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PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

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List of Abbreviations

AGR	Abgasrückführung (see EGR)
BAU	Business As Usual
BEW	Burmeister & Wain Energy A/S
BoA	Braunkohlekraftwerk mit optimierter Anlagentechnik (German for Lignite plant with optimized systems engineering)
CC	Combined Cycle
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
EGR	Exhaust gas recirculation (see AGR)
FGD	Flue Gas Desulphurization
GCC	Gas Combined Cycle
GE	General Electric
GHG	Greenhouse Gas
GT	Gas Turbine
HHV	High heating value
IEA	International Energy Agency
LCI	Life cycle inventory
LHV	Lower heating value
Luvo	Luftvorwärmung (German for Preheating of the combustion air)
MHD	Magnetohydrodynamic
NGCC	Natural gas combined cycle
NMVOC	Non-Methane Volatile Organic Compounds
O&M	Operation and Maintenance
PC	Pulverized coal
PF	Pulverized fuel
SOFC	Solid oxide fuel cell
TSP	Total Suspended Particulates
USC-PC	Ultra Super Critical Pulverized Coal power plant technology
VOC	Volatile Organic Compounds

Executive summary

This report is the documentation of the work performed in Work Package 7 (WP7) "Advanced fossil power generation technologies" within the Research Stream 1a (RS1a) as part of the integrated European NEEDS ("New Energy Externalities Development for Sustainability") project. It represents a technology roadmap for fossil-fuelled power plants likely to be installed within the next four decades in Europe. Although – especially in Europe – power generation will be very likely facing more stringent ecological requirements like curbing/reducing greenhouse gas (GHG) emissions, fossil technologies are considered as substantial contributors to reliable large-scale electricity supply at any load level (base, medium and peak) within the next 40 years. Additionally to lignite, hard coal and natural gas power plants, a gas turbine and a small-scale combined heat and power plant are included in this analysis.[1]

The core of the analytical work within this project was the establishment of Life Cycle Inventories (LCI data) of fossil energy chains for power generation with current state-of-the-art power plants as well as with future technologies (reference years: 2025 and 2050). Additionally, the development of costs of these power plants and the associated costs of electricity production were estimated. The analysis of future technologies includes different concepts for Carbon Capture & Storage (CCS) technologies: it covers the three main technologies of CO_2 separation at the power plant, transport of CO_2 by pipeline and storage of CO_2 in generic (non site-specific) saline aquifers and depleted gasfields. The analysis of the disposal sites does not aim at completeness in the assessment of potential sites in Europe, but rather at providing a first estimation of environmental burdens originating from the application of CCS in fossil power generation chains and therefore the analysis of generic, representative conditions for transport and storage of CO_2 in Europe is sufficient. The modeling of future technologies is performed with three different scenarios for technology development – pessimistic, realistic-optimistic, and very optimistic from the perspective of technological progress. The realistic-optimistic perspective is considered as the most realistic pathway of development.

The results of the analysis show a progress in the environmental performance of fossil power generation until 2050, mainly originating from increasing power plant efficiencies based on advanced materials for the boilers allowing increasing combustion temperatures. However, this envisaged progress alone does not sufficiently reduce Greenhouse Gas emissions (GHG) for fossil power generation as a contributor to a less GHG intensive future electricity mix as part of a sound strategy against increasing CO_2 concentrations in the atmosphere and the associated global warming. The employment of CCS for fossil fuel-based electricity production can substantially reduce GHG emissions in the order of minus 70-95% until year 2050 (corresponding to about 30-200 g(CO_2-eq.)/kWh), mainly depending on the fuel and the technology used for CO_2 separation. The least GHG intensive fossil chains with CCS can reach levels of GHG emissions competitive with renewables and nuclear power. However, this advantage of reduced GHG emissions goes along with several drawbacks. The high energy demand for CO_2 separation reduces power plant net efficiencies and therefore increases fuel demand in the order of about 10-20%. As an implication, all environmental burdens associated with fuel production and transport (which can be significant especially for

[1] Due to the currently small and furthermore continuously decreasing share of oil as fuel for power generation, oil power plants are not included in this study. A "revival" of oil power plants in Europe is not considered as a realistic scenario.

hard coal and natural gas) increase by the same factor. Furthermore, Carbon Capture & Storage technologies are expensive: compared to conventional fossil fuel-based electricity production, generation costs are estimated to increase by 30% to almost 50% in year 2050.

1 Introduction

This report serves as documentation of the work carried out in Work Package 7 (WP7) "Advanced fossil power generation technologies" within the Research Stream 1a (RS1a) as part of the integrated European NEEDS ("New Energy Externalities Development for Sustainability") project.

1.1 Goal and scope

Fossil technologies are facing the challenge of reliably supplying substantial share of near/medium future electricity demand at any load levels (base, medium and peak), and heat demand (as well as fuel for transportation in case of oil and gas) against more stringent ecological requirements like curbing/reducing greenhouse gas (GHG) emissions. NEEDS RS1a focuses on electricity generation systems. Amongst fossil energy carriers, the most promising candidates for new capacity for electricity supply in Europe are natural gas and coal, both hard coal and lignite. In the last two decades, European oil power plants have been systematically replaced, mostly by natural gas power plants, but they still contribute to supply in some countries and may contribute marginally also in near future scenarios (e.g. for peak load management or in combined cycle power plants). Anyhow, only gas and coal technologies, current as well as in the reference years 2025 and 2050 are dealt with within RS1a WP7. Detailed descriptions of all parts of the whole NEEDS project – on methodological, organisational and political issues – are available on the project website.[2]

The analytical work of WP7 covers a) the establishment of Life Cycle Inventories (so-called LCI data) of current state-of-the-art fossil-fuelled power plant technologies (also referred to as "year 2005") with the associated fuel chains as well as of evolutionary power plant technologies for the two reference years 2025 and 2050 and b) the estimation of economic charcteristics of the power plants allowing a consistent calculation of the costs of electricity generation for the reference years. The two future time horizons also include different concepts for Carbon Capture & Storage (CCS) technologies, integrated in the LCI data of the energy chains. Representative average European conditions have been chosen for modeling of CCS, not aiming at completely covering all types of sites for storage of CO_2 available in Europe.

The future technology development for the years 2025 and 2050 is modeled in three different scenarios: "pessimistic", "realistic-optimistic", and "very optimistic". These terms refer to the pace of technological progress. The realistic-optimistic development is considered to be the most likely, the other two are supposed to show realistic ranges of deviation from the most likely pathway. Only evolutionary development of power plants based on existing concepts is taken into account for the modeling of the 2025 and 2050 technologies. Furthermore, the modeling of LCI data is limited to the power plant concepts considered as the most promising ones – meaning the most successful ones on the market – until year 2050. However, the less promising concepts (from point of view of the authors)are briefly discussed and described in a sort of overview. Additionally to technology description, the main drivers – positive and negative – for fossil power plant technology development are discussed.

The discussion of LCA results is limited to the most important cumulative environmental burdens (emissions to air, water and soil; consumption of resources; land use) per kWh electricity generated. A list of burdens is selected from the more than 1000 elementary flows,

[2] http://www.needs-project.org/

which constitute the complete LCA results, and shown in the Annex for all analyzed technologies.

1.2 System boundaries

Modeling of the Life Cycle Inventories covers the complete fossil energy chains and therefore includes worldwide exploration and production of the fossil energy carriers finally used for electricity generation, their transport to the European power plants as well as operation, construction and dismantling of the plants and disposal of waste. Within this project, the complete energy chains are split into three sections: fuel supply (often called "upstream chain"), power plant infrastructure (construction and dismantling), and power plant operation. In case of energy chains with CCS, transport and storage of CO_2 are further separated.

Ecoinvent v1.3 data[3] are use as generic background data for LCI modeling and calculation of cumulative LCA results. Since these background data represent current conditions which might not be completely applicable for the future time horizons, key aspects of these background processes (e.g. electricity mixes, key materials as well as transport services) are modified according to expected developments in these economic sectors (ESU & IFEU 2008).

[3] www.ecoinvent.org

2 Fossil technology development pathways

2.1 Current status of technology

Coal is the fossil fuel with widest resources world-wide. Construction of coal power stations has been steadily going on at high rate in fast developing countries like China and India. Since the early 1990s in Europe, the highly efficient combined cycle technology fuelled by natural gas has been successfully expanding to replace older fossil units (especially oil-fuelled) and meet increasing demand.

Although continuous efforts to reducing effluents from coal power plants, especially in advanced economies, by increasing efficiency and installing pollution control devices, coal still remains the most polluting power source for its harmful effluents and residues. However, if electricity demand will continue to grow in Europe, coal may continue to play an important role in the energy mix besides natural gas. This is likely to be even more pronounced in case of ban or limited use of nuclear power for base load.

In order to obtain long term acceptability of coal (and other fossil fuels), near-zero emissions requirements will likely become a goal for policy and technology improvement, first in highly industrialized countries but soon also in developing ones. Worldwide research on Clean Coal Technology (CCT) pursues the satisfactorily environmental and economical utilization of coal. Many of the conventional technologies of today can be further improved or refurbished with effective pollution control technologies. CO_2 capture for sequestration is an extreme option in line with zero-emission strategy that may be implemented for some power plant technologies. CO_2 capture and sequestration technologies are described in a separate Chapter.

The challenges coal (and other fossil systems) are facing are (WCI 2005b):

1. Curbing or virtually eliminating emissions of pollutants such as particulate matter and oxides of sulphur and nitrogen. This has largely been achieved and costs decreasing, but implementation should be continued to as many units as possible and extended to as many countries as possible, if compliance were required with more restrictive national emission (or air/water quality) standards.

2. Increasing thermal efficiency in order to reduce CO_2 and other emissions per unit of net electricity supplied to the network. Efficiency of modern technology has been significantly increasing and there is still potential for further improvements.

3. Curbing or nearly eliminating CO_2 emissions.

Additionally, the coal industry is also promoting the vision of clean coal as a likely source of hydrogen for stationary and transport applications (WCI 2005b).

Table 2.1 shows a summary of the environmental challenges and how conventional and advanced technologies are coping with them (WCI 2005b). Coal cleaning by washing and beneficiation can reduce the ash content of coal by over 50%, reduce SO_2 emissions and improve thermal efficiency. While coal preparation is standard in many countries, it could be usefully extended in developing countries as a low-cost way to improve the environmental performance of coal use (WCI 2005b; Eliasson and Lee (Eds) 2003).

Table 2.1 Environmental challenges and technology response of coal power plants; reworked after (WCI 2005b).

Environmental Challenges	Technological response	Status	Technology maturity assumed for LCA modeling
Particulate Emissions	Electrostatic precipitators and fabric filters, with removal efficiencies of over 99.5%.	Technology developed and widely applied in developed and developing countries.	Already available
Trace Elements	Particulate control devices, fluidized bed combustion, activated carbon injection & desulphurisation equipment can significantly reduce trace element emissions.	Technologies developed, commercialised and widely applied in developed countries. The application of NOx control and desulphurisation techniques is less prevalent in developing countries and, although increasing, could be more widely deployed.	Already available
NOx	NOx emissions can be cut by the use of low NOx burners, advanced combustion technologies and post-combustion techniques such as selective catalytic reduction (SCR) & selective non-catalytic reduction (SNCR) Over 90% of NOx emissions can be removed using existing technologies.		Already available
SOx	Technologies are available to reduce SOx emissions, such as flue gas desulphurization (FGD) (90-95% removal efficiency) and advanced fluidized bed combustion (FBC) technologies (up to 99%).		FGD already available and optimized FBC could be assumed effectively operational before 2025
Waste from Coal Combustion	Waste can be minimized both prior to and during coal combustion. Coal cleaning prior to combustion is a very cost-effective method for providing high quality coal; it reduces power station waste and emissions of SOx, as well as help at increasing thermal efficiencies. Waste can also be minimized with use of high efficiency coal combustion technologies.	Technologies are developed and continually improving. Awareness of opportunities for the re-use of power station residual waste (e.g. fly ash in cement making) is steadily increasing.	PC wastes are recycled already today Optimization for waste recycling for advanced coal technologies reached before 2025

Table 2.1 (cont.) Environmental challenges and technology response of coal power plants; reworked after (WCI 2005b).

CO_2 reduction	In the short to medium term, substantial reductions in the greenhouse intensity of coal-fired power generation can be achieved by increased combustion efficiency.	The efficiency of pulverised coal (PC) generation increased substantially towards the end of the 20th century and, with the development of supercritical (SC) and ultra-supercritical (USC) processes, will continue its steady upward advance over the next two decades. Circulating FBC technology offers similar benefits and is well suited to co-combustion of coal with biomass.	Potential for improvements of SC-PC efficiency fully reached before 2025 CFBC efficiency improvements achieved before 2025
CO_2 sequestration	'Zero-emissions technologies' (ZET) to enable the separation and capture of CO_2 from coal-based generation and its permanent storage in the geological subsurface.	CO_2 separation, capture and geological storage technologies have been developed beyond the stage of technical feasibility. Research & Industry are working at improving these technologies & demonstrate them in integrated configurations. Deployment may start within a decade.	Test/pilot plants in early 2010's. First commercial applications operational by 2025. Technology fully mature before 2050

Emissions of particulate is controlled by electrostatic precipitators (ESP), fabric filters (baghouses), wet particulate scrubbers, and hot gas filtration systems. Electrostatic precipitators use an electrical field to charge the particles in the exhaust; the particles are attracted by collecting plates. Fabric filters are made of a tightly woven fabric. Both systems have very high particulate removal efficiency, well above 99%. (WCI 2005b)

The identification of health and environmental effects due to SOx emissions (e.g. respiratory diseases, acid rain) has imposed the development and utilisation of specific control technologies. Flue gas desulphurisation (FGD) technology removes SO_2 from the flue gas by means of absorption in lime or limestone as the most dominant technology option. This can be achieved in wet (the most widely diffused technology) as well as in dry scrubbers. Wet scrubbers can achieve removal efficiencies up to 99% (WCI 2005b), but on the average they work at efficiency 90-95%, due to cost and operation optimization. The cost of FGD units has reduced by two third from the 1970s (see Figure 2.1).

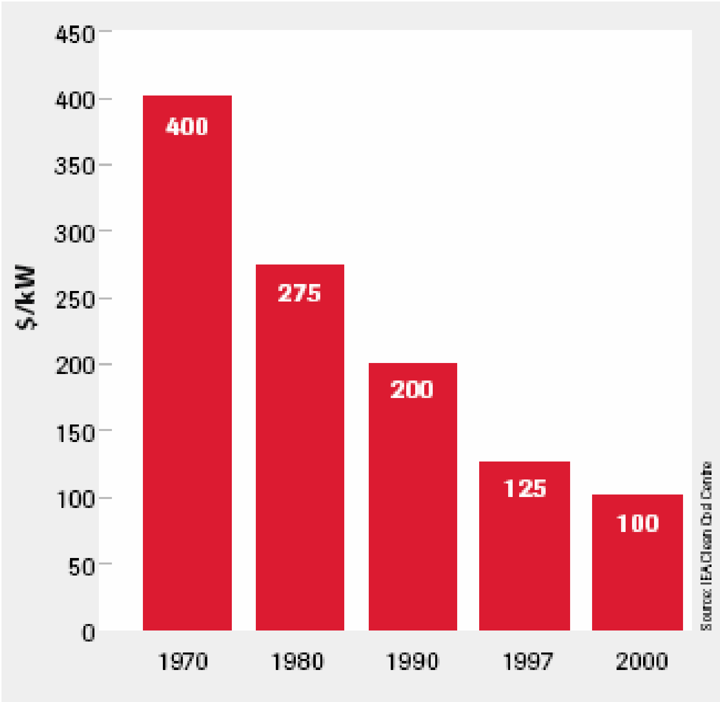

Figure 2.1 Reductions in FGD costs in the USA (WCI 2005b).

NOx reduction technologies include low NOx burners, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Low NOx burners and burner optimisation minimise formation of NOx during combustion. Conversely, SCR and SNCR treat the NOx post-combustion in the flue gas. SCR technology can achieve 80%-90% NOx reduction. It is commercially available in Japan since 1980 and in Germany since 1986 (WCI 2005b). There are about 15 GWe of coal fired SCR capacity in Japan and nearly 30 GWe in Germany, which together makes 85% of the total worldwide. SCR demonstration and full-scale systems were installed in US coal-fired power plants in the 1990s (WCI 2005b).

For CCT, key factors to take into consideration can be summarized as follows (IEA Clean Coal (2005 b):

- various cost components for plant construction and operation;
- characteristics and cost of coal;
- thermal efficiency, load range, and operational flexibility; for Combined Heat & Power (CHP) units, the pattern of heat demand;
- compliance with environmental requirements, and what operational constraints this determines;
- maturity of technology.

Figure 2.2 schematically shows the progression in CO_2 reduction from coal combustion.

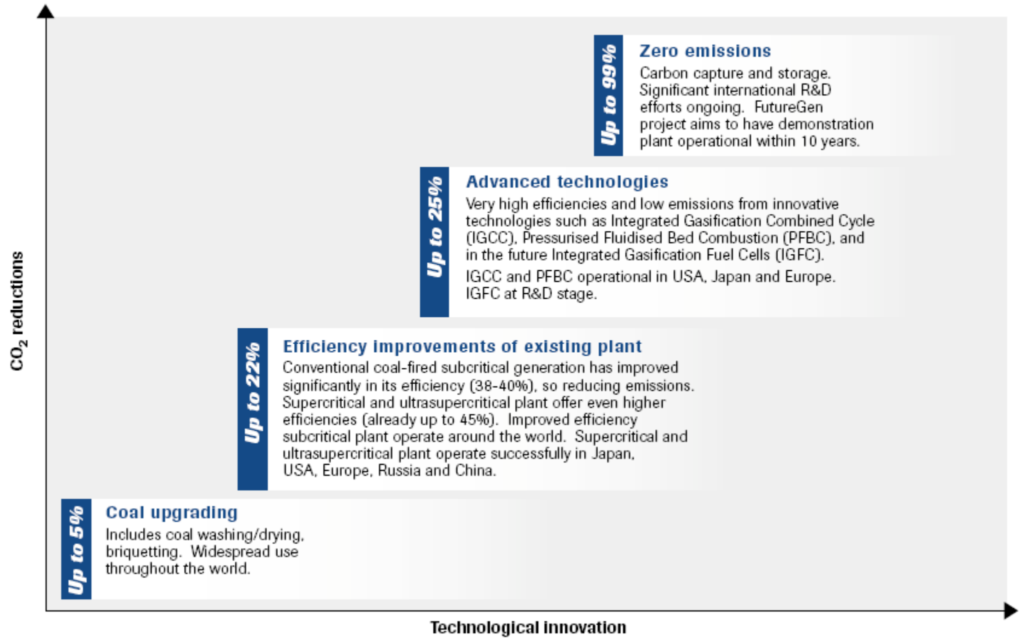

Figure 2.2 The coal-fired route to CO_2 reduction (WCI 2005b).

The efficiency of average plants in many developing countries is around 30%, but individual, especially small size and old units may have much lower rating. OECD average plants have efficiency around 36% (WCI 2005b), but individual countries may reach averages up to 40% (Röder, Bauer, Dones 2004). New supercritical plants can achieve overall thermal efficiencies in the 43-45% range and even up to 47% with suitable waste heat sink (WCI 2005b).

Individual current and future technologies will be described in the following Chapters.

2.2 Main drivers influencing future fossil technology development

2.2.1 General

The main driver for fossil technology deployment and development is the demand for cheap, large scale electricity generation. However, the demand for individual fossil technologies is not only driven by economy, also other key factors like the suitability to meet a likely growing demand, to substitute outdated facilities, the need of environmentally sound performance, public acceptance, use of domestic resources, availability and security of supply of fuels as commodities, and the need for fast responding capacity for network management are decisive.

In the following, the focus will be on natural gas and coal (hard coal and lignite), since already today oil is of minor importance for electricity production in Europe and expected to further lose share in the EU electricity market.[4]

2.2.2 Fuel costs and resource availability

In case of fossil electricity systems, fuel cost is amongst the factors with the highest influence

[4] According to (EC 2003), the share of fuel oil and diesel to total electricity production in the EU25 was about 6% in the year 2000. In the baseline scenario, a share of 2% is expected for the year 2030 in EU25, basically for peak load management.

on total electricity production costs. Estimations for future fuel prices are difficult and quite uncertain. Different scenarios on the development of fossil fuel prices are presented in (EC 2004). While the coal price remains fairly constant until 2030, oil and gas prices are considerably varied in those scenarios. In the "Baseline scenario", the GDP in EU-25 is projected to grow at a rate of 2.5% per annum in 2000-2010, 2.4% in 2010-2020 and 2.3% in 2020-2030; oil prices are assumed to remain about stable while gas prices are slightly increasing, which nevertheless does not reflect the quickly rising prices in 2005. Alternative developments are assumed in the scenarios "High oil and gas prices", "Low gas availability for Europe", "De-linking of oil and gas prices", and "Soaring oil and gas prices" (EC 2004). The "High oil and gas prices" scenario describes a situation of faster world economic growth (change in rate of development not quantified) together with relatively less abundant resources. The "Low gas availability for Europe" scenario focuses on impacts that higher economic growth and gas demand in Asia as well as tighter supplies from countries of the former Soviet Union to Europe could have. Gas reserves are also assumed to be lower than in the baseline scenario. The "De-linking of oil and gas prices" scenario combines the hypothesis of smaller oil resources and higher gas resources compared to the baseline case. The "Soaring oil and gas prices" scenario takes into account the possibility of severe supply disruptions that could last for a prolonged period of time. The rising oil and gas prices in 2005 go about along with the upper range of the different scenarios.

The amount, distribution, and transport of fossil resources are important factors for fuel price development. According to BP (2005), worldwide proved natural gas reserves would be depleted in about 65 years and worldwide proved coal reserves in about 170 years at present production levels. [Other information sources will be used in next deliverables.] However, although hard coal and lignite resources are abundant on a global scale, in the long term neither coal nor natural gas resources currently extracted within the EU can meet the demand, which is not even possible at present levels. The main European natural gas resources in the UK, Norway, and the Netherlands will likely be depleted in 20-30 years (BP 2005, Götz 2004b). The only European countries with important hard coal resources for economic extraction are Poland and the Czech Republic, but also those will be depleted before the end of this century at current production. Germany has only resources of sub-bituminous coal and lignite, which will likely be depleted in about 30 years at current rate of consumption (BP 2005). German coal reserves are not only relatively small, but also uneconomic for extraction. The German mining industry was subsidized with nearly 3 billion € in 2005 for a production of 26 million tonnes. These subsidies are going to be reduced, reaching about 2 billion € in 2012 for an expected production of approximately 20 million tonnes (GVSt 2004).

The situation regarding supply with fuel imports is different for natural gas and coal. While coal reserves are evenly distributed globally, large resources of gas are concentrated in a few regions of the world, mainly the Russian Federation and the Middle East.[5] Such regions might experience political instabilities and therefore their fuel supply to Europe cannot be considered as fully secured. The possibility of insufficient gas supply to Europe seems to be also supported by the fact that Russia intends to increase natural gas exports to Europe until 2020 only by 31 billion m3 per year, while the demand within the EU is forecasted to increase by about 300 billion m3 per year (Götz 2004a, Vorholz 2004). In case of lacking imports from Russia, Europe would have to satisfy its demand of gas with imports from other regions over longer distances such as the Barents Sea (the Jamal region in Russian northern shelves), and

[5] According to (BP 2005) nearly 70% of proved reserves are located in the Russian Federation and the Middle East.

Iran, partially as Liquefied Natural Gas (LNG).[6] The consequence would be higher average costs. The economy of LNG vs. pipeline transport primarily depends on the energy expenditures for liquefaction & regasification for LNG and the transport distances. Both pipeline and LNG production & transport decrease the overall efficiency of the electricity system, since energizing these activities requires consumption of the gas. As reported in Dones, Zhou, Tian (2003), 7-9% of extracted gas is needed for liquefaction (the lower range value for near future processes), 0.15-0.25% is consumed during transport by tanker for a shipping distance of about 500 nautical miles (corresponding to about one day navigation), and 2.5% of the delivered LNG is used for regasification. As of beginning of the 2000s, gas delivered by onshore pipeline transport costs less than LNG transported by tanker for distances lower than about 4000 km, by offshore pipeline transport for roughly 2000 km (Götz 2004a, Jensen 2002). Best technology available today exhibits a self consumption of 1.4% of natural gas per 1000 km pipeline transport at pumping stations (Dones et al. 2003).

Today, South Africa, Australia, South America, and the Russian Federation are the most important coal exporters to Western Europe (GVSt 2004). Large resources are also located in the USA, China, and India (BP 2005). Although hard coal apparently shows more advantages for security of supply than natural gas (lignite is a typical domestic resource), its supply might incur restrictions to some extent, since Australia, South Africa and South America alone will likely not meet future European demand.[7]

Taking into account the worldwide rising demand for both natural gas and coal, more limited global gas resources, and higher uncertainties concerning Europe's gas supply, an increasing difference between gas and coal prices seems to be a realistic development.

The influence of fuel cost on electricity production costs is higher for natural gas plants than for conventional steam coal plants. Depending on operating central European conditions and 2003 fuel costs according to ECG (2004), share of fuel to total electricity cost is about 65% for gas CC plants with fuel costs of about 4 $/MBTU[8] (3.8 $/GJ), while only about 40% for hard coal steam plants assuming a fuel cost of 56 $/t. Slightly different values for gas prices in 2004 and before can be found in the literature, for example BP (2005) gives average prices fur European natural gas of 3.46 $/MBTU in 2002, 4.40 $/MBTU in 2003, and 4.56 $/MBTU in 2004. The latter would make the contribution of gas to total electricity production cost in 2004 of about 70%. However, gas prices increased substantially during year 2005, since they are coupled with the oil price. At an assumed gas price of 8 $/MBTU (7.6 $/GJ), which should reflect the 2005 price developments in Europe and the USA,[9,10,11] the share of fuel cost to total electricity production cost makes about 80%.

Higher costs for natural gas would favour coal technology deployment and development, as R&D for coal systems could be considered a better long term investment. However, high natural gas prices also promote more rapid development and adoption of new energy efficient

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[6] Already today, some European countries, mainly France, Spain, and Italy are importing LNG, mostly from Algeria and Nigeria (BP 2005).

[7] Coal consumption in Europe in 2004 was nearly 500 Mtoe. Australia, South Africa, and South America produced about 380 Mtoe in year 2004.

[8] The quoted presentation dates 2 July 2004; the gas price reflects the relatively stable values in 2004 before the rise in 2005.

[9] http://www.diw.de/deutsch/produkte/publikationen/wochenberichte/docs/04-44-2.html (19.9.2005).

[10] http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp (19.9.2005).

[11] http://epp.eurostat.cec.eu.int/portal/page?_pagid=0,1136239,0_45571447&_dad=portal&_schema=PORTAL (19.9.2005).

natural gas technologies, foster greater investment in exploration and field development, and subsequently increased investment in distribution systems, which helps to keep prices down (NEPDG 2001). Within a shorter time horizon, since gas power plants are more flexible and can provide middle and peak load (purchased at higher prices than base load), they may secure higher revenues per kWh than coal, which constitute another incentive for developing gas systems.

2.2.3 Environmental aspects and international policies

Reduction of CO_2 and other airborne pollutants from fossil power plants and associated energy chain are among the main drivers for fossil technology improvement in industrialized countries. Lower CO_2 emissions per unit of power supply can be realized with higher plant efficiencies and application of CO_2 capture and storage (CCS) technologies. However, the potential of increasing plant efficiencies is limited by the thermodynamics of the Carnot cycle and the availability of high-strength materials. CO_2 sequestration has negative effects on the economy of fossil power plants, since the overall efficiency is substantially reduced and costs are increased. Targets beyond Kyoto and requirements of substantial national reduction of CO_2 emissions, would be strong incentives for R&D on CCS technologies. Meeting the aspired reductions depends primarily on political decisions, resulting in national or international emission limits, establishment of emission trading systems (including certificates) or taxes, and factual implementation of proper technologies. These factors have been taken into account in the demand and supply scenarios developed by the EC (2004).

The European energy policy on EU level contains a variety of focuses. For example, the Directive 2001/77/EC[12] and the Directive 2003/30/EC[13] both support renewables in the electricity and transport sectors, and aim at their technological development and penetration in the market. The member states should define national targets for electricity to be produced by renewable energy sources in order to achieve the EU overall targets, which in the first directive is a share of renewables in gross (total primary) energy consumption of 12% and a share of renewable electricity of 22.1% by 2010. The second directive defines the goal of achieving a share of bio-fuels for transportation of 5.75% within the EU in 2010. The member states should ensure a minimum proportion of biofuels on their markets, and, to that effect, shall set national indicative targets. Also a “Technology Platform for Zero Emission Fossil Fuel Power Plants” is currently implemented by the European Commission (EC 2005), in order to “identify and remove the obstacles to the creation of highly efficient power plants with near-zero emissions which will drastically reduce the environmental impact of fossil fuel use, particularly coal”.[14] More and updated details about energy research on European level can be found at the specific internet site of the Commission.[15] In the long term, political decisions towards reduction of dependency on fossil systems in Europe might have effects on support to R&D of fossil technologies. However, since technology development is not confined within national or regional borders, also R&D policies outside Europe, namely USA and Japan, will have an influence on the future of the fossil energy sector within the EU.

[12] Directive 2001/77/EC of the European parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market, http://www.ewea.org/documents/17_RES_directive_OJ_sep_2001_final.pdf (12.9.2005).
[13] Directive 2003/30/EC of the European parliament and of the Council of 8 May 2003 on the promotion of the use of biofuels or other renewable fuels for transport, http://europa.eu.int/comm/energy/res/legislation/doc/biofuels/en_final.pdf (12.9.2005).
[14] http://europa.eu.int/comm/research/energy/nn/nn_rt/nn_rt_co/article_2268_en.htm (12.9.2005).
[15] http://europa.eu.int/comm/research/energy/gp/article_1073_en.htm (12.9.2005).

According to (DOE 2004a), current US policy is aiming at a "carbon-free society", while ensuring continued use the domestic supply of coal. In order to reach this goal, the focus is on the development of fossil technologies on the one hand, and on nuclear power on the other hand. The "Vision 21" program[16] aims at the development of "fuel-flexible, multi-product energy plants that boost power efficiencies to 60+ percent, emit virtually no pollutants, and with carbon sequestration release minimal or no carbon emissions" by 2015. Both coal and gas power technologies are included. The establishment of a large-scale hydrogen-economy is also envisaged at an unspecified time horizon for the USA (DOE 2004a). The hydrogen production shall be based on emission free coal power plants, i.e. including CCS, and on new nuclear plants. Large scale CCS technologies, which increase electricity production cost by less than 10%, are expected to be developed by 2015 (DOE 2004a). Within the US national energy strategy it is expected that coal, contributing 52% of US electricity production in year 2000, will remain the dominant fuel in meeting increasing U.S. electricity demand through 2020. Based on the US governmental expectations at the turn of the century, natural gas is expected to cover about 90% of the projected increase in electricity production between 1999 and 2020. Thus, electricity generation by natural gas is expected to grow from 16% share in 2000 to 33% in 2020, driven by electricity restructuring and the economics of natural gas power plants. However, gas price increases by 2005, if established for a longer period may lead to a different evolution. Regulatory uncertainty concerning future environmental controls of coal power plants is one reason why the US is relying so heavily on natural gas electricity production (NEPDG 2001). Under US policies at the beginning of the 2000s, nuclear (20% of electricity production in 2000), hydropower (7%), and oil (3%) were projected to slightly decline in absolute and relative terms in the first two decades of 2000. Share of non-hydro renewables was expected to increase from 2% in 2000 to 2.8% in 2020 (NEPDG 2001). These predictions may somewhat change with newer policies.

Public research programs are usually developed in collaboration with industry, establishing R&D partnerships like the "AD 700 Power Project" in Europe or the "Canadian Clean Power Coalition" (WCI 2005b). "Zero-emission" power plants are also in the interest of industry at least in industrialized countries, since not only low costs but also a good environmental performance to comply with environmental regulations and reduce external costs are necessary. Therefore, industry is interested in "Clean Coal Technologies" (CCT) in all parts of the coal chain, from extraction and preparation to power plants (WCI 2005a).

The current trends in Germany, the country with the highest share in fossil electricity production within Europe, show a relatively clear development towards new coal power plants. More than 75% of the currently operated fossil power plants with a cumulative capacity of nearly 70000 MW will reach the end of the lifetime before 2030. However, the situation is different for lignite plants on the one hand and hard coal and natural gas plants on the other hand: several lignite plants have recently been installed; therefore nearly half of the currently operating 20000 MW should still be operated in 2030. Contrary, current hard coal and natural gas capacities will be reduced to about 4000 MW and 3000 MW, respectively. Additionally, German nuclear capacities in the order of 20000 MW will have to be replaced after 2025 according to the current plants (UBA 2006a).

At present, electricity suppliers intend to build new fossil power plants with a cumulative capacity of 30'000 MW until 2015, thereof about 4000 MW based on lignite, 15'000 MW based on hard coal and 11'000 MW based on natural gas. The cumulative electricity

[16] http://www.fossil.energy.gov/programs/powersystems/vision21/index.html (12.9.2005).

production of these plants will be in the order of 125 TWh/a. Taking into account the different typical load profiles, lignite will account for about 22%, hard coal for 54%, and natural gas for 24% of the production (UBA 2006a). However, the authors of (UBA 2006a) state that despite of the CO_2 reductions related to efficiency increase of new coal power plants, the foreseen development does not correspond to the goals of the German climate policy. Reaching these goals would need a more significant trend towards natural gas plants. Policy measures in order to accelerate this switch of fossil fuels might be expected.

2.2.4 Electricity market – development of renewables and nuclear energy

Switch of R&D resources from fossil to renewables might occur, depending on the likelihood that the renewables have to reach, in the not far future, the break even point in competition with fossil and nuclear. The rate of improvement of the economic performance of renewables strongly depends on the specific technology, subsidies, and total installed capacity.[17] While on the one hand most of renewables start from substantially higher total production costs than fossil and nuclear as of the beginning of the 2000s, on the other hand potentials for reductions are expected to be higher in relative terms for renewables than for fossil. Besides, increase of total costs of natural gas electricity due to increasing fuel prices is expected to establish soon, and possible shortages of gas are likely to occur in the second half of this century.[18] However, considering the intrinsic characteristics of renewables (some have stochastic production), current perspectives on their technological development, and their limited potentials, renewables are not suited to provide substantial base load capacity especially facing steadily growing total demand of electricity. Therefore fossil and nuclear will continue to dominate in this respect at least for the next decades unless revolutionary technologies would emerge. Nevertheless in the medium to long run renewable technologies might displace some fossil for base load, like solar thermal and solar chemical electricity production in Mediterranean countries with following export to Europe or geothermal (Hirschberg et al. 2005).

Countries with domestic fossil resources will possibly rely for a long time on fossil electricity production on political and social grounds. Additionally, rising demand of backup systems for renewables such as wind implies the installation of fast responding systems, which are currently gas turbines and gas combined cycle plants. Phasing out of nuclear energy would lead to a rising demand of large base load coal and natural gas CC power plants. On the contrary, a revival of nuclear energy would somewhat decrease this demand. The electricity market is also linked with future mobility concepts. Substitution of oil-based fuels (gasoline and diesel) with electric cars or large scale hydrogen economy would entail substantial additional electricity production capacities. Considering environmental shortcomings of fossil systems and limited domestic resources, this additional electricity production might not be based on coal, natural gas or oil in the long term within the EU.

2.2.5 The potential role of fossil in a future energy supply system

Although challenged for the emissions of carbon dioxide and other pollutants, fossil systems should remain major contributors to the European electricity mix in the next decades. The issue is to what extent implementation of new or replacement capacity will be via renewables, the effectiveness of demand side management and savings policies. Besides, in case nuclear would be banned in some European countries, its substitution may require most likely further

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[17] Learning curves for specific non-fossil technologies can be found in other reports within NEEDS RS1a.
[18] The time horizon should not be limited with 2050 in this context, since the economy of plants over their entire lifetime must be taken into account.

fossil for the technologies for these two types of energy carriers are most suited for base load. Demonstration and subsequent fast implementation of CCS may favour acceptance and continuation of fossil-base electricity.

2.2.6 Conclusion

From the previous discussion it is expected that in the next decades the overall condition is such that research and development for fossil technologies will progress steadily and deployment of improved and advanced fossil technologies will continue in the EU as well as worldwide. Hence, the moderately optimistic expectations of research and industry are highly likely to occur within the timeframe set for this project. Open remains the rate of development and deployment, hence costs, of large scale CCS.

2.3 Development of cost

This chapter contains an overview of data and characteristics of fossil fuelled power plants for electricity generation comprising technical and economic parameters. To take the future development into account, all datasets are specified for the years 2005, 2025 and 2050, whereas the development of efficiencies, electrical power and specific investments over these time horizons is to be understood as trend.

The specific investment costs of thermal power plants decline with increasing power of the units installed (cost degression due to economy of scale). The price development of gas turbines, gas and steam power plants as well as hard coal and lignite power plants follow this economic rule.

2.3.1 Hard coal condensing steam power plant

The efficiency of power plants using conventional high-temperature carbon steel alloys is restricted to values < 45%. Only at advantageous north-European cooling conditions (e.g. Denmark, sea water cooling, and condenser pressure of 35 mbar) efficiencies of 45% are reached. Siemens Power Generation states 44.5% as maximum efficiency for such hard coal-fired power plants (VARIO PLANT concept) (Segal and Alf 2000).

Hard coal power plants with high efficiencies ≥ 45% and power ratings > 300 MW require raising the live steam conditions on values exceeding 270 bar / 580 °C. Those steam conditions can be realized using ferritic-martensic materials (T 92, P 92, E 911 etc.), which facilitate to generate live steam at high super-critical pressures and temperatures without austenitic materials. However, they are four times more costly than conventional ferritic alloys. These ferritic-martensic materials have recently been developed in Japan (EPDC), in USA (EPRI) and within the EU (COST - program) for the application in power plants.

In Denmark such a hard coal-fired power plant using advanved materials is operated with a full load efficiency of 47% (Kjaer and Thomsen 1998). From this power plant and from German projects for high-efficient hard coal-fired power plants (for instance a planned unit in Westfalen (Germany) featuring a net power plant capacity of 325 MW_e, live steam conditions of 290 bar / 600 °C, temperature at reheater outlet of 620 °C and a full load efficiency of 47.4% (Stapper 1997). Cost information is available and was used by IER to estimate specific costs of future hard coal power plants with high efficiency.

In the German research project ‘KOMET 650’ high-temperature materials for live steam conditions up to 300 bar/650°C are tested (BMWi 1999). This will allow reaching net efficiencies up to 48%. The EC funded research program ‘Advanced (700°C) PF Power Plant’ puts super alloys on a Ni-basis on the test in hard coal-fired power plants with steam conditions of 375 bar/700°C (Ultra Super Critical Steam, USC). Alloys on Ni-basis (super alloys) are more expensive then the ferritic-martensic materials P 92, T 92, E 911 etc., so that higher specific investment costs have to be anticipated (but not necessarily higher electricity generation costs). After a successful testing of the materials the project planning outlined the construction of a hard coal-fired power plant with efficiencies in the range of 52% to 54% within the next decade (Kjaer 2000). This efficiency range is a result of different assumptions for cooling conditions.

Other measures for efficiency enhancement are intermediate superheating, regenerative feed water preheating and the application of super-critical live steam pressures. Currently operated hard coal-fired condensing steam power plants normally feature single intermediate superheating and up to ten feed water preheating stages.

In order to reach high overall efficiencies (component efficiencies, power plant efficiency) also the losses outside of the cycle process have to be minimised (e.g. combustion and flue gas losses). Measures for utilizing the flue gas enthalpy are air preheating, cold end optimisation and flue gas release through a wet cooling tower.

In modern power plants all these measures for efficiency enhancement are applied. Under the assumption that the efficiency of power plant processes, components and boilers as they are applied in the ultra-supercritical power plant AD700 of the EU-project ’Advanced (700 °C) PF Power Plant’ cannot be substantially improved, there is only an increase in the live steam temperature left for a further efficiency improvement. A temperature increase from 700 °C to 800 °C will improve the overall efficiency by 2.8 percentage points. With this rough estimation starting from current conditions, the highest efficiency attainable and thus the top end for efficiency improvements for hard coal condensing steam power plants is 55%.

Summarizing it can be stated:

- By the time horizon 2015 new hard coal-fired power plants with net efficiencies of 46-48% can be realized.

- In the period between 2015 and 2025 hard coal-fired condensing steam power plants with net efficiencies around 50% (maybe by 52%) can be built.

- Between 2025 and 2035 it is assumed that new hard coal steam condensing power plants are able to reach net efficiencies higher than 52%.

Table 2.2 shows technical and economic data for three power classes of hard coal-fired power plants for the time horizons 2005, 2025 and 2050. As nowadays power plant producers offer hard coal-fired power plants, which already at power regions around 300 MW_e show similar steam parameters and efficiencies as large-scale power plants, but feature different cost degression by economy of scale, a distinction in different power classes was considered reasonable.

The specific power plant costs shown in Table 2.2 are estimated with the assumption that electricity generation costs of ultra-supercritical (USC) power plants do not exceed electricity generation costs of at this time sold ‘economic’ power plants (additional investment ≤

reduction in fuel costs). This approach is supported by publications and presentations given for instance at the International Congress 'Zukunft Kohle' (Zukunft Kohle 2001).

Table 2.2 Data on modern and future hard coal-fired condensing steam power plants

	Unit	2005			2015			2025			2050		
Electrical net power $P_{el, max}$	MW_e	350	600	800	350	600	800	350	600	800	350	600	800
Net efficiency η_{net}	%	46	46	46	47	47	47	50	50	50	52	52	52
Technical life time	Year	35	35	35	35	35	35	35	35	35	35	35	35
Spec. investment cost	€/kW_e	1,060	920	820	1,000	900	850	995	895	845	995	895	845
Construction interest	%-invest	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2	8.2
Dismantling costs	€/kW_e	33	33	33	33	33	33	33	33	33	33	33	33
Fixed operational costs	€/(kW_e*a)	50	41	35	50	41	35	50	41	35	50	41	35
Variable operational costs	€/MWh_e	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6

2.3.2 Lignite condensing steam power plant

Lignite power plants with super-critical steam conditions are installed exclusively in Germany. In other countries only lignite-fired power plants with subcritical parameters are operated. Cost data on current lignite condensing steam power plants stem from Siemens, ALSTOM and RWE Rheinbraun. The most advanced lignite power plant so far, which was commissioned in Niederaußem in autumn 2002, applies state-of-the-art BoA technology (lignite plants with optimised systems engineering) and features a gross capacity of 1,012 MW_e, net efficiency of 965 MW_e, live steam conditions of 269 bar / 580 °C, intermediate superheating to 59 bar / 600 °C, a ten-staged regenerative feed water preheating, a condenser pressure (two-staged) of 28 /34 mbar and a net efficiency of 44.5% (Kallmeyer et al. 1999). The specific investment costs account for 1,180 €/kW_e. The power plant industry (Rheinbraun AG) plans further reduction of specific investment costs for BoA power plants up to 920 €/kW_e in 2010.

Further efficiency improvements could be reached by integrating recent coal drying technology within the system engineering of the lignite power plants (BoA+) (Kallmeyer et al. 1999). This would allow efficiencies up to 50%. From technical point of view power plants using BoA+-technology are anticipated to be build past 2015. However, market penetration of the BoA+-technology depends on its costs, which will be higher compared to the BoA technology, which is currently in use.

Summarizing it can be stated:

- By 2015 lignite condensing steam power plants with specific investment costs of 1,180 €/kW_e and efficiencies around 45% can be realized.

- Between 2015 and 2025 it will be possible to reduce the specific investment costs to 920 €/kW_e. Efficiencies up to 50% are possible using BoA+-technology, but market penetration of this technology is not sure.

- With further technological development the BoA+-technology and efficiencies around 50% are reachable between 2025 and 2035. However, the new technology BoA+ is much more complex than BoA. Thus according to the approach used for ultra-supercritical hard coal power plants, it was estimated that the increase in investment costs never exceeds the savings in fuel costs (investment cost increase ≤ fuel costs saving).

Currently in the field of lignite-fired power plants there is no trend to power plants with lower power ranges as it was the demand for hard coal-fired power plants. Therefore only one power class was considered as reference technology for lignite-fired power plants. Technical and economic data of representative lignite-fired condensing steam power plants are shown for different time horizons in Table 2.3.

Table 2.3 Data on modern and future lignite-fired condensing steam power plants

	Unit	2005	2015	2025	2050
Electrical net power $P_{el, max}$	MW_e	1,050	1,050	1,050	1,050
Net efficiency η_{net}	%	45	45	50[19]	50
Technical life time	Year	35	35	35	35
Spec. investment cost	€/kW_e	1,200	900	900	900
Construction interest	%-Invest	8.2	8.2	8.2	8.2
Dismantling costs	€/kW_e	30	30	30	30
Fixed operational costs	€/(kW_e*a)	33	33	33	33
Variable operational costs	€/MWh_e	1	1	1	1

2.3.3 Natural gas combined cycle power plant

Natural gas combined cycle power plants feature the best efficiency of all thermal based electricity generation technologies applied at present. This efficiency is mainly determined by the efficiency of the gas turbine turbo set (gas turbine + compressor). About two thirds of the capacity of the gas and steam power plant account for the gas turbine, the remaining third is supplied by the steam turbine. The efficiency of the gas turbine is basically depending on the gas turbine inlet temperature and the pressure ratio.

Power plant producers of heavy duty gas turbines state an efficiency of 57.5% for current natural gas fired combined cycle power plants. The 60 percent barrier is to be reached in about 6 years. The specific investment is anticipated to further decline as gas turbines with higher capacity are expected to penetrate the market. The breakeven capacity allowing further cost degression is not achieved yet. The technical development aims at the construction of gas turbines with a capacity of 500 MW. However cost information on such future gas turbines are not available from power plant producers.

As the specific investment costs of natural gas combined cycle power plants is approximately half of those of hard coal power plants, the fuel costs have considerable influence on their cost effectiveness.

Summarizing it can be stated:

– Between 2015 and 2025 it is anticipated that natural gas and steam power plants with capacities around 500 MW and efficiencies of 60% are offered at the world market. The

[19] Assumed is more efficient lignite drying, which is in line with efficiency augments, but also with increased costs.

specific investment costs of these power plants are calculated taking into account fuel savings due to higher efficiencies and cost degression due to higher capacities.

– For 2025 to 2035 further efficiency enhancement at same capacity level is assumed. This implies gas turbines with higher inlet temperatures, higher compressor pressure ratio, and advanced vane materials as well as enhanced vane cooling.

In the long run the efficiency of natural gas combined cycle power plants won't exceed considerably the 65% barrier, even if gas turbines with intermediate heating and measures for component enhancements are assumed.

Table 2.4 shows data for natural gas combined cycle power plants. The life time of 25 years is reached under the assumption that highly stressed components of the turbines with lower life time are revised or replaced ahead of time.

Table 2.4 Data on modern and future natural gas combined cycle power plants

	Unit	2005		2015		2025		2035	
Electrical net power $P_{el, max}$	MW_e	400	800	500	1,000	500	1,000	500	1,000
Net efficiency η_{net}	%	57.5	57.5	60	60	62	62	63	63
Technical life time	Year	25	25	25	25	25	25	25	25
Spec. investment cost	€/kW_e	440	440	440	440	430	430	425	425
Construction interest	%-Invest	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Dismantling costs	€/kW_e	15	15	15	15	15	15	15	15
Fixed operational costs	€/(kW_e*a)	8.8	7.4	8.6	7.3	8.4	7.1	8.4	7.1
Variable operational costs	€/MWh_e	2.0	2.0	2.2	2.2	2.2	2.2	2.2	2.2

2.3.4 Hard coal-fuelled IGCC power plant

Efficiencies higher than 55% are hardly feasible for conventional hard coal-fuelled steam power plants, even if applying Ni-based alloys. Thus other hard coal conversion technologies featuring higher efficiencies have been researched. As cheapest and promising solution the combination of gas-fired gas turbines with downstream steam turbine turned out. As gas turbines, however, cannot be charged with uncleaned flue gas from hard coal combustion, hard coal first of all has to be gasified. This is the concept of IGCC (Integrated Gasification Combined Cycle) power plants, which can be constructed using components and materials that are already technically approved and available in the market. Depending on the development of gas turbines, hard coal-fuelled IGCC power plants can potentially feature higher efficiencies than hard coal-fired steam power plants. When gas combined cycle efficiencies achieve 63% in future, hard coal-fuelled IGCC power plants could (timely delayed) reach an efficiency of 56% (Kloster 1998).

Summarizing it can be stated:

– By 2015 this reports considers IGCC power plants as demonstration plants or 'First-of-its-kind'. The most representative European IGCC power plants (Buggenum, Puertollano) are neither representative in terms of costs nor in terms of efficiency. They didn't have commercial financing and feature gas turbines, which are not current state of the art and are already technologically outdated.

- From 2015 to 2025 the technical data of the representative IGCC power plant stem from an IGCC optimisation in the European Joule III Programme (Advanced Cycles 1998). Such an optimised IGCC power plant could be built with currently available and approved materials, components and gas cleaning facilities. The efficiency of this hard coal-fuelled power plant was calculated to 51,5% and can be achieved by gas turbine improvements, which are anticipated to be reached by 2015. As specific investment costs 1,100 US$/kW$_e$ were obtained.

- Between 2025 and 2035 the efficiency of hard coal-fuelled IGCC power plants is calculated according to the expected efficiency development of natural gas combined cycle power plants to 63% minus 8% = 55%. The efficiency reduction of 8% lies in the exergy losses during gasification and gas cleaning. Future progress in gasification and gas cleaning will further reduce this efficiency difference between IGCC, gas and steam power plants.

Table 2.5 shows data on future hard coal-fuelled IGCC power plants.

Table 2.5 Data on future hard coal-fuelled IGCC power plants

	Unit	2005	2015	2025	2035	2050
Electrical net power $P_{el, max}$	MW$_e$	450	450	450	450	450
Net efficiency η_{net}	%	45	51	54	54.5	54.5
Technical life time	Year	35	35	35	35	35
Spec. investment cost	€/kW$_e$	1,200	1,100	1,100	1,100	1,100
Construction interest	%-Invest	8.2	8.2	8.2	8.2	8.2
Dismantling costs	€/kW$_e$	50	50	50	50	50
Fixed operational costs	€/(kW$_e$*a)	53	53	53	53	53
Variable operational costs	€/MWh$_e$	3.1	3.1	3.1	3.1	3.1

2.3.5 Lignite-fuelled IGCC power plant

IGCC technology can also be applied to lignite. Currently there is one lignite-fuelled IGCC power plant installed in Europe, which is located in Vresova in the Czech Republic. Cost data on current and future lignite-fuelled IGCC power plants have been derived from hard coal IGCC technology and are shown in Table 2.6.

Table 2.6 Data on future lignite-fuelled IGCC power plants

	Unit	2005	2015	2025	2035	2050
Electrical net power $P_{el, max}$	MW$_e$	450	450	450	450	450
Net efficiency η_{net}	%	44	49	52	52.5	52.5
Technical life time	Year	35	35	35	35	35
Spec. investment cost	€/kW$_e$	1,200	1,100	1,100	1,100	1,100
Construction interest	%-Invest	8.2	8.2	8.2	8.2	8.2
Dismantling costs	€/kW$_e$	50	50	50	50	50
Fixed operational costs	€/(kW$_e$*a)	53	53	53	53	53
Variable operational costs	€/MWh$_e$	3.1	3.1	3.1	3.1	3.1

2.3.6 Future coal power plants with CO_2 capture

Details about CO_2 Capture and Storage (CCS) technologies and its implementation within this study can be found in chapter 4.3.

The analysis includes selected CCS technologies, which can be assumed to be representative for the implementation of CCS in Europe within the next four decades. Pulverized coal (PC) power plants with post-combustion and oxyfuel combustion as CO_2 separation technologies are included as well as IGCC power plants with pre-combustion technology.

Power plants with post-combustion and oxyfuel combustion are analyzed based on the most relevant literature (Hendriks et al. 2004, Hendriks 2007, IPCC 2005, Rubin et al. 2007). Most important factor in terms of cost of electricity as well as LCA is the energy consumption for CO_2 separation and as a consequence the reduction in power plant net efficiency.

The basic engineering for a hard coal IGCC power plants with CO_2 capture has been investigated in an EC funded study (Pruschek et al. 1997), where costs of the power plant components for CO_2 capture (shift reactor, facilities for CO_2 scrubbing and compression) were estimated. Furthermore, the consumption of adsorption liquid and the energy demand for CO_2 capture were analysed. The CO_2 capture caused an efficiency reduction of about 6%-points compared to an IGCC power plant without CO_2 capture (Pruschek et al. 1997), (Pruschek et al. 1998).

Table 2.7 and Table 2.8 show data on PC coal power plants with CO_2 capture, Table 2.9 and Table 2.10 show data on IGCC power plants with CO_2 capture obtained from engineering studies on IGCC CO_2 capture using rectisol scrubbing for CO_2 separation. Summarizing it can be stated:

- Due to the fact that there is currently no market penetration, but only demonstration plants costs of current CCS technologies are not estimated.
- After 2015 CCS technologies are assumed to penetrate the market. Costs and efficiencies of the power plants with CO_2 capture are derived from the specifications of power plants without CO_2 capture based on literature.
- The data are calculated for a CO_2 capture rate of 90% for pre- and post-combustion capture and 99.5% for oxyfuel combustion.

Table 2.7 Data on future hard coal-fuelled PC power plants with CO_2 capture

	unit	2005	2050
Electrical net power $P_{el, max}$	MW_e	Not modeled	600
Net efficiency η_{net}	%		47/49[a]
Technical life time	Year		35
Spec. investment cost	€/kW_e		1420
Construction interest	%-Invest		8.2
Dismantling costs	€/kW_e		55
Fixed operational costs	€/(kW_e*a)		0.83
Variable operational costs	€/MWh_e		0.3

[a] oxyfuel combustion/post combustion CO_2 capture.

Table 2.8 Data on future lignite-fuelled PC power plants with CO_2 capture

	unit	2005	2050
Electrical net power $P_{el,\,max}$	MW_e	Not modeled	950
Net efficiency η_{net}	%		47/49[a]
Technical life time	Year		35
Spec. investment cost	€/kW_e		1390
Construction interest	%-Invest		8.2
Dismantling costs	€/kW_e		55
Fixed operational costs	€/(kW_e*a)		0.81
Variable operational costs	€/MWh_e		0.12

[a] oxyfuel combustion/post combustion CO_2 capture.

Table 2.9 Data on future hard coal-fuelled IGCC power plants with CO_2 capture

	unit	2005	2015	2025	2050
Electrical net power $P_{el,\,max}$	MW_e	-	425	425	425
Net efficiency η_{net}	%	-	45	48	48,5
Technical life time	Year	-	35	35	35
Spec. investment cost	€/kW_e	-	1,370	1,370	1,370
Construction interest	%-Invest	-	8,2	8,2	8,2
Dismantling costs	€/kW_e	-	55	55	55
Fixed operational costs	€/(kW_e*a)	-	65	65	65
Variable operational costs	€/MWh_e	-	3,6	3,6	3,6

Table 2.10 Data on future lignite-fuelled IGCC power plants with CO_2 capture

	unit	2005	2015	2025	2050
Electrical net power $P_{el,\,max}$	MW_e	-	425	425	425
Net efficiency η_{net}	%	-	44	46	46,5
Technical life time	Year	-	35	35	35
Spec. investment cost	€/kW_e	-	1,370	1,370	1,370
Construction interest	%-Invest	-	8,2	8,2	8,2
Dismantling costs	€/kW_e	-	55	55	55
Fixed operational costs	€/(kW_e*a)	-	65	65	65
Variable operational costs	€/MWh_e	-	3,6	3,6	3,6

The CO_2 abatement costs account for 30 to 40 €/t CO_2. Liquefaction and pipeline transportation cause further expenses (Göttlicher 1999). Altogether the CO_2 abatement costs per ton of liquefied CO_2 transported in pipeline over 1000 km are calculated to approximately 50 €. This calculation is based on costs of existing technologies.

2.3.7 Estimation of market development for different coal technologies

Since IGCC power plants are still in their early stage of development, supercritical steam power plants will probably be the preferred technology to be installed in the short term for coal-based power generation. Thereby a development towards more advanced steam conditions is anticipated. Due to their relative flexibility concerning fuel type and their good environmental performance, IGCC power plants are able to efficiently use also feedstock such as biomass and refinery residual. Moreover, IGCC systems could be part of a particularly clean power plant system, when advanced gas turbines and fuel cells are integrated within the electricity generation process.

3 Current fossil technologies

Besides a short summary on current fossil technology, this Chapter includes a survey of power plant technologies that can be identified today as candidates for future supply. From these, a selection suitable for Europe to be modelled within NEEDS is taken.

Focus is on coal and natural gas technologies. Oil is not considered a main source option for power generation in the next future, although it might be used as alternative (may be limited in time) fuel to natural gas in combined cycle power plants and peak-load turbines, as well as used (as diesel) in small size cogeneration plants.

3.1 Coal technologies

3.1.1 Pulverized Coal combustion subcritical and supercritical power plants

Pulverised Coal (PC) combustion is the technology most widely used today for power generation. Thousands of units exist worldwide, accounting for well over 90% of total coal-fired capacity (IEA Clean Coal 2005b; WCI 2005a). Different coals can be burned in PC, but this technology may not be best for coals with high ash content (IEA Clean Coal 2005b). The coal is crushed and milled to a fine powder, so that in the case of a bituminous coal, 70 75% is <75 µm while less than 2% is >300 µm (IEA Clean Coal 2005b).[20] The pulverised coal is blown with part of the combustion air into the boiler through the burners. Secondary and tertiary air is also added in the burners or directly in the combustion chamber.

Conventional PC units operate at nearly atmospheric pressure, thus simplifying the material flows through the plant (IEA Clean Coal 2005b).

Excess air is required to obtain as complete as possible combustion of the carbon (>99%), but modern designs are such to control and stage the addition of air in order to minimize the formation of NOx. However, a de-NOx plant may still be necessary to comply with environmental requirements (IEA Clean Coal 2005b). Combustion temperatures range 1500-1700°C with bituminous coal, 1300-1600°C with lower rank coals (IEA Clean Coal 2005b). Superheated steam is produced in the heat exchanger, which is expanded in a steam turbine coupled with a power generator. Figure 3.1 shows a simplified scheme of a pulverized coal combustion power plant with de-NOx and de-SOx (WCI 2005a).

[20] Particle residence time in the boiler is typically two to five seconds, therefore smaller sizes (i.e. higher ratio surface to volume) favour complete combustion (IEA Clean Coal 2005b,a).

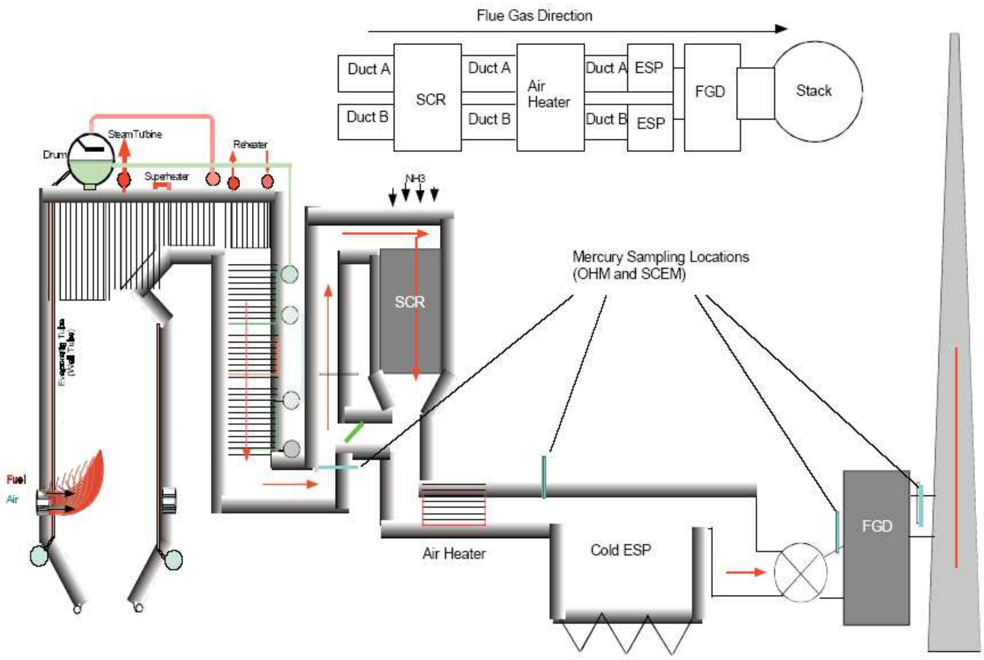

Figure 3.1 **Simplified scheme of pulverized coal combustion power plant with SCR and FGD (Behrooz Ghorishi et al. 2005).**

Different configurations of the burners in the combustion chamber are possible (IEA Clean Coal 2005b):

– wall-mounted burners on one side;

– opposed-fired wall mounted burners;

– tangential burners in the corners or on the walls.

Choice of burners is mostly based on cost factors, operating experience, environmental constraints and manufacturer's experience (IEA Clean Coal 2005b). Additional important parameters are also the capacity of the boiler and the requirements to turn-down ration.

Two broadly different boiler designs are mainly used. One is the two-pass layout made of a furnace chamber topped by the heat exchanger for superheating the steam. The flue gases then turn through 180° to move downwards through the main heat transfer and economiser sections (as in Fig. 3). The other type is a tower boiler with the combustion chamber at the bottom and nearly all the heat transfer sections stacked vertically above each other. Tower designs are diffused in Europe, and applied to supercritical (SC) units (see below). In Japan, due to earthquakes, the two-pass layout is preferred because of the smaller height. (IEA Clean Coal 2005b)

PC power plant units installed worldwide range generally between 50 and 1300 MW_e (IEA Clean Coal 2005b). Most new PC units are rated at over 300 MW_e, for the performance increases and costs decrease with economies of scale. However, only a few large units with outputs from a single boiler/turbine combination of more than 700 MW_e exist, which are suitable only in relatively large and relatively dense power grids (IEA Clean Coal 2005b).

An average net thermal efficiency of 35% 36% is commonly assumed for large existing plants with subcritical steam burning relatively high quality coals (IEA Clean Coal 2005b). The maximum efficiencies achievable with lower grade and lower rank coals are somewhat lower than with burning high quality coal (IEA Clean Coal 2005b). The overall thermal efficiency of some older, relatively small units can be as low as 30% (IEA Clean Coal 2005b). In developing countries such as China, the efficiency of old coal plants can be lower or even much lower than 30% (Dones, Zhou, Tian 2003). In small units, the net efficiency is further penalized by the high ratio of auxiliary power. In particular for supercritical conditions (see below), the maximum efficiencies expected for lignite fired plants currently under construction in Germany are around 42% compared with 45% for new bituminous coal fired units with comparable waste heat sink (IEA Clean Coal 2005b).

New conventional PC power plants burning high quality coal achieve above 40% efficiency when used for base-load and working at optimum level. However, units which load follow (intermediate load), which is typical for hard coal units as opposed to lignite units, may operate a considerable proportion of their time below maximum output. According to (CCTP 2003), the efficiency of SC power plants is in relative terms less affected by part-load operation than subcritical plants, with efficiency reductions for the former less than half those experienced in the latter. For example, available data suggest reductions in plant efficiency for SC units of around 2% at 75% load compared with 4% reduction for subcritical plant under comparable conditions. Furthermore, it must be considered that units operate more efficiently with colder air temperatures, and with lower temperature cooling water (IEA Clean Coal 2005b). The cooling conditions going from near-river cooling tower to direct sea water cooling operation make a gain in efficiency of about 2 point percent. Realistic modeling and economic comparison should be based on normal or typical operating conditions.

The costs for retrofitting a SC steam system to an existing subcritical boiler are prohibitive according to (IEA Clean Coal 2005b). Therefore, other ways to increase efficiency by retrofitting should be pursued or new SC plant should substitute old subcritical PCs in order to improve the cost and environmental performance (including reduction of CO_2 emission rate) of average coal plants. Various measures to increase the thermal efficiency relative to current design practice are given below, from (IEA Clean Coal 2005b):

- reducing the excess air ratio from 25% to 15%, which gives a small increase;
- reducing the stack gas exit temperature by 10°K (while recovering the heat involved) can bring about a similar (small) increase;
- increasing the steam pressure and temperature from 25 MPa/540°C to 30 MPa/600°C can increase efficiency by nearly 2%;
- using a second reheat stage can add another 1%;
- decreasing the condenser pressure from 0.0065 MPa to 0.003 MPa can further increase efficiency.

Implementation is subject to trade-off analysis between costs (both capital and operating), the risk element in the decision and the energy recovered (IEA Clean Coal 2005b). These measures will not be modeled within WP7.

PC using steam in supercritical conditions has become the norm for new installations in industrialized countries (PF 03-05 2003). Capital costs of supercritical PCs are slightly higher than those of conventional PCs; however, unit fuel costs are significantly lower than subcritical PCs because of the increased efficiency and, in many cases, also higher plant availability (WCI 2005b). More than 400 plants are in operation worldwide, some of them in developing countries (WCI 2005b). Modern installed plants can achieve overall thermal efficiencies in the 43-45% range, depending on location (IEA Clean Coal 2005b; WCI 2005a). Net efficiencies of 45-47% are achievable with supercritical steam using bituminous coals and currently developed materials with best seawater-cooled conditions (IEA Clean Coal 2005b). An electric net efficiency of 43% is documented for the hard coal power plants Staudinger V near Hamburg and in Rostock, Germany. These plants have net capacities of 509 MW, steam pressure of 26.2 MPa, and steam temperatures of 545°C/562°C (Schuknecht 2003). The hard coal plant Nordjylland 3 in Denmark with a capacity of 400 MW shows the currently highest net efficiency in Europe, 47%. Steam parameters are 290 bar/582°C/580°C (Bernero 2002). One of the most advanced lignite power plants of today is the unit Niederaussem K with a capacity of 950 MW, a net efficiency of 43.2% and steam parameters are 600/605°C and 272/55.5 bar, live steam/reheater (RWE 2006a, RWE 2005).

Most PC boilers operate with a dry bottom, which produces coarse bottom ash (IEA Clean Coal 2005b); the other boiler type uses wet bottom, which produces boiler slags. Most of the ash, 65%-85% according to (Pflughoeft-Hassett, Hassett, Schroeder 1999) and 80-90% with a low level of carbon-in-ash, averaging around 0.5% according to (IEA Clean Coal 2005b) is transported out of the boiler by the flue gases as fine solid particles. Boilers with cyclone burners use coarser coal feed (95% is <1/4 in. (Pflughoeft-Hassett, Hassett, Schroeder 1999)), and shall be considered separately from PCs. They produce much higher bottom ash than PCs, up to 75% 90% depending on coal quality, and smaller amounts of fly ash (Pflughoeft-Hassett, Hassett, Schroeder 1999).

The most effective way to reduce most of the emissions species produced by coal combustion in PCs is through post-combustion pollution control devices. ESP and/or fabric filters can remove well over 99% of fly ash from flue gases in current plants. Flue gas desulphurisation (FGD) plants can remove 90-97% of sulphur oxides from flue gases, and convert it into gypsum for use in buildings (WCI 2005a). Selective catalytic NOx reduction (SCR), also a post-combustion technique, can achieve reductions of 80-90% (WCI 2005a). NOx can also be controlled using low-NOx burners, effective up to 40%, and re-burning techniques Together these two techniques reduce NOx emissions up to 70% (WCI 2005a).

Emissions from new PC units equipped with pollution control plants can meet all current emission standards reliably and economically, although the capital cost can represent about one third of the cost of the unit when meeting the most stringent current standards (IEA Clean Coal 2005b). The operation of these emission control measures has a relatively small effect on overall thermal efficiency (IEA Clean Coal 2005b).

3.1.1.1 Hard Coal PC reference power plant considered in NEEDS

This study assumes for the reference state-of-the-art coal power plant technology from year 2000 on the Ultra Supercritical Pulverized Coal (USC-PC) technology. Figure 3.2 gives a schematic overview of this technology in the case of Danish power plants at the end of the 1990s.

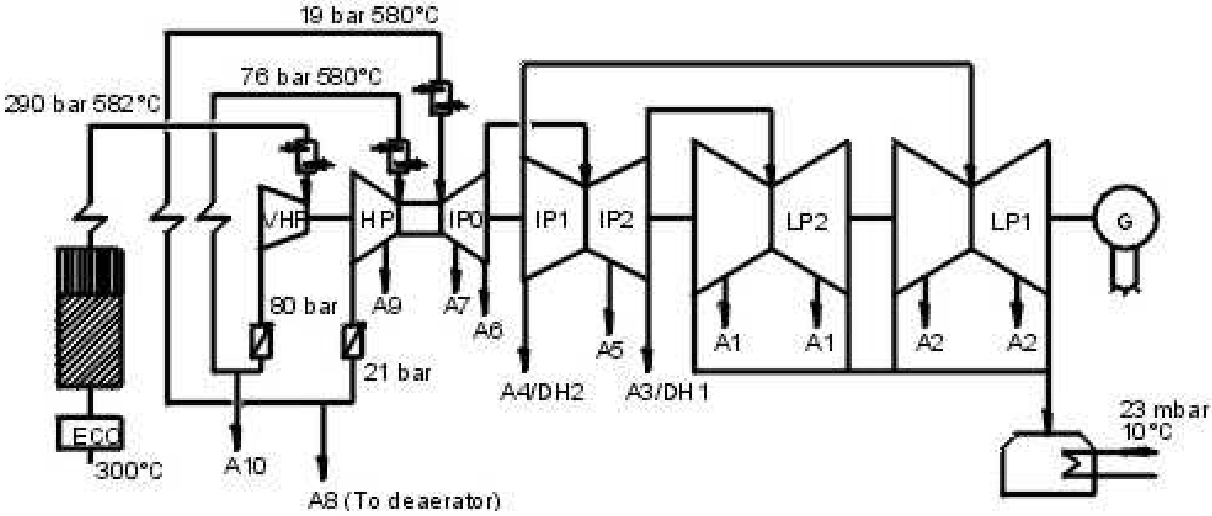

Figure 3.2 USC water/steam cycle with double reheat used in Nordjyllandsværket Unit 3 (coal) and Skaerbaeksværket (gas) Power Plants, Denmark (Kjær 1997).

However, under the constraints of data availability, the power plant in Rostock,[21] with gross capacity of 553 MW_e, net capacity 509 MW_e, gross efficiency 46.7%, and net efficiency of about 43% can be considered a suitable approximation for an LCI study. The plant in Rostock was commissioned in 1994 and is operated at middle load. The unit is shut down in the evening and started up in the morning; load ramping rates are as high as 7% per minute (Vitalis et al. 2000). Boiler availability for the four year period after startup has been 98.5% (Vitalis et al. 2000). The Benson boiler is a tower boiler with once-through circuitry, in which the water flows through the economizer, evaporator, and superheater surfaces without recirculation through any subsystem during normal operation (Vitalis et al. 2000). Outlet steam conditions are 545ºC superheat, 562ºC reheat, and 265 barg pressure (Vitalis et al. 2000). According to the classification of UNIPEDE as reported in (Lako 2004) these are typical characteristics for supercritical plants.

In the more than one decade after commissioning of the Rostock power plant, several new units based on the USC combustion technology have been installed in Europe that have higher net efficiency than Rostock. As reported in (BWE 2006), the net electrical efficiency has increased from 42% up to even 49% (in best conditions), see Figure 3.3. Matching curves are given in (Poulsen 2005; Kjaer 2003; Noer and Kjær 2006), showing the development of the steam power cycle in Denmark. The steam temperature has increased up to 600°C and the pressure up to 305 bar. Double reheating has been introduced to further increase efficiency. The above characteristics correspond to the minimum ones for defining USC technology according to the aforementioned UNIPEDE classification.

[21] http://www.kraftwerk-rostock.de/

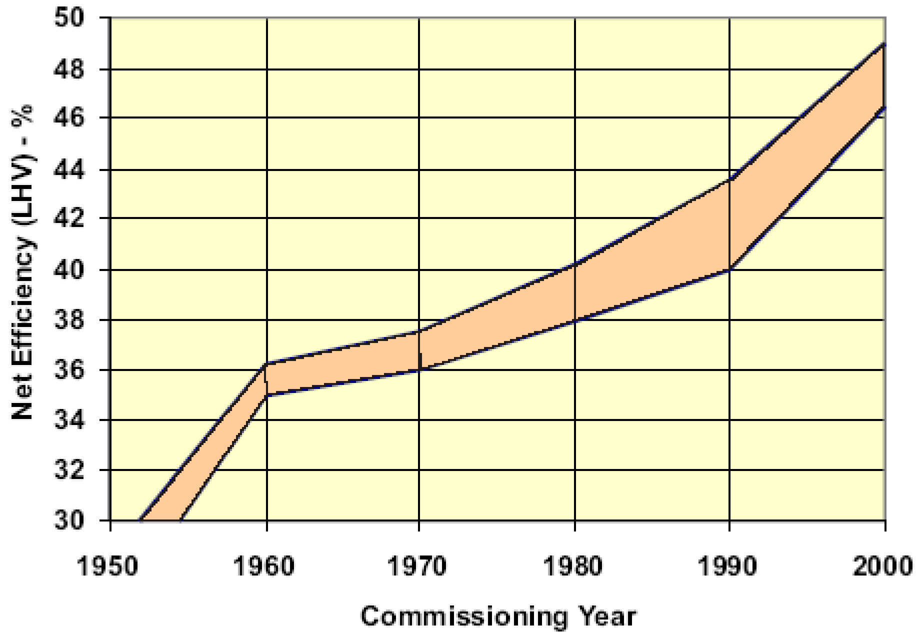

Figure 3.3 **Progress in net plant efficiency for hard coal power plants: from subcritical to Ultra Super Critical (USC) technology (BWE 2006).**

The best performer around year 2000 is the 411 MW_e (net) power plant Nordjyllandsværket Unit 3 in Denmark, commissioning year 1998, with a net efficiency of 47.2% (power production only;[22] 100% load; condensing mode; 10°C cooling water; steam parameters 290 bar/582°C/580°C (Kjær S. 2003); tower boiler); this plant is operated for base load (Poulsen 2005).

However, the high efficiency of the Nordjyllandsværket Unit 3 is achieved also thanks to the temperature of the heat sink which is the water of the North Sea. In order to reflect average conditions in Central Europe, i.e. different ambient temperature and use of a cooling tower, the efficiency should be decreased by about 2%. This value has been estimated on the basis of a hypothesized difference of condenser pressure from about 23 mbar (abs) for the Danish conditions to about 50 mbar (abs) for average European conditions and the corresponding decrease of turbine efficiency calculated after (AGO 2000).

For integration within NEEDS, three unit sizes are required by the energy economy modeling in RS2a, namely 350 MW_e, 600 MW_e, and 800 MW_e (net). Considering that units with larger capacities are in general more efficient than units with smaller capacities, for the LCI modeling it has been assumed a net efficiency of 46% for the 800 MW_e unit, and 45% for the units of 350 MW_e and 600 MW_e (Rostock unit size lies in between). Table 3.1 gives an overview of the key data of the reference Critical Pulverized Coal (USC-PC).

[22] The plant is designed for combined heat and power production, with 90% total thermal efficiency, 339.5% MW_e generator output, and 442 MJ/s district heating output (Poulsen 2005).

Table 3.1 Technical data of the reference USC-PC Power Plants investigated in NEEDS.

Gross Power [1]	[MW_e]	378	642	848
Net Power	[MW_e]	350	600	800
Technical Life Time	[a]	35	35	35
Load	[h/a]	7600	7600	7600
Net Electricity Generation (over the life time)	[TWh]	93.1	159.6	212.8
Net Efficiency	[%]	45	45	46
Efficiency FGD	[%]	93	93	93
Efficiency de-NOx	[%]	70	70	70

[1] Calculated from the net power using an auxiliary consumption of 8%, 7%, and 6% of gross power, respectively for the 350 MW, 600 MW, and 800 MW units.

Modeling of the construction of the reference hard coal power plants is based on data from (Köhler et al. 1996a). The unit actually inventoried in (Köhler et al. 1996a) is installed in Rostock, and has gross capacity of 553 MW_e, net capacity of 509 MW_e, gross efficiency 46.7%, and a net efficiency of about 43%. The masses of the three modelled units with 350 MW_e, 600 MW_e, and 800 MW_e (net) capacity have been scaled from Rostock material inventory assessed in (Köhler et al. 1996a) using a regression curve on the basis of the average concrete and steel masses given in (Jensch 1988) for hard coal power plants of 10, 100, 450, and 700 MW. In order to approximate average European conditions, the electricity mix used for modeling electricity uses during construction has been composed on the basis of statistical electricity production data in year 2000 in UCTE and CENTREL grids, which were separately modelled in ecoinvent (Frischknecht et al. 2004).

An occupation area of 53’000 m^2 is reported in (Köhler et al. 1996a) for the Rostock plant. In first approximation the land occupation has been modelled assuming a linear relation with the power rate. The shares of different land use categories are assumed as 70% industrial area and 30% road area. The dismantling of the power plant is modelled using exclusively ecoinvent datasets designed for waste management (Doka 2003). For concrete, reinforcing bars, mineral wool, and glass datasets of type “disposal, building, xx, to sorting plant” were used. These datasets describe the energy requirements for dismantling of the buildings, components and other parts of the plant as well as the emissions during dismantling and transport of the dismantled materials to the sorting plant. Due to the construction of ecoinvent background database, also the final fate of these materials (final disposal or recycling) is automatically included in the calculation of cumulative burdens. Other materials like bitumen, plastics used in buildings, waste wood, paint remains, and inert materials (masonry) are assumed to be directly disposed of. Plastics used in auxiliary and electrotechnic systems, mineral oil, and rubber are assumed to be directly incinerated. All metals except steel in reinforcement bars are assumed to be directly recycled, hence the corresponding items are not included in the dismantling database.

The modeling of the operation of the reference hard coal power plants is based on two sources: a German database of power plants (UBA 2002) for technical specification of Rostock and its emission of criteria pollutants, and the description of the average hard coal power plant, operational around 2000 in Germany, as modelled in ecoinvent (Röder et al. 2004) for defining the emissions of GHG, VOCs, and trace elements, including radioactive isotopes. For the second group, the emissions are assumed to remain the same in terms of fuel input (kg emission per MJ_{in}). These data have been normalized to the kWh on the basis of the assumed net efficiencies.

Efficiency of the FGD of the Rostock power plant is about 93%, whereas the de-NO_x works with about 70% removal efficiency (Hojczyk et al. 1997). The unit in Rostock is herewith assumed to be representative for hard coal best power plant technology available around year 2000 for what concerns construction material utilization and emission rates (per unit of MJ_{in} fuel input) of criteria pollutants during its operation. In particular, the efficiency of FGD produced by BWE using the Chiyoda advanced CT-121 FGD process (2nd generation wet limestone process using a Jet Bubbling Reactor (Rübner-Petersen and Pollastro 2005)) for coal units commissioned between 1994 and 2004 exhibit values between 85% (Okinawa Electric Power Co., Japan, 156 MW_e plant, 1994) and 99% (Kobe Steel Ltd., Japan, two units of 700 MW_e each, 2002-2004), with an average around 95%. However, working efficiency of FGDs depends on economics and SO_x emission constraints, therefore they are dependent on the site and coal S-content. Efficiency of de-NO_x and ESP for Rostock are such to achieve full compliance with current emissions limits. The Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants EC (2002) established the emission limits for new plants put into operation after November 2003 as shown in Table 3.2. The emissions of SO_x and NO_x for solid fuels correspond to approximately 5.6E-5 kg/MJ_{in}. Therefore, the chosen values from Rostock unit for NO_x and SO_x are equal to or below, respectively, this limit (see Table 3.2) and can be used for representing compliance of modern pollution control technology with the European environmental law. Incidentally, the SO_x emission from the Rostock unit, whose coal feed has 0.9% S-content (estimation after (Hojczyk et al. 1997)), is equal to the low emission rate from the TNO CEPMEIP database[23] also reported in (Nielsen et al. 2003). The limit for Total Suspended Particulates (TSP) in the EC directive corresponds to approximately 8.6E-6 kg/MJ_{in}. Therefore, the chosen value from Rostock unit stack of 5.6E-6 kg/MJ_{in} is well within the limit.[24] Moreover, the TSP emissions from the most modern Danish coal supercritical PF plants reported in (Nielsen et al. 2003) are 2.5 to 3 kg/MJ_{in} for Avedøreværket (fraction $PM_{2.5}$ between 66-78% of total TSP) and 2.6 to 5 kg/MJ_{in} for Nordjyllandsværket (fraction $PM_{2.5}$ between 48-66% of total TSP). Therefore, it can be concluded that although the assumed value (thereof $PM_{2.5}$ makes 85% of total PM from stack) is not the minimum that can be found in the literature, it is in the low range and well complying with the EC directive, thus likely representing average Europe for best available technology.

Maintenance/refurbishment during the lifetime of the power plant may require substitution of components and thus some material flow. However, assuming this is of the order of the hundredth of the total materials used for construction, it can be neglected from the accounting. The cumulative results combined to give external costs show only very minor contributions from the construction of the plant (see discussion of results below), therefore neglecting material substitution during operation is acceptable in first approximation. However, this may not be applicable for some individual emitted species.

[23] http://www.air.sk/tno/cepmeip/

[24] To take into account fugitive emissions from coal stock (heaps) and coal loading/unloading from freight trains at plant, an approximate value of 5E-6 kg/MJ_{in} has been inputted for PM >10 μm, along with ecoinvent (Röder et al. 2004). These emissions seem not be captured by official reporting which always refers to stack emissions. However, considering the rather low importance for external cost calculations, a possibly meaningful uncertainty in these TSP emissions can be fully tolerated in the NEEDS context.

Table 3.2 Emission limits from large combustion plants in Directive 2001/80/EC (EC 2002).

Fuel[1]	Plant size	Limit [Mg/Nm^3]		
	MWh_{th}	SO_x	NO_x	Dust
Solid fuels (O_2 content 6%)	> 100			30
	> 300	200	200	
Liquid fuels (O_2 content 3%)	> 300	200	200	
Natural gas(O_2 content 3%)	> 300	35	100	
Liquefied gas		5		
Gas Turbines (O_2 content 15%)[2]	> 50[3]			
Natural gas			50[4]	
Liquid fuels[5]			120	

[1] Shown here only fuels and plant sizes of interest for NEEDS
[2] The limit values apply only above 70% load.
[3] Thermal input at ISO conditions.
[4] 75 mg/Nm^3 in the following cases, where the efficiency of the gas turbine is determined at ISO base load conditions:
- gas turbines, used in combined heat and power systems having an overall efficiency greater than 75%;
- gas turbines used in combined cycle plants having an annual average overall electrical efficiency greater than 55%;
- gas turbines for mechanical drives.
For single cycle gas turbines not falling into any of the above categories, but having an efficiency greater than 35% determined at ISO base load conditions the emission limit value shall be 50*g/35 where g is the gas turbine efficiency expressed as a percentage (and at ISO base load conditions).
[5] This emission limit value only applies to gas turbines firing light and middle distillates.

