,780
NUON	Hemweg ³⁾	Gas / Coal	1,229	2,866,300	1,046,390	11,523	108	2,968,670
NUON	Diemen	Gas	249	379,787			16	574,628
NUON	Velsen ³⁾	Hoogoven gas / gas	845	1,084,360	298,449	8,097	90	3,600,260
NUON	IJmond	Hoogoven gas / gas	145	291,026	122,277		6	1,680,120
NUON	Merwedekanaal	Gas	416	408,512			4	393,535
NUON	Lage Weide	Gas	247	355,352	18		11	567,186
TOTAL			13,509	31,786	9,561	360	4²⁾	38.1

¹⁾ The threshold for reporting NH₃ emissions is 10,000 kg/year. ²⁾ The emission of NH₃ for power generation (category 1A1a) submitted for CLRTAP (2006) is 65 tonne/yr. This value seems more suitable and will be used for the scenario analysis. ³⁾ Will be closed before 2020 (Seebregts, 2007) ⁴⁾ NH₃ emission from (ER, 2006) are contradicting with IIASA emission factor for IGCC.

5.2.2 Future Power plants

Power plants in 2020

In the near future a considerable amount of new power plants will be built in the Netherlands. Table 5.2 shows an overview of plants which are likely to be built. Some plants are under construction, others are in the phase of obtaining a permit. The plans will result in 8 GWatt of mainly additional power to be added to the existing 13.5 GWatt. Only a small part will be a replacement of older power plants. For the Netherlands this will result in a change from an energy importing to an energy-exporting nation. The impact on the power net in the Netherlands can be serious. Not only the larger amount of power transport, but especially the change from nightly import to a daytime export will demand for a growth of the power net (Ploumen, 2009).

The Dutch public electricity sector, as shown in Table 5.2, will have 3 large coal fired plants (PC - 3.5 GWatt), with the option of co-firing biomass. The others plants are gas fired (NGCC - 3.3 GW) and possibly there will be one IGCC (NUON). The latter will

start as a NGCC, NUON has not decided whether to continue the construction of an IGCC (Ploumen, 2009).

The emissions shown in the table are obtained from the Environmental Impact Assessment reports from the companies. In the table the maximum emissions as allowed in the permits are used. Note that NH₃ emissions are only mentioned in a few EIA reports. NUON shows a yearly load of 85 tonne NH₃ in its EIA, which is higher than the total reported NH₃ emissions from the Dutch public electricity sector.

A source for eventual NH₃ emissions is the SCR. This de-NO_x technology is not applied at the gas fired plants Delta and Electrabel because of the high costs. It is assumed that the SCR units will not be applied for the other gas fired plants and only be deployed for the coal fired plants. A NH₃ emission is assumed for all coal fired plants of 0.5 mg/m³ NH₃, because of slip from the SCR (ELECTRABEL, 2007).

Table 5.2 Overview of planned power plants, adapted from (Seebregts, 2007;Seebregts, 2008;Ploumen, 2009) and emissions adapted from (DELTA, 2004;EON, 2006;ELECTRABEL, 2007;RWE, 2009;NUON, 2009a).

Producer	Plant	Main Fuel	Power (MWatt)	NO ₂ (kg/year)	SO ₂ (kg/year)	PM ₁₀ (kg/year)	NH ₃ (kg/year) ⁴⁾	CO ₂ (1000 kg/year) ⁵⁾
Delta/EdF	Sloegebied	Gas	820	2,028,000 ¹⁾	0	0	0	2,127,817
E.ON	Rijnmond	Coal/ Biomass	1,100	1,535,000 ¹⁾	832,000 ¹⁾	94,000 ¹⁾	11,538 ³⁾	6,068,210
Electrabel	Lelystad	Gas	800	1,978,537 ²⁾	0	0	0	2,075,919
Electrabel	Maasvlakte	Coal/ Biomass	800	730,000 ¹⁾	580,000 ¹⁾	45,000 ¹⁾	8,391 ³⁾	4,413,244
ENECO	Europoort	Gas	840	2,077,463 ²⁾	0	0	0	2,179,715
Essent	Moerdijk	Gas	400	989,268 ²⁾	0	0	0	1,037,959
InterGen	Rijnmond	Gas	400	989,268 ²⁾	0	0	0	1,037,959
NUON	Eemshaven	Coal/ Biomass/ Gas	1,200	1,212,700 ¹⁾	197,500 ¹⁾	19,400 ¹⁾	12,587 ³⁾	7,081,717
RWE	Eemshaven	Coal/ Biomass	1,600	2,566,000 ¹⁾	1,818,000 ¹⁾	171,000 ¹⁾	16,783 ³⁾	8,826,488
TOTAL			7,960 MWatt	14,106 tonne/yr	3,428 tonne/yr	329 tonne/yr	49 tonne/yr	34.8 Mtonne/yr

¹⁾ Based on maximum emissions in MER. ²⁾ Based on maximum emissions from MER Delta Sloe power station.

³⁾ SCR assumed at coal fired plants with NH₃ emissions from the SCR of 0.5 mg/m³. ⁴⁾ No SCR (with corresponding NH₃ emissions) at gas fired power plants. ⁵⁾ Calculation, based on power, capacity factor (0.85) and CO₂ emission factors and efficiencies (Markal), PC 94.7 ktonne/PJ, 46%; IGCC 94.7 ktonne/PJ, 43%.

5.2.3 Emission of NEC pollutants from BREF

Since October 1999, new (and substantially changed) installations must comply with the IPPC (Integrated Pollution Prevention and Control) Directive 2008/1/EC. Since October 2007, existing installations must comply. The IPPC Directive has been adopted in the Environmental Management Act and the Environmental Management Establishments and Licences Decree. Based on the IPPC Directive, permits for industrial installations must ensure that those installations will take all appropriate preventive measures against pollution, in particular through application of the Best Available Techniques (BAT) (Infomil, 2009). The BAT for large combustion plants are described in the Reference Document on Best Available Techniques for Large Combustion Plants (BREF LCP) (EUROPEAN COMMISSION, 2006). In Table 5.3 an

indication of the emissions is given which can be met by implementing the best available techniques. The emissions strongly depend on detailed information of the technology and fuel. In Appendix H, a more detailed overview of the emissions related to BAT is given.

Table 5.3 Indication of emission ranges which can be reached by applying best available technologies for power plants (>300 MWatt)¹⁾ (European Commission, 2006).

	Emissions (mg/m ³)					
	Coal and lignite		Biomass and peat		Liquid fuels for boilers	
	New plants	Existing plants	New plants	Existing plants	New plants	Existing plants
NO _x	50-200	50-200	50-150	50-200	50-100	50-150
SO ₂	20-200	20-200	50-200	50-200	50-150	50-200
PM	5-10	5-20	5-20	5-30	5-20	5-20

¹⁾ Emissions strongly depend on detail on fuel and technology, for details see Appendix H.

5.3 Impact assessment Power plant sector

The impact of applying CO₂ capture technologies to the power generating sector is assessed in this section for the years 2020, 2030 and 2050. The 2020 scenario is based on the actual and planned power plants. Note that the approach differs from the one which was used in BOLK I, see section 2.4.

5.3.1 Results scenario 2020

The impact analysis for applying CCS to the (coal based) power plant sector in 2020 is based on three scenarios:

- **2020 without CCS** : No CCS is applied to the power plant sector in 2020
- **2020 with CCS -S1** : CCS is applied to two new coal fired power plants
 - IGCC – NUON (Eemshaven) (pre combustion)
 - PC – EON (Maasvlakte) (post combustion)
- **2020 with CCS -S2** : CCS is applied to all new coal fired power plants
 - IGCC – NUON (Eemshaven) (pre combustion)
 - PC – EON (Maasvlakte) (post combustion)
 - PC – Electrabel (Maasvlakte) (post combustion)
 - PC – RWE (Eemshaven) (post combustion)

In section 0 the current and future power sector for the Netherlands are described as well as the level of emissions without CO₂ capture. The emissions are based on (ER, 2006) as allowed in the permits. The emissions with CCS are estimated, using the following relative factors.

In Figure 5.4 the emissions from the Dutch power sector for CO₂, NO₂, SO₂, PM₁₀ and NH₃ are given for the year 2006 and the three scenarios for 2020. For the scenario of 2020 without CCS all emissions increase, because of an increase in the capacity of the power generation, since we assumed equal net electricity production in all scenarios. This makes a comparison of the scenarios more easy and transparent, although it may be more realistic that in case of large-scale CCS deployment, the electricity export will be reduced instead of building extra capacity. In the latter case, emissions will be lower than presented. In addition to the emission increase due to the capacity increase, especially emissions of PM₁₀ will significantly increase due to the new coal fired plants.

Table 5.4 Relative factors.

	PC	IGCC
Primary Energy	1.42	1.24
NO ₂	0.94	0.85
SO ₂	0.03	0.52
PM ₁₀	0.86	1.000
NH ₃	14.08	n.a.

Applying CO₂ capture technologies leads to an increase in the emission of NO_x, PM₁₀ and especially NH₃. NO_x and PM₁₀ emissions increase due to the fuel penalty for CCS. NH₃ is emitted as a result of the degradation process of the amines. For the scenarios the emission data of amines are used. Developments are going on to reduce the degradation and with it the emissions from solvents. With the improvement of the solvent technology, NH₃ emissions will be strongly reduced.

The results show that SO₂ emissions decrease below the 2006 level because of the use of solvents in the post combustion capture process. As described before (section 4.1) the SO₂ concentration has to be reduced before the CO₂ capture can take place because of the unwanted reaction of SO₂ with the amine solvent.

The NH₃ emissions from solvent degradation are surrounded with large uncertainties. The development of new solvents and/or the use of reduction technologies can reduce the NH₃ emissions. For clarity it is good to put these NH₃ emissions in the right perspective. The NH₃ emissions from power plants are relatively small compared to the total NH₃ emissions in the Netherlands. The total Dutch NH₃ emission for the year 2006 was 135 ktonne (ER, 2006). The NH₃ emissions from the 2020 scenarios vary from 0.12 ktonne/yr for the baseline scenario without CCS, up to 0.8 ktonne/yr for the scenario S2 with CCS applied to all new coal based power plants. The introduction of CCS leads to a relative large increase in the contribution of the power generation sector to the NH₃ emissions, but the overall NH₃ emission is limited.

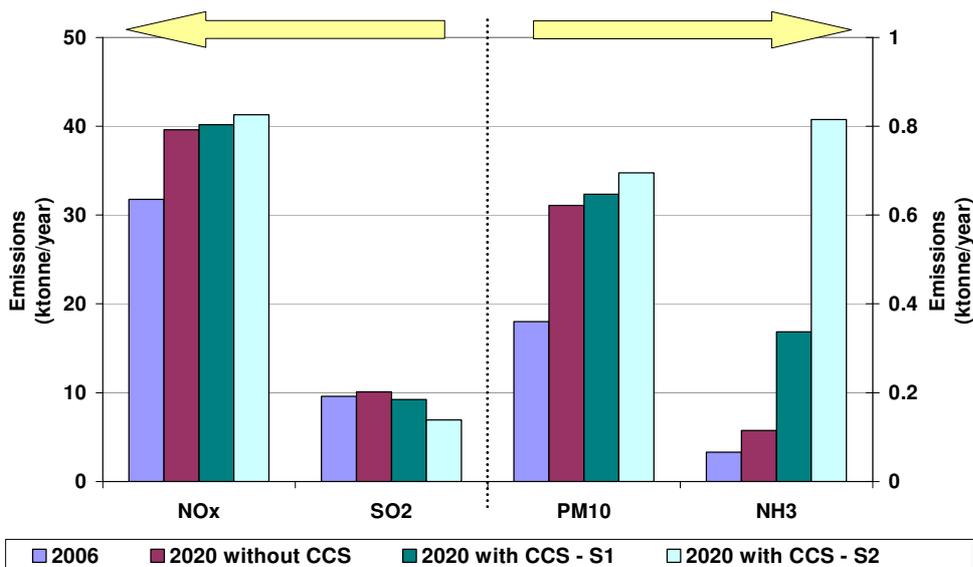


Figure 5.4 Emissions of NO₂, SO₂ (ktonne/year) on left axis and of PM₁₀, NH₃ (ktonne/yr) on right axis, in the Dutch power plant sector in 2020.

Figure 5.5 shows the CO₂ emissions for 2006 and the scenarios for 2020 with and without CCS. The blue bars show that CO₂ emissions increase with 25 Mtonne for the 2020 scenario without CCS. Scenario S2 (CCS applied to all new coal based power plants) reduces the CO₂ emissions to the level of 2006. The figure shows the avoided CO₂ emissions in scenario S1 (11 Mtonne) and S2 (23 Mtonne) compared to the 2020 level without CCS. The purple bars show the captured CO₂. These amounts are higher than the avoided CO₂ amounts because of the fuel penalty of the capture process. The extra fuel needed for the capture process produces additional CO₂ which are consequently captured.