3.1.1.2 Lignite PC reference power plant considered in NEEDS

Reference for the current state-of-the-art lignite technology is the power plant "Niederaussem K" in Bergheim, Nordrhein-Westfalen, Germany. The plant is named "BoA-unit" (Braunkohlekraftwerk mit optimierter Anlagentechnik), i.e. lignite plant with optimized systems engineering, in order to characterize its technology advancements. The plant has a net capacity of 950 MW_e and a net efficiency of 43.2%. It started commercial operation in year 2003.[25] Steam parameters are 265/60 bar and 580/600°C. The remarkable increase in net efficiency compared to older lignite power plants is due to a combination of several factors: an optimized cooling tower, use of the heat of the exhaust gases, increase in steam pressure and temperature, increased efficiency of the turbine, and reduced auxiliary power (RWE 2006, RWE 2005). Figure 3.4 shows a schematic overview of the BoA lignite reference power plant. Table 3.3 gives an overview of the key data of the reference lignite plant (RWE 2006, RWE 2005).

[25] http://www.rwe.com/generator.aspx/rwe-power-icw/standorte/braunkohle/kraftwerke/niederaussem/language=de/id=121102/niederaussem-page.html (8.9.2006).

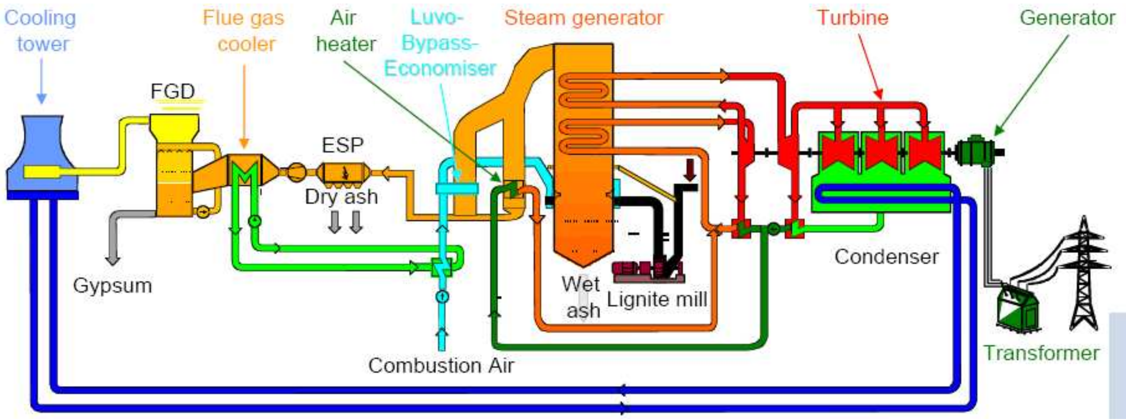

Figure 3.4 Schematic of the BoA lignite reference power plant (RWE 2005).[26]

Modeling of the construction of the reference lignite power plant is based on (Köhler et al. 1996b), which contains a comprehensive analysis of a modern lignite power plant with a net capacity of 929 MW_e and a net efficiency of 43%. Construction of this plant was supposed to start in 1996. Since there are no specific data available for construction of the BoA reference power plant, and since the characteristics of the unit analysed in (Köhler et al. 1996b) are very close to those of the BoA plant, data from (Köhler et al. 1996b) are assumed to be representative for the construction of the reference BoA plant. The overall electricity mix used for modeling construction is based on statistical electricity production data from year 2000 in UCTE and CENTREL areas, which were separately modelled in ecoinvent (Frischknecht et al. 2004), in order to approximate average European conditions. An occupation area of 134’000 m2 is reported in (Köhler et al. 1996b). The shares of different land use categories are assumed as 70% industrial area and 30% road area, along with what assumed for the hard coal power plant. The dismantling of the power plant is modelled using the ecoinvent datasets “disposal, building, xx” (Doka 2003), which describe the energy requirements for dismantling of the buildings, components and other parts of the plant as well as the emissions during dismantling and transport of the dismantled materials to the disposal facilities. Plastics, construction wood and bitumen are assumed to be finally disposed of. Concrete (including reinforcement), steel (as bulk iron) except of steel used for reinforcement, mineral wool, glass and masonry are assumed to be delivered to a sorting plant preceding final disposal or recycling. All metals except steel are assumed to be directly recycled.

The modeling of the operation of the reference lignite power plant is as far as possible based on currently available data from the plant “Niederaussem K” in Germany. According to (RWE 2006, 2005) emission factors for SO_2, NO_x, and PM_{10} per kWh electricity are 30% lower compared to the previously installed lignite power plant units Niederaussem. This corresponds to the ratio of net efficiencies of 30% of the old units vs. 43.2% of the BoA unit. Therefore the emission factors per MJ (thermal) lignite input, available for the same power station in the PSI-internal database used in (Röder et al. 2004), are assumed identical for the new BoA-unit. Other emission factors not directly available for Niederaussem (e.g., trace elements) and operational flows have been extrapolated from the dataset of the average German lignite power plant operational around 2000 described in (Röder et al. 2004), on the basis of the ratio of the respective efficiencies. The efficiencies of pollution control systems in Niederaussem, i.e. de-SO_x (97.5%) and de-NO_x (80%), are among the highest values for currently installed European lignite power plants.

[26] „Luvo“ is an acronym for „Luftvorwärmung“ meaning preheating of the combustion air.

Table 3.3 Technical data of the reference lignite Power Plant investigated in NEEDS.

Gross Power	[MW_e]	1012
Net Power	[MW_e]	950
Technical Life Time[27]	[a]	35
Load	[h/a]	7760
Net Electricity Generation (over the life time)	[TWh]	258
Gross Efficiency	[%]	46.0
Efficiency loss for auxiliary power	[%]	2.8
Net Efficiency	[%]	43.2

3.1.2 Integrated Gasification Combined Cycle technology description

Integrated Gasification Combined Cycle (IGCC) is an emerging advanced power generation system having the potential of generating electricity from coal with high efficiency and lower air pollution (NO_x, SO2, CO and PM10) than other current coal-based technologies (Australian Coal Association 2004, WCI 2005a), down to levels comparable to those of natural gas-based power production (DOE 2001).

An IGCC power plant consists of a gasification unit and a gas-fired combined-cycle unit. In the gasification unit fuel gas is produced from the coal (or other solid or liquid combustibles). This high temperature coal gas is firstly cleaned then fired in a gas turbine. A power generator coupled to the gas turbine generates electricity. The high temperature exhaust of the gas turbine still has enough heat to produce super-heated steam in a steam generator belonging to a conventional steam cycle. The super-heated steam drives a conventional steam turbine and produces electricity in a connected second generator. This use of two thermodynamic cycles in cascade, which gives the name of "combined cycle" to the technology, explains why gasification-based power systems can achieve high power generation efficiencies. The process flow of an IGCC power plant is pictured in Figure 3.5.

[27] Since there is only limited experience with this type of lignite power plant, the technical lifetime of 35 years is an assumption, made consistently with other fossil power plants within NEEDS RS1a.

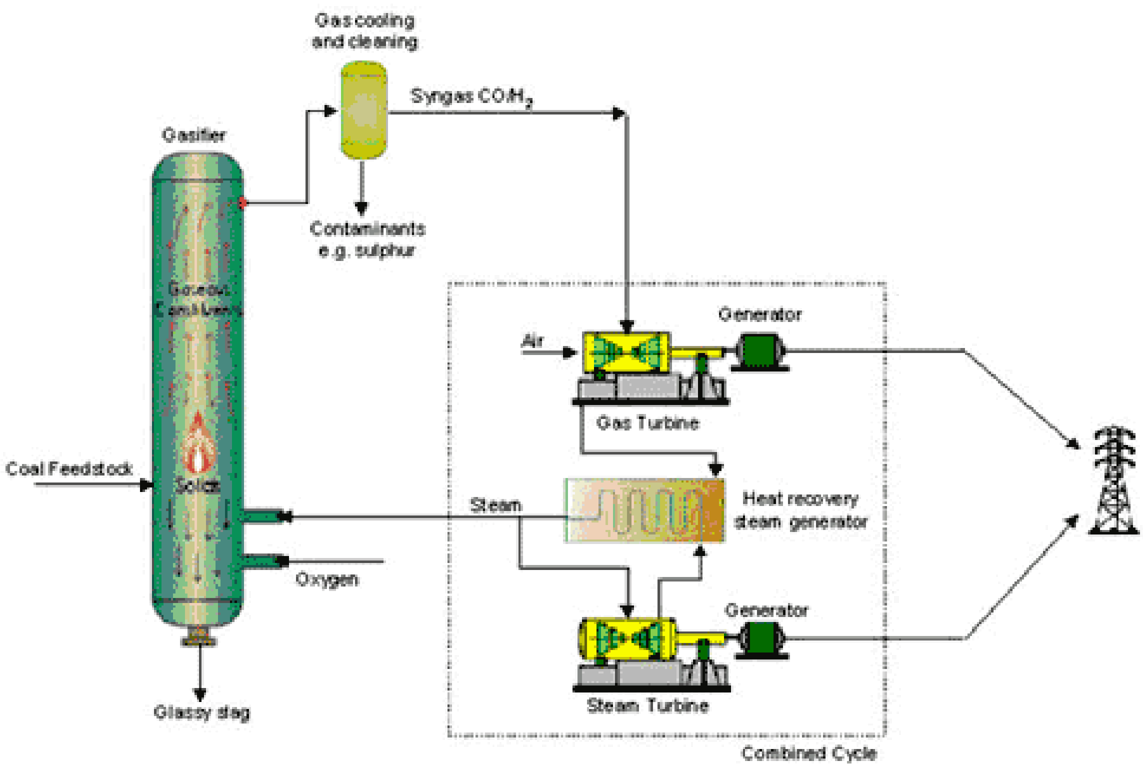

Figure 3.5 Simplified process flow of an IGCC power plant (CCSD 2002)

3.1.2.1 Coal gasification

The gasifier converts the hydrocarbon feedstock into gaseous components by applying heat under pressure in the presence of oxygen or steam. A gasifier differs from a combustor in that the amount of air or oxygen available inside the gasifier is carefully controlled to facilitate partial oxidation. Only a relatively small portion of the fuel burns completely, the main reaction is the generation of incomplete burned hydrocarbons from feedstock as gaseous constituents. The produced synthesis gas or “syngas” is primarily made of hydrogen and carbon monoxide. Figure 3.6 shows an example of an entrained flow gasifier (CCSD 2002).

Minerals in the fuel (i.e., the rocks, dirt and other impurities that don't gasify like carbon-based constituents) separate and for the most part leave the bottom of the gasifier either as an inert glass-like slag or other marketable solid products. Only a small fraction of the mineral matter is blown out of the gasifier as fly ash and requires removal downstream. The high temperature syngas leaving the gasifier is cleaned from impurities before being fired in a gas turbine. There are two pathways for syngas cleaning, either wet scrubbing (cold conditions), which is presently applied, or gas cleaning in hot conditions. The wet scrubbing process is technically proven and commercially applied in the industry, but when applied to IGCC power plants it lowers the efficiency of the plant by some 2% to 3%. This is due to loss of sensible heat in the gas during scrubbing. This loss can be prevented by cleaning the gas in hot condition. Hot gas cleanup is ultimately desired for IGCC, but presently this technology is still under development and is not commercial applicable.

Sulfur impurities in the feedstock form hydrogen sulfide, from which sulfur can be easily extracted, typically as elemental sulfur or sulfuric acid, which both are marketable byproducts notwithstanding low market prices. Over 99% of the sulphur present in the coal can be recovered for sale as chemically pure sulphur (Australian Coal Association 2004). Nitrogen oxides, another potential pollutant, are not formed in the (reducing) environment of the gasifier. Instead, ammonia is created by nitrogen-hydrogen reactions. The ammonia can be easily stripped out of the gas stream. As much as 95 to 99% of NO_x and SO_2 emissions are removed (DOE 2004, WCI 2005a; WCI 2005b).

IGCC plants are characterized by the type of gasifier and the oxidant fed to the gasifier (oxygen or air) (Bernero 2002). Most IGCC plants in operation or under construction use entrained flow gasifiers, which are oxygen blown (Financing IGCC 2004). Since pure oxygen isn't diluted by the large quantities of nitrogen present in air, oxygen-blown coal gasifiers can be more efficient. Making oxygen today, however, typically involves an air separation unit with a complex, energy-intensive super-cooling (cryogenic) process to extract oxygen from the air (DOE 2004b). Only one IGCC plant is currently based on a fluidized bed gasifier, which is air-blown (IEA Clean Coal 2005a). The commercial gasification processes believed most suited for near-term IGCC applications using coal or petroleum feedstocks are the ChevronTexaco, Conoco Phillips, and Shell entrained-flow gasifiers. Each of these technologies is currently used at a commercial IGCC facility. (Financing IGCC 2004). In this study an oxygen-blown Texaco entrained-flow gasifier is considered.

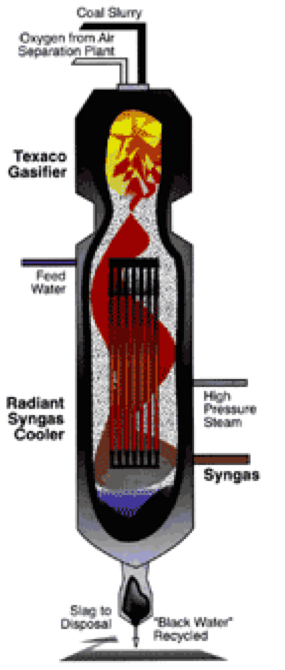

Figure 3.6 Texaco Entrained Flow Gasifier (CCSD 2002).

3.1.2.2 Feedstock and products

In addition to its high efficiency potential and excellent environmental performance, IGCC technology features relatively high flexibility concerning feedstocks. Besides hard coal, IGCC power plants can be fuelled by lignite, biomass, municipal and other solid wastes or residues of the petrochemical industry (DOE 2004b). However, the choice of feedstock determines the selection and the design of the gasifier.

Besides electricity production, alternative products can be generated via coal gasification. Meanwhile coal gasification is an established route for producing hydrogen and there is considerable potential for hydrogen-producing IGCC plants (PowerClean 2004) especially attractive when coupled with CO_2 capture and sequestration (see dedicated Chapter below).

The syngas from coal gasification can also be used to produce chemicals and liquid fuels as well as for upgrading of refinery and petrochemical feedstock. These products have the potential to offset the cost of electricity generation using IGCC (Australian Coal Association 2004). This capability of co-production makes coal gasification one of the most promising technologies for the energy plants of tomorrow (DOE 2001).

Furthermore it is possible to produce ultra-clean fuels from syngas via Fischer-Tropsch synthesis (DOE 2001). These fuels contain no sulphur or nitrogen and are virtually free of aromatics. Fischer-Tropsch derived diesel fuel is of excellent quality, having a cetane number greater than 70, and can be used as a blending stock for low-sulphur gasoline production.

Besides fuel, the syngas can be used to produce methanol or higher alcohols. From methanol again several chemicals, such as formaldehyde, acetic acid, and other derivatives can be processed.

Co-production is of particular relevance for LCA. Since there are several end-products it is necessary when balancing an IGCC power plant with co-production to allocate the resources used and the emissions released to each of the respective co-products. However, modeling for RS1a WP7 will be limited to electricity production only.

3.1.2.3 Present market and use of IGCC technology

Despite the worldwide commercial use and acceptance of gasification processes and natural gas combined cycle power systems, until recently IGCC was still cited not to be established as a mature technology for electricity generation (Financing IGCC 2004). It is still characterized as ‘at demonstration stage’ (EC 2001) or as ‘near commercial technology‘ (Australian Coal Association 2004).

Each major component of IGCC had been broadly utilized in industrial and power generation applications, but the integration of a gasification unit with a combined cycle power block to produce commercial electricity as a primary output is relatively new. The technology has been demonstrated at only a handful of facilities around the world. The milestone facilities of coal-based IGCCs are shown in Table 3.4. Most plants in Table 3.4 are around the size of 250 MW_e, which mainly has its reason in the specification of the gasifiers. As gasifiers constitute pressure vessels, in general they cannot be manufactured on site but need to be transported. Hence, due to their weight and sheer size, capacities much above 300 MW_e are not likely (IEA Clean Coal 2005a).

Table 3.4 Coal fuelled IGCC plants worldwide. Source: Financing IGCC 2004; Mayer 2006.

	Cool Water Demonstration Plant	Wabash Power Station	Polk Power Station	Willem Alexander	Vresova[28]	Puertollano
Location	California, US	Indiana, US	Florida, US	Netherlands	Czech Republic	Spain
Capacity (MW net)	120	262	250	253	350 (430)	298
Gasifier	Texaco	Conoco Phillips	Chevron Texaco	Shell	Lurgi	Prenflo
Gas Turbine	GE 7E	GE MS 700IFA	GE MS 700IFA	Siemens V 94.2	GE 209E	Siemens V 94.2
Efficiency (% HHV)	33	39.7	37.5	41.4	41 (44)	41.5
Fuel Feedstock	Bituminous coal	Bit. coal / pet coke	Bit. coal/ pet coke	Bit. coal	Lignite	Bit. coal / pet coke
Start of Operation	1984	1995	1996	1994	1996 (2005)	1998

The IGCC plant in Cool Water in 1984 showed the technical feasibility of IGCC. The commercial feasibility was demonstrated at Polk Tampa Electric in 1996. Two variants of the entrained bed concept have been demonstrated at the commercial prototype scale at Buggenum (Netherlands) and at Puertollano (Spain). Both plants operate reasonably reliable with efficiencies of over 42% and the Puertollano unit is widely regarded as the state of the art operational IGCC technology (Power Clean 2004).

However, meanwhile IGCC technology has further developed and more commercial IGCC power plants are operational at present. According to the recent status report on IGCC power plants by the World Coal Institute, there has been a strong increase of such plants. Currently there are around 160 IGCC plants worldwide (WCI 2005a). Around 16,500 MW_e of IGCC capacity is expected to be operating in the USA by 2020 (WCI 2005a, NMA 2005)

All the current coal-fuelled demonstration plants are subsidized. The European plants are part of the Thermie programme, and in the US, the DOE is partly funding the design and construction, as well as the operating costs for the first few years. Some plants constitute repowering projects, but from the point of view of demonstrating the viability of various systems, they are effectively new plants, even though tied to an existing steam turbine. (IEA Clean Coal 2005b).

3.1.2.4 Hard Coal-fuelled IGCC reference power plant considered in NEEDS

The latest hard coal based IGCC power plant installed in Europe is located in Puertollano, Spain, and has been commissioned in 1998. This IGCC power plant has been taken as basis for the reference power plant considered in NEEDS. However, to some extent the Puertollano IGCC power plant comprises out-dated power plant components, which have been further developed in the meantime and thus would allow capacity and efficiency improvements. Therefore, the reference IGCC power plant considered in NEEDS for year 2005 is an ‘enhanced Puertollano IGCC power plant’, which is modified to a higher net capacity

[28] Only plant in this list firing lignite. Numbers in brackets show a power plant retrofit and optimisation conducted in 2005.

(450 MW_e instead of 300 MW_e). The feedstock mix of hard coal and bitumen used in Puertollano has been changed to a complete hard coal input. Taking into account the assumed hard coal feed, ISO ambient conditions (15°C average ambient temperature, 1,013 bar, 60% relative humidity) instead of local conditions in Puertollano, and technical enhancements in power plant components, the efficiency of the NEEDS reference IGCC power plant is assumed to 45% instead of the efficiency of 42.2% in Puertollano,. For the calculation of the capacity and efficiency of the NEEDS reference IGCC power plant, the outline of the European JOULE-project, at which a concept for an IGCC power plant with higher capacity applying state of the art components based on an optimisation of the Puertollano IGCC power plant concept (EC 2000) had been developed, has been taken into account. This concept represents state of the art IGCC technology and could be built nowadays with current power plant components.

The flow sheet of the IGCC reference power plant considered in NEEDS is pictured in Figure 3.7. Table 3.5 shows the technical data of the IGCC reference power plant. Cost data is presented in Table 2.5. In Table 3.6 the characteristics of the hard coal used in the IGCC reference power plant are listed.

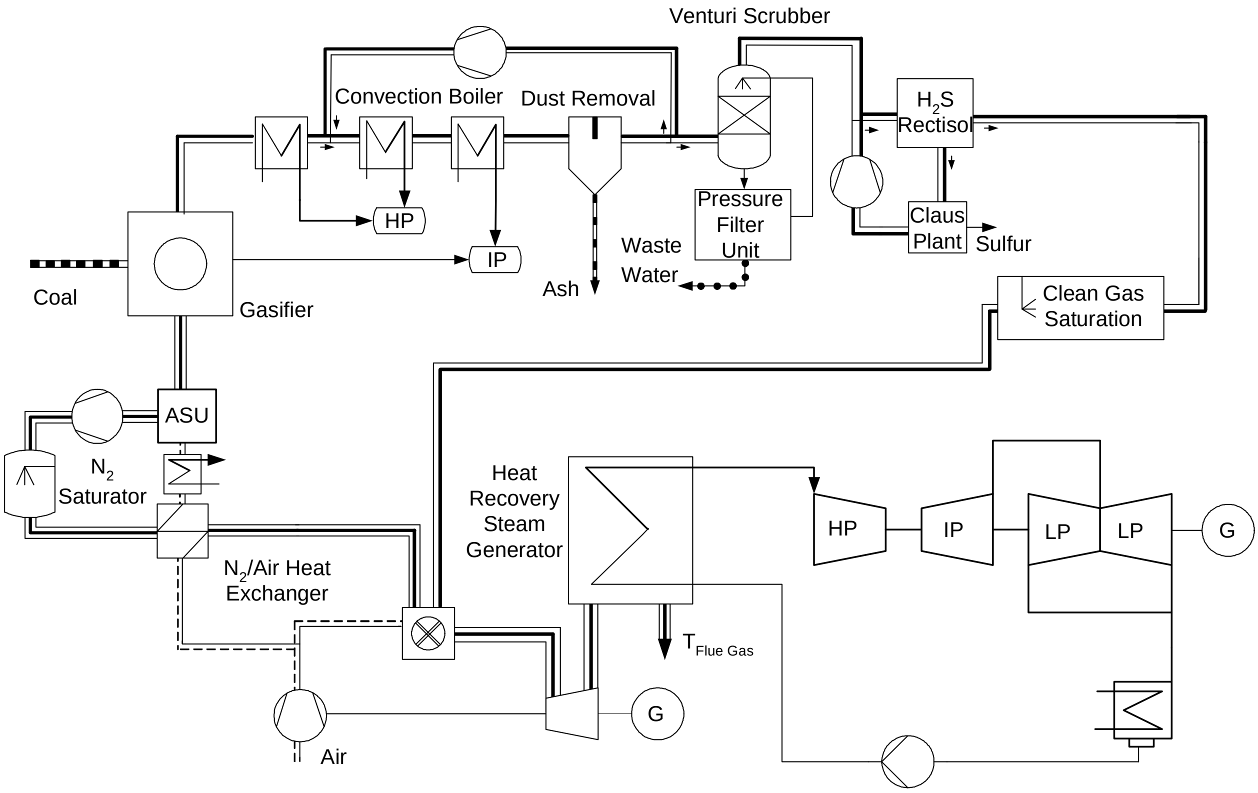

Figure 3.7 Flow sheet of the hard coal IGCC reference power plant investigated in NEEDS. Source: IER based on information from (EC 2000)

Table 3.5 Technical data of the hard coal-fuelled IGCC power plant investigated in NEEDS.

Gross Capacity	[MW_e]	484
Net Capacity	[MW_e]	450
Technical Life Time	[a]	35
Load	[h/a]	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118
Gross Efficiency	[%]	48.3
Efficiency Decrease by Own Consumption	[%]	3.3
Net Efficiency	[%]	45

Table 3.6 Characteristics of the hard coal used in the hard coal-fuelled IGCC reference plant investigated in NEEDS.

Upper Heating Value	MJ/kg	29.1 [a]
Lower Heating Value	MJ/kg	27.7
Water content	% weight	10
Ash content	% weight	6
S content	% weight	3.21

[a] Calculated from the LHV in multiplication by 1.05

3.1.2.5 Lignite-fuelled IGCC reference power plant considered in NEEDS

There is one lignite-fuelled IGCC power plant installed in Europe, which is located in Vresova, Czech Republic. Until 1996 this was a facility designed for town gas production. As however the town gas was replaced by natural gas from Russia, this plant was converted to a unit for electricity generation by installation of two combined cycle units of 200 MW_e. The plant processes about 2,000 tons of local lignite per day (Bucko et al. 1999). As output the Vresova complex generates electricity, but also makes briquettes and produces steam. In the scope of NEEDS the lignite-fuelled IGCC reference power plant is considered without co-production and only electricity is modelled as output. Thus the entire capacity of 400 MW_e of the Vresova power plant is modeled for electricity generation. According to Bucko et al. 1999 and NETL 2005 in this unit an efficiency of 44% is achieved, which is also applied for the lignite-fuelled IGCC reference power plant in NEEDS.

The technical and cost data of the lignite-fuelled IGCC reference power plant in NEEDS are shown in Table 3.7 and Table 2.6, respectively. Table 3.8 shows the characteristics of the Czech lignite used in the lignite-fuelled IGCC reference power plant.

Table 3.7 Technical data of the lignite-fuelled IGCC reference Power Plant investigated in NEEDS.

Gross Capacity	[MW_e]	430
Net Capacity	[MW_e]	400
Technical Life Time	[a]	35
Load	[h/a]	7,500
Net Electricity Generation (over the life time)	[TWh_e]	105
Gross Efficiency	[%]	47.3
Efficiency Decrease by Own Consumption	[%]	3.3
Net Efficiency	[%]	44

Table 3.8 Characteristics of the lignite used in the lignite-fuelled IGCC reference power plant investigated in NEEDS.

Upper Heating Value	MJ/kg	17.1 [a]
Lower Heating Value	MJ/kg	16.3
Water content	% weight	33.2
Ash content	% weight	30.8
S content	% weight	1.2

[a] Calculated from the LHV times 1.05

3.1.3 Fluidized Bed Combustion (FBC) power plants

Fluidised bed combustion (FBC) is a method of burning coal in a bed of heated particles suspended in an upward gas flow (WCI 2005a). At sufficient flow rates, the bed performs as a fluid. The continuous and fast mixing of the particles promotes nearly complete combustion at lower temperatures than in PC combustion. The maximum gas temperature available from the FBC is limited by ash fusion characteristics, therefore the gas turbines differ from those used in IGCCs and GCCs (IEA Clean Coal 2005b). The primary driving force for the development of fluidized-bed combustion was the reduction in SO_2 and NOx emissions at the combustor (Bernero 2002). The relatively low combustion temperature (800-900°C) reduces the production of NOx in the outlet gas compared to PC, but increases the amount of the greenhouse gas N_2O. FBCs produce dramatically less SOx when limestone or dolomite is continuously added to the coal feed. FBCs can also use a wider range of fuels than PCs (WCI 2005a). Relatively coarse particles at around 3 mm size are fed into the combustion chamber (IEA Clean Coal 2005b). The efficiency of most fluidised beds used for power generation is similar to that of conventional plants (WCI 2005a). FBC technologies include: atmospheric pressure fluidized bed combustion (AFBC) and pressurized fluidized bed combustion (PFBC). The development of this technology has been stimulated by its better environmental performance than PCs with lower grade fuels, in particular high ash coals, and/or those with variable characteristics, although PFBC has also been used on a commercial scale in Sweden and Japan with traded coals of higher quality (IEA Clean Coal 2005b). Between 1985 and 1995, installation of FBCs was rapidly growing, but at present they represent less than 2% of the world total coal capacity (IEA Clean Coal 2005b).

3.1.3.1 Atmospheric fluidised bed combustion (AFBC)

Atmospheric-pressure fluidised bed plants are commercially available in two types: bubbling-bed (Bubbling-bed Fluidised Bed Combustion – BFBC) and circulating-bed (CFBC). Both technologies use mainly subcritical steam turbines, together with sorbent injection of limestone or dolomite into the bed for SO_2 reduction and particulates (ash together with reacted sorbent) removal from flue gases. Carbon-in-ash losses are higher in FBC residues that in those from PC. Combustion temperatures of AFBC are between 800°C and 900°C. Air staging can further reduce NOx formation. (IEA Clean Coal 2005b) AFBC are particularly suited for high ash coals, coals with variable characteristics and co-combustion of biomass/waste/coal slurries, and any type or size unit can be repowered, which are all advantages on PC (Decon 2003).

3.1.3.1.1 Bubbling fluidised bed combustion (BFBC) at atmospheric pressure

Bubbling beds use a lower fluidizing velocity than circulating beds. The bed has a depth of about 1 m (IEA Clean Coal 2005b). Sand is often used to improve bed stability, together with limestone for SO_2 absorption. As the coal particles are burned away and become smaller, they are elutriated with the gases, and ultimately removed as fly ash (IEA Clean Coal 2005b). In-bed tubes are used to control the bed temperature and generate steam. The flue gases are normally cleaned using a cyclone, and then pass through further heat exchangers to generate further steam (IEA Clean Coal 2005b).

Atmospheric BFBC is mainly used for boilers up to about 25 MW_e, although there are a few larger plants where it has been used to retrofit an existing unit. There are hundreds of such small BFBC units in China. Overall thermal efficiency is around 30% (IEA Clean Coal 2005b). Low capacity units are of lesser interest for European conditions.

The residues consist of the inert material originally in the coal, most of which does not melt at the combustion temperatures used. Where sorbent is added for SO_2 removal, there will be additional CaO/MgO, CaSO4 and CaCO3 present. In BFBCs, a much higher Ca/S ratio is needed than in atmospheric CFBC in order to remove SO_2. This increases costs, and in particular the cost of residues disposal (IEA Clean Coal 2005b).

3.1.3.1.2 Circulating fluidised bed combustion (CFBC) at atmospheric pressure

Combustion temperatures and NOx/N_2O formation are similar to BFBC. Reduced NOx emissions by 60% when compared with conventional PC technology are reported for CFBC (Decon 2003). SO_2 emissions can be reduced by the injection of sorbent (limestone or dolomite) into the bed, and the subsequent removal of ash together with reacted sorbent, again similarly to BFBCs.

Circulating beds use a higher fluidizing velocity than bubbling beds. The coal particles are constantly held in the flue gases, and pass through the main combustion chamber with very short residence time and vigorous mixing (IEA Clean Coal 2005b). Immediately following, a cyclone, operating at a temperature near that of the exhaust gas, separates the larger particles (unburned coal and ash) to return them back to the combustion chamber. Individual particles may undergo this process anything from 10 to 50 times, depending on their size, and how quickly the char burns away, with residence times in the bed on the order of tens of seconds (IEA Clean Coal 2005b).

CFBCs are designed for the particular coal to be used; the design must take into account ash quantities and properties.[29] Circulating beds are suited for low grade, high ash coals which are

[29] "Fuel flexibility often mentioned in connection with FBC units can be misleading." It does refer to the

difficult to pulverise, and which may have variable combustion characteristics. CFBCs are also appropriate for co-firing coal with low grade fuels, including some waste materials (IEA Clean Coal 2005b).

The finest fly-ash leaves the cyclone with the flue gases, and is normally separated by using an ESP. The fly-ash can contain quite high proportions of carbon, possibly up to 15% (IEA Clean Coal 2005b)

Atmospheric CFBC is used in a number of units around 250-260 MW_e size, and there are a number of commercially operating plants (IEA Clean Coal 2005b). New units are being built up to 300 MW_e size, and there are designs for units up to 600 MW_e size (IEA Clean Coal 2005b). However, CFBC boilers are used more extensively by industrial and commercial operators in smaller sizes, both for the production of process heat, and for on-site power supply. A few are used by independent power producers, mainly in sizes in the 50 MW_e to 100 MW_e range (IEA Clean Coal 2005b).

In the 100-200 MW_e range, the thermal efficiency of FBC units is commonly lower than that for equivalent size PC units by 3 to 4 percentage points (IEA Clean Coal 2005b). The reasons are manifold. In CFBCs, the heat losses from the cyclone are considerable. High heat losses are associated with the removal of both ash and spent sorbent from the system, in spite of the ash heat recovery systems. The use of a low grade coal with variable characteristics tends to result in lower efficiency (IEA Clean Coal 2005b).

The residues consist of the original mineral matter, most of which does not melt at the combustion temperatures used, like in BFBCs. Where sorbent is added for SO_2 removal, there will be additional CaO/MgO, $CaSO_4$ and $CaCO_3$ present, although in less amounts than in BFBCs (IEA Clean Coal 2005b).

3.1.3.2 Pressurised fluidised bed combustion (PFBC)

Pressurized fluidized bed combustion (PFBC) is a FBC technology where the combustor and hot gas cyclones are all enclosed in a pressure vessel. Both coal and sorbent for sulphur removal have to be fed across the pressure boundary, and similar condition applies for ash removal, which introduces some significant operating complications compared to AFBC designs. With hard coal as fuel, the coal and limestone can be crushed together, and then fed as a paste, with 25% water.

Figure 3.8 shows a simplified flow diagram of a PFBC power plant.

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capability to burn different coal qualities but in different appropriate units. “Once the unit is built, it will operate most efficiently with whatever design fuel is specified.” (IEA Clean Coal 2005b)

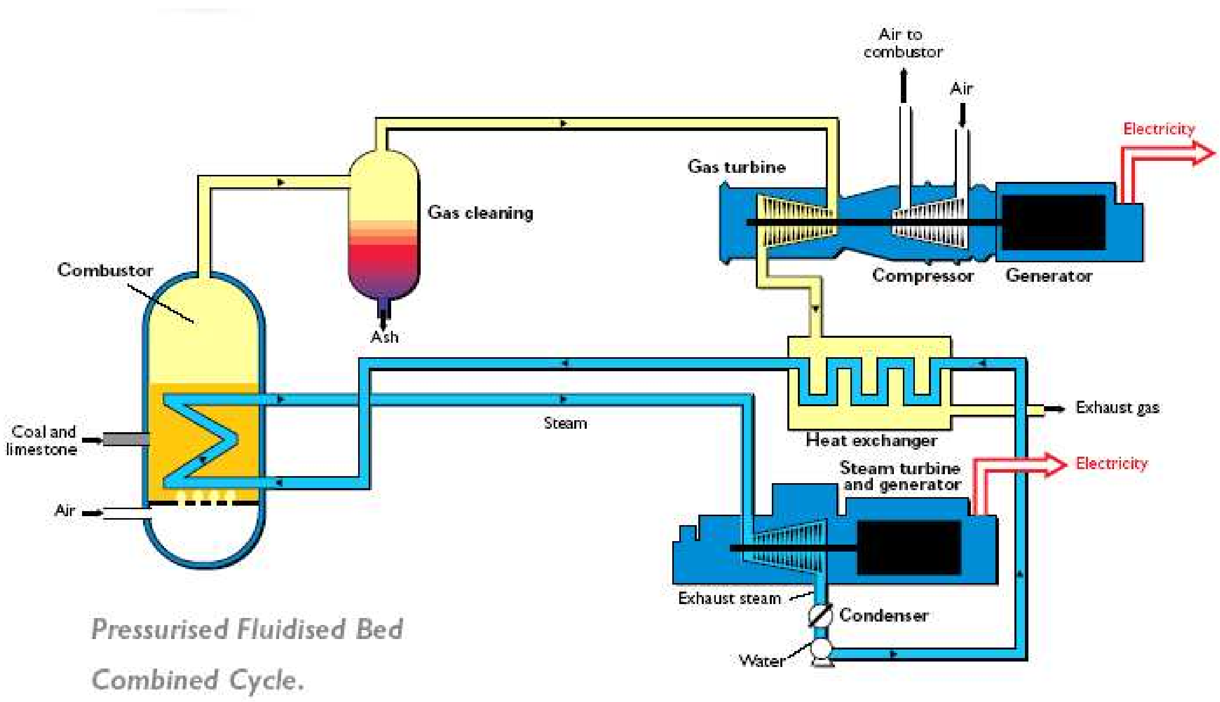


Figure 3.8 Simplified scheme of a PFBC power plant (WCI 2005a).

As with AFBC, bubbling beds as well as circulating beds are possible. However, currently commercial-scale operating units all use bubbling beds (first generation of PFBC), and hence the name PFBC is normally used to refer to the latter technology (IEA Clean Coal 2005b). Gas and steam are produced which are driving a combined cycle. The combustion air is pressurized in the compressor section of the gas turbine. PFBC is a combined cycle technology. The proportion of electricity produced at the steam:gas turbines is approximately 80%:20% (IEA Clean Coal 2005b).

Considerable efforts have been made for the development of PFBC during the 1990s especially in Sweden and Japan, with traded coals of high quality, but also in Germany, Spain, and the USA (IEA Clean Coal 2005b). PFBC has been deployed at commercial scale. However, the number of installations is still small and it is likely to remain a niche technology (PF 03-05 2003).

The pulverized coal is burned at 1-1.6 MPa and at relatively low temperature, approximately 800°C to 900°C (IEA Clean Coal 2005b; Dones et al. 1996). The maximum gas temperature must be kept around 900°C in order to prevent ash softening and alkali metals vaporisation, otherwise they will re-condense elsewhere in the system. As a result, a high pressure ratio gas turbine with compression inter-cooling is used (IEA Clean Coal 2005b).

Limestone is added into the combustion chamber (approximately 6500 kg/GWh$_{th}$ (PFBC, 1991)), reacting with sulphur to yield calcium sulphate (gypsum). The efficiency of this process depends on the Ca/S ratio and can reach 97% (PFBC, 1991). If an excellent coal quality is chosen, the SOx production may decrease to about 18 kg/GWh$_{th}$, whereas for lower fuel quality, the double can be assumed. Conditioned by the low combustion temperature, only very low NOx is produced 36 kg/GWh$_{th}$, but N_2O emissions increase to 72-216 kg/GWhth compared to 1.8 kg/GWh$_{th}$ generated in PCs (Dones et al. 1996).

From the combustion chamber the flue gas is routed to cyclones and other dust removal systems. The cleaned flue gas drives gas turbines that contribute 25% to 30% to the total electricity generated by the plant. Moreover, the turbine drives an air compressor to keep the combustion chamber under pressure. Before reaching the stack, the flue gas is further used to preheat the feedwater for the steam cycle.

Heat release per unit bed area is much greater in pressurized systems than in AFBCs. Bed depths of 3-4 m are required in order to accommodate the heat exchange area necessary for the control of bed temperature (IEA Clean Coal 2005b). At reduced load, bed material is extracted (IEA Clean Coal 2005b).

PFBC units are intended to give an efficiency value of over 40%, and low emissions. Current commercial PFBC achieve efficiencies of up to 45% (WCI 2005a).

The current PFBC demonstration units are all of about 80 MW_e capacity, but two larger units have started commercial operation in Japan at Karita (New Unit 1, owned by Kyushu Electric Power, July 2001 (WCI 2005b)) and Osaki (IEA Clean Coal 2005b). These are of 360 MW_e and 250 MW_e capacity, respectively. The Karita unit uses supercritical steam with 241 bar/565°C/593°C (IEA Clean Coal 2005b; Bernero 2002). The Karita facility uses in-furnace desulphurisation, denitrification equipment, and two-stage cyclones and an electrostatic precipitator to reduce dust emissions. The plant achieves net efficiency levels of around 41% (WCI 2005b).

From the environmental point of view, the technology has several advantages. Practically no thermal NOx is produced due to the relatively low combustion temperatures. However, about 10% of the nitrogen in the fuel is converted to NOx. Conversely, substantial emissions of N_2O occur. The in-bed sulfur absorption by dolomite or limestone injection is amplified by the elevated operation pressure. Within the bed operation temperature range, H_2S and SO_2 generated from fuel-sulfur can be absorbed within the beds. Sulfur exits the PFBC system as solid sulphate with ash, allowing easy handling. Thus, 98-99% of SO_2 can be removed. The result is SO_2 emissions of 0.19 g/kWh at 3.65% sulphur content in the coal and 99% SO_2 removal (Bernero 2002). Another advantage is that NOx, SOx, and CO are quite independent in a pressurized process, therefore very low emissions of all three pollutants can be achieved at the same time. Since excess oxygen is available in the fluidized bed, H_2S emissions are at or below detectable amounts and carbonyl-sulfide cannot be detected as well. Also the carbon monoxide emissions are negligible (less than 20ppm) under the pressurized operation (Bernero 2002).

As for other FBCs, the residues consist of the original mineral matter contained in the coal feed and additional CaO/MgO, $CaSO_4$ and $CaCO_3$ due to the used sorbent for sulphur removal. For the construction of the plant, a higher amount of high quality steel is required for a PFBC in comparison to a PC because of the higher pressures involved.

3.2 Natural gas technologies

3.2.1 Gas Combined Cycle (GCC) power plants

3.2.1.1 Description of combined cycle technology

A combined cycle power plant includes one or more gas turbines and one or more steam turbines. Figure 3.9 illustrates the principle of a combined cycle power plant with one gas turbine and one steam turbine. The exhaust gas from the gas turbine is used as heat source for the steam generator which supplies steam to the steam turbine.

Currently, a large number of commercial Gas Combined Cycle (GCC) power plants utilizing the Brayton Cycle gas turbine and the Rankine Cycle steam system with exhaust from combustion and water as working fluids are installed in various countries worldwide. Due to its high thermal efficiency and the relatively low capital costs for construction, and its reliability this technology has been largely expanding in the last two decades.

The Brayton Cycle has high source temperature and its sink temperature is high enough to be used as the energy source for the Rankine Cycle. Besides the most commonly used working fluids exhaust from combustion and steam, GCC can use organic fluids, potassium vapor, mercury vapor, and others, which have been applied on a limited scale (Chase 2004). Systems with these fluids will not be addressed in the study.

CC technology is fuel flexible. Besides natural gas, CC plants can operate efficiently also burning distillate oil fuels, ash-bearing crude oil, residual oil fuels, and coal-derived gas fuels (Chase 2004).

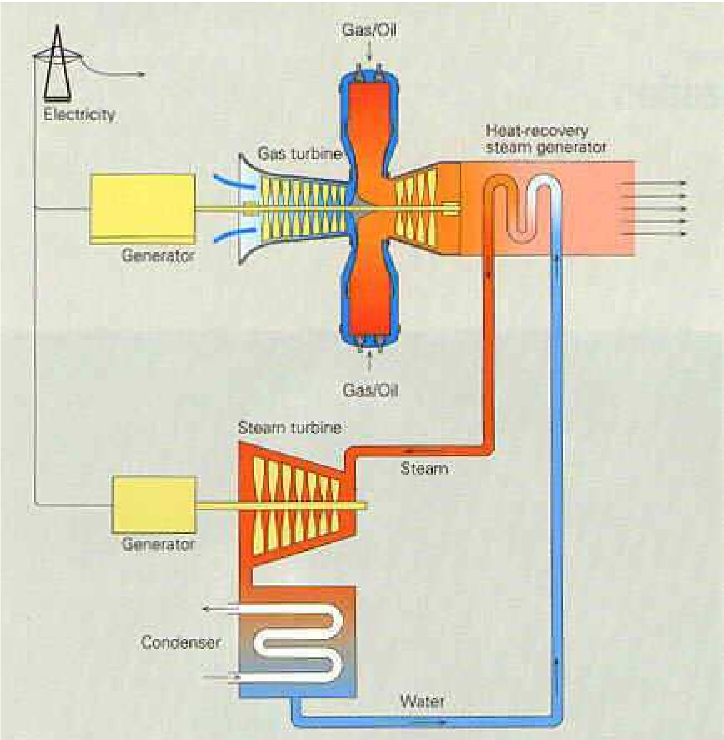


Figure 3.9 Schematic figure of a combined cycle power plant (Siemens 2002)

The gas turbine is an essential component of a combined cycle power plant. The development of gas turbine technology has direct consequences for the technical progress of combined cycle plants. The technology of gas turbines is described in Chapter 3.2.2.

Actually, the first gas turbine (GT) installed in 1949 in an electric utility in the USA was applied in a combined cycle. This was a 3.5 MW GT, whose exhaust heated feedwater for a 35 MW conventional steam unit (Chase 2004). The commercial development of CC systems has proceeded in parallel with GT development (Chase 2004). General Electric (GE) produces presently the third generation technology, with the fourth generation available on the market soon within this decade (Chase 2004).

The refurbishment of gas steam power plants with GT and heat recovery steam generators (HRSG) is still attractive in many applications today (Chase 2004).

GCC has a relatively flexible duty cycle. GCC provides flexibility in operation for both base-load and mid-range duty with daily startup (Chase 2004). GCC also provides efficient operation and excellent efficiency at part load, particularly for multiple gas turbine combined-cycle systems (Chase 2004). Flexibility provided by GCC with air/water fluids satisfies also industrial cogeneration applications (Chase 2004).

Combined-cycle equipment is pre-engineered and factory-packaged as much as possible to minimize installation time and cost (Chase 2004). All major and most auxiliary equipment is shipped to the construction site as assembled and tested components. This minimizes installation time and cost (Chase 2004). Although for the above reasons CC equipment cost is higher than that for conventional steam power plants, CC plant installation time and costs are significantly lower (Chase 2004).

Typical total time between commitment of the plant and its start-up commercial operation is according to (Chase 2004) approximately 30 months (Chase 2004). Of this, strictly construction period lasts about 14 months, and pre-operation and operation checkout about 3 months (Chase 2004). However, when gas turbines are installed the plant can start operation in simple-cycle mode during the steam-cycle equipment installation (phased installation), which enables the user to generate power and revenue in as little as a year from order date (Chase 2004).

High reliability of CC system operation results from evolutionary design development. High availability is achieved through development of good operation and maintenance practice of utility operators (Chase 2004).

Low operation & maintenance costs are achieved through quality design, appropriate operation, and equipment design (Chase 2004).

GT generators are designed and manufactured in discrete frame sizes (Chase 2004). For example, the GE heavy-duty, gas turbine-packaged power plant product line includes units covering an output range of approximately 37 MW to 250 MW (Chase 2004). GCC units can have single or multiple GT installed (Chase 2004).

The third generation GE “F” Technology gas turbine was designed in the 1980s with the aim at optimization for combined cycle peak efficiency rather than simple cycle peak efficiency (Chase 2004). It has been commercialized in 1990. It has pressure ratio of about 14:1 and firing temperature of ~1300°C (Chase 2004). Table 3.9 from (Chase 2004) shows GE third generation CC system characteristics. Table 3.10, again from (Chase 2004), shows a list of installed CC using GE third generation technology.

Table 3.9 GE third generation CC system characteristics (Chase 2004)

Gas Turbines	70-250 MW (MS6001FA, MS7001FA, MS9001EC and MS9001FA)
Application	Heat Recovery Feedwater Heating CC in the 1990s
Steam Cycle	Reheat, Three Pressure
Emission Control	DLN Combustion with Natural Gas and Water / Steam Injection with Oil Fuels plus SCR Installed in the HRSG
Fuel	Natural Gas / Distillate Oil / Low Btu Gas

Table 3.10 GE third generation CC experience (Chase 2004), illustrative table.

60 Hz. STAG Combined Cycle Experience with iF i Te chnology Gas Turbine

Country	Installation	Configuration	COD	Output (MW)
USA	Virginia Power #7	S107F	1990	214
USA	Virginia Power #8	S107F	1992	218
Korea	KEPCO Seo-Inchon #1 & #2	8 x S107F	1992	1887
USA	Sithe Independence	2 x S207FA	1995	1062
USA	Tampa Electric, Polk Co.	S107FA	1996	313
Korea	KEPCO Seo-Inchon #3 & #4	2 x S207FA	1996	1004
USA	US Gen. Co., Hermiston	2 x S107FA	1996	425
USA	Crockett Cogen	S107FA *	1996	202/248
Mexico	CFE Samalayuca	3 x S107FA *	1998	506
USA	Cogentrix, Clark Co.	S107FA *	1998	254
USA	Ft. St. Vrain	S207FA	1999	487
Korea	KEPCO, POSCO	S207FA	1999	498
Columbia	EPM LaSierra	S207FA	2001	478
USA	Bucksport Energy	S107FA	2001	176
USA	Westbrook	S207FA	2001	528
USA	Santee Cooper	S207FA	2001	600
Korea	Pusan	4 x S207FA	2003/4	2000

*Single-shaft Combined Cycle

Number of gas turbines = 45 Units

Installed Capacity = 12,411 MW

50 Hz. STAG Combined Cycle Experience with iF i Te chnology Gas Turbine

Country	Installation	Configuration	COD	Output (MW)
Japan	TEPCO, Yokahama	8 x S109FA *	1996/7	2800
China	China Power & Light	8 x S109FA *	1996/72	2731
Japan	TEPCO, Chiba	4 x S109FA *	1998	1440
India	Enron, Dabhol I	S209FA	1998	698
Chile	Renca	S109FA	1998	370
Netherlands	AKZO, Delesto	S109FA *	1999	364
U.K.	Sutton Bridge	S209FA	1999	800
Thailand	Ratchaburi	3 x S209FA	2000	2130
Argentina	Central Puerto	S209FA	2000	769
Japan	Hitachi Zosen	S106FA	1999	106
U.K.	Tri-Energy	S209FA	2000	700
U.K.	Great Yarmouth	S109FA *	2001	407
India	Enron, Dabhol II	2 x S209FA	2001	1600
Japan	TEPCO, Futtsu 3	4 x S109FA *	2002	1590
Spain	Castellon	S209FA	2002	285

* Single-shaft Combined Cycle

Number of gas turbines = 50 units

Installed capacity = 17,795 MW

Table 3.11 shows some technical data on current natural gas combined cycle plants from literature or manufacturers.

Table 3.11 Technical key parameters for current natural gas combined cycle plants

Parameter	Unit	2000	2005	Reference
General NGCC data:				
Net electric efficiency	%		58	Bachmann 2005
	%		52.9-57.8	ALSTOM 2005
	%		58	IEA 2004, high estimate
	%		50	IEA 2004, low estimate
	%	57		DWTC 2001
	%		55	Boyce 2006
Maximal net electric efficiency	%	58.4		Siemens Mainz-Wiesbaden power plant (2001)
Technical lifetime	a		25	Boyce 2006
Time from planning to completion	months		22-24	
Specific NGCC data:				
Capacity	MW_e		410	ALSTOM 2005
Net electric efficiency	%		57.8	
Technical lifetime	a		25	
Construction time	months		24	

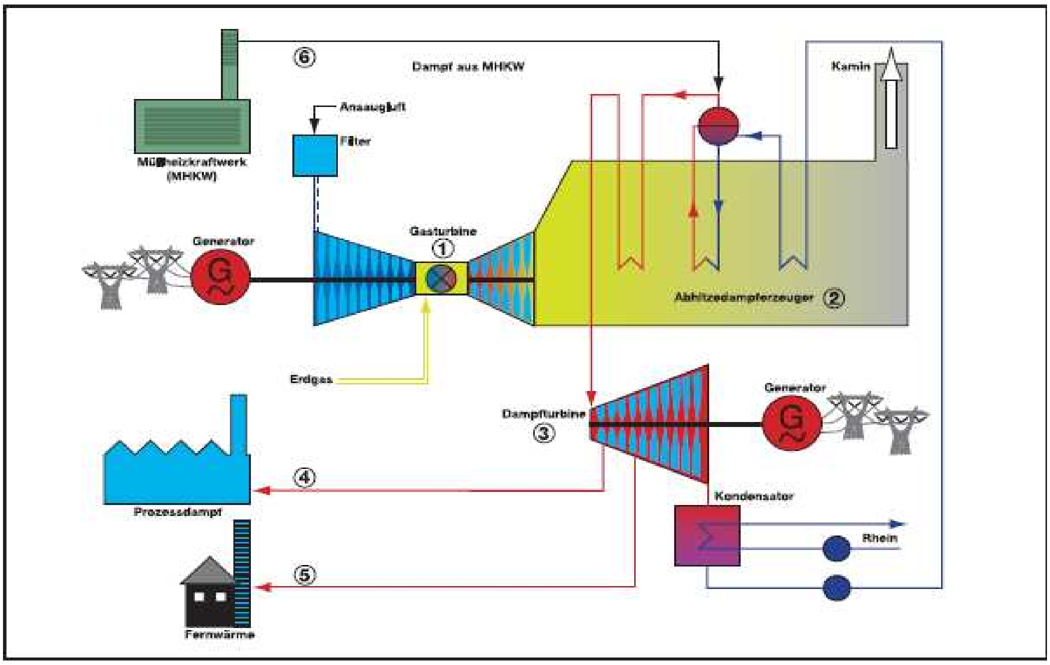
Table 3.12 shows some cost data for current natural gas combined cycle power plants from literature or manufacturers, which have been used to specify the costs of the modelled NGCC plants.

Table 3.12 Cost data for current natural gas combined cycle plants

Parameter	Unit	2000	2005	Reference
General NGCC data:				
Total capital costs	US$/kW		515-724	IPCC 2005
Investment costs	$US\$_{1990}$/kW		370	Claeson Colpier & Cornland 2002
Investment costs	€/kW	500		DWTC 2001
Capital costs	US$/kW		600-900	Boyce 2006
O&M (fixed)	$/MWh		0.35	
O&M (variable)	$/MWh		4.0	
Share initial costs	%		8	
Share maintenance costs	%		17	
Share fuel costs	%		75	
Investment costs	US$/kW	600		Barreto 2001
O&M (fixed)	US$/kWa	36.6		
O&M (variable)	US$/kWa	19.7		
400 MW NGCC:				
Capacity	MW_e		410	ALSTOM 2005
Net electric efficiency	%		57.8	
Total capital costs	€/kW		434	
Installation costs, plant (turnkey)	€/kW		366	
Other capital costs	€/kW		68	(approval by authorities, land etc. for Switzerland) ALSTOM 2005
O&M (fixed)	€/MWa		8839	ALSTOM 2005
O&M (variable)	€/MWh		2.01	

3.2.1.2 Natural gas combined cycle plant considered in NEEDS

The modelled reference natural gas combined cycle power plant is based on data of the 400 MW_e plant Mainz-Wiesbaden in Germany. The scheme of the Mainz-Wiesbaden GCC plant is shown in Figure 3.10. It started operation in year 2001. (The waste incineration plant (MHKW) included in Figure 3.10 started operation in year 2004 and since then delivers additional heat to the steam generator. Furthermore, the GCC can operate in CHP mode and supply heat for long-distance heating and steam for industry. These heat components and the CHP mode are not considered here.) The technical data sheet of the Mainz-Wiesbaden plant specifies a total net electric capacity of 406 MW_e (KMW 2002a, b). The gas turbine of the plant is a Siemens V94.3A2 model with a nominal capacity of 265 MW_e. The steam turbine supplies about 140 MW_e. According to the operators, the Mainz-Wiesbaden plant is the natural gas combined cycle power plant with the highest actual net electric efficiency worldwide of 58.4% (as of year 2001) (KMW 2002a). However, considering that the thermal efficiency depends, among other factors, also on the ambient temperature at the site, definition of an average efficiency for a region like Europe requires estimates of average environmental temperatures and average cooling conditions. Thus, a net electric efficiency of 57.5% is assumed for the current reference best GCC natural gas combined cycle power plant, along with the ecoinvent database (Faist Emmenegger, Heck, Jungbluth 2004). For the modelling, it was assumed that the plant is mainly used for base load operation.



Erdgas = natural gas; Ansaugluft = intake air; Gasturbine = gas turbine; Abhitzedampferzeuger = steam generator; Kamin = chimney; Dampfturbine = steam turbine; Kondensator = condenser; Rhein = river Rhine; MHKW = waste incineration plant; Dampf/Prozessdampf = steam; Fernwärme = long-distance heating.

Figure 3.10 Schematic figure of the 400 MW_e natural gas combined cycle power plant Mainz-Wiesbaden, Germany (Source: KMW (2002a)b).

Table 3.13 and Table 3.14 show the technical data and the costs data, respectively, of the NGCC plant modelled in this study. A life time of about 25 years was assumed after (Boyce 2006; ALSTOM 2005). The costs data have been estimated based on the literature data shown in Table 3.12.

Table 3.13 Technical data of the reference current natural gas combined cycle power plant investigated in NEEDS.

Net Electric Power	[MW_e]	400
Technical Life Time	[a]	25
Load	[h/a]	7200
Net Electricity Generation (over the life time)	[TWh]	72.0
Net Electric Efficiency	[%]	57.5

Table 3.14 Cost data of the reference current natural gas combined cycle power plant investigated in NEEDS.

Spec. investment costs (overnight capital costs)	[€/kW]	440
Spec. demolition costs (greenfield)	[€/kW]	15
Fixed costs of operation	[€/kW/yr]	8.8
Other variable costs	[€/MWhel]	2.0

3.2.2 Gas turbine technology

3.2.2.1 Gas turbine categories

The following categories of gas turbines can be distinguished (Boyce 2006):

– Frame type heavy-duty gas turbines, ranging from about 3 MW to 480 MW.

The "frame type heavy-duty gas turbine" is the classical gas turbine design for large plants. It has been introduced already in the early 1950s. Its main application is electricity generation. At present, new heavy-duty gas turbines can reach turbine inlet temperatures of about 1370°C and pressure ratios of about 35:1. The efficiencies range from 30% to 46% (Boyce 2006). Industrial heavy-duty turbines are using axial-flow compressors and turbines. They include thick casings and other heavy weight components since restriction in weight and size are usually not important for this design. The advantages of the design are a long lifetime, high availability, high efficiency, and relatively low noise level of the gas turbine. Heavy duty gas turbines are also widely used in combined-cycle power plants.

– Aero-derivative gas turbines, typically in the range between 2.5 MW and 50 MW.

Aero-derivative gas turbines have been derived from aircraft turbines. Compared to stationary turbines, gas turbines for aircrafts are designed for a shorter lifetime and therefore are operating at higher temperatures and higher pressure ratios reaching higher efficiencies. Thus aero-derivative gas turbines have been adopted to and optimized for the needs of electricity generation and other stationary applications. Efficiencies range from 35% to 45% (Boyce 2006). An aero-derivative gas turbine consists of an aircraft-derivative gas generator and a free-power turbine. It has a relatively thin casing compared to a heavy-duty gas turbine. In many cases, the axial-flow compressor is divided into a low-pressure section and a high-pressure section. Usually, two gas turbines, a low-pressure and a high-pressure turbine, corresponding to the two compressor sections, are used. The speeds of the high-pressure and low-pressure sections can be optimized. Advantages of the aero-derivative design are the compactness of the gas turbines and a flexible maintenance concept. The gas turbine can be tested at the manufacturer's plant. It can be transported as a complete unit to the final location where it can be installed quickly. The aero-derivative gas turbines are used e.g. in combined-cycle power plants below 100 MW, in particular in remote areas. They are also used by the gas industry for gas transport and by the petrochemical industry e.g. on offshore platforms.

– Industrial type gas turbines, ranging from about 2.5 MW to 15 MW.

The design of industrial type gas turbines is similar to the design of heavy-duty gas turbines. The capacity ranges from about 2.5 MW to 15 MW and the efficiency from about 30% to 35% (Boyce 2006). The thickness of the casing ranges between that of a heavy-duty turbine and that of an aero-derivative turbine. Industrial type gas turbines are still efficient in part load operation. Because the simple-cycle turbine has low efficiency, many industrial type gas turbines use regenerators or recuperators in order to improve the efficiency. Industrial type gas turbines with recuperators can reach efficiencies of about 38% (Boyce 2006).

– Small gas turbines, ranging from about 0.5 MW to 5 MW.

Small gas turbines are designed for power needs between 0.5 MW and 5 MW. In many cases, a small gas turbine includes a single-stage centrifugal compressor, a single side combustor and radial inflow turbines. Efficiencies range from 15% to 25% (Boyce 2006).

– Micro-turbines, typically in the range between 20 kW and 350 kW.

Micro-turbines are usually units with a capacity below about 350 kW. They can be axial-flow or centrifugal-radial inflow units. A common application of micro-turbines is the cogeneration of heat and power.

3.2.2.2 Overview on major gas turbine components

A gas turbine consists of the following major components:

- Compressor

The compressor pressurizes the working fluid. Compressor types are

  - Axial-flow compressors (entrance and exit of the flow are in the axial direction)
  - Centrifugal flow compressors.

- Combustor

The combustor is the chamber where the combustion reaction takes place and where the temperature of the high-pressure gas increases. Combustor types are

  - Annular combustors
  - Can-annular combustors
  - Tubular (side combustors)
  - External combustors.

- Regenerator (optional)

Regenerators are used in order to increase the efficiency of the gas turbine. In most cases, ambient air is compressed and routed to the regenerator which heats the air to about 480°C (Boyce 2006). The hot air from the regenerator is then routed into the combustor. The regenerator reduces the amount of fuel needed to heat up the gas and thus increases the efficiency of the process.

- Turbine expander section

The turbines can be categorizes into two types: Axial-flow turbines and radial-inflow turbines.

Today, most gas turbines are axial-flow turbines. Radial-inflow turbines are a new concept which is not widespread yet. In an axial-flow turbine, the entrance and exit of the flow are in the axial direction, like in the axial-flow compressors. Radial-inflow turbines can be shorter and more compact than axial turbines.

3.2.2.3 Literature data for gas turbines

Table 3.15 shows some technical data on natural gas fired gas turbines from literature and manufacturers. An important key parameter is the electric efficiency. The efficiency of the gas turbine depends on the gas turbine inlet temperature and the pressure ratio.

Table 3.15 Technical key parameters for current gas turbines.

Parameter	Unit	2000	2005	Reference
General GT data				
Net electric efficiency	%		21-45	Boyce 2006
Technical lifetime	a		25	
Time from planning to completion	months		10-12	
Net electric efficiency	%		38	Bachmann 2005
Net electric efficiency			39	eurelectric 2003
Net electric efficiency			33.1-38.1	ALSTOM 2006
Medium-size aero-derivative GT				
Output Power	MW	42.6		General Electric 2001
Nominal thermal efficiency	%	41.2		
Firing temperature	°C	1288		
Exhaust temperature	°C	466		
Pressure ratio		30:1		
Large GT				
Capacity	MW_e		280	ALSTOM 2005
Net electric efficiency	%		38.3	
Technical lifetime	a		25	
Construction time	months		15	
Large GT				
Capacity	MW_e		265	Pauls 2003 (Siemens)
Net electric efficiency	%		38.6	

Table 3.16 shows some cost data for current gas turbines from literature or manufacturers.

Table 3.16 Costs data for gas turbines.

Parameter	Unit	2000	2005	Reference
General GT data				
Capital costs	US$/kW		300-350	Boyce 2006
O&M (fixed)	$/MWh		0.23	
O&M (variable)	$/MWh		5.8	
Share initial costs	%		7-10	
Share maintenance costs	%		15-20	
Share fuel costs	%		70-80	
Investment costs	US$/kW	350		Barreto 2001
O&M (fixed)	US$/kWa	58.5		
O&M (variable)	US$/kWa	16.03		
Medium-size aero-derivative GT				
Output Power	MW	42.6		General Electric 2001
Cost of Gen Set (simple cycle)	US$/kW	346		
Large GT				
Capacity	MW_e		172-280	ALSTOM 2005
Total capital costs	€/kW		235-248	
Installation costs, plant (turnkey)	€/kW		214-227	
Other capital costs	€/kW		20-22	
O&M (fixed)	€/MWa		6299-7874	
O&M (variable)	€/MWh		4.57-5.04	

3.2.2.4 Natural gas turbines considered in NEEDS

For the NEEDS project, a gas turbine of the 50 MW class is modelled. The modelled reference natural gas turbine is not based on a specific operating plant. Instead, general information about gas turbines has been used.

Modern medium size gas turbines can achieve efficiencies of about 38% (Boyce 2002). According to EURELECTRIC, gas turbines in the MW range have efficiencies up to 39% (eurelectric 2003). ALSTOM declares efficiencies between 33.1% and 38.1% for gas turbines (ALSTOM 2006). Siemens reports an efficiency of 38.6% for the large (265 MW_e) V94.3A gas turbine (Pauls 2003). For the electricity production of the reference gas turbine, a net electric efficiency of 38% has been assumed in this study.

Table 3.17 and Table 3.18 show the technical data and the cost data, respectively, of the natural gas turbine modelled in this study.

Table 3.17 Technical data of the reference current natural gas turbine plant investigated in NEEDS.

Net Electric Power	[MW_e]	50
Technical Life Time	[a]	25
Load	[h/a]	5000
Net Electricity Generation (over the life time)	[TWh]	6.25
Net Electric Efficiency	[%]	38.0

Table 3.18 Cost data of the reference current natural gas turbine plant investigated in NEEDS.

Spec. investment costs (overnight capital costs)	[€/kW]	250
Guarding costs for period between shut-down and demolition	[Mio. €]	0
Spec. demolition costs (greenfield)	[€/kW]	9
Fixed costs of operation	[€/kW/yr]	7.8
Other variable costs	[€/MWhel]	4.6

3.2.3 Combined Heat and Power (CHP)

3.2.3.1 Description of CHP technology

The idea of the combined heat and power (CHP) concept is the utilization of the waste heat of a power plant for useful heat. Practically all fossil power plants can provide heat in a CHP mode if necessary. Natural gas CHP plants are available in almost all sizes starting from the smallest CHP with about 2 kW_e for a single family house up to the large combined cycle plants of about 800 MW_e. Nevertheless, an economic use of CHP depends on the demand for heat close to the power plant. Therefore, in particular a market for small CHP plants (between 2 kW_e and about 8 MW_e) has developed in the past decades. Small CHP plants can be integrated into residential or industrial buildings. They are applied to provide space heating for e.g. apartment buildings, office buildings, hospitals, and school buildings. Another common application is the production of process heat for the industry.

An important class of small natural gas CHP comprises the motor CHP plants (or Internal Combustion Engine CHP plants). A motor CHP plant includes a gas motor and a generator. A heat exchanger provides heat to the water circulation of the heating system. Usually, a heat storage is used in order to buffer between the operation of the plant and the demand for heat. Often a heat pump is added for a more efficient use of the heat from the motor.

Lean burn gas motors yield high efficiency with relatively low costs compared to other CHP types. Depending on the emissions limits, lean burn gas motors can operate without catalysts or with catalysts. Selective catalytic reduction (SCR) catalysts can be applied in order to reduce nitrogen oxide emissions from the gas motor. If necessary, an oxidation catalyst can be added for the reduction of carbon monoxide and hydrocarbon emissions.

Lambda1 gas motors apply a three-way catalyst in order to reduce nitrogen oxide, carbon monoxide and hydrocarbon emissions.

The exhaust gas recirculation (EGR) (in German: AGR=Abgasrückführung) motor CHP plant is a relatively new concept. The EGR CHP employs a turbo motor with refeeding of the flue gas in order to improve the electric efficiency. The EGR engine operates in lamba1 mode and is equipped with a three-way catalyst. The EGR CHP combines high efficiency with low NOx emissions.

Table 3.19 shows some technical data on natural gas CHP plants based on information from literature or manufacturers.

Table 3.19 Technical key parameters for current small CHP plants.

Parameter	Electric power kW_e	Electric efficiency%	Thermal efficiency%	Total efficiency%	Year	Reference
Mini-CHP	2	25	65	90	2000	Heck 2004
Lambda1 motor	160	32	55	87	2000	
Lean burn motor	50	30	54	84	2000	
Lean burn motor	200	33	52	85	2000	
Lean burn motor	500	36	46	82	2000	
Lean burn motor	1000	38	44	82	2000	
EGR motor	125-330	37.1-39.1	51.9-51.0	89.0-90.2	2005	Heck & Bauer 2005
Motor unspecified	100	33			2000	BFE 2003
Motor unspecified	400	36			2000	
Motor unspecified	120	33			2000	ASUE 2001
Average, motor unspecified	4.7-8380	34	54	88	2000	

Table 3.20 shows some cost data for current natural gas CHP plants based on information from literature or manufacturers.

Table 3.20 Cost data for current small CHP plants.

Parameter	Unit	2000	2005	El. power (kW_e)	Reference
Gen Set costs	$/kW_e$		250-600	50-7000	Boyce 2006
Capital costs (turnkey)	$/kW_e$		600-1000	50-7000	
Total O&M	$/MWh_e$		5-12	50-7000	
O&M (fixed)	$/MWh_e$		4.7		
O&M (variable)	$/MWh_e$		5.2		
Investment costs module	€/kW_e		840	200	Heck&Bauer 2005
Total investment costs	€/kW_e		1350	200	
Total O&M	€/MWh_e		18.7	200	
Investment costs module	€/MWh_e	1030		100	BFE 2003
Investment costs module	€/MWh_e	710		400	
Total O&M	€/MWh_e	22.6		100	
Total O&M	€/MWh_e	19.4		400	
Investment costs module	€/kW_e	750		200	ASUE 2001
Total O&M	€/MWh_e	14		200	

3.2.3.2 Small CHP plant considered in NEEDS

A small natural gas CHP plant with an output of 200 kW_e is modeled as reference plant here. The data is based on manufacturer information and literature. A CHP plant with lean burn gas motor is considered. It was assumed that the CHP plant is operating without catalysts. Table 3.21 and Table 3.22 show the technical data and the cost data of the reference 200 kW_e natural gas CHP plant. A heat pump can be used to improve the heat output but this is not considered here. The specification of the heat temperature is the basis for the exergy allocation applied to LCA results.

Table 3.21 Technical data of the reference current natural gas CHP plant investigated in NEEDS.

Net Electric Power	[MW_e]	0.2
Technical Life Time	[a]	20
Load	[h/a]	5000
Net Electricity Generation (over the life time)	[TWh]	0.02
Electric Efficiency	[%]	36.0
Thermal Efficiency	[%]	54.0
Ambient Temperature	[℃]	20
Temperature of Heat	[℃]	80

Table 3.22 Costs data of the reference current natural gas CHP plant investigated in NEEDS.

Spec. investment costs (overnight capital costs)	[€/kW]	1100
Guarding costs for period between shut-down and demolition	[Mio. €]	0
Spec. demolition costs (greenfield)	[€/kW]	3
Fixed costs of operation	[€/kW/yr]	60
Other variable costs	[€/MWhel]	7

3.3 Description of the fuel chains

In the context of NEEDS integration between RS1a and RS2a, each energy chain has been structured in four main phases: operation, production and dismantling of the power plant, and fuel supply. Each of these parts is represented by one process dataset. These parts are assembled in one dataset which represents the electricity production at the busbar by a specific plant technology (Figure 3.11). Although Fuel Supply should naturally be one input of power plant “Operation”, it is here connected with “Electricity” in order to facilitate the contribution analysis of cumulative results into emissions associated with the power plant infrastructure and operation separately from emissions associated with the upstream fuel chain.

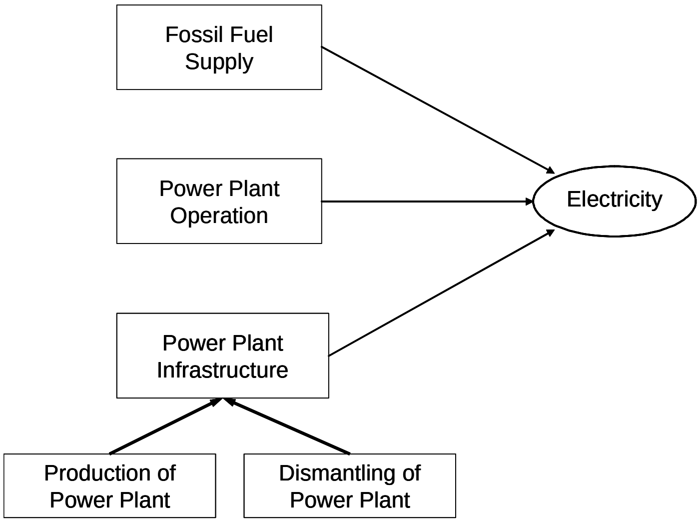


Figure 3.11 Generic structure of the fossil energy chains according to the scheme adopted for integration within NEEDS.

The dataset Fossil Fuel Supply represents the delivery of fuel to the power plant. Therefore, it connects to the ecoinvent dataset representing the end of the upstream energy chain, which is in general made of mining, processing, and transport of the fuel to the power plant (Dones et al. 2004 a,b). Therefore, the Fossil Fuel Supply dataset as such is made of one link rather than of a list of elementary flows, like it is the case for the other datasets depicted in Figure 3.11. The results for such dataset represent the cumulative burdens associated with the whole upstream chain up to the supply to the power plant.

3.3.1 Hard Coal

3.3.1.1 Fuel characteristics

Assumptions on fuel characteristics may somewhat differ for the modeling of the USC-PC and IGCC power plants. Although this may be consistent with the characteristics of the technologies (IGCC is designed to cope with high sulphur coal), what is important in LCI is that the primary emissions from the stack and from other sources within the plant describe the overall burdens from a typical best-technology plant.

In particular, for the USC-PC units, a coal with the characteristics of average supply to the Rostock power plant have been assumed, which are summarized in Table 3.23.

Table 3.23 Selected fuel characteristics of the hard coal used in the Rostock power plant (Röder et al. 2004 after Hojczyk et al. 1997) and assumed here for USC-PC units.

		Hard coal burned in USC-PC
Upper Heating Value	MJ/kg	27.3 [1]
Lower Heating Value	MJ/kg	26
Water content	% weight	9
Ash content	% weight	10
S content	% weight	0.9

[1] Calculated from the LHV multiplying it by 1.05.

For the IGCC reference power plant, hard coal with the characteristics indicated in Table 3.24 has been used

Table 3.24 Selected fuel characteristics of the hard coal used in the IGCC reference power plant.

		Hard coal burned in USC-PC
Upper Heating Value	MJ/kg	27.7 [1]
Lower Heating Value	MJ/kg	26.4
Water content	% weight	10
Ash content	% weight	6
S content	% weight	3.21

[1] Calculated from the LHV multiplying it by 1.05.

3.3.1.2 Upstream Chain

Figure 3.12 shows a schematic of the structure of the hard coal chain for the USC-PC and IGCC reference power plants. The hard coal supply chain to European power plants around year 2000 is taken from the ecoinvent database v1.3. It is described in detail in (Röder et al. 2004) and will not be reproduced here.

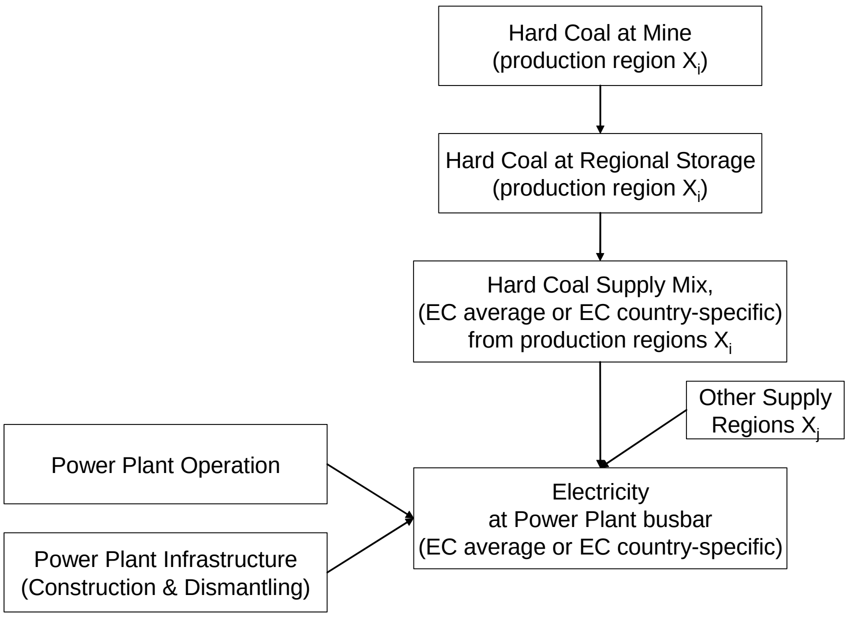


Figure 3.12 Structure of the hard coal chain for the USC-PC reference power plants; modeling of the power plant follows the scheme adopted within NEEDS.

3.3.2 Lignite

3.3.2.1 Fuel characteristics

Average German lignite, described in (Röder et al. 2004), is chosen as average fuel for the reference European lignite power plant. This assumption is based on the high share of German lignite electricity production in total European lignite electricity production in (about 41% in EU-25 in year 2000). The main characteristics of the average German lignite are given in Table 3.25 (Röder et al. 2004).

Table 3.25 Fuel characteristics of the German lignite used as reference fuel (Röder et al. 2004).

		Raw lignite
Upper Heating Value	MJ/kg	9.9
Lower Heating Value	MJ/kg	8.8
Water content	% weight	58
Ash content	% weight	2.5
C content	% weight	27.1
N content	% weight	0.3
S content	% weight	0.2

3.3.2.2 Upstream Chain

The power plant is directly located at the mining site ("mine-mouth"). Therefore, the upstream chain is made of mining only. Figure 3.13 illustrates the structure of the lignite chain for the BoA reference power plant.

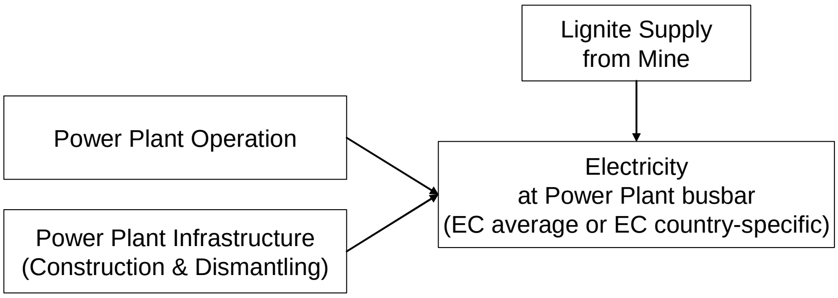


Figure 3.13 Structure of the lignite chain for the BoA reference power plant; modeling of the power plant follows the scheme adopted within NEEDS.

3.3.3 Natural Gas

3.3.3.1 Gas Combined Cycle (GCC) power plant and Gas Turbine

In order to represent a natural gas combined cycle plant and a gas turbine in an average European site, the average gas supply for Europe in year 2000 is used. These power plants are attached to the high pressure natural gas network. The corresponding data is provided by the ecoinvent module "natural gas, high pressure, at consumer, RER" (RER = Region Europe). The gas supply chain and the gas characteristics are described in (Faist Emmenegger et al. 2004) and will not be reproduced here. The scheme of the natural gas supply chain for the natural gas combined cycle power plant as modelled in ecoinvent is illustrated in Figure 3.14. In principle, the same structure of the upstream supply chain applies to the gas turbine as well.

3.3.3.2 Combined Heat and Power (CHP)

It is assumed that the small CHP plant is attached to the low pressure natural gas network. The local distribution in the low pressure network has been modelled in detail for Switzerland. Therefore, the natural gas supply for Switzerland is used for the gas CHP plant. The corresponding data is provided in the ecoinvent module "natural gas, low pressure, at consumer, CH". The origin and characteristics of the Swiss natural gas supply are similar to the origin and characteristics of the average European gas supply. The gas supply chain and the gas characteristics are described in ecoinvent (Faist Emmenegger et al. 2004). The scheme of the natural gas supply chain for the natural gas CHP plant as modelled in ecoinvent is shown in Figure 3.15.

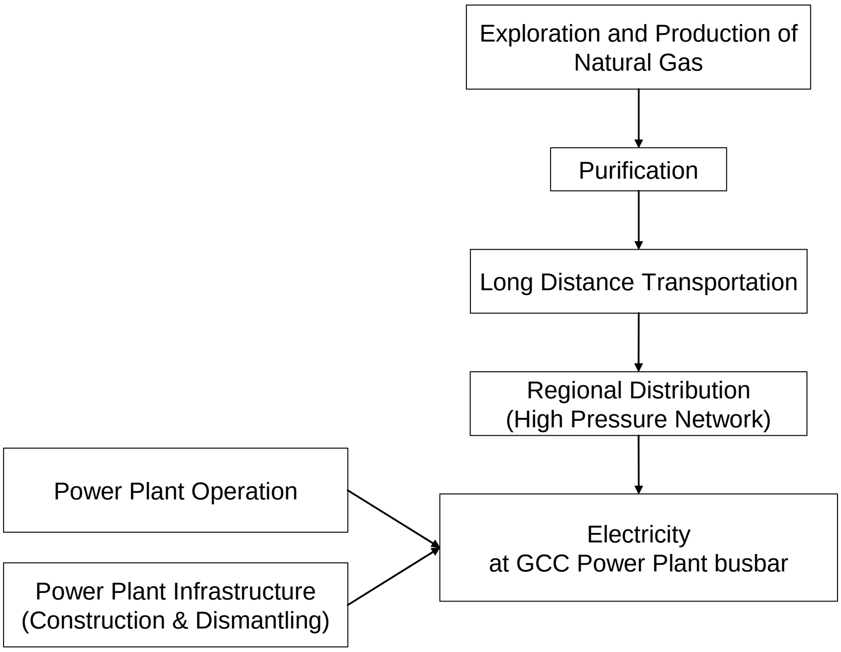


Figure 3.14 Structure of the natural gas chain for the GCC power plant; modeling of the power plant follows the scheme adopted within NEEDS.

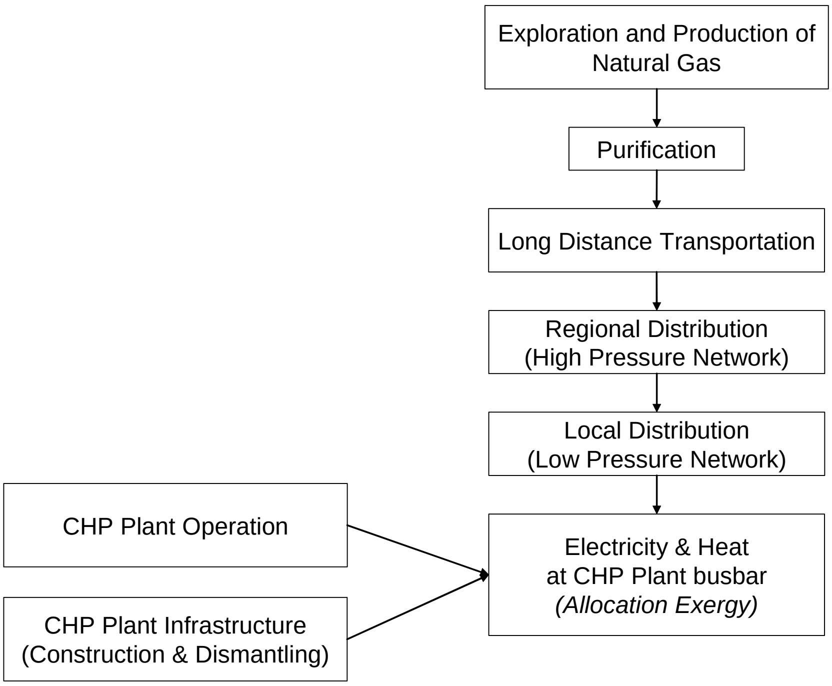


Figure 3.15 Structure of the natural gas chain for the CHP plant; modeling of the CHP plant follows the scheme adopted within NEEDS.

4 Future fossil technologies

The selection of future reference coal technologies for LCA modeling performed in RS1a and for integration in the energy-economy model in RS2a is based on:

- their development perspective, mainly in terms of economic and environmental performance, complying with possibly changing environmental but also in terms of operational and fuel flexibility, which would favor their market penetration;

- their environmental and costs representativeness for future fossil technologies which have high potential for attaining substantial capacity installed in Europe up to year 2050 and beyond.

However, this chapter includes firstly the description of a wide selection of candidates. Table 4.1 shows an overview of the different coal power plant technology options, their characteristics and potential development after (Decon 2003), whereas Table 4.2 shows the gas technologies. More details are provided in the next sections.

Table 4.1 Overview of main characteristics of different hard coal power plant technologies (without carbon capture); adapted from (Decon 2003).

Technology name	Technology description	Efficiency	Criteria pollutant emission	Availability / Maturity
Pulverized Coal combustion (PCC) Ultrasupercritical (USC)	The advanced USC technology is based on wide PCC technology experience. Currently operational typical USC steam parametrs are about 29 MPa/582℃/580℃ (Nordjyllandsværket Unit 3 in Denmark). Development of heat resistant materials (nickel-based superalloys) is ongoing.	Modern PCC plants today: 43-45%. Seawater cooled PCC supercritical power plants reach efficiencies of 45-47%. With future USC technology in the range of 700℃/35 MPa, efficiencies of about 50%	Emissions from new PCC units with appropriate flue gas cleaning units (ESP, FGD, SCR) can meet all current environmental requirements reliably and economically, and using well-proven technology	Commercially: Standard PCC and USC power plants. Development: PCC with advanced USC steam technology with 650/700℃ is predicted to be available in 2010/2020
Integrated gasification combined-cycle systems (IGCC)	Like FBC, the biggest advantages of IGCC over PCC is the capability for combustion of lower rank fuels (waste, coal, biomass, tar) with low SOx and NOx emission levels.	Presently about 43%. It is expected that through continuous developments in higher turbine inlet temperature, increased steam conditions (ultra critical steam) and hot syngas cleanup, net efficiency will exceed 50%.	Sulphur capture for IGCC projects were about 98% and NOx emissions reductions were 90% compared to those of a conventional PCC. No additional equipment is required to meet the environment standards.	Demonstration: At present, the secondary generation of IGCC power technology is at a matured stage.
Atmospheric fluidized bed combustion (AFBC)	BFBC (bubbling fluidized bed combustion) or CFBC (circulating fluidized bed combustion) types	ACFB: efficiency is on par with conventional PC. CFBC: 38-40% net efficiency can be reached..	Direct sorbent injection has SO_2 removal efficiency of 95% and higher,: Low furnace temperature plus staging of air feed to the furnace produce very low NOx emissions	Commercially: At present, there are about 300 operating CFBC boilers in the world with the capacity above 12 MW, 40% of them are in the US, 40% in Europe and 20% in Asia.
Pressurised fluidized bed combustion (PFBC)	Combustor and hot gas cyclones are all enclosed in a pressure vessel. In contrast to AFBC, PFBC is combined cycle thus increasing the overall efficiency. Advanced PFBC is also equipped with a carboniser and a topping combustor.	Current PFBC: over 42%, about 4-5% higher than AFBC or subcritical PCC. Goal for second generation PFBCs is over 46%	Combustion takes place at temperatures from 800-900℃ resulting in reduced NOx formation compared with PCC. SO_2 emissions is reduced by sorbent injection into the bed, and the subsequent removal of ash together with reacted sorbent.	Demonstration/commercially available: The PFBC is now under construction for commercial plant scale.. Advanced PFBC is in a demonstration phase.
Pressurised pulverised coal combustion (PPCC)	Combined cycle. PPCC boiler operates at 1-2 MPa, and about 1600℃; temperature of gas turbine inlet 1000-1300℃.	Future efficiencies of up to 55%.	Basically same as PCC with FGD/SCR	Development/pilot scale: No large scale power plants installed yet.
Integrated gasification	Hybrid technology. Triple combined cycle.	Pilot: net thermal	Same level as for	Development: pilot plant

fuel cell systems (IGFC)	IGFC combines coal gasification technology (gas-steam combined cycle) with fuel cells.	efficiency 53%. Future: 55%-60%	IGCC	IGMCFC in Japan. Availability of IGFC power plants deemed possible (Japan) in: 2010 (20 MW) 2015 (50 MW) 2020 (600 MW)
High Performance Power Systems (HIPPS)	Indirectly fired gas turbine combined cycle, where heat is provided to the gas turbine by high temperature heat exchangers with air temperature of T>1000℃.	Net efficiency: 47% Estimated: >50%		Demonstration: Two demo power plants in the USA
Magnetohydrodynamic Electricity generation (MHD)	A fluid conductor, typically an ionized flue gas from combustion of coal or other fossil fuels, flows through a static magnetic field, resulting in a direct current electric flow. A gas/steam combined cycle follows.	A triple combined cycle power plant has the potential for ~52% efficiency.	SOx and NOx emission levels predicted to be very low.	Early development stage: Several prototype units are being tested in the USA.

Table 4.2 Overview of main characteristics of different natural gas power plant technologies (without carbon capture).

	Technology description	Efficiency	Emission	Availability / Maturity
Combined Cycle	A combined cycle plant includes a gas turbine and a steam turbine. The combination yields high efficiencies.	Modern CC plants today: 55-58.5%. Efficiencies of about 65% are expected in the future.	Emissions from CC units meet all current environmental requirements reliably and economically, and using well-proven technology.	Commercially: Standard CC, well established technology.
GT	A gas turbine burns gas at a high inlet temperature (e.g. 1350℃) in order to produce electricity.	Modern gas turbines reach efficiencies of 38%. Future efficiencies might be 46%.	Emissions from GT units meet all current environmental requirements reliably and economically, and using well-proven technology.	Commercially: well established technology.
CHP	A CHP plant provides heat and electricity. The small CHP plants considered here employ gas motors.	Current small CHP plants (0.2-2 MW_e): 36%-39% electric efficiency. Future: 44%-48% electric efficiency.	Emissions from CHP units meet all current environmental requirements reliably and economically, and using well-proven technology.	Commercially: well established technology.

For the goals of RS1a, ultrasupercritical coal plants using pulverized coal on the one hand and IGCC plants on the other hand, in both configurations with and without CCS, appear to be the most suitable hard coal options to model for electricity supply in Europe until 2050. Lignite power plants are represented by the PC technology BoA+, again with and without CCS. Natural gas power plant technologies will be represented by Combined Cycle, with and without CCS, advanced GT and CHP.

4.1 Coal technologies

4.1.1 Advanced PC: hard coal supercritical and ultra-supercritical power plants

The principal developments of Pulverized Coal (PC) technology include (IEA Clean Coal 2005b):

- Increasing plant thermal efficiencies by rising steam pressure and temperature at the boiler outlet/steam turbine inlet;
- Ensuring that units can load follow satisfactorily; and,
- Flue gas cleaning units installed in order to meet emissions limits and environmental requirements for criteria pollutants.

The potential for efficiency improvements of supercritical (SC) hard coal PC power plants remains substantial. Figure 4.1 shows the possible increases of net efficiency up to more than 50% starting from an actual German power plant with 43% (Staudinger V), by optimizing plant design and using advanced materials in order to increase steam parameters.

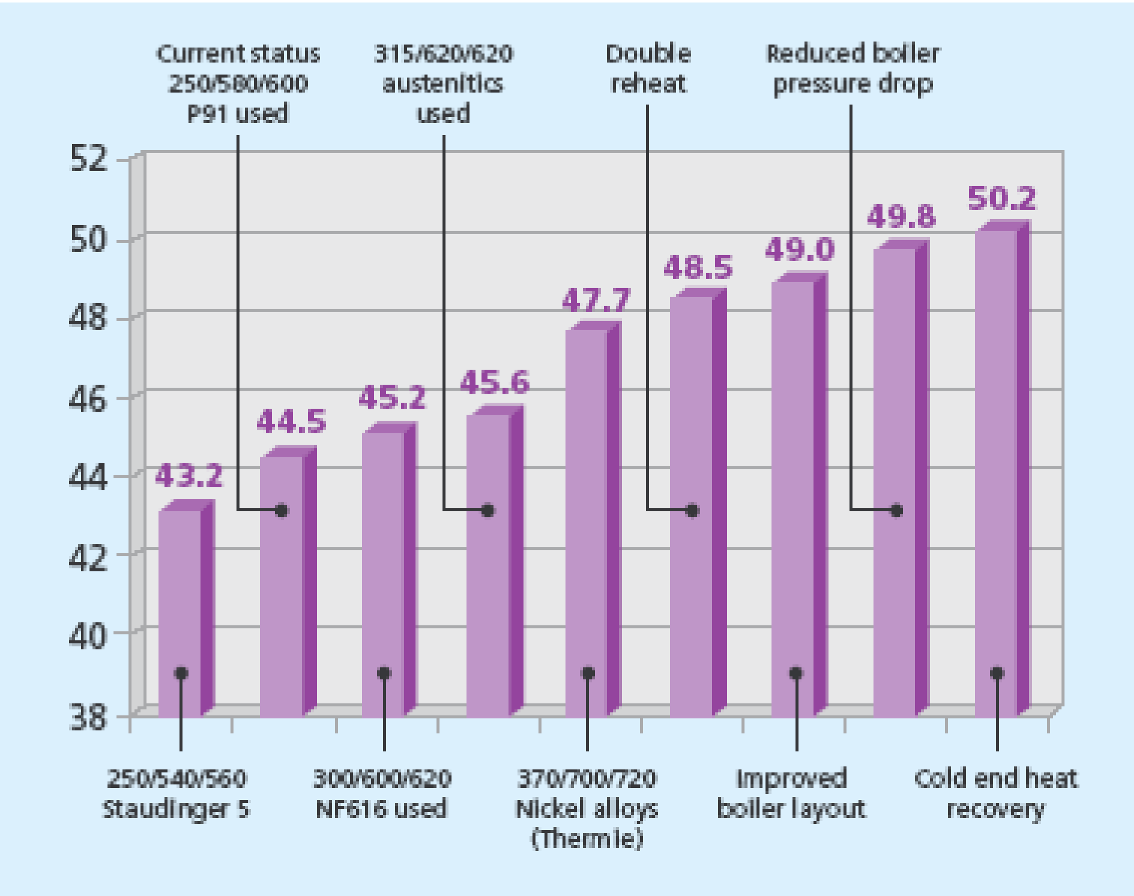


Figure 4.1 Likely increase of net efficiency, with reference to a currently operational power plant in Germany, due to use of advanced materials and improved plant design (CCTP 2002).

Schuknecht (2003) estimates a similar potential, his calculations result in an increase in efficiency from 44.7% of the reference plant up to 51.1% (LHV) by increasing the efficiencies of single components, reaching steam parameters of 35 MPa/700°C/720°C, and implementing double reheat.

Bernero (2002) analyzed the operation of an advanced SC power plant with a net capacity of 508 MW with steam conditions 365 bar/700°C/700°C at a condenser pressure of 0.083 bar. An efficiency of 45% (LHV) is calculated, compared to 41.9% (LHV) for a less advanced plant with steam parameters of 290 bar/580°C/582°C and 38.3% (LHV) for a conventional PC plant with steam parameters of 165 bar/538°C/538°C. The 20-years levelized cost of electricity are calculated as 7.54 $cents/kWh, 7.51 $cents/kWh, and 6.81 $cents/kWh, respectively.

In general, low condenser pressure is a decisive requirement for high efficiencies of supercritical steam power plants. Every 10 mbar increase in the condenser vacuum would result in nearly 0.4 percentage points to the plant exergetic efficiency under the conditions provided in the case study for the SC plant with 290 bar/580°C/582°C in (Bernero 2002). In addition, the low flue gas temperature is important for better system efficiencies. Also reduction of boiler auxiliary power consumption is worth of further consideration, as 6.0-7.3% of gross power output of a supercritical steam power plant is self-consumed (Bernero 2002).

The aspired increases in power plant efficiencies require the development of more stress resistant materials, since steel as it is used today does not tolerate steam temperatures and pressures in the range of 700°C and above 350 bar (Figure 4.2). Without such non-steel alloys, the highest achievable efficiency would be around 51%, while the development of so-called “Super Alloys” would allow figures around 58% in the long term (Bugge et al. 2006, see also Figure 4.3). A general advantage of supercritical PC units is the superior part-load performance, compared to HIPPS, IGCC, and PFBC plants (Bernero 2002).

Operation of advanced plants requires resistant materials, which enable the use of supercritical and ultra-supercritical steam (pressures >248 bar and temperatures >566°C and as high as 700°C) (WCI 2005a; IEA Clean Coal 2005b). Advanced materials are used for the boiler (water walls/evaporators, steam separating vessels, superheater tubes, steam pipes) and the steam turbine (CCTP 2002). Nowadays, steam conditions up to 300 bar/600°C/620°C are achievable using steels with 12% chromium content. Up to 315 bar/620°C/620°C austenite is needed. According to Bernero (2002), nickel-based alloys would permit 350 bar/700°C/720°C. CCTP (2002) shows an increase of steam parameters up to 370 bar/700°C/720°C (see Figure 7). Together with other optimization measures, this would allow net efficiencies of about 50% for the best seawater-cooled power plants (Bernero 2002, CCTP 2002). A demonstration plant (capacity 400-1000 MW) within the joint European project “Advanced (700°C) PCC Power Plant” is planned to be in operation by 2010 (Bernero 2002).

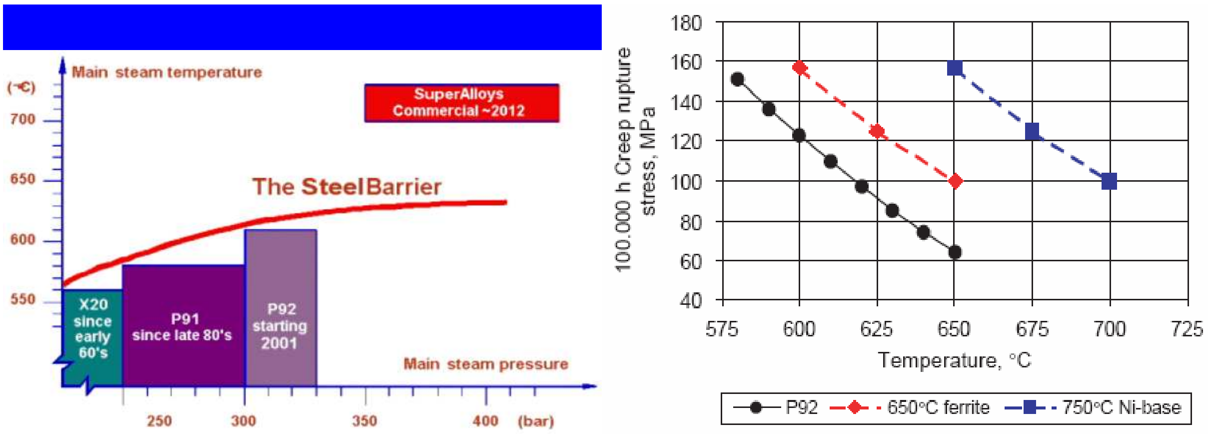


Figure 4.2 **Characteristics of different materials with respect to possible steam parameters at the power plant (Decon 2003, Bugge et al. 2006).**

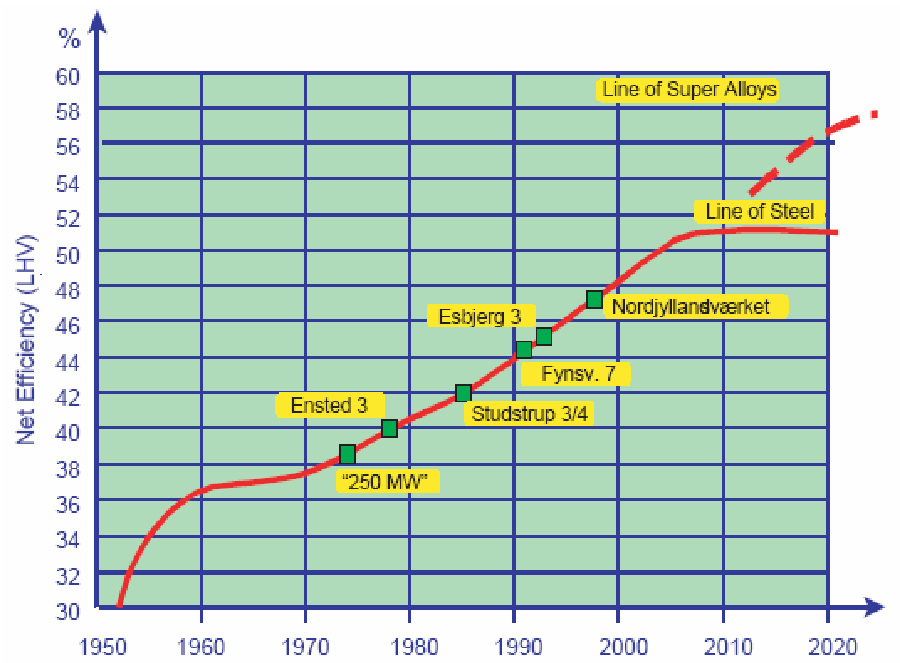


Figure 4.3 **Historical and potential future development of hard coal power plant efficiencies (Bugge et al. 2006).**

Long-term research is ongoing to achieve, with advanced steam conditions for supercritical and ultra-supercritical PC cycles, thermal efficiencies of 50% (IEA Clean Coal 2005b) and beyond (PF 03-05 2003). The industry indicates the possibility to reach 55% efficiency (WCI 2005a). This requires a considerable amount of work (IEA Clean Coal 2005b) for the development of new advanced materials, including superalloys.

Current pollution control technology can meet all environmental standards for criteria pollutants, as described previously. More tightening emission limits for most species could be coped with rather easily, but controlling (and monitoring) mercury emissions need further work to ensure compliance with future likely requirements in the USA (PF 03-05 2003).

4.1.1.1 Specification of future technology configurations

Table 4.3 through Table 4.5 provide an overview of the technology characteristics of the future (2025 and 2050) hard coal fuelled PC reference power plants without CO_2 capture. Key specifications of future hard coal power plants can be found in chapter 4.3.4 (Table 4.46).

LCI data – emission parameters of the power plants as well as consumption of materials for their operation, construction and decommissioning – are based on the current reference technologies (chapter 3.1). Data for construction and decommissioning of the power plants are the same in all scenarios and time horizons: this simplifying assumption is justified by the very low contribution of infrastructure to cumulative LCA results (see chapter 5). Power plant emissions per kWh electricity production depend on the net efficiencies, emission parameters per unit of fuel input are assumed to be the same as for the current hard coal reference technologies.

Table 4.3 Technical characteristics of the hard coal-fuelled PC power plant without CO_2 capture for future time horizons, pessimistic scenario.

		2025			2050		
Gross Capacity[1]	[MW_e]	378	642	848	374.5	636	840
Net Capacity	[MW_e]	350	600	800	350	600	800
Technical Life Time	[a]	35	35	35	35	35	35
Load	[h/a]	7600	7600	7600	7600	7600	7600
Net Electricity Generation (over the life time)	[TWh_e]	93.1	159.6	212.8	93.1	159.6	212.8
Net Efficiency	[%]	47	47	47	50	50	50

[1] Calculated from the net power using an auxiliary consumption of 8%, 7%, and 6% (2025) and 7%, 6%, 5% (2050) of gross power, respectively for the 350 MW, 600 MW, and 800 MW units.

Table 4.4 Technical characteristics of the hard coal-fuelled PC power plant without CO_2 capture for future time horizons, realistic-optimistic scenario.

		2025			2050		
Gross Capacity[1]	[MW_e]	374.5	636	840	371	630	832
Net Capacity	[MW_e]	350	600	800	350	600	800
Technical Life Time	[a]	35	35	35	35	35	35
Load	[h/a]	7600	7600	7600	7600	7600	7600
Net Electricity Generation (over the life time)	[TWh_e]	93.1	159.6	212.8	93.1	159.6	212.8
Net Efficiency	[%]	49	49	49	54	54	54

[1] Calculated from the net power using an auxiliary consumption of 7%, 6%, 5% (2025) and 6%, 5%, 4% (2050) of gross power, respectively for the 350 MW, 600 MW, and 800 MW units.

Table 4.5 Technical characteristics of the hard coal-fuelled PC power plant without CO_2 capture for future time horizons, very optimistic scenario.

		2025			2050		
Gross Capacity[1]	[MW_e]	371	630	832	367.5	624	824
Net Capacity	[MW_e]	350	600	800	350	600	800
Technical Life Time	[a]	35	35	35	35	35	35
Load	[h/a]	7600	7600	7600	7600	7600	7600
Net Electricity Generation (over the life time)	[TWh_e]	93.1	159.6	212.8	93.1	159.6	212.8
Net Efficiency	[%]	52	52	52	57	57	57

[1] Calculated from the net power using an auxiliary consumption of 6%, 5%, 4% (2025) and 5%, 4%, 3% (2050) of gross power, respectively for the 350 MW, 600 MW, and 800 MW units.

4.1.2 Advanced PC: lignite BoA+ power plants

Substantial increase in the net efficiency can also be foreseen for supercritical lignite power plants. Especially Germany is currently following this line of technology development.

Two new BoA power plant units, Neurath 2/3, similar to Niederaussem K, will start commercial operation in 2010 with a net electric efficiency above 43%. The electrostatic precipitator will have an efficiency of above 99.8%, and the FGD above 90%. Envisaged steam parameters (live steam/reheater/condenser) are 600/605°C and 272/55.5 bar/48 mbar (RWE 2006b). Further improvements are expected with the “BoA Plus”-concept. According to (RWE 2005), net efficiencies of 52% could be reached in 2020; (Heithoff 2005) claims net efficiencies of about 54% (see Figure 4.4).

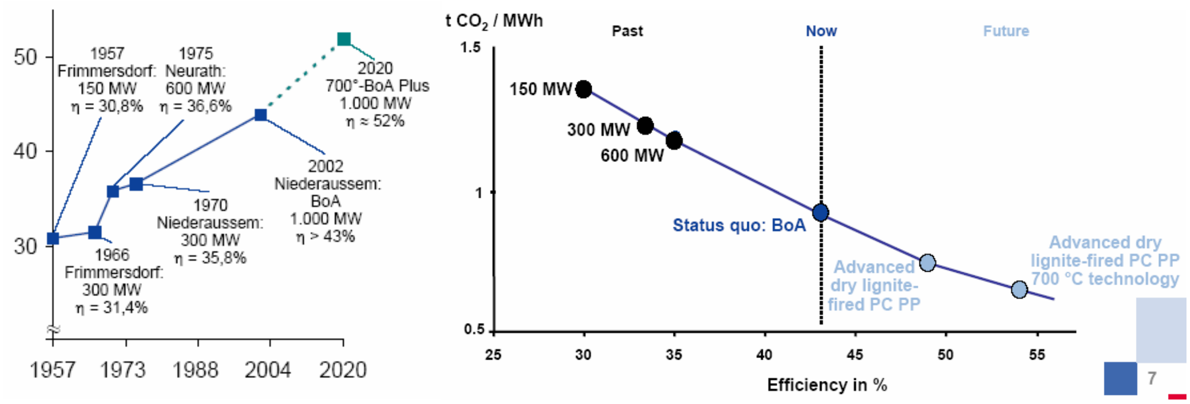


Figure 4.4 Future development of lignite power plant net efficiencies (RWE 2005, Heithoff 2005).

Compared to the currently implemented BoA concept, the further sophisticated BoA-Plus concept contains a separate lignite drying section (Figure 4.5). The lignite fuel is dried at a low temperature level, using a heat pump driven by electricity from the power plant and profiting of the energy embedded in the vapour (RWE 2005). Key characteristics of BoA+ modelled in RS1a for future time conditions are listed in Table 2.3.

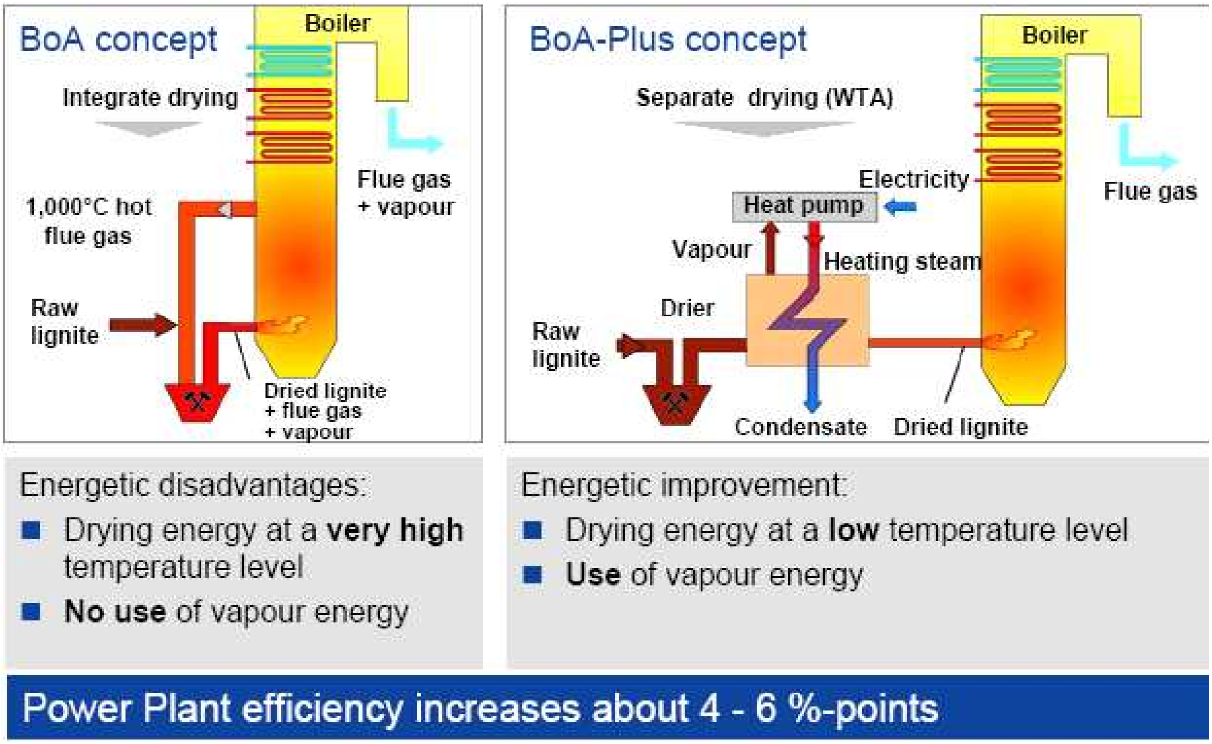


Figure 4.5 Evolution of BoA to BoA-Plus concept (RWE 2005).

4.1.2.1 Specification of future technology configurations

Table 4.6 through Table 4.8 provide an overview of the technology characteristics of the future (2025 and 2050) hard coal fuelled PC reference power plants without CO_2 capture. Key specifications of future lignite power plants can be found in chapter 4.3.4 (Table 4.46).

LCI data – emission parameters of the power plants as well as consumption of materials for their operation, construction and decommissioning – are based on the current reference technologies (chapter 3.1). Data for construction and decommissioning of the power plants are the same in all scenarios and time horizons: this simplifying assumption is justified by the very low contribution of infrastructure to cumulative LCA results (see chapter 5). Power plant emissions per kWh electricity production depend on the net efficiencies, emission parameters per unit of fuel input are assumed to be the same as for the current lignite reference technology.

Table 4.6 Technical characteristics of the lignite-fuelled PC power plant without CO_2 capture for future time horizons, pessimistic scenario.

		2025	2050
Gross Capacity	[MW_e]	1007	997.5
Net Capacity	[MW_e]	950	950
Technical Life Time	[a]	35	35
Load	[h/a]	7760	7760
Net Electricity Generation (over the life time)	[TWh_e]	258	258
Net Efficiency	[%]	47	50

[1] Calculated from the net power using an auxiliary consumption of 6% (2025) and 5% (2050) of gross power.

Table 4.7 Technical characteristics of the lignite-fuelled PC power plant without CO_2 capture for future time horizons, realistic-optimistic scenario.

		2025	2050
Gross Capacity	[MW_e]	997.5	988
Net Capacity	[MW_e]	950	950
Technical Life Time	[a]	35	35
Load	[h/a]	7760	7760
Net Electricity Generation (over the life time)	[TWh_e]	258	258
Net Efficiency	[%]	49	54

[1] Calculated from the net power using an auxiliary consumption of 5% (2025) and 4% (2050) of gross power.

Table 4.8 Technical characteristics of the lignite-fuelled PC power plant without CO_2 capture for future time horizons, very optimistic scenario.

		2025	2050
Gross Capacity	[MW_e]	988	978.5
Net Capacity	[MW_e]	950	950
Technical Life Time	[a]	35	35
Load	[h/a]	7760	7760
Net Electricity Generation (over the life time)	[TWh_e]	258	258
Net Efficiency	[%]	52	57

[1] Calculated from the net power using an auxiliary consumption of 4% (2025) and 3% (2050) of gross power.

4.1.3 IGCC technology development perspectives

A way to make coal gasification more economical in future is to develop lower-cost ways to produce the oxygen used in the gasification process, such as ceramic membranes to separate oxygen from the air at elevated temperatures (DOE 2004b). Membranes may also become an important new technology for separating gases produced by coal gasifiers. Membranes are explored and developed that can selectively remove hydrogen from syngas, which becomes especially relevant for IGCC power plants with CO_2 capture. IGCC can offer further substantial increases in efficiency, when hot gas clean-up is applied. Currently the gas cleaning stages for removal of particulates and sulphur are operated at relatively low temperatures, which limits the overall efficiency obtainable (IEA Clean Coal 2005a). Further efficiency improvements are expected through advances in gas turbine technology (higher pressure ratios, higher turbine entry temperatures, reheat). With recent advances in gas turbine technology and current state of the art of power plant components, IGCC designs offering efficiencies close to 50% are already available (WCI 2005b, Australian Coal Association 2004).

Within the Joule Program of the European Union efficiencies of 51-53% are expected for IGCC technology already in 2015 (EC 2001). According to the coal industry, IGCC offers the prospect of future net efficiencies of 56% (WCI 2005b). In the same direction goes DOE citing that in future IGCC technology may be able to achieve efficiencies approaching 60% (DOE 2004b). Very optimistic are also the forecasts by the German COORETEC project: Starting from a current efficiency of 45-48%, an efficiency of 54-57% is anticipated between 2010 to 2020. Past 2025 an IGCC efficiency of 62% is expected (BMWA 2003).

An advantage of IGCC against PC technology is that gasification produces a gas stream with a higher concentration of CO_2, which furthermore is generated at an elevated pressure level, and thus favours the capture of CO_2 (see related section below).

Future IGCC concepts may incorporate a fuel cell or a fuel cell-gas turbine hybrid, which is able to achieve further enhancements of the efficiency. Such a hybrid system is called Integrated Gasification Fuel Cell (IGFC). The total potential efficiency of a system of gasifier – fuel cell – gas/expansion turbine – steam turbine cycle could be as high as 65% (Australian Coal Association 2004). IGFC hybrids have the potential to achieve near-zero CO_2 emissions, because the concentrated CO_2 produced in fuel cells fuelled by hydrogen can be removed by separation. Thus high efficiency while capturing CO_2 is possible with IGFC (WCI 2005a; WCI 2005b).

Fuel cells convert the chemical energy of a fuel, such as hydrogen, directly into electricity at high rates of efficiency and with almost no emissions. Emerging fuel cells have efficiency levels of 60% (WCI 2005b). Some fuel cells types also produce very high-temperature exhaust gases that can either be used directly in combined-cycle or used to drive a gas turbine. If any of the remaining waste heat can be channeled into process steam or heat, perhaps for nearby factories or district heating plants, the overall fuel use efficiency of future gasification plants could reach 70 to 80% (DOE 2004b).

For a coal gasification power station involving fuel cells, MW-scale fuel cells are not available today, but must be developed (Australian Coal Association 2004). At present only Molten Carbonate Fuel Cells (MCFC) are available at a modest MW-scale. The use of fuel cells has been demonstrated at the 2 MW_e size and they can be used modularly. (WCI 2005a; 2005b). Another promising type of fuel cell for MW-scale application is the Solid Oxide Fuel Cell (SOFC) (Australian Coal Association 2004). Within the Clean 21 program of the Australian Coal Association it has been started to develop KW-scale fuel cells. In the action plan of Clean 21 it is assumed that in the longer term, fuel cells could contribute substantially to facilitating large scale power generation from hydrogen derived from coal (Australian Coal Association 2004). Currently fuel cells require further development for application in large stationary power plants and currently are not competitive to gas- and steam turbine-based combined cycles for power generation or in transportation applications. (WCI 2005b)

The New Energy and Industrial Technology Development Organization (NEDO) has been undertaking a major project to develop coal gasification for use in fuel cells. The project is known as EAGLE (coal Energy Application for Gas, Liquid and Electricity), started in 1998 and is due to run until 2006 (WCI 2005b). A pilot plant has been constructed, which aims to develop a coal gasifier suitable for IGFC. The integrated coal gasification fuel cell combined cycle system should achieve efficiencies of at least 53-55%. Deployment of IGCC fuel cells in Japan is expected to begin in 2010 with the introduction of 50 MW_e distributed power generation installations, followed by the introduction of a 600 MW_e system for utility use by 2020 (IEA Clean Coal 2003).

The US Department of Energy (DOE) has formed the Solid State Energy Conversion Alliance (SECA)[30] with a goal of producing a core solid-state fuel cell module that would be able to compete with gas turbine and diesel generators and likely gain widespread market acceptance.

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[30] http://www.fe.doe.gov/programs/powersystems/fuelcells/fuelcells_seca.html

The SECA Program is currently focused on small, 3-10 kW scale fuel cell systems for distributed generation applications. These relatively small fuel cells can be scaled up to larger megawatt class systems for use as power modules in coal based applications, including FutureGen. Large fuel cell systems will then be combined with other power generation modules (e.g., a gas turbine as a fuel cell-turbine hybrid), into hybrid power systems. The ultimate goal of this new initiative is the development of large (>100 MW_e) fuel cell power systems that will produce affordable, efficient and environmentally-friendly electrical power at greater than 50% overall efficiency in systems that include CO_2 separation for sequestration. (DOE 2004b)

4.1.3.1 IGCC hot spots

The main disadvantages of IGCC technology are the high technological complexity, low operational flexibility, and relatively high specific investment cost. IGCC power plants have to be designed for a specific type of coal or solid fuels in order to warrant a high reliability. These aspects as well as further efficiency enhancements will be addressed in the future technical research and development.

The main advantages of IGCC technology are its high efficiency, demonstrated very low emissions of SO_2, NO_x and particulates as well as the advantageous characteristics for CO_2 capture. The elevated pressure and concentration of CO_2 in the syngas favour CO_2 separation in pre-combustion capture. If CO_2 capture is required, a CO shift conversion unit downstream of the particulate removal and both a CO_2 separation and compression unit are integrated in the IGCC technology. The syngas is reacted with steam prior to combustion (water / CO – shift reaction) to produce hydrogen and a separate highly concentrated stream of CO_2. In the CO_2 capture unit the CO_2 is finally separated from hydrogren and is following compressed for transportation and storage.

The preferred technique for CO_2 capture in applications at higher pressure (i.e. IGCC) currently physical absorption is considered (IEA (2003a)). Physical solvents commonly used in commercial processes include cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor solvent process) and sulfolane. Others absorbents comprise Calcium Oxide (CaO), Sodium Hydroxide (NaOH) and Potassium Hydroxide (KOH). Absorption technology, which has not yet been optimised for large-scale CO_2 capture, is a mature technology and considered the bridge to carbon sequestration. (IEA 2002)

CO_2 capture is accompanied by an efficiency decrease and an increase of costs. However, in an IGCC power plant, CO_2 can be captured from the high pressure and concentrated syngas stream at far lower cost and lower efficiency decrease than from the dilute low pressure flue gas of a conventional PF power station (Australian Coal Association 2004).

4.1.3.2 Potential role of IGCC in a future energy supply system

According to the World Energy Outlook 2006 of the International Energy Agency (IEA), globally fossil fuels will remain the dominant source of energy by 2030 and most probably also along the following two decades (IEA 2006). The global hard coal demand is projected to grow at an average annual rate of 1.8%, whereas power generation accounts for 81% of this increase. For Europe this would imply an increase in the hard coal demand by 9% until 2030. In parallel, the share of demand on coal for power generation to the total European coal consumption is anticipated to rise by some 10%. Coal prices are assumed to change proportionately less over time, but are anticipated to increase along the trend of oil and gas prices, though not at the same rate. Starting from these general conditions, electricity generation from hard coal in Europe is expected to stay at current or even slightly elevated capacity level by 2030 and the following decades.

There is a broad consensus about the capability of IGCC technology for mitigating the environmental impact of power generation from fossil fuels: the high efficiency potential of approximately 52%, which is anticipated to be achieved within year 2025, is one precondition for saving primary energy and reducing CO_2 emissions by substitution of less efficient fossil power plants. Via gasification a wide range of feedstock including biomass and low-grade opportunity fuels such as refinery residues or waste material can substitute valuable fossil fuels. IGCC applications will be increasingly limited not only to electricity generation, but will extend to CHP or even co- or poly-generation. Besides electricity generation IGCC technology can be applied for hydrogen production or the generation of synthetic fuels via Fischer-Tropsch process.

IGCC is seen as the most promising technology when removal of CO_2 as the most important greenhouse gas would be required for power plants based on fossil fuels. Incentives for market penetration of CCS technology and thus IGCC power plants with CO2 capture could be triggered for instance by a carbon dioxide tax as presently established in Norway or by CO_2 emissions trading. The latter is already established in the European emission trading being currently in the trading period from 2008 to 2812. Processes for CO_2 separation from the pressurized fuel gas are based on state-of-the-art technology and lead to an efficiency decrease of typically 5 to 7% points (product CO_2 at gaseous state), which constitutes a low efficiency loss when compared to other capture technologies as far as developed today (Hannemann et al. 2003). This is the reason why several power plant industries and research organisations worldwide are pushing this technology, also promoted by various national and international institutions such as the U.S. Department of Energy (DOE) or the European Commission (EC). Several technology road maps on clean coal technologies from different organizations worldwide (Australian Coal Association, Canadian Clean Power Association, Center for Coal Utilization, IEA Clean Coal Centre etc.) attach importance to IGCC for future electricity generation from hard coal.

Furthermore, IGCC could become an economic option for new power generation schemes depending on the natural gas price tendency and if emission standards become more stringent.

Currently, around 132 GW_e of coal fired electricity generation capacity are installed in Europe, thereof some 1 GW_e IGCC capacity. Starting from the above described positive frame conditions for market penetration of IGCC technology and according to IER modeling, it is expected that installed capacity of IGCC power plants in Europe will be considerably boosted within the next decades. In 2025 a capacity for coal fired electricity generation of 270 GW_e is anticipated, of which 90 GW_e should be IGCC power plants.

4.1.3.3 Specification of future technology configurations

Based on the described IGCC development perspectives, future scenarios on IGCC technology have been created taking into account several parameters influencing the frame conditions of its R&D. Table 4.9 gives an overview on these parameters and the tendency which was assumed for their influence on future IGCC technology development within the respective future scenarios.

Table 4.9 Influence of main parameters on the velocity of IGCC technology development outlined in three future scenarios. Upward green arrows show positive influence (driver). Downward red arrows show negative influence (inhibitor). Horizontal grey arrows: parameter does not influence the development.

	Pessimistic Scenario	Realistic-Optimistic Scenario	Very Optimistic Scenario	Comments
General Parameters				
Cheap electricity generation	→	↗	↑	IGCC as efficient fossil fuelled technology based on cheap feedstock of hard coal / lignite has a competitive advantage against other electricity generation technologies
Large scale electricity generation	↗	↑	↑	IGCC technology allows electricity generation in power plants of high capacity levels comparable to capacity levels of NGCC power plants
Environmental Performance	↘	→	→	Compared to other technologies, coal based electricity generation features high emissions. However compared to currently installed coal power plants, the environmental performance of IGCC technology is considerably improved.
Public acceptance	↘	→	↗	Public acceptance affects market penetration. Hereby electricity prices, resource use and environmental performance are the main drivers
Feedstock availability	→	↗	↑	Currently coal features the most abundant proved recoverable fossil reserves and also additional resources
Feedstock prices	→	↗	↑	In comparison to natural gas or oil, hard coal and lignite feature lower price fluctuation and are less affected by political supply insecurities
Parameter with particular relevance for technology development				
Development of advanced materials for higher live steam conditions	→	↗	↑	Technical prerequisite for further efficiency enhancement in IGCC technology
Synthesis gas cleaning (hot gas instead of wet scrubbing)	→	↗	↑	Technical prerequisite for further efficiency enhancement in IGCC technology
Advances in gas turbine technology	→	↗	↑	One prerequisite for further efficiency enhancement in IGCC technology

The technology specifications for IGCC power plants without and with CCS for the time horizons 2025 and 2050, which have been derived from the scenario reflection, are presented in Table 4.10 through Table 4.21.

Table 4.10 Technical data of the hard coal-fuelled IGCC power plant without CO_2 capture for future time horizons, pessimistic scenario

		2025	2050
Gross Capacity	[MW_e]	478	478
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	56.3	56.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	53	53.5

Table 4.11 Technical data of the hard coal-fuelled IGCC power plant without CO_2 capture for future time horizons, realistic-optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	477	477
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	57.3	57.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	54	54.5

Table 4.12 Technical data of the hard coal-fuelled IGCC power plant without CO_2 capture for future time horizons, very optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	477	477
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	58.3	58.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	55	55.5

Table 4.13 Technical data of the lignite-fuelled IGCC power plant without CO_2 capture for future time horizons, pessimistic scenario

		2025	2050
Gross Capacity	[MW_e]	479	479
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	54.3	54.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	51	51.5

Table 4.14 Technical data of the lignite-fuelled IGCC power plant without CO_2 capture for future time horizons, realistic-optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	479	479
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	55.3	557.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	52	52.5

Table 4.15 Technical data of the lignite-fuelled IGCC power plant without CO_2 capture for future time horizons, very optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	478	478
Net Capacity	[MW_e]	450	450
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	118	118
Gross Efficiency	[%]	56.3	56.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Net Efficiency	[%]	53	53.5

Table 4.16 Technical data of the hard coal-fuelled IGCC power plant with CO_2 capture for future time horizons, pessimistic scenario

		2025	2050
Gross Capacity	[MW_e]	509.1	508.2
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	56.3	56.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	47	47.5

Table 4.17 Technical data of the hard coal-fuelled IGCC power plant with CO_2 capture for future time horizons, realistic optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	507	507
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	57.3	57.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	48	48.5

Table 4.18 Technical data of the hard coal-fuelled IGCC power plant with CO_2 capture for future time horizons, very optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	506	506
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	58.3	58.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	49	49.5

Table 4.19 Technical data of the lignite-fuelled IGCC power plant with CO_2 capture for future time horizons, pessimistic scenario

		2025	2050
Gross Capacity	[MW_e]	513	513
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	54.3	54.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	45	45.5

Table 4.20 Technical data of the lignite-fuelled IGCC power plant with CO_2 capture for future time horizons, realistic optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	511	511
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	55.3	55.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	46	46.5

Table 4.21 Technical data of the lignite-fuelled IGCC power plant with CO_2 capture for future time horizons, very optimistic scenario

		2025	2050
Gross Capacity	[MW_e]	509	509
Net Capacity	[MW_e]	425	425
Technical Life Time	[a]	35	35
Load	[h/a]	7,500	7,500
Net Electricity Generation (over the life time)	[TWh_e]	111.6	111.6
Gross Efficiency	[%]	56.3	56.8
Efficiency Decrease by Own Consumption	[%]	3.3	3.3
Efficiency Decrease by CO_2 capture	[%]	6.0	6.0
Net Efficiency	[%]	47	47.5

4.1.4 Hybrid gasification/combustion systems

Future concepts that incorporate a fuel cell or a fuel cell-gas turbine hybrid could achieve high efficiencies, nearly twice as much as today's typical coal combustion plants (DOE 2004b). Fuel cells convert the chemical energy of a fuel, such as hydrogen, directly into electricity at high rates of efficiency and with almost no emissions. Emerging fuel cells have efficiency levels of 60% (WCI 2005b). Some fuel cells types also produce very high-temperature exhaust gases that can either be used directly in combined-cycle or used to drive a gas turbine. If any of the remaining waste heat can be channeled into process steam or heat, perhaps for nearby factories or district heating plants, the overall fuel use efficiency of future gasification plants could reach 70% to 80% (DOE 2004b).

4.1.4.1 Integrated gasification fuel cell systems (IGFC)

The efficiency of power generation from syngas (produced from coal) could be improved by the use of a fuel cell in the power cycle. Such a hybrid system promising high efficiency is called Integrated Gasification Fuel Cell (IGFC). It is based on a triple combined cycle. IGFC consists of a coal gasification unit (high oxygen content required for high overall efficiency), a gas cleanup unit, an air separation unit, MW-scale high temperature / high pressure fuel cells (FC) unit, a gas turbine unit, and a steam turbine unit. The FC can be either MCFC (molten carbonate FC at 600°C) or a SOFC (solid oxides FC at 900-1000°C).

The use of fuel cells has been demonstrated at the 2 MW_e size and they can be used modularly (WCI 2005a; 2005b). Fuel cells require further development for application in large stationary power plants. Current FC are not competitive with gas- and steam turbine-based combined cycles for power generation or in transportation applications (WCI 2005b).

Plans are under way to use hydrogen from coal gasification (see below) in this and other technologies (ACA 2004; WCI 2005b). The total potential efficiency of a gasifier + fuel cell + gas/expansion turbine + steam turbine cycle could be as high as 65 percent with a consequent substantial reduction in greenhouse gas emissions intensity of the order of 40%-50% compared to Ultra supercritical technology (Australian Coal Association 2004). This also substantially reduces the load upon and cost of carbon capture and sequestration. IGFC hybrids have the potential to achieve near-zero emissions, because the concentrated CO_2 produced can be removed by separation. Thus high efficiency while capturing CO_2 is possible with IGFC (WCI 2005a; WCI 2005b).

The New Energy and Industrial Technology Development Organization (NEDO) is undertaking a major project to develop coal gasification for use in fuel cells. The project is known as EAGLE (coal Energy Application for Gas, Liquid and Electricity) which started in 1998 and is due to run until 2006 (WCI 2005b). Since 1998, a pilot IGMCFC plant, net power output of 551 MW_e, has been under construction in Wakamatsu (Japan). Its net thermal efficiency is 53% (HHV) (Maruyama and Suzuki 2000). Future plants may reach 55%-60% (Decon 2003). Deployment of IGCC-fuel cells in Japan is expected to begin in 2010, with the introduction of 50 MW_e distributed power generation installations, followed by the introduction of a 600 MW_e system for utility use by 2020 (IEA Clean Coal 2003).

The US Department of Energy (DOE) has formed the Solid State Energy Conversion Alliance (SECA) with a goal of producing a core solid-state fuel cell module that would be able to compete with gas turbine and diesel generators and likely gain widespread market acceptance.

The SECA Program is currently focused on small, 3-10 kW scale fuel cell systems for distributed generation applications. These relatively small fuel cells can be scaled up to larger megawatt class systems for use as power modules in coal based applications, including FutureGen. Large fuel cell systems will then be combined with other power generation modules (e.g., a gas turbine as a fuel cell-turbine hybrid), into hybrid power systems. The ultimate goal of this new initiative is the development of large (>100 MW_e) fuel cell power systems that will produce affordable, efficient and environmentally-friendly electrical power at greater than fifty percent (50% HHV) overall efficiency from coal to AC power, in systems that include CO_2 separation for sequestration (DOE 2004b).

4.1.5 Fluidized Bed Combustion (FBC) power plants

As with PC plants, efforts are aiming at achieving higher steam conditions in order to further increase the thermal efficiency (WCI 2005a). Only a short description is provided here, for completeness of exposition. The technologies under this category will not be modelled in RS1a, under the assumption that consideration of PC-USC and IGCC with and without CCS is already addressing the main features of coal technologies for integrated modeling within NEEDS.

Circulating fluidised bed combustion (CFBC) at atmospheric pressure

Supercritical CFBC represents the way forward for CFBC technology. The first of such plants is being established at Polish utility PKE's Lagisza site in Southern Poland (WCI 2005b). The plant is also the largest CFBC to date, at 460 MW_e (PF 03-05 2003). Commercial operation has been scheduled for 2006 and efficiency levels are projected to be around 43% [IEA CCC 2003c] (WCI 2005b). CFBC is likely to be the most attractive form of FBC technology for the global market of power generation (WCI 2005b).

4.1.6 Pressurised fluidised bed combustion (PFBC)

Developments of the system using more advanced cycles are intended to achieve efficiencies of over 45% (IEA Clean Coal 2005b). The industry ambition in mid 1990s was to achieve efficiency of 53% within the next two decades (Dones et al. 1996). Schuknecht (2003) mentions a possible efficiency of 55% for second generation plants with a first stage for partial gasification.

The PFBC analyzed in (Bernero 2002) can be considered as an operational plant in near future. Figure 4.6 shows a schematic for a second generation PFBC power plant (Bernero 2002). Its thermal efficiency is 48.9% (LHV). The net plant power output is 417 MW, of which the steam turbine contributes 227 MW, the gas turbine 190 MW. Steam parameters are 166 bar/538°C/538°C. Several measures for an increase of efficiency are here presented. A rising carbon conversion ratio (CCR) in the carbonizer, which is defined as the ratio of the carbon converted in the carbonizer to the total carbon present in the coal, is expected to increase overall efficiency. An increase of the CCR from about 0.6 to 0.8 leads to an increase in the system efficiency of about 1%. However, higher CCR means higher carbonizer bed temperature while this temperature has to be within a certain range (820°C to 900°C), otherwise the carbonizer malfunctions. An increase in carbonizer bed temperature is limited by the turbine exhaust temperature at the current plant configuration.

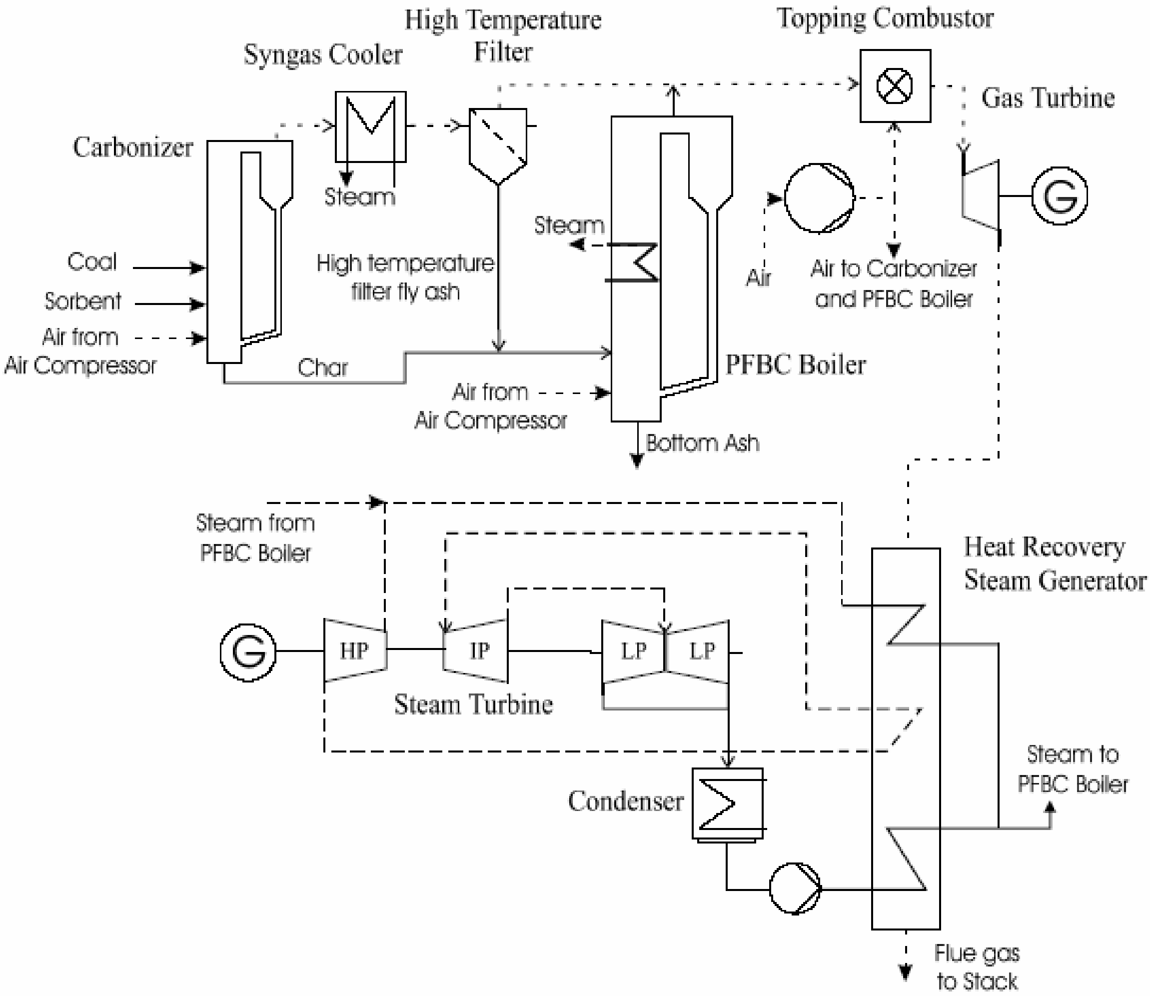

Figure 4.6 Schematic for a second generation PFBC power plant (Bernero 2002).

In general, overall efficiency depends more on the steam turbine performance than on that of the gas turbine, especially at low carbon conversion rates (Bernero 2002). Every 50°C increase in the gas turbine inlet temperature boosts the overall efficiency by about 0.25 percentage points. This improvement strongly depends on turbine technology. Steam temperature must be taken into account as well. An increase of 100°C in the steam temperature corresponds to about one percentage point improvement in the overall exergetic efficiency. The economic analysis performed by (Bernero 2002) results in 20-year levelized cost of electricity of 6.94 $cent/kWh.

As for other FBCs, the residues consist of the original mineral matter contained in the coal feed and additional CaO/MgO, $CaSO_4$ and $CaCO_3$ due to the used sorbent for sulphur removal. Carbon-in-ash levels are higher in FBC residues that in those from PC (IEA Clean Coal 2005b).

4.1.6.1 Pressurised circulating fluidised bed combustion (PCFBC)

Second generation of PFBC is based on the circulating bed technology. Developments of the system using more advanced cycles are intended to achieve efficiencies of over 45% (IEA Clean Coal 2005b). The industry ambition in mid 1990s was to achieve efficiency of 53% within the next two decades (Dones et al. 1996). Schuknecht (2003) mentions a possible efficiency of 55% for second generation plants with a first stage for partial gasification.

PCFBC is still in its demonstration period. A test system started operating in Cottbus, Germany, in year 2000. A fully integrated PFBC power system with net capacity of 103 MW and an expected efficiency of 45% (HHV) is scheduled to be in operation in 2006 in the Lakeland Electric's McIntosh power station (DOE 2000). Efficiency of a commercial second generation PFBC plants could reach 46% (HHV) or higher. Critical components are hot gas cleanup system (ceramic barrier filters), advanced carbonizer (gasifier), hot gas piping, solids transfer valves, coal-water paste pumps, and gas turbine optimized for PFBC systems (Bernero 2002).

4.1.7 Pressurised pulverised coal combustion (PPCC)

It is based on a combined cycle. PPCC boiler is, like PFBC's, operated at elevated pressure levels in the range 1-2 MPa, but in PPCC the temperature in the boiler is about 1600°C and at the gas turbine inlet 1000-1300°C (the upper temperature requires gas turbine development). Molten ash particles form because of the high combustion temperatures, which must be removed together with the alkalis (mainly sodium and calcium compounds) from the flue gas to protect the gas turbine (RAG and STEAG 2002). The flue-gas cleaning technology has still not been completely solved. Future efficiencies of up to 55% are envisaged (Decon 2003).

4.1.8 High Performance Power Systems (HIPPS)

HIPPS stands for "High Performance Power Systems", which is a power plant concept based on an indirectly fired gas turbine combined cycle, proposed by the US Department of Energy. There are two concepts: "One HIPPS design uses a fluidized-bed coal pyrolyzer operating at about 927°C and 18 bar. The pyrolyzer converts pulverized coal feedstock into two components: a low-heating-value fuel gas and solid char. The char is separated and burned in the HTF (High Temperature Furnace) at atmospheric pressure, raising superheated steam and preheating the gas turbine air. The fuel gas is burned with the air from the HTF in a multi-annular swirl burner to further heat this air to the gas turbine inlet temperature. In the other HIPPS design, the HTF is a direct-fired slagging furnace that utilizes flame radiation to heat air flowing through alloy tubes located within a refractory wall. The HTF is currently designed to heat air to 930°C-1000°C. In order to further boost this temperature, natural gas or another clean fuel can be used. It is fuelled with both coal and natural gas at the same time" (Bernero 2002). Figure 4.7 provides a schematic overview of the second type.

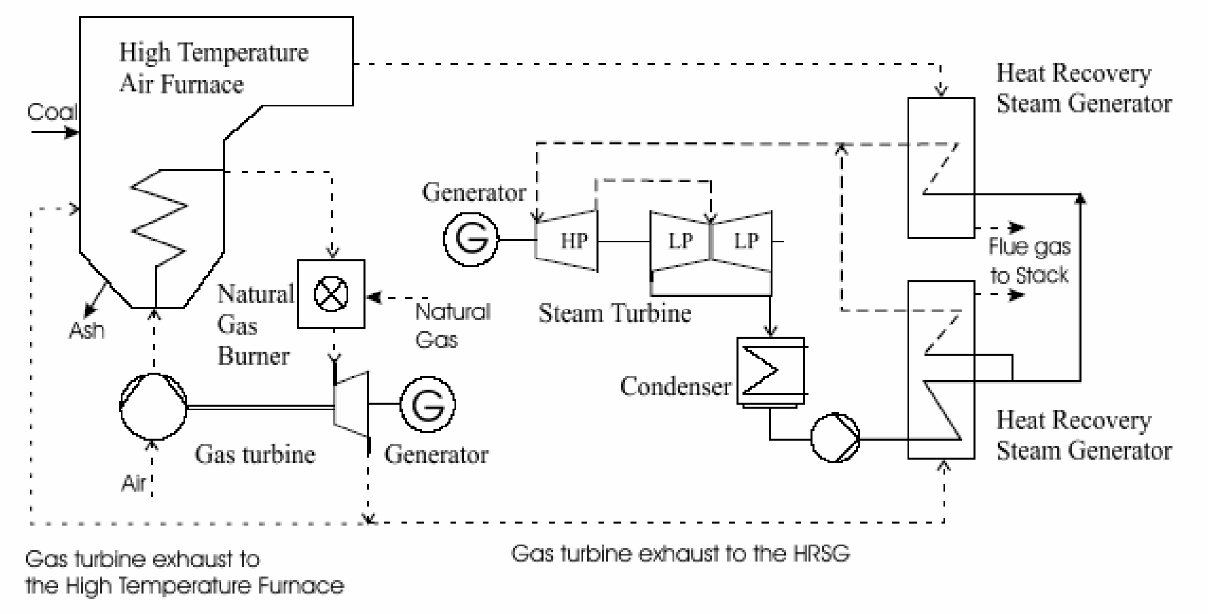

Figure 4.7 Schematic picture of a HIPPS unit (Bernero 2002).

The performance of such a device is analyzed in (Bernero 2002): the analysed system has an efficiency of 48.1% (HHV) or 51.3% (LHV), at a net power output of 568 MW and steam parameters of 93 bar/621°C. Based on HHV, about 65% of fuel input is coal, 35% natural gas. 20-year levelized costs of electricity are calculated as 7.06 $cents/kWh. An increase of the steam parameters to 162 bar/680°C increases the efficiency by about 1.2%. Operation with coal as only fuel would result in a slightly decreased efficiency of 49.9% (LHV). Further improvements of the system efficiency require an increase in both the air temperature at the air heater exit and the gas turbine inlet temperature (currently 1340°C and 1260°C, respectively). Improved materials and advanced gas turbine technologies will have significant influence on the overall efficiency. Compared to a supercritical steam power plant, reduction of the condenser pressure of a HIPPS is as beneficial. Every 10 mbar decrease in the condensing pressure increase the efficiency of a HIPPS system by less than 0.3 percentage points.

The environmental performance of this type of power plant is very good, compared to a conventional PC plant. According to (Bernero 2002) CO_2 emissions are reduced by 35% (552 g/kWh vs. 854 g/kWh at efficiencies of 51.3% and 38.3%, respectively) and SO_2 emissions by 95% (2.39 g/kWh vs. 0.12 g/kWh with coal of 3.65% sulphur content). Different desulphurisation efficiencies of 90% for the PC plant and 99% for the HIPPS are assumed.

At the moment, there is no operational experience for this type of power plant. According to (Bernero 2002) the cycle performance should not be difficult. A potential problem could be ash deposition in the HTF.

4.1.9 Magnetohydrodynamic (MHD) electricity generation

A high temperature fluid conductor flows through a static magnetic field, resulting in a direct current electric flow perpendicular to the magnetic field. The fluid conductor is typically an ionised flue gas resulting from combustion of coal or other fossil fuels. Hence, contrary to all other systems above, the electric generator is static. Potassium carbonate, called “seed”, is injected during the combustion process to increase fluid conductivity. The fluid temperature is typically around 2,480 to 2,650º C with pressures ranging 0.5-1 MPa. A power plant featuring an MHD will also include a combined cycle section, thus producing electricity at three different generators. Such triple combined cycle unit has the potential for very low heat rates (in the range of 6858 kJ/kWh) and ~52% net efficiency. (Decon 2003)

4.1.10 Hydrogen from coal

Using hydrogen to produce electricity in gas turbines and fuel cells or using it to fuel vehicles has the obvious advantage of producing no direct pollution (WCI 2005b). Being hydrogen an energy carrier and not an energy source, the problem is to produce it in an environmentally respectful way and at reasonable costs. Fossil fuels are candidates for conversion into hydrogen, besides use of renewables and nuclear energy. Coal, with the largest and most widespread reserves of any fossil fuel, appears as a natural candidate to provide hydrogen (via coal gasification) in large quantities and for a long time horizon (WCI 2005b). As seen in the Section describing IGCC, if hydrogen production from coal would be coupled with CO_2 capture and sequestration (CSS), coal would compete on this ground with other CO_2-free means of hydrogen production. See Chapter on CSS below.

Several countries are starting to implement hydrogen programs and many of them – Europe, USA, Japan and New Zealand – are considering coal as an option for its production (WCI 2005b). For instance, the proposed 1.3 billion € Hypogen project of the European Commission regards the generation of hydrogen and electricity using fossil energy sources including coal (WCI 2005b). Similarly, the US DOE FutureGen 10 year program has the goal to demonstrate feasibility of hydrogen production from coal gasification (WCI 2005b).

4.1.11 Co-firing biomass or wastes with coal

A development which can apply to all of the generating systems is the co-firing of coal with biomass or wastes. These materials can be either directly burned or gasified together with coal.

Conventional coal-fired power plants can work with 10% and 20% biomass without modification in the combustion process. However, structural modifications like for biomass storage and handling equipment are necessary, which should be accounted for in the comprehensive assessment. On the whole, economics and efficiency of biomass renewable fuels could be improved through co-firing (WCI 2005).

Benefits of co-firing include: reductions in CO_2 (the carbon balance benefits from the co-firing of renewable wood or biomass; emissions from upstream of waste production are usually allocated to the production route rather than to the power production), SOx and NOx emissions per unit of electricity relative to coal-only fired plants (WCI 2005a); recovery of useful energy from biomass and wastes at high efficiencies which cannot be reached in plants burning biomass/wastes only; flexibility in the composition of the fuel to cope with irregular biomass flow.

4.1.12 Combined Heat & Power (CHP) plants

In combined heat and power (CHP) technology, the (subcritical) steam turbine is designed to produce both power and useful heat for process or district heating (IEA Clean Coal 2005b). However, although important for certain countries, large CHP plants are not modeled in this study.

4.1.13 Coal supply chain

Coal supply can be approximated by the current upstream chain to European countries as described in ecoinvent (Röder et al. 2004). Only the current import shares have been modified based on current trends and forecasts (GvSt 2004, OECD/IEA 2004).

Table 4.22 Shares of mining regions worldwide to the European hard coal supply mix in year 2050.

	%
Eastern Europe (Poland, Czech Republic)	49
USA	3
South America	14
East Asia (China, Inonesia)	5
Australia	9
Russia	5
South Africa	15

4.2 Gas technologies

4.2.1 Gas Combined Cycle (GCC)

4.2.1.1 Main drivers influencing future technology development

Natural gas is widely expected to play a crucial role also in the future energy supply. Within the natural gas power plants, the combined cycle plants have developed strongly in the past decades. A strong demand for the combined cycle technology is expected also in future. This will drive the future development of gas turbines as well.

A main driver for the future development of natural gas combined cycle plants are the political decisions on environmental targets. Natural gas combined cycle plants (without sequestration) have relatively low CO_2 emissions per kWhe compared to other fossil power plants. From the viewpoint of CO_2 emission reduction, natural gas CC plants are often seen as good alternatives to coal power plants. Nevertheless, the development of efficient CO_2 capture and storage methods for coal power plant could reduce this relative advantage of natural gas CC within the fossil technologies.

The technical parameters and costs of combined cycle plants will also be driven by emission targets for pollutants with regional impacts in particular the regulations on NOx emissions. NOx emissions from natural gas combined cycle plants are related to the high combustion temperature which is desirable for high efficiencies.

The technological development of natural gas combined cycle plants will be essentially determined by the development of gas turbines. A key driver is the progress in material research in order to increase the firing temperature and the pressure ratio of the gas turbine within the combined cycle plant.

Electricity from natural gas combined cycle plants is relatively cheap compared to most other electricity technologies i.e. the demand for cheap electricity is another essential driver.

Generally, the fuel prices will be a major driver for the future development of costs of natural gas electricity. Via the demand, the fuel prices have also a certain influence on the technology development.

Because natural gas combined cycle plants are relatively flexible in operation, the CC development will also depend on the needs of load management. The need for backup capacity for wind electricity or other stochastic electricity can be an essential reason for the decision to install new natural gas combined cycle plants.

4.2.1.2 The potential role of GCC in a future energy supply system

Currently, natural gas power plants provide about one quarter of the total installed power capacity of the world (IEA 2004). In 2002, about 21% of the global primary energy supply was attributed to natural gas (IEA 2004). Natural gas is widely expected to play a crucial role also in the future energy supply. For example the scenarios of the International Energy Agency for global electricity supply predict a large share of natural gas power plants. In the reference scenario for the world, IEA expects for the year 2030 an increase of the share of natural gas in the primary energy demand from the present 21% to 25% as well as an increase of natural gas electricity production from the present 21% to 29% (IEA 2004).

It is expected that the share of combined cycle within the newly installed capacity of natural gas power plants will further increase in future. Therefore a large number of newly installed natural gas combined cycle plants and a strong increase of the cumulative installed CC capacity can be expected between today and 2030 according to the above mentioned scenario. If the situation should develop even nearly as predicted by the IEA scenario, it seems unlikely that a sudden break down of the demand for natural gas power plants will occur between 2030 and 2050.

Nevertheless, the further development of natural gas combined cycle plants depends also on strategic political decisions e.g. on fuel supply security. Concerns about dependencies on natural gas imports from potentially instable regions may lead to a reduction of the share of natural gas electricity compared to scenarios which predict a dominant role of natural gas in future electricity production. Furthermore, a strong increase of renewable energy and/or nuclear power may lead to a less expansive growth of natural gas power plants and thus also to a weaker development of combined cycle plants.

4.2.1.3 Technology development perspective

Natural gas combined cycle power plants feature the best efficiency of all thermal based electricity generation technologies applied at present. This efficiency is mainly determined by the efficiency of the gas turbine turbo set (gas turbine + compressor). About two thirds of the capacity of the gas and steam power plant account for the gas turbine, the remaining third is supplied by the steam turbine. The efficiency of the gas turbine is basically depending on the gas turbine inlet temperature and the pressure ratio.

Current natural gas combined cycle power plants have an efficiency of about 57.5%. Net electric efficiencies of 60% or even greater are expected in the near future along with the development of high-temperature materials for gas turbine, ceramic hot gas path, metal surface cooling technology, as well as further increase of temperature and pressure for the steam cycle and steam-turbine stage-design enhancement. The 60 percent barrier may be reached until 2015.

The GE fourth generation CC plants with "H" Technology GT will be configured with an integrated closed-loop steam cooling system, as illustrated in Figure 4.8 (Chase 2004). This system allows higher turbine inlet temperature to be obtained without increasing combustion temperature (Chase 2004). The GE fourth generation CC technology is expected to achieve 60% LHV thermal efficiency in the first half of this decade (Chase 2004). "The application of ceramic hot gas path parts and coatings shows promise for further future performance gains. Steam cycle improvements that include increased steam pressure and temperature with supercritical steam cycles have near-term application. Current economic analysis indicates, however, that the thermodynamic gain associated with steam cycles that have steam temperatures and pressures above the current levels (1050°F and 1400 PSIG to 1800 PSIG) cannot be justified in most cases because of the added costs." (Chase 2004)

In the end, the trend for increased combined-cycle efficiency will be dictated by operating cost, especially the fuel price, and the cost of new technology development (Chase 2004).

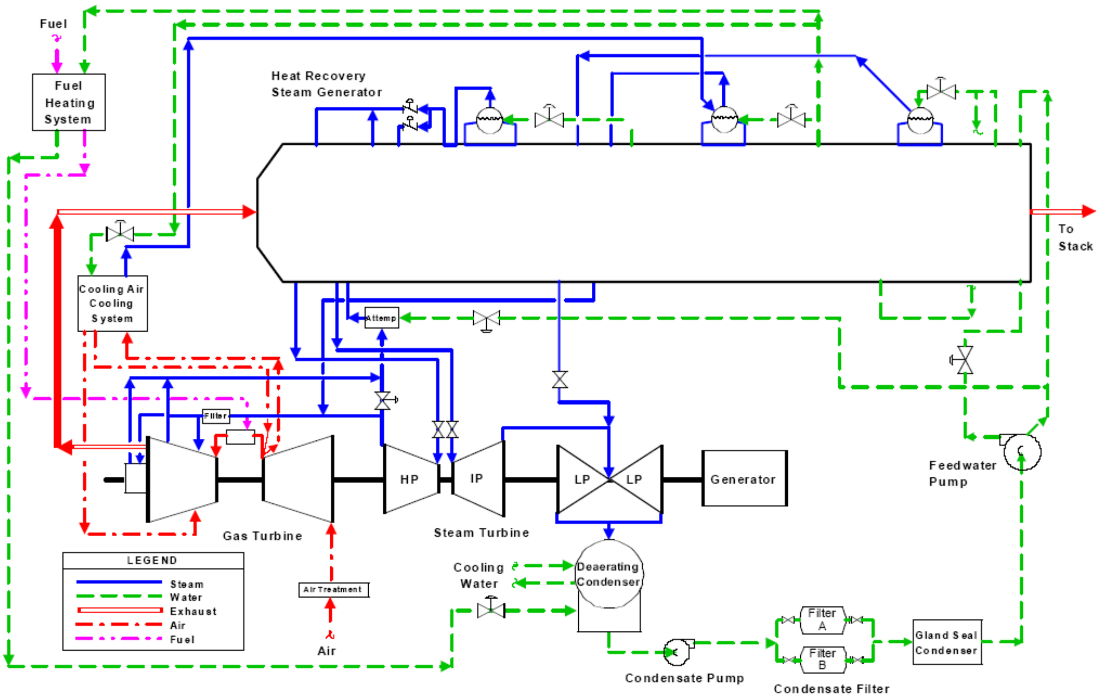

Figure 4.8 Diagram of GE fourth generation CC plants with "H" Technology GT (S107H/S109H cycle) (Chase 2004).

The major points to be considered for the future CC scenarios can be summarized as follows:

- Between 2015 and 2025 it is anticipated that natural gas combined cycle power plants with capacities around 500 to 1000 MW and efficiencies of 60% are offered at the world market. The specific investment costs of these power plants are estimated taking into account fuel savings due to higher efficiencies and cost degression due to higher capacities.

- For 2025 to 2035 further efficiency enhancement at same capacity level is assumed. This implies gas turbines with higher inlet temperatures, higher compressor pressure ratio, and advanced vane materials as well as enhanced vane cooling.

- In the long run the efficiency of natural gas combined cycle power plants is assumed to approach about 65%.

- It is considered unlikely that the efficiency of natural gas combined cycle power plants will become much higher than about 65-66%, even if gas turbines with intermediate heating and measures for component enhancements are assumed. By contrast, alternative designs like fuel cell/gas turbine hybrid plants promise efficiencies of 70% or beyond in future.

Table 4.23 shows some estimates of the future development of technical key parameters for natural gas combined cycle plants from literature or manufacturers.

Table 4.23 Future development of some technical parameters for natural gas combined cycle plants according to literature.

Parameter	Unit	2000	2005	2010	2015	2020	2025	2030	2035	2050	Reference
General NGCC data:											
Net electric efficiency	%		58				62		65		Bachmann 2005
	%		52.9-57.8			63					ALSTOM 2005
	%		58		60		63				IEA 2004, high estimate
	%		50		53		55				IEA 2004, low estimate
	%	57		60		60		65	65	65	DWTC 2001
Specific NGCC data:											
Capacity	MW_e		410			500					ALSTOM 2005
Net electric efficiency	%		57.8			63					
Technical lifetime	a		25			25					
Construction time	months		24			24					

4.2.1.4 Development of costs

According to Claeson Colpier & Cornland (2002), the specific investment price of combined cycle plants increased between 1981 and 1991. Between 1991 and 1997 the specific investment price decreased showing a strong progress ratio of 75%.

The specific investment is anticipated to further decline as gas turbines with higher capacity are expected to penetrate the market. The breakeven capacity allowing further cost degression is not achieved yet. The technical development aims at the construction of gas turbines with a capacity of 500 MW. However cost information on such future gas turbines are not available from power plant producers. For the near future, a progress ratio of about 90% may be expected (Claeson Colpier & Cornland 2002).

As the specific investment costs of natural gas and steam power plants is approximately half of those of hard coal power plants, and cost of the gas higher, the fuel costs have considerable influence on cost effectiveness of gas plants.

A moderate decrease of specific investment costs of combined cycle power plants is expected for the far future. Table 4.24 shows some estimates of future costs developments from literature or manufacturers.

Table 4.24 Future development of costs of natural gas combined cycle plants according to literature.

Parameter	Unit	2000	2005	2010	2015	2020	2025	2030	2035	2050	Reference
General NGCC data:											
Investment costs	€/kW	500		470		440		420	410	400	DWTC 2001
400-500 MW NGCC:											
Capacity	MW_e		410			500					ALSTOM 2005
Total capital costs	€/kW		434			438					
Installation costs, plant (turnkey)	€/kW		366			370					
Other capital costs	€/kW		68			68					(approval by authorities, land etc. for Switzerland) ALSTOM 2005
O&M (fixed)	€/MWa		8839			8397					ALSTOM 2005
O&M (variable)	€/MWh		2.01			2.23					

4.2.1.5 Specification of future technology configurations

Based on the considerations described above, the scenarios for natural gas combined cycle power plants have been estimated. The specifications of technology and costs for natural gas combined cycle power plants for 2005 to 2050 are presented in Table 4.25 through Table 4.31.

For the CHP mode of the combined cycle plants, it was assumed that the thermal efficiency is close to about 40-45% and the total efficiency is approximately 90%.

Table 4.25 Data of current and future 400-500 MW natural gas combined cycle plants, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	400	500	500	500	500
Net el. power at el. peak load	[MW]	400	500	500	500	500
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	57.5	60	62	63	65
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	440	440	430	420	400
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	8.8	8.6	8.4	8.4	8.4
Other variable costs	[€/MWh_{el}]	2.0	2.2	2.2	2.2	2.2

Table 4.26 Data of current and future 800-1000 MW natural gas combined cycle plants, realistic optimistic scenario.

realistic optimistic		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	800	1000	1000	1000	1000
Net el. power at el. peak load	[MW]	800	1000	1000	1000	1000
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	57.5	60	62	63	65
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	440	440	430	420	400
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	7.4	7.3	7.1	7.1	7.1
Other variable costs	[€/MWh$_{el}$]	2.0	2.2	2.2	2.2	2.2

Table 4.27 Data of current and future 200-250 MW natural gas combined cycle CHP plants, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	200	250	250	250	250
Net el. power at el. peak load	[MW]	200	250	250	250	250
Net el. power at thermal peak load	[MW]	166	208	208	208	208
Net thermal power at thermal peak load	[MW]	136	155	145	140	130
El. efficiency at el. peak load	[%]	55	57	59	60	62
El. efficiency at thermal peak load	[%]	45	47	49	50	51
Thermal efficiency at thermal peak load	[%]	45	43	41	40	39
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	570	570	557	544	518
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	11.7	11.5	11.2	11.2	11.2
Other variable costs	[€/MWh$_{el}$]	2.0	2.2	2.2	2.2	2.2

Table 4.28 Data of current and future 400-500 MW natural gas combined cycle plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	400	500	500	500	500
Net el. power at el. peak load	[MW]	400	500	500	500	500
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	57.5	60	63	64	66
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	440	430	420	400	380
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	8.8	8.6	8.4	8.2	8.0
Other variable costs	[€/MWh_{el}]	2.0	2.2	2.2	2.0	2.0

Table 4.29 Data of current and future 800-1000 MW natural gas combined cycle plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	800	1000	1000	1000	1000
Net el. power at el. peak load	[MW]	800	1000	1000	1000	1000
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	57.5	60	63	64	66
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	440	430	420	400	380
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	7.4	7.3	7.1	6.9	6.8
Other variable costs	[€/MWh_{el}]	2	2.2	2.2	2	2

Table 4.30 Data of current and future 200-250 MW natural gas combined cycle CHP plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	200	250	250	250	250
Net el. power at el. peak load	[MW]	200	250	250	250	250
Net el. power at thermal peak load	[MW]	166	208	208	208	208
Net thermal power at thermal peak load	[MW]	136	155	143	142	136
El. efficiency at el. peak load	[%]	55	57	60	61	63
El. efficiency at thermal peak load	[%]	45	47	50	50	52
Thermal efficiency at thermal peak load	[%]	45	43	41	42	41
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	570	557	544	518	492
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	11.7	11.5	11.2	10.9	10.7
Other variable costs	[€/MWh$_{el}$]	2.0	2.2	2.2	2.0	2.0

Table 4.31 Data of current and future 400-500 MW natural gas combined cycle plants, pessimistic scenario.

Pessimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	400	500	500	500	500
Net el. power at el. peak load	[MW]	400	500	500	500	500
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	57.5	59	60.5	61	62
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	440	440	440	440	440
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	15	15	15	15	15
Fixed costs of operation	[€/kW/yr]	8.8	8.8	8.8	8.8	8.8
Other variable costs	[€/MWh$_{el}$]	2.0	2.2	2.2	2.2	2.2

4.2.2 Gas Turbine

4.2.2.1 Main drivers influencing future technology development

The future progress of standalone gas turbines is influenced by the general development of gas turbines for all kinds of applications like e.g. in combined cycle plants.

The main drivers for the development of gas turbines are similar to the main drivers for the development for combined cycle plants.

The following drivers can be outlined:

- Development of the natural gas market (because of the many applications of gas turbines, not only the electricity market is relevant).
- Progress in material research (for increase of the temperature and the pressure ratio).
- Targets for CO_2 reduction.
- Other environmental targets in particular limits on NOx emissions which have influence on the gas turbine design.
- Fuel prices (prices of natural gas and of competing fuels).
- Demand for peak load electricity.
- Development of innovative concepts like SOFC/GT.

4.2.2.2 The potential role of gas turbines in a future energy supply system

Gas turbines are used in many applications and often in combination with other technologies. Gas turbines are employed for electricity generation, for combined heat and power generation but also for other purposes like gas transport in pipelines, on offshore platforms or for air transport. Gas turbines are used in natural gas combined cycle plants but also in new concepts like IGCC or the combinations of fuel cells and gas turbines. Future gas turbines may also play a role in hydrogen combustion.

Because of the broad application, it is almost certain that gas turbines as such will play an important role also in the future energy supply system. The share of gas turbines or combined cycle plants within the newly installed capacity of natural gas power plants may be close to 60% between 2020 and 2030 (naturalgas.org 2006). The installation of new gas turbines is also expected for example for renovations of the existing gas pipelines and, in case of an expansion of the gas network, also for new gas pipelines. Because gas turbines are also part of promising future technology concepts like SOFC/GT, it is likely that a strong demand for gas turbines will also persist for the time between 2030 and 2050.

4.2.2.3 Technology development perspectives

Between 1970 and 2000, the efficiency of gas turbines raised from 28% to over 38% (Pauls 2003). The Siemens V94.3A gas turbine achieves an efficiency of 38.6% (Pauls 2003). In the 1970s, gas turbine capacities were limited to about 50 MW_e. A modern gas turbine like the Siemens V94.3A exceeds a capacity of 260 MW_e. Standalone gas turbines are relatively inefficient power sources compared to combined cycle plants. The advantages of gas turbines are low capital costs, low maintenance costs, and fast completion time to full operation (Boyce 2002).

In order to achieve the optimum efficiency of a gas turbine, it is necessary to increase both, the firing temperature and the pressure ratio. Gas turbines for electricity production are optimized with the objective of a long lifetime. This sets limits to the firing temperature and pressure ratio. Between the 1970s and the early 2000s, gas turbine inlet temperatures increased from about 800 to 1230°C (Pauls 2003). The pressure ratio of gas turbines has increased from about 17:1 in 1980 to about 35:1 around year 2000 (Boyce 2002).