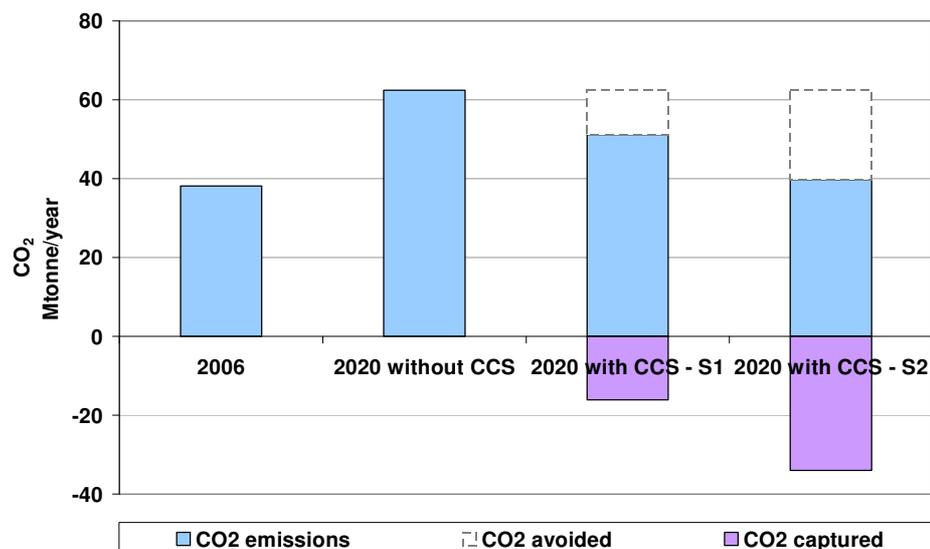


Figure 5.5 Emissions of CO₂ in 2006 and three 2020 scenarios and the avoided and captured CO₂.

5.3.2 Mitigation costs for emissions in the power generating sector in 2020

The previous section showed the in- or decreases in emissions for the various scenarios. These emissions can be monetized to mitigation costs, using the marginal costs of the NEC pollutants. These marginal costs are given in Table 5.5. Marginal costs are always debatable. An important remark which has to be made is that the costs, as shown in Table 5.5 are valid for the current situation. The costs will increase in the future and depend on the specific situation where the reduction is needed (Kroon, 2009).

Table 5.5 Marginal costs of NEC pollutants ((Harmelen et al., 2002; Harmelen et al., 2007a; Harmelen et al., 2007b; Horssen and Harmelen, 2008)).

Marginal costs (Euro/tonne)	
NO _x	4000
SO ₂	1000
PM ₁₀	50 000
NH ₃	1800 ¹⁾

¹⁾ NH₃ = 1.88 SO₂-eq

In Figure 5.6 the mitigation costs are shown for the three 2020 scenarios with the year 2006 as the reference situation. The increase in mitigation costs is caused by the increase in power generation, and consequently the emissions. The costs of NO_x and PM₁₀ dominate the overall mitigation costs of approximately 50 million Euros per year.

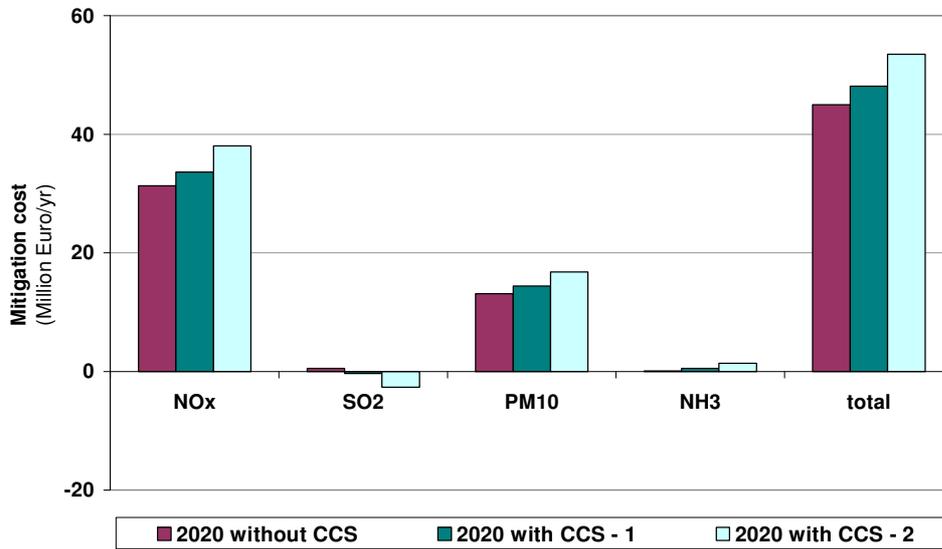


Figure 5.6 Mitigation costs for CCS scenarios with 2006 as reference.

The overall mitigation costs of CCS cannot be neglected (up to 8 million Euro per year), see Figure 5.7. In this figure the two scenarios with CCS are compared with the 2020 scenario without CCS. The costs of NO₂, PM₁₀ and NH₃ are positive, because of the increase of the emissions in the CCS scenarios. The costs of SO₂ is negative due to the emission reduction of this component.

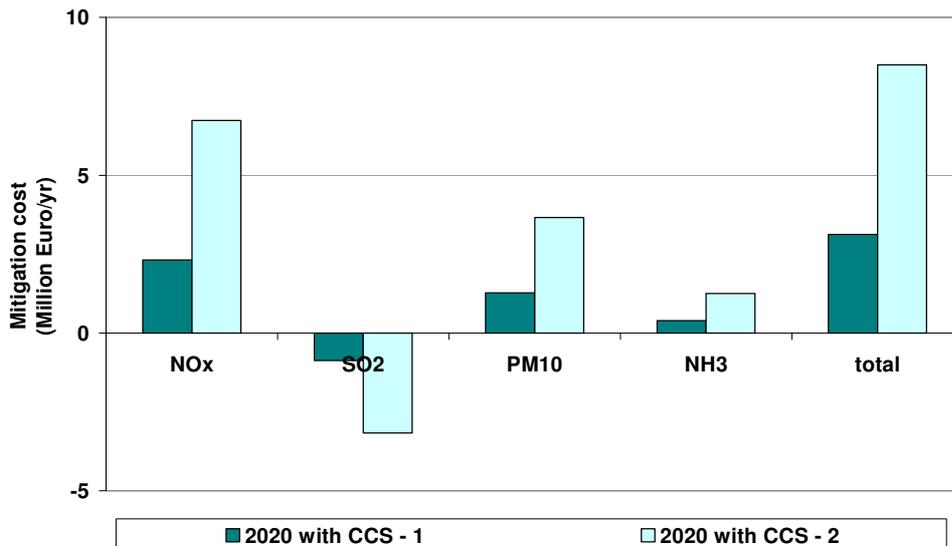


Figure 5.7 Mitigation costs for CCS scenarios with 2020 without CCS as reference.

The use of amines for post combustion capture requires a reduction of the SO₂ concentration before the capture process. The costs for the reduction as part of the overall capture costs are calculated from the emissions of SO₂ and CO₂ (in kg/kWh) and the marginal costs (Table 5.5). The mitigation costs of SO₂ are calculated to get insights into the share of these costs on the overall CO₂ capture costs. Post combustion capture (PC) brings a reduction of about 0.27 g SO₂/kWh and of 680 g CO₂/kWh. This results in a reduction of SO₂ of 0.40 kg SO₂ / tonne of CO₂. The reduction is obtained by an additional de-SO_x step and for a small part by the interaction with the solvent. Using a marginal cost of 1 Euro/kg SO₂ (Table 5.5), the mitigation costs for SO₂ are 0.40 Euro per tonne of CO₂. The SO₂ reduction costs are only a small part (1%) of the total costs of CO₂ capture (38 Euro per tonne of CO₂).

5.3.3 Results scenario 2030 and 2050

Three scenarios are developed using the cost optimization model 'MARKAL-NL-UU' developed by Utrecht University (for more information see Broek et al, 2008). These scenarios encompass the Business as Usual (BAU), Postponed Action (PA) and the Direct Action (DA) scenario. These scenarios are based on the assumption that GDP grows with 1.6% per year and electricity demand will increase until 2020 with 1.5% per year and with 0.8% per year between 2020 and 2050.

The difference between the scenarios entails the amount and timing of CO₂ reduction. In the BAU no CO₂ reduction targets are in place. In the PA and DA 50% is to be reduced in the power and heat sector in 2050 compared to 1990 levels. In the latter scenario action is taken directly (2010) whereas in the PA actions are delayed (2020). In addition to these three cost effective scenarios, two 'What if' variants of the DA are developed to assess the impact of CO₂ capture technology choices. For the substances CO₂, NO_x and SO₂ an additional scenario is presented: Oxyfuel Demo. This scenario incorporates the emission factors that have been reported on the demonstration power plant for oxyfuel combustion in Germany. This is done to place values reported in the literature, based on hypothetical power plants, into perspective. Emission factors for other substances could not be derived for this scenario.

Relevant results are the electricity production, primary fossil energy use, and the emissions of CO₂, SO₂, NO_x, NH₃, NMVOC, PM₁₀, PM_{2.5} and CO₂. The results of this exercise are depicted in Figure 5.8 to Figure 5.16 and are discussed below.

As discussed in section 2-4, the methodology for this scenario analysis for 2030/2050 is somewhat different compared to the scenario analysis for the year 2020 in this report and for the analysis presented in the BOLK I project. New emission factors and updated relative factors have been used in the new scenario analysis for the 2030/2050. The result of the methodological update compared to the BOLK I project is depicted in Table 5.6. As already mentioned, an important update is that emission factors for power plants with oxyfuel combustion that allow co-sequestration have been excluded when calculating the relative factor. In Table 5.6 this is reflected by the relative large number of emission factors that have been changed for oxyfuel combustion, in particular the PM emissions. Furthermore, the standardization of emission data has resulted in significant changes in the emission factors for NH₃ and SO₂. A large change is depicted for NH₃ emissions for gas fired power plants with and without CO₂ capture. This is due to the new applied calculation method described in section 2.4. NH₃ emission factors are updated for other technologies, which are adjusted downwards.

Table 5.6 Overview of changes in emission factors used in this study compared to the BOLK I study.

Technology	Capture	Substance	BOLK I mg/MJ	BOLK II mg/MJ	Change %
IGCC	No	SO ₂	5.00	4.12	-18%
		NH ₃	0.01	0	-100%
IGCC-CCS***	Pre	SO ₂	2.23	0.97	-57%
		NH ₃	0.001	0	-100%
PC*	No	SO ₂	29.00	29.6	2%
		NH ₃	1.20	0.67	-44%
PC new**	No	SO ₂	24.00	29.6	23%
		NH ₃	1.00	0.67	-33%
PC new with capture	Oxy	SO ₂	1.42	1.5	6%
		NO _x	12.51	20.5	64%
		NH ₃	1.00	0.67	-33%
		PM ₁₀	0.14	0.27	93%
PC capture retrofit	Oxy	PM _{2.5}	0.11	0.21	91%
		SO ₂	1.72	1.5	-13%
		NO _x	23.36	20.5	-12%
		NH ₃	1.20	0.67	-44%
PC capture retrofit	Post	PM ₁₀	0.14	0.27	93%
		PM _{2.5}	0.11	0.21	91%
		SO ₂	0.27	0.7	159%
		NH ₃	21.00	11.56	-45%
PC capture retrofit on capture ready power plants	Post	PM ₁₀	2.14	2.07	-3%
		PM _{2.5}	1.67	0.61	-63%
		SO ₂	-	0.7	-
		NH ₃	-	11.56	-
Existing gas*	No	PM ₁₀	2.14	2.07	-3%
		PM _{2.5}	1.67	0.61	-63%
Gas new**	No	NH ₃	0.10	0.06	-40%
		NH ₃	0.01	0.06	500%
Gas new capture	Post	NH ₃	0.25	10.8	4220%
Gas new capture	Oxy	NH ₃	0.01	0.06	500%
Gas capture retrofit	Post	NO _x	48.92	49.79	2%

Electricity production

Figure 5.8 shows a higher electricity production with large-scale power plants in the Business As Usual (BAU) scenario compared to scenarios with a CO₂ reduction target. The total electricity demand is assumed to be equal in all scenarios. Electricity demand is however expected to increase between 2030 and 2050, as shown in the figure. In the reduction scenarios relatively more electricity is generated with alternative energy sources (i.e. wind energy) and CHP plants. This explains the somewhat lower electricity production values for the reduction scenarios. The emissions from these sources are not included in the results presented in this study as these are not directly affected by the implementation of CCS in the sector.