Breakthroughs in blade metallurgy and new concepts of air-cooling have been important prerequisites to achieve high inlet temperatures for gas turbines (Boyce 2002).

The efficiency of the gas turbines increases with increasing firing temperature. The dependency of the efficiency on the pressure ratio at a given temperature is not a simple monotone function. At first, the increase of the pressure ratio leads to an increase of the efficiency. But increasing the pressure ratio beyond a certain value can lower the overall cycle efficiency at a given firing temperature. The optimum pressure ratio for a simple cycle at turbine inlet temperature of 1650°C is about 40:1. In a regenerative cycle (i.e. if a regenerator is used in order to increase the efficiency of the gas turbine), the optimum pressure ratio at 1650°C is about 20:1. Furthermore, very high pressure ratios result in a reduced tolerance of the turbine compressor to dirt in the inlet air filter and on the compressor blades (Boyce 2002).

A study by General Electric for the US Department of Energy (DOE) investigated key design parameters of next generation gas turbines (NGGT). A hybrid aero-derivative/heavy duty concept was identified as being the top candidate technology with a time horizon 2010 for development and availability for demonstration testing (General Electric 2001).

The life time of the gas turbine is an important parameter for life cycle assessment. The main parameters that affect the life expectancy of the hot section components of gas turbines are (Boyce 2006): type of fuel, firing temperature, materials stress and strain properties, effectiveness of the cooling systems, number of starts, number of trips, controllable expander losses (backpressure, turbine fouling/combustion deposits), and uncontrollable expander losses (turbine ageing).

Improvements in materials may lead to an increase of the lifetime of the gas turbine. Nevertheless, it is expected that the increase of the efficiency will play a more important role than the increase of the lifetime compared to current values. It is therefore assumed here that the technical lifetime will remain approximately constant also in the long run i.e. the same technical lifetime is used for all years from 2005 to 2050.

4.2.2.4 Development of costs

Experience curves based on MacGregor et al. (1991) indicate a continuous reduction of specific costs for gas turbines between 1958 and 1990. McDonald & Schrattenholzer (2001) show a learning rate of 22% from 1958-1963 and of 9.9% for 1963-1980 for gas turbines.

It is assumed that the capital costs of gas turbines will moderately decrease in future. The future cost development is assumed to be approximately in line with the future cost development of combined cycle power plants.

4.2.2.5 Specification of future technology configurations

The specifications of technology and costs for gas turbines for 2005 to 2050 are presented in Table 4.32 and Table 4.34.

Table 4.32 Data of current and future gas turbines, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	50	50	50	50	50
Net el. power at el. peak load	[MW]	50	50	50	50	50
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	38	41	43	44	46
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	250	250	240	230	210
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	9	9	9	9	9
Fixed costs of operation	[€/kW/yr]	7.8	7.8	7.8	7.8	7.8
Other variable costs	[€/MWh_{el}]	4.6	4.6	4.6	4.6	4.6

Table 4.33 Data of current and future gas turbines, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	50	50	50	50	50
Net el. power at el. peak load	[MW]	50	50	50	50	50
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	38	41	44	45	47
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	250	240	230	210	190
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	9	9	9	9	9
Fixed costs of operation	[€/kW/yr]	7.8	7.6	7.4	7.2	7.2
Other variable costs	[€/MWh_{el}]	4.6	4.6	4.4	4.2	4.0

Table 4.34 Data of current and future gas turbines, pessimistic scenario.

Pessimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	50	50	50	50	50
Net el. power at el. peak load	[MW]	50	50	50	50	50
Net el. power at thermal peak load	[MW]					
Net thermal power at thermal peak load	[MW]					
El. efficiency at el. peak load	[%]	38	39	40	41	42
El. efficiency at thermal peak load	[%]					
Thermal efficiency at thermal peak load	[%]					
Technical life time	[a]	25	25	25	25	25
Spec. investment costs (overnight capital costs)	[€/kW]	250	250	250	250	250
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	9	9	9	9	9
Fixed costs of operation	[€/kW/yr]	7.8	7.8	7.8	7.8	7.8
Other variable costs	[€/MWh_{el}]	4.6	4.6	4.6	4.6	4.6

4.2.3 Combined Heat and Power (CHP)

4.2.3.1 Main drivers influencing future technology development

Drivers for natural gas CHP (in particular small CHP):

- Political decisions to promote decentralized electricity generation.

- Demand for process heat in industrial production.

- Demand for CHP heat in buildings, related to the development of building materials and heat management in buildings (e.g. heat pumps versus CHP heating).

- Development of the natural gas market in general.

- Development of the gas price and of other fuel prices.

- Development of the low pressure gas network i.e. the availability of natural gas in residential areas (not specifically for electricity generation only, but also for other purposes like cooking).

- Targets for CO_2 reduction.

- Other emission targets which determine which catalysts are necessary or whether the small CHP plants are allowed to operate at lower costs without catalysts.

- Development of the electricity network; because small CHP pants are driven by heat demand, they cannot usually be used for peak load electricity.

4.2.3.2 The potential role of CHP in a future energy supply system

The share of CHP electricity (all size CHPs) in total electricity production has been estimated at about 12% in the year 2000 for EU-15 (Heck 2004). The CHP share varies strongly between different European countries. E.g. in Denmark, the share of CHP in electricity production is about 69%, in Germany the share is about 11%, in Greece and Ireland the shares are only about 3%. In 1997, the European Commission decided to set a target of 18% for European electricity production from CHP until the year 2010 (Eurelectric 2002). Thus a significant increase of installed CHP power can be expected in future. Nevertheless it is expected that the market will not develop homogeneously also in future in Europe and in the world.

4.2.3.3 Technology development perspectives

The efficiencies of small natural gas CHP plants have improved significantly during the past decades. The electric efficiency of 400 kW_e natural gas motor CHP plants in Switzerland has increased from about 33% in 1990 to about 36% in 2000 (BFE 2003). Further improvements are expected in future. The development of small natural gas combined heat and power plants will depend on the general development of the natural gas market. Insofar the situation is similar to that of the large natural gas power plants. But additionally, the small natural gas CHP plants are usually attached to the local gas network. Therefore the installation of a small natural gas CHP depends very much on the extension of the low pressure gas supply network.

The incentive for technical improvements of CHP plants of different sizes will be influenced essentially by the development of the heat demand. (For example the development of energy-efficienct buildings will most likely influence the demand for heating.) The development of small CHP depends also on the political views on decentralized versus centralized electricity production.

Table 4.35 shows estimates of the future development of the electric efficiency of small natural gas CHP plants.

Table 4.35 Estimates of future efficiencies of natural gas motor CHP plants.

Parameter	Unit	2000	2010	El. power (kW_e)	Reference
Electric efficiency	%	33	35-37	100	BFE 2003
	%	36	39-41	400	

4.2.3.4 Development of costs

A progress ratio of 61% for the timeframe of 1990-2001 has been reported for small natural gas CHP plants in Switzerland (BFE, 2003). Nevertheless, according to the authors, the reduction has been heavily supported by policy intervention and may not exactly reflect the real cost development. Significant reductions of investment costs and operation and maintenance costs are expected in future up to 2010 (BFE 2003). Moderate cost reductions can be expected in the long run. Table 4.36 shows estimates of future costs for small natural gas CHP plants.

Table 4.36 Cost estimates for future small natural gas CHP plants.

Parameter	Unit	2000	2010	El. power (kW_e)	Reference
Investment costs module	€/MWh_e	1030	840-970	100	BFE 2003
Investment costs module	€/MWh_e	710	580-645	400	
Total O&M	€/MWh_e	22.6	16.1-19.4	100	
Total O&M	€/MWh_e	19.4	12.9-16.1	400	

4.2.3.5 Specification of future technology configurations

The specifications of technology and costs for small natural gas CHP plants for 2005 to 2050 are presented in Table 4.37 through Table 4.43.

Table 4.37 Data of current and future 2 MW_e natural gas CHP plants, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	2.0	2.0	2.0	2.0	2.0
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	2.0	2.0	2.0	2.0	2.0
Net thermal power at thermal peak load	[MW]	2.6	2.2	2.0	1.9	1.8
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	39	43	46	47	48
Thermal efficiency at thermal peak load	[%]	51	47	45	43	42
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	785	685	643	607	571
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	46.2	42.4	38.5	38.5	38.5
Other variable costs	[€/MWh_{el}]	5.3	4.9	4.5	4.5	4.5

Table 4.38 Data of current and future 200 kW_e natural gas CHP plants, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	0.20	0.20	0.20	0.20	0.20
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	0.20	0.20	0.20	0.20	0.20
Net thermal power at thermal peak load	[MW]	0.30	0.25	0.23	0.22	0.21
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	36	40	42	43	44
Thermal efficiency at thermal peak load	[%]	54	50	48	47	46
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	1100	960	900	850	800
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	60	55	50	50	50
Other variable costs	[€/MWh_{el}]	7	6.5	6	6	6

Table 4.39 Data of current and future 5.5 kW_e natural gas CHP plants, realistic optimistic scenario.

Realistic optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	0.0055	0.0055	0.0055	0.0055	0.0055
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	0.0055	0.0055	0.0055	0.0055	0.0055
Net thermal power at thermal peak load	[MW]	0.012	0.010	0.010	0.009	0.009
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	28	31	33	33	34
Thermal efficiency at thermal peak load	[%]	62	59	57	57	56
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	2600	2256	2115	1998	1880
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	84.0	77.0	70.0	70.0	70.0
Other variable costs	[€/MWh_{el}]	9.8	9.1	8.4	8.4	8.4

Table 4.40 Data of current and future 2 MW_e natural gas CHP plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	2.0	2.0	2.0	2.0	2.0
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	2.0	2.0	2.0	2.0	2.0
Net thermal power at thermal peak load	[MW]	2.6	2.2	2.0	1.8	1.7
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	39	43	46	48	49
Thermal efficiency at thermal peak load	[%]	51	47	45	42	41
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	785	671	621	571	536
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	46.2	41.6	37.7	33.9	30.8
Other variable costs	[€/MWhel]	5.3	4.8	4.4	4.1	3.8

Table 4.41 Data of current and future 200 kW_e natural gas CHP plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	0.20	0.20	0.20	0.20	0.20
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	0.20	0.20	0.20	0.20	0.20
Net thermal power at thermal peak load	[MW]	0.30	0.25	0.23	0.21	0.20
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	36	40	42	44	45
Thermal efficiency at thermal peak load	[%]	54	50	48	46	45
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	1100	940	870	800	750
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	60	54	49	44	40
Other variable costs	[€/MWh_{el}]	7	6.4	5.9	5.4	5.0

Table 4.42 Data of current and future 5.5 kW_e natural gas CHP plants, very optimistic scenario.

Very optimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	0.0055	0.0055	0.0055	0.0055	0.0055
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	0.0055	0.0055	0.0055	0.0055	0.0055
Net thermal power at thermal peak load	[MW]	0.012	0.010	0.010	0.009	0.009
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	28	31	33	34	35
Thermal efficiency at thermal peak load	[%]	62	59	57	56	55
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	2600	2209	2045	1880	1763
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	84.0	75.6	68.6	61.6	56.0
Other variable costs	[€/MWh_{el}]	9.8	9.0	8.3	7.6	7.0

Table 4.43 Data of current and future 200 kW_e natural gas CHP plants, pessimistic scenario.

Pessimistic scenario		2005	2015	2025	2035	2050
Max. net el. power (busbar)	[MW]	0.20	0.20	0.20	0.20	0.20
Net el. power at el. peak load	[MW]					
Net el. power at thermal peak load	[MW]	0.20	0.20	0.20	0.20	0.20
Net thermal power at thermal peak load	[MW]	0.30	0.26	0.25	0.24	0.23
El. efficiency at el. peak load	[%]					
El. efficiency at thermal peak load	[%]	36	38	39	40	41
Thermal efficiency at thermal peak load	[%]	54	52	51	50	49
Technical life time	[a]	20	20	20	20	20
Spec. investment costs (overnight capital costs)	[€/kW]	1100	1100	1100	1100	1100
Guarding costs for period between shut-down and demolition	[M€]	0	0	0	0	0
Spec. demolition costs (greenfield)	[€/kW]	3	3	3	3	3
Fixed costs of operation	[€/kW/yr]	60	60	60	60	60
Other variable costs	[€/MWh_{el}]	7	7	7	7	7

4.2.3.6 Oil-fuelled Gas Combined Cycle (GCC) power plants

For supply safety and load management reasons, CCs can be alternatively or partially fuelled by easily storable fuel oil. Due to the different chemical composition of the fuel oil, the emission factors for the power plant are substantially different compared to natural gas. Emission factors have been derived in (Dones et al. 1996) from elemental analysis of the used low sulphur fuel oil and from literature data on GCCs. For VOC, the emission characteristics of oil fuelled industrial furnaces have been used as reference.

4.2.4 Natural Gas Supply chain

The modeling of the natural gas supply to future power plants is based on the current supply model to European countries as described in ecoinvent (Faist Emmenegger et al. 2004). The essential structure of the natural gas supply chain for large power plants and small CHP plants is shown in Figure 3.14 and Figure 3.15. The import structure for natural gas in Europe depends not only on the location of gas resources but also on the political development and on decisions concerning supply security. In order to avoid the influence of highly speculative suppositions about the future political conditions, it has been assumed for the scenario calculations that the import shares remain approximately constant, so that the changes reflect technological developments only.

Important parameters for the natural gas supply chain are the losses due to leackages in pipelines and due to the consumption of the compressor stations, in particular in the long-distance transport from Russia to Europe. For the different scenarios, it was assumed that a certain percentage of the current long-distance pipeline infrastructure will be replaced by high quality pipelines with low leackage rates according to ecoinvent data (Faist Emmenegger et al. 2004). For the optimistic-realistic scenario it was assumed that in 2050 about 80% of the long-distance pipelines in Russia will be replaced by very good pipelines. For the very optimistic scenario, a 100% replacement until 2050 was assumed. For the pessimistic scenario it was assumed that the losses remain at the current level. The scenario assumptions and the key input data are shown in Table 4.44. The lifetime of pipelines was assumed to be about 50 years.

Table 4.44 Assumptions for key parameters in natural gas upstream module “transport, natural gas, pipeline, long distance, Russia” for the different scenarios.

			2005	2025	2050
Optimistic-realistic					
	Share of future replacement with very good pipelines	%	0	30	80
	Methane emissions	kg/tkm	2.1E-03	1.5E-03	5.8E-04
	Natural gas in turbine compressor station	MJ/tkm	1.2E+00	1.1E+00	8.7E-01
Very optimistic					
	Share of future replacement with very good pipelines	%	0	60	100
	Methane emissions	kg/tkm	2.1E-03	9.6E-04	2.0E-04
	Natural gas in turbine compressor station	MJ/tkm	1.2E+00	9.4E-01	7.9E-01
Pessimistic					
	Share of future replacement with very good pipelines	%	0	0	0
	Methane emissions	kg/tkm	2.1E-03	2.1E-03	2.1E-03
	Natural gas in turbine compressor station	MJ/tkm	1.2E+00	1.2E+00	1.2E+00

4.3 CO_2 Capture & Storage (CCS)

4.3.1 CO_2 Capture

One way to reduce CO_2 emissions from electricity generation is to switch to less carbon intensive fuels such as natural gas or use non-fossil fuel nuclear or renewable energy systems. Another approach is to reduce emissions resulting from the use of coal (and possibly also gas) through improved efficiency and/or by capturing and permanently storing carbon dioxide. This second approach will be addressed in this Chapter.

While capture and geological storage of CO_2 has not yet been demonstrated for the specific purpose of abating emissions from power stations on a large scale[31], CO_2 separation is common in natural gas production and in gasification processes at petrochemical refineries. The injection of CO_2 into geological formations is being carried out routinely at more than 70 sites in enhanced oil recovery (EOR) operations, primarily in North America, North Africa and Europe (Australian Coal Association 2004).

Besides the recently started operation of a small-scale pilot unit (30 MW_{th}) with oxyfuel combustion in Schwarze Pumpe, Germany, and the subsequently planned demonstration power plant (500 MW_{el}) in Jänschwalde, Germany, announced by Vattenfall, also other German utilities like RWE and E.on are pursuing similar projects, starting between 2013 and 2020.[32]

It is unlikely that any technology combination that includes CO_2 capture and storage will be cost competitive with conventional coal-based power generation without the implementation of an international carbon market with substantial costs of CO_2 emissions, basically because of the additional energy requirements at the power plant, which cause substantial efficiency loss and need additional infrastructure. While costs should eventually fall significantly, there is considerable uncertainty about both the cost of abatement and the impact on generation costs (Australian Coal Association 2004). There are several projects under way aiming at cost reduction of CCS. For example, as reported by (WCI 2005b), the FutureGen project aims at producing electricity from a coal-fired power station incorporating carbon capture and storage at no more than 10% higher cost than one without CCS, starting operation in 2012. However, this limited cost increase seems referring more to future commercial units than pilot plants.

Capture of CO_2 can be achieved by separation either from the flue gas produced in conventional combustion or from the fuel gas before its combustion in gas turbines. Based on these two basic principles there are three main generic approaches for capturing CO_2 from power plants (Figure 4.9):

a) Post-combustion capture

b) Pre-combustion capture

c) Oxyfuel combustion

[31] A 30 MW_{th} unit with oxyfuel combustion ("Schwarze Pumpe") started its operation in September 2008 in Germany (http://www.welt.de/welt_print/article2416943/Auf-Schwarze-Pumpe-ruht-die-Hoffnung.html). However, when composing this report, no information about operational experience was available.

[32] http://www.welt.de/welt_print/article2416943/Auf-Schwarze-Pumpe-ruht-die-Hoffnung.html

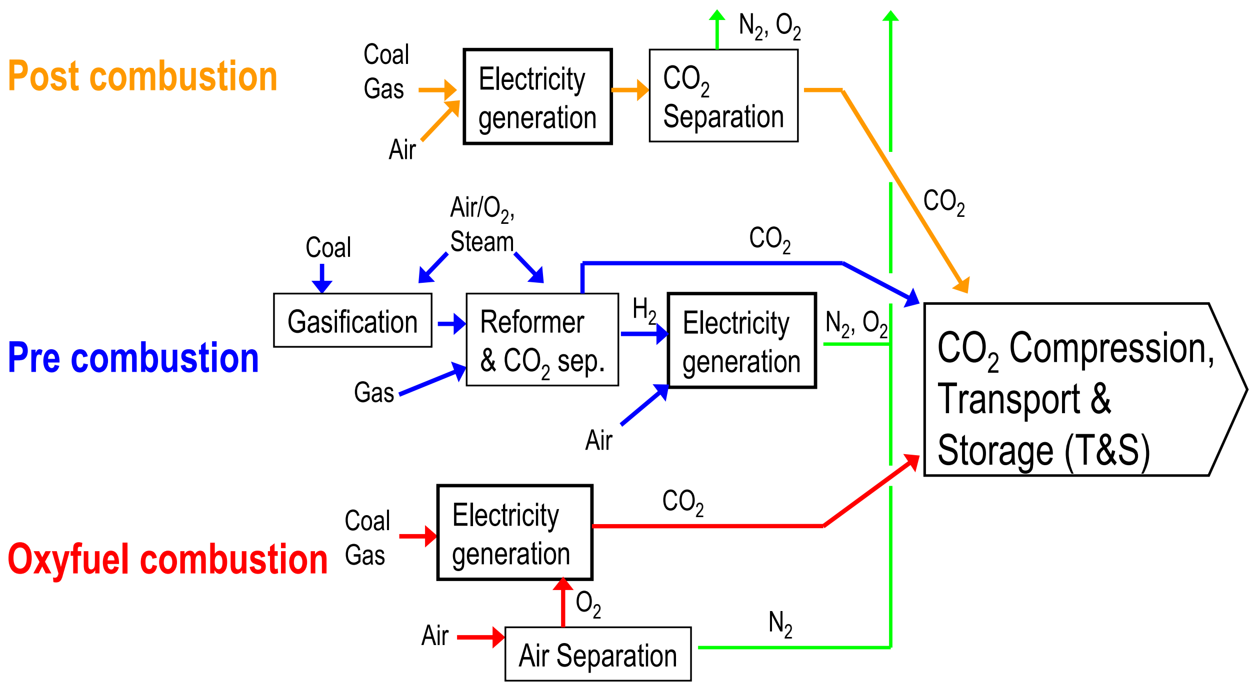

Figure 4.9 **Scheme of the three different technologies included in this study for CO_2 capture at the power plant, after (IPCC 2005).**

Post-combustion capture involves the separation of CO_2 from the flue gas. Flue gas separation and capture methods include the following technologies: chemical or physical absorption, adsorption/desorption, cryogenic separation and membrane separation (IEA 2002; APGTF 2004). The preferred technique for post-combustion capture at present is to scrub the flue gas with a chemical solvent and following to heat the solvent to release high purity CO_2 (APGTF 2004). The most common solvents used for neutralizing CO_2 in chemical absorption systems are alkanolamines such as monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA) (IEA 2002), but further developments are needed (PF 03-05 2003).

Alternative methods for separating CO_2 from flue gases, such as physical solvent scrubbing (absorption), adsorption/desorption, cryogenics and membranes, are presently more suited to pre-combustion and oxyfuel methods (APGTF 2004).

Pre-combustion capture involves reacting fuel with oxygen or air, and in some cases steam, to produce a gas consisting mainly of carbon monoxide and hydrogen (syngas). In a following shift reaction the carbon monoxide is reacted with steam in a catalytic shift converter to hydrogen and carbon dioxide. Finally the carbon dioxide is separated and the hydrogen can be burned in a gas turbine or used in fuel cells (APGTF 2004, WCI 2005b).

The advantage of pre-combustion capture relative to post-combustion capture is that a smaller volume of gas, being richer in CO_2 has to be treated. This reduces the size of the gas separation plant and thus reduces capital costs. Furthermore the higher concentration of CO_2 enables less selective gas separation techniques to be used (e.g. physical solvents, adsorption/desorption). These require less energy to operate per unit mass of CO_2 separated. Most of the technologies for pre-combustion capture are well proven in ammonia plants (APGTF 2004). However, the combustion system has to be completely redesigned and modified, thus costs and new risks arise.

The oxyfuel combustion CO_2 capture technology is based on the production of a highly concentrated, pressurized stream of CO_2 already at combustion, such that CO_2 can directly be captured. Oxyfuel combustion involves burning fuel in an environment of oxygen instead of ambient air. However, with pure oxygen the combustion temperature would be too high. Therefore, oxygen is mixed with CO_2 recycled from the exhaust in order to control the combustion temperature. The oxygen used is derived from an air separation unit. The exhaust from oxyfuel combustion is flue gas with very high CO_2 concentration (no NO_x formed). As further result, the volume of inert gas is reduced, which can increase boiler thermal efficiency (IEA 2002). The highly enriched CO_2 flue gas stream enables simple and low cost CO_2 purification methods to be used (APGTF 2004). The major drawback of this approach is that the production of O_2 using conventional cryogenic air separation plants is expensive, both in terms of capital cost and energy consumption (APGTF 2004). Oxyfuel combustion technique can be applied to conventional boilers and gas turbines, although a different design of gas turbine would be needed to work with highly concentrated CO_2, which rules out retrofit to existing Gas Turbine Combined Cycle (GTCC) stations (APGTF 2004).

New methods for carbon capture are being investigated. Among them, interesting is the chemical looping combustion (WCI 2005b). In chemical looping combustion, direct contact between the fuel and the combustion air is avoided by using a metal oxide to transfer O_2 to the fuel. Combustion takes place in two reactors: the reduction reactor, where the fuel is oxidized by the metal oxide and water and carbon dioxide are produced; and the oxidation reactor, where the metal it is re-oxidised by oxygen in air. Hence, there is continuously looping of the solid oxygen-carrier. Water is easily separated by condensation, thus yielding a fairly pure stream of CO_2 that can be compressed and liquefied (WCI 2005b). This technology appears less likely to be implemented on a significant scale in the time frame considered, hence it is not considered in the modeling herewith. Other concepts for capture technologies that are found in the literature are not reported here.

4.3.1.1 PCC with CO_2 Capture

For PC, two principal approaches can be implemented for CO_2 capture (PF 03-05 2003, IPCC 2005):

a) separation from the flue gas at the back end of an otherwise largely conventional PC unit;

b) separation from the CO_2-rich flue gas from oxy-coal combustion.

With oxy-coal combustion, total thermal efficiency could be higher than with post-combustion scrubbing but obviously still lower than for conventional PC without CO_2 recovery (PF 03-05 2003).

4.3.1.2 IGCC with CO_2 Capture

IGCC technology features advantageous characteristics for CO_2 sequestration. The pressure and concentration of CO_2 in the ‘shifted’ syngas favour CO_2 separation in pre-combustion capture (PF 03-05 2003).

If carbon capture is required, a shift-reactor and a CO_2 capture unit can be added to standard IGCC technology. The shift reactor is placed after the coal gasification and the syngas cleaning. The syngas is then reacted with steam prior to combustion (water/CO shift reaction) to produce hydrogen and a separate highly concentrated stream of CO_2. Thus CO_2 can be captured in a concentrated form in the CO_2 capture unit, and hydrogen remains available as a clean fuel (WCI 2005b).

The preferred technique for CO_2 capture in applications at higher pressure (i.e. IGCC) is currently physical absorption (IEA 2003a). Physical solvents commonly used in commercial processes include cold methanol (Rectisol process), dimethylether of polyethylene glycol (Selexol process), propylene carbonate (Fluor solvent process) and sulfolane. Others absorbents include Calcium Oxide (CaO), Sodium Hydroxide (NaOH) and Potassium Hydroxide (KOH).

In IGCC, CO_2 can be captured at lower energy expenditures than from the dilute low pressure flue gas of a conventional PF power station (Australian Coal Association 2004). Gasification and hydrogen production are widely considered the most promising technologies in coal-based power generation, if significant reductions in CO_2 emissions are required (Australian Coal Association 2004).

The process flow of an IGCC power plant with CO_2 sequestration is shown in Figure 4.10.

The addition of high temperature fuel cells fuelled by hydrogen to IGCC with CO_2 capture would raise efficiency further, but fuel cell stacks are currently still only at a relatively small scale and very expensive (PF 03-05 2003). See Section 4.1.4.1 for further information.

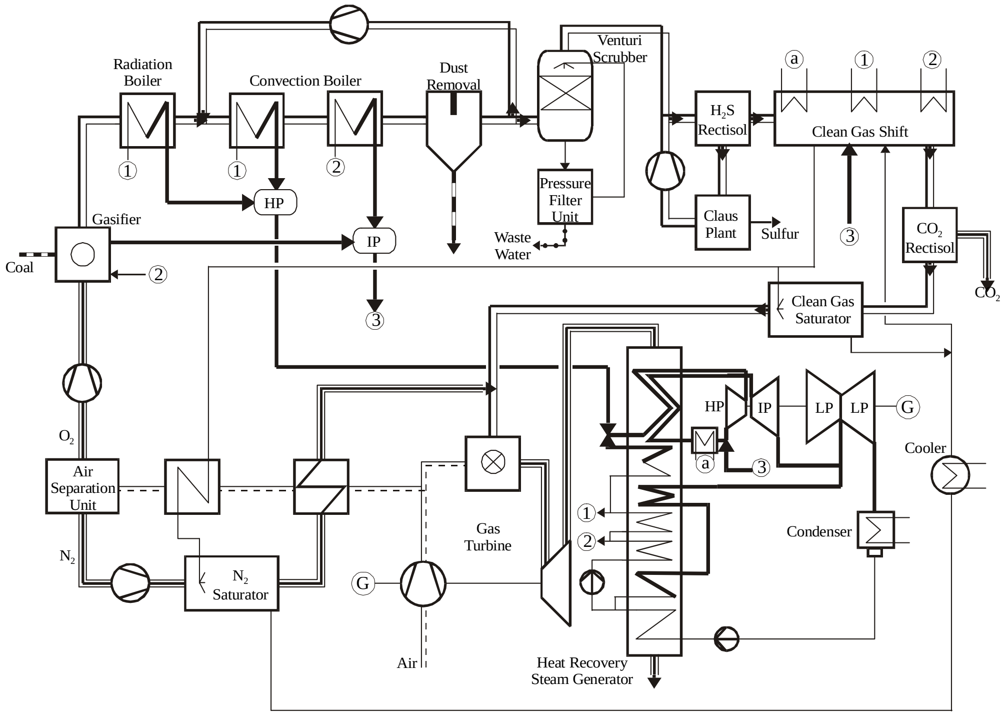

Figure 4.10 Process flow of an IGCC power plant with CO_2 sequestration (Advanced Cycles 1998).

4.3.2 Transportation of CO_2

After capture, CO_2 must be transported to the site of injection. Pipelines today operate as a mature market technology and are the most common method for transporting CO_2. Gaseous CO_2 is typically compressed to a pressure above 8 MPa in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it easier and less costly to transport. CO_2 also can be transported as a liquid per ship, road or rail tankers that carry CO_2

in insulated tanks at a temperature well below ambient, and at much lower pressures.. Transport of CO_2 in pipelines is cheaper than shipping over short distances. Due to relatively high fixed costs for harbors, loading and unloading, shipping becomes only competitive at distances between 1000 km and 2000 km (Figure 4.11, IPCC 2005, Radgen et al. 2005). Today, liquefied petroleum gases (LPG, principally propane and butane) are transported on a large commercial scale by marine tankers. CO_2 can be transported by ship in much the same way (typically at 0.7 MPa pressure), but this currently takes place on a small scale because of limited demand. Road and rail tankers also are technically feasible options. These systems transport CO_2 at a temperature of -20ºC and at 2 MPa pressure. However, they are uneconomical compared to pipelines and ships, except on a very small scale, and are unlikely to be relevant to large-scale CCS (IPCC 2005).

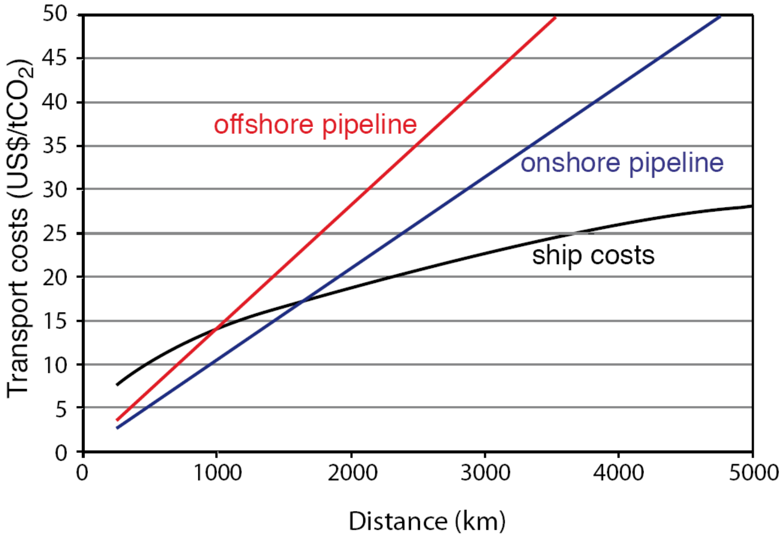

Figure 4.11 Costs of CO_2 transport, plotted as US\$/tCO_2 transported against distance, for onshore pipelines, offshore pipelines and ship transport (IPCC 2005).

About 3000 km of large land-based CO_2 pipelines are operational throughout the world, primarily in North America. Pipelines are used since the early 1980s. Most pipeline systems are usually designed so that recompression is not required beyond the power plant if distance is within about 200 km. Additionally, considerable offshore oil and gas pipeline infrastructure exists that may have the potential to support offshore CO_2 storage sites either for oil recovery or use of fully exploited gas fields (WCI 2005b, IEA 2002).

Internationally recognized standards for the design, construction, and monitoring of CO_2 pipelines are in place in the U.S. and Canada, and largely represent an extension of industry best practices for natural gas and other hazardous gas pipelines (IEA 2002). The IEA GHG R&D Programme compiled current CO_2 pipeline design data (IEA 2003a).

4.3.3 Storing CO_2

In order to contribute preventing that excess of anthropogenic CO_2 emissions from burning fossil fuels increase the concentration in the atmosphere to levels that may lead to harmful global warming, long-term storage of CO_2 has been proposed as an important option. The prime objective of CO_2 sequestration is to develop effective, verifiably safe, and environmentally sound storage sites that are acceptable to the public (IEA 2002, IPCC 2005).

Various technical options for the long-term storage of CO_2 are being researched. They include geological storage and mineral carbonation (WCI 2005b). Ocean sequestration is another option. However, for the time being there are major public and legal issues that must first be addressed before ocean storage can be applied. Other projects and studies on CO_2 storage presently exclude ocean sequestration from the main CO_2 options under closer investigation (CO2CRC 2003). Following the same line, the ocean sequestration option is herewith only described to a limited extent and not modeled.

4.3.3.1 Geological Storage

Injection of CO_2 into natural geological appropriate 'reservoirs' (Figure 4.12) offers potential for the permanent storage of very large quantities of CO_2 in different media. This is the most comprehensively studied storage option to date (WCI 2005b). The CO_2 is compressed to a dense (supercritical) state, then it is injected deep underground. The goal is store (and possibly monitor) CO_2 either trapped in the bedrock or dissolved in solution for very long time (WCI 2005b). Large volumes of CO_2 can potentially be stored long-term in a variety of geological structures including saline aquifers, depleted or nearly exhausted oil and gas reservoirs, and unmineable coal seams.

Research is ongoing in different countries to assess the viability and acceptability of the options. Several projects investigating the potentials for the storage of CO_2 have been and are being carried out in different countries and regions. Table 4.45 summarizes the results of projects investigating the CO_2 storage potential.

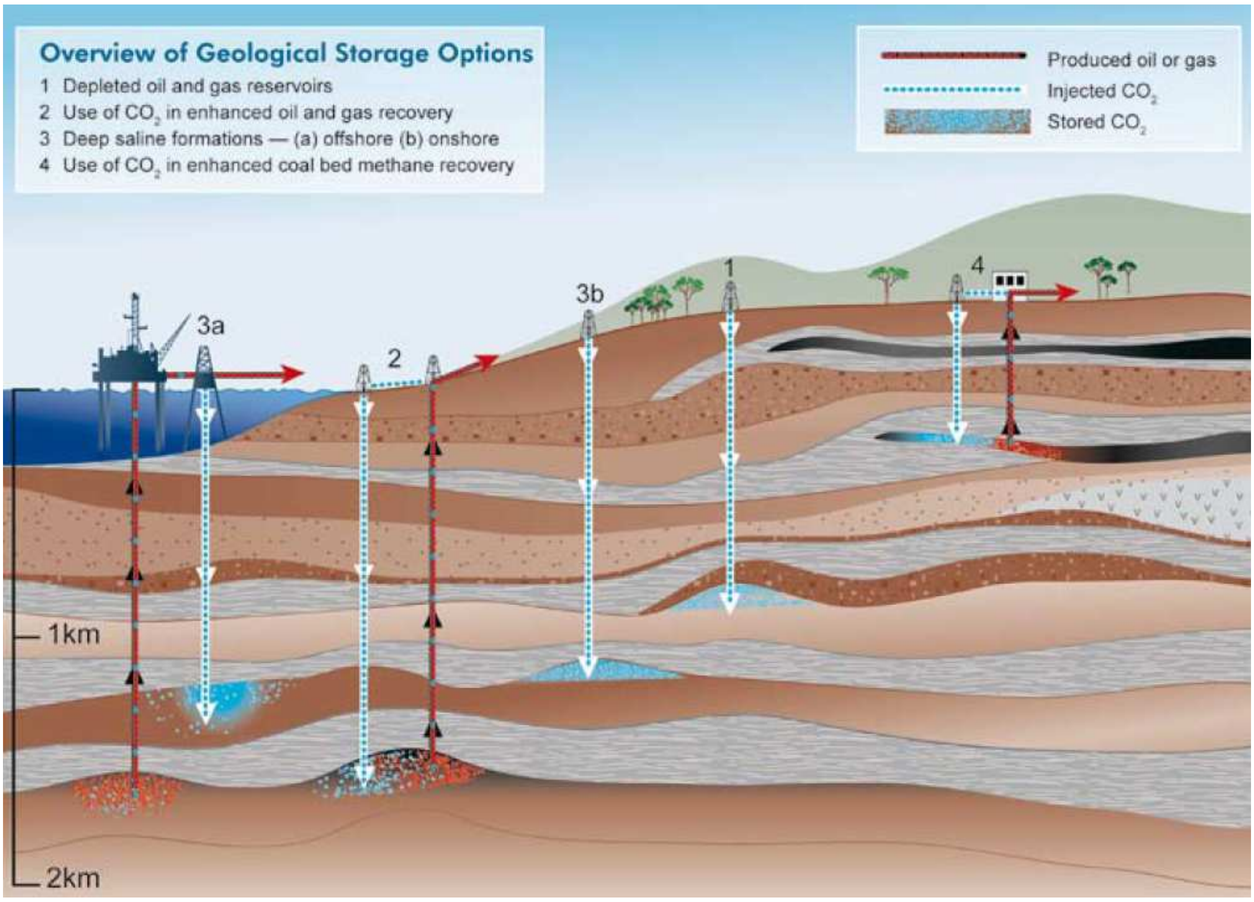

Figure 4.12 Options for CO_2-storage in geological structures (IPCC 2005).

Table 4.45 Technical potential for geological CO_2 storage [Gt CO_2], from various references.

Europe		Gas fields (depleted)	Oil fields (depleted, EOR)	Saline formations (Aquifers)	Unminable coal seams (ECBM)	Sum
Europe						
1	IEA GHG, R&D program, 1996	26	6	773	nn	806
Western Europe						
2	Dooley/Friedmann, 2004	42	7	215	4	268
3	GESTCO, 2004 (Denmark, Germany, Norway, UK, Netherlands, Greece)	30	7	91	nn	128
Worldwide						
4	IPCC 2005		675-900	1000-10'000	3-200	~ 1700-11'000
5	Fischedick et al. 2007	392-2126	54-1193	30-1081	0-1480	476-5880

4.3.3.1.1 Storage in saline aquifers

Storing large amounts of CO_2 in deep saline water-saturated reservoir rocks offers great potential (WCI 2005b). Deep saline aquifers are widely distributed below the continents and the ocean floor and are within easy access to a number of power plants. Deep aquifer sequestration (Figure 4.13) is currently being demonstrated and has proven to be technically feasible (IEA 2002).

Since October 1996 the Norwegian company Statoil is injecting about 1 million tonnes a year of CO_2 into the Utisira Formation at the Sleipner field in the Norwegian section of the North Sea, at a depth of about 800-1000 metres below the sea floor (WCI 2005b). This is equivalent to about 3% of Norway's total annual CO_2 emissions (IEA 2002).

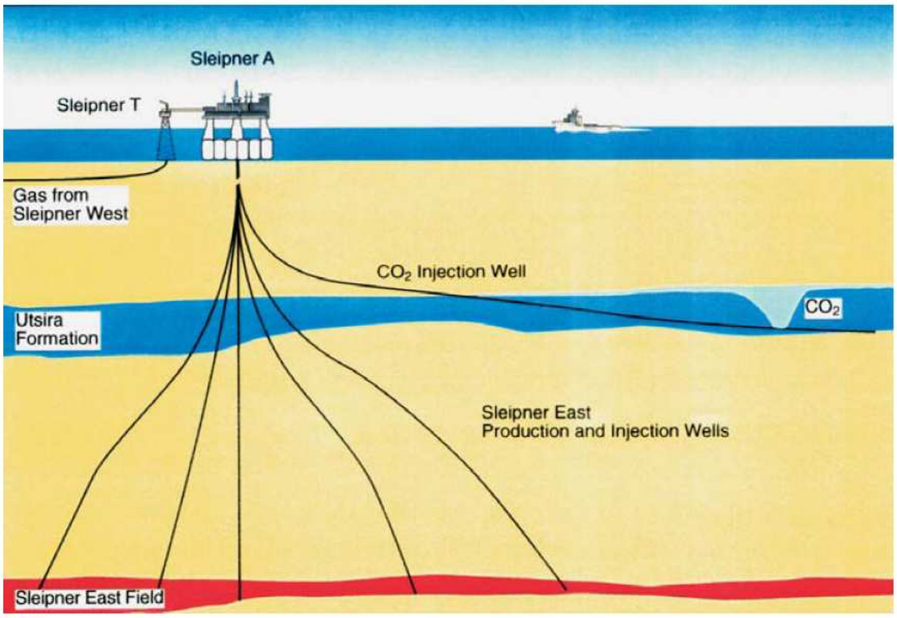

Figure 4.13 CO_2-storage in deep saline aquifers (IEA GHG 2001).

4.3.3.1.2 Storage in depleted gas reservoirs

Depleted gas reservoirs offer promising sites for geological storage of CO_2 (WCI 2005b). By their very existence, natural gas fields have demonstrated the ability to store gases for millions of years. The first successful natural gas storage project in depleted reservoirs was in Canada in 1915. An advantage of many of these sites is that they are an integral component of natural gas pipeline delivery systems, which can improve the economics of CO_2 transport and sequestration (IEA 2002). The US Department of Energy (DOE) estimated that the storage capacity of depleted gas reservoirs in the USA is about 80-100 Gt, or enough to store US emissions of CO_2 from major stationary sources for 50 years or more (Cook 2002; reported in WCI 2005b).

4.3.3.1.3 Enhanced Oil Recovery (EOR)

Enhanced Oil Recovery (EOR) is a process already widely used in the oil industry to increase oil production (Figure 4.14). CO_2 is injected into oil fields helping to pump out oil (IEA 2002). The reservoirs are natural stratagraphic traps that have held oil and gas over geological time. Furthermore, the geologic structure and physical properties of most oil fields have been extensively characterised and sophisticated computer models have been developed to predict the displacement behavior and trapping of CO_2 for EOR. Finally, industry has a significant amount of experience, technology, and expertise that can be applied to CO_2 storage at these sites (IEA 2002). Without such methods of enhanced production, many oil fields can only produce half or less of the original resource (WCI 2005b).

So far, there are about 70 currently active enhanced oil recovery operations, located primarily in Canada and the United States using about 60 million cubic metres per day of CO_2 (see Weyburn CO_2 flood project).[33] Currently, most of the CO_2 used for EOR comes from natural CO_2 reservoirs (IEA 2002).

Table 4.45 shows that the potential CO_2 storage in EOR is minimal for Europe.

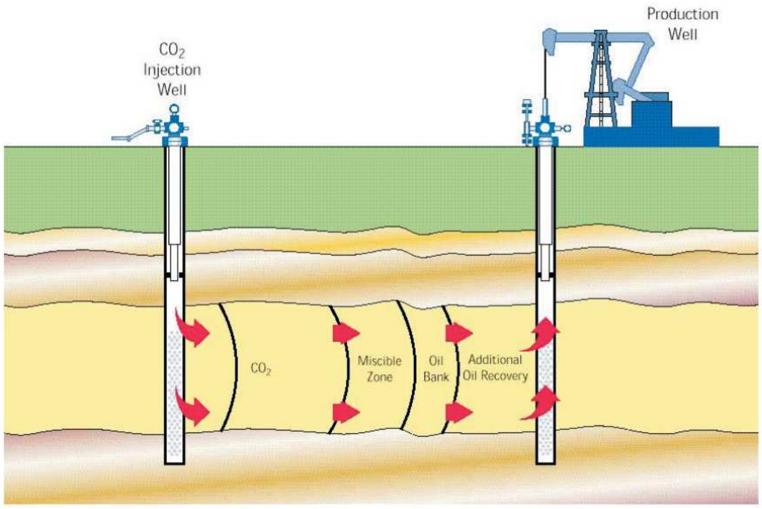

Figure 4.14 Principle of Enhanced Oil Recovery (EOR) (IEA GHG 2001).

[33] http://www.encana.com/operations/upstream/weyburn_scope_co2.html

4.3.3.1.4 Unmineable Coal Seams – Enhanced Coalbed Methane (ECBM)

Very deep coals seams cannot economically be mined with current best available technology. However these coal seams contain methane, which can be exploited and used as fossil feedstock.

Methane production from deep coalbeds can be enhanced by injecting CO_2 into coal formations (Figure 4.15), a process known as enhanced coalbed methane extraction (ECBM). At least two to three molecules of CO_2 are sequestered for each molecule of methane produced. Unlike in oil and gas reservoirs, the methane in coalbeds is retained by absorption rather than by trapping. Swelling of the coal matrix is a limiting factor for the absorption capacity. CBM technology is commercially available today and widely practiced in the U.S., and to some extent elsewhere. Since the early 1940s CBM extraction has been used for degassing exploitable coal and improving occupational safety in underground mines. When conditions are economic, CBM extraction is practiced by industry to produce electricity or heating fuel. The first commercial pilot application has been underway since 1996 at Burlington Resources' Allison Unit in the San Juan Basin in New Mexico, United States (IEA 2002).

From Table 4.45, potential CO_2 storage in ECBM appears a minor contribution to the estimated total potential geological storage capacity for Europe.

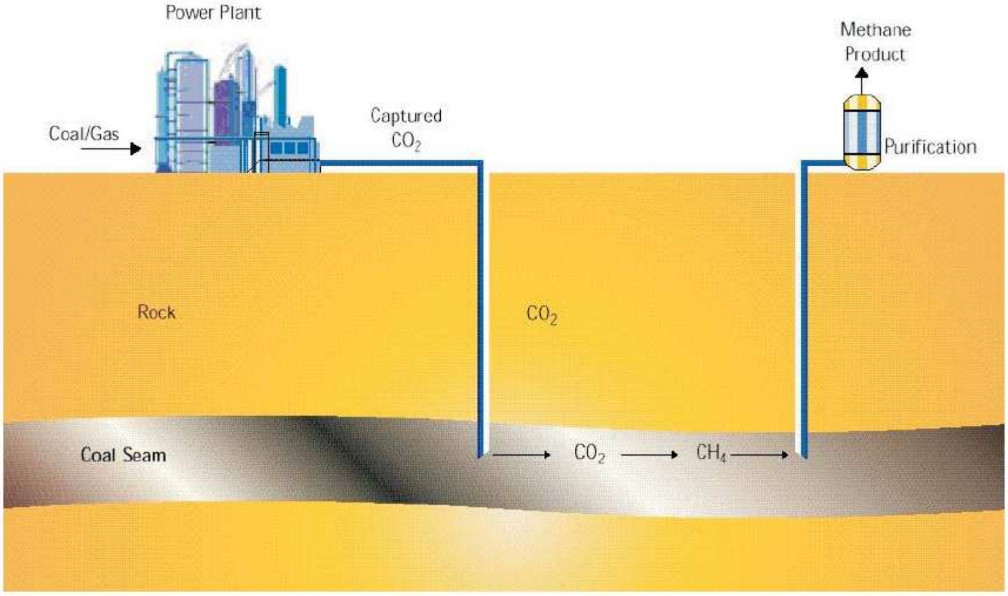

Figure 4.15 Principle of Enhanced Coal Bed Methane (IEA GHG 2001).

4.3.3.2 Mineral Carbonation

Another option for permanent storage is mineral carbonation. In this process, CO_2 is reacted with naturally occurring substances to create a product chemically equivalent to naturally occurring carbonate minerals (WCI 2005b). CO_2 can be reacted with minerals such as magnesium silicate (e.g., peridotites or serpentinites) to form stable, environmentally benign carbonates (IEA 2002). This process resembles the natural weathering of alkaline rocks, which normally occurs over long periods of time (WCI 2005b). CO_2 mineral storage could be obtained speeding up the reactions, but this is still at the laboratory stage of development.

4.3.3.3 Ocean storage

CO_2 can directly be stored in the deep ocean (at depths greater than 1,000 m), where most of it would be isolated from the atmosphere for centuries. This can be achieved by transporting CO_2 via pipelines or ships to an ocean storage site, where it is injected into the water column of the ocean or at the sea floor (Figure 4.16). The dissolved and dispersed CO_2 would subsequently become part of the global carbon cycle. Ocean storage has not yet been deployed or demonstrated at a pilot scale, and is still in the research phase. However, there have been small-scale field experiments and 25 years of theoretical, laboratory and modeling studies of intentional ocean storage of CO_2 (IPCC 2005).

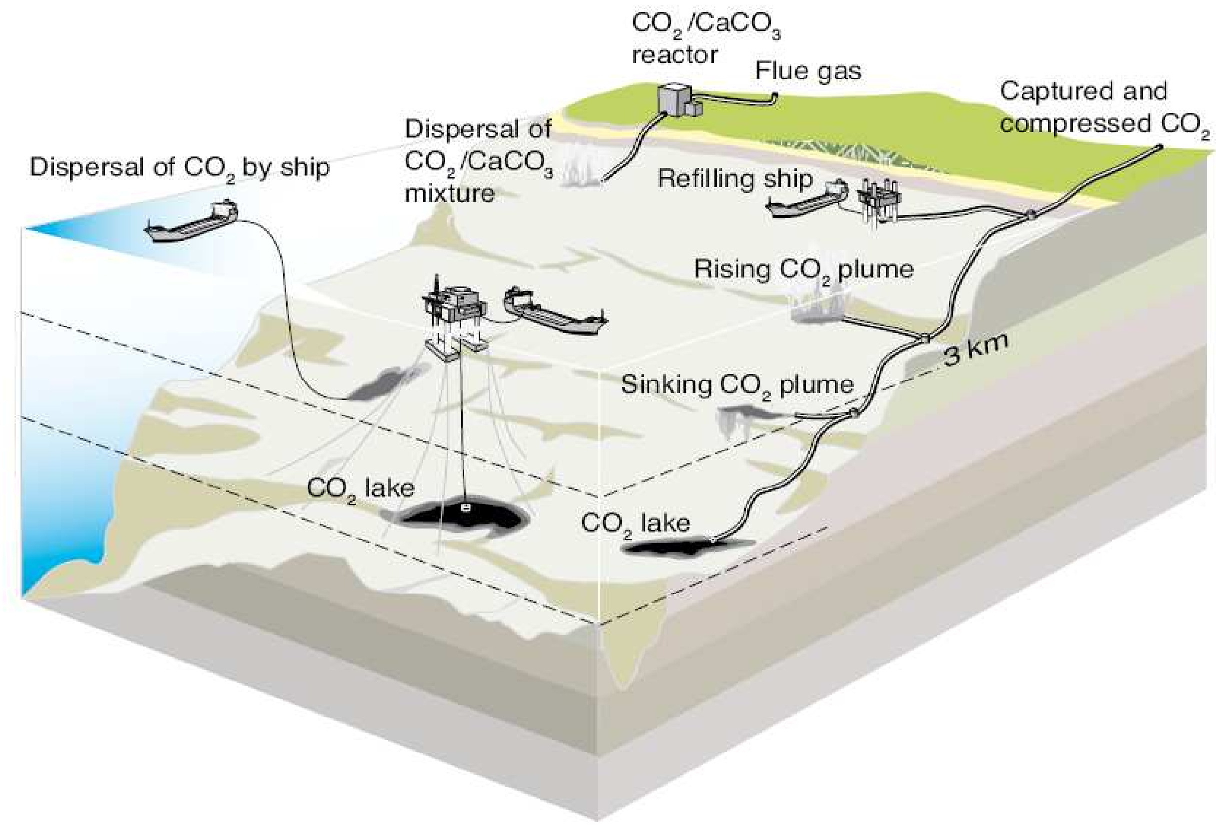

Figure 4.16 Methods of ocean storage of CO_2 (IPCC 2005).

4.3.4 Specification of future CCS technology configurations

Figure 4.17 illustrates the modeling approach for fossil power generation chains with CCS, as modeled in this study. The CCS part includes the separation of CO_2 at the power plant, its transport to the reservoir where it is injected and finally stored. It also includes the complete infrastructure for transport and storage, i.e pipelines, compressors, and injection wells.

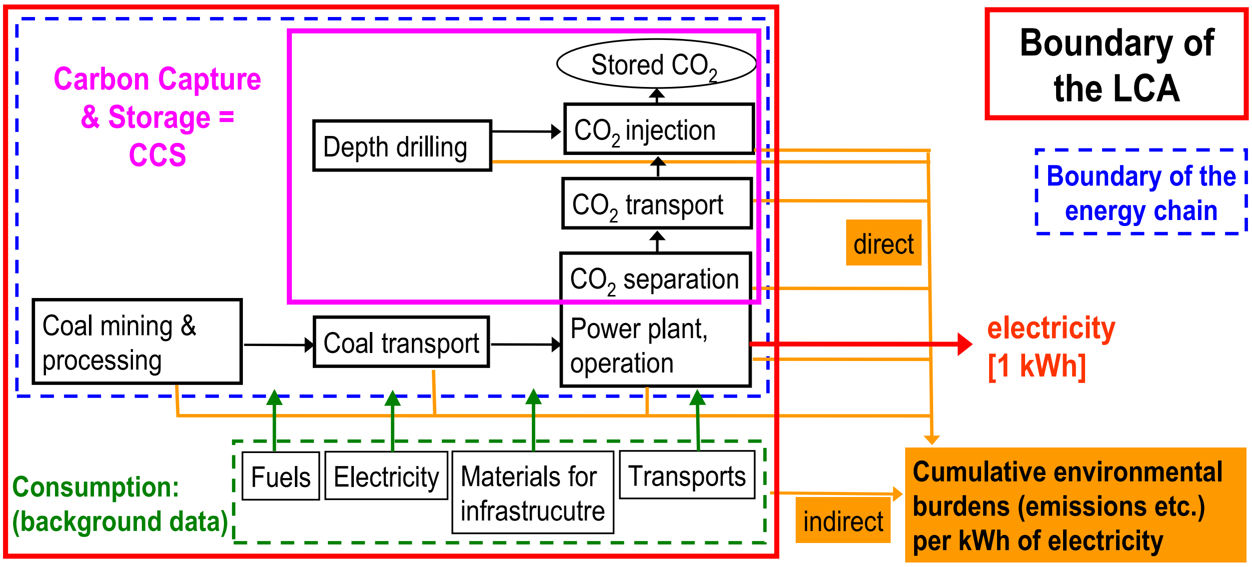

Figure 4.17 **Scheme of the hard coal chain for power generation including Carbon Capture and Storage.**

4.3.4.1 Capture (including compression)[34] at power plant

The following power plant reference technologies are modeled in this study, chosen as the most likely ones to be implemented in large scale within the next 40 years:

- Post-combustion, for the technologies supercritical PC (hard coal and lignite) and NGCC; using amine solvent separation;
- Pre-combustion, for IGCC technology (hard coal and lignite); using physical/chemical absorption separation;
- Oxyfuel combustion of coal (hard coal and lignite).

Among the three different hard coal power plants modeled without CO_2 capture (350 MW_{el}, 600 MW_{el}, 800 MW_{el}), the 600 MW_{el} unit was chosen as the one to be equipped with CO_2 capture for post- and oxyfuel combustion systems. The key factors for LCI of the power plant operation with CO_2 capture are the power plant efficiency with and without capture, CO_2 capture rate, and material use for operation (mainly chemicals for CO_2 separation). The electricity used for CO_2 compression at the power plant is treated as auxiliary uses and consequently subtracted from the gross electricity generated. Therefore, the LCA boundary of the operation of power plants with CCS includes the separation and compression of the CO_2. This means that the energy requirement for separation and compression of CO_2 at the power plant is taken into account by a reduction of the power plant net efficiencies, mainly based on (Hendriks 2007). Efficiencies of CO_2 separation differ for the three separation technologies considered – average values were extrapolated for the different time horizons and scenarios based on different sources (Hendriks 2007, Rubin et al. 2007, Fischedick et al. 2007). Table 4.46 summarizes the assumptions concerning reduction of power plant net efficiency and

[34] Unless otherwise explicitly noticed, hereinafter the term capture is always meant to include compression.

CO_2 capture efficiencies for the reference systems and the three different scenarios for the future time horizons (2025 and 2050). Net efficiencies of hard coal and lignite PC power plants are assumed to correspond in 2025 and 2050.

For what concerns the chemicals used for CO_2 separation from the exhaust in post-combustion processes, using an amine-based solvent, the upper range of the values reported in (IPCC 2005) for amine (modeled with mono-ethanolamine as the only appropriate substance available in the background LCI database), NaOH, and active carbon (modeled with charcoal) have been assumed in the study. Additionally, the difference between the total chemical requirements for separation reported in (Rubin et al. 2007) and the total materials (2.76 kg/kWh) from (IPCC 2005) has been modeled with generic organic chemicals (again the only appropriate substance available in the background LCI database). These values have not been changed for the different scenarios, because no information was available on process modifications in the future. This aspect would deserve a follow-up LCA modeling activity. Furthermore, in this study material needs for oxyfuel combustion could not be modeled, but only the energy uses for O_2 separation.

Concerning NO_x and SO_x emissions from PC plants, reductions along (Rubin et al. 2007, Andersson & Johnsson 2006) have been considered, but adjusting SO_2 emission to 0.1 g/kWh thus assuming scrubber efficiency of about 99%, and using bound N content in the hard coal for oxyfuel combustion exhaust (giving <0.2 g/kWh).

The infrastructure of the power plants (construction and dismantling) with CO_2 capture has been modeled the same way as for the units without CO_2 capture as first approximation. This simplification can be justified by the fact that although the infrastructure requirements for the capture plant are considerable, the construction materials do not contribute substantially to cumulative results (see chapter 5).

Table 4.46 Net efficiencies assumed for natural gas and coal power plants with and without CCS for the range of scenarios in year 2025 and 2050 defined in this study.

Fuel	Conversion technology	Capture technology class (combustion)	Year	Sc. *)	Net electric efficiency w/o CCS %	Net electric efficiency w/ CCS %	Efficiency penalty **) %	CO_2 capture efficiency %
Natural gas	NGCC	Post	2025	Pe	61	53	8	90
				RO	62	56	6	90
				VO	63	57	6	90
			2050	Pe	62	56	6	90
				RO	65	61	4	90
				VO	66	62	4	90
		Oxyfuel	2025	Pe	61	51	10	100
				RO	62	52	10	100
				VO	63	53	10	100
			2050	Pe	62	52	10	100
				RO	65	60	5	100
				VO	66	61	5	100
Coal	PC	Post	2025	Pe	47	37	10	90
				RO	49	42	7	90
				VO	52	45	7	90
			2050	Pe	50	43	7	90
				RO	54	49	5	90
				VO	57	52	5	90
		Oxyfuel	2025	Pe	47	37	10	99.5
				RO	49	41	8	99.5
				VO	52	44	8	99.5
			2050	Pe	50	42	8	100
				RO	54	47	7	100
				VO	57	50	7	100
	IGCC	Pre (hard coal)	2025	Pe	53	47	6	90
				RO	54	48	6	90
				VO	55	49	6	90
			2050	Pe	53.5	47.5	6	90
				RO	54.5	48.5	6	90
				VO	55.5	49.5	6	90
		Pre (lignite)	2025	Pe	51	45	6	90
				RO	52	46	6	90
				VO	53	47	6	90
			2050	Pe	51.5	45.5	6	90
				RO	52.5	46.5	6	90
				VO	53.5	47.5	6	90

* Sc. = Technology scenario: Pe = pessimistic; RO = realistic-optimistic; VO = very optimistic.
** Efficiency penalty = reduction in power plant net efficiency due to electricity demand for CO_2 capture and compression.

4.3.4.2 Transport of CO_2

The following reference technology is modeled in this study, chosen as the most likely to be implemented in large scale within the next 40 years in Europe:

- Transport of CO_2 by onshore pipeline, 200 km and 400 km.

Transport by ship is not modeled because of disadvantageous economics for average distances and capacities likely to occur in Europe until 2050.

The key factors for LCI are the pipeline capacity, the pressure, and the average distance for CO_2 transmission to storage sites in Europe (i.e. whether intermediate pumping stations are necessary or not). The modeling of the CO_2 transport in supercritical state has been conducted on the basis of an engineering bottom-up modeling approach (Wildbolz 2007, Doka 2007). The transport is assumed to occur by pipeline with mass flow of 250 kg/s, which would correspond to roughly three hard coal power plants with carbon capture of the 500 MW class, as modeled in this study. Two transport distances have been considered, 200 km and 400 km, the first without intermediate recompression, the second with one recompression (approximately 30 bar) unit after the first 200 km as illustrated in Figure 4.18. The UCTE electricity mix (at medium voltage level) is used for recompression of CO_2 (0.0389 kWh/tkm). The modeling of the pipeline infrastructure is extrapolated based on (Faist Emmenegger et al. 2004), considering the specific mass flow and pressure of supercritical CO_2. Leaking of CO_2 in the order of 0.26 g/tkm is taken into account.

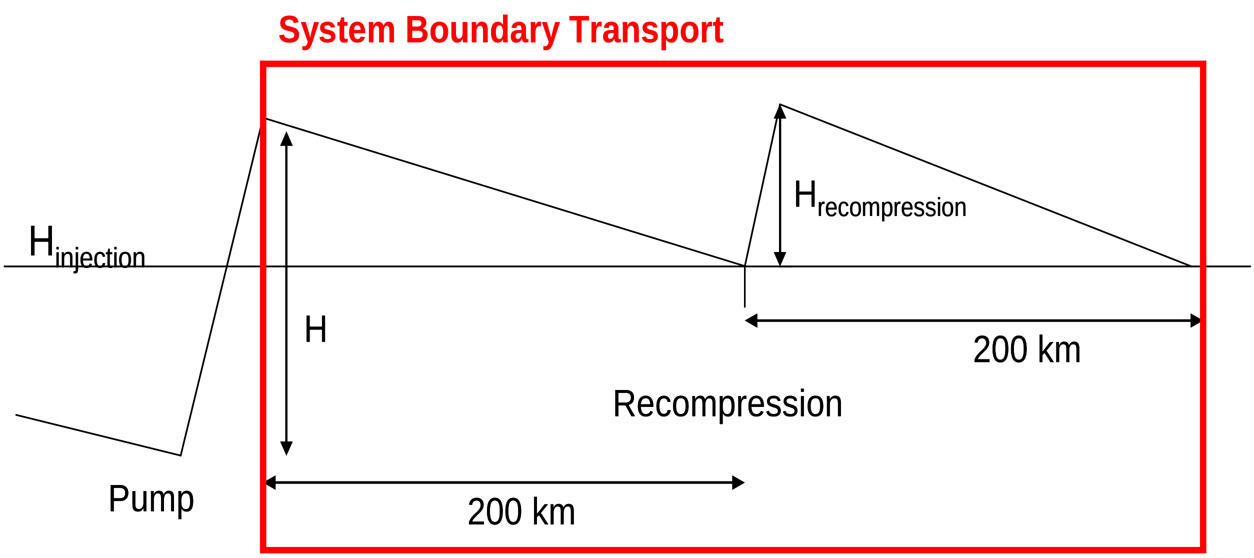

Figure 4.18 Schematic of the recompression for the transport process (Wildbolz 2007).

4.3.4.3 Storage of CO_2

Two different generic reference storage facilities are considered, being the options most likely to be realized in Europe until 2050:

- A saline aquifer at a depth of 800 m (for storage of CO_2 separated at hard coal and lignite power plants[35]);

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[35] It is assumed that the most economic and realistically implemented option for storage of CO_2 separated at natural gas power plants will be the "re-pumping" into exploited gasfields, relying on already used routes of gas pipelines and infrastructure relatively easy to be installed at already developed sites for natural gas production. Additionally the CO_2 to be injected can be used for increasing the production volumes of the gas reservoirs.

- A depleted gas reservoir at a depth of 2500 m (for storage of CO_2 separated at hard coal, lignite and natural gas power plants).

Capacity for un-mineable coal beds is of lesser importance for Europe (see Table 4.45) but it could still be an option for economical reasons, especially at local scale.

The key factors for LCI are the average depth for drilling, the power required for injection of CO_2 which in turn depends on the depth of the reservoir, and potential long-term leakages. It is assumed that the reservoirs are 100% imperviously, since this leakage rate of zero, guaranteed by tests and monitoring, can be assumed to be a prerequisite for any legal framework still to be established for storage of CO_2. The modeling of the CO_2 storage has been conducted on the basis of an engineering bottom-up modeling approach (Wildbolz 2007, Doka 2007). The number of wells required for a storage project will depend on various factors, like total injection rate, permeability and thickness of the geological formation, maximum injection pressure and availability of land-surface area for the injection wells (IPCC 2005). Taking into account the given boundaries – a mass flow of CO_2 of 250 kg/s correspoding to 7.9 Mt(CO_2) per year this results in the requirement of two injection wells for the modelled case (Wildbolz 2007). The hydrostatic pressure at the two reservoirs is assumed to be 78.4 bar and 171.5 bar (for the aquifer and the depleted gasfield, respectively). The required overpressure for the CO_2 injection of 30 bar results in an associated electricity demand of 0.0371 kWh/kg(CO_2) for the aquifer at 800 m depth and 0.1127 kWh/kg(CO_2) for the depleted gasfield at 2500 m depth (Wildbolz 2007, Doka 2007). Figure 4.19 illustrates the various pressure levels occuring within CO_2 transport and storage.

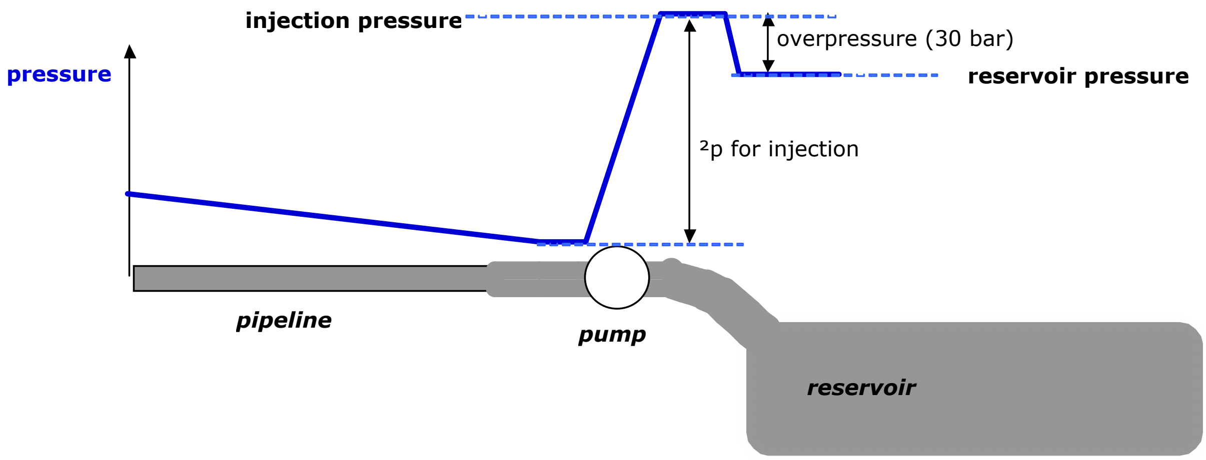


Figure 4.19 Illustration of different pressure levels for transport, injection and storage of CO_2 (Doka 2007).

Potential safety and risk issues associated with CCS technologies like accidents during CO_2 transport or injection, risks for humans and the environment due to spontaneous or gradual leakage of the reservoirs (IPCC 2005, UBA 2006b, Fischedick et al. 2007, Radgen et al. 2005) are not taken into account in this LCA study. Considering such issues would require alternative assessment methods.

4.3.5 Economics of CCS

In the longer term, technologies for CCS present one of the most promising options for economic and environmentally acceptable route to large-scale reductions in CO_2 emissions from fossil energy use (WCI 2005b). CCS has also the potential to enable coal and natural gas to contribute to form the basis of a future hydrogen economy (WCI 2005b) (see Section on IGCC with CO_2 capture). As described in the previous sections, besides obtaining permanent storage of CO_2, some processes can have economic benefits, like improving oil (EOR) and coal-bed methane (ECBM) extraction (WCI 2005b).

Carbon storage is not yet commercial, but some of the required technologies are proven and have been used in commercial applications in other contexts (WCI 2005b; Rubin et al. 2006). Technologies for capturing CO_2 from emission streams are being used in small scale to produce pure CO_2 for use in the food processing and chemicals industry. Petroleum companies routinely separate CO_2 from natural gas before it is transported to market by pipeline (WCI 2005b).

An integrated CCS system has three basic cost components: capture/compression, transport, and injection/storage. These costs are highly variable and depend on many factors including the source of CO_2, capture option, infrastructure availability, transport distance, and type and characteristics of the storage site.

The coal industry presents the economics of CCS as likely to be broadly comparable with those of other options, such as renewables (WCI 2005b). For instance, an IEA GHG study gives the cost of carbon capture and storage as 3 USc/kWh (2.5 €c/kWh) (WCI 2005b). "This compares with the current buy-out price for UK renewables of over 3p/kWh (5 €c/kWh) or the premium of 9 €c/kWh for wind power under the German Renewable Energy Law" (WCI 2005b). The costs of renewables are expected to fall in future as technology develops, but the same should be true for CCS, which is the object of several research projects (WCI 2005b). For example, as reported by (WCI 2005b), the FutureGen project aims at producing electricity from a coal-fired power station incorporating carbon capture and storage at no more than 10% higher cost than one without CCS.

Economic data for coal power plants with CO_2 capture used in this project for all time horizons are summarized in Table 2.7 through Table 2.10. Table 4.47 gives an overview about cost data including cost of electricity generation for the fossil reference power plants with and without CCS in year 2050 for the realistic-optimistic scenario.

Table 4.47 Economic specifications of fossil reference power plants in year 2050, realistic-optimistic scenario.

		Hard coal				
		PC	IGCC	PC, post combustion CCS	PC, oxyfuel combustion CCS	IGCC, pre combustion CCS
Overnight capital cost	€/kW	895	1100	1420	1420	1370
Levelized cap. Cost	€cents/kWh	0.89	1.11	1.42	1.42	1.38
Fixed O&M	€cents/kWh	0.54	0.71	0.83	0.83	0.87
Variable O&M	€cents/kWh	0.26	3.10	0.30	0.30	3.60
Fuel	€cents/kWh	1.26	1.25	1.39	1.45	1.41
Generation cost	€/MWh	29.6	61.7	39.4	40	72.6
		Lignite				
		PC	IGCC	PC, post combustion CCS	PC, oxyfuel combustion CCS	IGCC, pre combustion CCS
Overnight capital cost	€/kW	900	1100	1390	1390	1370
Levelized cap. Cost	€cents/kWh	0.88	1.11	1.39	1.39	1.11
Fixed O&M	€cents/kWh	0.43	0.71	0.81	0.81	0.71
Variable O&M	€cents/kWh	0.10	3.10	0.12	0.12	3.10
Fuel	€cents/kWh	1.60	1.65	1.77	1.84	1.86
Generation cost	€/MWh	30.1	65.7	40.8	41.6	67.8
		Natural gas				
		NGCC	NGCC, post combustion CCS			
Overnight capital cost	€/kW	400	560			
Levelized cap. Cost	€cents/kWh	0.48	0.67			
Fixed O&M	€cents/kWh	0.10	0.20			
Variable O&M	€cents/kWh	2.20	4.40			
Fuel	€cents/kWh	3.22	3.43			
Generation cost	€/MWh	59.9	86.9			

5 LCA results and conclusions

5.1 Current technologies

5.1.1 Hard Coal PC

5.1.1.1 Key resources and emissions

Table 5.1 shows selected LCI results for the electricity production at the busbar of the three reference hard coal power plants. The choice is based on the species included in the external cost estimation for recent projects of the ExternE series NewExt and ExternE-Pol (Rabl et al. 2004; Dones et al. 2005). Only primary nitrates and sulphates have been excluded from the list due to their negligible contribution (nitrates and sulphates are important as secondary pollutants, which are not accounted for in an LCI).

Table 5.1 Consumption of selected resources and key emissions for the hard coal reference technologies around year 2000, per kWh_e at the busbar.

Parameter	Path	Unit	USC-PC 350 MW	USC-PC 600 MW	USC-PC 800 MW
			kWh_e	kWh_e	kWh_e
Coal, hard, unspecified, in ground	resource	kg	4.28E-01	4.28E-01	4.18E-01
Arsenic	air	kg	1.53E-08	1.51E-08	1.49E-08
Cadmium	air	kg	1.74E-09	1.70E-09	1.66E-09
Carbon dioxide, fossil	air	kg	7.76E-01	7.76E-01	7.59E-01
Chromium VI	air	kg	2.79E-09	2.55E-09	2.53E-09
Dinitrogen monoxide	air	kg	3.36E-05	3.36E-05	3.28E-05
Formaldehyde	air	kg	5.07E-07	5.06E-07	4.95E-07
Lead	air	kg	1.66E-05	1.66E-05	1.62E-05
Methane, fossil	air	kg	2.36E-03	2.36E-03	2.31E-03
Nickel	air	kg	1.16E-07	1.15E-07	1.13E-07
Nitrogen oxides	air	kg	8.08E-04	8.07E-04	7.90E-04
NMVOC (total)	air	kg	4.00E-05	3.99E-05	3.90E-05
PM10					
PM2.5	air	kg	5.33E-05	5.31E-05	5.20E-05
PM2.5-10	air	kg	2.19E-05	2.17E-05	2.12E-05
Sulfur dioxide	air	kg	6.18E-04	6.18E-04	6.04E-04

5.1.1.2 Contribution analysis

The contribution analysis addresses only the above selected key emissions species split into the four life cycle phases defined for NEEDS integration. Figure 5.1 through Figure 5.3 show that in general for the energy chains associated with the 350 MW, 600 MW and 800 MW power plants the results are pretty much the same. Power plant operation is contributing the most to the total burdens of CO_2, N_2O, Formaldehyde, and lead. Nearly 80% of the nickel comes from the upstream chain, whereas Cr-VI originates from construction material manufacturing. Due to the high efficiency of the de-SO_x and de-NO_x at the power plants, their relative contribution to cumulative emissions of SO_x and NO_x remains below 60%; practically, the fuel upstream chain makes up the rest. Emission of CH_4 is almost entirely originated by mining (underground). About 70% of the cumulative emission of $PM_{2.5}$ stems from the power plant, the upstream chain making up almost the rest, whereas the proportions are practically inverted for $PM_{2.5\text{-}10}$. Emission of total NMVOC originates almost entirely from the upstream chain, e.g. from transport.

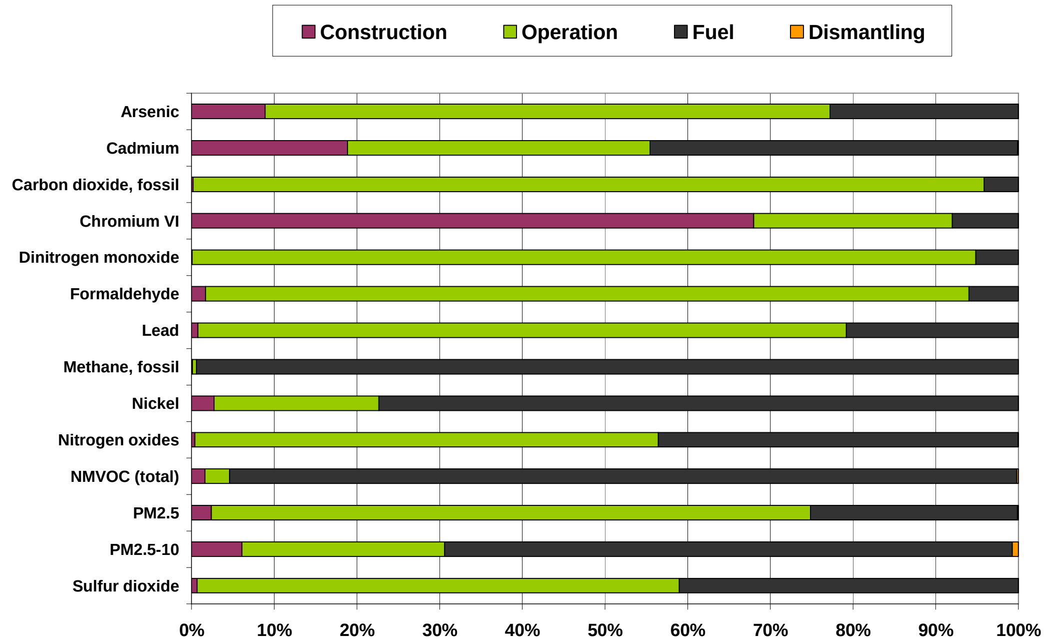


Figure 5.1 **Contribution analysis of selected cumulative air burdens associated with the electricity supplied to the grid by the current (year 2000) hard coal reference 350 MW power plant.**

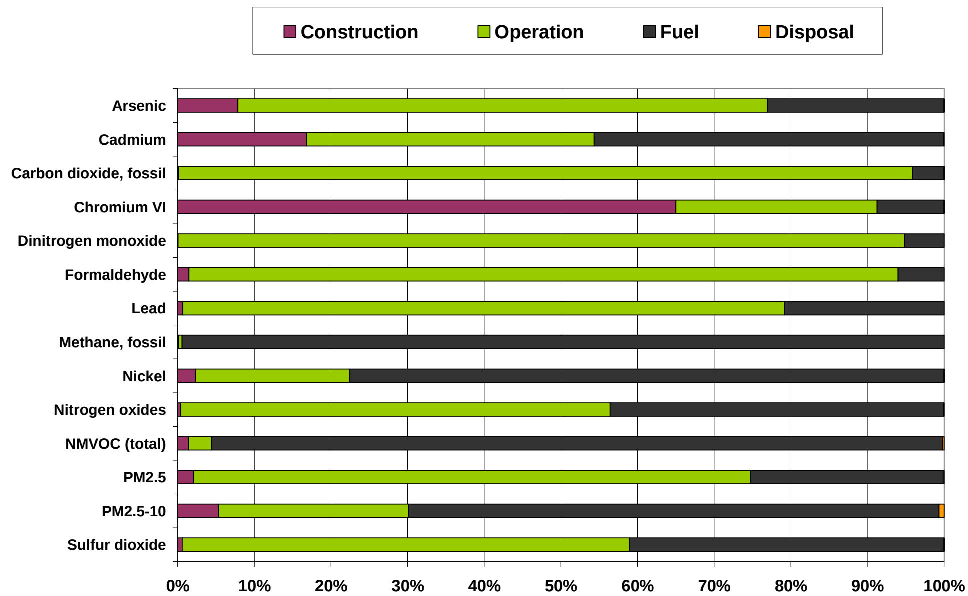


Figure 5.2 **Contribution analysis of selected cumulative air burdens associated with the electricity supplied to the grid by the current (year 2000) hard coal reference 600 MW power plant.**

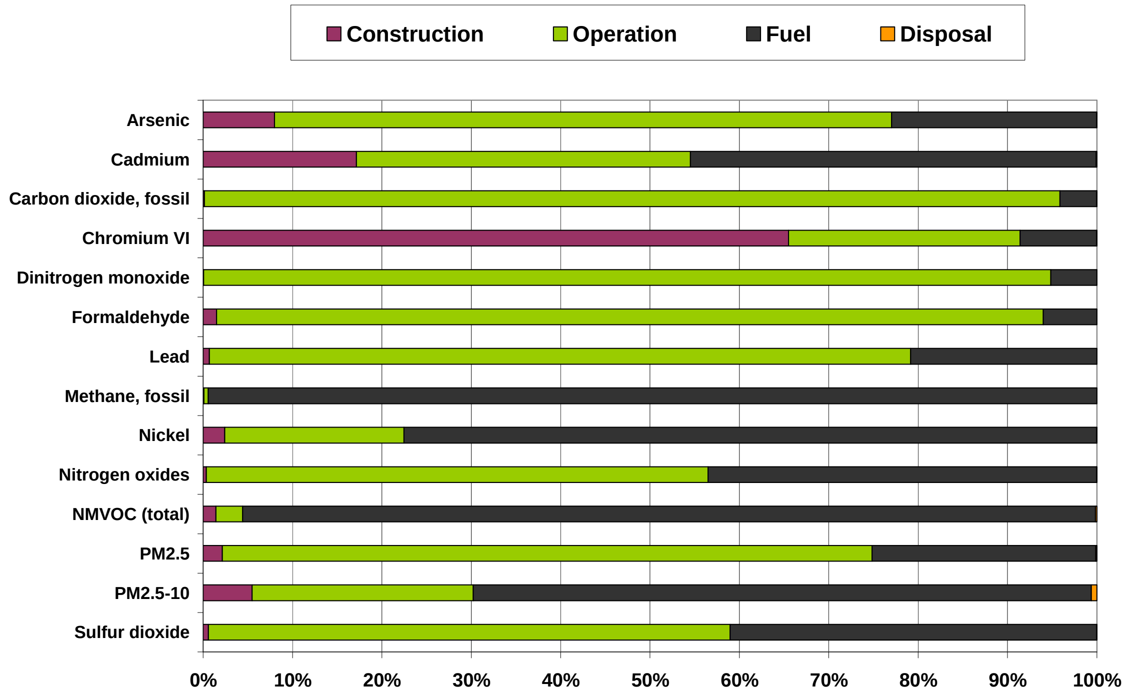


Figure 5.3 **Contribution analysis of selected cumulative air burdens associated with the electricity supplied to the grid by the current (year 2000) hard coal reference 800 MW power plant.**

5.1.2 Hard Coal IGCC

5.1.2.1 Key resources and emissions

Table 5.2 shows selected LCI results for the electricity production at the busbar of the present hard coal IGCC reference power plant per kWh of electricity generated.

Table 5.2 Consumption of selected resources and key emissions for present hard coal IGCC reference power plant.

Parameter	Path	Unit	IGCC 450 MW
			kWh_e
Coal, hard, unspecified, in ground	resource	kg	4.02E-01
Arsenic	air	kg	1.11E-09
Cadmium	air	kg	4.45E-10
Carbon dioxide, fossil	air	kg	7.83E-01
Chromium VI	air	kg	9.98E-11
Dinitrogen monoxide	air	kg	3.27E-05
Formaldehyde	air	kg	2.87E-08
Lead	air	kg	3.88E-09
Methane, fossil	air	kg	2.22E-03
Nickel	air	kg	1.09E-08
Nitrogen oxides	air	kg	5.11E-04
NMVOC (total)	air	kg	6.46E-05
PM10			
PM2.5	air	kg	1.76E-05
PM2.5-10	air	kg	1.79E-05
Sulfur dioxide	air	kg	3.01E-04

5.1.2.2 Contribution analysis

Figure 5.4 shows the shares of the cumulative results for the four life cycle phases defined for NEEDS integration. The contribution from construction is negligible for the specific emissions, having a maximum of 8% for $PM_{2.5}$. The operation is not as dominant as in case of other fossil fuelled technologies, because IGCC technology features no methane emissions, scarcely NMVOC as well as $PM_{2.5}$ emissions and considerably reduced sulphur dioxide emissions. In Figure 5.4 the operation phase is dominant only for carbon dioxide and dinitrogen monoxide emissions. The fuel supply accounts for nearly total of methane emissions and more than half of nitrogen oxide, NMVOC, $PM_{2.5}$ and sulphur dioxide emissions. Also for trace elements, most of emissions are released in the upstream fuel chain. The dismantling accounts for more than 80% of the nickel emissions. For the other heavy metal in Table 5.2, cadmium, 15% of its emissions are emitted during dismantling. For NMVOC and $PM_{2.5}$ around 20% of the cumulative emissions are released during dismantling. It is important to take into account that Figure 5.4 does not show absolute numbers for specific emissions, but their relative contribution from the herewith used life cycle phases to total cumulative results. As there is hardly methane emission in IGCC electricity generation, the gas emissions released during underground mining get high relative importance. The high contributions from power plant dismantling to NMVOC and $PM_{2.5}$ cumulative emissions result from very low emissions of these substances during the operation of the IGCC power plant.

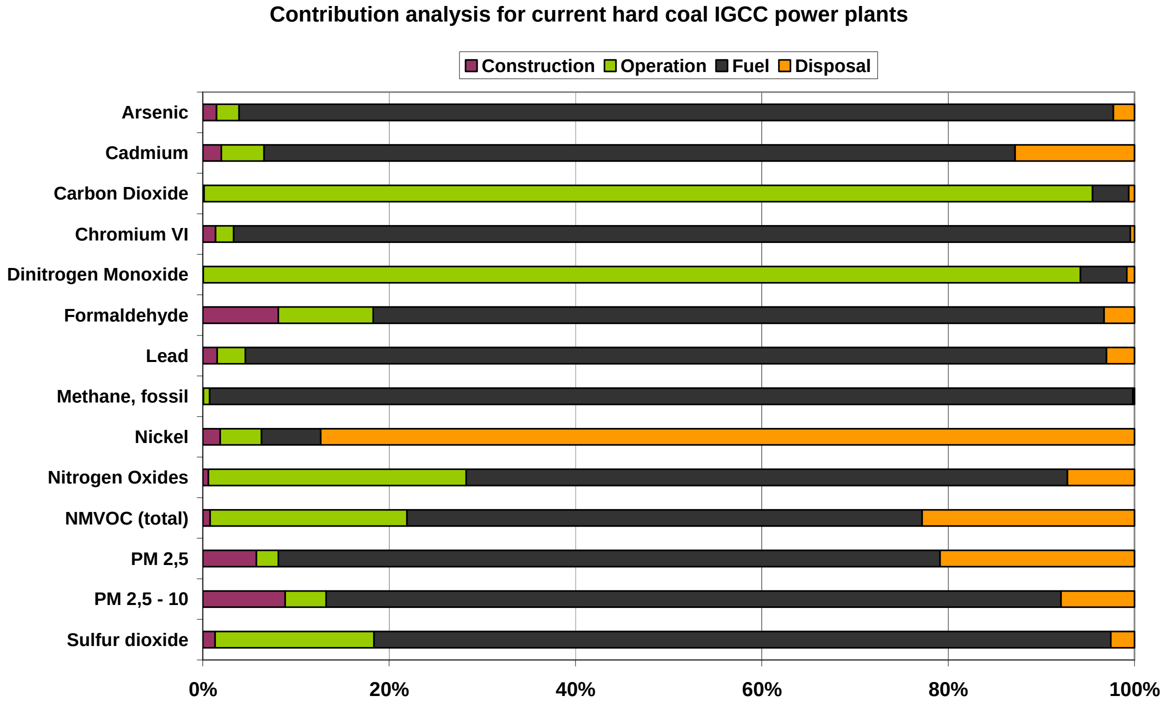


Figure 5.4 **Contribution analysis of selected cumulative air burdens associated with the electricity supplied to the grid by the current (year 2000) hard coal reference 450 MW IGCC power plant.**

5.1.3 Lignite

5.1.3.1 Key resources and emissions

Table 5.3 shows selected LCI results for the electricity production at the busbar of the reference lignite power plant.

Table 5.3 Consumption of selected resources and key emissions for present lignite reference technologies, per kWh_e at the busbar.

Parameter	Path	Unit	Lignite (BoA)
			kWh_e
Coal, brown, in ground	resource	kg	9.50E-01
Arsenic	air	kg	9.03E-09
Cadmium	air	kg	1.29E-09
Carbon dioxide, fossil	air	kg	9.21E-01
Chromium VI	air	kg	7.45E-10
Dinitrogen Monoxide	air	kg	2.20E-05
Formaldehyde	air	kg	5.22E-07
Lead	air	kg	1.19E-05
Methane, fossil	air	kg	2.48E-04
Nickel	air	kg	1.98E-08
Nitrogen oxides	air	kg	7.38E-04
NMVOC (total)	air	kg	2.17E-05
PM10	air	kg	7.61E-05
PM2.5	air	kg	6.47E-05
PM2.5-10	air	kg	1.14E-05
Sulfur dioxide	air	kg	1.69E-04

5.1.3.2 Contribution analysis

The contribution analysis addresses only selected key emissions species split into the four life cycle phases defined for NEEDS integration. Figure 5.5 shows that in general power plant operation is contributing the most to the selected burdens more remarkably for CO_2, NO_x, PM, N_2O, and Formaldehyde emissions. CH_4 and some heavy metals show a different behaviour: methane is emitted during lignite production for more than 90% (however, the absolute value per kWh is generally much lower than for hard coal mining), and significant parts of emissions of some heavy metals originate from power plant construction and lignite production. Contributions of power plant construction to cumulative results are around 5% or lower for the other selected emissions. Contributions from the dismantling phase are negligible.

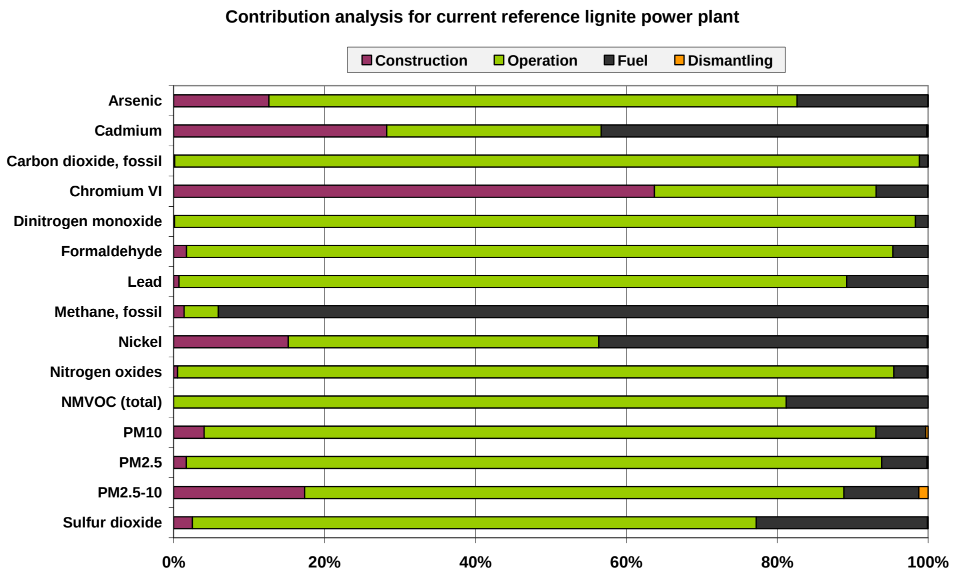


Figure 5.5 Contribution analysis of selected cumulative burdens associated with the electricity supplied to the grid by the current lignite reference power plant.

5.1.4 Natural Gas

5.1.4.1 Key resources and emissions

Table 5.4 shows selected LCI results for the electricity production at the busbar of the three natural gas reference power plants.

Table 5.4 Consumption of selected resources and key emissions for present natural gas reference technologies, per kWh_e at the busbar.

Parameter	Path	Unit	natural gas CHP, allocation exergy	natural gas turbine	natural gas combined cycle plant
			kWh_e	kWh_e	kWh_e
Gas, natural, in ground	resource	Nm3	2.67E-01	2.88E-01	1.90E-01
Arsenic	air	kg	3.89E-09	1.20E-09	1.66E-09
Cadmium	air	kg	1.42E-09	5.38E-10	6.27E-10
Carbon dioxide, fossil	air	kg	5.50E-01	6.02E-01	3.98E-01
Chromium VI	air	kg	1.24E-10	1.06E-10	6.04E-10
Formaldehyde	air	kg	2.15E-08	8.78E-09	2.15E-07
Methane, fossil	air	kg	3.25E-03	1.54E-03	9.94E-04
Dinitrogen monoxide	air	kg	4.42E-05	1.05E-05	6.98E-06
Lead	air	kg	3.24E-07	3.18E-07	2.48E-07
Nickel	air	kg	1.15E-08	7.20E-09	7.00E-09
Nitrogen oxides	air	kg	8.23E-04	1.45E-03	3.09E-04
NMVOC	air	kg	2.64E-04	1.61E-04	1.01E-04
PM10	air	kg	1.53E-05	1.22E-05	1.23E-05
PM2.5	air	kg	8.26E-06	6.95E-06	8.22E-06
PM2.5-10	air	kg	7.04E-06	5.25E-06	4.08E-06
Sulfur dioxide	air	kg	2.52E-04	2.19E-04	1.47E-04

5.1.4.2 Contribution analysis

Figure 5.6 shows the shares of the cumulative results for the four life cycle phases (power plant construction, operation and dismantling, and fuel supply) for the natural gas combined cycle power plant. Only selected key emissions which are important in the context of electricity generation by the natural gas plant are shown. Cumulative CO_2 emissions are dominated by the emissions from the operating power plant. Nevertheless, the contribution of the fuel supply to the total CO_2 emissions is significant (about 12%) due mostly to the gas burning for energy uses along the gas upstream chain. Cumulative methane emissions are strongly dominated by the losses along the natural gas supply chain. Methane emissions from operation are small and the other life cycle phases are negligible. About half of the cumulative NO_x emissions originate from the operating power plant, another half from the fuel supply. The construction phase contributes about 1.3% to cumulative NO_x emissions. NMVOC emissions originate mainly from the fuel supply phase. The operation contributes about 24% to cumulative NMVOC emission. SO_2 emissions from the operating power plant are very low due to the low sulphur content of the average natural gas mix distributed in Europe. The cumulative SO_2 emissions originate mainly from the gas supply; the major contributor is the gas production. Construction of the plant and operation contribute both about 2% to the cumulative SO_2 emissions.

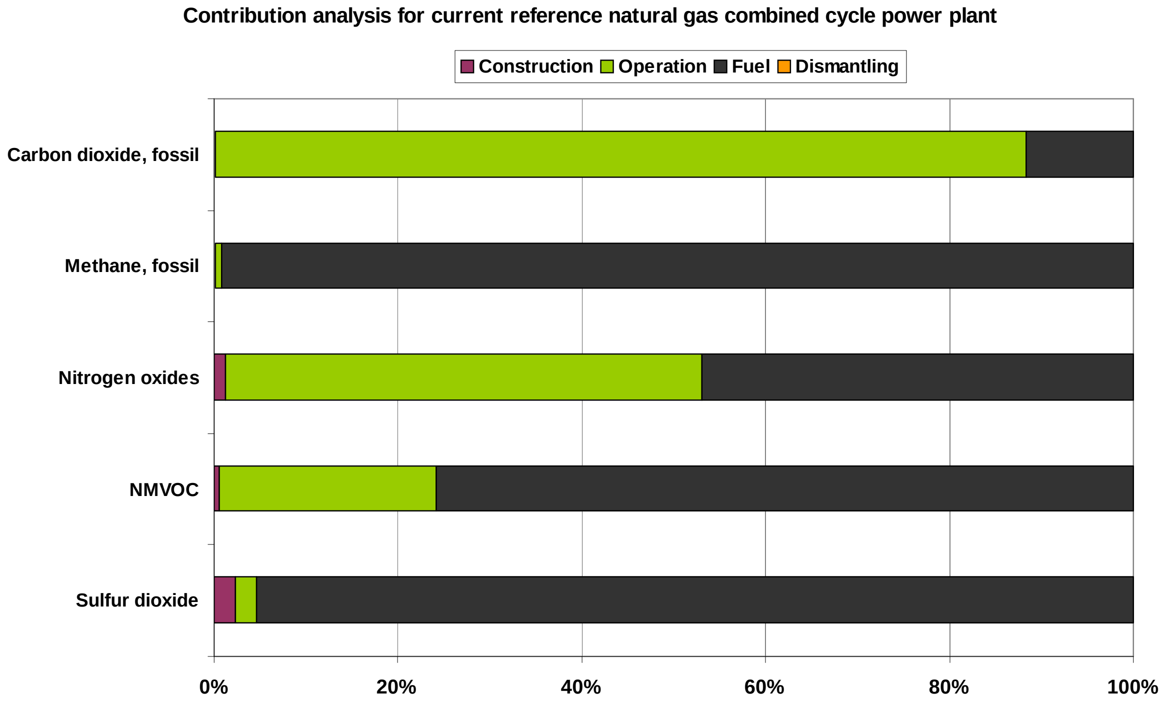


Figure 5.6 Contribution analysis of selected cumulative burdens associated with the electricity supplied to the grid by the current natural gas combined cycle power plant.

Figure 5.7 shows the shares of selected cumulative results for the modelled natural gas turbine. The shares of the cumulative CO_2 emissions related to the gas turbine are almost the same as the corresponding shares related to the combined cycle plant because the construction and dismantling phases are negligible in both cases and the lower efficiency of the gas turbine compared to the GCC increases the CO_2 emissions from operation and the gas input in the same proportion. Cumulative methane emissions are dominated by the gas supply phase, the operation contributes only about 3% and the other phases are negligible. Power plant operation contributes 85% to cumulative NO_x emissions; the gas supply contributes 15%, whereas the construction phase contributes negligibly. NMVOC and SO_2 emissions are strongly dominated by the gas supply phase.

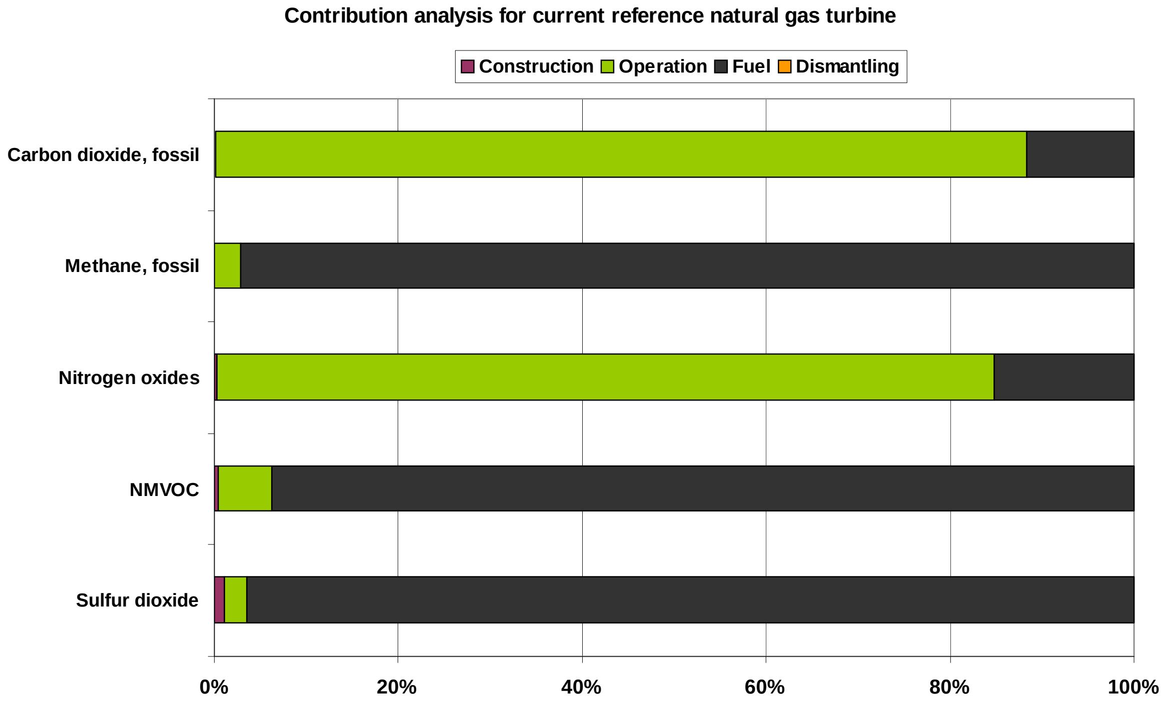


Figure 5.7 Contribution analysis of selected cumulative burdens associated with the electricity supplied to the grid by the current natural gas turbine.

Figure 5.8 shows the shares of selected cumulative results for the modelled natural gas CHP plant. The operation of the CHP plant contributes about 88%, and the fuel supply about 12% to the cumulative CO_2 emissions. The estimated methane emission factor for the small CHP plant is higher than the estimated emission factors for the large combined cycle plant and for the turbine. Therefore, the contribution of the operation phase of the CHP plant (21%) is significant although the cumulative methane emissions are again dominated by the gas supply. NO_x emissions from the operating CHP plant are relatively high because no catalyst is included in the modelled CHP plant. Thus, operation contributes about 73% to cumulative NO_x emissions; the fuel supply contributes about 26%. About one third of the cumulative NMVOC emissions originate from the operation phase, about two thirds from the gas supply. The construction and operation phases contribute about 2% and 3%, respectively, to cumulative SO_2 emissions, but the major part of SO_2 emission is related to the gas supply phase.

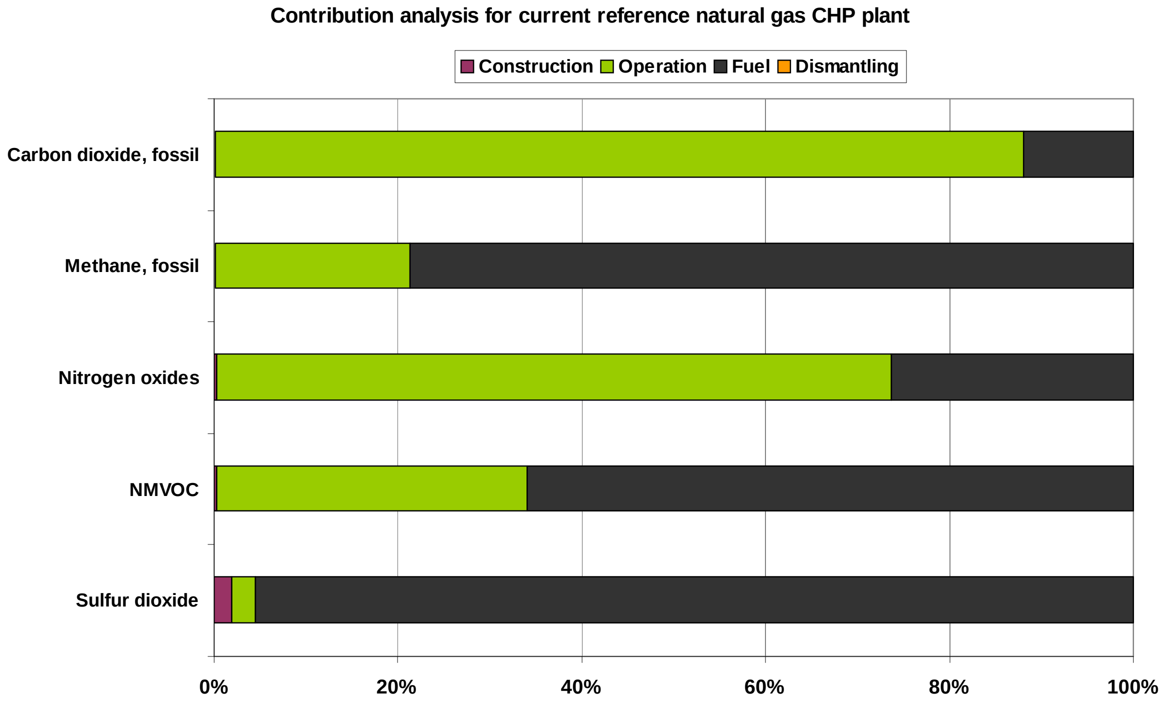


Figure 5.8 Contribution analysis of selected cumulative burdens associated with the electricity supplied to the grid by the current natural gas CHP plant, allocation exergy.

5.1.5 Conclusions

In general, for current fossil technologies the emissions of CO_2 are prevalently from power plant operation. However, for the total GHG emission the supply chain is important taking into account the differences of the natural gas and coal supply from different world regions. Considering that the environmental effects of GHG are independent from the site of emission, the knowledge of the exact distribution of their sources is not necessary for external cost estimation. For other air pollutant species, a variety of results has been obtained for the different systems, for which a general conclusion for fossil systems cannot be taken. Although for the lignite energy chain the power plant operation does remain the main contributor to most of the analysed species, for the hard coal PC the supply chain may contribute meaningfully to emissions like NO_x, SO_2, and PM_{10}, due to the high efficiency of pollution control devices at the power plant. In case of hard coal IGCC this aspect may even be enhanced due to the improved environmental performance of the power plant operation due to the gasification process. For the gas systems, depending whether the technology is GCC, GT or CHP, the power plant operation may be more or less important for the cumulative emissions of species like NMVOC and NO_x.

5.2 Future technologies

5.2.1 Hard coal PC

5.2.1.1 Key emissions and resource consumption

Selected LCA results for the hard coal PC technologies analyzed in this study for 2025 and 2050 with “realistic-optimistic” technology development in the “440 ppm-scenario” are presented in Table 5.5 through Table 5.10. More comprehensive results can be found in Appendix .

Table 5.5 Selected LCA results, hard coal technologies in year 2025, “realistic-optimistic” technology development, “440 ppm-scenario”.

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, hard, unspecified, in ground	resource	kg	3.92E-01	3.91E-01	3.91E-01
Emissions to air						
	Arsenic	air	kg	1.35E-08	1.34E-08	1.34E-08
	Cadmium	air	kg	1.38E-09	1.35E-09	1.35E-09
	Carbon dioxide, fossil	air	kg	7.06E-01	7.05E-01	7.05E-01
	Chromium VI	air	kg	4.33E-09	3.91E-09	3.91E-09
	Dinitrogen monoxide	air	kg	3.09E-05	3.09E-05	3.09E-05
	Lead	air	kg	5.44E-08	5.37E-08	5.37E-08
	Methane, fossil	air	kg	2.17E-03	2.17E-03	2.17E-03
	Nickel	air	kg	9.98E-08	9.94E-08	9.94E-08
	Nitrogen oxides	air	kg	7.26E-04	7.26E-04	7.26E-04
	NMVOC total	air	kg	5.41E-05	5.40E-05	5.40E-05
	PM2.5-10	air	kg	1.99E-05	1.97E-05	1.97E-05
	PM2.5	air	kg	4.67E-05	4.65E-05	4.65E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.21E-14	6.18E-14	6.18E-14
	Radon-222	air	kBq	5.95E+00	5.93E+00	5.93E+00
	Sulfur dioxide	air	kg	5.25E-04	5.24E-04	5.24E-04

Table 5.6 Selected LCA results, hard coal technologies in year 2025, “realistic-optimistic” technology development, “440 ppm-scenario”.

				electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
				Total	Total	Total	Total
				kWh	kWh	kWh	kWh
Resources							
	Coal, hard, unspecified, in ground	resource	kg	4.71E-01	4.71E-01	4.60E-01	4.60E-01
Emissions to air							
	Arsenic	air	kg	1.79E-08	1.81E-08	1.78E-08	1.80E-08
	Cadmium	air	kg	2.10E-09	2.14E-09	2.57E-09	2.61E-09
	Carbon dioxide, fossil	air	kg	5.71E-02	5.89E-02	1.40E-01	1.41E-01
	Chromium VI	air	kg	6.79E-09	6.95E-09	6.74E-09	6.88E-09
	Dinitrogen monoxide	air	kg	3.85E-05	3.86E-05	3.76E-05	3.77E-05
	Lead	air	kg	7.24E-08	7.37E-08	7.23E-08	7.34E-08
	Methane, fossil	air	kg	2.64E-03	2.64E-03	2.58E-03	2.59E-03
	Nickel	air	kg	1.24E-07	1.25E-07	1.31E-07	1.31E-07
	Nitrogen oxides	air	kg	6.11E-04	6.16E-04	8.89E-04	8.94E-04
	NMVOC total	air	kg	7.27E-05	7.40E-05	7.94E-05	8.05E-05
	PM2.5-10	air	kg	2.58E-05	2.66E-05	2.62E-05	2.69E-05
	PM2.5	air	kg	5.82E-05	5.89E-05	5.80E-05	5.86E-05
	PCDD/F (measured as I-TEQ)	air	kg	7.86E-14	7.97E-14	8.93E-14	9.03E-14
	Radon-222	air	kBq	2.67E+01	2.81E+01	2.48E+01	2.60E+01
	Sulfur dioxide	air	kg	3.62E-04	3.64E-04	3.68E-04	3.70E-04

Table 5.7 Selected LCA results, hard coal technologies in year 2025, "realistic-optimistic" technology development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, hard, unspecified, in ground	resource	kg	4.69E-01	4.69E-01	4.58E-01	4.58E-01
Emissions to air						
Arsenic	air	kg	1.71E-08	1.72E-08	1.70E-08	1.72E-08
Cadmium	air	kg	1.81E-09	1.86E-09	2.32E-09	2.36E-09
Carbon dioxide, fossil	air	kg	4.49E-02	4.67E-02	1.29E-01	1.30E-01
Chromium VI	air	kg	6.65E-09	6.81E-09	6.62E-09	6.76E-09
Dinitrogen monoxide	air	kg	3.74E-05	3.76E-05	3.67E-05	3.68E-05
Lead	air	kg	6.93E-08	7.05E-08	6.95E-08	7.06E-08
Methane, fossil	air	kg	2.61E-03	2.61E-03	2.56E-03	2.56E-03
Nickel	air	kg	1.21E-07	1.21E-07	1.28E-07	1.28E-07
Nitrogen oxides	air	kg	5.94E-04	5.99E-04	8.74E-04	8.79E-04
NMVOC total	air	kg	6.79E-05	6.91E-05	7.52E-05	7.62E-05
PM2.5-10	air	kg	2.53E-05	2.60E-05	2.57E-05	2.64E-05
PM2.5	air	kg	5.74E-05	5.80E-05	5.72E-05	5.78E-05
PCDD/F (measured as I-TEQ)	air	kg	7.68E-14	7.80E-14	8.77E-14	8.87E-14
Radon-222	air	kBq	1.36E+01	1.50E+01	1.32E+01	1.45E+01
Sulfur dioxide	air	kg	3.49E-04	3.52E-04	3.57E-04	3.59E-04

Table 5.8 Selected LCA results, hard coal technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

			electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, hard, unspecified, in ground	resource	kg	3.53E-01	3.53E-01	3.53E-01
Emissions to air					
Arsenic	air	kg	1.17E-08	1.16E-08	1.16E-08
Cadmium	air	kg	1.15E-09	1.13E-09	1.13E-09
Carbon dioxide, fossil	air	kg	6.37E-01	6.37E-01	6.37E-01
Chromium VI	air	kg	4.24E-09	3.82E-09	3.81E-09
Dinitrogen monoxide	air	kg	2.79E-05	2.79E-05	2.79E-05
Lead	air	kg	4.60E-08	4.56E-08	4.56E-08
Methane, fossil	air	kg	1.96E-03	1.96E-03	1.96E-03
Nickel	air	kg	8.86E-08	8.84E-08	8.84E-08
Nitrogen oxides	air	kg	6.55E-04	6.55E-04	6.55E-04
NMVOC total	air	kg	4.96E-05	4.95E-05	4.95E-05
PM2.5-10	air	kg	1.80E-05	1.78E-05	1.78E-05
PM2.5	air	kg	4.23E-05	4.21E-05	4.21E-05
PCDD/F (measured as I-TEQ)	air	kg	5.44E-14	5.42E-14	5.42E-14
Radon-222	air	kBq	4.47E+00	4.45E+00	4.45E+00
Sulfur dioxide	air	kg	4.73E-04	4.72E-04	4.72E-04

Table 5.9 Selected LCA results, hard coal technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, hard, unspecified, in ground	resource	kg	4.07E-01	4.07E-01	3.91E-01	3.91E-01
Emissions to air						
Arsenic	air	kg	1.37E-08	1.38E-08	1.37E-08	1.37E-08
Cadmium	air	kg	1.37E-09	1.40E-09	1.82E-09	1.84E-09
Carbon dioxide, fossil	air	kg	2.75E-02	2.82E-02	1.04E-01	1.04E-01
Chromium VI	air	kg	5.23E-09	5.37E-09	6.12E-09	6.24E-09
Dinitrogen monoxide	air	kg	3.23E-05	3.24E-05	3.12E-05	3.13E-05
Lead	air	kg	5.43E-08	5.50E-08	5.43E-08	5.49E-08
Methane, fossil	air	kg	2.26E-03	2.27E-03	2.18E-03	2.18E-03
Nickel	air	kg	1.02E-07	1.02E-07	1.06E-07	1.07E-07
Nitrogen oxides	air	kg	5.18E-04	5.22E-04	7.44E-04	7.47E-04
NMVOC total	air	kg	6.03E-05	6.15E-05	6.57E-05	6.68E-05
PM2.5-10	air	kg	2.15E-05	2.22E-05	2.20E-05	2.26E-05
PM2.5	air	kg	4.93E-05	4.98E-05	4.88E-05	4.93E-05
PCDD/F (measured as I-TEQ)	air	kg	6.34E-14	6.39E-14	7.40E-14	7.44E-14
Radon-222	air	kBq	9.76E+00	1.08E+01	9.38E+00	1.02E+01
Sulfur dioxide	air	kg	3.11E-04	3.13E-04	3.15E-04	3.16E-04

Table 5.10 Selected LCA results, hard coal technologies in year 2050, “realistic-optimistic” technology development, “440 ppm-scenario”.

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, hard, unspecified, in ground	resource	kg	4.08E-01	4.08E-01	3.91E-01	3.91E-01
Emissions to air						
Arsenic	air	kg	1.42E-08	1.42E-08	1.41E-08	1.41E-08
Cadmium	air	kg	1.55E-09	1.58E-09	1.97E-09	2.00E-09
Carbon dioxide, fossil	air	kg	3.04E-02	3.11E-02	1.06E-01	1.07E-01
Chromium VI	air	kg	5.33E-09	5.47E-09	6.21E-09	6.32E-09
Dinitrogen monoxide	air	kg	3.30E-05	3.31E-05	3.18E-05	3.19E-05
Lead	air	kg	5.61E-08	5.68E-08	5.59E-08	5.65E-08
Methane, fossil	air	kg	2.28E-03	2.28E-03	2.20E-03	2.20E-03
Nickel	air	kg	1.03E-07	1.03E-07	1.08E-07	1.08E-07
Nitrogen oxides	air	kg	5.26E-04	5.30E-04	7.51E-04	7.54E-04
NMVOC total	air	kg	6.59E-05	6.71E-05	7.06E-05	7.16E-05
PM2.5-10	air	kg	2.19E-05	2.26E-05	2.24E-05	2.29E-05
PM2.5	air	kg	4.98E-05	5.04E-05	4.93E-05	4.98E-05
PCDD/F (measured as I-TEQ)	air	kg	6.42E-14	6.47E-14	7.46E-14	7.51E-14
Radon-222	air	kBq	1.91E+01	2.01E+01	1.75E+01	1.83E+01
Sulfur dioxide	air	kg	3.17E-04	3.19E-04	3.20E-04	3.22E-04

5.2.2 Hard coal IGCC

5.2.2.1 Key emissions and land use

A “minimum air pollutant list” to be used for the external cost assessment was defined between RS 1a and RS 1b. These emissions shown in Figure 5.9 were analysed to be relevant for the evaluation of the environmental performance of the investigated electricity generation technologies. Thus all emissions are referred to the functional unit one kilowatt hour of electricity, which is delivered to the electricity grid.

In Figure 5.9 the emissions of both hard coal- and lignite-fuelled IGCC technology are compared for power plants with and without CCS respectively. In this comparison the life cycle of the considered scenarios is subdivided into the main phases ‘construction’, ‘operation’ and ‘dismantling’ of the power plant as well as the ‘fuel supply’ in order to show the contribution of these individual life cycle phases to the overall release of emissions.

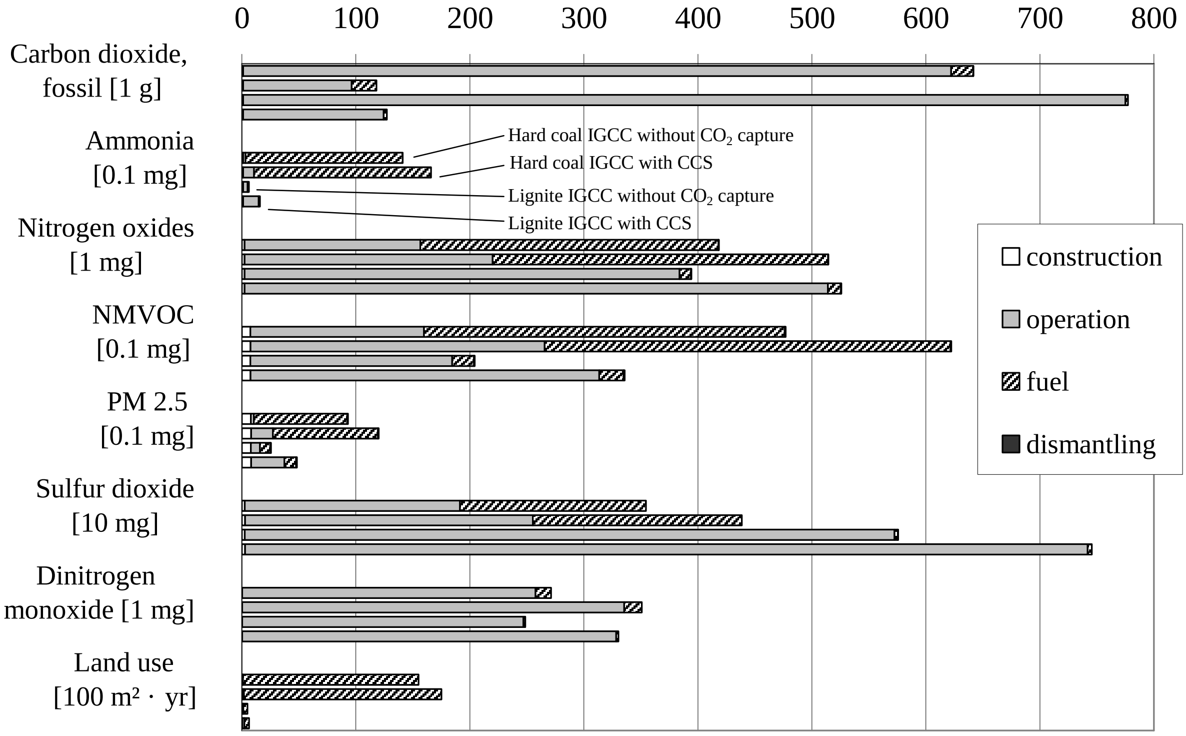


Figure 5.9 Parameter analysis for hard coal- and lignite-fuelled IGCC power plants (realistic-optimistic scenario 2025) per kWh_e.

5.2.2.2 Parameter analysis

The benefit of CCS technologies is shown in Figure 5.9 by the considerable reduction of specific CO_2 emissions in IGCC power plants with CCS. In hard coal-fuelled IGCC power plants with CO_2 capture a reduction of approximately 82% in the specific CO_2 emissions is achieved, in lignite-fuelled power plants a reduction of approximately 84% is realised. Lignite IGCC power plants are mine-mouth operated and thus feature lower specific CO_2 emissions from fuel supply than hard coal-fuelled IGCC power plants. Hard coal originates from both domestic hard coal mining and in the major part from hard coal imports, which due to transportation services go along with higher emissions into air. The different fuel supply of hard coal and lignite becomes also obvious for the parameter land use. The world-wide infrastructure use and thus land use for hard coal mining and transportation is much more spread and thus more space intensive than the land use for lignite mining. Transportation of lignite occurs over very short distances and is often carried out by only conveyer belts.

Also bulk of the release of particulate emissions from hard coal-fuelled IGCC power plants originates from the fuel supply. This is, as the deposition of hard coal for intermediate storage and processing to different hard coal products is involved with a considerable release of particulate emissions. Further contribution from fuel supply of hard coal arises for ammonia, NMVOC, nitrogen oxides and sulphur dioxide emissions. Hereby the major part of these emissions is released at the transportation of the steam coal. The combustion of diesel and fuel is involved with major amounts of nitrogen oxides and sulphur dioxide. The latter gets particular contribution from ship transportation due to the high sulphur content of ship diesel.

For all investigated emissions in Figure 5.9 strong contribution arises from operational emissions of the electricity generation process. These emissions are generated during the gasification of hard coal and the following combustion of the generated syngas in a gas turbine. The carbon of the hard coal is reacted to build CO_2, whereas fuel impurities are oxidised to build different emissions into air. Since lignite comprises more fuel impurities than hard coal than hard coal used for IGCC in this analysis, lignite IGCC power plants are associated with higher specific operational emissions than hard coal IGCC power plants, as it is shown in Figure 5.9. The lower calorific value of lignite compared to hard coal furthermore causes a lower efficiency for lignite-fuelled power plants and thus higher specific emissions.

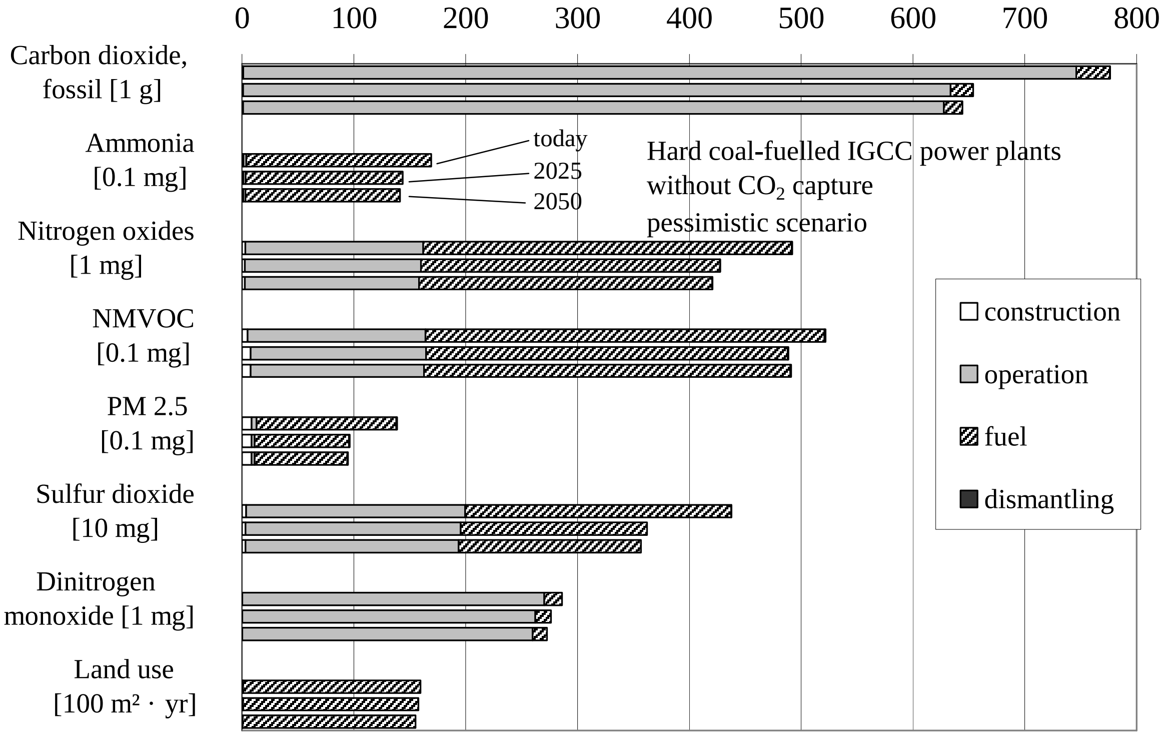
The relevance of the power plant efficiency for the specific power plant emissions is also shown, when CO_2 capture technology is integrated into the considered IGCC power plants. Due to the efficiency penalty due to CO_2 capture the release of higher specific emissions is caused. This can be followed in Figure 5.9 for both lignite- and hard coal-fuelled power plants.

Compared to the fuel supply and the operational emissions the contribution from the construction and dismantling of the investigated IGCC power plants is only marginal for the release of most emissions. Only for particulate and NMVOC emissions contribution of these life cycle phases is visible in Figure 5.9. Though there are major emissions of all investigated substances during the construction and the dismantling of the IGCC power plants, these emissions are outweighed by the contribution from fuel supply and power plant operation over the life time.

5.2.2.3 Future development

The emissions of both hard coal- and lignite-fuelled power plants are anticipated to decline for future time horizons as shown in Figure 5.10 and Figure 5.11. The main reason for this decrease is the further increase of the power plant efficiency, which is the parameter with the most influence on the environmental performance of fossil fuelled power plants. Both hard coal- and lignite-fuelled IGCC power plants are expected to by 2025 incorporate flue gas cleaning under hot conditions, which will prevent a considerable loss of heat and thus a loss of efficiency. Furthermore, improvements at the oxygen production in the air separation unit are expected, which also contribute to an increase of IGCC power plant efficiency. Additionally, improvements in the CCS technology are expected, which will entail a reduction in the efficiency penalty due to CO_2 capture.

Changes in the background system for future time horizons involve efficiency improvements for the supply of materials and energy carriers as well as for the provision of basic services as for instance transportation. In the NEEDS scenario modeling these changes in background processes are also incorporated in the investigated scenarios on future time horizons and for some emissions become especially apparent in the transition from figures of 2005 to figures of 2025. Within this time span IGCC power plants feature a considerable increase of the power plant efficiency, but further improvements predominantly for nitrogen oxides and sulphur dioxides originate from improvements within the hard coal supply.



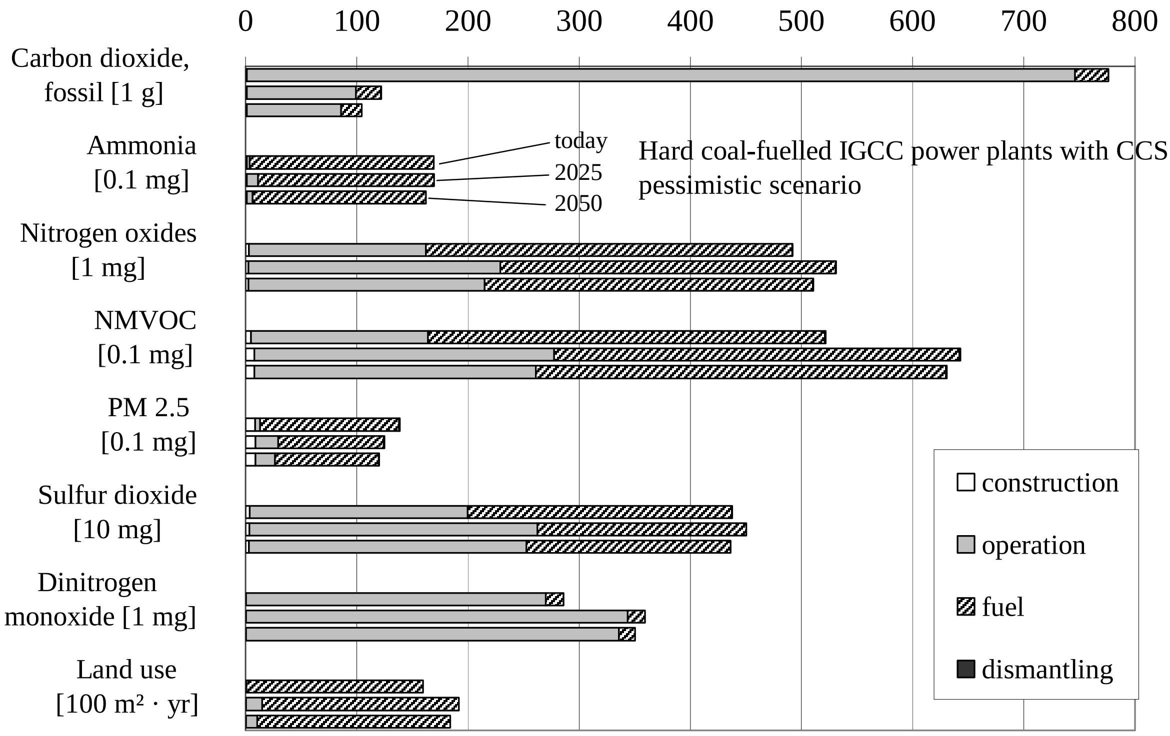
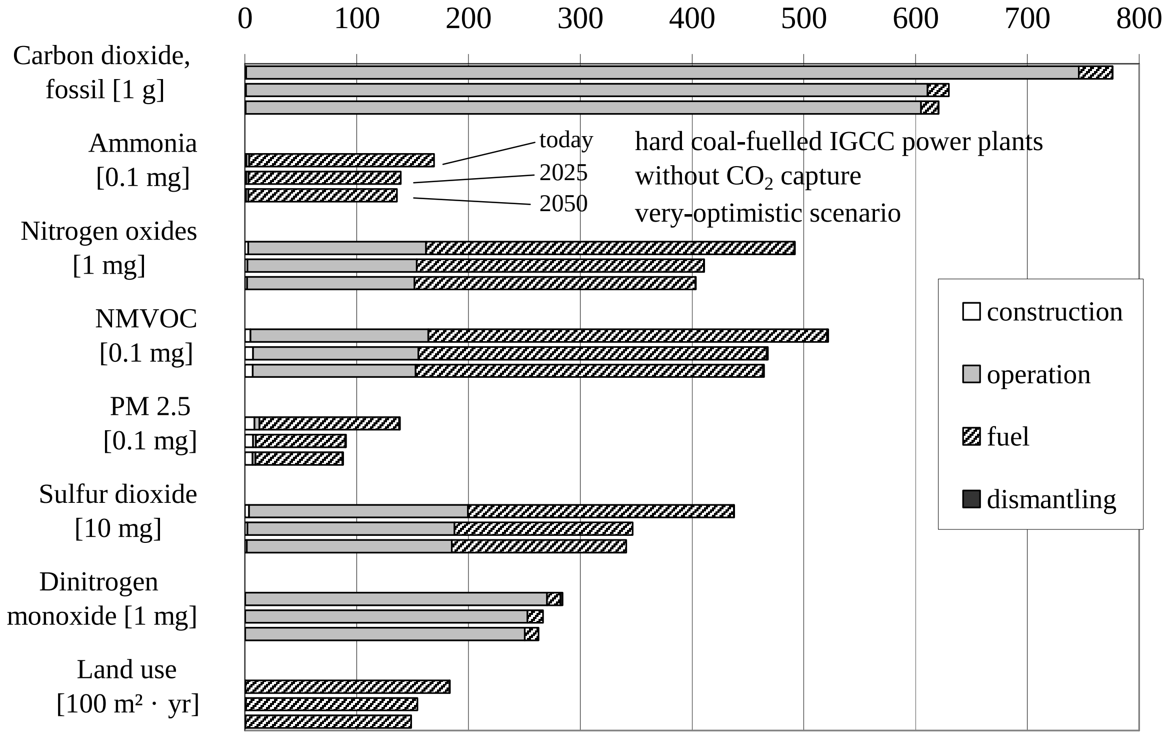


Figure 5.10 Future development pathways for the 'pessimistic' scenario regarding hard coal-fuelled IGCC power plant, per kWh$_e$.



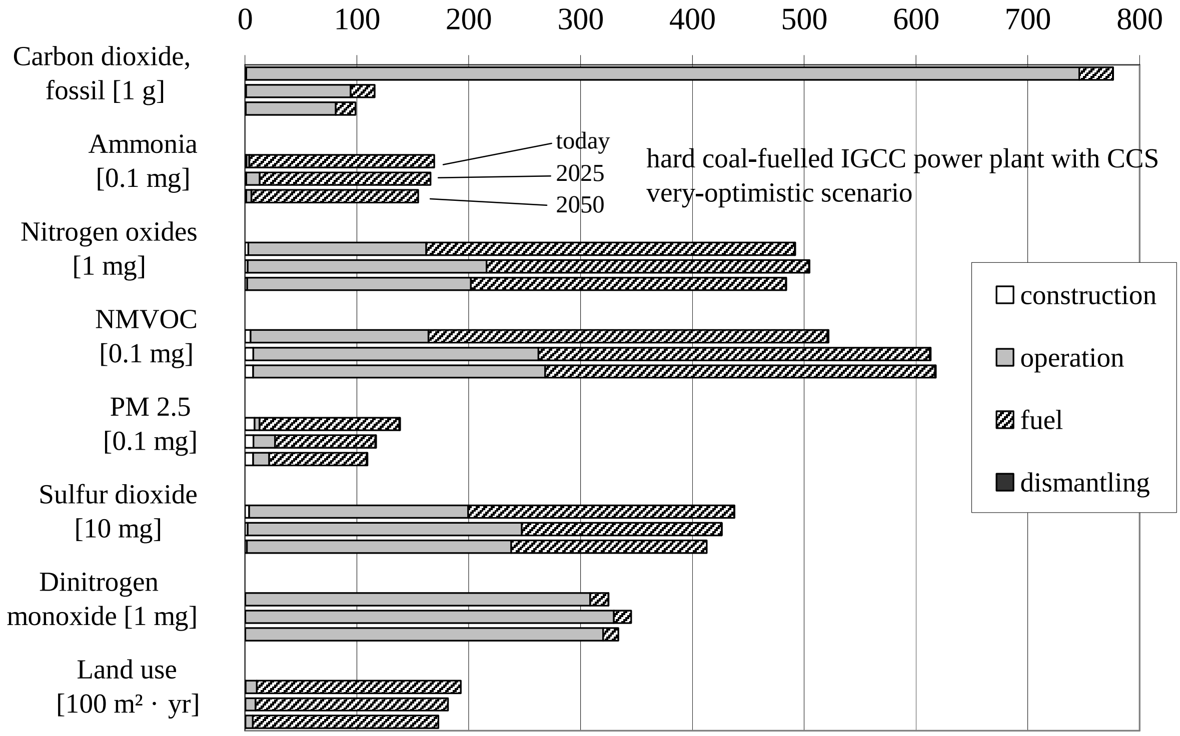


Figure 5.11 Future development pathways for 'very-optimistic' scenario regarding hard coal-fuelled IGCC power plant, per kWh_e.

5.2.3 Lignite

5.2.3.1 Key emissions and resource consumption

Selected LCA results for the lignite PC technologies analyzed in this study for 2025 and 2050 with "realistic-optimistic" technology development in the "440 ppm-scenario" are presented in Table 5.11 through Table 5.16. More comprehensive results can be found in Appendix .

Table 5.11 Selected LCA results, lignite technologies in year 2025, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	9.76E-01	9.76E-01	8.36E-01
Emissions to air						
	Arsenic	air	kg	1.00E-08	1.02E-08	7.32E-09
	Cadmium	air	kg	1.95E-09	1.99E-09	9.19E-10
	Carbon dioxide, fossil	air	kg	1.25E-01	1.27E-01	8.08E-01
	Chromium VI	air	kg	2.19E-09	2.36E-09	1.13E-09
	Dinitrogen monoxide	air	kg	2.35E-05	2.36E-05	1.94E-05
	Lead	air	kg	2.12E-08	2.25E-08	1.19E-08
	Methane, fossil	air	kg	2.85E-04	2.89E-04	2.15E-04
	Nickel	air	kg	2.81E-08	2.88E-08	1.25E-08
	Nitrogen oxides	air	kg	7.80E-04	7.85E-04	6.41E-04
	NMVOC total	air	kg	3.80E-05	3.93E-05	2.03E-05
	PM2.5-10	air	kg	1.48E-05	1.56E-05	9.83E-06
	PM2.5	air	kg	6.77E-05	6.84E-05	5.54E-05
	PCDD/F (measured as I-TEQ)	air	kg	8.18E-14	8.30E-14	5.59E-14
	Radon-222	air	kBq	1.20E+01	1.34E+01	3.94E+00
	Sulfur dioxide	air	kg	1.38E-04	1.41E-04	1.20E-04

Table 5.12 Selected LCA results, lignite technologies in year 2025, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	9.78E-01	1.00E+00	1.00E+00
Emissions to air						
	Arsenic	air	kg	1.11E-08	9.76E-09	9.95E-09
	Cadmium	air	kg	2.29E-09	1.28E-09	1.34E-09
	Carbon dioxide, fossil	air	kg	1.40E-01	2.70E-02	2.92E-02
	Chromium VI	air	kg	2.49E-09	2.10E-09	2.28E-09
	Dinitrogen monoxide	air	kg	2.47E-05	2.38E-05	2.40E-05
	Lead	air	kg	2.57E-08	1.94E-08	2.09E-08
	Methane, fossil	air	kg	3.21E-04	2.76E-04	2.81E-04
	Nickel	air	kg	3.25E-08	1.58E-08	1.67E-08
	Nitrogen oxides	air	kg	8.03E-04	3.02E-04	3.08E-04
	NMVOC total	air	kg	4.43E-05	2.83E-05	2.98E-05
	PM2.5-10	air	kg	1.62E-05	1.39E-05	1.48E-05
	PM2.5	air	kg	6.93E-05	6.79E-05	6.87E-05
	PCDD/F (measured as I-TEQ)	air	kg	8.48E-14	7.07E-14	7.20E-14
	Radon-222	air	kBq	2.69E+01	1.23E+01	1.40E+01
	Sulfur dioxide	air	kg	1.54E-04	1.23E-04	1.25E-04

Table 5.13 Selected LCA results, lignite technologies in year 2025, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	1.00E+00	1.00E+00	9.78E-01
Emissions to air						
	Arsenic	air	kg	1.08E-08	1.10E-08	1.10E-08
	Cadmium	air	kg	1.62E-09	1.67E-09	2.24E-09
	Carbon dioxide, fossil	air	kg	4.13E-02	4.34E-02	1.38E-01
	Chromium VI	air	kg	2.25E-09	2.44E-09	2.33E-09
	Dinitrogen monoxide	air	kg	2.51E-05	2.52E-05	2.46E-05
	Lead	air	kg	2.31E-08	2.46E-08	2.44E-08
	Methane, fossil	air	kg	3.12E-04	3.17E-04	3.17E-04
	Nickel	air	kg	2.00E-08	2.08E-08	3.17E-08
	Nitrogen oxides	air	kg	3.22E-04	3.28E-04	7.98E-04
	NMVOC total	air	kg	3.40E-05	3.55E-05	4.30E-05
	PM2.5-10	air	kg	1.46E-05	1.55E-05	1.54E-05
	PM2.5	air	kg	6.89E-05	6.97E-05	6.86E-05
	PCDD/F (measured as I-TEQ)	air	kg	7.28E-14	7.41E-14	8.36E-14
	Radon-222	air	kBq	2.77E+01	2.93E+01	2.55E+01
	Sulfur dioxide	air	kg	1.37E-04	1.40E-04	1.52E-04

Table 5.14 Selected LCA results, lignite technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.35E-01	8.35E-01	7.58E-01
Emissions to air						
	Arsenic	air	kg	7.63E-09	7.72E-09	6.10E-09
	Cadmium	air	kg	1.44E-09	1.47E-09	7.02E-10
	Carbon dioxide, fossil	air	kg	1.02E-01	1.02E-01	7.31E-01
	Chromium VI	air	kg	2.00E-09	2.13E-09	1.10E-09
	Dinitrogen monoxide	air	kg	1.99E-05	2.00E-05	1.76E-05
	Lead	air	kg	1.36E-08	1.43E-08	8.37E-09
	Methane, fossil	air	kg	2.34E-04	2.37E-04	1.92E-04
	Nickel	air	kg	2.11E-08	2.15E-08	9.95E-09
	Nitrogen oxides	air	kg	6.63E-04	6.67E-04	5.79E-04
	NMVOC total	air	kg	3.39E-05	3.51E-05	1.89E-05
	PM2.5-10	air	kg	1.28E-05	1.35E-05	9.04E-06
	PM2.5	air	kg	5.78E-05	5.84E-05	5.02E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.89E-14	6.95E-14	4.93E-14
	Radon-222	air	kBq	8.46E+00	9.47E+00	2.96E+00
	Sulfur dioxide	air	kg	1.28E-04	1.29E-04	1.07E-04

Table 5.15 Selected LCA results, lignite technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.35E-01	8.70E-01	8.70E-01
Emissions to air						
	Arsenic	air	kg	8.18E-09	7.38E-09	7.48E-09
	Cadmium	air	kg	1.65E-09	8.40E-10	8.76E-10
	Carbon dioxide, fossil	air	kg	1.05E-01	1.61E-02	1.70E-02
	Chromium VI	air	kg	2.24E-09	1.65E-09	1.81E-09
	Dinitrogen monoxide	air	kg	2.06E-05	2.05E-05	2.06E-05
	Lead	air	kg	1.62E-08	1.16E-08	1.24E-08
	Methane, fossil	air	kg	2.55E-04	2.31E-04	2.34E-04
	Nickel	air	kg	2.29E-08	1.04E-08	1.09E-08
	Nitrogen oxides	air	kg	6.76E-04	2.65E-04	2.69E-04
	NMVOC total	air	kg	4.07E-05	2.57E-05	2.71E-05
	PM2.5-10	air	kg	1.39E-05	1.17E-05	1.24E-05
	PM2.5	air	kg	5.89E-05	5.87E-05	5.94E-05
	PCDD/F (measured as I-TEQ)	air	kg	7.03E-14	5.80E-14	5.86E-14
	Radon-222	air	kBq	1.90E+01	8.81E+00	9.97E+00
	Sulfur dioxide	air	kg	1.36E-04	1.14E-04	1.15E-04

Table 5.16 Selected LCA results, lignite technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.70E-01	8.70E-01	8.35E-01
Emissions to air						
	Arsenic	air	kg	7.91E-09	8.01E-09	8.09E-09
	Cadmium	air	kg	1.05E-09	1.09E-09	1.62E-09
	Carbon dioxide, fossil	air	kg	1.94E-02	2.03E-02	1.04E-01
	Chromium VI	air	kg	1.77E-09	1.93E-09	2.10E-09
	Dinitrogen monoxide	air	kg	2.13E-05	2.14E-05	2.05E-05
	Lead	air	kg	1.37E-08	1.45E-08	1.55E-08
	Methane, fossil	air	kg	2.51E-04	2.54E-04	2.52E-04
	Nickel	air	kg	1.20E-08	1.25E-08	2.25E-08
	Nitrogen oxides	air	kg	2.74E-04	2.79E-04	6.72E-04
	NMVOC total	air	kg	3.22E-05	3.36E-05	3.95E-05
	PM2.5-10	air	kg	1.21E-05	1.28E-05	1.33E-05
	PM2.5	air	kg	5.94E-05	6.00E-05	5.84E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.89E-14	5.95E-14	6.97E-14
	Radon-222	air	kBq	1.97E+01	2.09E+01	1.80E+01
	Sulfur dioxide	air	kg	1.21E-04	1.22E-04	1.34E-04

5.2.4 Natural gas

LCA results for some selected flows for the natural gas technologies analyzed in this study for 2025 and 2050 with "realistic-optimistic" technology development in the "440 ppm-scenario" are presented in Table 5.17 and Table 5.18. More comprehensive results can be found in Appendix .

Table 5.17 Selected LCA results, natural gas technologies in year 2025, “realistic-optimistic” technology development, “440 ppm-scenario”.

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Gas, natural, in ground	resource	Nm3	1.76E-01	2.54E-01	1.99E-01	2.23E-01
Emissions to air						
Ammonia	air	kg	1.87E-07	2.20E-07	1.49E-06	3.82E-07
Arsenic	air	kg	1.11E-09	9.17E-10	2.37E-09	2.45E-09
Cadmium	air	kg	4.57E-10	4.62E-10	1.06E-09	9.45E-10
Carbon dioxide, fossil	air	kg	3.67E-01	5.28E-01	9.50E-02	4.58E-01
Carbon monoxide, fossil	air	kg	8.78E-05	1.88E-04	1.09E-04	3.98E-04
Carbon-14	air	kBq	3.06E-05	4.21E-05	4.59E-04	6.02E-05
Chromium	air	kg	2.45E-08	5.80E-09	4.61E-08	8.94E-09
Chromium VI	air	kg	5.82E-10	1.04E-10	1.11E-09	1.73E-10
Dinitrogen monoxide	air	kg	6.45E-06	9.29E-06	7.94E-06	3.69E-05
Iodine-129	air	kBq	2.65E-08	3.64E-08	3.93E-07	5.02E-08
Lead	air	kg	6.66E-09	7.06E-09	1.21E-08	1.27E-08
Methane, fossil	air	kg	7.71E-04	1.14E-03	8.87E-04	2.23E-03
Mercury	air	kg	1.71E-09	2.29E-09	2.47E-09	2.59E-09
Nickel	air	kg	5.09E-09	5.83E-09	1.33E-08	7.54E-09
Nitrogen oxides	air	kg	1.82E-04	3.54E-04	1.85E-04	2.46E-04
NMVOC total	air	kg	1.63E-04	2.01E-04	1.90E-04	3.15E-04
PM2.5-10	air	kg	3.66E-06	4.53E-06	5.68E-06	5.97E-06
PM2.5	air	kg	7.18E-06	5.68E-06	9.77E-06	6.43E-06
PCDD/F (measured as I-TEQ)	air	kg	6.60E-15	8.42E-15	1.19E-14	1.26E-14
Radon-222	air	kBq	5.11E-01	7.03E-01	7.27E+00	1.01E+00
Sulfur dioxide	air	kg	1.31E-04	1.88E-04	1.60E-04	2.07E-04

Table 5.18 Selected LCA results, natural gas technologies in year 2050, "realistic-optimistic" technology development, "440 ppm-scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Gas, natural, in ground	resource	Nm3	1.66E-01	2.35E-01	1.80E-01	2.13E-01
Emissions to air						
Ammonia	air	kg	1.72E-07	1.96E-07	1.30E-06	3.56E-07
Arsenic	air	kg	7.31E-10	6.14E-10	1.70E-09	1.56E-09
Cadmium	air	kg	3.50E-10	3.63E-10	8.00E-10	6.62E-10
Carbon dioxide, fossil	air	kg	3.46E-01	4.89E-01	8.00E-02	4.38E-01
Carbon monoxide, fossil	air	kg	7.89E-05	1.08E-04	9.00E-05	2.38E-04
Carbon-14	air	kBq	4.28E-05	5.78E-05	6.00E-04	7.92E-05
Chromium	air	kg	2.43E-08	5.49E-09	4.50E-08	8.55E-09
Chromium VI	air	kg	5.79E-10	9.94E-11	1.10E-09	1.66E-10
Dinitrogen monoxide	air	kg	6.09E-06	8.60E-06	7.00E-06	3.56E-05
Iodine-129	air	kBq	2.73E-08	3.69E-08	4.00E-07	5.16E-08
Lead	air	kg	3.94E-09	4.11E-09	7.00E-09	7.60E-09
Methane, fossil	air	kg	4.94E-04	7.25E-04	5.50E-04	1.62E-03
Mercury	air	kg	1.60E-09	2.08E-09	2.20E-09	2.43E-09
Nickel	air	kg	4.16E-09	4.95E-09	1.00E-08	5.49E-09
Nitrogen oxides	air	kg	1.30E-04	1.83E-04	1.60E-04	1.88E-04
NMVOC total	air	kg	1.50E-04	1.80E-04	1.70E-04	2.68E-04
PM2.5-10	air	kg	3.46E-06	4.19E-06	5.20E-06	5.70E-06
PM2.5	air	kg	6.72E-06	5.15E-06	9.00E-06	5.97E-06
PCDD/F (measured as I-TEQ)	air	kg	3.75E-15	4.57E-15	7.00E-15	7.94E-15
Radon-222	air	kBq	5.28E-01	7.13E-01	7.00E+00	1.04E+00
Sulfur dioxide	air	kg	1.22E-04	1.72E-04	1.40E-04	1.96E-04

Among the considered natural gas power plant options, the combined cycle plant without CCS has the lowest natural gas resource consumption per kWh_e due to its high efficieny. The comparison of combined cycle (CC) power plants with and without CCS shows that carbon capture and sequestration can lead to much lower total CO_2 emissions to air per kWh electricity considering the full LCA chain. Nevertheless, the price for the reduction of CO_2 emissions to air are increasing total emissions of several other substances per kWh and an increase of natural gas consumption due to the loss of efficiency of the power plant and the energy consumption of the CO_2 capture and sequestration processes. Due to its high efficiency, the combined cycle plant with carbon capture and sequestration yields lower total CO_2 emissions and resource consumption per kWh than a standalone natural gas turbine without carbon capture and sequestration. Thus, from the LCA perspective, the natural gas combined cycle plant with CCS remains an attractive option compared to other natural gas alternatives (provided, of course, that the sequestered carbon dioxide remains confined and does not leak out into the atmosphere) although the environmental price for the CCS process is not negligible.

5.3 Overall comparison and conclusions

Table 5.19 summarizes GHG emissions of the different analyzed power generation chains for the three different technology development paths for current and future technologies in the "440 ppm" scenario. The contributions of fuel extraction and processing, power plant construction and dismantling, power plant operation including capture and compression of CO_2 as well as transport and storage of CO_2 to total cumulative emissions per kWh electricity produced are quantified. The minimum emissions given in the table for the various coal power chains with CCS are valid for the CCS option “post combustion CO_2 separation, 200 km CO_2 transport by pipeline and CO_2 storage in the saline aquifer at a depth of 800 m”. The maximum emissions are valid for the CCS option “oxyfuel combustion CO_2 separation, 400 km CO_2 transport by pipeline and CO_2 storage in the depleted gasfield at a depth of 2500 m”.

Natural gas is clearly the fossil energy carrier with the lowest GHG emissions among the energy chains without CCS with emissions of more than 50% below those of hard coal and lignite chains for all time horizons and technology development scenarios analyzed. Lignite chains without CCS show the highest emissions, about 10% above hard coal chains. Differences between hard coal PC and IGCC power plants are not significant. Contributions from the power plant infrastructure (construction and dismantling) are negligible for all technologies. While fuel production and processing contributes about 10% to cumulative emissions per kWh in case of hard coal and natural gas chains without CCS, lignite mining contributes only 1-2% to total emissions for lignite chains without CCS since it is not associated with methane emissions from the coal mines and lignite plants are operated “mine-mouth”. Contrary, hard coal is imported to Europe over long distances by ship causing relatively significant CO_2 emissions; natural gas is imported via pipelines associated with CH_4 leakages mainly responsible for these GHG emissions.

Fossil energy chains with CCS show different patterns in their cumulative GHG emissions. Due to the energy demand for CO_2 separation at the power plant, net efficiencies are reduced (Table 4.46). Along with this reduction goes a proportional increase in the contribution of upstream processes (mainly fuel production and processing), which are not reduced by CCS, to cumulative emissions per kWh electricity produced. As a result, lignite based power generation with oxyfuel combustion becomes the energy chain with the lowest GHG emissions in the range of about 30 g (CO_2-eq.)/kWh in year 2050 – about one third of the emissions of the equivalent hard coal chain. Due to the lower efficiency of CO_2 removal of post and pre combustion CO_2 capture technologies (compared to oxyfuel combustion, Table 4.46), the cumulative emissions of post combustion PC and IGCC chains are significantly higher, in 2050 in the range of 120 g (CO_2-eq.)/kWh for lignite, 170 g (CO_2-eq.)/kWh for hard coal and 80 g (CO_2-eq.)/kWh for natural gas. Natural gas chains with oxyfuel combustion as CO_2 capture technology (not analyzed in this study) could approximately reach emission levels of about 40 g (CO_2-eq.)/kWh in year 2050. In general, the analyzed options of transport and injection of CO_2 for final storage do not cause significant GHG emissions. The development of GHG emissions of selected generation chains in the realistic-optimistic scenario for technology development is visualized in Table 5.19.

The advantage of CCS in reducing GHG emissions of fossil power generation (between minus 95% and minus 70% of cumulative emissions, depending on energy carrier, CO_2 capture technology and scenario) goes along with the disadvantage of increasing fuel demand (proportionally to the reduced power plant efficiency, Table 4.46) and therefore with the increase of all environmental burdens (emissions, land use) associated with the upstream chain. This effect is visible in Table 5.5 through Table 5.18 – several cumulative environmental flows are higher for electricity chains with CCS than without CCS. These advantages and disadvantages have to be weighted and aggregated in order to allow a comprehensive environmental assessment. An aggregation based on external costs is provided in (Krewitt 2009). Application of Life Cycle Impact Assessment (LCIA) methods for aggregation of overall environmental burdens – however, out of scope of this report – can serve as an alternative.

Table 5.19 Greenhouse gas emissions of hard coal and lignite[36] power generation chains for current and future (2025, 2050) technologies with and without CCS for pessimistic (PE), realistic-optimistic (RO) and very optimistic (VO) technology development, 440 ppm scenario.

GHG emissions (fossil) [g(CO2eq)/kWh]	fuel extraction & processing						power plant construction & dismantling						power plant operation (incl. CO_2 capture & compression)						CO_2 transport & storage						TOTAL						Year
	PE		RO		VO		PE		RO		VO		PE		RO		VO		PE		RO		VO		PE		RO		VO		
	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	min[a]	max[a]	
Lignite, PC			16						2						916						0						934				2005[b]
	10		9		9		1		1		1		843		809		762		0		0		0		854		819		772		2025
	7		6		6		1		1		1		792		733		695		0		0		0		800		741		702		2050
Lignite, PC, CCS															n.a.[c]																2005[b]
	13	13	11	11	10	10	3	3	2	2	2	2	26	154	23	135	22	127	5	11	4	9	4	9	46	178	41	156	39	147	2025
	8	8	7	7	6	6	2	2	2	2	2	2	18	118	16	102	15	96	3	8	3	7	3	7	32	136	28	118	26	111	2050
Hard coal, PC[d]			87						1						753						0						841				2005[b]
	77		73		69		1		1		1		720		691		651		0		0		0		798		765		721		2025
	68		63		59		1		1		1		677		627		593		0		0		0		746		691		654		2050
Hard coal, PC, CCS															n.a.[c]																2005[b]
	98	97	87	85	82	80	2	2	2	2	2	2	20	132	18	115	17	108	3	9	3	8	2	7	130	243	117	213	109	200	2025
	79	82	72	69	68	65	2	2	1	2	1	1	16	104	14	91	13	85	2	7	2	6	2	6	101	192	90	168	84	157	2050
Lignite, IGCC															n.a.[c]																2005[b]
	5		5		5		1		1		1		797		782		*618*		0		0		0		803		788		*623*		2025
	4		3		3		1		1		1		*635*		774		*612*		0		0		0		*640*		778		*616*		2050
Lignite, IGCC, CCS															n.a.[c]																2005[b]
	5	5	5	5	5	5	1	1	1	1	1	1	126	126	123	123	120	120	5	11	4	9	4	9	131	137	127	138	124	135	2025
	4	4	4	4	4	4	1	1	1	1	1	1	116	116	112	112	108	108	3	8	3	8	3	8	123	130	119	125	115	121	2050
Hard coal, IGCC			82						5						755						0						842				2005[b]
	64		62		61		1		1		1		641		629		618		0		0		0		706		692		680		2025
	60		58		57		1		1		1		635		623		612		0		0		0		696		682		670		2050
Hard coal, IGCC, CCS															n.a.[c]																2005[b]
	72	72	70	70	69	69	1	1	1	1	1	1	95	95	93	93	91	91	3	7	2	7	2	7	171	175	166	171	163	168	2025
	67	67	66	66	64	64	1	1	1	1	1	1	92	92	89	89	86	86	2	6	2	6	2	6	161	167	157	162	153	157	2050
Natural Gas CC			46						1						351						0						398				2005[b]
	43		41		38		1		1		1		333		325		320		0		0		0		377		366		359		2025
	42		35		34		1		1		1		325		310		305		0		0		0		368		346		340		2050
Natural Gas CC, CCS[e]															n.a.[c]																2005[b]
	50		45		42		1		1		1		47		44		43		3		3		3		101		93		90		2025
	48		38		37		1		1		1		38		36		33		3		3		3		90		77		74		2050

[a] Applicable for coal systems with CCS; min: lowest total GHG emissions of the 4 CCS options analyzed (oxyfuel combustion, 200km CO_2 transport, aquifer storage); max: highest total GHG emissions of the 4 CCS options analyzed (post combustion, 400km CO_2 transport, depleted gasfield storage).

[b] The analysis of current technologies does not include different scenarios.

[c] Power plants with CCS and lignite-fuelled IGCC plants were not analyzed for current technologies in this study.

[d] Only results for the 600MW plant are shown - the total emissions for the 350MW and 800MW units only differ by a few percent (maximum).

[e] Only one option for CCS analyzed: post combustion CO2 capture, 400km CO2 transport, depleted gasfield storage.

[36] Figures given in *cursive* for lignite IGCC (2025: VO and 2050: PE and VO) are assumed to be wrong. However the complete calculation of LCA results could not be repeated in order to correct these errors at the time the report was finalized

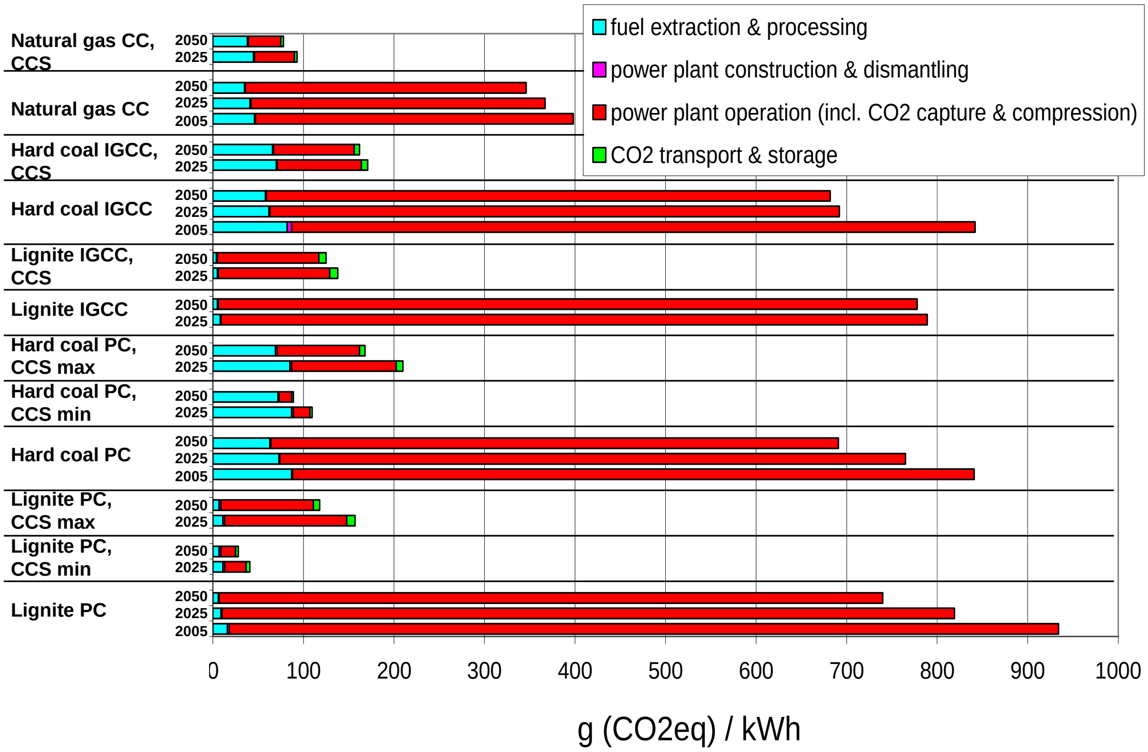


Figure 5.12 **GHG emissions of fossil power generation, realistic-optimistic technology development, "440 ppm scenario". "CCS min" = oxyfuel combustion CO_2 capture, 200 km CO_2 transport, saline aquifer CO_2 storage; "CCS max" = post combustion CO_2 capture, 200 km CO_2 transport, depleted gasfield CO_2 storage.**

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7 Appendix 1

Appendix 1 provides a summary overview of all datasets for advanced fossil power generation technologies analyzed in this project. Only the "final" datasets for electricity production are shown in Table 7.1 (lignite), Table 7.2 (hard coal) and Table 7.3 (natural gas).

Table 7.1 Datasets for lignite based electricity production analyzed within this project.

	Lignite
2005	electricity, lignite, at power plant 950 MW
2025	electricity, lignite, at power plant 950 MW
	electricity, lignite, at IGCC power plant 450MW
	electricity, lignite power plant 800MW class post CCS, 200km & 800m aquifer
	electricity, lignite power plant 800MW class post CCS, 400km & 800m aquifer
	electricity, lignite plant 800MW class post CCS, 200km & 2500m depl. gasfield
	electricity, lignite plant 800MW class post CCS, 400km & 2500m depl. gasfield
	electricity, lignite power plant 800MW class oxyf CCS, 200km & 800m aquifer
	electricity, lignite power plant 800MW class oxyf CCS, 400km & 800m aquifer
	electricity, lignite plant 800MW class oxyf CCS, 200km & 2500m depl. gasfield
	electricity, lignite plant 800MW class oxyf CCS, 400km & 2500m depl. gasfield
	electricity, lignite IGCC plant 400MW, CCS, 200km & 800m aquifer
	electricity, lignite IGCC plant 400MW, CCS, 400km & 800m aquifer
	electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield
	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield
2050	electricity, lignite, at power plant 950 MW
	electricity, lignite, at IGCC power plant 450MW
	electricity, lignite power plant 800MW class post CCS, 200km & 800m aquifer
	electricity, lignite power plant 800MW class post CCS, 400km & 800m aquifer
	electricity, lignite plant 800MW class post CCS, 200km & 2500m depl. gasfield
	electricity, lignite plant 800MW class post CCS, 400km & 2500m depl. gasfield
	electricity, lignite power plant 800MW class oxyf CCS, 200km & 800m aquifer
	electricity, lignite power plant 800MW class oxyf CCS, 400km & 800m aquifer
	electricity, lignite plant 800MW class oxyf CCS, 200km & 2500m depl. gasfield
	electricity, lignite plant 800MW class oxyf CCS, 400km & 2500m depl. gasfield
	electricity, lignite IGCC plant 400MW, CCS, 200km & 800m aquifer
	electricity, lignite IGCC plant 400MW, CCS, 400km & 800m aquifer
	electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield
	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield

Table 7.2 Datasets for hard coal based electricity production analyzed within this project.

	Hard coal
2005	electricity, hard coal, at power plant 350 MW
	electricity, hard coal, at power plant 600 MW
	electricity, hard coal, at power plant 800 MW
	electricity, hard coal, at IGCC power plant 450MW
2025	electricity, hard coal, at power plant 350 MW
	electricity, hard coal, at power plant 600 MW
	electricity, hard coal, at power plant 800 MW
	electricity, hard coal, at IGCC power plant 450MW
	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer
	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
	electricity, hard coal plant 500MW class post CCS, 200km & 2500m depl. gasfield
	electricity, hard coal plant 500MW class post CCS, 400km & 2500m depl. gasfield
	electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer
	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer
	electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m depl. gasfield
	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m depl. gasfield
	electricity, hard coal IGCC plant 400MW, CCS, 200km & 800m aquifer
	electricity, hard coal IGCC plant 400MW, CCS, 400km & 800m aquifer
	electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield
	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield
2050	electricity, hard coal, at power plant 350 MW
	electricity, hard coal, at power plant 600 MW
	electricity, hard coal, at power plant 800 MW
	electricity, hard coal, at IGCC power plant 450MW
	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer
	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
	electricity, hard coal plant 500MW class post CCS, 200km & 2500m depl. gasfield
	electricity, hard coal plant 500MW class post CCS, 400km & 2500m depl. gasfield
	electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer
	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer
	electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m depl. gasfield
	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m depl. gasfield
	electricity, hard coal IGCC plant 400MW, CCS, 200km & 800m aquifer
	electricity, hard coal IGCC plant 400MW, CCS, 400km & 800m aquifer
	electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield
	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield

Table 7.3 Datasets for natural gas based electricity production analyzed within this project.

	Natural gas
2005	electricity, natural gas, at combined cycle plant 500 MW
	electricity, natural gas, at gas turbine 50 MW
	electricity, natural gas, at cogeneration 200 kW_{el} lean burn, allocation exergy
2025	electricity, natural gas, at combined cycle plant 500 MW
	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield
	electricity, natural gas, at gas turbine 50 MW
	electricity, natural gas, at cogeneration 200 kW_{el} lean burn, allocation exergy
2050	electricity, natural gas, at combined cycle plant 500 MW
	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield
	electricity, natural gas, at gas turbine 50 MW
	electricity, natural gas, at cogeneration 200 kW_{el} lean burn, allocation exergy

8 Appendix 2

Appendix 2 provides selected LCA results (cumulative environmental burdens per kWh electricity), agreed upon in NEEDS RS1a as the most relevant ones, for all hard coal, lignite, and natural gas technologies analyzed in this project for the different scenarios and future time horizons (2025, 2050).