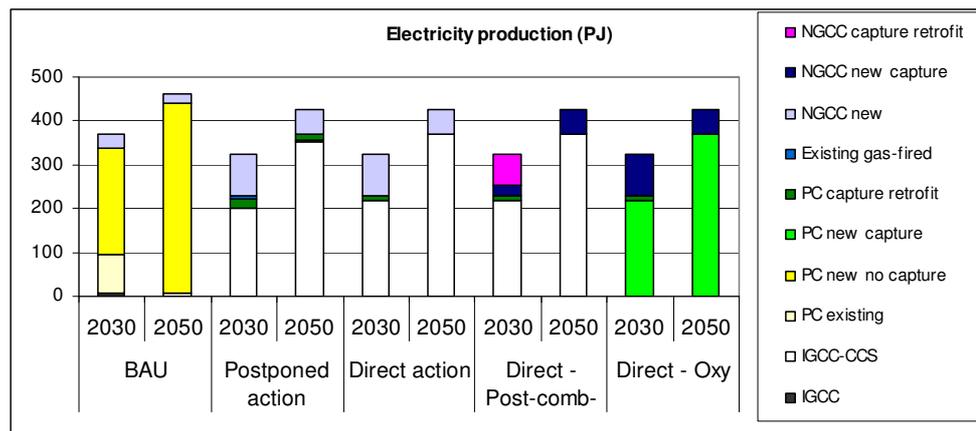


Figure 5.8 Electricity production in the Dutch power sector in the years 2030 and 2050.

The composition of the sector in the scenarios is very different. In the BAU a large share of the sector is represented by PC power plants without CO₂ capture. This technology is non-existent in the reduction scenarios. In the reduction scenarios a large share is represented by IGCC power plants with CCS. However, in the Direct Action-Oxyfuel (DA-Oxy) scenario a large share is fulfilled by PC power plants with oxyfuel combustion CO₂ capture. Another difference between the scenarios is the implementation of the NGCC power plants; in the Postponed Action (PA) and Direct Action (DA) scenarios these are NGCCs without CCS and in the Direct Action – Post combustion (DA-Post) and DA-Oxy these are NGCCs equipped with post combustion capture and oxyfuel combustion, respectively.

The main difference between 2030 and 2050 can be seen in the BAU and DA-Post scenarios. In the BAU scenario in 2030 still a considerable share of electricity is produced by coal-fired power plants built before 2010. This share has diminished in 2050. It is also shown that in the DA-Post scenario NGCC power plants retrofitted with CO₂ capture are in operation in 2030, i.e. 71 PJ. These power plants have been phased out and replaced by IGCC power plants with CCS in 2050 in the same scenario. Overall, the trend between 2030 and 2050 shows that gas fired capacity is replaced by coal-fired power plants.

Fuel consumption

Results depicted in Figure 5.9 show that the fossil fuel use¹⁹ (in primary energy) in the reduction scenarios is somewhat comparable with that in the BAU scenario. Not depicted is the primary energy use of the renewable energy technologies. The overall primary energy use in the reduction scenario is thus higher, obviously caused by the efficiency penalty due to CO₂ capture. The highest score, i.e. a 21% increase in fossil primary energy in 2050, is found for the DA-Oxy scenario, as there the largest share of the sector is equipped with CCS.

¹⁹ For reference, fossil fuel consumption in the recently published updated Referentieramingen (Daniels and van der Maas 2009) is estimated for 2020 to be 1069 PJ (466 PJ coal and 574 PJ natural gas).

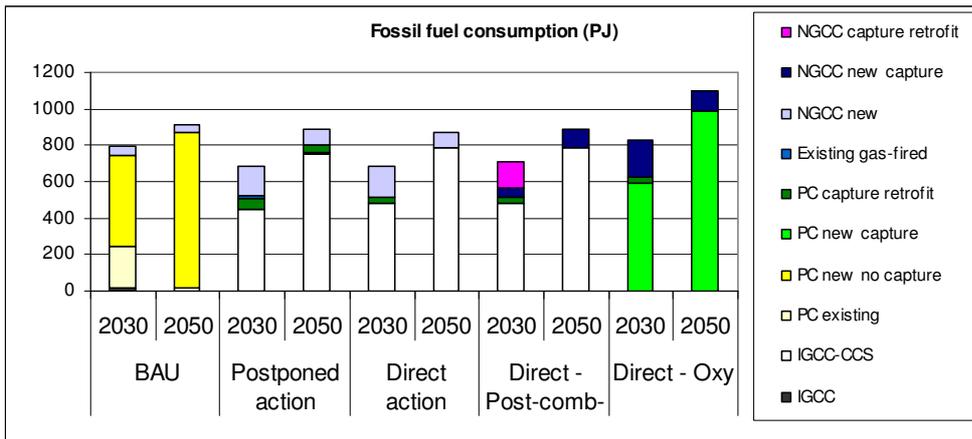


Figure 5.9 Fossil fuel consumption in the Dutch power sector in the years 2030 and 2050.

CO₂ emissions

Figure 5.10 shows CO₂ emissions in the various scenarios. The deepest reduction and hence lowest CO₂ emissions, are found for the DA-Oxy scenario with an emission of 3 and 4.6 Mtonne in the year 2030 and 2050, respectively. Furthermore, comparing the results for 2050 and 2030 for the DA-post and DA-Oxy scenarios shows that CO₂ emissions increase between 2030 and 2050, whereas this is not the case for the other scenarios. This is the consequence of the manual construction of these scenario variants. For these variants holds that an increase in electricity demand results in an increase in CO₂ emissions as the CO₂ emissions are already below the target.

A difference can be seen between the DA-Oxy and the ‘Oxyfuel demo’ scenario. This is the consequence of a somewhat lower capture efficiency reported for the demonstration project. This is the result of the venting of gas from the CO₂ treatment plant that contains some CO₂, i.e. 10% of the CO₂ is vented.

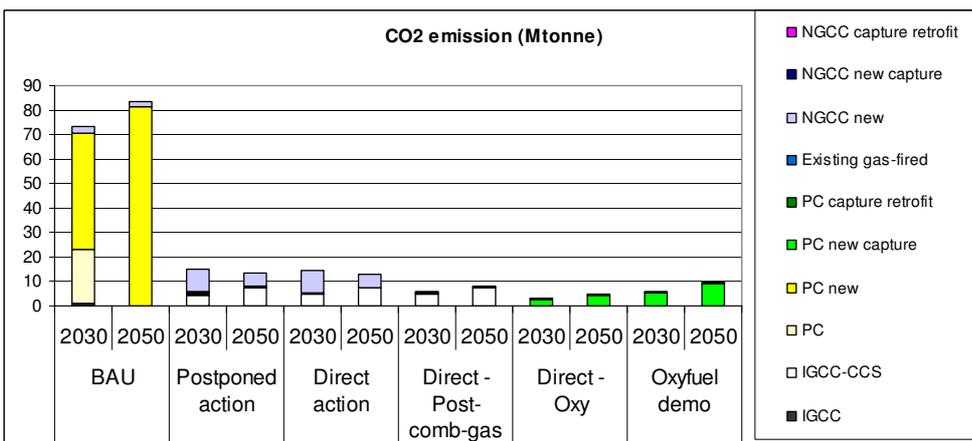


Figure 5.10 CO₂ emission from the Dutch power sector in the years 2030 and 2050.

SO₂ emissions

In

Figure 5.11 a considerable reduction in SO₂ emissions between 94-98% for the CO₂ reduction scenarios compared to the BAU scenario is shown. For the BAU scenario approximately 22 and 25 ktonne of SO₂ emissions in 2030 and 2050, respectively, were calculated. This contrast the value between 0.8 ktonne and 1.5 ktonne found for the PA and DA-Oxy scenarios in 2050, respectively. The lowest reduction can be seen in the Oxyfuel demo scenario, which indicates that the coal fired oxyfuel concept is suitable for achieving very low SO₂ emission levels. The difference between the DA-Oxy and Oxyfuel demo scenario results can be explained by differences in the performance of the CO₂ purification sections, which heavily determines the reduction efficiency. This deep reduction is the result of the high efficiency removal of SO₂ emissions in IGCC power plants compared to normal PC power plants. A second explanation, for the DA-Oxy scenario, is the reduction of SO₂ emissions due to oxyfuel combustion with CO₂ capture.

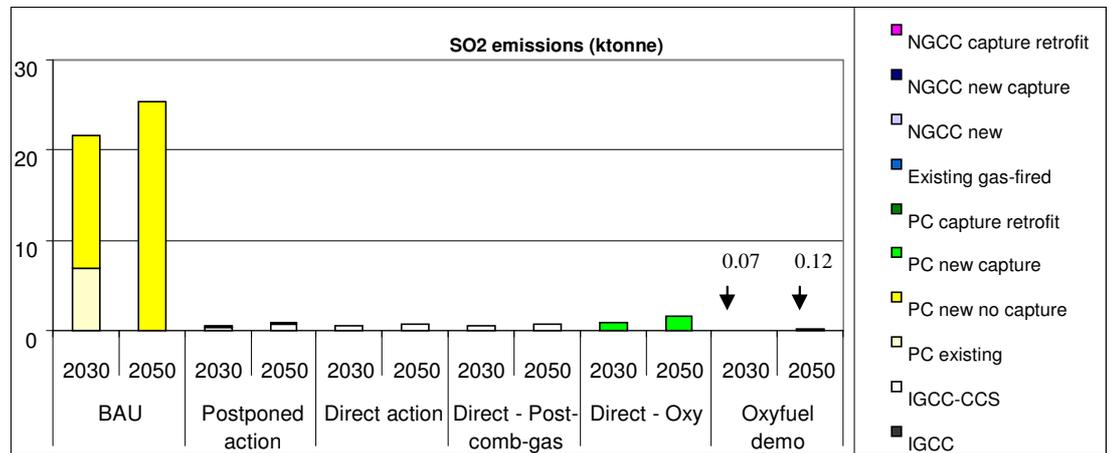


Figure 5.11 SO₂ emissions from the Dutch power sector in the years 2030 and 2050.

NO_x emissions

Figure 5.12 shows that the BAU scenario results in 25 ktonne of NO_x emissions in the year 2050. Compared to this BAU scenario a high reduction (68-75%) was found in the PA, DA and DA-Post scenarios through the wide scale implementation of IGCC with CCS. This technology has lower NO_x emissions compared to PC power plant without capture, the dominant technology in the BAU scenario. Somewhat less reduction is found in the PA scenario due to the emission of NO_x from PC power plants retrofitted with post combustion CO₂ capture. A significant lower reduction, i.e. 20%, is found in the DA-Oxy scenario. This is due to the higher increase in primary energy use compared to the other scenarios and due to the higher NO_x emissions for PC power plants with oxyfuel combustion compared to an IGCC power plant with pre combustion CO₂ capture. This result is however based on emission factors reported for literature cases. In practice the oxyfuel concept is expected to achieve much lower NO_x

emissions. This can be seen in the figure below when reviewing the results for the Oxyfuel demo scenario.

The figure also shows a difference in outcomes for 2030 and 2050. The most important is the higher NO_x emissions in the CO₂ reduction scenarios PA, DA and DA-Post in the year 2030 compared to 2050. This is due to the contribution of NGCC without CCS and PC power plants with CCS. In the DA-Post the NO_x emissions in 2030 are even somewhat higher due to the emission from NGCC power plants with CO₂ capture. The increase between 2030 and 2050 in the DA-Oxy scenario can be entirely attributed to volume effects, i.e. increase in electricity demand.

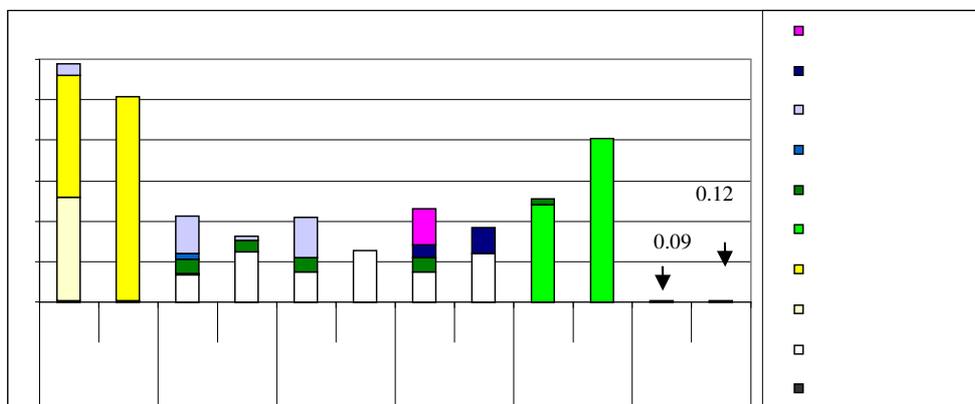


Figure 5.12 NO_x emission from the Dutch power sector in the years 2030 and 2050.

NH₃ emissions

Figure 5.13 shows that an increase in ammonia is expected in 2030 and 2050 for the scenarios with a relative large share of power plants equipped with post combustion CO₂ capture compared to the respective BAU scenarios.