Table 8.1 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	9.38E-04	9.33E-04	9.33E-04
	Coal, hard, unspecified, in ground	resource	kg	3.92E-01	3.91E-01	3.91E-01
	Gas, natural, in ground	resource	Nm3	2.42E-03	2.40E-03	2.40E-03
	Oil, crude, in ground	resource	kg	5.06E-03	5.04E-03	5.04E-03
	Uranium, in ground	resource	kg	1.83E-07	1.83E-07	1.82E-07
	Freshwater (lake, river, groundwater)	resource	m3	1.97E-03	1.97E-03	1.97E-03
	Occupation, agricultural and forestal area	resource	m2a	1.83E-02	1.83E-02	1.83E-02
	Occupation, built up area incl. mineral extractic	resource	m2a	4.24E-03	4.23E-03	4.23E-03
Emissions to air						
	Ammonia	air	kg	1.92E-05	1.92E-05	1.92E-05
	Arsenic	air	kg	1.35E-08	1.34E-08	1.34E-08
	Cadmium	air	kg	1.38E-09	1.35E-09	1.35E-09
	Carbon dioxide, fossil	air	kg	7.06E-01	7.05E-01	7.05E-01
	Carbon monoxide, fossil	air	kg	1.42E-04	1.42E-04	1.42E-04
	Carbon-14	air	kBq	3.75E-04	3.74E-04	3.74E-04
	Chromium	air	kg	1.53E-07	1.36E-07	1.36E-07
	Chromium VI	air	kg	4.33E-09	3.91E-09	3.91E-09
	Dinitrogen monoxide	air	kg	3.09E-05	3.09E-05	3.09E-05
	Iodine-129	air	kBq	3.20E-07	3.18E-07	3.18E-07
	Lead	air	kg	5.44E-08	5.37E-08	5.37E-08
	Methane, fossil	air	kg	2.17E-03	2.17E-03	2.17E-03
	Mercury	air	kg	3.15E-08	3.15E-08	3.15E-08
	Nickel	air	kg	9.98E-08	9.94E-08	9.94E-08
	Nitrogen oxides	air	kg	7.26E-04	7.26E-04	7.26E-04
	NMVOC total	air	kg	5.41E-05	5.40E-05	5.40E-05
	thereof:					
	Benzene	air	kg	1.85E-06	1.85E-06	1.85E-06
	Benzo(a)pyrene	air	kg	9.37E-11	9.04E-11	9.04E-11
	Formaldehyde	air	kg	4.50E-07	4.49E-07	4.49E-07
	PAH	air	kg	1.83E-08	1.81E-08	1.81E-08
	PM2.5-10	air	kg	1.99E-05	1.97E-05	1.97E-05
	PM2.5	air	kg	4.67E-05	4.65E-05	4.65E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.21E-14	6.18E-14	6.18E-14
	Radon-222	air	kBq	5.95E+00	5.93E+00	5.93E+00
	Sulfur dioxide	air	kg	5.25E-04	5.24E-04	5.24E-04
Emissions to Water						
	Ammonium, ion	water	kg	7.81E-07	7.81E-07	7.81E-07
	Arsenic, ion	water	kg	1.18E-07	1.18E-07	1.18E-07
	Cadmium, ion	water	kg	1.12E-08	1.09E-08	1.09E-08
	Carbon-14	water	kBq	1.28E-04	1.28E-04	1.28E-04
	Cesium-137	water	kBq	5.98E-05	5.95E-05	5.95E-05
	Chromium, ion	water	kg	1.60E-08	1.59E-08	1.59E-08
	Chromium VI	water	kg	2.40E-07	2.34E-07	2.34E-07
	COD	water	kg	1.15E-04	1.14E-04	1.14E-04
	Copper, ion	water	kg	4.53E-07	4.49E-07	4.49E-07
	Lead	water	kg	1.92E-07	1.89E-07	1.87E-07
	Mercury	water	kg	2.66E-09	2.64E-09	2.64E-09
	Nickel, ion	water	kg	9.65E-07	9.03E-07	9.01E-07
	Nitrate	water	kg	2.41E-05	2.41E-05	2.41E-05
	Oils, unspecified	water	kg	2.21E-05	2.20E-05	2.20E-05
	PAH	water	kg	4.97E-09	4.62E-09	4.62E-09
	Phosphate	water	kg	2.75E-06	2.72E-06	2.72E-06
Emissions to Soil						
	Arsenic	soil	kg	6.30E-11	6.28E-11	6.28E-11
	Cadmium	soil	kg	6.37E-12	6.29E-12	6.28E-12
	Chromium	soil	kg	8.96E-10	8.93E-10	8.92E-10
	Chromium VI	soil	kg	2.86E-09	2.84E-09	2.84E-09
	Lead	soil	kg	4.61E-11	4.56E-11	4.55E-11
	Mercury	soil	kg	5.21E-13	5.20E-13	5.20E-13
	Oils, unspecified	soil	kg	2.24E-05	2.23E-05	2.23E-05

Table 8.2 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	2.14E-03	2.36E-03	2.09E-03	2.28E-03
Coal, hard, unspecified, in ground	resource	kg	4.69E-01	4.69E-01	4.58E-01	4.58E-01
Gas, natural, in ground	resource	Nm3	4.85E-03	5.31E-03	7.00E-03	7.41E-03
Oil, crude, in ground	resource	kg	6.23E-03	6.34E-03	7.73E-03	7.83E-03
Uranium, in ground	resource	kg	4.19E-07	4.61E-07	4.09E-07	4.47E-07
Freshwater (lake, river, groundwater)	resource	m3	2.48E-03	2.51E-03	2.46E-03	2.48E-03
Occupation, agricultural and forestal area	resource	m2a	2.24E-02	2.25E-02	2.22E-02	2.23E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.13E-03	5.16E-03	5.03E-03	5.06E-03
Emissions to air						
Ammonia	air	kg	2.13E-05	2.14E-05	2.45E-04	2.45E-04
Arsenic	air	kg	1.71E-08	1.72E-08	1.70E-08	1.72E-08
Cadmium	air	kg	1.81E-09	1.86E-09	2.32E-09	2.36E-09
Carbon dioxide, fossil	air	kg	4.49E-02	4.67E-02	1.29E-01	1.30E-01
Carbon monoxide, fossil	air	kg	1.79E-04	1.85E-04	1.80E-04	1.85E-04
Carbon-14	air	kBq	8.60E-04	9.48E-04	8.36E-04	9.14E-04
Chromium	air	kg	2.42E-07	2.49E-07	2.41E-07	2.47E-07
Chromium VI	air	kg	6.65E-09	6.81E-09	6.62E-09	6.76E-09
Dinitrogen monoxide	air	kg	3.74E-05	3.76E-05	3.67E-05	3.68E-05
Iodine-129	air	kBq	7.34E-07	8.09E-07	7.14E-07	7.80E-07
Lead	air	kg	6.93E-08	7.05E-08	6.95E-08	7.06E-08
Methane, fossil	air	kg	2.61E-03	2.61E-03	2.56E-03	2.56E-03
Mercury	air	kg	3.81E-08	3.83E-08	3.76E-08	3.78E-08
Nickel	air	kg	1.21E-07	1.21E-07	1.28E-07	1.28E-07
Nitrogen oxides	air	kg	5.94E-04	5.99E-04	8.74E-04	8.79E-04
NMVOC total	air	kg	6.79E-05	6.91E-05	7.52E-05	7.62E-05
thereof:						
Benzene	air	kg	2.24E-06	2.24E-06	2.37E-06	2.38E-06
Benzo(a)pyrene	air	kg	1.31E-10	1.38E-10	1.32E-10	1.38E-10
Formaldehyde	air	kg	5.45E-07	5.47E-07	5.45E-07	5.47E-07
PAH	air	kg	2.31E-08	2.35E-08	2.29E-08	2.33E-08
PM2.5-10	air	kg	2.53E-05	2.60E-05	2.57E-05	2.64E-05
PM2.5	air	kg	5.74E-05	5.80E-05	5.72E-05	5.78E-05
PCDD/F (measured as I-TEQ)	air	kg	7.68E-14	7.80E-14	8.77E-14	8.87E-14
Radon-222	air	kBq	1.36E+01	1.50E+01	1.32E+01	1.45E+01
Sulfur dioxide	air	kg	3.49E-04	3.52E-04	3.57E-04	3.59E-04
Emissions to Water						
Ammonium, ion	water	kg	9.91E-07	9.99E-07	4.47E-06	4.48E-06
Arsenic, ion	water	kg	1.50E-07	1.53E-07	1.48E-07	1.50E-07
Cadmium, ion	water	kg	1.60E-08	1.73E-08	1.59E-08	1.71E-08
Carbon-14	water	kBq	2.95E-04	3.25E-04	2.87E-04	3.14E-04
Cesium-137	water	kBq	1.37E-04	1.51E-04	1.33E-04	1.46E-04
Chromium, ion	water	kg	2.11E-08	2.14E-08	2.07E-08	2.11E-08
Chromium VI	water	kg	3.58E-07	3.96E-07	3.59E-07	3.92E-07
COD	water	kg	1.50E-04	1.55E-04	2.32E-04	2.36E-04
Copper, ion	water	kg	5.99E-07	6.12E-07	6.13E-07	6.24E-07
Lead	water	kg	2.60E-07	2.64E-07	2.57E-07	2.61E-07
Mercury	water	kg	3.70E-09	3.94E-09	3.72E-09	3.93E-09
Nickel, ion	water	kg	1.44E-06	1.51E-06	1.44E-06	1.50E-06
Nitrate	water	kg	3.03E-05	3.04E-05	3.97E-05	3.98E-05
Oils, unspecified	water	kg	2.73E-05	2.79E-05	2.92E-05	2.98E-05
PAH	water	kg	7.34E-09	7.62E-09	7.48E-09	7.73E-09
Phosphate	water	kg	3.70E-06	3.88E-06	6.63E-06	6.80E-06
Emissions to Soil						
Arsenic	soil	kg	1.10E-10	1.12E-10	1.14E-10	1.15E-10
Cadmium	soil	kg	8.46E-12	9.05E-12	1.18E-11	1.23E-11
Chromium	soil	kg	1.51E-09	1.54E-09	1.70E-09	1.73E-09
Chromium VI	soil	kg	9.54E-09	1.08E-08	9.27E-09	1.04E-08
Lead	soil	kg	5.99E-11	6.34E-11	1.06E-10	1.09E-10
Mercury	soil	kg	6.42E-13	6.48E-13	7.43E-13	7.49E-13
Oils, unspecified	soil	kg	2.75E-05	2.80E-05	2.94E-05	2.98E-05

Table 8.3 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.20E-03	4.42E-03	3.91E-03	4.10E-03
Coal, hard, unspecified, in ground	resource	kg	4.71E-01	4.71E-01	4.60E-01	4.60E-01
Gas, natural, in ground	resource	Nm3	8.96E-03	9.42E-03	1.06E-02	1.10E-02
Oil, crude, in ground	resource	kg	6.44E-03	6.56E-03	7.91E-03	8.02E-03
Uranium, in ground	resource	kg	8.21E-07	8.63E-07	7.64E-07	8.02E-07
Freshwater (lake, river, groundwater)	resource	m3	2.67E-03	2.70E-03	2.63E-03	2.65E-03
Occupation, agricultural and forestal area	resource	m2a	2.34E-02	2.36E-02	2.31E-02	2.32E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.17E-03	5.21E-03	5.07E-03	5.10E-03
Emissions to air						
Ammonia	air	kg	2.18E-05	2.19E-05	2.45E-04	2.45E-04
Arsenic	air	kg	1.79E-08	1.81E-08	1.78E-08	1.80E-08
Cadmium	air	kg	2.10E-09	2.14E-09	2.57E-09	2.61E-09
Carbon dioxide, fossil	air	kg	5.71E-02	5.89E-02	1.40E-01	1.41E-01
Carbon monoxide, fossil	air	kg	1.85E-04	1.90E-04	1.84E-04	1.89E-04
Carbon-14	air	kBq	1.69E-03	1.78E-03	1.57E-03	1.64E-03
Chromium	air	kg	2.47E-07	2.54E-07	2.46E-07	2.52E-07
Chromium VI	air	kg	6.79E-09	6.95E-09	6.74E-09	6.88E-09
Dinitrogen monoxide	air	kg	3.85E-05	3.86E-05	3.76E-05	3.77E-05
Iodine-129	air	kBq	1.44E-06	1.52E-06	1.34E-06	1.41E-06
Lead	air	kg	7.24E-08	7.37E-08	7.23E-08	7.34E-08
Methane, fossil	air	kg	2.64E-03	2.64E-03	2.58E-03	2.59E-03
Mercury	air	kg	3.84E-08	3.86E-08	3.79E-08	3.81E-08
Nickel	air	kg	1.24E-07	1.25E-07	1.31E-07	1.31E-07
Nitrogen oxides	air	kg	6.11E-04	6.16E-04	8.89E-04	8.94E-04
NMVOC total	air	kg	7.27E-05	7.40E-05	7.94E-05	8.05E-05
thereof:						
Benzene	air	kg	2.25E-06	2.26E-06	2.39E-06	2.39E-06
Benzo(a)pyrene	air	kg	1.40E-10	1.47E-10	1.40E-10	1.46E-10
Formaldehyde	air	kg	5.55E-07	5.57E-07	5.54E-07	5.56E-07
PAH	air	kg	2.43E-08	2.48E-08	2.40E-08	2.44E-08
PM2.5-10	air	kg	2.58E-05	2.66E-05	2.62E-05	2.69E-05
PM2.5	air	kg	5.82E-05	5.89E-05	5.80E-05	5.86E-05
PCDD/F (measured as I-TEQ)	air	kg	7.86E-14	7.97E-14	8.93E-14	9.03E-14
Radon-222	air	kBq	2.67E+01	2.81E+01	2.48E+01	2.60E+01
Sulfur dioxide	air	kg	3.62E-04	3.64E-04	3.68E-04	3.70E-04
Emissions to Water						
Ammonium, ion	water	kg	1.05E-06	1.06E-06	4.53E-06	4.53E-06
Arsenic, ion	water	kg	1.57E-07	1.60E-07	1.54E-07	1.56E-07
Cadmium, ion	water	kg	1.69E-08	1.82E-08	1.67E-08	1.79E-08
Carbon-14	water	kBq	5.80E-04	6.10E-04	5.38E-04	5.65E-04
Cesium-137	water	kBq	2.70E-04	2.84E-04	2.50E-04	2.63E-04
Chromium, ion	water	kg	2.24E-08	2.28E-08	2.19E-08	2.22E-08
Chromium VI	water	kg	4.03E-07	4.41E-07	3.98E-07	4.32E-07
COD	water	kg	1.62E-04	1.68E-04	2.42E-04	2.47E-04
Copper, ion	water	kg	6.32E-07	6.45E-07	6.42E-07	6.53E-07
Lead	water	kg	2.75E-07	2.80E-07	2.70E-07	2.74E-07
Mercury	water	kg	3.98E-09	4.22E-09	3.97E-09	4.18E-09
Nickel, ion	water	kg	1.48E-06	1.56E-06	1.48E-06	1.55E-06
Nitrate	water	kg	3.06E-05	3.06E-05	4.00E-05	4.00E-05
Oils, unspecified	water	kg	2.83E-05	2.89E-05	3.01E-05	3.07E-05
PAH	water	kg	7.54E-09	7.82E-09	7.66E-09	7.90E-09
Phosphate	water	kg	4.15E-06	4.33E-06	7.03E-06	7.19E-06
Emissions to Soil						
Arsenic	soil	kg	1.82E-10	1.84E-10	1.77E-10	1.79E-10
Cadmium	soil	kg	8.95E-12	9.55E-12	1.22E-11	1.27E-11
Chromium	soil	kg	2.42E-09	2.45E-09	2.50E-09	2.53E-09
Chromium VI	soil	kg	2.19E-08	2.32E-08	2.02E-08	2.13E-08
Lead	soil	kg	6.42E-11	6.77E-11	1.09E-10	1.12E-10
Mercury	soil	kg	6.72E-13	6.78E-13	7.69E-13	7.75E-13
Oils, unspecified	soil	kg	2.84E-05	2.89E-05	3.02E-05	3.06E-05

Table 8.4 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	9.76E-01	9.76E-01	8.36E-01
Coal, hard, unspecified, in ground	resource	kg	3.02E-03	3.39E-03	1.15E-03
Gas, natural, in ground	resource	Nm3	6.80E-03	7.28E-03	1.64E-03
Oil, crude, in ground	resource	kg	3.05E-03	3.17E-03	7.92E-04
Uranium, in ground	resource	kg	3.71E-07	4.15E-07	1.21E-07
Freshwater (lake, river, groundwater)	resource	m3	5.14E-03	5.17E-03	4.26E-03
Occupation, agricultural and forestal area	resource	m2a	2.27E-03	2.40E-03	1.00E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.30E-03	1.33E-03	1.02E-03
Emissions to air					
Ammonia	air	kg	2.39E-04	2.39E-04	4.86E-06
Arsenic	air	kg	1.00E-08	1.02E-08	7.32E-09
Cadmium	air	kg	1.95E-09	1.99E-09	9.19E-10
Carbon dioxide, fossil	air	kg	1.25E-01	1.27E-01	8.08E-01
Carbon monoxide, fossil	air	kg	2.16E-04	2.22E-04	1.68E-04
Carbon-14	air	kBq	7.57E-04	8.48E-04	2.49E-04
Chromium	air	kg	8.27E-08	8.94E-08	4.03E-08
Chromium VI	air	kg	2.19E-09	2.36E-09	1.13E-09
Dinitrogen monoxide	air	kg	2.35E-05	2.36E-05	1.94E-05
Iodine-129	air	kBq	6.48E-07	7.25E-07	2.12E-07
Lead	air	kg	2.12E-08	2.25E-08	1.19E-08
Methane, fossil	air	kg	2.85E-04	2.89E-04	2.15E-04
Mercury	air	kg	2.18E-08	2.20E-08	1.77E-08
Nickel	air	kg	2.81E-08	2.88E-08	1.25E-08
Nitrogen oxides	air	kg	7.80E-04	7.85E-04	6.41E-04
NMVOC total	air	kg	3.80E-05	3.93E-05	2.03E-05
thereof:					
Benzene	air	kg	2.13E-06	2.13E-06	1.61E-06
Benzo(a)pyrene	air	kg	8.94E-11	9.63E-11	4.91E-11
Formaldehyde	air	kg	5.50E-07	5.52E-07	4.50E-07
PAH	air	kg	1.38E-08	1.42E-08	1.01E-08
PM2.5-10	air	kg	1.48E-05	1.56E-05	9.83E-06
PM2.5	air	kg	6.77E-05	6.84E-05	5.54E-05
PCDD/F (measured as I-TEQ)	air	kg	8.18E-14	8.30E-14	5.59E-14
Radon-222	air	kBq	1.20E+01	1.34E+01	3.94E+00
Sulfur dioxide	air	kg	1.38E-04	1.41E-04	1.20E-04
Emissions to Water					
Ammonium, ion	water	kg	4.20E-06	4.21E-06	4.13E-08
Arsenic, ion	water	kg	9.54E-07	9.56E-07	8.08E-07
Cadmium, ion	water	kg	3.35E-08	3.49E-08	2.50E-08
Carbon-14	water	kBq	2.60E-04	2.92E-04	8.53E-05
Cesium-137	water	kBq	1.21E-04	1.36E-04	3.97E-05
Chromium, ion	water	kg	2.55E-09	2.96E-09	9.74E-10
Chromium VI	water	kg	8.41E-07	8.80E-07	6.19E-07
COD	water	kg	1.40E-04	1.46E-04	2.81E-05
Copper, ion	water	kg	1.07E-06	1.08E-06	8.49E-07
Lead	water	kg	1.01E-06	1.01E-06	8.39E-07
Mercury	water	kg	6.19E-09	6.44E-09	4.66E-09
Nickel, ion	water	kg	1.98E-06	2.06E-06	1.47E-06
Nitrate	water	kg	1.18E-05	1.18E-05	1.26E-07
Oils, unspecified	water	kg	8.52E-06	9.14E-06	3.72E-06
PAH	water	kg	2.71E-09	3.00E-09	1.25E-09
Phosphate	water	kg	3.65E-05	3.67E-05	2.82E-05
Emissions to Soil					
Arsenic	soil	kg	6.20E-11	6.43E-11	1.30E-11
Cadmium	soil	kg	9.93E-12	1.06E-11	3.70E-12
Chromium	soil	kg	1.02E-09	1.05E-09	2.14E-10
Chromium VI	soil	kg	7.72E-09	9.07E-09	6.32E-10
Lead	soil	kg	8.93E-11	9.30E-11	2.37E-11
Mercury	soil	kg	2.22E-13	2.29E-13	6.33E-14
Oils, unspecified	soil	kg	7.72E-06	8.22E-06	3.42E-06

Table 8.5 LCA results for year 2025, realistic-optimistic development, “440 ppm-scenario”.

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	9.78E-01	1.00E+00	1.00E+00
Coal, hard, unspecified, in ground	resource	kg	5.64E-03	3.01E-03	3.43E-03
Gas, natural, in ground	resource	Nm3	1.15E-02	4.19E-03	4.73E-03
Oil, crude, in ground	resource	kg	3.39E-03	1.15E-03	1.29E-03
Uranium, in ground	resource	kg	8.31E-07	3.80E-07	4.30E-07
Freshwater (lake, river, groundwater)	resource	m3	5.37E-03	5.23E-03	5.26E-03
Occupation, agricultural and forestal area	resource	m2a	3.48E-03	1.95E-03	2.09E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.38E-03	1.31E-03	1.34E-03
Emissions to air					
Ammonia	air	kg	2.39E-04	2.78E-06	2.90E-06
Arsenic	air	kg	1.11E-08	9.76E-09	9.95E-09
Cadmium	air	kg	2.29E-09	1.28E-09	1.34E-09
Carbon dioxide, fossil	air	kg	1.40E-01	2.70E-02	2.92E-02
Carbon monoxide, fossil	air	kg	2.27E-04	2.17E-04	2.24E-04
Carbon-14	air	kBq	1.71E-03	7.81E-04	8.84E-04
Chromium	air	kg	9.50E-08	7.85E-08	8.62E-08
Chromium VI	air	kg	2.49E-09	2.10E-09	2.28E-09
Dinitrogen monoxide	air	kg	2.47E-05	2.38E-05	2.40E-05
Iodine-129	air	kBq	1.46E-06	6.68E-07	7.56E-07
Lead	air	kg	2.57E-08	1.94E-08	2.09E-08
Methane, fossil	air	kg	3.21E-04	2.76E-04	2.81E-04
Mercury	air	kg	2.24E-08	2.18E-08	2.21E-08
Nickel	air	kg	3.25E-08	1.58E-08	1.67E-08
Nitrogen oxides	air	kg	8.03E-04	3.02E-04	3.08E-04
NMVOC total	air	kg	4.43E-05	2.83E-05	2.98E-05
thereof:					
Benzene	air	kg	2.15E-06	1.95E-06	1.96E-06
Benzo(a)pyrene	air	kg	1.06E-10	8.72E-11	9.50E-11
Formaldehyde	air	kg	5.63E-07	5.47E-07	5.49E-07
PAH	air	kg	1.56E-08	1.37E-08	1.42E-08
PM2.5-10	air	kg	1.62E-05	1.39E-05	1.48E-05
PM2.5	air	kg	6.93E-05	6.79E-05	6.87E-05
PCDD/F (measured as I-TEQ)	air	kg	8.48E-14	7.07E-14	7.20E-14
Radon-222	air	kBq	2.69E+01	1.23E+01	1.40E+01
Sulfur dioxide	air	kg	1.54E-04	1.23E-04	1.25E-04
Emissions to Water					
Ammonium, ion	water	kg	4.28E-06	8.86E-08	9.83E-08
Arsenic, ion	water	kg	9.63E-07	9.75E-07	9.78E-07
Cadmium, ion	water	kg	3.58E-08	3.40E-08	3.56E-08
Carbon-14	water	kBq	5.87E-04	2.68E-04	3.04E-04
Cesium-137	water	kBq	2.73E-04	1.25E-04	1.41E-04
Chromium, ion	water	kg	4.34E-09	2.45E-09	2.91E-09
Chromium VI	water	kg	9.27E-07	8.52E-07	8.96E-07
COD	water	kg	1.58E-04	4.70E-05	5.30E-05
Copper, ion	water	kg	1.11E-06	1.06E-06	1.07E-06
Lead	water	kg	1.03E-06	1.03E-06	1.04E-06
Mercury	water	kg	6.73E-09	6.22E-09	6.50E-09
Nickel, ion	water	kg	2.11E-06	1.99E-06	2.08E-06
Nitrate	water	kg	1.21E-05	3.04E-07	3.40E-07
Oils, unspecified	water	kg	1.02E-05	5.60E-06	6.30E-06
PAH	water	kg	3.20E-09	2.40E-09	2.73E-09
Phosphate	water	kg	3.71E-05	3.43E-05	3.45E-05
Emissions to Soil					
Arsenic	soil	kg	1.39E-10	5.60E-11	5.85E-11
Cadmium	soil	kg	1.11E-11	5.94E-12	6.64E-12
Chromium	soil	kg	1.99E-09	7.69E-10	8.08E-10
Chromium VI	soil	kg	2.19E-08	7.97E-09	9.51E-09
Lead	soil	kg	9.74E-11	3.51E-11	3.92E-11
Mercury	soil	kg	2.59E-13	9.76E-14	1.05E-13
Oils, unspecified	soil	kg	9.16E-06	4.87E-06	5.44E-06

Table 8.6 LCA results for year 2025, realistic-optimistic development, “440 ppm-scenario”.

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	1.00E+00	1.00E+00	9.78E-01
Coal, hard, unspecified, in ground	resource	kg	5.55E-03	5.97E-03	5.27E-03
Gas, natural, in ground	resource	Nm3	9.01E-03	9.55E-03	1.11E-02
Oil, crude, in ground	resource	kg	1.40E-03	1.54E-03	3.27E-03
Uranium, in ground	resource	kg	8.51E-07	9.02E-07	7.87E-07
Freshwater (lake, river, groundwater)	resource	m3	5.46E-03	5.49E-03	5.34E-03
Occupation, agricultural and forestal area	resource	m2a	3.17E-03	3.32E-03	3.35E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.36E-03	1.40E-03	1.35E-03
Emissions to air					
Ammonia	air	kg	3.39E-06	3.52E-06	2.39E-04
Arsenic	air	kg	1.08E-08	1.10E-08	1.10E-08
Cadmium	air	kg	1.62E-09	1.67E-09	2.24E-09
Carbon dioxide, fossil	air	kg	4.13E-02	4.34E-02	1.38E-01
Carbon monoxide, fossil	air	kg	2.24E-04	2.30E-04	2.22E-04
Carbon-14	air	kBq	1.75E-03	1.85E-03	1.61E-03
Chromium	air	kg	8.48E-08	9.24E-08	8.82E-08
Chromium VI	air	kg	2.25E-09	2.44E-09	2.33E-09
Dinitrogen monoxide	air	kg	2.51E-05	2.52E-05	2.46E-05
Iodine-129	air	kBq	1.50E-06	1.59E-06	1.38E-06
Lead	air	kg	2.31E-08	2.46E-08	2.44E-08
Methane, fossil	air	kg	3.12E-04	3.17E-04	3.17E-04
Mercury	air	kg	2.22E-08	2.24E-08	2.21E-08
Nickel	air	kg	2.00E-08	2.08E-08	3.17E-08
Nitrogen oxides	air	kg	3.22E-04	3.28E-04	7.98E-04
NMVOC total	air	kg	3.40E-05	3.55E-05	4.30E-05
thereof:					
Benzene	air	kg	1.97E-06	1.98E-06	2.15E-06
Benzo(a)pyrene	air	kg	9.80E-11	1.06E-10	9.90E-11
Formaldehyde	air	kg	5.59E-07	5.61E-07	5.61E-07
PAH	air	kg	1.52E-08	1.57E-08	1.52E-08
PM2.5-10	air	kg	1.46E-05	1.55E-05	1.54E-05
PM2.5	air	kg	6.89E-05	6.97E-05	6.86E-05
PCDD/F (measured as I-TEQ)	air	kg	7.28E-14	7.41E-14	8.36E-14
Radon-222	air	kBq	2.77E+01	2.93E+01	2.55E+01
Sulfur dioxide	air	kg	1.37E-04	1.40E-04	1.52E-04
Emissions to Water					
Ammonium, ion	water	kg	1.60E-07	1.70E-07	4.27E-06
Arsenic, ion	water	kg	9.83E-07	9.86E-07	9.61E-07
Cadmium, ion	water	kg	3.50E-08	3.66E-08	3.44E-08
Carbon-14	water	kBq	6.03E-04	6.39E-04	5.56E-04
Cesium-137	water	kBq	2.80E-04	2.97E-04	2.58E-04
Chromium, ion	water	kg	4.01E-09	4.48E-09	3.93E-09
Chromium VI	water	kg	9.04E-07	9.49E-07	8.87E-07
COD	water	kg	6.13E-05	6.74E-05	1.53E-04
Copper, ion	water	kg	1.10E-06	1.11E-06	1.10E-06
Lead	water	kg	1.05E-06	1.05E-06	1.03E-06
Mercury	water	kg	6.55E-09	6.83E-09	6.48E-09
Nickel, ion	water	kg	2.04E-06	2.13E-06	2.03E-06
Nitrate	water	kg	6.00E-07	6.37E-07	1.21E-05
Oils, unspecified	water	kg	6.78E-06	7.49E-06	9.57E-06
PAH	water	kg	2.63E-09	2.96E-09	2.92E-09
Phosphate	water	kg	3.48E-05	3.50E-05	3.70E-05
Emissions to Soil					
Arsenic	soil	kg	1.41E-10	1.43E-10	1.37E-10
Cadmium	soil	kg	6.52E-12	7.22E-12	1.04E-11
Chromium	soil	kg	1.83E-09	1.87E-09	1.96E-09
Chromium VI	soil	kg	2.25E-08	2.40E-08	2.05E-08
Lead	soil	kg	4.01E-11	4.42E-11	9.38E-11
Mercury	soil	kg	1.33E-13	1.40E-13	2.53E-13
Oils, unspecified	soil	kg	5.93E-06	6.50E-06	8.66E-06

Table 8.7 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	7.95E-04	4.25E-01
Coal, hard, unspecified, in ground	resource	kg	3.33E-01	9.33E-04
Gas, natural, in ground	resource	Nm3	1.90E-03	8.70E-04
Oil, crude, in ground	resource	kg	4.14E-03	1.00E-03
Uranium, in ground	resource	kg	1.58E-07	7.76E-08
Freshwater (lake, river, groundwater)	resource	m3	5.98E-04	1.58E-03
Occupation, agricultural and forestal area	resource	m2a	1.55E-02	4.89E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.79E-03	1.02E-03
Emissions to air				
Ammonia	air	kg	1.41E-05	6.20E-07
Arsenic	air	kg	6.13E-08	5.60E-09
Cadmium	air	kg	1.33E-09	9.02E-10
Carbon dioxide, fossil	air	kg	6.42E-01	7.77E-01
Carbon monoxide, fossil	air	kg	1.25E-04	8.07E-05
Carbon-14	air	kBq	3.24E-04	1.58E-04
Chromium	air	kg	4.30E-08	3.50E-08
Chromium VI	air	kg	1.39E-09	9.51E-10
Dinitrogen monoxide	air	kg	2.71E-05	2.49E-05
Iodine-129	air	kBq	2.75E-07	1.33E-07
Lead	air	kg	3.73E-08	1.07E-08
Methane, fossil	air	kg	1.85E-03	1.21E-04
Mercury	air	kg	1.96E-08	1.10E-08
Nickel	air	kg	7.98E-08	7.99E-09
Nitrogen oxides	air	kg	4.18E-04	3.94E-04
NMVOC total	air	kg	4.77E-05	2.04E-05
thereof:				
Benzene	air	kg	1.18E-06	9.82E-07
Benzo(a)pyrene	air	kg	7.58E-11	3.52E-11
Formaldehyde	air	kg	2.75E-07	2.70E-07
PAH	air	kg	5.34E-08	4.59E-08
PM2.5-10	air	kg	1.35E-05	3.34E-06
PM2.5	air	kg	9.31E-06	2.55E-06
PCDD/F (measured as I-TEQ)	air	kg	4.76E-14	4.56E-14
Radon-222	air	kBq	5.13E+00	2.51E+00
Sulfur dioxide	air	kg	3.54E-04	5.76E-04
Emissions to Water				
Ammonium, ion	water	kg	3.54E-07	5.67E-08
Arsenic, ion	water	kg	8.12E-08	1.30E-06
Cadmium, ion	water	kg	1.22E-08	8.06E-08
Carbon-14	water	kBq	1.11E-04	5.31E-05
Cesium-137	water	kBq	5.15E-05	2.48E-05
Chromium, ion	water	kg	2.06E-09	8.94E-10
Chromium VI	water	kg	7.18E-07	8.32E-06
COD	water	kg	2.17E-04	1.86E-03
Copper, ion	water	kg	1.28E-06	6.02E-06
Lead	water	kg	3.26E-07	1.68E-06
Mercury	water	kg	4.87E-09	5.45E-08
Nickel, ion	water	kg	5.90E-07	3.50E-06
Nitrate	water	kg	1.21E-06	7.16E-07
Oils, unspecified	water	kg	1.83E-05	3.19E-06
PAH	water	kg	2.47E-09	1.10E-09
Phosphate	water	kg	7.03E-06	9.83E-05
Emissions to Soil				
Arsenic	soil	kg	5.18E-11	1.09E-11
Cadmium	soil	kg	6.34E-12	5.68E-12
Chromium	soil	kg	7.59E-10	2.22E-10
Chromium VI	soil	kg	2.54E-09	7.14E-10
Lead	soil	kg	5.02E-11	4.34E-11
Mercury	soil	kg	5.57E-13	1.92E-13
Oils, unspecified	soil	kg	1.86E-05	2.93E-06

Table 8.8 LCA results for year 2025, realistic-optimistic development, “440 ppm-scenario”.

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	3.55E-03	3.74E-03	1.77E-03	1.96E-03
Coal, hard, unspecified, in ground	resource	kg	3.77E-01	3.78E-01	3.76E-01	3.76E-01
Gas, natural, in ground	resource	Nm3	7.45E-03	7.85E-03	3.90E-03	4.30E-03
Oil, crude, in ground	resource	kg	5.00E-03	5.10E-03	4.82E-03	4.92E-03
Uranium, in ground	resource	kg	6.96E-07	7.33E-07	3.49E-07	3.85E-07
Freshwater (lake, river, groundwater)	resource	m3	9.32E-04	9.57E-04	7.63E-04	7.88E-04
Occupation, agricultural and forestal area	resource	m2a	1.88E-02	1.89E-02	1.79E-02	1.80E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.32E-03	4.35E-03	4.28E-03	4.31E-03
Emissions to air						
Ammonia	air	kg	1.66E-05	1.67E-05	1.61E-05	1.62E-05
Arsenic	air	kg	7.71E-08	7.72E-08	7.63E-08	7.65E-08
Cadmium	air	kg	1.85E-09	1.89E-09	1.60E-09	1.64E-09
Carbon dioxide, fossil	air	kg	1.18E-01	1.20E-01	1.08E-01	1.09E-01
Carbon monoxide, fossil	air	kg	1.58E-04	1.63E-04	1.53E-04	1.58E-04
Carbon-14	air	kBq	1.43E-03	1.51E-03	7.16E-04	7.92E-04
Chromium	air	kg	5.99E-08	6.55E-08	5.52E-08	6.09E-08
Chromium VI	air	kg	1.88E-09	2.02E-09	1.76E-09	1.90E-09
Dinitrogen monoxide	air	kg	3.51E-05	3.52E-05	3.42E-05	3.43E-05
Iodine-129	air	kBq	1.22E-06	1.29E-06	6.11E-07	6.76E-07
Lead	air	kg	4.92E-08	5.03E-08	4.65E-08	4.76E-08
Methane, fossil	air	kg	2.12E-03	2.12E-03	2.09E-03	2.10E-03
Mercury	air	kg	2.48E-08	2.50E-08	2.46E-08	2.47E-08
Nickel	air	kg	9.56E-08	9.62E-08	9.25E-08	9.32E-08
Nitrogen oxides	air	kg	5.15E-04	5.19E-04	5.00E-04	5.04E-04
NMVOC total	air	kg	6.22E-05	6.33E-05	5.80E-05	5.91E-05
thereof:						
Benzene	air	kg	1.48E-06	1.48E-06	1.46E-06	1.47E-06
Benzo(a)pyrene	air	kg	1.00E-10	1.06E-10	9.23E-11	9.80E-11
Formaldehyde	air	kg	3.55E-07	3.57E-07	3.46E-07	3.48E-07
PAH	air	kg	6.74E-08	6.78E-08	6.63E-08	6.67E-08
PM2.5-10	air	kg	1.63E-05	1.69E-05	1.58E-05	1.65E-05
PM2.5	air	kg	1.20E-05	1.26E-05	1.13E-05	1.18E-05
PCDD/F (measured as I-TEQ)	air	kg	6.03E-14	6.12E-14	5.88E-14	5.97E-14
Radon-222	air	kBq	2.26E+01	2.38E+01	1.13E+01	1.25E+01
Sulfur dioxide	air	kg	4.39E-04	4.41E-04	4.28E-04	4.30E-04
Emissions to Water						
Ammonium, ion	water	kg	4.78E-07	4.85E-07	4.25E-07	4.32E-07
Arsenic, ion	water	kg	1.00E-07	1.02E-07	9.42E-08	9.64E-08
Cadmium, ion	water	kg	1.56E-08	1.68E-08	1.49E-08	1.61E-08
Carbon-14	water	kBq	4.92E-04	5.18E-04	2.46E-04	2.72E-04
Cesium-137	water	kBq	2.29E-04	2.41E-04	1.14E-04	1.26E-04
Chromium, ion	water	kg	4.24E-09	4.58E-09	3.08E-09	3.43E-09
Chromium VI	water	kg	8.83E-07	9.15E-07	8.44E-07	8.77E-07
COD	water	kg	2.60E-04	2.65E-04	2.50E-04	2.54E-04
Copper, ion	water	kg	1.47E-06	1.48E-06	1.44E-06	1.45E-06
Lead	water	kg	3.81E-07	3.85E-07	3.67E-07	3.71E-07
Mercury	water	kg	5.95E-09	6.15E-09	5.70E-09	5.91E-09
Nickel, ion	water	kg	7.73E-07	8.39E-07	7.32E-07	7.98E-07
Nitrate	water	kg	1.68E-06	1.71E-06	1.46E-06	1.49E-06
Oils, unspecified	water	kg	2.23E-05	2.28E-05	2.14E-05	2.19E-05
PAH	water	kg	3.22E-09	3.46E-09	3.05E-09	3.29E-09
Phosphate	water	kg	8.50E-06	8.66E-06	8.11E-06	8.27E-06
Emissions to Soil						
Arsenic	soil	kg	1.51E-10	1.53E-10	8.84E-11	9.03E-11
Cadmium	soil	kg	8.13E-12	8.64E-12	7.70E-12	8.22E-12
Chromium	soil	kg	2.02E-09	2.05E-09	1.24E-09	1.27E-09
Chromium VI	soil	kg	1.88E-08	1.99E-08	8.10E-09	9.23E-09
Lead	soil	kg	6.39E-11	6.69E-11	6.02E-11	6.32E-11
Mercury	soil	kg	6.65E-13	6.71E-13	6.40E-13	6.45E-13
Oils, unspecified	soil	kg	2.23E-05	2.27E-05	2.15E-05	2.20E-05

Table 8.9 LCA results for year 2025, realistic-optimistic development, "440 ppm-scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.84E-01	4.80E-01	4.82E-01	4.82E-01
Coal, hard, unspecified, in ground	resource	kg	4.67E-03	5.10E-03	2.32E-03	2.71E-03
Gas, natural, in ground	resource	Nm3	7.66E-03	8.20E-03	3.21E-03	3.71E-03
Oil, crude, in ground	resource	kg	1.57E-03	1.69E-03	1.34E-03	1.47E-03
Uranium, in ground	resource	kg	7.36E-07	7.80E-07	3.01E-07	3.48E-07
Freshwater (lake, river, groundwater)	resource	m3	2.11E-03	2.14E-03	1.90E-03	1.93E-03
Occupation, agricultural and forestal area	resource	m2a	2.25E-03	2.38E-03	1.12E-03	1.25E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.22E-03	1.25E-03	1.17E-03	1.20E-03
Emissions to air						
Ammonia	air	kg	1.59E-06	1.70E-06	1.02E-06	1.13E-06
Arsenic	air	kg	8.05E-09	8.20E-09	7.09E-09	7.27E-09
Cadmium	air	kg	1.44E-09	1.49E-09	1.13E-09	1.18E-09
Carbon dioxide, fossil	air	kg	1.27E-01	1.29E-01	1.14E-01	1.16E-01
Carbon monoxide, fossil	air	kg	1.13E-04	1.19E-04	1.07E-04	1.13E-04
Carbon-14	air	kBq	1.51E-03	1.61E-03	6.18E-04	7.13E-04
Chromium	air	kg	5.37E-08	6.10E-08	4.79E-08	5.49E-08
Chromium VI	air	kg	1.44E-09	1.61E-09	1.29E-09	1.46E-09
Dinitrogen monoxide	air	kg	3.30E-05	3.32E-05	3.19E-05	3.20E-05
Iodine-129	air	kBq	1.29E-06	1.37E-06	5.27E-07	6.08E-07
Lead	air	kg	1.78E-08	1.92E-08	1.44E-08	1.58E-08
Methane, fossil	air	kg	1.89E-04	1.93E-04	1.55E-04	1.60E-04
Mercury	air	kg	1.44E-08	1.46E-08	1.41E-08	1.43E-08
Nickel	air	kg	1.50E-08	1.58E-08	1.11E-08	1.19E-08
Nitrogen oxides	air	kg	5.26E-04	5.30E-04	5.07E-04	5.13E-04
NMVOC total	air	kg	3.36E-05	3.50E-05	2.83E-05	2.96E-05
thereof:						
Benzene	air	kg	1.28E-06	1.29E-06	1.26E-06	1.27E-06
Benzo(a)pyrene	air	kg	5.88E-11	6.60E-11	4.88E-11	5.60E-11
Formaldehyde	air	kg	3.56E-07	3.60E-07	3.45E-07	3.47E-07
PAH	air	kg	5.99E-08	6.00E-08	5.85E-08	5.89E-08
PM2.5-10	air	kg	5.26E-06	6.10E-06	4.66E-06	5.45E-06
PM2.5	air	kg	4.82E-06	5.50E-06	3.88E-06	4.58E-06
PCDD/F (measured as I-TEQ)	air	kg	5.90E-14	6.00E-14	5.71E-14	5.83E-14
Radon-222	air	kBq	2.39E+01	2.54E+01	9.80E+00	1.13E+01
Sulfur dioxide	air	kg	7.46E-04	7.50E-04	7.32E-04	7.34E-04
Emissions to Water						
Ammonium, ion	water	kg	1.64E-07	1.72E-07	9.80E-08	1.06E-07
Arsenic, ion	water	kg	1.47E-06	1.47E-06	1.46E-06	1.46E-06
Cadmium, ion	water	kg	9.25E-08	9.40E-08	9.20E-08	9.30E-08
Carbon-14	water	kBq	5.20E-04	5.50E-04	2.12E-04	2.44E-04
Cesium-137	water	kBq	2.42E-04	2.57E-04	9.80E-05	1.14E-04
Chromium, ion	water	kg	3.42E-09	3.80E-09	1.97E-09	2.40E-09
Chromium VI	water	kg	9.38E-06	9.40E-06	9.30E-06	9.38E-06
COD	water	kg	2.10E-03	2.10E-03	2.09E-03	2.09E-03
Copper, ion	water	kg	6.78E-06	6.80E-06	6.74E-06	6.75E-06
Lead	water	kg	1.90E-06	1.90E-06	1.88E-06	1.89E-06
Mercury	water	kg	6.15E-08	6.20E-08	6.12E-08	6.14E-08
Nickel, ion	water	kg	4.05E-06	4.10E-06	4.00E-06	4.08E-06
Nitrate	water	kg	1.21E-06	1.24E-06	9.40E-07	9.70E-07
Oils, unspecified	water	kg	5.69E-06	6.30E-06	4.59E-06	5.24E-06
PAH	water	kg	1.80E-09	2.10E-09	1.59E-09	1.89E-09
Phosphate	water	kg	1.11E-04	1.11E-04	1.10E-04	1.10E-04
Emissions to Soil						
Arsenic	soil	kg	1.28E-10	1.30E-10	5.00E-11	5.24E-11
Cadmium	soil	kg	7.67E-12	8.30E-12	7.13E-12	7.78E-12
Chromium	soil	kg	1.71E-09	1.75E-09	7.30E-10	7.67E-10
Chromium VI	soil	kg	2.08E-08	2.22E-08	7.38E-09	8.79E-09
Lead	soil	kg	5.84E-11	6.20E-11	5.38E-11	5.76E-11
Mercury	soil	kg	2.65E-13	2.72E-13	2.33E-13	2.40E-13
Oils, unspecified	soil	kg	5.12E-06	5.60E-06	4.14E-06	4.67E-06

Table 8.10 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	1.04E-03	1.03E-03	1.03E-03
	Coal, hard, unspecified, in ground	resource	kg	4.08E-01	4.08E-01	4.08E-01
	Gas, natural, in ground	resource	Nm3	2.60E-03	2.58E-03	2.58E-03
	Oil, crude, in ground	resource	kg	5.28E-03	5.26E-03	5.26E-03
	Uranium, in ground	resource	kg	1.92E-07	1.91E-07	1.91E-07
	Freshwater (lake, river, groundwater)	resource	m3	2.06E-03	2.06E-03	2.06E-03
	Occupation, agricultural and forestal area	resource	m2a	1.91E-02	1.90E-02	1.90E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	4.42E-03	4.41E-03	4.41E-03
Emissions to air						
	Ammonia	air	kg	2.00E-05	2.00E-05	2.00E-05
	Arsenic	air	kg	1.47E-08	1.45E-08	1.45E-08
	Cadmium	air	kg	1.56E-09	1.52E-09	1.52E-09
	Carbon dioxide, fossil	air	kg	7.36E-01	7.36E-01	7.36E-01
	Carbon monoxide, fossil	air	kg	1.51E-04	1.50E-04	1.50E-04
	Carbon-14	air	kBq	3.93E-04	3.91E-04	3.91E-04
	Chromium	air	kg	1.54E-07	1.37E-07	1.37E-07
	Chromium VI	air	kg	4.37E-09	3.95E-09	3.95E-09
	Dinitrogen monoxide	air	kg	3.22E-05	3.21E-05	3.21E-05
	Iodine-129	air	kBq	3.35E-07	3.34E-07	3.34E-07
	Lead	air	kg	6.04E-08	5.95E-08	5.94E-08
	Methane, fossil	air	kg	2.26E-03	2.26E-03	2.26E-03
	Mercury	air	kg	3.29E-08	3.28E-08	3.28E-08
	Nickel	air	kg	1.05E-07	1.05E-07	1.05E-07
	Nitrogen oxides	air	kg	7.58E-04	7.58E-04	7.58E-04
	NMVOC total	air	kg	5.65E-05	5.64E-05	5.64E-05
	thereof:					
	Benzene	air	kg	1.93E-06	1.93E-06	1.93E-06
	Benzo(a)pyrene	air	kg	1.19E-10	1.15E-10	1.15E-10
	Formaldehyde	air	kg	4.69E-07	4.68E-07	4.68E-07
	PAH	air	kg	1.92E-08	1.91E-08	1.91E-08
	PM2.5-10	air	kg	2.08E-05	2.06E-05	2.06E-05
	PM2.5	air	kg	4.89E-05	4.87E-05	4.87E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.67E-14	6.64E-14	6.64E-14
	Radon-222	air	kBq	6.24E+00	6.21E+00	6.21E+00
	Sulfur dioxide	air	kg	5.48E-04	5.48E-04	5.48E-04
Emissions to Water						
	Ammonium, ion	water	kg	8.18E-07	8.17E-07	8.17E-07
	Arsenic, ion	water	kg	1.23E-07	1.23E-07	1.22E-07
	Cadmium, ion	water	kg	1.16E-08	1.14E-08	1.13E-08
	Carbon-14	water	kBq	1.35E-04	1.34E-04	1.34E-04
	Cesium-137	water	kBq	6.27E-05	6.24E-05	6.24E-05
	Chromium, ion	water	kg	1.67E-08	1.66E-08	1.66E-08
	Chromium VI	water	kg	2.48E-07	2.42E-07	2.42E-07
	COD	water	kg	1.21E-04	1.20E-04	1.20E-04
	Copper, ion	water	kg	4.71E-07	4.67E-07	4.67E-07
	Lead	water	kg	2.00E-07	1.96E-07	1.94E-07
	Mercury	water	kg	2.77E-09	2.74E-09	2.74E-09
	Nickel, ion	water	kg	9.85E-07	9.23E-07	9.21E-07
	Nitrate	water	kg	2.51E-05	2.51E-05	2.51E-05
	Oils, unspecified	water	kg	2.30E-05	2.29E-05	2.29E-05
	PAH	water	kg	5.07E-09	4.71E-09	4.71E-09
	Phosphate	water	kg	2.86E-06	2.84E-06	2.84E-06
Emissions to Soil						
	Arsenic	soil	kg	6.59E-11	6.57E-11	6.57E-11
	Cadmium	soil	kg	6.71E-12	6.63E-12	6.63E-12
	Chromium	soil	kg	9.38E-10	9.35E-10	9.34E-10
	Chromium VI	soil	kg	2.98E-09	2.96E-09	2.96E-09
	Lead	soil	kg	4.93E-11	4.88E-11	4.87E-11
	Mercury	soil	kg	5.60E-13	5.59E-13	5.59E-13
	Oils, unspecified	soil	kg	2.34E-05	2.33E-05	2.33E-05

Table 8.11 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

				electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
				Total	Total	Total	Total
				kWh	kWh	kWh	kWh
Resources							
	Coal, brown, in ground	resource	kg	2.48E-03	2.73E-03	2.48E-03	2.71E-03
	Coal, hard, unspecified, in ground	resource	kg	5.19E-01	5.19E-01	5.19E-01	5.19E-01
	Gas, natural, in ground	resource	Nm3	5.56E-03	6.10E-03	8.12E-03	8.60E-03
	Oil, crude, in ground	resource	kg	6.90E-03	7.03E-03	8.75E-03	8.87E-03
	Uranium, in ground	resource	kg	4.65E-07	5.13E-07	4.66E-07	5.08E-07
	Freshwater (lake, river, groundwater)	resource	m3	2.74E-03	2.78E-03	2.78E-03	2.81E-03
	Occupation, agricultural and forestal area	resource	m2a	2.48E-02	2.49E-02	2.51E-02	2.53E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	5.67E-03	5.71E-03	5.70E-03	5.73E-03
Emissions to air							
	Ammonia	air	kg	2.35E-05	2.36E-05	2.48E-04	2.48E-04
	Arsenic	air	kg	2.00E-08	2.02E-08	2.06E-08	2.08E-08
	Cadmium	air	kg	2.21E-09	2.27E-09	2.86E-09	2.92E-09
	Carbon dioxide, fossil	air	kg	5.04E-02	5.25E-02	1.46E-01	1.48E-01
	Carbon monoxide, fossil	air	kg	2.04E-04	2.10E-04	2.09E-04	2.15E-04
	Carbon-14	air	kBq	9.55E-04	1.05E-03	9.50E-04	1.04E-03
	Chromium	air	kg	2.59E-07	2.66E-07	2.64E-07	2.71E-07
	Chromium VI	air	kg	7.13E-09	7.31E-09	7.27E-09	7.43E-09
	Dinitrogen monoxide	air	kg	4.14E-05	4.16E-05	4.16E-05	4.17E-05
	Iodine-129	air	kBq	8.15E-07	8.99E-07	8.12E-07	8.87E-07
	Lead	air	kg	8.31E-08	8.50E-08	8.56E-08	8.73E-08
	Methane, fossil	air	kg	2.89E-03	2.89E-03	2.90E-03	2.91E-03
	Mercury	air	kg	4.22E-08	4.25E-08	4.28E-08	4.30E-08
	Nickel	air	kg	1.36E-07	1.37E-07	1.47E-07	1.48E-07
	Nitrogen oxides	air	kg	6.48E-04	6.54E-04	9.95E-04	1.00E-03
	NMVOC total	air	kg	7.54E-05	7.68E-05	8.55E-05	8.67E-05
	thereof:						
	Benzene	air	kg	2.47E-06	2.48E-06	2.69E-06	2.70E-06
	Benzo(a)pyrene	air	kg	1.76E-10	1.84E-10	1.82E-10	1.89E-10
	Formaldehyde	air	kg	6.03E-07	6.06E-07	6.18E-07	6.20E-07
	PAH	air	kg	2.58E-08	2.63E-08	2.62E-08	2.67E-08
	PM2.5-10	air	kg	2.81E-05	2.89E-05	2.93E-05	3.00E-05
	PM2.5	air	kg	6.39E-05	6.47E-05	6.53E-05	6.60E-05
	PCDD/F (measured as I-TEQ)	air	kg	8.83E-14	9.01E-14	1.01E-13	1.03E-13
	Radon-222	air	kBq	1.51E+01	1.67E+01	1.51E+01	1.64E+01
	Sulfur dioxide	air	kg	3.78E-04	3.80E-04	3.93E-04	3.96E-04
Emissions to Water							
	Ammonium, ion	water	kg	1.11E-06	1.12E-06	5.07E-06	5.08E-06
	Arsenic, ion	water	kg	1.66E-07	1.69E-07	1.68E-07	1.71E-07
	Cadmium, ion	water	kg	1.76E-08	1.91E-08	1.79E-08	1.93E-08
	Carbon-14	water	kBq	3.28E-04	3.61E-04	3.26E-04	3.56E-04
	Cesium-137	water	kBq	1.52E-04	1.68E-04	1.52E-04	1.66E-04
	Chromium, ion	water	kg	2.34E-08	2.38E-08	2.35E-08	2.39E-08
	Chromium VI	water	kg	3.95E-07	4.37E-07	4.05E-07	4.43E-07
	COD	water	kg	1.67E-04	1.73E-04	2.59E-04	2.64E-04
	Copper, ion	water	kg	6.63E-07	6.78E-07	6.95E-07	7.07E-07
	Lead	water	kg	2.87E-07	2.92E-07	2.90E-07	2.94E-07
	Mercury	water	kg	4.10E-09	4.37E-09	4.22E-09	4.46E-09
	Nickel, ion	water	kg	1.56E-06	1.64E-06	1.59E-06	1.67E-06
	Nitrate	water	kg	3.37E-05	3.38E-05	4.49E-05	4.49E-05
	Oils, unspecified	water	kg	3.02E-05	3.09E-05	3.31E-05	3.37E-05
	PAH	water	kg	7.94E-09	8.25E-09	8.29E-09	8.57E-09
	Phosphate	water	kg	4.10E-06	4.31E-06	7.13E-06	7.32E-06
Emissions to Soil							
	Arsenic	soil	kg	1.22E-10	1.25E-10	1.29E-10	1.31E-10
	Cadmium	soil	kg	9.48E-12	1.02E-11	1.35E-11	1.41E-11
	Chromium	soil	kg	1.68E-09	1.72E-09	1.93E-09	1.96E-09
	Chromium VI	soil	kg	1.06E-08	1.20E-08	1.05E-08	1.18E-08
	Lead	soil	kg	6.90E-11	7.32E-11	1.22E-10	1.25E-10
	Mercury	soil	kg	7.53E-13	7.65E-13	8.76E-13	8.86E-13
	Oils, unspecified	soil	kg	3.04E-05	3.10E-05	3.32E-05	3.37E-05

Table 8.12 LCA results for year 2025, pessimistic development, “440 ppm-scenario”.

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.82E-03	5.07E-03	4.60E-03	4.83E-03
Coal, hard, unspecified, in ground	resource	kg	5.21E-01	5.22E-01	5.21E-01	5.22E-01
Gas, natural, in ground	resource	Nm3	1.03E-02	1.09E-02	1.24E-02	1.29E-02
Oil, crude, in ground	resource	kg	7.14E-03	7.27E-03	8.96E-03	9.08E-03
Uranium, in ground	resource	kg	9.11E-07	9.58E-07	8.68E-07	9.11E-07
Freshwater (lake, river, groundwater)	resource	m3	2.96E-03	3.00E-03	2.98E-03	3.01E-03
Occupation, agricultural and forestal area	resource	m2a	2.60E-02	2.61E-02	2.62E-02	2.63E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.73E-03	5.76E-03	5.75E-03	5.78E-03
Emissions to air						
Ammonia	air	kg	2.41E-05	2.42E-05	2.49E-04	2.49E-04
Arsenic	air	kg	2.12E-08	2.15E-08	2.17E-08	2.19E-08
Cadmium	air	kg	2.61E-09	2.67E-09	3.22E-09	3.28E-09
Carbon dioxide, fossil	air	kg	6.45E-02	6.66E-02	1.59E-01	1.61E-01
Carbon monoxide, fossil	air	kg	2.11E-04	2.18E-04	2.16E-04	2.22E-04
Carbon-14	air	kBq	1.87E-03	1.97E-03	1.78E-03	1.87E-03
Chromium	air	kg	2.65E-07	2.72E-07	2.70E-07	2.76E-07
Chromium VI	air	kg	7.28E-09	7.46E-09	7.41E-09	7.57E-09
Dinitrogen monoxide	air	kg	4.26E-05	4.28E-05	4.27E-05	4.28E-05
Iodine-129	air	kBq	1.60E-06	1.68E-06	1.52E-06	1.60E-06
Lead	air	kg	8.76E-08	8.95E-08	8.96E-08	9.13E-08
Methane, fossil	air	kg	2.93E-03	2.93E-03	2.94E-03	2.94E-03
Mercury	air	kg	4.26E-08	4.28E-08	4.31E-08	4.33E-08
Nickel	air	kg	1.40E-07	1.41E-07	1.51E-07	1.52E-07
Nitrogen oxides	air	kg	6.70E-04	6.76E-04	1.01E-03	1.02E-03
NMVOC total	air	kg	8.11E-05	8.25E-05	9.06E-05	9.18E-05
thereof:						
Benzene	air	kg	2.49E-06	2.50E-06	2.71E-06	2.71E-06
Benzo(a)pyrene	air	kg	1.89E-10	1.97E-10	1.93E-10	2.00E-10
Formaldehyde	air	kg	6.15E-07	6.17E-07	6.29E-07	6.31E-07
PAH	air	kg	2.73E-08	2.78E-08	2.76E-08	2.80E-08
PM2.5-10	air	kg	2.87E-05	2.95E-05	2.99E-05	3.06E-05
PM2.5	air	kg	6.49E-05	6.57E-05	6.62E-05	6.69E-05
PCDD/F (measured as I-TEQ)	air	kg	9.05E-14	9.23E-14	1.03E-13	1.05E-13
Radon-222	air	kBq	2.96E+01	3.11E+01	2.81E+01	2.95E+01
Sulfur dioxide	air	kg	3.92E-04	3.95E-04	4.06E-04	4.09E-04
Emissions to Water						
Ammonium, ion	water	kg	1.18E-06	1.19E-06	5.14E-06	5.15E-06
Arsenic, ion	water	kg	1.74E-07	1.77E-07	1.75E-07	1.78E-07
Cadmium, ion	water	kg	1.86E-08	2.01E-08	1.88E-08	2.02E-08
Carbon-14	water	kBq	6.44E-04	6.77E-04	6.12E-04	6.42E-04
Cesium-137	water	kBq	2.99E-04	3.15E-04	2.84E-04	2.99E-04
Chromium, ion	water	kg	2.48E-08	2.53E-08	2.48E-08	2.52E-08
Chromium VI	water	kg	4.46E-07	4.88E-07	4.51E-07	4.89E-07
COD	water	kg	1.81E-04	1.87E-04	2.71E-04	2.76E-04
Copper, ion	water	kg	7.01E-07	7.15E-07	7.29E-07	7.41E-07
Lead	water	kg	3.04E-07	3.09E-07	3.06E-07	3.10E-07
Mercury	water	kg	4.42E-09	4.69E-09	4.50E-09	4.75E-09
Nickel, ion	water	kg	1.61E-06	1.70E-06	1.64E-06	1.72E-06
Nitrate	water	kg	3.41E-05	3.41E-05	4.52E-05	4.52E-05
Oils, unspecified	water	kg	3.13E-05	3.20E-05	3.41E-05	3.47E-05
PAH	water	kg	8.16E-09	8.47E-09	8.49E-09	8.77E-09
Phosphate	water	kg	4.62E-06	4.82E-06	7.60E-06	7.78E-06
Emissions to Soil						
Arsenic	soil	kg	2.03E-10	2.05E-10	2.02E-10	2.04E-10
Cadmium	soil	kg	1.01E-11	1.08E-11	1.40E-11	1.46E-11
Chromium	soil	kg	2.69E-09	2.73E-09	2.84E-09	2.88E-09
Chromium VI	soil	kg	2.43E-08	2.57E-08	2.29E-08	2.42E-08
Lead	soil	kg	7.62E-11	8.04E-11	1.28E-10	1.32E-10
Mercury	soil	kg	8.29E-13	8.40E-13	9.44E-13	9.55E-13
Oils, unspecified	soil	kg	3.15E-05	3.20E-05	3.42E-05	3.46E-05

Table 8.13 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	1.11E+00	1.11E+00	8.71E-01
	Coal, hard, unspecified, in ground	resource	kg	3.56E-03	4.00E-03	1.23E-03
	Gas, natural, in ground	resource	Nm3	7.91E-03	8.48E-03	1.76E-03
	Oil, crude, in ground	resource	kg	3.45E-03	3.59E-03	8.26E-04
	Uranium, in ground	resource	kg	4.22E-07	4.72E-07	1.27E-07
	Freshwater (lake, river, groundwater)	resource	m3	5.85E-03	5.88E-03	4.44E-03
	Occupation, agricultural and forestal area	resource	m2a	2.57E-03	2.71E-03	1.03E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.48E-03	1.52E-03	1.06E-03
Emissions to air						
	Ammonia	air	kg	2.40E-04	2.40E-04	5.08E-06
	Arsenic	air	kg	1.26E-08	1.29E-08	8.21E-09
	Cadmium	air	kg	2.52E-09	2.59E-09	1.12E-09
	Carbon dioxide, fossil	air	kg	1.42E-01	1.44E-01	8.43E-01
	Carbon monoxide, fossil	air	kg	2.50E-04	2.57E-04	1.77E-04
	Carbon-14	air	kBq	8.61E-04	9.64E-04	2.60E-04
	Chromium	air	kg	9.11E-08	9.88E-08	4.06E-08
	Chromium VI	air	kg	2.42E-09	2.61E-09	1.14E-09
	Dinitrogen monoxide	air	kg	2.67E-05	2.68E-05	2.02E-05
	Iodine-129	air	kBq	7.37E-07	8.25E-07	2.22E-07
	Lead	air	kg	2.99E-08	3.19E-08	1.51E-08
	Methane, fossil	air	kg	3.31E-04	3.36E-04	2.25E-04
	Mercury	air	kg	2.48E-08	2.51E-08	1.85E-08
	Nickel	air	kg	3.44E-08	3.54E-08	1.43E-08
	Nitrogen oxides	air	kg	8.88E-04	8.94E-04	6.69E-04
	NMVOC total	air	kg	4.34E-05	4.48E-05	2.13E-05
	thereof:					
	Benzene	air	kg	2.42E-06	2.42E-06	1.68E-06
	Benzo(a)pyrene	air	kg	1.17E-10	1.25E-10	5.83E-11
	Formaldehyde	air	kg	6.24E-07	6.26E-07	4.69E-07
	PAH	air	kg	1.59E-08	1.64E-08	1.06E-08
	PM2.5-10	air	kg	1.68E-05	1.77E-05	1.02E-05
	PM2.5	air	kg	7.71E-05	7.79E-05	5.79E-05
	PCDD/F (measured as I-TEQ)	air	kg	9.45E-14	9.64E-14	5.98E-14
	Radon-222	air	kBq	1.36E+01	1.53E+01	4.11E+00
	Sulfur dioxide	air	kg	1.45E-04	1.48E-04	1.25E-04
Emissions to Water						
	Ammonium, ion	water	kg	4.78E-06	4.79E-06	4.54E-08
	Arsenic, ion	water	kg	1.08E-06	1.08E-06	8.41E-07
	Cadmium, ion	water	kg	3.77E-08	3.93E-08	2.59E-08
	Carbon-14	water	kBq	2.96E-04	3.32E-04	8.91E-05
	Cesium-137	water	kBq	1.38E-04	1.54E-04	4.15E-05
	Chromium, ion	water	kg	2.87E-09	3.34E-09	1.00E-09
	Chromium VI	water	kg	9.48E-07	9.93E-07	6.42E-07
	COD	water	kg	1.56E-04	1.62E-04	2.94E-05
	Copper, ion	water	kg	1.21E-06	1.22E-06	8.84E-07
	Lead	water	kg	1.14E-06	1.15E-06	8.73E-07
	Mercury	water	kg	6.99E-09	7.28E-09	4.84E-09
	Nickel, ion	water	kg	2.23E-06	2.32E-06	1.52E-06
	Nitrate	water	kg	1.31E-05	1.32E-05	1.43E-07
	Oils, unspecified	water	kg	9.61E-06	1.03E-05	3.86E-06
	PAH	water	kg	3.01E-09	3.33E-09	1.27E-09
	Phosphate	water	kg	4.10E-05	4.12E-05	2.94E-05
Emissions to Soil						
	Arsenic	soil	kg	7.07E-11	7.33E-11	1.36E-11
	Cadmium	soil	kg	1.13E-11	1.20E-11	3.83E-12
	Chromium	soil	kg	1.16E-09	1.20E-09	2.25E-10
	Chromium VI	soil	kg	8.75E-09	1.03E-08	6.56E-10
	Lead	soil	kg	1.03E-10	1.07E-10	2.52E-11
	Mercury	soil	kg	2.82E-13	2.94E-13	7.73E-14
	Oils, unspecified	soil	kg	8.72E-06	9.29E-06	3.56E-06

Table 8.14 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	1.12E+00	1.11E+00	1.11E+00
	Coal, hard, unspecified, in ground	resource	kg	6.71E-03	3.47E-03	8.45E-03
	Gas, natural, in ground	resource	Nm3	1.35E-02	4.82E-03	9.43E-03
	Oil, crude, in ground	resource	kg	3.84E-03	1.28E-03	4.35E-02
	Uranium, in ground	resource	kg	9.45E-07	4.22E-07	6.85E-07
	Freshwater (lake, river, groundwater)	resource	m3	6.11E-03	5.81E-03	6.41E-03
	Occupation, agricultural and forestal area	resource	m2a	3.95E-03	2.15E-03	3.08E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.57E-03	1.45E-03	3.18E-03
Emissions to air						
	Ammonia	air	kg	2.40E-04	2.96E-06	4.99E-06
	Arsenic	air	kg	1.42E-08	1.19E-08	1.90E-08
	Cadmium	air	kg	3.01E-09	1.71E-09	6.54E-09
	Carbon dioxide, fossil	air	kg	1.59E-01	3.05E-02	1.59E-01
	Carbon monoxide, fossil	air	kg	2.66E-04	2.45E-04	6.12E-04
	Carbon-14	air	kBq	1.94E-03	8.68E-04	1.38E-03
	Chromium	air	kg	1.05E-07	8.44E-08	1.20E-07
	Chromium VI	air	kg	2.77E-09	2.26E-09	2.90E-09
	Dinitrogen monoxide	air	kg	2.81E-05	2.64E-05	3.18E-05
	Iodine-129	air	kBq	1.66E-06	7.43E-07	1.15E-06
	Lead	air	kg	3.66E-08	2.70E-08	1.06E-07
	Methane, fossil	air	kg	3.79E-04	3.12E-04	4.53E-04
	Mercury	air	kg	2.54E-08	2.42E-08	2.99E-08
	Nickel	air	kg	4.03E-08	1.98E-08	6.55E-08
	Nitrogen oxides	air	kg	9.18E-04	3.21E-04	9.13E-04
	NMVOC total	air	kg	5.08E-05	3.16E-05	3.42E-04
	thereof:					
	Benzene	air	kg	2.44E-06	2.16E-06	6.01E-06
	Benzo(a)pyrene	air	kg	1.39E-10	1.11E-10	5.24E-10
	Formaldehyde	air	kg	6.39E-07	6.05E-07	6.36E-07
	PAH	air	kg	1.80E-08	1.54E-08	3.13E-08
	PM2.5-10	air	kg	1.83E-05	1.54E-05	3.85E-05
	PM2.5	air	kg	7.90E-05	7.55E-05	1.11E-04
	PCDD/F (measured as I-TEQ)	air	kg	9.87E-14	8.15E-14	1.25E-13
	Radon-222	air	kBq	3.06E+01	1.37E+01	2.21E+01
	Sulfur dioxide	air	kg	1.63E-04	1.26E-04	3.16E-04
Emissions to Water						
	Ammonium, ion	water	kg	4.87E-06	1.06E-07	4.24E-07
	Arsenic, ion	water	kg	1.09E-06	1.08E-06	1.13E-06
	Cadmium, ion	water	kg	4.04E-08	3.74E-08	7.49E-08
	Carbon-14	water	kBq	6.67E-04	2.99E-04	4.61E-04
	Cesium-137	water	kBq	3.10E-04	1.39E-04	2.16E-04
	Chromium, ion	water	kg	4.91E-09	2.70E-09	2.61E-08
	Chromium VI	water	kg	1.05E-06	9.38E-07	1.72E-06
	COD	water	kg	1.76E-04	5.23E-05	6.47E-04
	Copper, ion	water	kg	1.26E-06	1.17E-06	1.49E-06
	Lead	water	kg	1.17E-06	1.14E-06	1.25E-06
	Mercury	water	kg	7.61E-09	6.86E-09	1.15E-08
	Nickel, ion	water	kg	2.37E-06	2.19E-06	2.98E-06
	Nitrate	water	kg	1.35E-05	3.75E-07	2.02E-06
	Oils, unspecified	water	kg	1.15E-05	6.17E-06	1.70E-04
	PAH	water	kg	3.57E-09	2.59E-09	1.80E-08
	Phosphate	water	kg	4.17E-05	3.79E-05	4.09E-05
Emissions to Soil						
	Arsenic	soil	kg	1.59E-10	6.25E-11	5.17E-10
	Cadmium	soil	kg	1.26E-11	6.56E-12	1.49E-09
	Chromium	soil	kg	2.27E-09	8.58E-10	2.18E-08
	Chromium VI	soil	kg	2.49E-08	8.85E-09	1.70E-08
	Lead	soil	kg	1.15E-10	4.07E-11	7.89E-09
	Mercury	soil	kg	3.74E-13	1.47E-13	1.07E-12
	Oils, unspecified	soil	kg	1.04E-05	5.38E-06	1.73E-04

Table 8.15 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	1.12E+00	1.12E+00	1.11E+00
Coal, hard, unspecified, in ground	resource	kg	6.47E-03	6.96E-03	6.27E-03
Gas, natural, in ground	resource	Nm3	1.04E-02	1.10E-02	1.30E-02
Oil, crude, in ground	resource	kg	1.56E-03	1.71E-03	3.70E-03
Uranium, in ground	resource	kg	9.46E-07	1.00E-06	8.95E-07
Freshwater (lake, river, groundwater)	resource	m3	6.06E-03	6.10E-03	6.08E-03
Occupation, agricultural and forestal area	resource	m2a	3.52E-03	3.68E-03	3.80E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.51E-03	1.56E-03	1.54E-03
Emissions to air					
Ammonia	air	kg	3.66E-06	3.79E-06	2.40E-04
Arsenic	air	kg	1.34E-08	1.37E-08	1.39E-08
Cadmium	air	kg	2.18E-09	2.25E-09	2.95E-09
Carbon dioxide, fossil	air	kg	4.71E-02	4.95E-02	1.57E-01
Carbon monoxide, fossil	air	kg	2.54E-04	2.62E-04	2.58E-04
Carbon-14	air	kBq	1.95E-03	2.06E-03	1.83E-03
Chromium	air	kg	9.14E-08	9.99E-08	9.75E-08
Chromium VI	air	kg	2.43E-09	2.64E-09	2.58E-09
Dinitrogen monoxide	air	kg	2.79E-05	2.80E-05	2.79E-05
Iodine-129	air	kBq	1.67E-06	1.76E-06	1.57E-06
Lead	air	kg	3.22E-08	3.44E-08	3.47E-08
Methane, fossil	air	kg	3.59E-04	3.65E-04	3.73E-04
Mercury	air	kg	2.46E-08	2.49E-08	2.52E-08
Nickel	air	kg	2.51E-08	2.63E-08	3.92E-08
Nitrogen oxides	air	kg	3.46E-04	3.54E-04	9.11E-04
NMVOC total	air	kg	3.82E-05	3.99E-05	4.94E-05
thereof:					
Benzene	air	kg	2.18E-06	2.19E-06	2.44E-06
Benzo(a)pyrene	air	kg	1.26E-10	1.36E-10	1.30E-10
Formaldehyde	air	kg	6.19E-07	6.22E-07	6.36E-07
PAH	air	kg	1.71E-08	1.77E-08	1.75E-08
PM2.5-10	air	kg	1.62E-05	1.71E-05	1.75E-05
PM2.5	air	kg	7.67E-05	7.76E-05	7.82E-05
PCDD/F (measured as I-TEQ)	air	kg	8.41E-14	8.62E-14	9.68E-14
Radon-222	air	kBq	3.08E+01	3.26E+01	2.90E+01
Sulfur dioxide	air	kg	1.44E-04	1.47E-04	1.61E-04
Emissions to Water					
Ammonium, ion	water	kg	1.95E-07	2.07E-07	4.86E-06
Arsenic, ion	water	kg	1.09E-06	1.09E-06	1.09E-06
Cadmium, ion	water	kg	3.86E-08	4.04E-08	3.88E-08
Carbon-14	water	kBq	6.70E-04	7.10E-04	6.32E-04
Cesium-137	water	kBq	3.11E-04	3.30E-04	2.94E-04
Chromium, ion	water	kg	4.44E-09	4.96E-09	4.45E-09
Chromium VI	water	kg	9.98E-07	1.05E-06	1.00E-06
COD	water	kg	6.86E-05	7.55E-05	1.70E-04
Copper, ion	water	kg	1.22E-06	1.23E-06	1.25E-06
Lead	water	kg	1.16E-06	1.17E-06	1.16E-06
Mercury	water	kg	7.23E-09	7.55E-09	7.33E-09
Nickel, ion	water	kg	2.25E-06	2.35E-06	2.28E-06
Nitrate	water	kg	7.54E-07	8.00E-07	1.35E-05
Oils, unspecified	water	kg	7.51E-06	8.30E-06	1.08E-05
PAH	water	kg	2.86E-09	3.22E-09	3.24E-09
Phosphate	water	kg	3.85E-05	3.88E-05	4.15E-05
Emissions to Soil					
Arsenic	soil	kg	1.57E-10	1.60E-10	1.56E-10
Cadmium	soil	kg	7.27E-12	8.06E-12	1.19E-11
Chromium	soil	kg	2.05E-09	2.09E-09	2.23E-09
Chromium VI	soil	kg	2.50E-08	2.67E-08	2.33E-08
Lead	soil	kg	4.91E-11	5.40E-11	1.10E-10
Mercury	soil	kg	2.36E-13	2.50E-13	3.62E-13
Oils, unspecified	soil	kg	6.58E-06	7.22E-06	9.80E-06

Table 8.16 LCA results for year 2025, pessimistic development, "440 ppm-scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	8.56E-04	4.33E-01
Coal, hard, unspecified, in ground	resource	kg	3.39E-01	1.03E-03
Gas, natural, in ground	resource	Nm3	2.00E-03	9.10E-04
Oil, crude, in ground	resource	kg	4.23E-03	1.06E-03
Uranium, in ground	resource	kg	1.62E-07	7.95E-08
Freshwater (lake, river, groundwater)	resource	m3	6.10E-04	1.61E-03
Occupation, agricultural and forestal area	resource	m2a	1.58E-02	5.02E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.86E-03	1.03E-03
Emissions to air				
Ammonia	air	kg	1.44E-05	6.36E-07
Arsenic	air	kg	6.43E-08	6.53E-09
Cadmium	air	kg	1.58E-09	1.13E-09
Carbon dioxide, fossil	air	kg	6.54E-01	7.93E-01
Carbon monoxide, fossil	air	kg	1.30E-04	8.53E-05
Carbon-14	air	kBq	3.31E-04	1.62E-04
Chromium	air	kg	4.36E-08	3.54E-08
Chromium VI	air	kg	1.41E-09	9.65E-10
Dinitrogen monoxide	air	kg	2.76E-05	2.53E-05
Iodine-129	air	kBq	2.82E-07	1.36E-07
Lead	air	kg	4.21E-08	1.39E-08
Methane, fossil	air	kg	1.88E-03	1.25E-04
Mercury	air	kg	2.04E-08	1.15E-08
Nickel	air	kg	8.31E-08	9.80E-09
Nitrogen oxides	air	kg	4.28E-04	4.06E-04
NMVOC total	air	kg	4.89E-05	2.12E-05
thereof:				
Benzene	air	kg	1.22E-06	1.02E-06
Benzo(a)pyrene	air	kg	9.50E-11	4.15E-11
Formaldehyde	air	kg	2.85E-07	2.80E-07
PAH	air	kg	5.54E-08	4.77E-08
PM2.5-10	air	kg	1.37E-05	3.45E-06
PM2.5	air	kg	9.63E-06	2.74E-06
PCDD/F (measured as I-TEQ)	air	kg	5.11E-14	4.80E-14
Radon-222	air	kBq	5.26E+00	2.58E+00
Sulfur dioxide	air	kg	3.62E-04	5.89E-04
Emissions to Water				
Ammonium, ion	water	kg	3.64E-07	5.93E-08
Arsenic, ion	water	kg	8.27E-08	1.33E-06
Cadmium, ion	water	kg	1.24E-08	8.21E-08
Carbon-14	water	kBq	1.13E-04	5.44E-05
Cesium-137	water	kBq	5.27E-05	2.54E-05
Chromium, ion	water	kg	2.10E-09	9.18E-10
Chromium VI	water	kg	7.31E-07	8.48E-06
COD	water	kg	2.21E-04	1.90E-03
Copper, ion	water	kg	1.30E-06	6.14E-06
Lead	water	kg	3.31E-07	1.71E-06
Mercury	water	kg	4.96E-09	5.56E-08
Nickel, ion	water	kg	5.99E-07	3.57E-06
Nitrate	water	kg	1.25E-06	7.37E-07
Oils, unspecified	water	kg	1.87E-05	3.30E-06
PAH	water	kg	2.51E-09	1.12E-09
Phosphate	water	kg	7.16E-06	1.00E-04
Emissions to Soil				
Arsenic	soil	kg	5.30E-11	1.14E-11
Cadmium	soil	kg	6.55E-12	5.88E-12
Chromium	soil	kg	7.77E-10	2.30E-10
Chromium VI	soil	kg	2.59E-09	7.31E-10
Lead	soil	kg	5.24E-11	4.51E-11
Mercury	soil	kg	5.82E-13	2.02E-13
Oils, unspecified	soil	kg	1.89E-05	3.02E-06

Table 8.17 LCA results for year 2025, pessimistic development, “440 ppm-scenario”.