In 2030, relative high NH₃ emissions are expected in the DA-Post scenario (approximately factor 5 higher) and PA scenario (approximately 38% higher) due to the implementation of post combustion capture technology. Reduction of NH₃ emissions between 2030 and 2050 in the PA, DA and DA-Post scenarios are mainly the result of the phase out of NGCC and PC power plants with post combustion capture and the introduction of IGCC with CCS.

In 2050, NH₃ emissions in the PA show a 12% decrease and the DA-Post a 97% increase compared to the BAU. This is the result of NH₃ emissions from the power plants equipped with post combustion CO₂ capture; either through decomposition product of the solvent or the direct emission of solvent in the case of the chilled ammonia capture system. The latter is however not quantitatively taken into account due to lack of data. The 16% increase for the DA-Oxy scenario should be considered highly uncertain as NH₃ emissions are dominated by DeNO_x in power plants without CO₂ capture. It is also uncertain whether power plants equipped with the oxyfuel combustion technology will also be equipped with a DeNO_x and what consequently the

NH₃ emission would be of such a technological configuration. The 99% reduction in the DA scenario is due to the implementation of IGCC with CCS for which emission of NH₃ is assumed to be negligible, see Table 5.6. Comparing with the NH₃ emissions reported for the Buggenum IGCC power plant (section 5.2.1), this can be considered an optimistic estimate.

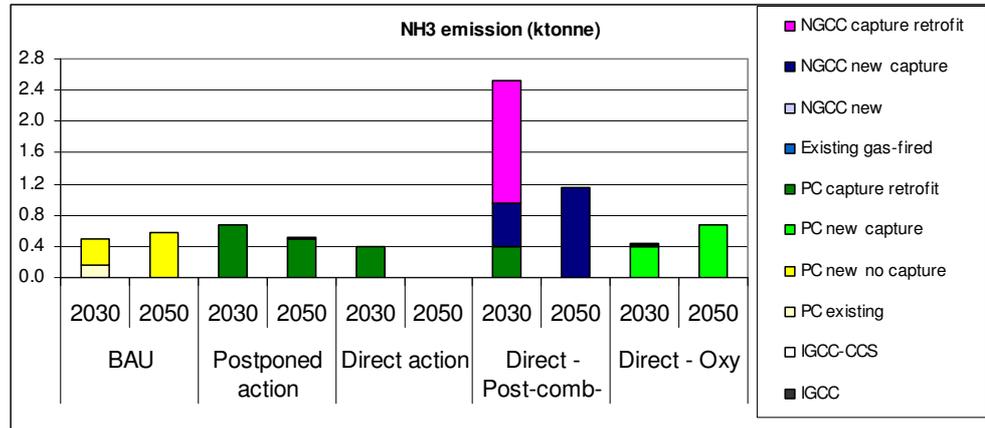


Figure 5.13 NH₃ emission from the Dutch power sector in the years 2030 and 2050.

NM VOC emissions

In this study it could not be determined to what extent the application of CO₂ capture would affect the emission of NMVOC from power plants. Therefore, estimates for NMVOC emissions for the BAU and CO₂ reduction scenarios are merely based on the emission factors derived from the GAINS database. The NMVOC emissions are assumed to be unaffected by CO₂ capture and to increase with the increase in primary energy demand by CCS.

Note however that the DA-Oxy scenario shows a higher emission level compared to the BAU and other reduction scenarios. This is due to the lower emission factor for IGCC power plants (1 mg/MJ) compared to other power generation technologies (2 mg/MJ). The share of IGCC power plants versus the share of PC power plants thus explains to a large extent the difference between the scenarios. This together with volume effects also explains the difference between the outcomes for the years 2030 and 2050.

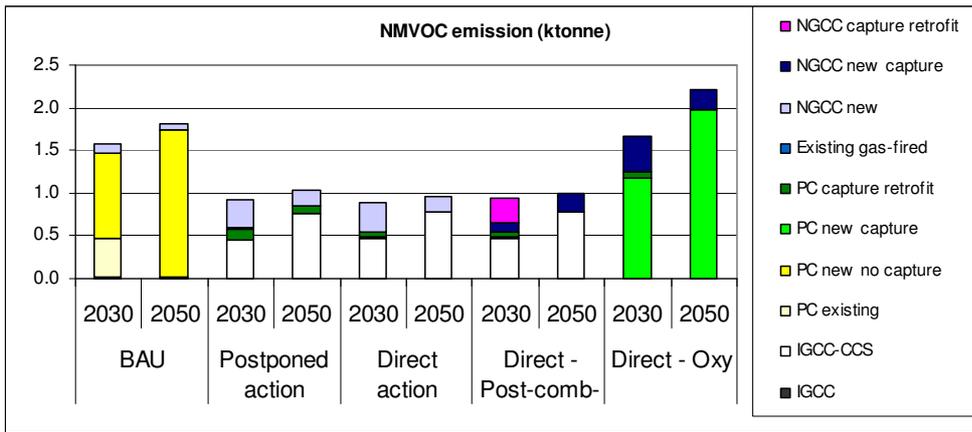


Figure 5.14 NMVOC emission from the Dutch power sector in the years 2030 and 2050.

PM_{2.5} and PM₁₀ emission

Figure 5.15 and Figure 5.16 show similar emission profiles for PM₁₀ and PM_{2.5}. This is due to the assumption that PM₁₀ and PM_{2.5} represent a constant fraction of total particulate matter smaller than 10 μm, i.e. 43% of particulate matter is estimated to be PM_{2.5} and 57% is PM₁₀, see also (Harmelen et al., 2008).

The figures show that in 2050 a reduction compared to the BAU between 30% and 33% is expected for all scenarios with a large share of IGCC power plants equipped with CCS and a small share of power plants with post combustion; in 2030 this reduction is found to be 47%. This is due to the highly efficient removal of particulate matter in the gas cleaning section of an IGCC and due to the absence of PC power plants without CO₂ capture, having higher PM emissions. In the DA-Oxy even lower PM emissions are expected due to the low PM emission from PC power plants equipped with oxyfuel combustion, i.e. an 87% and 90 % reduction is foreseen for respectively 2050 and 2030. The difference between 2030 and 2050 is mainly the result of the increase in electricity demand and with it an increase in emissions.

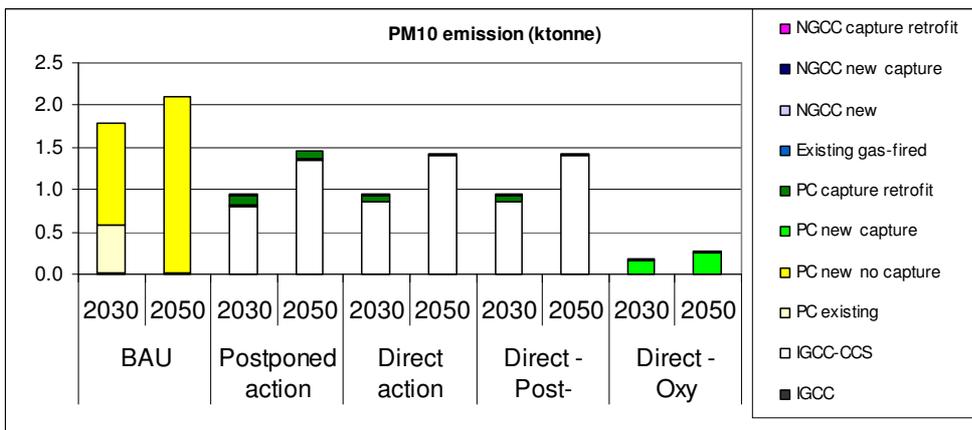


Figure 5.15 PM₁₀ emission from the Dutch power sector in the years 2030 and 2050.

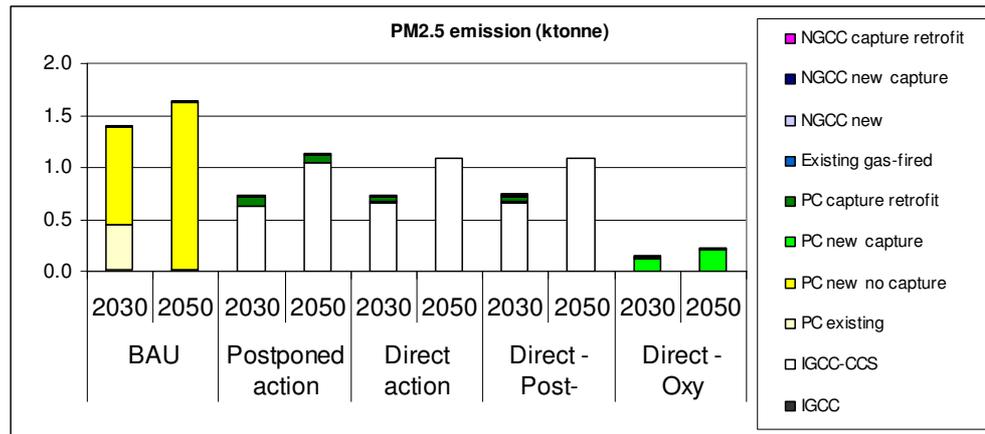


Figure 5.16 PM_{2.5} emission from the Dutch power sector in the years 2030 and 2050.

CO₂ reduction cost

In Figure 5.17 the marginal cost of CO₂ reduction for the DA and PA scenarios is shown. This result cannot be shown for the two variants, DA-Post and DA-Oxy, as these scenarios are not derived with a cost optimization model. For these variants no marginal cost of CO₂ reduction is thus calculated. The figure indicates that the CO₂ avoidance cost between 2030 and 2050 goes down from 32 Euro₂₀₀₀/tonne to approximately 25 Euro₂₀₀₀/tonne. The cost decrease as a result of the phasing out of older power plants and due to the introduction of highly advanced power plants with CCS. The cost estimates agrees reasonably well with the ranges indicated for IGCC (16-27 Euro/t) and PC (28-47 Euro/t) power plants with CO₂ capture in section 3.2.

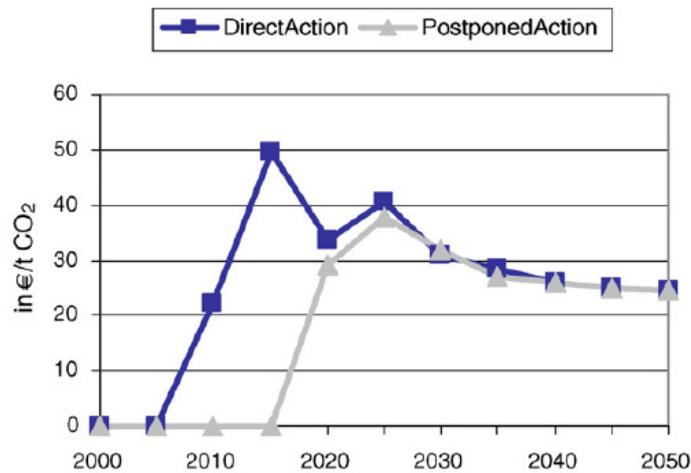


Figure 5.17 Marginal cost of CO₂ reduction (in €₂₀₀₀) for the Direct Action and Postponed Action scenario (source: (van den Broek et al., 2008)).

Conclusions

A large part of the results is determined by the aspect of our scenarios that the IGCC power plant equipped with CCS is the dominant technology applied in 2050. Comparing the results for the year 2030 and 2050 the conclusion can be drawn that in the reduction scenarios gas fired capacity is replaced by coal-fired capacity, i.e. IGCC with CCS. Furthermore, the increase in demand is met by IGCC power plants with CO₂ capture. Power plants equipped with post combustion capture are gradually phased out towards 2050 which also has consequences for NEC emissions. Dominant are for instance the effects on NH₃ and NO_x emissions, which are higher in scenarios with post combustion capture technologies implemented, thus in 2030. Another important difference between 2030 and 2050 is the increase in electricity demand and fossil fuel consumption resulting in an increase in NEC emissions in general from 2030 to 2050 for the other substances.

For the year 2050 it is concluded that all emissions except NMVOC in the DA-Oxy scenario and NH₃ will decrease as a result of GHG mitigation policies. They would even decrease further for NO_x and SO₂ when taken into account recent emission data reported on an oxyfuel demonstration project. Further, in all GHG mitigation scenarios NO_x and SO₂ emissions will decrease moderately to considerably. Particulate matter emissions will also in general decrease to a lesser extent, however this effect is considerable for the scenario with a PC power sector equipped with oxyfuel combustion CO₂ capture.

NMVOC emissions for such a scenario may increase but this is uncertain and mainly dependent on the energy conversion technology implemented (i.e. PC vs. IGCC). An increase in NH₃ emissions is expected due to emission from post combustion capture technologies. Post combustion is however expected to fulfil a limited share compared to IGCC power plants with CCS in 2050. Furthermore, the NH₃ emissions from post combustion technologies may prove to be insignificant in the year 2050 due to the development of new solvents and mitigation technologies for NH₃ emissions.

When comparing all scenarios and substances it is clear that the scenario with the oxyfuel combustion technology widely implemented shows relatively higher emission levels for SO₂, NO_x and NMVOC compared to the other GHG mitigation scenarios. Lower relative emissions are expected for particulate matter in this scenario, however. It should be stressed that the configuration and performance of flue gas cleaning equipment for coal fired oxyfuel fired power plants is still an area of development and thus remains uncertain. Emission estimates for this technology should thus also be regarded uncertain.

5.4 Comparison OF BOLK I and BOLK II

In this report the impacts of CO₂ capture in power generation and industry on transboundary air pollution are assessed. The assessment is, in comparison with the first phase of the BOLK project, more dedicated to the Dutch situation. The main improvements are in the harmonization of the data inventory and the scenario analysis, focused on the Dutch power generation and industrial sector. In this paragraph the results from BOLK I and BOLK II are compared.

5.4.1 Methodology 2020 of BOLK I vs. BOLK II

In this study a different approach is used to estimate the level of implementation of CO₂ capture in the power sector in 2020. In the BOLK I project an economic optimization model was used to determine the composition of the power sector under different policy scenarios. In this study, BOLK II, scenarios for the power sector in 2020 are formulated

based on expert opinions and actual planned capacity additions. The outcome of these two different approaches is consequently different. Nevertheless, in qualitative terms the conclusion of both approaches is equal for NO₂, NH₃ and SO₂: the introduction of CCS leads to an increase in NO₂ and NH₃ emissions and a decrease (in absolute terms) of SO₂ emissions. BOLK I shows a relative decrease on the PM₁₀ emissions compared to a scenario without CCS, BOLK II shows an increase. This can be explained by the choice of the capture technology. In the BOLK I scenarios mainly pre-combustion IGCC was applied, in BOLK II post-combustion was the dominating capture technology. The quantitative estimates however vary. The extent of the variance is shown in the table below where the results from the scenarios analysis for the year 2020 in the BOLK I and II project are compared.

Table 5.7 Comparison of NEC emissions estimates for the year 2020 between BOLK I and BOLK II project.

	BOLK I		BOLK II	
	BAU	Reduction scenarios	BAU ⁷⁾	Reduction scenarios
SO ₂ (ktonne/yr)	17.5	0.9-1.0	10.1	6.9 - 9.2
NO _x (ktonne/yr)	29.7	10.2-20.8	39.6	40.2 - 41.3
NH ₃ (tonne/yr)	727	624-4856	115	337-815
VOC (tonne/yr)	1479	865-1583	-	-
PM ₁₀ (tonne/yr)	1644	104-1038	622	647 - 695

⁷⁾ BAU: No CCS applied to the power plants; Reduction scenarios: 1 pre combustion - IGCC and 1 to 3 post combustion (coal fired) power plants with CCS are installed.

The main difference in the results is that the impacts of implementing CCS in the power sector are less extreme in the BOLK II project. This is the result of assuming a less drastic change in composition in the power sector both in terms of the expected shift in the application of conversion technologies and on the level of CO₂ capture implementation. In addition, both factors are important to the change in emission factors due to standardisation of the collected data for NH₃ and SO₂.

5.4.2 Scenario 2020 2030 2050 in perspective

As discussed above, in this study the methodology for deriving the emission estimates for 2030 and 2050 differs from the methodology used for the year 2020. The main differences between the scenarios is that for the 2030 and 2050 scenarios, it is assumed that deep reductions are met in the power sector and that CO₂ capture is thus implemented to a high degree. This also results in a significant change in the composition of the public electricity sector. This assumption should be carefully taken into account when reviewing and comparing the results of the various scenarios developed in this study.

5.4.3 Adequacy of applied emission factors

The uncertainty regarding the used emission factors is considered to be high. Although harmonization of emission data has been performed, still uncertainties persist. Variables causing uncertainty that have not been controlled for all substances are for instance: the technical configuration and performance of power plant and CO₂ capture technology, and exact fuel composition.

The application of emission factors from current literature (mainly given up to 2030) are used to estimate the emission loads in the year 2050. This brings forth large uncertainties as well. In this long time horizon new conversion and CO₂ capture

technologies may emerge that are not taken into account here. The lack of quantitative data is the main reason for excluding these technologies from the scenarios. Furthermore, mitigation technologies for NEC substances may also improve, resulting in lower emission factors. The emission factors presented here should thus be considered as conservative, in this respect.

Another point to take into account is that an increase in demand for coal up to 2050 may result in mining and use of lower rank and lower quality coals. A change in coal quality may increase, for instance, the formation and subsequent emission of SO₂ and NO_x.

Finally, it should be noted that deep reductions of NEC emissions and CO₂ might result in unwanted trade-offs in other environmental compartments such as soil and water. Decrease in emissions to air may result in an increase in environmental interventions beyond the scope of this study. Examples are waste water effluent, water use, waste formation and disposal, and environmental interventions in the fuel supply chain.

6 Conclusions and recommendations

Based upon data from the international literature, interviews with leading experts and own calculations and analysis in phase 1 and 2 of the project, an assessment has been made of the impacts of CO₂ capture technologies in power generation and industry on greenhouse gas and transboundary air pollution mitigation in the Netherlands on the short and long term. In this section conclusions are drawn based on the results provided in *both* phases of BOLK.

6.1 Technology assessment

6.1.1 *Techno-economic characterisation (from phase 1)*

Application of CO₂ capture is expected to become techno-economically feasible in large-scale combustion processes such as power generation and energy intensive industry. Industrial processes suited for CO₂ capture are purification of natural gas, the production of hydrogen, ammonia, ethylene and ethylene oxide, iron and steel and cement. These processes emit gas streams with relative high CO₂ concentrations and hence provide potentially cost-effective opportunities for CO₂ capture.

Three types of CO₂ capture technologies have been investigated, viz. post combustion, pre combustion and oxyfuel combustion. All three CO₂ capture technologies are likely to be ready for demonstration before 2020.

Post combustion technologies require additional energy (in the order of 15% for gas and 25% for coal firing plants) but does not interfere with the combustion process itself, making it a robust technology suited for retrofitting existing power plants. Post combustion using amines is one of the most mature technologies and is likely to be ready for full-scale implementation by 2020 on new and existing power plants.

Pre combustion technologies have lower efficiency penalties and better environmental performance than post combustion technologies using amines. Today, only a few Integrated Gasification Combined Cycle (IGCC) power plants are operating. Pre combustion capture is however proven at commercial scale and pilots for its application in IGCC concepts are underway. This technology has a lower efficiency penalty than post combustion technologies using amines.

Oxyfuel combustion processes use nearly pure oxygen for the combustion instead of air. The resulting flue gas contains mainly CO₂ and H₂O. A coal fired demonstration project using this technology is currently being operated. The oxyfuel technology promises to have the highest CO₂ removal efficiencies and very good environmental performance.

Retrofitting existing power plants with CO₂ capture seems to favour post-combustion CO₂ capture technologies principally because they do not require modification of the combustion process. Retrofitting existing coal fired power plants with oxyfuel combustion is according to some sources also possible but requires combustion modifications. Retrofitting IGCCs with pre combustion CO₂ capture brings forwards numerous issues but is possible when facilities are built capture ready.

6.1.2 *Environmental characterisation*

In both phases of BOLK, data from literature sources on environmental characteristics of different carbon capture technologies have been assessed. The main difference between both phases is the standardisation of key parameter values which was performed in the second phase using parameter values representative of the Dutch situation.

CO₂ avoidance costs in 2020

The range of CO₂ avoidance cost reported in the literature narrowed significantly after the parameter standardisation. The obtained results enable the drawing of (more) robust estimates on cost performance of CO₂ capture.

Our results show that IGCC with pre combustion capture was found to offer the lowest costs in 2020 (between 18 and 27 Euro/tonne CO₂ avoided; results do not include transport and storage costs). This is followed by post combustion capture and oxyfuel capture from coal power plants. Cost figures for some CO₂ capture routes have decreased after parameter standardization. The influential parameters are, e.g. annual operation time, economic lifetime of a plant and interest rates.

It should, however, be noted that most of the cost figures reported in the literature are based on the assumption that the technology is mature. Higher costs for the demonstration plants and the “first-of-a-kind” commercial plants are not included. The results therefore do not imply that in the short and mid term future IGCC with pre-combustion CO₂ capture would be the cheapest.

SO₂

For all coal firing conversion technologies, the application of CO₂ capture results in a decrease of SO₂ emissions per kWh. Sulphur has to be removed to avoid degradation of the solvent in post combustion processes. In pre combustion and oxyfuel the efficient treatment of, respectively, the syngas and flue gas (CO₂ purification) is expected to result in low SO₂ emissions, below the BAT levels for power plants.

Standardisation of parameter values resulted in even lower SO₂ emissions from coal fired power plants with CO₂ capture than indicated in phase 1. This is mainly because the average sulphur content in the Dutch coal mix is considerably lower than generally assumed in the literature. Post combustion capture was found to emit the least SO₂.

NO_x

Standardisation of NO_x emission was not possible due to lack of supporting information in the relevant literature and the amount of factors affecting the end-of-pipe NO_x emission level. Results are based solely on the data reported in the literature.

In the post combustion concepts NO_x emissions are believed to be largely unaffected by the (amine based) capture process, although consensus seems to be absent. The NO₂ part of NO_x (~10%) is assumed to be removed since it reacts with the amine based solvent. NO_x emissions per kWh seem to increase almost proportionally with the increase in primary energy demand due to the energy penalty induced by CO₂ capture.

NO_x emissions from oxyfuel concepts are in general expected to be very low, particularly for gas. However, the literature is ambiguous about this subject for coal fired plants. Reduction of NO_x in the latter is highly dependent on the performance of (new) treatment and purification sections applied in this concept.

NH₃

Only for post-combustion capture, NH₃ emissions are estimated to significantly increase for coal-fired power plants up to a factor 45 (average factor 14). NH₃ emissions can also occur at gas fired plants with CCS, although at lower rates than at coal fired plants with CCS. This is caused by solvent degradation (i.e. an amine based solvent) that is used in the post-combustion capture concept. However, the uncertainty regarding the estimates is considered to be high.

PM

The emission of particulate matter from natural gas fired cycles can be considered negligible. PM needs to be removed for a stable capture process and subsequently is expected to be removed in the post-combustion capture process. Overall the PM emissions are assumed to decrease per MJ. In absolute terms, however, PM emissions may increase due the efficiency penalty.

NMVOC

Pre-combustion CO₂ capture can increase or decrease the emission of NMVOC. Quantitative estimates of this reduction are absent in the literature. It is largely unknown whether and to what extent NMVOC emissions are affected by the CO₂ capture process in the oxyfuel and post-combustion concepts.

Life cycle analysis

Indicative life cycle analysis performed in phase 1 indicates that for coal fired power generation, the indirect emissions exceed the direct emissions in most cases for all NEC substances. The major part of these indirect emissions is caused by mining, preparation and transport of coal and occurs outside the Netherlands. Results also indicate that switching from coal to gas fired power generation has larger impacts on direct and indirect NEC emissions than the application of carbon capture and storage (CCS).

In general, CO₂ capture is likely to increase emissions of transboundary air pollutants over the lifecycle due to increased fuel consumption in the order of 15% to 25% depending on the capture technology type. Emissions will increase as well due to equipment and solvent manufacturing and treatment, and to a smaller extent due to CO₂ storage. For the coal cases these activities contribute in the order of 0-15% to the total emissions over the life cycle.

6.2 Specific technological developments and applications

6.2.1 Solvents

Post combustion capture, using amine based solvents will most likely be the first available CO₂ capture technology applicable for large-scale applications. However, the

largest industrial CO₂ capture plants have a capacity of up to 500 tonne CO₂/day at this moment. This is still a factor of 25 smaller than needed for an average power plant.

The most important trends in solvent development are: the development of solvents with a reduced energy consumption and the development of amine based salts. Related to the first trend is the development of the chilled ammonia process, which has a potential for strongly reduce the energy penalty. Nevertheless it is a complex technology and at the moment first test results of pilot plants are presented.

The introduction of solvents can become an additional source of emissions, e.g. NH₃. Ammonia can be emitted by the MEA based solvents when no additional measures are taken. The amine salts will not emit any NH₃ during the capture process. It is possible to reduce NH₃ emissions with (acid) scrubbers, but this will lead to additional costs. First results from the chilled ammonia process show (some) problems with ammonia slip, which result in unwanted emissions.

6.2.2 Biomass and CCS (BECS)

Substituting coal in large power plants with biomass can have neutral to positive effects on air pollution. The main reason for (co) firing biomass is that it is expected to reduce CO₂ emissions. In general, co-firing biomass with coal provides means to reduce SO₂, PM, NMVOCs and it may reduce NO_x emissions. There is not enough data to make conclusions about NH₃ emissions. The use of biomass or biofuels in gas-fired power plants may increase air pollution, mainly emissions of SO_x and PM compared to natural gas.