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	3.76E-03	3.96E-03	1.89E-03	2.08E-03
Coal, hard, unspecified, in ground	resource	kg	3.86E-01	3.86E-01	3.84E-01	3.84E-01
Gas, natural, in ground	resource	Nm3	7.94E-03	8.37E-03	4.14E-03	4.57E-03
Oil, crude, in ground	resource	kg	5.12E-03	5.23E-03	4.93E-03	5.04E-03
Uranium, in ground	resource	kg	7.13E-07	7.51E-07	3.57E-07	3.95E-07
Freshwater (lake, river, groundwater)	resource	m3	9.56E-04	9.82E-04	7.81E-04	8.07E-04
Occupation, agricultural and forestal area	resource	m2a	1.92E-02	1.93E-02	1.83E-02	1.84E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.41E-03	4.44E-03	4.37E-03	4.40E-03
Emissions to air						
Ammonia	air	kg	1.70E-05	1.71E-05	1.65E-05	1.66E-05
Arsenic	air	kg	8.14E-08	8.16E-08	8.04E-08	8.06E-08
Cadmium	air	kg	2.21E-09	2.26E-09	1.89E-09	1.94E-09
Carbon dioxide, fossil	air	kg	1.22E-01	1.24E-01	1.11E-01	1.12E-01
Carbon monoxide, fossil	air	kg	1.67E-04	1.72E-04	1.61E-04	1.66E-04
Carbon-14	air	kBq	1.47E-03	1.54E-03	7.33E-04	8.11E-04
Chromium	air	kg	6.10E-08	6.67E-08	5.62E-08	6.20E-08
Chromium VI	air	kg	1.92E-09	2.06E-09	1.80E-09	1.94E-09
Dinitrogen monoxide	air	kg	3.59E-05	3.60E-05	3.50E-05	3.51E-05
Iodine-129	air	kBq	1.25E-06	1.32E-06	6.26E-07	6.93E-07
Lead	air	kg	5.64E-08	5.79E-08	5.28E-08	5.43E-08
Methane, fossil	air	kg	2.17E-03	2.18E-03	2.14E-03	2.15E-03
Mercury	air	kg	2.59E-08	2.61E-08	2.56E-08	2.58E-08
Nickel	air	kg	1.00E-07	1.01E-07	9.68E-08	9.76E-08
Nitrogen oxides	air	kg	5.31E-04	5.36E-04	5.14E-04	5.19E-04
NMVOC total	air	kg	6.43E-05	6.54E-05	5.98E-05	6.09E-05
thereof:						
Benzene	air	kg	1.54E-06	1.54E-06	1.52E-06	1.52E-06
Benzo(a)pyrene	air	kg	1.25E-10	1.31E-10	1.15E-10	1.21E-10
Formaldehyde	air	kg	3.70E-07	3.72E-07	3.60E-07	3.62E-07
PAH	air	kg	7.03E-08	7.07E-08	6.91E-08	6.95E-08
PM2.5-10	air	kg	1.67E-05	1.74E-05	1.62E-05	1.69E-05
PM2.5	air	kg	1.25E-05	1.31E-05	1.17E-05	1.23E-05
PCDD/F (measured as I-TEQ)	air	kg	6.53E-14	6.67E-14	6.35E-14	6.49E-14
Radon-222	air	kBq	2.32E+01	2.44E+01	1.16E+01	1.28E+01
Sulfur dioxide	air	kg	4.50E-04	4.53E-04	4.39E-04	4.41E-04
Emissions to Water						
Ammonium, ion	water	kg	5.01E-07	5.09E-07	4.41E-07	4.49E-07
Arsenic, ion	water	kg	1.03E-07	1.05E-07	9.63E-08	9.86E-08
Cadmium, ion	water	kg	1.60E-08	1.72E-08	1.52E-08	1.64E-08
Carbon-14	water	kBq	5.04E-04	5.31E-04	2.52E-04	2.78E-04
Cesium-137	water	kBq	2.34E-04	2.47E-04	1.17E-04	1.30E-04
Chromium, ion	water	kg	4.35E-09	4.70E-09	3.16E-09	3.51E-09
Chromium VI	water	kg	9.02E-07	9.36E-07	8.62E-07	8.95E-07
COD	water	kg	2.67E-04	2.72E-04	2.56E-04	2.60E-04
Copper, ion	water	kg	1.50E-06	1.51E-06	1.47E-06	1.48E-06
Lead	water	kg	3.89E-07	3.93E-07	3.75E-07	3.79E-07
Mercury	water	kg	6.08E-09	6.29E-09	5.83E-09	6.04E-09
Nickel, ion	water	kg	7.89E-07	8.56E-07	7.46E-07	8.14E-07
Nitrate	water	kg	1.78E-06	1.82E-06	1.53E-06	1.56E-06
Oils, unspecified	water	kg	2.28E-05	2.33E-05	2.19E-05	2.24E-05
PAH	water	kg	3.29E-09	3.54E-09	3.11E-09	3.36E-09
Phosphate	water	kg	8.70E-06	8.86E-06	8.29E-06	8.46E-06
Emissions to Soil						
Arsenic	soil	kg	1.55E-10	1.57E-10	9.08E-11	9.28E-11
Cadmium	soil	kg	8.48E-12	9.02E-12	8.00E-12	8.54E-12
Chromium	soil	kg	2.08E-09	2.11E-09	1.27E-09	1.30E-09
Chromium VI	soil	kg	1.92E-08	2.04E-08	8.29E-09	9.45E-09
Lead	soil	kg	6.96E-11	7.29E-11	6.39E-11	6.72E-11
Mercury	soil	kg	7.47E-13	7.56E-13	6.86E-13	6.96E-13
Oils, unspecified	soil	kg	2.28E-05	2.33E-05	2.20E-05	2.25E-05

Table 8.18 LCA results for year 2025, pessimistic development, “440 ppm-scenario”.

			electricity, lignite IGCC plant 400MW, CCS, 200km	electricity, lignite IGCC plant 400MW, CCS, 400km	electricity, lignite IGCC power plant 400MW, CCS,	electricity, lignite IGCC power plant 400MW, CCS,
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.95E-01	5.00E-01	4.92E-01	4.95E-01
Coal, hard, unspecified, in ground	resource	kg	5.09E-03	5.50E-03	2.54E-03	5.09E-03
Gas, natural, in ground	resource	Nm3	8.17E-03	8.70E-03	3.42E-03	8.17E-03
Oil, crude, in ground	resource	kg	1.66E-03	1.79E-03	1.42E-03	1.66E-03
Uranium, in ground	resource	kg	7.55E-07	8.00E-07	3.09E-07	7.55E-07
Freshwater (lake, river, groundwater)	resource	m3	2.16E-03	2.20E-03	1.94E-03	2.16E-03
Occupation, agricultural and forestal area	resource	m2a	2.32E-03	2.46E-03	1.15E-03	2.32E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.25E-03	1.28E-03	1.19E-03	1.25E-03
Emissions to air						
Ammonia	air	kg	1.64E-06	1.76E-06	1.05E-06	1.64E-06
Arsenic	air	kg	9.55E-09	9.80E-09	8.30E-09	9.55E-09
Cadmium	air	kg	1.82E-09	1.88E-09	1.42E-09	1.82E-09
Carbon dioxide, fossil	air	kg	1.31E-01	1.34E-01	1.17E-01	1.31E-01
Carbon monoxide, fossil	air	kg	1.22E-04	1.29E-04	1.15E-04	1.22E-04
Carbon-14	air	kBq	1.55E-03	1.65E-03	6.34E-04	1.55E-03
Chromium	air	kg	5.46E-08	6.20E-08	4.87E-08	5.46E-08
Chromium VI	air	kg	1.46E-09	1.64E-09	1.31E-09	1.46E-09
Dinitrogen monoxide	air	kg	3.39E-05	3.40E-05	3.27E-05	3.39E-05
Iodine-129	air	kBq	1.33E-06	1.41E-06	5.40E-07	1.33E-06
Lead	air	kg	2.32E-08	2.51E-08	1.87E-08	2.32E-08
Methane, fossil	air	kg	2.03E-04	2.09E-04	1.64E-04	2.03E-04
Mercury	air	kg	1.51E-08	1.53E-08	1.47E-08	1.51E-08
Nickel	air	kg	1.80E-08	1.90E-08	1.35E-08	1.80E-08
Nitrogen oxides	air	kg	5.47E-04	5.50E-04	5.25E-04	5.47E-04
NMVOC total	air	kg	3.52E-05	3.70E-05	2.95E-05	3.52E-05
thereof:						
Benzene	air	kg	1.34E-06	1.34E-06	1.32E-06	1.34E-06
Benzo(a)pyrene	air	kg	6.97E-11	7.80E-11	5.72E-11	6.97E-11
Formaldehyde	air	kg	3.71E-07	3.70E-07	3.60E-07	3.71E-07
PAH	air	kg	6.26E-08	6.30E-08	6.12E-08	6.26E-08
PM2.5-10	air	kg	5.47E-06	6.30E-06	4.84E-06	5.47E-06
PM2.5	air	kg	5.17E-06	5.90E-06	4.17E-06	5.17E-06
PCDD/F (measured as I-TEQ)	air	kg	6.30E-14	6.50E-14	6.09E-14	6.30E-14
Radon-222	air	kBq	2.45E+01	2.61E+01	1.00E+01	2.45E+01
Sulfur dioxide	air	kg	7.67E-04	7.70E-04	7.52E-04	7.67E-04
Emissions to Water						
Ammonium, ion	water	kg	1.81E-07	1.91E-07	1.06E-07	1.81E-07
Arsenic, ion	water	kg	1.50E-06	1.50E-06	1.49E-06	1.50E-06
Cadmium, ion	water	kg	9.45E-08	9.60E-08	9.40E-08	9.45E-08
Carbon-14	water	kBq	5.33E-04	5.70E-04	2.17E-04	5.33E-04
Cesium-137	water	kBq	2.48E-04	2.63E-04	1.01E-04	2.48E-04
Chromium, ion	water	kg	3.52E-09	4.00E-09	2.03E-09	3.52E-09
Chromium VI	water	kg	9.59E-06	9.60E-06	9.50E-06	9.59E-06
COD	water	kg	2.15E-03	2.15E-03	2.13E-03	2.15E-03
Copper, ion	water	kg	6.92E-06	6.90E-06	6.89E-06	6.92E-06
Lead	water	kg	1.94E-06	1.95E-06	1.92E-06	1.94E-06
Mercury	water	kg	6.28E-08	6.30E-08	6.25E-08	6.28E-08
Nickel, ion	water	kg	4.14E-06	4.20E-06	4.09E-06	4.14E-06
Nitrate	water	kg	1.31E-06	1.35E-06	9.90E-07	1.31E-06
Oils, unspecified	water	kg	5.89E-06	6.60E-06	4.75E-06	5.89E-06
PAH	water	kg	1.85E-09	2.16E-09	1.63E-09	1.85E-09
Phosphate	water	kg	1.13E-04	1.13E-04	1.12E-04	1.13E-04
Emissions to Soil						
Arsenic	soil	kg	1.32E-10	1.35E-10	5.17E-11	1.32E-10
Cadmium	soil	kg	8.03E-12	8.70E-12	7.43E-12	8.03E-12
Chromium	soil	kg	1.77E-09	1.81E-09	7.56E-10	1.77E-09
Chromium VI	soil	kg	2.13E-08	2.27E-08	7.56E-09	2.13E-08
Lead	soil	kg	6.43E-11	6.80E-11	5.72E-11	6.43E-11
Mercury	soil	kg	3.42E-13	3.50E-13	2.66E-13	3.42E-13
Oils, unspecified	soil	kg	5.30E-06	5.80E-06	4.28E-06	5.30E-06

Table 8.19 LCA results for year 2025, very optimistic development, "440 ppm-scenario".

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	1.85E-04	1.83E-04	1.83E-04
	Coal, hard, unspecified, in ground	resource	kg	3.68E-01	3.68E-01	3.68E-01
	Gas, natural, in ground	resource	Nm3	2.39E-03	2.37E-03	2.37E-03
	Oil, crude, in ground	resource	kg	4.75E-03	4.73E-03	4.73E-03
	Uranium, in ground	resource	kg	9.52E-09	9.40E-09	9.36E-09
	Freshwater (lake, river, groundwater)	resource	m3	1.81E-03	1.81E-03	1.81E-03
	Occupation, agricultural and forestal area	resource	m2a	1.74E-02	1.74E-02	1.74E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	3.99E-03	3.98E-03	3.98E-03
Emissions to air						
	Ammonia	air	kg	1.81E-05	1.81E-05	1.81E-05
	Arsenic	air	kg	1.23E-08	1.22E-08	1.22E-08
	Cadmium	air	kg	1.23E-09	1.21E-09	1.20E-09
	Carbon dioxide, fossil	air	kg	6.65E-01	6.65E-01	6.65E-01
	Carbon monoxide, fossil	air	kg	1.32E-04	1.32E-04	1.32E-04
	Carbon-14	air	kBq	1.77E-05	1.75E-05	1.74E-05
	Chromium	air	kg	1.53E-07	1.36E-07	1.36E-07
	Chromium VI	air	kg	4.31E-09	3.89E-09	3.88E-09
	Dinitrogen monoxide	air	kg	2.91E-05	2.91E-05	2.91E-05
	Iodine-129	air	kBq	1.33E-08	1.31E-08	1.31E-08
	Lead	air	kg	4.89E-08	4.84E-08	4.84E-08
	Methane, fossil	air	kg	2.04E-03	2.04E-03	2.04E-03
	Mercury	air	kg	2.97E-08	2.97E-08	2.97E-08
	Nickel	air	kg	9.28E-08	9.26E-08	9.26E-08
	Nitrogen oxides	air	kg	6.84E-04	6.83E-04	6.83E-04
	NMVOC total	air	kg	5.11E-05	5.10E-05	5.09E-05
	thereof:					
	Benzene	air	kg	1.75E-06	1.75E-06	1.75E-06
	Benzo(a)pyrene	air	kg	8.42E-11	8.11E-11	8.12E-11
	Formaldehyde	air	kg	4.24E-07	4.23E-07	4.23E-07
	PAH	air	kg	1.71E-08	1.70E-08	1.70E-08
	PM2.5-10	air	kg	1.87E-05	1.85E-05	1.85E-05
	PM2.5	air	kg	4.40E-05	4.38E-05	4.38E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.69E-14	5.67E-14	5.67E-14
	Radon-222	air	kBq	3.06E-01	3.02E-01	3.01E-01
	Sulfur dioxide	air	kg	4.93E-04	4.93E-04	4.93E-04
Emissions to Water						
	Ammonium, ion	water	kg	7.43E-07	7.42E-07	7.42E-07
	Arsenic, ion	water	kg	1.10E-07	1.09E-07	1.09E-07
	Cadmium, ion	water	kg	1.06E-08	1.03E-08	1.03E-08
	Carbon-14	water	kBq	5.17E-06	5.11E-06	5.09E-06
	Cesium-137	water	kBq	2.53E-06	2.49E-06	2.49E-06
	Chromium, ion	water	kg	1.47E-08	1.46E-08	1.46E-08
	Chromium VI	water	kg	2.20E-07	2.14E-07	2.14E-07
	COD	water	kg	1.07E-04	1.06E-04	1.05E-04
	Copper, ion	water	kg	4.23E-07	4.19E-07	4.18E-07
	Lead	water	kg	1.79E-07	1.75E-07	1.73E-07
	Mercury	water	kg	2.46E-09	2.44E-09	2.43E-09
	Nickel, ion	water	kg	9.40E-07	8.78E-07	8.76E-07
	Nitrate	water	kg	2.28E-05	2.28E-05	2.28E-05
	Oils, unspecified	water	kg	2.07E-05	2.06E-05	2.06E-05
	PAH	water	kg	4.87E-09	4.52E-09	4.51E-09
	Phosphate	water	kg	2.48E-06	2.46E-06	2.46E-06
Emissions to Soil						
	Arsenic	soil	kg	5.99E-11	5.96E-11	5.96E-11
	Cadmium	soil	kg	7.04E-12	6.87E-12	6.86E-12
	Chromium	soil	kg	8.62E-10	8.57E-10	8.57E-10
	Chromium VI	soil	kg	2.70E-09	2.68E-09	2.68E-09
	Lead	soil	kg	5.55E-11	5.45E-11	5.45E-11
	Mercury	soil	kg	6.42E-13	6.40E-13	6.40E-13
	Oils, unspecified	soil	kg	2.10E-05	2.10E-05	2.10E-05

Table 8.20 LCA results for year 2025, very optimistic development, “440 ppm-scenario”.

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	6.89E-04	7.23E-04	6.57E-04	6.87E-04
Coal, hard, unspecified, in ground	resource	kg	4.40E-01	4.40E-01	4.30E-01	4.30E-01
Gas, natural, in ground	resource	Nm3	8.88E-03	9.34E-03	1.04E-02	1.08E-02
Oil, crude, in ground	resource	kg	5.97E-03	6.08E-03	7.36E-03	7.45E-03
Uranium, in ground	resource	kg	1.23E-08	1.25E-08	1.49E-08	1.51E-08
Freshwater (lake, river, groundwater)	resource	m3	2.25E-03	2.27E-03	2.23E-03	2.24E-03
Occupation, agricultural and forestal area	resource	m2a	2.29E-02	2.31E-02	2.26E-02	2.27E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.85E-03	4.88E-03	4.76E-03	4.78E-03
Emissions to air						
Ammonia	air	kg	2.08E-05	2.09E-05	2.44E-04	2.44E-04
Arsenic	air	kg	1.60E-08	1.62E-08	1.60E-08	1.61E-08
Cadmium	air	kg	1.82E-09	1.86E-09	2.25E-09	2.29E-09
Carbon dioxide, fossil	air	kg	5.38E-02	5.55E-02	1.31E-01	1.33E-01
Carbon monoxide, fossil	air	kg	1.70E-04	1.74E-04	1.70E-04	1.74E-04
Carbon-14	air	kBq	2.24E-05	2.28E-05	2.37E-05	2.40E-05
Chromium	air	kg	2.49E-07	2.55E-07	2.47E-07	2.53E-07
Chromium VI	air	kg	6.78E-09	6.93E-09	6.73E-09	6.86E-09
Dinitrogen monoxide	air	kg	3.61E-05	3.62E-05	3.54E-05	3.55E-05
Iodine-129	air	kBq	1.67E-08	1.70E-08	1.78E-08	1.80E-08
Lead	air	kg	6.41E-08	6.49E-08	6.39E-08	6.47E-08
Methane, fossil	air	kg	2.46E-03	2.46E-03	2.41E-03	2.41E-03
Mercury	air	kg	3.58E-08	3.59E-08	3.54E-08	3.56E-08
Nickel	air	kg	1.14E-07	1.15E-07	1.20E-07	1.21E-07
Nitrogen oxides	air	kg	5.73E-04	5.78E-04	8.31E-04	8.36E-04
NMVOC total	air	kg	6.85E-05	6.97E-05	7.48E-05	7.59E-05
thereof:						
Benzene	air	kg	2.10E-06	2.10E-06	2.23E-06	2.23E-06
Benzo(a)pyrene	air	kg	1.28E-10	1.34E-10	1.28E-10	1.33E-10
Formaldehyde	air	kg	5.16E-07	5.18E-07	5.16E-07	5.18E-07
PAH	air	kg	2.25E-08	2.29E-08	2.23E-08	2.26E-08
PM2.5-10	air	kg	2.42E-05	2.49E-05	2.46E-05	2.52E-05
PM2.5	air	kg	5.43E-05	5.49E-05	5.42E-05	5.47E-05
PCDD/F (measured as I-TEQ)	air	kg	7.10E-14	7.17E-14	8.19E-14	8.25E-14
Radon-222	air	kBq	3.87E-01	3.94E-01	4.09E-01	4.16E-01
Sulfur dioxide	air	kg	3.41E-04	3.43E-04	3.47E-04	3.49E-04
Emissions to Water						
Ammonium, ion	water	kg	1.02E-06	1.03E-06	4.24E-06	4.25E-06
Arsenic, ion	water	kg	1.39E-07	1.41E-07	1.37E-07	1.39E-07
Cadmium, ion	water	kg	1.56E-08	1.69E-08	1.55E-08	1.66E-08
Carbon-14	water	kBq	6.50E-06	6.62E-06	6.93E-06	7.03E-06
Cesium-137	water	kBq	3.17E-06	3.23E-06	3.38E-06	3.43E-06
Chromium, ion	water	kg	1.89E-08	1.92E-08	1.86E-08	1.89E-08
Chromium VI	water	kg	3.41E-07	3.75E-07	3.41E-07	3.70E-07
COD	water	kg	1.42E-04	1.46E-04	2.19E-04	2.23E-04
Copper, ion	water	kg	5.64E-07	5.75E-07	5.76E-07	5.85E-07
Lead	water	kg	2.39E-07	2.42E-07	2.36E-07	2.39E-07
Mercury	water	kg	3.46E-09	3.67E-09	3.47E-09	3.66E-09
Nickel, ion	water	kg	1.44E-06	1.51E-06	1.43E-06	1.50E-06
Nitrate	water	kg	2.89E-05	2.90E-05	3.78E-05	3.78E-05
Oils, unspecified	water	kg	2.63E-05	2.68E-05	2.80E-05	2.85E-05
PAH	water	kg	7.40E-09	7.67E-09	7.51E-09	7.75E-09
Phosphate	water	kg	3.36E-06	3.51E-06	6.30E-06	6.42E-06
Emissions to Soil						
Arsenic	soil	kg	1.71E-10	1.74E-10	1.67E-10	1.69E-10
Cadmium	soil	kg	1.08E-11	1.15E-11	1.37E-11	1.43E-11
Chromium	soil	kg	2.31E-09	2.34E-09	2.39E-09	2.42E-09
Chromium VI	soil	kg	2.05E-08	2.17E-08	1.89E-08	2.00E-08
Lead	soil	kg	1.05E-10	1.10E-10	1.44E-10	1.49E-10
Mercury	soil	kg	1.31E-12	1.35E-12	1.36E-12	1.40E-12
Oils, unspecified	soil	kg	2.63E-05	2.67E-05	2.80E-05	2.84E-05

Table 8.21 LCA results for year 2025, very optimistic development, “440 ppm-scenario”.

				electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
				Total	Total	Total	Total
				kWh	kWh	kWh	kWh
Resources							
	Coal, brown, in ground	resource	kg	3.74E-04	4.08E-04	3.78E-04	4.08E-04
	Coal, hard, unspecified, in ground	resource	kg	4.37E-01	4.38E-01	4.28E-01	4.28E-01
	Gas, natural, in ground	resource	Nm3	4.79E-03	5.25E-03	6.79E-03	7.20E-03
	Oil, crude, in ground	resource	kg	5.79E-03	5.89E-03	7.20E-03	7.29E-03
	Uranium, in ground	resource	kg	1.18E-08	1.20E-08	1.45E-08	1.47E-08
	Freshwater (lake, river, groundwater)	resource	m3	2.19E-03	2.20E-03	2.17E-03	2.19E-03
	Occupation, agricultural and forestal area	resource	m2a	2.14E-02	2.16E-02	2.13E-02	2.14E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	4.79E-03	4.82E-03	4.71E-03	4.74E-03
Emissions to air							
	Ammonia	air	kg	2.01E-05	2.02E-05	2.43E-04	2.43E-04
	Arsenic	air	kg	1.53E-08	1.54E-08	1.53E-08	1.54E-08
	Cadmium	air	kg	1.58E-09	1.62E-09	2.04E-09	2.07E-09
	Carbon dioxide, fossil	air	kg	4.21E-02	4.38E-02	1.21E-01	1.22E-01
	Carbon monoxide, fossil	air	kg	1.65E-04	1.70E-04	1.65E-04	1.69E-04
	Carbon-14	air	kBq	2.18E-05	2.22E-05	2.31E-05	2.35E-05
	Chromium	air	kg	2.41E-07	2.47E-07	2.40E-07	2.46E-07
	Chromium VI	air	kg	6.58E-09	6.73E-09	6.55E-09	6.68E-09
	Dinitrogen monoxide	air	kg	3.50E-05	3.51E-05	3.44E-05	3.45E-05
	Iodine-129	air	kBq	1.62E-08	1.65E-08	1.74E-08	1.76E-08
	Lead	air	kg	6.09E-08	6.18E-08	6.11E-08	6.19E-08
	Methane, fossil	air	kg	2.43E-03	2.43E-03	2.38E-03	2.39E-03
	Mercury	air	kg	3.55E-08	3.56E-08	3.52E-08	3.53E-08
	Nickel	air	kg	1.11E-07	1.11E-07	1.18E-07	1.18E-07
	Nitrogen oxides	air	kg	5.56E-04	5.61E-04	8.17E-04	8.21E-04
	NMVOC total	air	kg	6.36E-05	6.48E-05	7.05E-05	7.15E-05
	thereof:						
	Benzene	air	kg	2.08E-06	2.09E-06	2.22E-06	2.22E-06
	Benzo(a)pyrene	air	kg	1.18E-10	1.24E-10	1.19E-10	1.24E-10
	Formaldehyde	air	kg	5.08E-07	5.10E-07	5.08E-07	5.10E-07
	PAH	air	kg	2.14E-08	2.17E-08	2.13E-08	2.16E-08
	PM2.5-10	air	kg	2.36E-05	2.43E-05	2.41E-05	2.47E-05
	PM2.5	air	kg	5.34E-05	5.40E-05	5.34E-05	5.39E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.92E-14	6.99E-14	8.03E-14	8.09E-14
	Radon-222	air	kBq	3.76E-01	3.83E-01	4.00E-01	4.06E-01
	Sulfur dioxide	air	kg	3.30E-04	3.32E-04	3.38E-04	3.40E-04
Emissions to Water							
	Ammonium, ion	water	kg	9.41E-07	9.50E-07	4.18E-06	4.19E-06
	Arsenic, ion	water	kg	1.36E-07	1.38E-07	1.35E-07	1.37E-07
	Cadmium, ion	water	kg	1.49E-08	1.62E-08	1.49E-08	1.60E-08
	Carbon-14	water	kBq	6.31E-06	6.43E-06	6.76E-06	6.86E-06
	Cesium-137	water	kBq	3.08E-06	3.14E-06	3.30E-06	3.35E-06
	Chromium, ion	water	kg	1.87E-08	1.89E-08	1.84E-08	1.86E-08
	Chromium VI	water	kg	3.19E-07	3.52E-07	3.20E-07	3.50E-07
	COD	water	kg	1.35E-04	1.39E-04	2.14E-04	2.17E-04
	Copper, ion	water	kg	5.47E-07	5.57E-07	5.61E-07	5.70E-07
	Lead	water	kg	2.34E-07	2.37E-07	2.32E-07	2.35E-07
	Mercury	water	kg	3.33E-09	3.54E-09	3.36E-09	3.54E-09
	Nickel, ion	water	kg	1.39E-06	1.46E-06	1.39E-06	1.45E-06
	Nitrate	water	kg	2.85E-05	2.85E-05	3.74E-05	3.74E-05
	Oils, unspecified	water	kg	2.54E-05	2.59E-05	2.73E-05	2.77E-05
	PAH	water	kg	7.15E-09	7.42E-09	7.29E-09	7.53E-09
	Phosphate	water	kg	3.20E-06	3.34E-06	6.15E-06	6.28E-06
Emissions to Soil							
	Arsenic	soil	kg	1.04E-10	1.06E-10	1.07E-10	1.09E-10
	Cadmium	soil	kg	9.75E-12	1.04E-11	1.28E-11	1.34E-11
	Chromium	soil	kg	1.44E-09	1.48E-09	1.62E-09	1.65E-09
	Chromium VI	soil	kg	8.92E-09	1.01E-08	8.69E-09	9.77E-09
	Lead	soil	kg	8.13E-11	8.69E-11	1.24E-10	1.28E-10
	Mercury	soil	kg	9.48E-13	9.89E-13	1.04E-12	1.07E-12
	Oils, unspecified	soil	kg	2.55E-05	2.60E-05	2.73E-05	2.77E-05

Table 8.22 LCA results for year 2025, very optimistic development, "440 ppm-scenario".

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	9.09E-01	9.09E-01	7.87E-01
Coal, hard, unspecified, in ground	resource	kg	3.26E-03	3.65E-03	1.22E-03
Gas, natural, in ground	resource	Nm3	6.59E-03	7.07E-03	1.62E-03
Oil, crude, in ground	resource	kg	2.85E-03	2.96E-03	7.46E-04
Uranium, in ground	resource	kg	9.11E-09	9.36E-09	4.42E-09
Freshwater (lake, river, groundwater)	resource	m3	4.69E-03	4.70E-03	3.98E-03
Occupation, agricultural and forestal area	resource	m2a	2.63E-03	2.81E-03	1.12E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.23E-03	1.26E-03	9.64E-04
Emissions to air					
Ammonia	air	kg	2.38E-04	2.38E-04	4.66E-06
Arsenic	air	kg	8.82E-09	8.95E-09	6.58E-09
Cadmium	air	kg	1.64E-09	1.68E-09	7.64E-10
Carbon dioxide, fossil	air	kg	1.18E-01	1.19E-01	7.62E-01
Carbon monoxide, fossil	air	kg	2.00E-04	2.05E-04	1.57E-04
Carbon-14	air	kBq	1.23E-05	1.27E-05	8.07E-06
Chromium	air	kg	8.35E-08	9.01E-08	4.09E-08
Chromium VI	air	kg	2.20E-09	2.36E-09	1.14E-09
Dinitrogen monoxide	air	kg	2.20E-05	2.22E-05	1.83E-05
Iodine-129	air	kBq	9.58E-09	9.89E-09	6.34E-09
Lead	air	kg	1.71E-08	1.80E-08	9.74E-09
Methane, fossil	air	kg	2.65E-04	2.69E-04	2.02E-04
Mercury	air	kg	2.04E-08	2.06E-08	1.67E-08
Nickel	air	kg	2.49E-08	2.56E-08	1.11E-08
Nitrogen oxides	air	kg	7.28E-04	7.34E-04	6.04E-04
NMVOC total	air	kg	3.59E-05	3.71E-05	1.93E-05
thereof:					
Benzene	air	kg	1.99E-06	1.99E-06	1.52E-06
Benzo(a)pyrene	air	kg	8.29E-11	8.93E-11	4.57E-11
Formaldehyde	air	kg	5.13E-07	5.15E-07	4.25E-07
PAH	air	kg	1.28E-08	1.32E-08	9.44E-09
PM2.5-10	air	kg	1.40E-05	1.48E-05	9.37E-06
PM2.5	air	kg	6.32E-05	6.39E-05	5.22E-05
PCDD/F (measured as I-TEQ)	air	kg	7.48E-14	7.55E-14	5.15E-14
Radon-222	air	kBq	2.15E-01	2.23E-01	1.42E-01
Sulfur dioxide	air	kg	1.34E-04	1.36E-04	1.12E-04
Emissions to Water					
Ammonium, ion	water	kg	3.94E-06	3.95E-06	4.42E-08
Arsenic, ion	water	kg	8.87E-07	8.89E-07	7.59E-07
Cadmium, ion	water	kg	3.15E-08	3.28E-08	2.37E-08
Carbon-14	water	kBq	3.73E-06	3.85E-06	2.47E-06
Cesium-137	water	kBq	1.82E-06	1.88E-06	1.20E-06
Chromium, ion	water	kg	1.55E-09	1.82E-09	6.55E-10
Chromium VI	water	kg	7.76E-07	8.10E-07	5.82E-07
COD	water	kg	1.29E-04	1.34E-04	2.53E-05
Copper, ion	water	kg	9.86E-07	9.97E-07	7.97E-07
Lead	water	kg	9.36E-07	9.39E-07	7.88E-07
Mercury	water	kg	5.70E-09	5.92E-09	4.37E-09
Nickel, ion	water	kg	1.87E-06	1.95E-06	1.39E-06
Nitrate	water	kg	1.13E-05	1.14E-05	1.83E-07
Oils, unspecified	water	kg	7.98E-06	8.55E-06	3.52E-06
PAH	water	kg	2.68E-09	2.95E-09	1.25E-09
Phosphate	water	kg	3.40E-05	3.42E-05	2.65E-05
Emissions to Soil					
Arsenic	soil	kg	5.89E-11	6.11E-11	1.26E-11
Cadmium	soil	kg	1.05E-11	1.12E-11	4.00E-12
Chromium	soil	kg	9.77E-10	1.01E-09	2.13E-10
Chromium VI	soil	kg	7.25E-09	8.51E-09	6.09E-10
Lead	soil	kg	1.04E-10	1.10E-10	2.97E-11
Mercury	soil	kg	5.19E-13	5.63E-13	1.61E-13
Oils, unspecified	soil	kg	7.19E-06	7.64E-06	3.22E-06

Table 8.23 LCA results for year 2025, very optimistic development, "440 ppm-scenario".

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	9.10E-01	9.30E-01	9.30E-01
Coal, hard, unspecified, in ground	resource	kg	6.27E-03	3.26E-03	3.71E-03
Gas, natural, in ground	resource	Nm3	1.13E-02	4.16E-03	4.69E-03
Oil, crude, in ground	resource	kg	3.15E-03	1.07E-03	1.20E-03
Uranium, in ground	resource	kg	9.84E-09	5.74E-09	6.02E-09
Freshwater (lake, river, groundwater)	resource	m3	4.77E-03	4.76E-03	4.78E-03
Occupation, agricultural and forestal area	resource	m2a	4.38E-03	2.34E-03	2.54E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.32E-03	1.23E-03	1.27E-03
Emissions to air					
Ammonia	air	kg	2.39E-04	2.80E-06	2.94E-06
Arsenic	air	kg	9.78E-09	8.58E-09	8.73E-09
Cadmium	air	kg	1.93E-09	1.04E-09	1.08E-09
Carbon dioxide, fossil	air	kg	1.32E-01	2.55E-02	2.75E-02
Carbon monoxide, fossil	air	kg	2.10E-04	2.01E-04	2.06E-04
Carbon-14	air	kBq	1.33E-05	1.03E-05	1.08E-05
Chromium	air	kg	9.85E-08	7.96E-08	8.71E-08
Chromium VI	air	kg	2.57E-09	2.11E-09	2.29E-09
Dinitrogen monoxide	air	kg	2.33E-05	2.24E-05	2.25E-05
Iodine-129	air	kBq	1.04E-08	7.83E-09	8.19E-09
Lead	air	kg	2.12E-08	1.55E-08	1.65E-08
Methane, fossil	air	kg	2.99E-04	2.57E-04	2.62E-04
Mercury	air	kg	2.09E-08	2.04E-08	2.06E-08
Nickel	air	kg	2.87E-08	1.36E-08	1.43E-08
Nitrogen oxides	air	kg	7.51E-04	2.84E-04	2.90E-04
NMVOC total	air	kg	4.22E-05	2.68E-05	2.82E-05
thereof:					
Benzene	air	kg	2.01E-06	1.82E-06	1.82E-06
Benzo(a)pyrene	air	kg	1.00E-10	8.09E-11	8.80E-11
Formaldehyde	air	kg	5.24E-07	5.10E-07	5.12E-07
PAH	air	kg	1.44E-08	1.27E-08	1.31E-08
PM2.5-10	air	kg	1.54E-05	1.32E-05	1.40E-05
PM2.5	air	kg	6.48E-05	6.33E-05	6.40E-05
PCDD/F (measured as I-TEQ)	air	kg	7.73E-14	6.35E-14	6.43E-14
Radon-222	air	kBq	2.34E-01	1.80E-01	1.88E-01
Sulfur dioxide	air	kg	1.47E-04	1.19E-04	1.22E-04
Emissions to Water					
Ammonium, ion	water	kg	4.03E-06	9.93E-08	1.10E-07
Arsenic, ion	water	kg	8.92E-07	9.05E-07	9.08E-07
Cadmium, ion	water	kg	3.36E-08	3.19E-08	3.34E-08
Carbon-14	water	kBq	4.05E-06	3.05E-06	3.19E-06
Cesium-137	water	kBq	1.97E-06	1.49E-06	1.56E-06
Chromium, ion	water	kg	2.11E-09	1.42E-09	1.73E-09
Chromium VI	water	kg	8.34E-07	7.84E-07	8.23E-07
COD	water	kg	1.41E-04	3.96E-05	4.46E-05
Copper, ion	water	kg	1.01E-06	9.77E-07	9.89E-07
Lead	water	kg	9.44E-07	9.54E-07	9.58E-07
Mercury	water	kg	6.06E-09	5.71E-09	5.96E-09
Nickel, ion	water	kg	2.00E-06	1.88E-06	1.96E-06
Nitrate	water	kg	1.19E-05	4.85E-07	5.45E-07
Oils, unspecified	water	kg	9.47E-06	5.22E-06	5.87E-06
PAH	water	kg	3.21E-09	2.39E-09	2.70E-09
Phosphate	water	kg	3.44E-05	3.17E-05	3.19E-05
Emissions to Soil					
Arsenic	soil	kg	1.31E-10	5.31E-11	5.56E-11
Cadmium	soil	kg	1.22E-11	6.73E-12	7.51E-12
Chromium	soil	kg	1.91E-09	7.44E-10	7.85E-10
Chromium VI	soil	kg	2.05E-08	7.47E-09	8.90E-09
Lead	soil	kg	1.34E-10	5.37E-11	6.02E-11
Mercury	soil	kg	9.40E-13	4.08E-13	4.58E-13
Oils, unspecified	soil	kg	8.43E-06	4.49E-06	5.01E-06

Table 8.24 LCA results for year 2025, very optimistic development, “440 ppm-scenario”.

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total	Total	Total
			kWh	kWh	kWh
Resources					
Coal, brown, in ground	resource	kg	9.31E-01	9.31E-01	9.10E-01
Coal, hard, unspecified, in ground	resource	kg	6.22E-03	6.67E-03	5.88E-03
Gas, natural, in ground	resource	Nm3	8.96E-03	9.50E-03	1.08E-02
Oil, crude, in ground	resource	kg	1.28E-03	1.41E-03	3.04E-03
Uranium, in ground	resource	kg	6.28E-09	6.56E-09	9.59E-09
Freshwater (lake, river, groundwater)	resource	m3	4.84E-03	4.85E-03	4.76E-03
Occupation, agricultural and forestal area	resource	m2a	4.11E-03	4.32E-03	4.20E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.30E-03	1.33E-03	1.28E-03
Emissions to air					
Ammonia	air	kg	3.61E-06	3.74E-06	2.39E-04
Arsenic	air	kg	9.52E-09	9.66E-09	9.65E-09
Cadmium	air	kg	1.32E-09	1.37E-09	1.89E-09
Carbon dioxide, fossil	air	kg	3.92E-02	4.12E-02	1.30E-01
Carbon monoxide, fossil	air	kg	2.06E-04	2.12E-04	2.05E-04
Carbon-14	air	kBq	1.10E-05	1.15E-05	1.29E-05
Chromium	air	kg	8.90E-08	9.65E-08	9.18E-08
Chromium VI	air	kg	2.35E-09	2.53E-09	2.41E-09
Dinitrogen monoxide	air	kg	2.37E-05	2.38E-05	2.32E-05
Iodine-129	air	kBq	8.40E-09	8.75E-09	1.01E-08
Lead	air	kg	1.92E-08	2.02E-08	2.03E-08
Methane, fossil	air	kg	2.91E-04	2.95E-04	2.94E-04
Mercury	air	kg	2.07E-08	2.09E-08	2.08E-08
Nickel	air	kg	1.71E-08	1.78E-08	2.81E-08
Nitrogen oxides	air	kg	3.04E-04	3.10E-04	7.46E-04
NMVOC total	air	kg	3.25E-05	3.39E-05	4.09E-05
thereof:					
Benzene	air	kg	1.84E-06	1.84E-06	2.00E-06
Benzo(a)pyrene	air	kg	9.32E-11	1.00E-10	9.38E-11
Formaldehyde	air	kg	5.20E-07	5.22E-07	5.22E-07
PAH	air	kg	1.41E-08	1.45E-08	1.40E-08
PM2.5-10	air	kg	1.40E-05	1.48E-05	1.47E-05
PM2.5	air	kg	6.44E-05	6.51E-05	6.41E-05
PCDD/F (measured as I-TEQ)	air	kg	6.56E-14	6.64E-14	7.66E-14
Radon-222	air	kBq	1.93E-01	2.01E-01	2.27E-01
Sulfur dioxide	air	kg	1.32E-04	1.34E-04	1.45E-04
Emissions to Water					
Ammonium, ion	water	kg	1.87E-07	1.98E-07	4.02E-06
Arsenic, ion	water	kg	9.08E-07	9.11E-07	8.90E-07
Cadmium, ion	water	kg	3.28E-08	3.43E-08	3.23E-08
Carbon-14	water	kBq	3.27E-06	3.41E-06	3.93E-06
Cesium-137	water	kBq	1.60E-06	1.66E-06	1.91E-06
Chromium, ion	water	kg	1.74E-09	2.05E-09	1.83E-09
Chromium VI	water	kg	8.11E-07	8.50E-07	7.99E-07
COD	water	kg	4.74E-05	5.24E-05	1.36E-04
Copper, ion	water	kg	9.97E-07	1.01E-06	1.00E-06
Lead	water	kg	9.59E-07	9.63E-07	9.41E-07
Mercury	water	kg	5.87E-09	6.12E-09	5.84E-09
Nickel, ion	water	kg	1.94E-06	2.02E-06	1.93E-06
Nitrate	water	kg	1.01E-06	1.07E-06	1.18E-05
Oils, unspecified	water	kg	6.26E-06	6.90E-06	8.90E-06
PAH	water	kg	2.68E-09	2.99E-09	2.93E-09
Phosphate	water	kg	3.19E-05	3.21E-05	3.42E-05
Emissions to Soil					
Arsenic	soil	kg	1.33E-10	1.35E-10	1.29E-10
Cadmium	soil	kg	7.94E-12	8.72E-12	1.15E-11
Chromium	soil	kg	1.76E-09	1.80E-09	1.88E-09
Chromium VI	soil	kg	2.10E-08	2.25E-08	1.92E-08
Lead	soil	kg	8.10E-11	8.75E-11	1.28E-10
Mercury	soil	kg	8.35E-13	8.84E-13	8.96E-13
Oils, unspecified	soil	kg	5.38E-06	5.90E-06	7.97E-06

Table 8.25 LCA results for year 2025, very optimistic development, “440 ppm-scenario”.

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	1.54E-04	4.17E-01
Coal, hard, unspecified, in ground	resource	kg	3.27E-01	7.56E-04
Gas, natural, in ground	resource	Nm3	1.97E-03	8.15E-04
Oil, crude, in ground	resource	kg	4.05E-03	5.15E-04
Uranium, in ground	resource	kg	8.90E-09	3.54E-09
Freshwater (lake, river, groundwater)	resource	m3	5.41E-04	1.50E-03
Occupation, agricultural and forestal area	resource	m2a	1.54E-02	5.38E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.73E-03	7.22E-04
Emissions to air				
Ammonia	air	kg	1.39E-05	4.56E-07
Arsenic	air	kg	5.87E-08	5.69E-08
Cadmium	air	kg	1.15E-09	8.51E-10
Carbon dioxide, fossil	air	kg	6.30E-01	6.13E-01
Carbon monoxide, fossil	air	kg	1.21E-04	6.54E-05
Carbon-14	air	kBq	1.66E-05	6.44E-06
Chromium	air	kg	4.36E-08	3.61E-08
Chromium VI	air	kg	1.39E-09	1.17E-09
Dinitrogen monoxide	air	kg	2.67E-05	2.55E-05
Iodine-129	air	kBq	1.22E-08	4.72E-09
Lead	air	kg	3.41E-08	2.97E-08
Methane, fossil	air	kg	1.81E-03	1.15E-04
Mercury	air	kg	1.89E-08	1.82E-08
Nickel	air	kg	7.72E-08	1.53E-08
Nitrogen oxides	air	kg	4.11E-04	1.64E-04
NMVOC total	air	kg	4.68E-05	1.75E-05
thereof:				
Benzene	air	kg	1.14E-06	9.42E-07
Benzo(a)pyrene	air	kg	7.00E-11	2.80E-11
Formaldehyde	air	kg	2.65E-07	2.60E-07
PAH	air	kg	5.15E-08	4.42E-08
PM2.5-10	air	kg	1.32E-05	2.42E-06
PM2.5	air	kg	9.05E-06	1.94E-06
PCDD/F (measured as I-TEQ)	air	kg	4.44E-14	3.92E-14
Radon-222	air	kBq	2.84E-01	1.11E-01
Sulfur dioxide	air	kg	3.47E-04	1.91E-04
Emissions to Water				
Ammonium, ion	water	kg	3.54E-07	5.43E-08
Arsenic, ion	water	kg	7.82E-08	6.93E-08
Cadmium, ion	water	kg	1.19E-08	8.74E-09
Carbon-14	water	kBq	4.73E-06	1.84E-06
Cesium-137	water	kBq	2.31E-06	8.99E-07
Chromium, ion	water	kg	1.64E-09	5.81E-10
Chromium VI	water	kg	6.98E-07	6.16E-07
COD	water	kg	2.10E-04	1.56E-04
Copper, ion	water	kg	1.25E-06	1.22E-06
Lead	water	kg	3.16E-07	3.07E-07
Mercury	water	kg	4.73E-09	4.34E-09
Nickel, ion	water	kg	5.83E-07	4.63E-07
Nitrate	water	kg	1.27E-06	7.06E-07
Oils, unspecified	water	kg	1.80E-05	2.27E-06
PAH	water	kg	2.45E-09	9.49E-10
Phosphate	water	kg	6.80E-06	6.44E-06
Emissions to Soil				
Arsenic	soil	kg	5.12E-11	7.79E-12
Cadmium	soil	kg	6.65E-12	3.60E-12
Chromium	soil	kg	7.55E-10	1.60E-10
Chromium VI	soil	kg	2.50E-09	5.34E-10
Lead	soil	kg	5.78E-11	3.43E-11
Mercury	soil	kg	6.80E-13	2.37E-13
Oils, unspecified	soil	kg	1.82E-05	2.10E-06

Table 8.26 LCA results for year 2025, very optimistic development, "440 ppm-scenario".

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	5.98E-04	6.29E-04	3.13E-04	3.44E-04
Coal, hard, unspecified, in ground	resource	kg	3.71E-01	3.71E-01	3.68E-01	3.69E-01
Gas, natural, in ground	resource	Nm3	7.76E-03	8.17E-03	4.05E-03	4.46E-03
Oil, crude, in ground	resource	kg	4.86E-03	4.96E-03	4.69E-03	4.79E-03
Uranium, in ground	resource	kg	1.06E-08	1.09E-08	1.02E-08	1.04E-08
Freshwater (lake, river, groundwater)	resource	m3	6.99E-04	7.13E-04	6.42E-04	6.55E-04
Occupation, agricultural and forestal area	resource	m2a	1.94E-02	1.95E-02	1.80E-02	1.81E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.25E-03	4.28E-03	4.20E-03	4.23E-03
Emissions to air						
Ammonia	air	kg	1.66E-05	1.67E-05	1.60E-05	1.61E-05
Arsenic	air	kg	7.36E-08	7.37E-08	7.29E-08	7.30E-08
Cadmium	air	kg	1.61E-09	1.65E-09	1.39E-09	1.43E-09
Carbon dioxide, fossil	air	kg	1.16E-01	1.18E-01	1.05E-01	1.07E-01
Carbon monoxide, fossil	air	kg	1.52E-04	1.56E-04	1.48E-04	1.52E-04
Carbon-14	air	kBq	1.95E-05	1.98E-05	1.89E-05	1.93E-05
Chromium	air	kg	6.44E-08	7.02E-08	5.71E-08	6.29E-08
Chromium VI	air	kg	1.98E-09	2.12E-09	1.80E-09	1.94E-09
Dinitrogen monoxide	air	kg	3.45E-05	3.46E-05	3.35E-05	3.36E-05
Iodine-129	air	kBq	1.43E-08	1.46E-08	1.39E-08	1.42E-08
Lead	air	kg	4.54E-08	4.62E-08	4.26E-08	4.34E-08
Methane, fossil	air	kg	2.08E-03	2.08E-03	2.05E-03	2.05E-03
Mercury	air	kg	2.39E-08	2.41E-08	2.36E-08	2.38E-08
Nickel	air	kg	9.19E-08	9.25E-08	8.92E-08	8.97E-08
Nitrogen oxides	air	kg	5.05E-04	5.09E-04	4.90E-04	4.94E-04
NMVOC total	air	kg	6.13E-05	6.24E-05	5.69E-05	5.80E-05
thereof:						
Benzene	air	kg	1.42E-06	1.42E-06	1.41E-06	1.41E-06
Benzo(a)pyrene	air	kg	9.56E-11	1.01E-10	8.61E-11	9.16E-11
Formaldehyde	air	kg	3.40E-07	3.41E-07	3.32E-07	3.33E-07
PAH	air	kg	6.48E-08	6.51E-08	6.37E-08	6.40E-08
PM2.5-10	air	kg	1.61E-05	1.67E-05	1.56E-05	1.62E-05
PM2.5	air	kg	1.17E-05	1.23E-05	1.09E-05	1.15E-05
PCDD/F (measured as I-TEQ)	air	kg	5.62E-14	5.68E-14	5.45E-14	5.51E-14
Radon-222	air	kBq	3.35E-01	3.42E-01	3.25E-01	3.32E-01
Sulfur dioxide	air	kg	4.26E-04	4.28E-04	4.17E-04	4.18E-04
Emissions to Water						
Ammonium, ion	water	kg	5.00E-07	5.08E-07	4.32E-07	4.40E-07
Arsenic, ion	water	kg	9.13E-08	9.30E-08	8.89E-08	9.07E-08
Cadmium, ion	water	kg	1.52E-08	1.63E-08	1.45E-08	1.57E-08
Carbon-14	water	kBq	5.59E-06	5.69E-06	5.42E-06	5.52E-06
Cesium-137	water	kBq	2.73E-06	2.78E-06	2.65E-06	2.70E-06
Chromium, ion	water	kg	2.41E-09	2.65E-09	2.16E-09	2.40E-09
Chromium VI	water	kg	8.31E-07	8.61E-07	8.10E-07	8.41E-07
COD	water	kg	2.46E-04	2.50E-04	2.40E-04	2.44E-04
Copper, ion	water	kg	1.41E-06	1.42E-06	1.40E-06	1.41E-06
Lead	water	kg	3.56E-07	3.59E-07	3.52E-07	3.55E-07
Mercury	water	kg	5.60E-09	5.79E-09	5.48E-09	5.67E-09
Nickel, ion	water	kg	7.69E-07	8.34E-07	7.24E-07	7.89E-07
Nitrate	water	kg	2.03E-06	2.08E-06	1.62E-06	1.67E-06
Oils, unspecified	water	kg	2.17E-05	2.22E-05	2.09E-05	2.14E-05
PAH	water	kg	3.27E-09	3.51E-09	3.05E-09	3.29E-09
Phosphate	water	kg	7.87E-06	8.00E-06	7.72E-06	7.85E-06
Emissions to Soil						
Arsenic	soil	kg	1.49E-10	1.50E-10	8.71E-11	8.90E-11
Cadmium	soil	kg	9.26E-12	9.87E-12	8.32E-12	8.93E-12
Chromium	soil	kg	2.01E-09	2.05E-09	1.23E-09	1.26E-09
Chromium VI	soil	kg	1.84E-08	1.95E-08	7.94E-09	9.04E-09
Lead	soil	kg	9.83E-11	1.03E-10	7.72E-11	8.23E-11
Mercury	soil	kg	1.25E-12	1.29E-12	9.26E-13	9.64E-13
Oils, unspecified	soil	kg	2.17E-05	2.21E-05	2.10E-05	2.14E-05

Table 8.27 LCA results for year 2025, very optimistic development, "440 ppm-scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km	electricity, lignite IGCC plant 400MW, CCS, 400km	electricity, lignite IGCC power plant 400MW, CCS,	electricity, lignite IGCC power plant 400MW, CCS,
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.71E-01	4.71E-01	4.70E-01	4.70E-01
Coal, hard, unspecified, in ground	resource	kg	5.42E-03	5.85E-03	2.56E-03	2.99E-03
Gas, natural, in ground	resource	Nm3	7.97E-03	8.48E-03	3.33E-03	3.85E-03
Oil, crude, in ground	resource	kg	1.47E-03	1.59E-03	1.26E-03	1.39E-03
Uranium, in ground	resource	kg	1.26E-08	1.29E-08	1.21E-08	1.24E-08
Freshwater (lake, river, groundwater)	resource	m3	1.84E-03	1.86E-03	1.77E-03	1.79E-03
Occupation, agricultural and forestal area	resource	m2a	3.21E-03	3.40E-03	1.50E-03	1.69E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.22E-03	1.25E-03	1.16E-03	1.19E-03
Emissions to air						
Ammonia	air	kg	1.92E-06	2.05E-06	1.14E-06	1.28E-06
Arsenic	air	kg	7.25E-09	7.39E-09	6.35E-09	6.49E-09
Cadmium	air	kg	1.19E-09	1.24E-09	9.20E-10	9.63E-10
Carbon dioxide, fossil	air	kg	1.24E-01	1.26E-01	1.11E-01	1.13E-01
Carbon monoxide, fossil	air	kg	1.09E-04	1.14E-04	1.04E-04	1.09E-04
Carbon-14	air	kBq	2.30E-05	2.35E-05	2.24E-05	2.28E-05
Chromium	air	kg	5.87E-08	6.59E-08	4.96E-08	5.68E-08
Chromium VI	air	kg	1.56E-09	1.73E-09	1.33E-09	1.50E-09
Dinitrogen monoxide	air	kg	3.25E-05	3.27E-05	3.12E-05	3.14E-05
Iodine-129	air	kBq	1.68E-08	1.71E-08	1.62E-08	1.66E-08
Lead	air	kg	1.57E-08	1.67E-08	1.22E-08	1.32E-08
Methane, fossil	air	kg	1.84E-04	1.88E-04	1.51E-04	1.56E-04
Mercury	air	kg	1.39E-08	1.41E-08	1.36E-08	1.38E-08
Nickel	air	kg	1.31E-08	1.38E-08	9.66E-09	1.04E-08
Nitrogen oxides	air	kg	5.15E-04	5.20E-04	4.96E-04	5.01E-04
NMVOC total	air	kg	3.32E-05	3.45E-05	2.76E-05	2.90E-05
thereof:						
Benzene	air	kg	1.23E-06	1.23E-06	1.21E-06	1.21E-06
Benzo(a)pyrene	air	kg	5.90E-11	6.59E-11	4.72E-11	5.41E-11
Formaldehyde	air	kg	3.40E-07	3.42E-07	3.30E-07	3.32E-07
PAH	air	kg	5.74E-08	5.78E-08	5.60E-08	5.64E-08
PM2.5-10	air	kg	5.33E-06	6.10E-06	4.62E-06	5.39E-06
PM2.5	air	kg	4.75E-06	5.41E-06	3.76E-06	4.42E-06
PCDD/F (measured as I-TEQ)	air	kg	5.59E-14	5.66E-14	5.39E-14	5.46E-14
Radon-222	air	kBq	3.93E-01	4.01E-01	3.80E-01	3.88E-01
Sulfur dioxide	air	kg	7.25E-04	7.28E-04	7.14E-04	7.16E-04
Emissions to Water						
Ammonium, ion	water	kg	1.94E-07	2.04E-07	1.09E-07	1.19E-07
Arsenic, ion	water	kg	1.43E-06	1.43E-06	1.43E-06	1.43E-06
Cadmium, ion	water	kg	9.04E-08	9.19E-08	8.96E-08	9.10E-08
Carbon-14	water	kBq	6.54E-06	6.67E-06	6.32E-06	6.46E-06
Cesium-137	water	kBq	3.20E-06	3.26E-06	3.09E-06	3.16E-06
Chromium, ion	water	kg	1.50E-09	1.81E-09	1.20E-09	1.50E-09
Chromium VI	water	kg	9.15E-06	9.19E-06	9.13E-06	9.17E-06
COD	water	kg	2.05E-03	2.05E-03	2.04E-03	2.04E-03
Copper, ion	water	kg	6.61E-06	6.62E-06	6.59E-06	6.60E-06
Lead	water	kg	1.84E-06	1.85E-06	1.84E-06	1.84E-06
Mercury	water	kg	5.99E-08	6.02E-08	5.98E-08	6.00E-08
Nickel, ion	water	kg	3.98E-06	4.06E-06	3.92E-06	4.00E-06
Nitrate	water	kg	1.59E-06	1.65E-06	1.08E-06	1.14E-06
Oils, unspecified	water	kg	5.40E-06	6.02E-06	4.40E-06	5.02E-06
PAH	water	kg	1.88E-09	2.18E-09	1.60E-09	1.90E-09
Phosphate	water	kg	1.08E-04	1.08E-04	1.08E-04	1.08E-04
Emissions to Soil						
Arsenic	soil	kg	1.26E-10	1.28E-10	4.92E-11	5.16E-11
Cadmium	soil	kg	8.80E-12	9.56E-12	7.63E-12	8.39E-12
Chromium	soil	kg	1.71E-09	1.75E-09	7.28E-10	7.67E-10
Chromium VI	soil	kg	2.03E-08	2.17E-08	7.21E-09	8.60E-09
Lead	soil	kg	9.45E-11	1.01E-10	6.82E-11	7.44E-11
Mercury	soil	kg	8.94E-13	9.42E-13	4.83E-13	5.30E-13
Oils, unspecified	soil	kg	4.81E-06	5.31E-06	3.95E-06	4.45E-06

Table 8.28 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	4.89E-05	4.75E-05	4.74E-05
	Coal, hard, unspecified, in ground	resource	kg	3.53E-01	3.53E-01	3.53E-01
	Gas, natural, in ground	resource	Nm3	3.03E-03	3.01E-03	3.01E-03
	Oil, crude, in ground	resource	kg	4.54E-03	4.53E-03	4.52E-03
	Uranium, in ground	resource	kg	1.38E-07	1.37E-07	1.37E-07
	Freshwater (lake, river, groundwater)	resource	m3	1.80E-03	1.80E-03	1.80E-03
	Occupation, agricultural and forestal area	resource	m2a	1.64E-02	1.64E-02	1.64E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	3.83E-03	3.82E-03	3.82E-03
Emissions to air						
	Ammonia	air	kg	1.72E-05	1.72E-05	1.72E-05
	Arsenic	air	kg	1.17E-08	1.16E-08	1.16E-08
	Cadmium	air	kg	1.15E-09	1.13E-09	1.13E-09
	Carbon dioxide, fossil	air	kg	6.37E-01	6.37E-01	6.37E-01
	Carbon monoxide, fossil	air	kg	1.27E-04	1.27E-04	1.27E-04
	Carbon-14	air	kBq	3.86E-04	3.84E-04	3.84E-04
	Chromium	air	kg	1.51E-07	1.34E-07	1.34E-07
	Chromium VI	air	kg	4.24E-09	3.82E-09	3.81E-09
	Dinitrogen monoxide	air	kg	2.79E-05	2.79E-05	2.79E-05
	Iodine-129	air	kBq	2.38E-07	2.37E-07	2.37E-07
	Lead	air	kg	4.60E-08	4.56E-08	4.56E-08
	Methane, fossil	air	kg	1.96E-03	1.96E-03	1.96E-03
	Mercury	air	kg	2.85E-08	2.85E-08	2.85E-08
	Nickel	air	kg	8.86E-08	8.84E-08	8.84E-08
	Nitrogen oxides	air	kg	6.55E-04	6.55E-04	6.55E-04
	NMVOC total	air	kg	4.96E-05	4.95E-05	4.95E-05
	thereof:					
	Benzene	air	kg	1.68E-06	1.68E-06	1.68E-06
	Benzo(a)pyrene	air	kg	6.64E-11	6.40E-11	6.40E-11
	Formaldehyde	air	kg	4.08E-07	4.07E-07	4.07E-07
	PAH	air	kg	1.67E-08	1.66E-08	1.66E-08
	PM2.5-10	air	kg	1.80E-05	1.78E-05	1.78E-05
	PM2.5	air	kg	4.23E-05	4.21E-05	4.21E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.44E-14	5.42E-14	5.42E-14
	Radon-222	air	kBq	4.47E+00	4.45E+00	4.45E+00
	Sulfur dioxide	air	kg	4.73E-04	4.72E-04	4.72E-04
Emissions to Water						
	Ammonium, ion	water	kg	7.20E-07	7.20E-07	7.20E-07
	Arsenic, ion	water	kg	1.06E-07	1.05E-07	1.05E-07
	Cadmium, ion	water	kg	1.02E-08	9.95E-09	9.92E-09
	Carbon-14	water	kBq	1.03E-04	1.02E-04	1.02E-04
	Cesium-137	water	kBq	4.44E-05	4.42E-05	4.42E-05
	Chromium, ion	water	kg	1.44E-08	1.44E-08	1.44E-08
	Chromium VI	water	kg	2.10E-07	2.04E-07	2.04E-07
	COD	water	kg	1.02E-04	1.01E-04	1.01E-04
	Copper, ion	water	kg	4.05E-07	4.01E-07	4.00E-07
	Lead	water	kg	1.74E-07	1.70E-07	1.69E-07
	Mercury	water	kg	2.35E-09	2.33E-09	2.33E-09
	Nickel, ion	water	kg	9.16E-07	8.54E-07	8.52E-07
	Nitrate	water	kg	2.18E-05	2.18E-05	2.18E-05
	Oils, unspecified	water	kg	1.98E-05	1.98E-05	1.98E-05
	PAH	water	kg	4.75E-09	4.40E-09	4.39E-09
	Phosphate	water	kg	2.36E-06	2.34E-06	2.34E-06
Emissions to Soil						
	Arsenic	soil	kg	5.84E-11	5.82E-11	5.82E-11
	Cadmium	soil	kg	5.63E-12	5.56E-12	5.55E-12
	Chromium	soil	kg	8.29E-10	8.25E-10	8.25E-10
	Chromium VI	soil	kg	2.47E-09	2.45E-09	2.45E-09
	Lead	soil	kg	4.16E-11	4.10E-11	4.10E-11
	Mercury	soil	kg	4.70E-13	4.69E-13	4.69E-13
	Oils, unspecified	soil	kg	2.01E-05	2.00E-05	2.00E-05

Table 8.29 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	5.48E-05	5.60E-05	6.90E-05	7.01E-05
Coal, hard, unspecified, in ground	resource	kg	4.07E-01	4.07E-01	3.91E-01	3.91E-01
Gas, natural, in ground	resource	Nm3	6.10E-03	6.70E-03	7.81E-03	8.33E-03
Oil, crude, in ground	resource	kg	5.32E-03	5.42E-03	6.57E-03	6.65E-03
Uranium, in ground	resource	kg	3.00E-07	3.31E-07	2.91E-07	3.17E-07
Freshwater (lake, river, groundwater)	resource	m3	2.18E-03	2.21E-03	2.12E-03	2.15E-03
Occupation, agricultural and forestal area	resource	m2a	1.91E-02	1.92E-02	1.87E-02	1.87E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.45E-03	4.47E-03	4.30E-03	4.32E-03
Emissions to air						
Ammonia	air	kg	1.83E-05	1.84E-05	2.41E-04	2.41E-04
Arsenic	air	kg	1.37E-08	1.38E-08	1.37E-08	1.37E-08
Cadmium	air	kg	1.37E-09	1.40E-09	1.82E-09	1.84E-09
Carbon dioxide, fossil	air	kg	2.75E-02	2.82E-02	1.04E-01	1.04E-01
Carbon monoxide, fossil	air	kg	1.53E-04	1.57E-04	1.52E-04	1.55E-04
Carbon-14	air	kBq	8.52E-04	9.40E-04	8.18E-04	8.93E-04
Chromium	air	kg	1.88E-07	1.94E-07	2.25E-07	2.30E-07
Chromium VI	air	kg	5.23E-09	5.37E-09	6.12E-09	6.24E-09
Dinitrogen monoxide	air	kg	3.23E-05	3.24E-05	3.12E-05	3.13E-05
Iodine-129	air	kBq	5.23E-07	5.77E-07	5.03E-07	5.49E-07
Lead	air	kg	5.43E-08	5.50E-08	5.43E-08	5.49E-08
Methane, fossil	air	kg	2.26E-03	2.27E-03	2.18E-03	2.18E-03
Mercury	air	kg	3.30E-08	3.31E-08	3.21E-08	3.23E-08
Nickel	air	kg	1.02E-07	1.02E-07	1.06E-07	1.07E-07
Nitrogen oxides	air	kg	5.18E-04	5.22E-04	7.44E-04	7.47E-04
NMVOC total	air	kg	6.03E-05	6.15E-05	6.57E-05	6.68E-05
thereof:						
Benzene	air	kg	1.93E-06	1.94E-06	2.02E-06	2.02E-06
Benzo(a)pyrene	air	kg	8.45E-11	8.97E-11	8.94E-11	9.39E-11
Formaldehyde	air	kg	4.72E-07	4.74E-07	4.66E-07	4.68E-07
PAH	air	kg	2.03E-08	2.07E-08	2.01E-08	2.05E-08
PM2.5-10	air	kg	2.15E-05	2.22E-05	2.20E-05	2.26E-05
PM2.5	air	kg	4.93E-05	4.98E-05	4.88E-05	4.93E-05
PCDD/F (measured as I-TEQ)	air	kg	6.34E-14	6.39E-14	7.40E-14	7.44E-14
Radon-222	air	kBq	9.76E+00	1.08E+01	9.38E+00	1.02E+01
Sulfur dioxide	air	kg	3.11E-04	3.13E-04	3.15E-04	3.16E-04
Emissions to Water						
Ammonium, ion	water	kg	8.92E-07	9.02E-07	3.85E-06	3.86E-06
Arsenic, ion	water	kg	1.25E-07	1.27E-07	1.23E-07	1.25E-07
Cadmium, ion	water	kg	1.34E-08	1.46E-08	1.36E-08	1.46E-08
Carbon-14	water	kBq	2.26E-04	2.49E-04	2.17E-04	2.37E-04
Cesium-137	water	kBq	9.75E-05	1.08E-04	9.37E-05	1.02E-04
Chromium, ion	water	kg	1.80E-08	1.83E-08	1.75E-08	1.78E-08
Chromium VI	water	kg	2.80E-07	3.11E-07	2.90E-07	3.17E-07
COD	water	kg	1.23E-04	1.27E-04	1.98E-04	2.01E-04
Copper, ion	water	kg	4.96E-07	5.05E-07	5.09E-07	5.17E-07
Lead	water	kg	2.14E-07	2.17E-07	2.16E-07	2.19E-07
Mercury	water	kg	3.03E-09	3.22E-09	3.05E-09	3.22E-09
Nickel, ion	water	kg	1.16E-06	1.23E-06	1.29E-06	1.35E-06
Nitrate	water	kg	2.64E-05	2.64E-05	3.42E-05	3.43E-05
Oils, unspecified	water	kg	2.33E-05	2.38E-05	2.48E-05	2.53E-05
PAH	water	kg	5.89E-09	6.13E-09	6.77E-09	6.97E-09
Phosphate	water	kg	2.88E-06	3.01E-06	5.83E-06	5.94E-06
Emissions to Soil						
Arsenic	soil	kg	9.87E-11	1.01E-10	1.01E-10	1.02E-10
Cadmium	soil	kg	7.04E-12	7.53E-12	9.92E-12	1.04E-11
Chromium	soil	kg	1.35E-09	1.39E-09	1.50E-09	1.53E-09
Chromium VI	soil	kg	8.03E-09	9.15E-09	7.71E-09	8.67E-09
Lead	soil	kg	5.12E-11	5.42E-11	9.11E-11	9.37E-11
Mercury	soil	kg	5.54E-13	5.60E-13	6.43E-13	6.47E-13
Oils, unspecified	soil	kg	2.35E-05	2.38E-05	2.49E-05	2.52E-05

Table 8.30 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

				electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
				Total	Total	Total	Total
				kWh	kWh	kWh	kWh
Resources							
	Coal, brown, in ground	resource	kg	6.03E-05	6.16E-05	7.38E-05	7.49E-05
	Coal, hard, unspecified, in ground	resource	kg	4.08E-01	4.08E-01	3.91E-01	3.91E-01
	Gas, natural, in ground	resource	Nm3	1.16E-02	1.22E-02	1.25E-02	1.31E-02
	Oil, crude, in ground	resource	kg	5.43E-03	5.53E-03	6.67E-03	6.75E-03
	Uranium, in ground	resource	kg	5.89E-07	6.19E-07	5.40E-07	5.66E-07
	Freshwater (lake, river, groundwater)	resource	m3	2.37E-03	2.40E-03	2.29E-03	2.32E-03
	Occupation, agricultural and forestal area	resource	m2a	1.97E-02	1.97E-02	1.91E-02	1.92E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	4.46E-03	4.49E-03	4.32E-03	4.34E-03
Emissions to air							
	Ammonia	air	kg	1.85E-05	1.86E-05	2.41E-04	2.41E-04
	Arsenic	air	kg	1.42E-08	1.42E-08	1.41E-08	1.41E-08
	Cadmium	air	kg	1.55E-09	1.58E-09	1.97E-09	2.00E-09
	Carbon dioxide, fossil	air	kg	3.04E-02	3.11E-02	1.06E-01	1.07E-01
	Carbon monoxide, fossil	air	kg	1.57E-04	1.61E-04	1.55E-04	1.59E-04
	Carbon-14	air	kBq	1.68E-03	1.77E-03	1.53E-03	1.61E-03
	Chromium	air	kg	1.93E-07	1.98E-07	2.28E-07	2.33E-07
	Chromium VI	air	kg	5.33E-09	5.47E-09	6.21E-09	6.32E-09
	Dinitrogen monoxide	air	kg	3.30E-05	3.31E-05	3.18E-05	3.19E-05
	Iodine-129	air	kBq	1.03E-06	1.08E-06	9.39E-07	9.86E-07
	Lead	air	kg	5.61E-08	5.68E-08	5.59E-08	5.65E-08
	Methane, fossil	air	kg	2.28E-03	2.28E-03	2.20E-03	2.20E-03
	Mercury	air	kg	3.31E-08	3.32E-08	3.22E-08	3.23E-08
	Nickel	air	kg	1.03E-07	1.03E-07	1.08E-07	1.08E-07
	Nitrogen oxides	air	kg	5.26E-04	5.30E-04	7.51E-04	7.54E-04
	NMVOC total	air	kg	6.59E-05	6.71E-05	7.06E-05	7.16E-05
	thereof:						
	Benzene	air	kg	1.94E-06	1.94E-06	2.02E-06	2.03E-06
	Benzo(a)pyrene	air	kg	9.05E-11	9.58E-11	9.46E-11	9.92E-11
	Formaldehyde	air	kg	4.79E-07	4.81E-07	4.73E-07	4.74E-07
	PAH	air	kg	2.20E-08	2.24E-08	2.16E-08	2.19E-08
	PM2.5-10	air	kg	2.19E-05	2.26E-05	2.24E-05	2.29E-05
	PM2.5	air	kg	4.98E-05	5.04E-05	4.93E-05	4.98E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.42E-14	6.47E-14	7.46E-14	7.51E-14
	Radon-222	air	kBq	1.91E+01	2.01E+01	1.75E+01	1.83E+01
	Sulfur dioxide	air	kg	3.17E-04	3.19E-04	3.20E-04	3.22E-04
Emissions to Water							
	Ammonium, ion	water	kg	9.74E-07	9.84E-07	3.92E-06	3.93E-06
	Arsenic, ion	water	kg	1.26E-07	1.28E-07	1.24E-07	1.26E-07
	Cadmium, ion	water	kg	1.40E-08	1.52E-08	1.41E-08	1.51E-08
	Carbon-14	water	kBq	4.45E-04	4.68E-04	4.06E-04	4.26E-04
	Cesium-137	water	kBq	1.92E-04	2.02E-04	1.75E-04	1.84E-04
	Chromium, ion	water	kg	1.89E-08	1.93E-08	1.83E-08	1.86E-08
	Chromium VI	water	kg	2.94E-07	3.25E-07	3.03E-07	3.29E-07
	COD	water	kg	1.27E-04	1.31E-04	2.01E-04	2.05E-04
	Copper, ion	water	kg	5.05E-07	5.14E-07	5.17E-07	5.24E-07
	Lead	water	kg	2.21E-07	2.24E-07	2.22E-07	2.25E-07
	Mercury	water	kg	3.10E-09	3.30E-09	3.11E-09	3.28E-09
	Nickel, ion	water	kg	1.19E-06	1.25E-06	1.32E-06	1.37E-06
	Nitrate	water	kg	2.66E-05	2.66E-05	3.44E-05	3.44E-05
	Oils, unspecified	water	kg	2.39E-05	2.44E-05	2.53E-05	2.57E-05
	PAH	water	kg	6.03E-09	6.26E-09	6.88E-09	7.09E-09
	Phosphate	water	kg	2.96E-06	3.09E-06	5.91E-06	6.02E-06
Emissions to Soil							
	Arsenic	soil	kg	1.65E-10	1.67E-10	1.58E-10	1.60E-10
	Cadmium	soil	kg	7.46E-12	7.95E-12	1.03E-11	1.07E-11
	Chromium	soil	kg	2.19E-09	2.22E-09	2.22E-09	2.25E-09
	Chromium VI	soil	kg	1.86E-08	1.97E-08	1.68E-08	1.78E-08
	Lead	soil	kg	5.56E-11	5.86E-11	9.49E-11	9.75E-11
	Mercury	soil	kg	5.76E-13	5.81E-13	6.61E-13	6.66E-13
	Oils, unspecified	soil	kg	2.38E-05	2.42E-05	2.52E-05	2.55E-05

Table 8.31 LCA results for year 2050, realistic-optimistic development, “440 ppm-scenario”.

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.35E-01	8.35E-01	7.58E-01
	Coal, hard, unspecified, in ground	resource	kg	1.07E-03	1.20E-03	5.32E-04
	Gas, natural, in ground	resource	Nm3	7.50E-03	8.11E-03	2.06E-03
	Oil, crude, in ground	resource	kg	2.58E-03	2.68E-03	7.04E-04
	Uranium, in ground	resource	kg	2.63E-07	2.94E-07	9.12E-08
	Freshwater (lake, river, groundwater)	resource	m3	4.43E-03	4.45E-03	3.88E-03
	Occupation, agricultural and forestal area	resource	m2a	1.64E-03	1.71E-03	8.13E-04
	Occupation, built up area incl. mineral extractio	resource	m2a	1.10E-03	1.13E-03	9.21E-04
Emissions to air						
	Ammonia	air	kg	2.37E-04	2.37E-04	4.35E-06
	Arsenic	air	kg	7.63E-09	7.72E-09	6.10E-09
	Cadmium	air	kg	1.44E-09	1.47E-09	7.02E-10
	Carbon dioxide, fossil	air	kg	1.02E-01	1.02E-01	7.31E-01
	Carbon monoxide, fossil	air	kg	1.84E-04	1.89E-04	1.52E-04
	Carbon-14	air	kBq	7.42E-04	8.31E-04	2.57E-04
	Chromium	air	kg	7.58E-08	8.15E-08	3.96E-08
	Chromium VI	air	kg	2.00E-09	2.13E-09	1.10E-09
	Dinitrogen monoxide	air	kg	1.99E-05	2.00E-05	1.76E-05
	Iodine-129	air	kBq	4.55E-07	5.10E-07	1.59E-07
	Lead	air	kg	1.36E-08	1.43E-08	8.37E-09
	Methane, fossil	air	kg	2.34E-04	2.37E-04	1.92E-04
	Mercury	air	kg	1.87E-08	1.88E-08	1.60E-08
	Nickel	air	kg	2.11E-08	2.15E-08	9.95E-09
	Nitrogen oxides	air	kg	6.63E-04	6.67E-04	5.79E-04
	NMVOC total	air	kg	3.39E-05	3.51E-05	1.89E-05
	thereof:					
	Benzene	air	kg	1.81E-06	1.81E-06	1.47E-06
	Benzo(a)pyrene	air	kg	6.59E-11	7.13E-11	3.90E-11
	Formaldehyde	air	kg	4.71E-07	4.73E-07	4.09E-07
	PAH	air	kg	1.23E-08	1.27E-08	9.30E-09
	PM2.5-10	air	kg	1.28E-05	1.35E-05	9.04E-06
	PM2.5	air	kg	5.78E-05	5.84E-05	5.02E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.89E-14	6.95E-14	4.93E-14
	Radon-222	air	kBq	8.46E+00	9.47E+00	2.96E+00
	Sulfur dioxide	air	kg	1.28E-04	1.29E-04	1.07E-04
Emissions to Water						
	Ammonium, ion	water	kg	3.63E-06	3.64E-06	4.63E-08
	Arsenic, ion	water	kg	8.15E-07	8.16E-07	7.31E-07
	Cadmium, ion	water	kg	2.91E-08	3.03E-08	2.29E-08
	Carbon-14	water	kBq	1.97E-04	2.20E-04	6.85E-05
	Cesium-137	water	kBq	8.48E-05	9.49E-05	2.96E-05
	Chromium, ion	water	kg	2.04E-09	2.36E-09	8.47E-10
	Chromium VI	water	kg	7.12E-07	7.43E-07	5.61E-07
	COD	water	kg	1.20E-04	1.24E-04	2.41E-05
	Copper, ion	water	kg	9.01E-07	9.11E-07	7.67E-07
	Lead	water	kg	8.64E-07	8.67E-07	7.61E-07
	Mercury	water	kg	5.22E-09	5.42E-09	4.21E-09
	Nickel, ion	water	kg	1.72E-06	1.79E-06	1.35E-06
	Nitrate	water	kg	1.04E-05	1.04E-05	1.11E-07
	Oils, unspecified	water	kg	7.16E-06	7.65E-06	3.33E-06
	PAH	water	kg	2.43E-09	2.67E-09	1.20E-09
	Phosphate	water	kg	3.15E-05	3.16E-05	2.55E-05
Emissions to Soil						
	Arsenic	soil	kg	5.62E-11	5.85E-11	1.28E-11
	Cadmium	soil	kg	8.60E-12	9.10E-12	3.43E-12
	Chromium	soil	kg	9.15E-10	9.49E-10	2.09E-10
	Chromium VI	soil	kg	6.41E-09	7.54E-09	5.01E-10
	Lead	soil	kg	7.84E-11	8.15E-11	2.22E-11
	Mercury	soil	kg	1.97E-13	2.02E-13	5.69E-14
	Oils, unspecified	soil	kg	6.37E-06	6.75E-06	3.02E-06

Table 8.32 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.35E-01	8.70E-01	8.70E-01
	Coal, hard, unspecified, in ground	resource	kg	1.35E-03	9.01E-04	1.05E-03
	Gas, natural, in ground	resource	Nm3	1.37E-02	5.36E-03	6.06E-03
	Oil, crude, in ground	resource	kg	2.78E-03	9.08E-04	1.02E-03
	Uranium, in ground	resource	kg	5.86E-07	2.71E-07	3.07E-07
	Freshwater (lake, river, groundwater)	resource	m3	4.65E-03	4.57E-03	4.61E-03
	Occupation, agricultural and forestal area	resource	m2a	2.25E-03	1.29E-03	1.37E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.15E-03	1.11E-03	1.14E-03
Emissions to air						
	Ammonia	air	kg	2.37E-04	2.21E-06	2.28E-06
	Arsenic	air	kg	8.18E-09	7.38E-09	7.48E-09
	Cadmium	air	kg	1.65E-09	8.40E-10	8.76E-10
	Carbon dioxide, fossil	air	kg	1.05E-01	1.61E-02	1.70E-02
	Carbon monoxide, fossil	air	kg	1.93E-04	1.84E-04	1.89E-04
	Carbon-14	air	kBq	1.67E-03	7.73E-04	8.76E-04
	Chromium	air	kg	8.57E-08	6.15E-08	6.80E-08
	Chromium VI	air	kg	2.24E-09	1.65E-09	1.81E-09
	Dinitrogen monoxide	air	kg	2.06E-05	2.05E-05	2.06E-05
	Iodine-129	air	kBq	1.02E-06	4.74E-07	5.36E-07
	Lead	air	kg	1.62E-08	1.16E-08	1.24E-08
	Methane, fossil	air	kg	2.55E-04	2.31E-04	2.34E-04
	Mercury	air	kg	1.89E-08	1.88E-08	1.89E-08
	Nickel	air	kg	2.29E-08	1.04E-08	1.09E-08
	Nitrogen oxides	air	kg	6.76E-04	2.65E-04	2.69E-04
	NMVOC total	air	kg	4.07E-05	2.57E-05	2.71E-05
	thereof:					
	Benzene	air	kg	1.82E-06	1.69E-06	1.69E-06
	Benzo(a)pyrene	air	kg	7.74E-11	5.79E-11	6.40E-11
	Formaldehyde	air	kg	4.80E-07	4.74E-07	4.75E-07
	PAH	air	kg	1.45E-08	1.21E-08	1.26E-08
	PM2.5-10	air	kg	1.39E-05	1.17E-05	1.24E-05
	PM2.5	air	kg	5.89E-05	5.87E-05	5.94E-05
	PCDD/F (measured as I-TEQ)	air	kg	7.03E-14	5.80E-14	5.86E-14
	Radon-222	air	kBq	1.90E+01	8.81E+00	9.97E+00
	Sulfur dioxide	air	kg	1.36E-04	1.14E-04	1.15E-04
Emissions to Water						
	Ammonium, ion	water	kg	3.73E-06	1.02E-07	1.14E-07
	Arsenic, ion	water	kg	8.18E-07	8.45E-07	8.47E-07
	Cadmium, ion	water	kg	3.09E-08	2.88E-08	3.01E-08
	Carbon-14	water	kBq	4.43E-04	2.05E-04	2.32E-04
	Cesium-137	water	kBq	1.90E-04	8.83E-05	9.99E-05
	Chromium, ion	water	kg	3.30E-09	1.84E-09	2.21E-09
	Chromium VI	water	kg	7.57E-07	7.05E-07	7.41E-07
	COD	water	kg	1.29E-04	3.31E-05	3.75E-05
	Copper, ion	water	kg	9.19E-07	9.00E-07	9.10E-07
	Lead	water	kg	8.74E-07	8.87E-07	8.91E-07
	Mercury	water	kg	5.50E-09	5.19E-09	5.42E-09
	Nickel, ion	water	kg	1.82E-06	1.68E-06	1.76E-06
	Nitrate	water	kg	1.06E-05	2.46E-07	2.76E-07
	Oils, unspecified	water	kg	8.21E-06	4.43E-06	4.99E-06
	PAH	water	kg	2.81E-09	1.89E-09	2.17E-09
	Phosphate	water	kg	3.17E-05	2.95E-05	2.97E-05
Emissions to Soil						
	Arsenic	soil	kg	1.25E-10	5.12E-11	5.38E-11
	Cadmium	soil	kg	9.53E-12	4.80E-12	5.37E-12
	Chromium	soil	kg	1.80E-09	7.01E-10	7.40E-10
	Chromium VI	soil	kg	1.82E-08	6.66E-09	7.97E-09
	Lead	soil	kg	8.60E-11	2.94E-11	3.29E-11
	Mercury	soil	kg	2.24E-13	7.90E-14	8.50E-14
	Oils, unspecified	soil	kg	7.13E-06	3.78E-06	4.22E-06

Table 8.33 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.70E-01	8.70E-01	8.35E-01
	Coal, hard, unspecified, in ground	resource	kg	1.08E-03	1.22E-03	1.23E-03
	Gas, natural, in ground	resource	Nm3	1.17E-02	1.25E-02	1.30E-02
	Oil, crude, in ground	resource	kg	1.03E-03	1.14E-03	2.69E-03
	Uranium, in ground	resource	kg	6.08E-07	6.44E-07	5.55E-07
	Freshwater (lake, river, groundwater)	resource	m3	4.80E-03	4.83E-03	4.62E-03
	Occupation, agricultural and forestal area	resource	m2a	1.91E-03	1.99E-03	2.18E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.13E-03	1.16E-03	1.12E-03
Emissions to air						
	Ammonia	air	kg	2.42E-06	2.50E-06	2.37E-04
	Arsenic	air	kg	7.91E-09	8.01E-09	8.09E-09
	Cadmium	air	kg	1.05E-09	1.09E-09	1.62E-09
	Carbon dioxide, fossil	air	kg	1.94E-02	2.03E-02	1.04E-01
	Carbon monoxide, fossil	air	kg	1.89E-04	1.94E-04	1.88E-04
	Carbon-14	air	kBq	1.74E-03	1.84E-03	1.58E-03
	Chromium	air	kg	6.63E-08	7.29E-08	8.00E-08
	Chromium VI	air	kg	1.77E-09	1.93E-09	2.10E-09
	Dinitrogen monoxide	air	kg	2.13E-05	2.14E-05	2.05E-05
	Iodine-129	air	kBq	1.06E-06	1.13E-06	9.68E-07
	Lead	air	kg	1.37E-08	1.45E-08	1.55E-08
	Methane, fossil	air	kg	2.51E-04	2.54E-04	2.52E-04
	Mercury	air	kg	1.89E-08	1.91E-08	1.88E-08
	Nickel	air	kg	1.20E-08	1.25E-08	2.25E-08
	Nitrogen oxides	air	kg	2.74E-04	2.79E-04	6.72E-04
	NMVOC total	air	kg	3.22E-05	3.36E-05	3.95E-05
	thereof:					
	Benzene	air	kg	1.69E-06	1.70E-06	1.82E-06
	Benzo(a)pyrene	air	kg	6.50E-11	7.11E-11	7.21E-11
	Formaldehyde	air	kg	4.82E-07	4.84E-07	4.78E-07
	PAH	air	kg	1.41E-08	1.46E-08	1.41E-08
	PM2.5-10	air	kg	1.21E-05	1.28E-05	1.33E-05
	PM2.5	air	kg	5.94E-05	6.00E-05	5.84E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.89E-14	5.95E-14	6.97E-14
	Radon-222	air	kBq	1.97E+01	2.09E+01	1.80E+01
	Sulfur dioxide	air	kg	1.21E-04	1.22E-04	1.34E-04
Emissions to Water						
	Ammonium, ion	water	kg	1.98E-07	2.10E-07	3.72E-06
	Arsenic, ion	water	kg	8.46E-07	8.48E-07	8.16E-07
	Cadmium, ion	water	kg	2.94E-08	3.08E-08	2.97E-08
	Carbon-14	water	kBq	4.61E-04	4.88E-04	4.19E-04
	Cesium-137	water	kBq	1.98E-04	2.10E-04	1.80E-04
	Chromium, ion	water	kg	2.92E-09	3.29E-09	2.98E-09
	Chromium VI	water	kg	7.22E-07	7.58E-07	7.26E-07
	COD	water	kg	3.84E-05	4.28E-05	1.25E-04
	Copper, ion	water	kg	9.10E-07	9.20E-07	9.10E-07
	Lead	water	kg	8.95E-07	8.99E-07	8.71E-07
	Mercury	water	kg	5.28E-09	5.51E-09	5.30E-09
	Nickel, ion	water	kg	1.72E-06	1.79E-06	1.75E-06
	Nitrate	water	kg	4.85E-07	5.14E-07	1.06E-05
	Oils, unspecified	water	kg	5.06E-06	5.63E-06	7.72E-06
	PAH	water	kg	2.04E-09	2.32E-09	2.56E-09
	Phosphate	water	kg	2.96E-05	2.98E-05	3.16E-05
Emissions to Soil						
	Arsenic	soil	kg	1.28E-10	1.31E-10	1.23E-10
	Cadmium	soil	kg	5.29E-12	5.87E-12	9.03E-12
	Chromium	soil	kg	1.68E-09	1.72E-09	1.76E-09
	Chromium VI	soil	kg	1.90E-08	2.03E-08	1.71E-08
	Lead	soil	kg	3.46E-11	3.81E-11	8.29E-11
	Mercury	soil	kg	1.04E-13	1.10E-13	2.19E-13
	Oils, unspecified	soil	kg	4.22E-06	4.66E-06	6.75E-06

Table 8.34 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	3.34E-05	4.21E-01
Coal, hard, unspecified, in ground	resource	kg	3.29E-01	5.29E-04
Gas, natural, in ground	resource	Nm3	2.67E-03	1.22E-03
Oil, crude, in ground	resource	kg	4.06E-03	9.52E-04
Uranium, in ground	resource	kg	1.30E-07	6.48E-08
Freshwater (lake, river, groundwater)	resource	m3	6.02E-04	1.57E-03
Occupation, agricultural and forestal area	resource	m2a	1.52E-02	4.08E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.75E-03	1.00E-03
Emissions to air				
Ammonia	air	kg	1.39E-05	5.60E-07
Arsenic	air	kg	5.94E-08	4.74E-09
Cadmium	air	kg	1.10E-09	6.75E-10
Carbon dioxide, fossil	air	kg	6.32E-01	7.68E-01
Carbon monoxide, fossil	air	kg	1.21E-04	7.89E-05
Carbon-14	air	kBq	3.64E-04	1.75E-04
Chromium	air	kg	4.25E-08	3.47E-08
Chromium VI	air	kg	1.37E-09	9.41E-10
Dinitrogen monoxide	air	kg	2.67E-05	2.46E-05
Iodine-129	air	kBq	2.24E-07	1.09E-07
Lead	air	kg	3.29E-08	7.59E-09
Methane, fossil	air	kg	1.83E-03	1.17E-04
Mercury	air	kg	1.92E-08	1.08E-08
Nickel	air	kg	7.68E-08	6.04E-09
Nitrogen oxides	air	kg	4.11E-04	3.88E-04
NMVOC total	air	kg	4.77E-05	2.03E-05
thereof:				
Benzene	air	kg	1.16E-06	9.61E-07
Benzo(a)pyrene	air	kg	5.75E-11	2.92E-11
Formaldehyde	air	kg	2.69E-07	2.65E-07
PAH	air	kg	5.26E-08	4.51E-08
PM2.5-10	air	kg	1.32E-05	3.25E-06
PM2.5	air	kg	8.99E-06	2.39E-06
PCDD/F (measured as I-TEQ)	air	kg	4.47E-14	4.38E-14
Radon-222	air	kBq	4.21E+00	2.10E+00
Sulfur dioxide	air	kg	3.48E-04	5.68E-04
Emissions to Water				
Ammonium, ion	water	kg	3.62E-07	6.13E-08
Arsenic, ion	water	kg	7.84E-08	1.29E-06
Cadmium, ion	water	kg	1.20E-08	7.98E-08
Carbon-14	water	kBq	9.66E-05	4.68E-05
Cesium-137	water	kBq	4.18E-05	2.04E-05
Chromium, ion	water	kg	1.94E-09	8.35E-10
Chromium VI	water	kg	7.01E-07	8.24E-06
COD	water	kg	2.12E-04	1.84E-03
Copper, ion	water	kg	1.26E-06	5.96E-06
Lead	water	kg	3.20E-07	1.66E-06
Mercury	water	kg	4.76E-09	5.39E-08
Nickel, ion	water	kg	5.80E-07	3.47E-06
Nitrate	water	kg	1.19E-06	7.06E-07
Oils, unspecified	water	kg	1.80E-05	3.06E-06
PAH	water	kg	2.43E-09	1.08E-09
Phosphate	water	kg	6.83E-06	9.73E-05
Emissions to Soil				
Arsenic	soil	kg	5.25E-11	1.12E-11
Cadmium	soil	kg	6.06E-12	5.40E-12
Chromium	soil	kg	7.66E-10	2.23E-10
Chromium VI	soil	kg	2.39E-09	6.52E-10
Lead	soil	kg	4.90E-11	4.20E-11
Mercury	soil	kg	5.50E-13	1.89E-13
Oils, unspecified	soil	kg	1.82E-05	2.79E-06

Table 8.35 LCA results for year 2050, realistic-optimistic development, "440 ppm-scenario".