It is expected that emissions of NEC pollutants will not be a problem due to BECS introduction. For low co-firing ratios, no irresolvable issues are expected although there are poor combinations of fuel, boiler and operation process. Replacing a substantial share of fossil fuel by biomass requires intensive redesign of processes and installations.

In principle, all three CCS technological approaches being advanced for fossil fuels systems (such as gasification and oxy-fuel) could be applied to bio-energy systems. However, CCS would be most beneficial both in financial and CO₂ reduction terms, when applied to large, coal-fired power plants (scale effect). For solid biomass as well as for coal the same volume of CO₂ is expected in flue gases. Moreover, due to similar characteristics of solid biomass and brown coal, for both fuels the same concentration of CO₂ in flue gases is expected. Thus biomass should not affect the performance of the CO₂ capture unit. However, the efficiency of co-firing biomass is, on average, 0-10% points lower than the efficiency of coal combustion in a PC plant. This decrease, together with the energy loss due to the energy penalty caused by the CO₂ capture process, constitute the main drawback of BECS.

Moreover, the treatment of BECS under EU ETS is still unknown and under discussion. Only if allowances are given to the negative emissions from biomass with CCS, BECS will become attractive. Currently negative emissions are not acknowledged.

Possible commercial BECS options are limited for the short term and more knowledge and research are needed on BECS effects. In order to avoid technological uncertainties, it is recommended to keep both options separate as long as enough coal-fired power plants are available in the power sector. It will help to avoid the double fuel penalty and

possible technical complications, especially if shares above 10-20% of biomass are desired.

6.2.3 Industry

In the Dutch industrial sector, cost-effective CO₂ capture may be possible in the year 2020 for the hydrogen production process and iron and steel making process at a cost of 30-50 \$/tonne CO₂ avoided. Together with pure CO₂ streams available for underground storage (2.6 Mtonne CO₂/year), the CCS potential for the Dutch industrial sector can be as high as 8 Mtonne CO₂/year. Additional potential lies in the cement sector. The ENCI Maastricht plant, which emits 0.6 Mtonne CO₂/year, will shut down before 2020. This might be an opportunity to build a new integrated cement plant with CO₂ capture, if a new cement plant will ever be built in the Netherlands.

Amine-based CO₂ capture from industrial processes such as cement production, ethylene production and petroleum refineries were found to be expensive (around 100 Euro/tonne CO₂ avoided). Amine-based CO₂ capture, however, will significantly reduce SO₂ and dust emissions and the co-benefits may be significant. Our findings also show that the capital and O&M costs for SO₂ removal are significant, accounting for up to 18 €/tCO₂ avoided.

The effect of CO₂ capture on NEC emissions from the Dutch industrial sector in the year 2020 is largely dependent on the CO₂ capture from Corus IJmuiden iron and steel plant. CO₂ capture using oxygen blast furnace may reduce various NEC emissions because the oxygen blast furnace consumes significantly less coke and coal compared to conventional blast furnace.

6.3 Impact analysis

6.3.1 Industry 2020

The CO₂ emission reduction potential from the industrial sector in the year 2020 was estimated to be up to 8 million tonnes per year. The sources will likely be the pure CO₂ streams and the Corus IJmuiden iron and steel plant. The CO₂ emission reduction potential, however, largely depends on which CO₂ capture technique will be applied to the Corus IJmuiden site.

The increase in primary energy consumption due to CO₂ capture and storage from industrial sector will be at least 4 PJ per year, largely dependent on the CO₂ capture technique applied to the Corus IJmuiden site.

6.3.2 Power generation 2020

The power generating capacity of the Dutch power plant sector is expected to increase from 13.5 GWatt in 2006 to 18 GWatt in the year 2020. Some older plants will be closed and new plants with 8 GWatt capacity will be build.

Emissions of NO₂, SO₂, PM₁₀ and NH₃ increase in the scenario for the year 2020 without CCS, due to the increase in capacity of the power generating sector, mainly with coal fired plants. The introduction of CCS leads to a further increase of NO₂, PM₁₀ and NH₃ emissions. SO₂ emissions decrease below the 2006 level. NH₃ emissions are surrounded with uncertainties and can be avoided by the use of new solvents and or

reduction technologies. In any case, the amount of NH₃ emissions from power generation is lower than 1% of the total NH₃-NEC for the Netherlands.

The mitigation costs for 2020, compared to the 2006 situation, consist out of the costs for pollution control related to the capacity increase of the power plant sector and to the implementation of CCS. The mitigation costs due to CCS cannot be neglected compared to those costs. The SO₂ reduction, needed for post combustion capture with amines, contributes for only a small part to the total costs of CCS (1%).

6.3.3 Power generation 2030 and 2050

Five scenarios were developed in this study: business as usual (BAU) scenario, direct action, postponed action, direct action post combustion and direct action oxyfuel combustion. For the year 2050 it is concluded that in all GHG mitigation scenarios NO_x and SO₂ emissions will decrease moderately to considerably. They would even decrease further when taken into account recent emission data reported on an oxyfuel demonstration project. Particulate matter emissions will also decrease though to a lesser extent. Only for the scenario with a PC power plant park equipped with oxyfuel combustion CO₂ capture there was a considerable decrease in PM. Results for NMVOC emissions are uncertain and mainly dependent on the energy conversion technology implemented (PC vs. IGCC). An increase in NH₃ emissions is expected due to the use of amine based solvents in post combustion capture technologies. Post combustion is however expected to fulfil a limited share compared to IGCC power plants with CCS in 2050. Furthermore, the NH₃ emissions from post combustion technologies may prove to be insignificant in the year 2050 due to the development of new solvents and mitigation technologies for NH₃ emissions.

When comparing all scenarios and substances it is clear that the scenario with the oxyfuel combustion technology widely implemented shows relatively higher emission levels for SO₂, NO_x and NMVOC compared to the other scenarios. When taking the results of the pilot projects into account oxyfuel has the lowest SO₂ and NO_x emissions.

A large part of the results is determined by the fact that in the scenarios IGCC power plants equipped with CCS are the dominant technology applied in 2050. The results show a replacement of gas fired capacity by coal fired capacity. The replacement of old plants and an increase in demand is met by IGCC power plants with CO₂ capture. This also means that in our scenarios post combustion capture gradually phases out towards 2050 which has consequences for NEC emissions. Dominant are, for instance, the effects on NH₃ and NO_x emissions. In one variant, 'Direct action post combustion', the NH₃ emissions in 2030 is estimated to be more than a factor 5 higher compared to the BAU scenario. Another important difference between 2030 and 2050 is the increase in electricity demand and fossil fuel consumption resulting in an increase in NEC emissions.

6.4 Recommendations for further research

Four research activities are recommended to address the knowledge gaps which were revealed in the present analysis:

- **Improve inventory** on transboundary air pollutants from CO₂ capture technologies by including values taken from *measurements in pilots and demonstration plants*, particularly SO₂, NO_x, PM, NH₃, NMVOC and (other) degradation products of amines, preferably on existing coal and gas fired power plants.
- **Improve application** for the Dutch situation by clarifying the role of European and Dutch legislation, particularly on e.g. CO₂ accounting in emission trading, combustion of waste and storage of other pollutants than CO₂.
- **Refine the analysis** by providing continuous attention to:
 - Novel technologies, including new solvent which are under development
 - Other environmental aspects such as waste and emissions to water
 - Co-firing biomass: impact on NEC emissions of different forms and qualities of biomass, based upon experiences in power plants.
 - Economic and environmental (NEC-emissions) impacts of possible strategies for utilities and industry to mitigate CO₂ emissions by using biomass co-firing and/or CO₂ capture separately or in combination.
- **Improve scenarios** for the Netherlands:
 - policy analysis of both greenhouse gases and transboundary air pollution for 2020 (ECN / PBL)
 - cost-effectiveness analysis of both greenhouse gases and transboundary air pollution for the long term using the energy model MARKAL (UU)

7 Acknowledgements

The authors kindly acknowledge the interviewees: Arjen Boersma (ECN, Unit Biomass, Coal and Environmental Research, Department Heat and Power), Kay Damen (NUON), Earl Goetheer (TNO, Post combustion/Solvents expert), Gerard Jägers, Chris Treadgold, Christiaan Zeilstra (Corus Steel), Ton Pereboom (ENCI), Pierre Ploumen (KEMA, Plant configuration expert), Jiri van Straelen (Shell), Noim Uddin (Lead Climate Change Verifier, Det Norske Veritas Australia and New Zealand), Kenneth Möllersten (Swedish Energy Agency), James S. Rhodes (Carnegie Mellon University, Department of Engineering and Public Policy) for providing valuable information and fruitful discussion of the results.

Last but not least we are grateful to the BOLK programme coordinators Jan Wijmenga (VROM) and Pieter Hammingh (PBL) who provided us with valuable comments, remarks and guidance.

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Appendix A: Methodology for adjusting net power output and capital investment costs after standardising the CO₂ compression pressure

Adjustment of net power output due to the standardisation of CO₂ compression pressure

Power consumption for CO₂ compression is assumed to be proportional to the natural logarithm of (outlet pressure/inlet pressure). The power consumption for CO₂ compression is corrected by using the following equation, based on a general trend that the gas compression power requirement is proportional to the logarithm of outlet/inlet pressure ratio (Hendriks et al., 2009):

$$E_{\text{comp},110} = E_{\text{comp,orig}} \ln\left(\frac{110 \text{ bar}}{P_{\text{in,orig}}}\right) / \ln\left(\frac{P_{\text{out,orig}}}{P_{\text{in,orig}}}\right) \quad \text{Eq. 1}$$

where,

$E_{\text{comp},110}$: electricity consumption for CO₂ compression to 110 bar (MW)

$E_{\text{comp,orig}}$: electricity consumption for CO₂ compression to the nominal pressure in the original literature (MW)

$P_{\text{out,orig}}$: nominal CO₂ compression pressure in the original literature (bar)

$P_{\text{in,orig}}$: CO₂ compressor inlet pressure in the original literature (bar)

Consequently the net electrical output of a power plant is also corrected:

$$E_{\text{out,net,adj}} = E_{\text{out,net,orig}} + E_{\text{comp,orig}} - E_{\text{comp},110} \quad \text{Eq. 2}$$

Where,

$E_{\text{out,net,adj}}$: adjusted net electrical output of a power plant (MWe)

$E_{\text{out,net,orig}}$: nominal net electrical output of a power plant given in the original literature (MW)

There are cases where the report does not specify P_{in} and/or $E_{\text{comp,orig}}$. When $E_{\text{comp,orig}}$ is not reported, specific power consumption is estimated using the following equation from (Hendriks et al., 2009):

$$E_{\text{spec,comp}} = C_{\text{el}} * \ln\left(\frac{P_{\text{outlet}}}{P_{\text{inlet}}}\right) \quad \text{Eq. 3}$$

Where $E_{\text{spec,comp}}$ is the specific power requirement for CO₂ compression (kJe/kgCO₂), C_{el} is a constant (87.85 kJe/kgCO₂), P_{outlet} is the compressor outlet pressure (bar), P_{inlet} is the compressor inlet pressure (bar). P_{inlet} is assumed to be 1.013 bar for post combustion and oxy-combustion capture routes, and 10 bar for pre combustion capture, unless otherwise indicated in the literature.

For pre combustion there are also cases with multiple CO₂ streams into compressor inlet with different pressures. In such cases, lower pressure streams are compressed to a pressure equivalent to the highest-pressure stream and then all streams are compressed together to higher pressures. We chose the pressure of the largest CO₂ stream value as P_{in} .

Adjustment of capital investment costs due to the standardisation of CO₂ compression pressure

Because of compression pressure standardization, the compressor cost needs to be adjusted as well. The cost (installed cost) is adjusted by using a scaling factor:

$$C_{\text{comp,adj}} = C_{\text{comp,orig}} * \left(\frac{E_{\text{comp,adj}}}{E_{\text{comp,orig}}} \right)^{\text{SF}} \quad \text{Eq. 4}$$

where,

$C_{\text{comp,adj}}$: adjusted compressor cost (Euro)

$C_{\text{comp,orig}}$: original compressor cost (Euro)

SF: scaling factor (0.67; Sjardin et al., 2006).

Thus the process plant cost (PPC) must also be adjusted:

$$C_{\text{PPC,adj}} = C_{\text{PPC,orig}} - C_{\text{comp,orig}} + C_{\text{comp,adj}} \quad \text{Eq. 5}$$

Where,

$C_{\text{PPC,adj}}$: adjusted process plant cost (Euro)

$C_{\text{PPC,orig}}$: process plant cost in the original literature (Euro)

$C_{\text{comp,orig}}$: installed cost of CO₂ compressor in the original literature (Euro)

$C_{\text{comp,adj}}$: installed cost of CO₂ compressor after CO₂ compression pressure standardization (Euro)

When the CO₂ compression is not taken into account at all in a report, it was calculated by using an equation from Hendriks et al. (Hendriks et al., 2009).

$$I = \left(C_1 F^{C_2} + C_3 \ln \left(\frac{P_{\text{Outlet}}}{P_{\text{Inlet}}} \right) F^{C_4} \right) F \quad \text{Eq. 6}$$

Where I is total investment costs (M Euro), C_1 (0.1×10^6 Euro/(kg/s)), C_2 (-0.71), C_3 (1.1×10^6 Euro/(kg/s)) and C_4 (-0.60) are constants. P_{inlet} was assumed to be 1.013 bar and P_{outlet} was assumed to be 110 bar.

CO₂ transport and storage

CO₂ transport and storage costs were assumed to be 7 Euro/tonne, as suggested for the year 2020 by Mueller-Langer et al. (Mueller-Langer et al., 2007).

Appendix B: Methodology for calculating NH₃ emissions from available data

PC and NGCC without CO₂ capture, IGCC and oxyfuel power plants

The main source of NH₃ emission is the slip from SCR. The NH₃ emission from SCR is calculated as follows:

$$Em_{NH_3,slip} = Em_{NO_x,orig} * \frac{\eta_{SCR}}{1 - \eta_{SCR}} * f_{NH_3/NO_x} * f_{slip} * \frac{E_{out,net,orig}}{E_{out,net,adj}} \quad \text{Eq. 7}$$

Where

$Em_{NH_3,slip}$: NH₃ emissions from SCR ammonia slip (gNH₃/kWh)

Em_{NO_x} : NO_x emission intensity (gNO_x/kWh)

η_{SCR} : NO_x removal efficiency of SCR provided in the literature (unitless)

f_{NH_3/NO_x} : NH₃ consumption per unit of NO_x captured (0.3 gNH₃/gNO_x removed: (Koornneef et al., 2008))

f_{slip} : ammonia slipping rate 1%: (Koornneef et al., 2008)).

PC and NGCC with post combustion capture

When the CO₂ is captured by amine solvents, there are additional NH₃ emissions as the degradation of amine solvents also lead to the formation of NH₃. In order to calculate the NH₃ emissions from amine solvent degradation, the following equation is used:

$$Em_{NH_3,MEA} = f_{deg} * \eta_{cap} * M_{CO_2} \quad \text{Eq. 8}$$

Where

$Em_{NH_3,MEA}$: specific NH₃ emission due to amine degradation (gNH₃/kWh)

f_{deg} : NH₃ generation rate due to solvent degradation (gNH₃/kgCO₂ captured)

η_{cap} : CO₂ capture efficiency (kgCO₂ captured/kgCO₂ generated)

M_{CO_2} : specific CO₂ generation (kgCO₂ generated/kWh).

Thus the overall specific NH₃ emission for the PC plants with post combustion CO₂ capture ($Em_{NH_3,tot}$: gNO_x/kWh) is:

$$Em_{NH_3,tot} = Em_{NH_3,slip} + Em_{NH_3,MEA} \quad \text{Eq. 9}$$

Table B-1 Parameters for the NH₃ emission calculations (Koornneef et al., 2008).

Parameter	Unit	Value
NH ₃ from SCR		
NH ₃ slip rate	% NH ₃ consumed	1%
NH ₃ consumption per unit of NO _x captured	gNH ₃ /gNO _x removed	0.3
NH ₃ from MEA degradation		
NH ₃ emission rate	Kg/tCO ₂	0.21

Appendix C: Raw results from parameter standardisation for a fair comparison of CO₂ capture technologies

Table C-1 Overview of values for NEC emissions reported in the literature.

Capture technology	Energy conversion technology	SO ₂ emissions (g/kWh)						SO ₂ emissions (g/MJ)					
		Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N		
No-capture	IGCC	7.05E-03	3.63E-02	8.29E-02	1.18E+01	11	9.21E-04	4.12E-03	9.09E-03	9.88E+00	11		
	NGCC	0	0	0	0	2	0	0	0	2			
	PC	9.31E-02	2.53E-01	7.55E-01	8.11E+00	19	1.17E-02	2.69E-02	6.98E-02	5.97E+00	19		
Oxyfuel	GC	-	-	-	-	0	-	-	-	-	0		
	NGCC	-	0	0	0	1	-	0	-	1			
Post-combustion	PC	2.47E-03	1.64E-02	3.11E-02	1.26E+01	5	2.29E-04	1.50E-03	3.01E-03	1.32E+01	5		
	NGCC: amine	-	-	-	-	0	-	-	-	-	0		
	NGCC: chilled ammonia	-	-	-	-	0	-	-	-	-	0		
Pre-combustion	PC	4.25E-04	6.05E-03	8.87E-03	2.09E+01	3	3.69E-05	5.88E-04	8.69E-04	2.35E+01	3		
	GC	-	-	-	-	0	-	-	-	-	0		
	IGCC	4.68E-03	9.93E-03	1.60E-02	3.41E+00	11	4.41E-04	9.73E-04	1.48E-03	3.36E+00	11		

Capture technology	Energy conversion technology	NH ₃ emissions (g/kWh)						NH ₃ emissions (g/MJ)					
		Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N		
No-capture	IGCC	-	0.00E+00	-	-	1	-	0	-	-	1		
	NGCC	0	3.74E-04	7.48E-04	0	2	0	5.84E-05	1.17E-04	0	2		
	PC	3.15E-03	5.80E-03	1.17E-02	3.71E+00	10	4.02E-04	6.73E-04	1.34E-03	3.33E+00	10		
Oxyfuel	GC	-	-	-	-	0	-	-	-	-	0		
	NGCC	-	-	-	-	0	-	-	-	-	0		
Post-combustion	PC	-	-	-	-	0	-	-	-	-	0		
	NGCC: amine	2.00E-03	4.12E-02	8.04E-02	4.02E+01	2	-	1.08E-02	-	-	1		
	NGCC: chilled ammonia	-	1.19E-01	-	-	1	-	-	-	-	0		
Pre-combustion	PC	0	1.72E-01	2.45E-01	0	11	0	1.47E-02	2.00E-02	0	11		
	GC	-	-	-	-	0	-	-	-	-	0		
IGCC	-	0	-	-	1	-	0	-	-	1			

Capture technology	Energy conversion technology	NOx emissions (g/kWh)					NOx emissions (g/MJ)				
		Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N
No-capture	IGCC	0.090	0.230	0.580	6.444	9	0.010	0.027	0.069	7.104	9
	NGCC	0.028	0.089	0.160	5.777	5	0.004	0.014	0.026	5.932	5
	PC	0.159	0.368	0.840	5.287	21	0.020	0.057	0.098	4.851	21
Oxyfuel	GC	-	-	-	-	0	-	-	-	-	0
	NGCC	-	0	-	-	1	-	0	-	-	1
Post-combustion	PC	0	0.268	0.382	0	6	0	0.024	0.033	0	6
	NGCC: amine	0	0.057	0.190	0	13	0	0.007	0.025	0	13
	NGCC: chilled ammonia	0.205	0.564	0.844	4.111	12	0.020	0.049	0.071	3.551	11
Pre-combustion	GC	-	-	-	-	0	-	-	-	-	0
	IGCC	0.099	0.210	0.550	5.530	11	0.009	0.020	0.053	5.644	11

Capture technology	Energy conversion technology	PM10 (g/kWh)					PM10 (g/MJ)				
		Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N
No-capture	IGCC	0.027	0.028	0.029	1.084	8	0.003	0.003	0.003	1.008	3
	NGCC	0	0	0	0	4	0	0	0	0	0
	PC	0.007	0.042	0.055	7.828	9	0.001	0.004	0.006	7.060	17
Oxyfuel	GC	-	-	-	-	0	-	-	-	-	0
	NGCC	-	0	-	-	1	-	0	-	-	0
Post-combustion	PC	0.001	0.006	0.009	9.421	4	0	0.001	0.001	8.811	5
	NGCC: amine	0	0	0	0	5	0	0	0	0	2
	NGCC: chilled ammonia	0	0.048	0.080	0.000	8	0	0.004	0.006	0.000	8
Pre-combustion	GC	-	-	-	-	0	-	-	-	-	0
	IGCC	0.034	0.034	0.034	1.017	9	0.003	0.003	0.003	1.250	12

Table C-2 Overview of values CO₂ avoidance cost and cost of electricity reported in the literature.

Energy conversion technology	CO ₂ emissions (g/kWh)					CO ₂ avoidance cost (€/tonne)					COE (€/cent/kWh)				
	Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N	Min	Mean	Max	Max/min	N
Capture technology No-capture	IGCC	694	761	833	1	12	-	-	-	0	4,44	5,39	6,02	1,35	11
	NGCC	338	366	379	0	8	-	-	-	0	6,27	6,55	6,89	1,10	7
	PC	589	786	941	7	26	-	-	-	0	4,52	5,37	6,29	1,39	14
Oxyfuel	GC	0	10	60	0	6	-	-	-	0	-	-	-	-	0
	NGCC	0	6	12	0	2	88,86	-	-	1	-	9,53	-	-	1
Post-combustion	PC	0	51	146	9	6	31,18	35,54	40,43	5	7,75	8,26	8,97	1,16	6
	NGCC: amine	0	40	66	0	10	44,02	62,78	86,31	6	7,89	8,57	9,55	1,21	7
	NGCC: chilled ammonia	-	-	-	-	0	-	-	-	-	0	-	-	-	0
Pre	GC	0	21	42	0	2	31,40	42,26	47,45	12	6,78	8,29	9,83	1,47	12
	IGCC	71	97	152	1	17	18,18	23,46	27,37	14	6,00	6,80	7,79	1,30	14

Appendix D: Summary of the characterisation of the CO₂ capture technologies, based on BOLK-I

Table D-1 Overview of aspects and criteria to characterise several CO₂ capture technologies and their reference technologies based on the improved inventory developed in BOLK-I. N.D.= No data, PC = pulverised coal, NGCC = natural gas combined cycle, IGCC = integrated gasification combined cycle, GC = gas cycle.

Technology	Development phase	Application	Economic performance			Environmental performance						
			electrical efficiency (%)	CoE constant (€-cts/kWh) constant 2007	€ per tonne avoided (constant 2007)	efficiency penalty (% pts)	CO ₂ emissions (g/kWh)	NO _x emissions (g/kWh)	SO ₂ emissions (g/kWh)	PM10 emissions (g/kWh)	NH ₃ emissions (g/kWh)	Other impacts
no capture	commercial	retrofit/robust/process industry	40%	4.1	-	0	830	0.39	0.44	0.05	0.01	
	commercial		56%	4.4	-	0	370	0.17	-	-	-	
	commercial		42%	5.7	-	0	766	0.23	0.05	0.014	-	
Post	pre-commercial	yyy	30%	7.9	53	11	145	0.57	0.001	0.06	0.23	Toxic waste
	pre-commercial	yyy	49%	6.4	55	8	55	0.19	-	-	0.002	Toxic waste
	pilot	yyy	39%	N.D.	16	N.D.		n.a. (estimated in order of Amine PC)				
	lab scale	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	
Pre	demonstration	nyy	49%	N.D.	N.D.	9	21	n.a. (estimated in order of Amine NGCC)				
	demonstration	nyy	36%	7.6	30	7	98	0.21	0.016	0.003	0.0007	
Oxyfuel	pilot	y?ny	32%	7.7	42	11	47	0.17	0.025	0.0003	-	
	pilot	y?ny	53%	N.D.	N.D.	4	10	-	-	-	-	
	pilot	y?ny	46%	6.9	77	11	8	0	0	-	-	

Appendix E: Typical properties of solid fuels

Table E-1 Typical properties of solid fuels. d- dry basis; *- in ash (European Bioenergy Network, 2004).

Property	Coal	Peat	Wood without bark	Bark	Forest residues (coniferous tree with needles)	Willow	Straw	Reed canary grass (spring harvested)	Olive residues
Ash content (d)	8.5-10.9	4-7	0.4-0.5	2-3	1-3	1.1-4.0	5	6.2-7.5	2-7
moisture content, w-[%]	6-10	40-55	5-60	45-65	50-60	50-60	17-25	15-20	60-70
Net calorific value [MJ/kg]	26-28.3	20.9-21.3	18.5-20	18.5-23	18.5-20	18.4-19.2	17.4	17.1-17.5	17.5-19
C [%] (d)	76-87	52-56	48-52	48-52	48-52	47-51	45-47	45.5-46.1	48-50
H [%] (d)	3.5-5	5-6.5	6.2-6.4	5.7-6.8	6-6.2	5.8-6.7	5.8-6.0	5.7-5.8	5.5-6.5
N [%] (d)	0.8-1.5	1-3	0.1-0.5	0.3-0.8	0.3-0.5	0.2-0.8	0.4-0.6	0.65-1.04	0.5-1.5
O [%] (d)	2.8-11.3	30-40	38-42	24.3-40.2	40-44	40-46	40-46	44	34
S [%] (d)	0.5-3.1	<0.05-0.3	<0.05	<0.05	<0.05	0.02-0.10	0.05-0.2	0.08-0.13	0.07-0.17
Cl [%] (d)	<0.1	0.02-0.06	0.01-0.03	0.01-0.03	0.01-0.04	0.01-0.05	0.14-0.97	0.09	0.1*
K [%] (d)	0.003	0.8-5.8	0.02-0.05	0.1-0.4	0.1-0.4	0.2-0.5	0.69-1.3	0.3-0.5	30*
Ca [%] (d)	4-12	0.05-0.1	0.1-1.5	0.02-0.08	0.2-0.9	0.2-0.7	0.1-0.6	9	

Appendix F: Reported (ranges of) emission factors, based on lower heating value of the (wet) input fuel

Table F-1 Reported (ranges of) emission factors, based on lower heating value of the (wet) input fuel (Boersma et al., 2008).

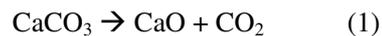
	NO_x [mg/MJ]	SO_x [mg/MJ]	NH₃ [mg/MJ]	Dust [mg/MJ]	NMVOC [mg/MJ]	Basis/ Remarks
Existing technologies						
coal-fired power stations						
direct co-firing (10% biomass)	99	11.2	100% biomass: 1-5 (no deNO _x) 5-10 (SCR) 21 (SNCR)	0.3-0.5	no data	Fuel mix, 10% biomass
	100% coal: 56-130	100% coal: 19	100% coal: 3-13	100% coal: 1-2	no data	
indirect co-firing (gasification)	no data	5	no data	2	no data	assuming flue gases pass FGC in coal plant
Gas-fired power stations						
(directly)	66	4	no data	12	no data	Bio-oil
	100% gas: 46	100% gas: 1				
Medium scale biomass application						
Combustion	48-219	0.3-108	1-5 (no deNO _x) 5-10 (SCR) 21 (SNCR)	1-10	1.5-1.8 (VOC)	
Gasification (IGCC)	34-87	5-10	no data	0-2	0-1 (C _x H _y)	

Appendix G: Supporting information on the assessment of CO₂ capture performance for cement production process

General description

Cement production is one of the most CO₂ intensive industrial processes that accounts for 1.8 GtCO₂/year in 2005 (IEA GHG, 2008). High CO₂ emission intensity of cement production is not only due to the large energy requirement but also due to the emissions from the raw materials.

The raw materials, mainly comprised of calcium carbonate (main component of limestone) with some silica, alumina and iron oxide, are firstly finely grinded into a fine powder. The raw material powder is then heated up to a sintering temperature of over 1400 °C in a cement kiln to produce clinker. In this process, calcination reaction takes place, in which calcium carbonate decomposed to CO₂ and calcium oxide (eq.1). Finally, the produced clinker is cooled and grinded with some additives to make cement.



The cement production can generally be categorized into four different routes: wet process, semi-wet process, semi-dry process and dry process. These process routes are distinguished by the moisture content of the feed going into the kiln (IEA GHG, 2008). Historically the clinker production process has evolved from 'wet' to 'dry' systems. Wet kilns enabled easier blending and homogenization of raw materials, but also required high-energy consumption. The technological development made possible to produce homogenous raw material mix in a dry process, significantly reducing the energy consumption. Today the best available technique (BAT) for cement production is based on a dry process ((p4-1, IEA GHG, 2008).

With regard to CO₂ emissions, 0.7-1.1 tonne of CO₂ is emitted for every tonne of cement produced (Bosoaga et al., 2008), of which the emissions from the kiln process account for up to 0.5 tCO₂ per tonne of cement produced (Hendriks, 1998). The rest of the emissions are due to the fossil fuel use, mainly used during the pre-processing step. Generally the CO₂ concentration in cement plant flue gas is around 15-30% (IEA GHG, 2008).

Environmental performance assessment: assumptions

The assumptions for the calculations are presented in Table G-1.

Table G-1 Parameters used to calculate the environmental performance of CO₂ capture from ENCI Maastricht cement plant.

Parameter	Unit	Value	Remarks/references
SCR performance			
SCR efficiency		90%	(Koornneef et al., 2008)
SCR ammonia consumption	kgNH ₃ /kgNO _x	0.30	(Koornneef et al., 2008)
SCR ammonia slipping rate	of total ammonia consumption	1%	(Koornneef et al., 2008)
Flue gas requirement for CO ₂ scrubber			
NO ₂ content	mg/Nm ³	41	(IEA GHG, 2004)
SO ₂ content limit	mg/Nm ³	10	(IEA GHG, 2004)
Dust content limit	mg/Nm ³	15	(Chapel et al., 1999)
CO ₂ capture process performance			
CO ₂ capture rate		85%	Lower-end value indicated in (van Harmelen et al., 2008)
NO ₂ removal rate		25%	(Koornneef et al., 2008)
SO ₂ removal rate		90%	(Koornneef et al., 2008)
PM removal rate		50%	(Koornneef et al., 2008)
Regeneration heat requirement	MEA MDEA	MJ/kgCO ₂ captured 3.0	(Koornneef et al., 2008)
Electricity requirement		kWh/tCO ₂ captured 23.6	(Koornneef et al., 2008)
CO ₂ compression power		MJe/kgCO ₂ 0.35	
Fraction of NO ₂ in total NO _x content in the flue gas			
Coal combustion		5 vol.%	(Tzimas et al., 2007)
Natural gas combustion		10 vol.%	(Tzimas et al., 2007)
Heat supply plant performance			
GT-CHP			
Excess air ratio	of stoichiometric requirement	150 vol.%	O ₂ concentration in the flue gas will be 15 vol.%
NO _x generation	ppmv at 15% O ₂	15	With a dry low-NO _x burner, 9-25 ppmv is already achievable (GE Energy, 2009)

NH₃ emission from CO₂ capture from cement production process was calculated by applying the same equation presented in Appendix A for NGCC and PC with post combustion CO₂ capture.

Calculation of electricity demand for cement production process

The ENCI Maastricht plant does not have a CHP. For CO₂ capture performance analysis, we assumed that the gas turbine CHP that supplies electricity and heat for CO₂

capture also supplies electricity to the cement production process. The energy consumption for the cement production plant was calculated based on the specific energy requirement values suggested by (Kim and Worrell, 2002) as shown in Table G-2.

Table G-2 Specific energy consumption values for clinker and cement production (Kim and Worrell, 2002).

Parameter	Value (MJ/kg)
Power consumption: clinker production	0.36
Power consumption: cement production (from clinker)	0.24

Appendix H: BREF LCP

Table H-1 BAT for the reduction of particulate emissions from some combustion plants.

Capacity (MWatt _{th})	Dust emission level (mg/m ³)						BAT to reach these levels
	Coal and lignite		Biomass and peat		Liquid fuels for boilers		
	New plants	Existing plants	New plants	Existing plants	New plants	Existing plants	
50-100	5-20	5-30	5-20	5-30	5-20	5-30	ESP or FF
100-300	5-20	5-25	5-20	5-30	5-20	5-25	ESP or FF in combination FGD (wet, sd or dsi) for PCESP or FF for FBC
>300	5-10	5-20	5-20	5-30	5-20	5-20	
Notes:							
ESP: Electrostatic Precipitator		FBC: Fluidised bed combustion		FGD (wet): Wet flue-gas desulphurisation			
		sd: semi dry		Dsi: dry sorbent injection			
FF: Fabric Filter							

Table H-2 BAT for the reduction of SO₂ emissions from some combustion plants.

Capacity (MWatt _{th})	SO ₂ level (mg/m ³)						BAT to reach these levels
	Coal and lignite		Biomass and peat		Liquid fuels for boilers		
	New plant	Existing plants	New plants	Existing plants	New plants	Existing plants	
50-100	200-400 150-400 (FBC)	200-400 150-400 (FBC)	200-300	200-300	100-350	100-350	Low sulphur fuel or/and FGD (dsi) or FGD (sds) or FGD (wet) (depending on the plant size). Sea water scrubbing. Combined techniques for the reduction of NO _x and SO ₂ . Limestone injection (FBC)
100-300	100-200	100-250	200-300 150-300 (FBC)	200-300 150-300 (FBC)	100-200	100-250	
>300	20-150 100-200 (CFB C/PF BC)	20-200 100-200 (CFBC/P FBC)	50-150 50-200 (FBC)	50-200	50-150	50-200	
Notes							
FBC: Fluidised bed combustion		PFBC: Pressurised fluidised bed combustion		FGD (dsi): Flue gas desulphurisation by dry sorbent injection			
FGD (sds): Flue gas desulphurisation by using a spray tower				CFBC: Circulated fluidised bed combustion			
				FGD (wet): Wet flue-gas desulphurisation			

Table H-5 BAT for the reduction of NO_x and CO emissions from gas fired combustion plants.

Plant type	Emission level associated with BAT (mg/m ³)		O ₂ level (%)	BAT options to reach these levels
	NO _x	CO		
Gas Turbines				
New gas turbines	20-50	5-100	15	Dry low NO _x premix burners or SCR
DLN for existing gas turbines	20-75	5-100	15	Dry low NO _x premix burners as retrofitting packages if available
Existing gas turbines	50-90	30-100	15	Water and steam injection or SCR
Gas engines				
New gas engines	20-75	30-100	15	Lean-burn concept or SCR and oxidation catalyst for CO
New gas engine with HRSG in CHP mode	20-75	30-100	15	Lean-burn concept or SCR and oxidation catalyst for CO
Gas-fired boilers				
New gas-fired boilers	50-100	30-100	3	Low NO _x burners or SCR or SNCR
Existing gas-fired boiler	50-100	30-100	3	
CCGT				
New CCGT without supplementary firing (HRSG)	20-50	5-100	15	Dry low NO _x premix burners or SCR
Existing CCGT Without supplementary firing (HRSG)	20-90	5-100	15	Dry low NO _x premix burners or water and steam injection or SCR
New CCGT with supplementary firing	20-50	30-100	Plant spec.	Dry low NO _x premix burners and low NO _x burners for the boiler part or SCR or SNCR
Existing CCGT with supplementary firing	20-90	30-100	Plant spec.	Dry low NO _x premix burners or water and steam injection and low NO _x burners for the boiler part or SCR or SNCR
Notes:				
SCR: Selective catalytic reduction of NO _x		CCGT: combined cycle gas turbine		
SNCR: Selective non catalytic reduction of NO _x		DLN: dry low NO _x		
HRSG: heat recovery steam generator		CHP: Cogeneration		

Abbreviations

ABC	Ammonium BiCarbonate
AC	Ammonium Carbonate
AGR	Acid Gas Re-Injection
AGR	Acid Gas Removal
ASU	Air Separation Unit
ATR	Auto Thermal Reforming
AZEP	Advanced Zero Emmission Power plant
BAT	Best Available Techniques
BAU	Business As Usual
BECS	Biomass energy systems with CO ₂ capture technologies (Biomass+CCS)
BF	Blast Furnace
BOF	Basic Oxygen Furnace
BREF	Reference document on Best Available Techniques
CAP	Chilled Ammonia Process
CAPEX	Capital Expenditures
CCF	Cyclone Converter Furnace
CCS	Carbon Capture & Storage
CHP	Combined Heat and Power
CLC	Chemical Looping Combustion
CoE	Cost of Electricity
DoE	US Department of Energy
DRI	Direct-Reduced Iron
ESP	ElectroStatic Precipitation
FGD	Flue Gas Desulphurization
FGR	Flue Gas Recirculation
GC	Gas Cycle
GHG	Green House Gas
GJ	Giga Joule
GTCC	Gas Turbine Combined Cycle
HHV	High Heating Value
HRSG	Heat Recovery Steam Generator
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
ITM	Ion Transport Membrane
Kt	kilo tonne
kWh	kilo Watt hour
LCA	Life Cycle Analysis
LHV	Low Heating Value
LNG	Liquid Natural Gas
MCM	Mixed Conducting Membrane
MDEA	Methyl Diethanol Amine
MEA	Mono Ethanol Amine
MPa	Mega Pascal
MSR	Methane Steam Reformer
Mt	Mega tonne
MW	Mega Watt
NEC	National Emission Ceiling

NETL	National Energy Technology Laboratory (US)
NGCC	Natural Gas Combined Cycle
NMHCs	Non Methane Hydrocarbons
NMVOG	Non Methane Volatile Organic Compounds
NSCR	Non Selective catalytic Reduction
O&M	Operating & Maintenance
PC	Pulverized Coal
PJ	Peta Joule
PM	Particulate Matter
RFG	Recycled Flue Gas
SCR	Selective Catalytic Reduction
SEWGS	Sorption Enhanced Water Gas Shift
SNCR	Selective Non Catalytic Reduction
SOFC	Solid Oxide Fuel Cel
WGS	Water Gas Shift