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.59E-05	4.71E-05	4.05E-05	4.17E-05
Coal, hard, unspecified, in ground	resource	kg	3.70E-01	3.70E-01	3.70E-01	3.70E-01
Gas, natural, in ground	resource	Nm3	1.10E-02	1.16E-02	5.64E-03	6.22E-03
Oil, crude, in ground	resource	kg	4.78E-03	4.88E-03	4.68E-03	4.77E-03
Uranium, in ground	resource	kg	5.65E-07	5.95E-07	2.84E-07	3.14E-07
Freshwater (lake, river, groundwater)	resource	m3	9.64E-04	9.91E-04	7.75E-04	8.02E-04
Occupation, agricultural and forestal area	resource	m2a	1.78E-02	1.79E-02	1.73E-02	1.74E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.23E-03	4.26E-03	4.22E-03	4.24E-03
Emissions to air						
Ammonia	air	kg	1.59E-05	1.60E-05	1.57E-05	1.58E-05
Arsenic	air	kg	7.43E-08	7.43E-08	7.38E-08	7.39E-08
Cadmium	air	kg	1.50E-09	1.53E-09	1.32E-09	1.35E-09
Carbon dioxide, fossil	air	kg	1.02E-01	1.02E-01	9.89E-02	9.96E-02
Carbon monoxide, fossil	air	kg	1.52E-04	1.57E-04	1.49E-04	1.53E-04
Carbon-14	air	kBq	1.61E-03	1.70E-03	8.05E-04	8.91E-04
Chromium	air	kg	5.83E-08	6.38E-08	5.43E-08	5.98E-08
Chromium VI	air	kg	1.83E-09	1.96E-09	1.73E-09	1.86E-09
Dinitrogen monoxide	air	kg	3.41E-05	3.42E-05	3.35E-05	3.36E-05
Iodine-129	air	kBq	9.88E-07	1.04E-06	4.94E-07	5.47E-07
Lead	air	kg	4.27E-08	4.34E-08	4.10E-08	4.16E-08
Methane, fossil	air	kg	2.08E-03	2.08E-03	2.06E-03	2.06E-03
Mercury	air	kg	2.40E-08	2.42E-08	2.39E-08	2.41E-08
Nickel	air	kg	8.96E-08	9.00E-08	8.83E-08	8.87E-08
Nitrogen oxides	air	kg	4.95E-04	4.99E-04	4.87E-04	4.91E-04
NMVOC total	air	kg	6.39E-05	6.51E-05	5.85E-05	5.97E-05
thereof:						
Benzene	air	kg	1.43E-06	1.43E-06	1.42E-06	1.43E-06
Benzo(a)pyrene	air	kg	7.66E-11	8.17E-11	7.07E-11	7.58E-11
Formaldehyde	air	kg	3.45E-07	3.46E-07	3.38E-07	3.39E-07
PAH	air	kg	6.71E-08	6.75E-08	6.55E-08	6.58E-08
PM2.5-10	air	kg	1.59E-05	1.65E-05	1.55E-05	1.61E-05
PM2.5	air	kg	1.13E-05	1.18E-05	1.08E-05	1.13E-05
PCDD/F (measured as I-TEQ)	air	kg	5.54E-14	5.59E-14	5.46E-14	5.51E-14
Radon-222	air	kBq	1.84E+01	1.93E+01	9.22E+00	1.02E+01
Sulfur dioxide	air	kg	4.23E-04	4.25E-04	4.17E-04	4.19E-04
Emissions to Water						
Ammonium, ion	water	kg	5.28E-07	5.37E-07	4.47E-07	4.57E-07
Arsenic, ion	water	kg	8.97E-08	9.14E-08	8.86E-08	9.03E-08
Cadmium, ion	water	kg	1.51E-08	1.62E-08	1.45E-08	1.57E-08
Carbon-14	water	kBq	4.27E-04	4.50E-04	2.14E-04	2.36E-04
Cesium-137	water	kBq	1.84E-04	1.94E-04	9.21E-05	1.02E-04
Chromium, ion	water	kg	3.72E-09	4.04E-09	2.82E-09	3.13E-09
Chromium VI	water	kg	8.26E-07	8.56E-07	8.12E-07	8.42E-07
COD	water	kg	2.45E-04	2.49E-04	2.41E-04	2.44E-04
Copper, ion	water	kg	1.41E-06	1.42E-06	1.41E-06	1.41E-06
Lead	water	kg	3.63E-07	3.66E-07	3.57E-07	3.60E-07
Mercury	water	kg	5.56E-09	5.75E-09	5.49E-09	5.68E-09
Nickel, ion	water	kg	7.43E-07	8.07E-07	7.14E-07	7.78E-07
Nitrate	water	kg	1.63E-06	1.66E-06	1.43E-06	1.46E-06
Oils, unspecified	water	kg	2.13E-05	2.18E-05	2.08E-05	2.13E-05
PAH	water	kg	3.11E-09	3.34E-09	2.98E-09	3.21E-09
Phosphate	water	kg	7.81E-06	7.94E-06	7.73E-06	7.86E-06
Emissions to Soil						
Arsenic	soil	kg	1.55E-10	1.57E-10	9.02E-11	9.23E-11
Cadmium	soil	kg	7.76E-12	8.25E-12	7.36E-12	7.84E-12
Chromium	soil	kg	2.08E-09	2.11E-09	1.26E-09	1.29E-09
Chromium VI	soil	kg	1.80E-08	1.91E-08	7.74E-09	8.83E-09
Lead	soil	kg	6.33E-11	6.63E-11	5.90E-11	6.19E-11
Mercury	soil	kg	6.49E-13	6.54E-13	6.29E-13	6.34E-13
Oils, unspecified	soil	kg	2.13E-05	2.16E-05	2.09E-05	2.13E-05

Table 8.36 LCA results for year 2050, realistic-optimistic development, “440 ppm-scenario”.

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.75E-01	4.75E-01	4.75E-01	4.75E-01
Coal, hard, unspecified, in ground	resource	kg	9.84E-04	1.14E-03	7.99E-04	9.50E-04
Gas, natural, in ground	resource	Nm3	1.14E-02	1.21E-02	4.70E-03	5.43E-03
Oil, crude, in ground	resource	kg	1.36E-03	1.48E-03	1.23E-03	1.35E-03
Uranium, in ground	resource	kg	5.97E-07	6.35E-07	2.46E-07	2.83E-07
Freshwater (lake, river, groundwater)	resource	m3	2.13E-03	2.17E-03	1.90E-03	1.93E-03
Occupation, agricultural and forestal area	resource	m2a	1.43E-03	1.52E-03	7.89E-04	8.71E-04
Occupation, built up area incl. mineral extractio	resource	m2a	1.16E-03	1.20E-03	1.14E-03	1.17E-03
Emissions to air						
Ammonia	air	kg	1.01E-06	1.08E-06	7.82E-07	8.56E-07
Arsenic	air	kg	6.49E-09	6.59E-09	5.94E-09	6.04E-09
Cadmium	air	kg	1.07E-09	1.10E-09	8.45E-10	8.83E-10
Carbon dioxide, fossil	air	kg	1.10E-01	1.10E-01	1.06E-01	1.07E-01
Carbon monoxide, fossil	air	kg	1.09E-04	1.15E-04	1.04E-04	1.10E-04
Carbon-14	air	kBq	1.70E-03	1.81E-03	6.94E-04	8.01E-04
Chromium	air	kg	5.22E-08	5.90E-08	4.71E-08	5.40E-08
Chromium VI	air	kg	1.39E-09	1.56E-09	1.27E-09	1.43E-09
Dinitrogen monoxide	air	kg	3.21E-05	3.22E-05	3.13E-05	3.14E-05
Iodine-129	air	kBq	1.04E-06	1.11E-06	4.26E-07	4.92E-07
Lead	air	kg	1.24E-08	1.32E-08	1.02E-08	1.10E-08
Methane, fossil	air	kg	1.66E-04	1.70E-04	1.45E-04	1.48E-04
Mercury	air	kg	1.38E-08	1.40E-08	1.37E-08	1.39E-08
Nickel	air	kg	9.59E-09	1.01E-08	7.93E-09	8.44E-09
Nitrogen oxides	air	kg	5.04E-04	5.09E-04	4.94E-04	4.99E-04
NMVOC total	air	kg	3.56E-05	3.71E-05	2.88E-05	3.03E-05
thereof:						
Benzene	air	kg	1.23E-06	1.24E-06	1.23E-06	1.23E-06
Benzo(a)pyrene	air	kg	4.81E-11	5.45E-11	4.08E-11	4.72E-11
Formaldehyde	air	kg	3.45E-07	3.47E-07	3.36E-07	3.38E-07
PAH	air	kg	5.97E-08	6.02E-08	5.77E-08	5.82E-08
PM2.5-10	air	kg	4.97E-06	5.73E-06	4.49E-06	5.24E-06
PM2.5	air	kg	4.18E-06	4.81E-06	3.52E-06	4.16E-06
PCDD/F (measured as I-TEQ)	air	kg	5.50E-14	5.57E-14	5.41E-14	5.47E-14
Radon-222	air	kBq	1.94E+01	2.06E+01	7.98E+00	9.19E+00
Sulfur dioxide	air	kg	7.26E-04	7.27E-04	7.18E-04	7.20E-04
Emissions to Water						
Ammonium, ion	water	kg	2.20E-07	2.32E-07	1.19E-07	1.32E-07
Arsenic, ion	water	kg	1.44E-06	1.44E-06	1.44E-06	1.44E-06
Cadmium, ion	water	kg	9.11E-08	9.26E-08	9.04E-08	9.19E-08
Carbon-14	water	kBq	4.51E-04	4.80E-04	1.84E-04	2.12E-04
Cesium-137	water	kBq	1.94E-04	2.06E-04	7.95E-05	9.17E-05
Chromium, ion	water	kg	2.88E-09	3.27E-09	1.75E-09	2.14E-09
Chromium VI	water	kg	9.24E-06	9.27E-06	9.22E-06	9.26E-06
COD	water	kg	2.06E-03	2.07E-03	2.06E-03	2.06E-03
Copper, ion	water	kg	6.66E-06	6.67E-06	6.65E-06	6.66E-06
Lead	water	kg	1.86E-06	1.87E-06	1.86E-06	1.86E-06
Mercury	water	kg	6.05E-08	6.07E-08	6.04E-08	6.06E-08
Nickel, ion	water	kg	3.99E-06	4.07E-06	3.95E-06	4.03E-06
Nitrate	water	kg	1.16E-06	1.19E-06	9.13E-07	9.43E-07
Oils, unspecified	water	kg	4.88E-06	5.47E-06	4.22E-06	4.81E-06
PAH	water	kg	1.70E-09	1.99E-09	1.53E-09	1.83E-09
Phosphate	water	kg	1.09E-04	1.09E-04	1.09E-04	1.09E-04
Emissions to Soil						
Arsenic	soil	kg	1.32E-10	1.35E-10	5.16E-11	5.43E-11
Cadmium	soil	kg	7.29E-12	7.89E-12	6.78E-12	7.38E-12
Chromium	soil	kg	1.77E-09	1.81E-09	7.50E-10	7.92E-10
Chromium VI	soil	kg	1.99E-08	2.13E-08	7.05E-09	8.41E-09
Lead	soil	kg	5.79E-11	6.16E-11	5.25E-11	5.61E-11
Mercury	soil	kg	2.52E-13	2.59E-13	2.26E-13	2.33E-13
Oils, unspecified	soil	kg	4.18E-06	4.64E-06	3.71E-06	4.18E-06

Table 8.37 LCA results for year 2050, pessimistic development, “440 ppm-scenario”.

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.29E-05	8.01E-05	8.01E-05
	Coal, hard, unspecified, in ground	resource	kg	3.82E-01	3.82E-01	3.82E-01
	Gas, natural, in ground	resource	Nm3	3.52E-03	3.50E-03	3.50E-03
	Oil, crude, in ground	resource	kg	4.92E-03	4.91E-03	4.91E-03
	Uranium, in ground	resource	kg	1.55E-07	1.54E-07	1.54E-07
	Freshwater (lake, river, groundwater)	resource	m3	1.95E-03	1.95E-03	1.95E-03
	Occupation, agricultural and forestal area	resource	m2a	1.78E-02	1.77E-02	1.77E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	4.14E-03	4.13E-03	4.13E-03
Emissions to air						
	Ammonia	air	kg	1.86E-05	1.86E-05	1.86E-05
	Arsenic	air	kg	1.39E-08	1.37E-08	1.37E-08
	Cadmium	air	kg	1.47E-09	1.44E-09	1.44E-09
	Carbon dioxide, fossil	air	kg	6.88E-01	6.88E-01	6.88E-01
	Carbon monoxide, fossil	air	kg	1.42E-04	1.41E-04	1.41E-04
	Carbon-14	air	kBq	3.17E-04	3.15E-04	3.15E-04
	Chromium	air	kg	1.52E-07	1.36E-07	1.35E-07
	Chromium VI	air	kg	4.31E-09	3.89E-09	3.88E-09
	Dinitrogen monoxide	air	kg	3.01E-05	3.01E-05	3.01E-05
	Iodine-129	air	kBq	2.70E-07	2.69E-07	2.69E-07
	Lead	air	kg	5.71E-08	5.62E-08	5.62E-08
	Methane, fossil	air	kg	2.12E-03	2.12E-03	2.12E-03
	Mercury	air	kg	3.08E-08	3.08E-08	3.08E-08
	Nickel	air	kg	9.85E-08	9.81E-08	9.81E-08
	Nitrogen oxides	air	kg	7.10E-04	7.09E-04	7.09E-04
	NMVOC total	air	kg	5.40E-05	5.39E-05	5.39E-05
	thereof:					
	Benzene	air	kg	1.81E-06	1.81E-06	1.81E-06
	Benzo(a)pyrene	air	kg	1.14E-10	1.10E-10	1.10E-10
	Formaldehyde	air	kg	4.41E-07	4.40E-07	4.40E-07
	PAH	air	kg	1.84E-08	1.83E-08	1.83E-08
	PM2.5-10	air	kg	1.96E-05	1.94E-05	1.94E-05
	PM2.5	air	kg	4.60E-05	4.58E-05	4.57E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.27E-14	6.23E-14	6.23E-14
	Radon-222	air	kBq	5.03E+00	5.01E+00	5.01E+00
	Sulfur dioxide	air	kg	5.13E-04	5.13E-04	5.13E-04
Emissions to Water						
	Ammonium, ion	water	kg	7.84E-07	7.83E-07	7.83E-07
	Arsenic, ion	water	kg	1.14E-07	1.13E-07	1.13E-07
	Cadmium, ion	water	kg	1.09E-08	1.07E-08	1.06E-08
	Carbon-14	water	kBq	1.08E-04	1.08E-04	1.08E-04
	Cesium-137	water	kBq	5.05E-05	5.02E-05	5.02E-05
	Chromium, ion	water	kg	1.56E-08	1.55E-08	1.55E-08
	Chromium VI	water	kg	2.24E-07	2.18E-07	2.18E-07
	COD	water	kg	1.11E-04	1.10E-04	1.10E-04
	Copper, ion	water	kg	4.35E-07	4.31E-07	4.30E-07
	Lead	water	kg	1.86E-07	1.82E-07	1.81E-07
	Mercury	water	kg	2.53E-09	2.51E-09	2.51E-09
	Nickel, ion	water	kg	9.50E-07	8.88E-07	8.87E-07
	Nitrate	water	kg	2.36E-05	2.36E-05	2.36E-05
	Oils, unspecified	water	kg	2.15E-05	2.14E-05	2.14E-05
	PAH	water	kg	4.91E-09	4.56E-09	4.56E-09
	Phosphate	water	kg	2.55E-06	2.52E-06	2.52E-06
Emissions to Soil						
	Arsenic	soil	kg	6.38E-11	6.36E-11	6.35E-11
	Cadmium	soil	kg	6.18E-12	6.10E-12	6.10E-12
	Chromium	soil	kg	9.04E-10	9.00E-10	9.00E-10
	Chromium VI	soil	kg	2.68E-09	2.66E-09	2.66E-09
	Lead	soil	kg	4.53E-11	4.48E-11	4.47E-11
	Mercury	soil	kg	5.19E-13	5.18E-13	5.18E-13
	Oils, unspecified	soil	kg	2.18E-05	2.17E-05	2.17E-05

Table 8.38 LCA results for year 2050, pessimistic development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	9.89E-05	1.01E-04	1.19E-04	1.21E-04
Coal, hard, unspecified, in ground	resource	kg	4.56E-01	4.56E-01	4.45E-01	4.45E-01
Gas, natural, in ground	resource	Nm3	7.39E-03	8.13E-03	9.46E-03	1.01E-02
Oil, crude, in ground	resource	kg	5.97E-03	6.08E-03	7.48E-03	7.57E-03
Uranium, in ground	resource	kg	3.49E-07	3.85E-07	3.43E-07	3.75E-07
Freshwater (lake, river, groundwater)	resource	m3	2.45E-03	2.49E-03	2.43E-03	2.46E-03
Occupation, agricultural and forestal area	resource	m2a	2.15E-02	2.16E-02	2.13E-02	2.14E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.97E-03	5.00E-03	4.89E-03	4.91E-03
Emissions to air						
Ammonia	air	kg	2.04E-05	2.05E-05	2.44E-04	2.44E-04
Arsenic	air	kg	1.71E-08	1.73E-08	1.78E-08	1.79E-08
Cadmium	air	kg	1.88E-09	1.93E-09	2.48E-09	2.53E-09
Carbon dioxide, fossil	air	kg	3.12E-02	3.20E-02	1.18E-01	1.19E-01
Carbon monoxide, fossil	air	kg	1.77E-04	1.83E-04	1.79E-04	1.84E-04
Carbon-14	air	kBq	7.17E-04	7.90E-04	7.00E-04	7.64E-04
Chromium	air	kg	1.97E-07	2.04E-07	2.40E-07	2.45E-07
Chromium VI	air	kg	5.52E-09	5.67E-09	6.56E-09	6.69E-09
Dinitrogen monoxide	air	kg	3.62E-05	3.63E-05	3.56E-05	3.56E-05
Iodine-129	air	kBq	6.12E-07	6.74E-07	5.97E-07	6.53E-07
Lead	air	kg	7.14E-08	7.30E-08	7.41E-08	7.55E-08
Methane, fossil	air	kg	2.55E-03	2.55E-03	2.50E-03	2.51E-03
Mercury	air	kg	3.69E-08	3.71E-08	3.66E-08	3.68E-08
Nickel	air	kg	1.18E-07	1.18E-07	1.26E-07	1.26E-07
Nitrogen oxides	air	kg	5.75E-04	5.79E-04	8.49E-04	8.53E-04
NMVOC total	air	kg	6.84E-05	6.98E-05	7.57E-05	7.70E-05
thereof:						
Benzene	air	kg	2.17E-06	2.17E-06	2.31E-06	2.31E-06
Benzo(a)pyrene	air	kg	1.49E-10	1.56E-10	1.59E-10	1.66E-10
Formaldehyde	air	kg	5.28E-07	5.30E-07	5.32E-07	5.33E-07
PAH	air	kg	2.33E-08	2.38E-08	2.35E-08	2.39E-08
PM2.5-10	air	kg	2.43E-05	2.50E-05	2.53E-05	2.59E-05
PM2.5	air	kg	5.56E-05	5.63E-05	5.62E-05	5.67E-05
PCDD/F (measured as I-TEQ)	air	kg	7.68E-14	7.82E-14	8.86E-14	8.99E-14
Radon-222	air	kBq	1.14E+01	1.25E+01	1.11E+01	1.21E+01
Sulfur dioxide	air	kg	3.39E-04	3.41E-04	3.48E-04	3.49E-04
Emissions to Water						
Ammonium, ion	water	kg	1.01E-06	1.02E-06	4.40E-06	4.41E-06
Arsenic, ion	water	kg	1.40E-07	1.41E-07	1.40E-07	1.41E-07
Cadmium, ion	water	kg	1.49E-08	1.62E-08	1.53E-08	1.65E-08
Carbon-14	water	kBq	2.46E-04	2.71E-04	2.40E-04	2.62E-04
Cesium-137	water	kBq	1.14E-04	1.26E-04	1.12E-04	1.22E-04
Chromium, ion	water	kg	2.02E-08	2.06E-08	2.00E-08	2.03E-08
Chromium VI	water	kg	3.10E-07	3.44E-07	3.26E-07	3.56E-07
COD	water	kg	1.38E-04	1.43E-04	2.21E-04	2.25E-04
Copper, ion	water	kg	5.53E-07	5.63E-07	5.77E-07	5.86E-07
Lead	water	kg	2.38E-07	2.41E-07	2.44E-07	2.47E-07
Mercury	water	kg	3.38E-09	3.59E-09	3.46E-09	3.65E-09
Nickel, ion	water	kg	1.25E-06	1.32E-06	1.41E-06	1.47E-06
Nitrate	water	kg	2.97E-05	2.97E-05	3.88E-05	3.89E-05
Oils, unspecified	water	kg	2.61E-05	2.67E-05	2.82E-05	2.87E-05
PAH	water	kg	6.32E-09	6.59E-09	7.36E-09	7.60E-09
Phosphate	water	kg	3.22E-06	3.36E-06	6.22E-06	6.35E-06
Emissions to Soil						
Arsenic	soil	kg	1.12E-10	1.14E-10	1.16E-10	1.18E-10
Cadmium	soil	kg	8.01E-12	8.59E-12	1.14E-11	1.19E-11
Chromium	soil	kg	1.53E-09	1.57E-09	1.72E-09	1.75E-09
Chromium VI	soil	kg	9.01E-09	1.03E-08	8.79E-09	9.89E-09
Lead	soil	kg	5.78E-11	6.13E-11	1.04E-10	1.07E-10
Mercury	soil	kg	6.44E-13	6.52E-13	7.45E-13	7.53E-13
Oils, unspecified	soil	kg	2.63E-05	2.67E-05	2.83E-05	2.86E-05

Table 8.39 LCA results for year 2050, pessimistic development, "440 ppm-scenario".

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	1.08E-04	1.10E-04	1.27E-04	1.29E-04
Coal, hard, unspecified, in ground	resource	kg	4.56E-01	4.56E-01	4.45E-01	4.45E-01
Gas, natural, in ground	resource	Nm3	1.41E-02	1.48E-02	1.53E-02	1.60E-02
Oil, crude, in ground	resource	kg	6.10E-03	6.21E-03	7.59E-03	7.68E-03
Uranium, in ground	resource	kg	6.84E-07	7.20E-07	6.38E-07	6.69E-07
Freshwater (lake, river, groundwater)	resource	m3	2.68E-03	2.71E-03	2.63E-03	2.66E-03
Occupation, agricultural and forestal area	resource	m2a	2.22E-02	2.23E-02	2.20E-02	2.20E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.99E-03	5.02E-03	4.91E-03	4.93E-03
Emissions to air						
Ammonia	air	kg	2.06E-05	2.07E-05	2.44E-04	2.44E-04
Arsenic	air	kg	1.81E-08	1.83E-08	1.86E-08	1.88E-08
Cadmium	air	kg	2.22E-09	2.28E-09	2.79E-09	2.83E-09
Carbon dioxide, fossil	air	kg	3.47E-02	3.55E-02	1.21E-01	1.22E-01
Carbon monoxide, fossil	air	kg	1.82E-04	1.88E-04	1.84E-04	1.89E-04
Carbon-14	air	kBq	1.41E-03	1.48E-03	1.31E-03	1.37E-03
Chromium	air	kg	2.02E-07	2.08E-07	2.44E-07	2.49E-07
Chromium VI	air	kg	5.63E-09	5.79E-09	6.66E-09	6.79E-09
Dinitrogen monoxide	air	kg	3.70E-05	3.71E-05	3.63E-05	3.63E-05
Iodine-129	air	kBq	1.20E-06	1.26E-06	1.12E-06	1.17E-06
Lead	air	kg	7.51E-08	7.67E-08	7.74E-08	7.88E-08
Methane, fossil	air	kg	2.58E-03	2.59E-03	2.53E-03	2.54E-03
Mercury	air	kg	3.70E-08	3.72E-08	3.67E-08	3.69E-08
Nickel	air	kg	1.20E-07	1.21E-07	1.28E-07	1.29E-07
Nitrogen oxides	air	kg	5.86E-04	5.90E-04	8.59E-04	8.63E-04
NMVOC total	air	kg	7.54E-05	7.69E-05	8.19E-05	8.32E-05
thereof:						
Benzene	air	kg	2.17E-06	2.18E-06	2.31E-06	2.32E-06
Benzo(a)pyrene	air	kg	1.60E-10	1.67E-10	1.69E-10	1.75E-10
Formaldehyde	air	kg	5.37E-07	5.39E-07	5.40E-07	5.41E-07
PAH	air	kg	2.54E-08	2.59E-08	2.53E-08	2.58E-08
PM2.5-10	air	kg	2.48E-05	2.55E-05	2.57E-05	2.63E-05
PM2.5	air	kg	5.63E-05	5.70E-05	5.68E-05	5.73E-05
PCDD/F (measured as I-TEQ)	air	kg	7.82E-14	7.96E-14	8.98E-14	9.11E-14
Radon-222	air	kBq	2.22E+01	2.34E+01	2.07E+01	2.17E+01
Sulfur dioxide	air	kg	3.47E-04	3.49E-04	3.55E-04	3.56E-04
Emissions to Water						
Ammonium, ion	water	kg	1.11E-06	1.12E-06	4.49E-06	4.50E-06
Arsenic, ion	water	kg	1.41E-07	1.43E-07	1.41E-07	1.43E-07
Cadmium, ion	water	kg	1.55E-08	1.69E-08	1.59E-08	1.71E-08
Carbon-14	water	kBq	4.83E-04	5.08E-04	4.49E-04	4.71E-04
Cesium-137	water	kBq	2.25E-04	2.36E-04	2.09E-04	2.19E-04
Chromium, ion	water	kg	2.13E-08	2.16E-08	2.10E-08	2.13E-08
Chromium VI	water	kg	3.26E-07	3.61E-07	3.40E-07	3.70E-07
COD	water	kg	1.44E-04	1.48E-04	2.26E-04	2.30E-04
Copper, ion	water	kg	5.62E-07	5.72E-07	5.85E-07	5.94E-07
Lead	water	kg	2.45E-07	2.49E-07	2.51E-07	2.54E-07
Mercury	water	kg	3.47E-09	3.68E-09	3.53E-09	3.73E-09
Nickel, ion	water	kg	1.28E-06	1.36E-06	1.44E-06	1.50E-06
Nitrate	water	kg	2.99E-05	3.00E-05	3.91E-05	3.91E-05
Oils, unspecified	water	kg	2.68E-05	2.73E-05	2.88E-05	2.93E-05
PAH	water	kg	6.47E-09	6.74E-09	7.49E-09	7.73E-09
Phosphate	water	kg	3.31E-06	3.46E-06	6.31E-06	6.43E-06
Emissions to Soil						
Arsenic	soil	kg	1.87E-10	1.90E-10	1.82E-10	1.84E-10
Cadmium	soil	kg	8.53E-12	9.11E-12	1.19E-11	1.24E-11
Chromium	soil	kg	2.48E-09	2.52E-09	2.55E-09	2.59E-09
Chromium VI	soil	kg	2.09E-08	2.21E-08	1.92E-08	2.03E-08
Lead	soil	kg	6.30E-11	6.65E-11	1.08E-10	1.11E-10
Mercury	soil	kg	6.92E-13	7.00E-13	7.88E-13	7.95E-13
Oils, unspecified	soil	kg	2.67E-05	2.71E-05	2.87E-05	2.90E-05

Table 8.40 LCA results for year 2050, pessimistic development, “440 ppm-scenario”.

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	9.51E-01	9.51E-01	8.18E-01
	Coal, hard, unspecified, in ground	resource	kg	1.25E-03	1.41E-03	5.81E-04
	Gas, natural, in ground	resource	Nm3	9.06E-03	9.82E-03	2.38E-03
	Oil, crude, in ground	resource	kg	2.92E-03	3.04E-03	7.58E-04
	Uranium, in ground	resource	kg	3.10E-07	3.47E-07	1.02E-07
	Freshwater (lake, river, groundwater)	resource	m3	5.05E-03	5.09E-03	4.19E-03
	Occupation, agricultural and forestal area	resource	m2a	1.94E-03	2.03E-03	8.91E-04
	Occupation, built up area incl. mineral extractio	resource	m2a	1.25E-03	1.28E-03	9.91E-04
Emissions to air						
	Ammonia	air	kg	2.38E-04	2.38E-04	4.67E-06
	Arsenic	air	kg	1.09E-08	1.11E-08	7.75E-09
	Cadmium	air	kg	2.20E-09	2.26E-09	1.06E-09
	Carbon dioxide, fossil	air	kg	1.15E-01	1.16E-01	7.90E-01
	Carbon monoxide, fossil	air	kg	2.15E-04	2.21E-04	1.67E-04
	Carbon-14	air	kBq	6.31E-04	7.07E-04	2.09E-04
	Chromium	air	kg	8.17E-08	8.82E-08	4.01E-08
	Chromium VI	air	kg	2.16E-09	2.32E-09	1.12E-09
	Dinitrogen monoxide	air	kg	2.27E-05	2.28E-05	1.89E-05
	Iodine-129	air	kBq	5.40E-07	6.05E-07	1.78E-07
	Lead	air	kg	2.61E-08	2.78E-08	1.45E-08
	Methane, fossil	air	kg	2.85E-04	2.90E-04	2.12E-04
	Mercury	air	kg	2.12E-08	2.14E-08	1.74E-08
	Nickel	air	kg	2.86E-08	2.93E-08	1.32E-08
	Nitrogen oxides	air	kg	7.57E-04	7.61E-04	6.26E-04
	NMVOC total	air	kg	3.93E-05	4.08E-05	2.07E-05
	thereof:					
	Benzene	air	kg	2.07E-06	2.08E-06	1.58E-06
	Benzo(a)pyrene	air	kg	1.05E-10	1.12E-10	5.70E-11
	Formaldehyde	air	kg	5.37E-07	5.39E-07	4.41E-07
	PAH	air	kg	1.45E-08	1.50E-08	1.02E-08
	PM2.5-10	air	kg	1.46E-05	1.53E-05	9.71E-06
	PM2.5	air	kg	6.63E-05	6.69E-05	5.44E-05
	PCDD/F (measured as I-TEQ)	air	kg	8.30E-14	8.45E-14	5.63E-14
	Radon-222	air	kBq	9.99E+00	1.12E+01	3.31E+00
	Sulfur dioxide	air	kg	1.35E-04	1.36E-04	1.16E-04
Emissions to Water						
	Ammonium, ion	water	kg	4.15E-06	4.16E-06	5.31E-08
	Arsenic, ion	water	kg	9.27E-07	9.29E-07	7.89E-07
	Cadmium, ion	water	kg	3.26E-08	3.40E-08	2.45E-08
	Carbon-14	water	kBq	2.17E-04	2.43E-04	7.17E-05
	Cesium-137	water	kBq	1.01E-04	1.13E-04	3.34E-05
	Chromium, ion	water	kg	2.30E-09	2.68E-09	8.97E-10
	Chromium VI	water	kg	8.00E-07	8.36E-07	6.00E-07
	COD	water	kg	1.33E-04	1.38E-04	2.61E-05
	Copper, ion	water	kg	1.02E-06	1.03E-06	8.26E-07
	Lead	water	kg	9.81E-07	9.85E-07	8.20E-07
	Mercury	water	kg	5.90E-09	6.12E-09	4.52E-09
	Nickel, ion	water	kg	1.93E-06	2.01E-06	1.44E-06
	Nitrate	water	kg	1.16E-05	1.16E-05	1.29E-07
	Oils, unspecified	water	kg	8.06E-06	8.63E-06	3.56E-06
	PAH	water	kg	2.65E-09	2.92E-09	1.23E-09
	Phosphate	water	kg	3.54E-05	3.56E-05	2.75E-05
Emissions to Soil						
	Arsenic	soil	kg	6.50E-11	6.77E-11	1.41E-11
	Cadmium	soil	kg	9.72E-12	1.03E-11	3.64E-12
	Chromium	soil	kg	1.05E-09	1.09E-09	2.28E-10
	Chromium VI	soil	kg	7.30E-09	8.59E-09	5.40E-10
	Lead	soil	kg	8.83E-11	9.19E-11	2.36E-11
	Mercury	soil	kg	2.36E-13	2.44E-13	6.78E-14
	Oils, unspecified	soil	kg	7.18E-06	7.62E-06	3.24E-06

Table 8.41 LCA results for year 2050, pessimistic development, “440 ppm-scenario”.

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	**Total**	**Total**
				kWh	**kWh**	**kWh**
Resources						
	Coal, brown, in ground	resource	kg	9.51E-01	9.74E-01	9.74E-01
	Coal, hard, unspecified, in ground	resource	kg	1.60E-03	1.04E-03	1.21E-03
	Gas, natural, in ground	resource	Nm3	1.67E-02	6.52E-03	7.38E-03
	Oil, crude, in ground	resource	kg	3.17E-03	1.02E-03	1.14E-03
	Uranium, in ground	resource	kg	6.92E-07	3.15E-07	3.56E-07
	Freshwater (lake, river, groundwater)	resource	m3	5.32E-03	5.13E-03	5.17E-03
	Occupation, agricultural and forestal area	resource	m2a	2.75E-03	1.52E-03	1.62E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.31E-03	1.24E-03	1.27E-03
Emissions to air						
	Ammonia	air	kg	2.38E-04	2.38E-06	2.46E-06
	Arsenic	air	kg	1.21E-08	1.01E-08	1.03E-08
	Cadmium	air	kg	2.61E-09	1.42E-09	1.48E-09
	Carbon dioxide, fossil	air	kg	1.20E-01	1.83E-02	1.93E-02
	Carbon monoxide, fossil	air	kg	2.26E-04	2.10E-04	2.17E-04
	Carbon-14	air	kBq	1.42E-03	6.47E-04	7.32E-04
	Chromium	air	kg	9.31E-08	6.50E-08	7.24E-08
	Chromium VI	air	kg	2.44E-09	1.75E-09	1.93E-09
	Dinitrogen monoxide	air	kg	2.36E-05	2.30E-05	2.32E-05
	Iodine-129	air	kBq	1.21E-06	5.53E-07	6.26E-07
	Lead	air	kg	3.17E-08	2.20E-08	2.39E-08
	Methane, fossil	air	kg	3.27E-04	2.74E-04	2.79E-04
	Mercury	air	kg	2.15E-08	2.10E-08	2.12E-08
	Nickel	air	kg	3.20E-08	1.54E-08	1.63E-08
	Nitrogen oxides	air	kg	7.73E-04	2.89E-04	2.95E-04
	NMVOC total	air	kg	4.81E-05	2.94E-05	3.11E-05
	thereof:					
	Benzene	air	kg	2.08E-06	1.89E-06	1.89E-06
	Benzo(a)pyrene	air	kg	1.23E-10	8.90E-11	9.73E-11
	Formaldehyde	air	kg	5.48E-07	5.30E-07	5.32E-07
	PAH	air	kg	1.72E-08	1.40E-08	1.46E-08
	PM2.5-10	air	kg	1.58E-05	1.30E-05	1.38E-05
	PM2.5	air	kg	6.76E-05	6.60E-05	6.67E-05
	PCDD/F (measured as I-TEQ)	air	kg	8.60E-14	7.03E-14	7.20E-14
	Radon-222	air	kBq	2.24E+01	1.02E+01	1.16E+01
	Sulfur dioxide	air	kg	1.44E-04	1.18E-04	1.20E-04
Emissions to Water						
	Ammonium, ion	water	kg	4.27E-06	1.24E-07	1.39E-07
	Arsenic, ion	water	kg	9.31E-07	9.44E-07	9.47E-07
	Cadmium, ion	water	kg	3.47E-08	3.18E-08	3.34E-08
	Carbon-14	water	kBq	4.88E-04	2.22E-04	2.52E-04
	Cesium-137	water	kBq	2.27E-04	1.03E-04	1.17E-04
	Chromium, ion	water	kg	3.79E-09	2.05E-09	2.48E-09
	Chromium VI	water	kg	8.53E-07	7.81E-07	8.21E-07
	COD	water	kg	1.43E-04	3.74E-05	4.26E-05
	Copper, ion	water	kg	1.04E-06	1.00E-06	1.02E-06
	Lead	water	kg	9.93E-07	9.90E-07	9.95E-07
	Mercury	water	kg	6.21E-09	5.77E-09	6.02E-09
	Nickel, ion	water	kg	2.04E-06	1.86E-06	1.95E-06
	Nitrate	water	kg	1.19E-05	3.09E-07	3.46E-07
	Oils, unspecified	water	kg	9.29E-06	4.91E-06	5.55E-06
	PAH	water	kg	3.08E-09	2.02E-09	2.33E-09
	Phosphate	water	kg	3.57E-05	3.30E-05	3.32E-05
Emissions to Soil						
	Arsenic	soil	kg	1.46E-10	5.85E-11	6.16E-11
	Cadmium	soil	kg	1.08E-11	5.31E-12	5.98E-12
	Chromium	soil	kg	2.07E-09	7.95E-10	8.41E-10
	Chromium VI	soil	kg	2.08E-08	7.47E-09	8.94E-09
	Lead	soil	kg	9.73E-11	3.26E-11	3.66E-11
	Mercury	soil	kg	2.94E-13	1.10E-13	1.19E-13
	Oils, unspecified	soil	kg	8.09E-06	4.21E-06	4.71E-06

Table 8.42 LCA results for year 2050, pessimistic development, “440 ppm-scenario”.

				electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	9.74E-01	9.74E-01	9.51E-01
	Coal, hard, unspecified, in ground	resource	kg	1.25E-03	1.43E-03	1.44E-03
	Gas, natural, in ground	resource	Nm3	1.44E-02	1.52E-02	1.60E-02
	Oil, crude, in ground	resource	kg	1.16E-03	1.29E-03	3.06E-03
	Uranium, in ground	resource	kg	7.06E-07	7.48E-07	6.56E-07
	Freshwater (lake, river, groundwater)	resource	m3	5.39E-03	5.43E-03	5.29E-03
	Occupation, agricultural and forestal area	resource	m2a	2.34E-03	2.44E-03	2.66E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.26E-03	1.30E-03	1.28E-03
Emissions to air						
	Ammonia	air	kg	2.61E-06	2.69E-06	2.38E-04
	Arsenic	air	kg	1.12E-08	1.15E-08	1.19E-08
	Cadmium	air	kg	1.82E-09	1.88E-09	2.56E-09
	Carbon dioxide, fossil	air	kg	2.24E-02	2.34E-02	1.19E-01
	Carbon monoxide, fossil	air	kg	2.17E-04	2.23E-04	2.20E-04
	Carbon-14	air	kBq	1.45E-03	1.54E-03	1.34E-03
	Chromium	air	kg	7.05E-08	7.79E-08	8.66E-08
	Chromium VI	air	kg	1.89E-09	2.07E-09	2.28E-09
	Dinitrogen monoxide	air	kg	2.40E-05	2.41E-05	2.35E-05
	Iodine-129	air	kBq	1.24E-06	1.32E-06	1.15E-06
	Lead	air	kg	2.63E-08	2.82E-08	3.00E-08
	Methane, fossil	air	kg	3.16E-04	3.21E-04	3.22E-04
	Mercury	air	kg	2.11E-08	2.14E-08	2.13E-08
	Nickel	air	kg	1.84E-08	1.92E-08	3.12E-08
	Nitrogen oxides	air	kg	3.02E-04	3.08E-04	7.68E-04
	NMVOC total	air	kg	3.77E-05	3.94E-05	4.66E-05
	thereof:					
	Benzene	air	kg	1.90E-06	1.90E-06	2.08E-06
	Benzo(a)pyrene	air	kg	1.02E-10	1.10E-10	1.16E-10
	Formaldehyde	air	kg	5.40E-07	5.42E-07	5.46E-07
	PAH	air	kg	1.64E-08	1.70E-08	1.66E-08
	PM2.5-10	air	kg	1.36E-05	1.44E-05	1.51E-05
	PM2.5	air	kg	6.68E-05	6.75E-05	6.70E-05
	PCDD/F (measured as I-TEQ)	air	kg	7.19E-14	7.37E-14	8.45E-14
	Radon-222	air	kBq	2.29E+01	2.43E+01	2.12E+01
	Sulfur dioxide	air	kg	1.27E-04	1.29E-04	1.43E-04
Emissions to Water						
	Ammonium, ion	water	kg	2.43E-07	2.57E-07	4.25E-06
	Arsenic, ion	water	kg	9.46E-07	9.48E-07	9.29E-07
	Cadmium, ion	water	kg	3.26E-08	3.41E-08	3.33E-08
	Carbon-14	water	kBq	5.00E-04	5.29E-04	4.62E-04
	Cesium-137	water	kBq	2.32E-04	2.46E-04	2.15E-04
	Chromium, ion	water	kg	3.31E-09	3.74E-09	3.41E-09
	Chromium VI	water	kg	8.00E-07	8.40E-07	8.18E-07
	COD	water	kg	4.37E-05	4.89E-05	1.39E-04
	Copper, ion	water	kg	1.01E-06	1.03E-06	1.03E-06
	Lead	water	kg	9.99E-07	1.00E-06	9.89E-07
	Mercury	water	kg	5.87E-09	6.12E-09	5.99E-09
	Nickel, ion	water	kg	1.90E-06	1.99E-06	1.97E-06
	Nitrate	water	kg	6.20E-07	6.57E-07	1.19E-05
	Oils, unspecified	water	kg	5.66E-06	6.30E-06	8.73E-06
	PAH	water	kg	2.19E-09	2.51E-09	2.81E-09
	Phosphate	water	kg	3.31E-05	3.33E-05	3.55E-05
Emissions to Soil						
	Arsenic	soil	kg	1.47E-10	1.50E-10	1.43E-10
	Cadmium	soil	kg	5.91E-12	6.59E-12	1.03E-11
	Chromium	soil	kg	1.91E-09	1.95E-09	2.03E-09
	Chromium VI	soil	kg	2.13E-08	2.28E-08	1.95E-08
	Lead	soil	kg	3.87E-11	4.27E-11	9.37E-11
	Mercury	soil	kg	1.66E-13	1.76E-13	2.85E-13
	Oils, unspecified	soil	kg	4.73E-06	5.23E-06	7.64E-06

Table 8.43 LCA results for year 2050, pessimistic development, "440 ppm-scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	5.90E-05	4.29E-01
Coal, hard, unspecified, in ground	resource	kg	3.35E-01	3.94E-04
Gas, natural, in ground	resource	Nm3	2.94E-03	1.24E-03
Oil, crude, in ground	resource	kg	4.16E-03	5.26E-04
Uranium, in ground	resource	kg	1.38E-07	6.02E-08
Freshwater (lake, river, groundwater)	resource	m3	6.17E-04	1.57E-03
Occupation, agricultural and forestal area	resource	m2a	1.55E-02	4.03E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.81E-03	7.33E-04
Emissions to air				
Ammonia	air	kg	1.41E-05	3.82E-07
Arsenic	air	kg	6.31E-08	6.12E-08
Cadmium	air	kg	1.56E-09	1.25E-09
Carbon dioxide, fossil	air	kg	6.44E-01	6.29E-01
Carbon monoxide, fossil	air	kg	1.28E-04	6.91E-05
Carbon-14	air	kBq	2.81E-04	1.23E-04
Chromium	air	kg	4.31E-08	3.61E-08
Chromium VI	air	kg	1.39E-09	1.18E-09
Dinitrogen monoxide	air	kg	2.73E-05	2.61E-05
Iodine-129	air	kBq	2.39E-07	1.05E-07
Lead	air	kg	4.15E-08	3.55E-08
Methane, fossil	air	kg	1.87E-03	1.20E-04
Mercury	air	kg	1.99E-08	1.92E-08
Nickel	air	kg	8.17E-08	1.83E-08
Nitrogen oxides	air	kg	4.21E-04	1.68E-04
NMVOC total	air	kg	4.91E-05	1.86E-05
thereof:				
Benzene	air	kg	1.20E-06	9.94E-07
Benzo(a)pyrene	air	kg	9.44E-11	3.53E-11
Formaldehyde	air	kg	2.79E-07	2.75E-07
PAH	air	kg	5.48E-08	4.69E-08
PM2.5-10	air	kg	1.36E-05	2.51E-06
PM2.5	air	kg	9.48E-06	2.08E-06
PCDD/F (measured as I-TEQ)	air	kg	5.02E-14	4.28E-14
Radon-222	air	kBq	4.47E+00	1.95E+00
Sulfur dioxide	air	kg	3.57E-04	1.96E-04
Emissions to Water				
Ammonium, ion	water	kg	3.74E-07	6.01E-08
Arsenic, ion	water	kg	7.98E-08	7.10E-08
Cadmium, ion	water	kg	1.22E-08	8.92E-09
Carbon-14	water	kBq	9.60E-05	4.20E-05
Cesium-137	water	kBq	4.47E-05	1.96E-05
Chromium, ion	water	kg	1.99E-09	7.28E-10
Chromium VI	water	kg	7.14E-07	6.31E-07
COD	water	kg	2.17E-04	1.60E-04
Copper, ion	water	kg	1.28E-06	1.25E-06
Lead	water	kg	3.25E-07	3.15E-07
Mercury	water	kg	4.84E-09	4.45E-09
Nickel, ion	water	kg	5.90E-07	4.70E-07
Nitrate	water	kg	1.23E-06	6.91E-07
Oils, unspecified	water	kg	1.84E-05	2.29E-06
PAH	water	kg	2.47E-09	9.49E-10
Phosphate	water	kg	6.96E-06	6.60E-06
Emissions to Soil				
Arsenic	soil	kg	5.41E-11	8.62E-12
Cadmium	soil	kg	6.32E-12	3.37E-12
Chromium	soil	kg	7.89E-10	1.68E-10
Chromium VI	soil	kg	2.45E-09	4.97E-10
Lead	soil	kg	5.07E-11	3.09E-11
Mercury	soil	kg	5.70E-13	1.86E-13
Oils, unspecified	soil	kg	1.86E-05	2.10E-06

Table 8.44 LCA results for year 2050, pessimistic development, “440 ppm-scenario”.

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	7.81E-05	7.97E-05	6.99E-05	7.16E-05
Coal, hard, unspecified, in ground	resource	kg	3.78E-01	3.78E-01	3.78E-01	3.78E-01
Gas, natural, in ground	resource	Nm3	1.22E-02	1.29E-02	6.26E-03	6.92E-03
Oil, crude, in ground	resource	kg	4.92E-03	5.01E-03	4.81E-03	4.90E-03
Uranium, in ground	resource	kg	6.00E-07	6.32E-07	3.02E-07	3.33E-07
Freshwater (lake, river, groundwater)	resource	m3	1.00E-03	1.03E-03	8.01E-04	8.30E-04
Occupation, agricultural and forestal area	resource	m2a	1.84E-02	1.85E-02	1.78E-02	1.79E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.32E-03	4.35E-03	4.30E-03	4.33E-03
Emissions to air						
Ammonia	air	kg	1.62E-05	1.63E-05	1.60E-05	1.61E-05
Arsenic	air	kg	7.96E-08	7.98E-08	7.87E-08	7.89E-08
Cadmium	air	kg	2.18E-09	2.23E-09	1.87E-09	1.92E-09
Carbon dioxide, fossil	air	kg	1.05E-01	1.05E-01	1.02E-01	1.02E-01
Carbon monoxide, fossil	air	kg	1.63E-04	1.68E-04	1.58E-04	1.63E-04
Carbon-14	air	kBq	1.23E-03	1.30E-03	6.19E-04	6.84E-04
Chromium	air	kg	5.95E-08	6.52E-08	5.53E-08	6.09E-08
Chromium VI	air	kg	1.87E-09	2.01E-09	1.77E-09	1.91E-09
Dinitrogen monoxide	air	kg	3.50E-05	3.51E-05	3.43E-05	3.44E-05
Iodine-129	air	kBq	1.05E-06	1.11E-06	5.28E-07	5.84E-07
Lead	air	kg	5.50E-08	5.65E-08	5.17E-08	5.32E-08
Methane, fossil	air	kg	2.15E-03	2.16E-03	2.12E-03	2.12E-03
Mercury	air	kg	2.51E-08	2.52E-08	2.49E-08	2.51E-08
Nickel	air	kg	9.67E-08	9.73E-08	9.44E-08	9.50E-08
Nitrogen oxides	air	kg	5.11E-04	5.15E-04	5.01E-04	5.05E-04
NMVOC total	air	kg	6.71E-05	6.84E-05	6.08E-05	6.21E-05
thereof:						
Benzene	air	kg	1.49E-06	1.49E-06	1.48E-06	1.48E-06
Benzo(a)pyrene	air	kg	1.24E-10	1.30E-10	1.14E-10	1.20E-10
Formaldehyde	air	kg	3.60E-07	3.61E-07	3.52E-07	3.53E-07
PAH	air	kg	7.04E-08	7.08E-08	6.85E-08	6.90E-08
PM2.5-10	air	kg	1.64E-05	1.71E-05	1.60E-05	1.66E-05
PM2.5	air	kg	1.20E-05	1.26E-05	1.14E-05	1.20E-05
PCDD/F (measured as I-TEQ)	air	kg	6.32E-14	6.46E-14	6.20E-14	6.33E-14
Radon-222	air	kBq	1.95E+01	2.05E+01	9.80E+00	1.08E+01
Sulfur dioxide	air	kg	4.36E-04	4.38E-04	4.29E-04	4.31E-04
Emissions to Water						
Ammonium, ion	water	kg	5.57E-07	5.68E-07	4.66E-07	4.77E-07
Arsenic, ion	water	kg	9.18E-08	9.35E-08	9.05E-08	9.22E-08
Cadmium, ion	water	kg	1.54E-08	1.66E-08	1.48E-08	1.60E-08
Carbon-14	water	kBq	4.24E-04	4.46E-04	2.12E-04	2.35E-04
Cesium-137	water	kBq	1.97E-04	2.08E-04	9.87E-05	1.09E-04
Chromium, ion	water	kg	3.88E-09	4.20E-09	2.92E-09	3.24E-09
Chromium VI	water	kg	8.44E-07	8.74E-07	8.29E-07	8.59E-07
COD	water	kg	2.52E-04	2.56E-04	2.47E-04	2.51E-04
Copper, ion	water	kg	1.44E-06	1.45E-06	1.43E-06	1.44E-06
Lead	water	kg	3.71E-07	3.74E-07	3.64E-07	3.68E-07
Mercury	water	kg	5.68E-09	5.87E-09	5.60E-09	5.79E-09
Nickel, ion	water	kg	7.58E-07	8.24E-07	7.28E-07	7.94E-07
Nitrate	water	kg	1.73E-06	1.76E-06	1.49E-06	1.52E-06
Oils, unspecified	water	kg	2.19E-05	2.24E-05	2.13E-05	2.18E-05
PAH	water	kg	3.18E-09	3.42E-09	3.05E-09	3.28E-09
Phosphate	water	kg	7.98E-06	8.11E-06	7.90E-06	8.03E-06
Emissions to Soil						
Arsenic	soil	kg	1.61E-10	1.63E-10	9.35E-11	9.58E-11
Cadmium	soil	kg	8.16E-12	8.67E-12	7.70E-12	8.21E-12
Chromium	soil	kg	2.15E-09	2.19E-09	1.30E-09	1.34E-09
Chromium VI	soil	kg	1.85E-08	1.96E-08	7.95E-09	9.06E-09
Lead	soil	kg	6.58E-11	6.89E-11	6.12E-11	6.43E-11
Mercury	soil	kg	7.06E-13	7.13E-13	6.63E-13	6.70E-13
Oils, unspecified	soil	kg	2.18E-05	2.22E-05	2.14E-05	2.18E-05

Table 8.45 LCA results for year 2050, pessimistic development, "440 ppm-scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.85E-01	4.85E-01	4.85E-01	4.85E-01
Coal, hard, unspecified, in ground	resource	kg	1.18E-03	1.35E-03	9.73E-04	1.14E-03
Gas, natural, in ground	resource	Nm3	1.27E-02	1.35E-02	5.23E-03	6.05E-03
Oil, crude, in ground	resource	kg	1.48E-03	1.60E-03	1.34E-03	1.46E-03
Uranium, in ground	resource	kg	6.34E-07	6.74E-07	2.61E-07	3.01E-07
Freshwater (lake, river, groundwater)	resource	m3	2.20E-03	2.24E-03	1.95E-03	1.98E-03
Occupation, agricultural and forestal area	resource	m2a	1.68E-03	1.77E-03	8.95E-04	9.92E-04
Occupation, built up area incl. mineral extractio	resource	m2a	1.19E-03	1.22E-03	1.17E-03	1.20E-03
Emissions to air						
Ammonia	air	kg	1.01E-06	1.08E-06	7.93E-07	8.69E-07
Arsenic	air	kg	9.18E-09	9.40E-09	8.08E-09	8.30E-09
Cadmium	air	kg	1.78E-09	1.85E-09	1.40E-09	1.46E-09
Carbon dioxide, fossil	air	kg	1.13E-01	1.14E-01	1.09E-01	1.10E-01
Carbon monoxide, fossil	air	kg	1.18E-04	1.25E-04	1.12E-04	1.19E-04
Carbon-14	air	kBq	1.30E-03	1.39E-03	5.35E-04	6.16E-04
Chromium	air	kg	5.32E-08	6.03E-08	4.79E-08	5.50E-08
Chromium VI	air	kg	1.42E-09	1.59E-09	1.29E-09	1.46E-09
Dinitrogen monoxide	air	kg	3.30E-05	3.31E-05	3.21E-05	3.22E-05
Iodine-129	air	kBq	1.11E-06	1.18E-06	4.55E-07	5.25E-07
Lead	air	kg	2.25E-08	2.43E-08	1.84E-08	2.02E-08
Methane, fossil	air	kg	2.02E-04	2.08E-04	1.62E-04	1.68E-04
Mercury	air	kg	1.44E-08	1.46E-08	1.43E-08	1.45E-08
Nickel	air	kg	1.51E-08	1.59E-08	1.23E-08	1.30E-08
Nitrogen oxides	air	kg	5.25E-04	5.30E-04	5.12E-04	5.17E-04
NMVOC total	air	kg	3.84E-05	4.01E-05	3.06E-05	3.22E-05
thereof:						
Benzene	air	kg	1.29E-06	1.29E-06	1.28E-06	1.28E-06
Benzo(a)pyrene	air	kg	6.92E-11	7.71E-11	5.68E-11	6.47E-11
Formaldehyde	air	kg	3.61E-07	3.63E-07	3.51E-07	3.53E-07
PAH	air	kg	6.28E-08	6.34E-08	6.04E-08	6.10E-08
PM2.5-10	air	kg	5.25E-06	6.05E-06	4.73E-06	5.53E-06
PM2.5	air	kg	4.74E-06	5.46E-06	3.98E-06	4.69E-06
PCDD/F (measured as I-TEQ)	air	kg	6.10E-14	6.26E-14	5.94E-14	6.11E-14
Radon-222	air	kBq	2.06E+01	2.19E+01	8.47E+00	9.76E+00
Sulfur dioxide	air	kg	7.48E-04	7.50E-04	7.40E-04	7.41E-04
Emissions to Water						
Ammonium, ion	water	kg	2.43E-07	2.57E-07	1.30E-07	1.44E-07
Arsenic, ion	water	kg	1.47E-06	1.47E-06	1.47E-06	1.47E-06
Cadmium, ion	water	kg	9.31E-08	9.46E-08	9.24E-08	9.38E-08
Carbon-14	water	kBq	4.48E-04	4.76E-04	1.83E-04	2.11E-04
Cesium-137	water	kBq	2.08E-04	2.21E-04	8.51E-05	9.82E-05
Chromium, ion	water	kg	3.03E-09	3.44E-09	1.83E-09	2.23E-09
Chromium VI	water	kg	9.43E-06	9.47E-06	9.42E-06	9.45E-06
COD	water	kg	2.11E-03	2.11E-03	2.10E-03	2.11E-03
Copper, ion	water	kg	6.80E-06	6.82E-06	6.79E-06	6.81E-06
Lead	water	kg	1.90E-06	1.91E-06	1.90E-06	1.90E-06
Mercury	water	kg	6.18E-08	6.20E-08	6.17E-08	6.19E-08
Nickel, ion	water	kg	4.07E-06	4.15E-06	4.03E-06	4.12E-06
Nitrate	water	kg	1.26E-06	1.29E-06	9.61E-07	9.97E-07
Oils, unspecified	water	kg	5.13E-06	5.74E-06	4.41E-06	5.03E-06
PAH	water	kg	1.75E-09	2.05E-09	1.58E-09	1.88E-09
Phosphate	water	kg	1.11E-04	1.11E-04	1.11E-04	1.11E-04
Emissions to Soil						
Arsenic	soil	kg	1.38E-10	1.41E-10	5.42E-11	5.72E-11
Cadmium	soil	kg	7.70E-12	8.34E-12	7.12E-12	7.77E-12
Chromium	soil	kg	1.85E-09	1.89E-09	7.85E-10	8.29E-10
Chromium VI	soil	kg	2.05E-08	2.19E-08	7.25E-09	8.65E-09
Lead	soil	kg	6.04E-11	6.43E-11	5.46E-11	5.85E-11
Mercury	soil	kg	3.03E-13	3.12E-13	2.49E-13	2.59E-13
Oils, unspecified	soil	kg	4.37E-06	4.85E-06	3.87E-06	4.35E-06

Table 8.46 LCA results for year 2050, very optimistic development, "440 ppm-scenario".

				electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	4.69E-05	4.54E-05	4.29E-05
	Coal, hard, unspecified, in ground	resource	kg	3.35E-01	3.35E-01	3.35E-01
	Gas, natural, in ground	resource	Nm3	2.80E-03	2.78E-03	2.74E-03
	Oil, crude, in ground	resource	kg	4.30E-03	4.28E-03	4.26E-03
	Uranium, in ground	resource	kg	1.31E-07	1.30E-07	1.29E-07
	Freshwater (lake, river, groundwater)	resource	m3	1.70E-03	1.70E-03	1.70E-03
	Occupation, agricultural and forestal area	resource	m2a	1.55E-02	1.55E-02	1.55E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	3.63E-03	3.63E-03	3.62E-03
Emissions to air						
	Ammonia	air	kg	1.63E-05	1.63E-05	1.63E-05
	Arsenic	air	kg	1.05E-08	1.05E-08	1.04E-08
	Cadmium	air	kg	9.26E-10	9.15E-10	8.97E-10
	Carbon dioxide, fossil	air	kg	6.03E-01	6.03E-01	6.03E-01
	Carbon monoxide, fossil	air	kg	1.20E-04	1.19E-04	1.18E-04
	Carbon-14	air	kBq	3.66E-04	3.64E-04	3.62E-04
	Chromium	air	kg	1.50E-07	1.33E-07	1.03E-07
	Chromium VI	air	kg	4.19E-09	3.77E-09	3.02E-09
	Dinitrogen monoxide	air	kg	2.64E-05	2.64E-05	2.64E-05
	Iodine-129	air	kBq	2.26E-07	2.25E-07	2.23E-07
	Lead	air	kg	4.20E-08	4.18E-08	4.13E-08
	Methane, fossil	air	kg	1.85E-03	1.85E-03	1.85E-03
	Mercury	air	kg	2.70E-08	2.70E-08	2.70E-08
	Nickel	air	kg	8.29E-08	8.28E-08	8.25E-08
	Nitrogen oxides	air	kg	6.20E-04	6.20E-04	6.19E-04
	NMVOC total	air	kg	4.69E-05	4.68E-05	4.66E-05
	thereof:					
	Benzene	air	kg	1.59E-06	1.59E-06	1.59E-06
	Benzo(a)pyrene	air	kg	6.19E-11	5.95E-11	5.54E-11
	Formaldehyde	air	kg	3.87E-07	3.86E-07	3.84E-07
	PAH	air	kg	1.59E-08	1.58E-08	1.55E-08
	PM2.5-10	air	kg	1.71E-05	1.69E-05	1.66E-05
	PM2.5	air	kg	4.01E-05	3.99E-05	3.95E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.15E-14	5.13E-14	5.09E-14
	Radon-222	air	kBq	4.24E+00	4.22E+00	4.19E+00
	Sulfur dioxide	air	kg	4.47E-04	4.47E-04	4.47E-04
Emissions to Water						
	Ammonium, ion	water	kg	6.82E-07	6.81E-07	6.80E-07
	Arsenic, ion	water	kg	1.00E-07	9.96E-08	9.84E-08
	Cadmium, ion	water	kg	9.74E-09	9.52E-09	9.13E-09
	Carbon-14	water	kBq	9.74E-05	9.69E-05	9.62E-05
	Cesium-137	water	kBq	4.21E-05	4.19E-05	4.16E-05
	Chromium, ion	water	kg	1.37E-08	1.37E-08	1.35E-08
	Chromium VI	water	kg	2.01E-07	1.96E-07	1.85E-07
	COD	water	kg	9.67E-05	9.57E-05	9.39E-05
	Copper, ion	water	kg	3.85E-07	3.81E-07	3.74E-07
	Lead	water	kg	1.66E-07	1.63E-07	1.56E-07
	Mercury	water	kg	2.24E-09	2.22E-09	2.18E-09
	Nickel, ion	water	kg	8.94E-07	8.32E-07	7.22E-07
	Nitrate	water	kg	2.07E-05	2.07E-05	2.07E-05
	Oils, unspecified	water	kg	1.88E-05	1.87E-05	1.86E-05
	PAH	water	kg	4.65E-09	4.29E-09	3.66E-09
	Phosphate	water	kg	2.25E-06	2.23E-06	2.19E-06
Emissions to Soil						
	Arsenic	soil	kg	5.59E-11	5.56E-11	5.51E-11
	Cadmium	soil	kg	6.74E-12	6.51E-12	6.09E-12
	Chromium	soil	kg	8.02E-10	7.96E-10	7.86E-10
	Chromium VI	soil	kg	2.35E-09	2.33E-09	2.30E-09
	Lead	soil	kg	4.53E-11	4.40E-11	4.17E-11
	Mercury	soil	kg	4.52E-13	4.50E-13	4.47E-13
	Oils, unspecified	soil	kg	1.91E-05	1.90E-05	1.89E-05

Table 8.47 LCA results for year 2050, very optimistic development, “440 ppm-scenario”.

				electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
				Total	Total	Total	Total
				kWh	kWh	kWh	kWh
Resources							
	Coal, brown, in ground	resource	kg	5.66E-05	5.78E-05	6.97E-05	7.07E-05
	Coal, hard, unspecified, in ground	resource	kg	3.83E-01	3.83E-01	3.67E-01	3.68E-01
	Gas, natural, in ground	resource	Nm3	1.05E-02	1.11E-02	1.15E-02	1.20E-02
	Oil, crude, in ground	resource	kg	5.08E-03	5.17E-03	6.26E-03	6.34E-03
	Uranium, in ground	resource	kg	5.53E-07	5.82E-07	5.07E-07	5.32E-07
	Freshwater (lake, river, groundwater)	resource	m3	2.21E-03	2.24E-03	2.15E-03	2.17E-03
	Occupation, agricultural and forestal area	resource	m2a	1.83E-02	1.84E-02	1.78E-02	1.79E-02
	Occupation, built up area incl. mineral extractio	resource	m2a	4.19E-03	4.22E-03	4.06E-03	4.08E-03
Emissions to air							
	Ammonia	air	kg	1.73E-05	1.74E-05	2.40E-04	2.40E-04
	Arsenic	air	kg	1.23E-08	1.23E-08	1.21E-08	1.21E-08
	Cadmium	air	kg	1.11E-09	1.13E-09	1.49E-09	1.50E-09
	Carbon dioxide, fossil	air	kg	2.78E-02	2.85E-02	9.95E-02	1.00E-01
	Carbon monoxide, fossil	air	kg	1.46E-04	1.49E-04	1.44E-04	1.48E-04
	Carbon-14	air	kBq	1.58E-03	1.66E-03	1.44E-03	1.51E-03
	Chromium	air	kg	1.89E-07	1.94E-07	2.25E-07	2.29E-07
	Chromium VI	air	kg	5.21E-09	5.33E-09	6.08E-09	6.19E-09
	Dinitrogen monoxide	air	kg	3.10E-05	3.11E-05	2.99E-05	3.00E-05
	Iodine-129	air	kBq	9.66E-07	1.02E-06	8.83E-07	9.27E-07
	Lead	air	kg	5.01E-08	5.06E-08	4.97E-08	5.02E-08
	Methane, fossil	air	kg	2.13E-03	2.13E-03	2.06E-03	2.06E-03
	Mercury	air	kg	3.11E-08	3.12E-08	3.04E-08	3.05E-08
	Nickel	air	kg	9.46E-08	9.49E-08	9.88E-08	9.91E-08
	Nitrogen oxides	air	kg	4.94E-04	4.98E-04	7.06E-04	7.09E-04
	NMVOC total	air	kg	6.13E-05	6.25E-05	6.59E-05	6.68E-05
	thereof:						
	Benzene	air	kg	1.82E-06	1.82E-06	1.91E-06	1.91E-06
	Benzo(a)pyrene	air	kg	8.29E-11	8.73E-11	8.71E-11	9.10E-11
	Formaldehyde	air	kg	4.51E-07	4.53E-07	4.46E-07	4.47E-07
	PAH	air	kg	2.07E-08	2.10E-08	2.03E-08	2.06E-08
	PM2.5-10	air	kg	2.06E-05	2.11E-05	2.10E-05	2.15E-05
	PM2.5	air	kg	4.68E-05	4.73E-05	4.64E-05	4.69E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.02E-14	6.07E-14	7.10E-14	7.14E-14
	Radon-222	air	kBq	1.80E+01	1.89E+01	1.64E+01	1.72E+01
	Sulfur dioxide	air	kg	3.02E-04	3.04E-04	3.06E-04	3.07E-04
Emissions to Water							
	Ammonium, ion	water	kg	9.08E-07	9.17E-07	3.69E-06	3.70E-06
	Arsenic, ion	water	kg	1.19E-07	1.20E-07	1.17E-07	1.18E-07
	Cadmium, ion	water	kg	1.32E-08	1.43E-08	1.34E-08	1.43E-08
	Carbon-14	water	kBq	4.18E-04	4.40E-04	3.82E-04	4.01E-04
	Cesium-137	water	kBq	1.80E-04	1.89E-04	1.65E-04	1.73E-04
	Chromium, ion	water	kg	1.78E-08	1.81E-08	1.73E-08	1.75E-08
	Chromium VI	water	kg	2.78E-07	3.07E-07	2.88E-07	3.13E-07
	COD	water	kg	1.19E-04	1.23E-04	1.91E-04	1.94E-04
	Copper, ion	water	kg	4.75E-07	4.84E-07	4.88E-07	4.95E-07
	Lead	water	kg	2.09E-07	2.12E-07	2.11E-07	2.13E-07
	Mercury	water	kg	2.92E-09	3.10E-09	2.94E-09	3.10E-09
	Nickel, ion	water	kg	1.15E-06	1.21E-06	1.27E-06	1.33E-06
	Nitrate	water	kg	2.50E-05	2.50E-05	3.25E-05	3.25E-05
	Oils, unspecified	water	kg	2.24E-05	2.28E-05	2.38E-05	2.42E-05
	PAH	water	kg	5.82E-09	6.04E-09	6.67E-09	6.87E-09
	Phosphate	water	kg	2.79E-06	2.91E-06	5.74E-06	5.84E-06
Emissions to Soil							
	Arsenic	soil	kg	1.55E-10	1.57E-10	1.49E-10	1.51E-10
	Cadmium	soil	kg	8.71E-12	9.26E-12	1.17E-11	1.22E-11
	Chromium	soil	kg	2.06E-09	2.10E-09	2.10E-09	2.13E-09
	Chromium VI	soil	kg	1.75E-08	1.85E-08	1.58E-08	1.68E-08
	Lead	soil	kg	5.74E-11	6.05E-11	9.67E-11	9.94E-11
	Mercury	soil	kg	5.33E-13	5.37E-13	6.22E-13	6.26E-13
	Oils, unspecified	soil	kg	2.24E-05	2.27E-05	2.37E-05	2.40E-05

Table 8.48 LCA results for year 2050, very optimistic development, "440 ppm-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	5.19E-05	5.30E-05	6.56E-05	6.66E-05
Coal, hard, unspecified, in ground	resource	kg	3.82E-01	3.82E-01	3.67E-01	3.67E-01
Gas, natural, in ground	resource	Nm3	5.55E-03	6.10E-03	7.19E-03	7.66E-03
Oil, crude, in ground	resource	kg	4.99E-03	5.07E-03	6.18E-03	6.25E-03
Uranium, in ground	resource	kg	2.82E-07	3.11E-07	2.73E-07	2.98E-07
Freshwater (lake, river, groundwater)	resource	m3	2.04E-03	2.06E-03	2.00E-03	2.02E-03
Occupation, agricultural and forestal area	resource	m2a	1.79E-02	1.80E-02	1.75E-02	1.75E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.18E-03	4.20E-03	4.04E-03	4.06E-03
Emissions to air						
Ammonia	air	kg	1.72E-05	1.73E-05	2.40E-04	2.40E-04
Arsenic	air	kg	1.21E-08	1.21E-08	1.19E-08	1.20E-08
Cadmium	air	kg	1.04E-09	1.06E-09	1.42E-09	1.44E-09
Carbon dioxide, fossil	air	kg	2.54E-02	2.60E-02	9.74E-02	9.80E-02
Carbon monoxide, fossil	air	kg	1.42E-04	1.46E-04	1.41E-04	1.45E-04
Carbon-14	air	kBq	8.00E-04	8.82E-04	7.69E-04	8.40E-04
Chromium	air	kg	1.85E-07	1.91E-07	2.22E-07	2.26E-07
Chromium VI	air	kg	5.12E-09	5.25E-09	6.01E-09	6.12E-09
Dinitrogen monoxide	air	kg	3.04E-05	3.05E-05	2.94E-05	2.95E-05
Iodine-129	air	kBq	4.91E-07	5.42E-07	4.72E-07	5.16E-07
Lead	air	kg	4.89E-08	4.94E-08	4.87E-08	4.91E-08
Methane, fossil	air	kg	2.12E-03	2.12E-03	2.05E-03	2.05E-03
Mercury	air	kg	3.10E-08	3.11E-08	3.03E-08	3.04E-08
Nickel	air	kg	9.38E-08	9.41E-08	9.81E-08	9.84E-08
Nitrogen oxides	air	kg	4.87E-04	4.90E-04	6.99E-04	7.02E-04
NMVOC total	air	kg	5.64E-05	5.75E-05	6.16E-05	6.25E-05
thereof:						
Benzene	air	kg	1.81E-06	1.82E-06	1.90E-06	1.90E-06
Benzo(a)pyrene	air	kg	7.76E-11	8.20E-11	8.26E-11	8.64E-11
Formaldehyde	air	kg	4.45E-07	4.46E-07	4.40E-07	4.42E-07
PAH	air	kg	1.91E-08	1.95E-08	1.89E-08	1.93E-08
PM2.5-10	air	kg	2.02E-05	2.08E-05	2.07E-05	2.12E-05
PM2.5	air	kg	4.63E-05	4.68E-05	4.60E-05	4.64E-05
PCDD/F (measured as I-TEQ)	air	kg	5.95E-14	6.00E-14	7.04E-14	7.08E-14
Radon-222	air	kBq	9.16E+00	1.01E+01	8.82E+00	9.63E+00
Sulfur dioxide	air	kg	2.97E-04	2.98E-04	3.01E-04	3.02E-04
Emissions to Water						
Ammonium, ion	water	kg	8.34E-07	8.43E-07	3.63E-06	3.64E-06
Arsenic, ion	water	kg	1.18E-07	1.19E-07	1.16E-07	1.18E-07
Cadmium, ion	water	kg	1.27E-08	1.38E-08	1.29E-08	1.39E-08
Carbon-14	water	kBq	2.12E-04	2.34E-04	2.04E-04	2.23E-04
Cesium-137	water	kBq	9.15E-05	1.01E-04	8.80E-05	9.62E-05
Chromium, ion	water	kg	1.69E-08	1.72E-08	1.65E-08	1.68E-08
Chromium VI	water	kg	2.65E-07	2.94E-07	2.76E-07	3.01E-07
COD	water	kg	1.15E-04	1.19E-04	1.88E-04	1.91E-04
Copper, ion	water	kg	4.68E-07	4.76E-07	4.81E-07	4.89E-07
Lead	water	kg	2.03E-07	2.06E-07	2.06E-07	2.08E-07
Mercury	water	kg	2.85E-09	3.03E-09	2.88E-09	3.04E-09
Nickel, ion	water	kg	1.12E-06	1.18E-06	1.25E-06	1.30E-06
Nitrate	water	kg	2.48E-05	2.48E-05	3.23E-05	3.24E-05
Oils, unspecified	water	kg	2.19E-05	2.23E-05	2.34E-05	2.38E-05
PAH	water	kg	5.70E-09	5.93E-09	6.57E-09	6.77E-09
Phosphate	water	kg	2.71E-06	2.83E-06	5.68E-06	5.78E-06
Emissions to Soil						
Arsenic	soil	kg	9.32E-11	9.52E-11	9.53E-11	9.71E-11
Cadmium	soil	kg	8.35E-12	8.90E-12	1.14E-11	1.19E-11
Chromium	soil	kg	1.29E-09	1.32E-09	1.43E-09	1.46E-09
Chromium VI	soil	kg	7.56E-09	8.60E-09	7.26E-09	8.17E-09
Lead	soil	kg	5.47E-11	5.78E-11	9.44E-11	9.70E-11
Mercury	soil	kg	5.23E-13	5.28E-13	6.14E-13	6.18E-13
Oils, unspecified	soil	kg	2.20E-05	2.24E-05	2.34E-05	2.37E-05

Table 8.49 LCA results for year 2050, very optimistic development, “440 ppm-scenario”.

				electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	7.87E-01	7.87E-01	7.18E-01
	Coal, hard, unspecified, in ground	resource	kg	9.38E-04	1.05E-03	4.68E-04
	Gas, natural, in ground	resource	Nm3	6.92E-03	7.48E-03	1.90E-03
	Oil, crude, in ground	resource	kg	2.43E-03	2.52E-03	6.67E-04
	Uranium, in ground	resource	kg	2.48E-07	2.77E-07	8.64E-08
	Freshwater (lake, river, groundwater)	resource	m3	4.17E-03	4.19E-03	3.67E-03
	Occupation, agricultural and forestal area	resource	m2a	1.49E-03	1.55E-03	7.57E-04
	Occupation, built up area incl. mineral extractio	resource	m2a	1.04E-03	1.07E-03	8.75E-04
Emissions to air						
	Ammonia	air	kg	2.37E-04	2.37E-04	4.12E-06
	Arsenic	air	kg	6.14E-09	6.18E-09	5.18E-09
	Cadmium	air	kg	9.71E-10	9.88E-10	4.42E-10
	Carbon dioxide, fossil	air	kg	9.56E-02	9.63E-02	6.92E-01
	Carbon monoxide, fossil	air	kg	1.72E-04	1.76E-04	1.43E-04
	Carbon-14	air	kBq	6.99E-04	7.83E-04	2.44E-04
	Chromium	air	kg	7.42E-08	7.95E-08	3.93E-08
	Chromium VI	air	kg	1.95E-09	2.08E-09	1.08E-09
	Dinitrogen monoxide	air	kg	1.87E-05	1.88E-05	1.67E-05
	Iodine-129	air	kBq	4.29E-07	4.80E-07	1.50E-07
	Lead	air	kg	1.06E-08	1.11E-08	6.64E-09
	Methane, fossil	air	kg	2.16E-04	2.18E-04	1.80E-04
	Mercury	air	kg	1.76E-08	1.77E-08	1.52E-08
	Nickel	air	kg	1.79E-08	1.82E-08	8.31E-09
	Nitrogen oxides	air	kg	6.24E-04	6.28E-04	5.48E-04
	NMVOC total	air	kg	3.17E-05	3.28E-05	1.78E-05
	thereof:					
	Benzene	air	kg	1.71E-06	1.71E-06	1.39E-06
	Benzo(a)pyrene	air	kg	6.04E-11	6.49E-11	3.61E-11
	Formaldehyde	air	kg	4.45E-07	4.46E-07	3.87E-07
	PAH	air	kg	1.16E-08	1.20E-08	8.83E-09
	PM2.5-10	air	kg	1.22E-05	1.28E-05	8.62E-06
	PM2.5	air	kg	5.45E-05	5.50E-05	4.76E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.57E-14	6.62E-14	4.67E-14
	Radon-222	air	kBq	7.98E+00	8.93E+00	2.81E+00
	Sulfur dioxide	air	kg	1.25E-04	1.27E-04	1.01E-04
Emissions to Water						
	Ammonium, ion	water	kg	3.41E-06	3.42E-06	4.26E-08
	Arsenic, ion	water	kg	7.67E-07	7.69E-07	6.93E-07
	Cadmium, ion	water	kg	2.77E-08	2.88E-08	2.19E-08
	Carbon-14	water	kBq	1.86E-04	2.08E-04	6.49E-05
	Cesium-137	water	kBq	7.99E-05	8.95E-05	2.80E-05
	Chromium, ion	water	kg	1.95E-09	2.25E-09	8.20E-10
	Chromium VI	water	kg	6.77E-07	7.06E-07	5.36E-07
	COD	water	kg	1.15E-04	1.19E-04	2.30E-05
	Copper, ion	water	kg	8.50E-07	8.59E-07	7.28E-07
	Lead	water	kg	8.16E-07	8.19E-07	7.22E-07
	Mercury	water	kg	4.95E-09	5.14E-09	4.01E-09
	Nickel, ion	water	kg	1.64E-06	1.70E-06	1.29E-06
	Nitrate	water	kg	9.89E-06	9.91E-06	1.02E-07
	Oils, unspecified	water	kg	6.79E-06	7.25E-06	3.18E-06
	PAH	water	kg	2.36E-09	2.59E-09	1.18E-09
	Phosphate	water	kg	2.98E-05	3.00E-05	2.42E-05
Emissions to Soil						
	Arsenic	soil	kg	5.32E-11	5.53E-11	1.23E-11
	Cadmium	soil	kg	9.06E-12	9.62E-12	3.78E-12
	Chromium	soil	kg	8.70E-10	9.02E-10	2.03E-10
	Chromium VI	soil	kg	6.05E-09	7.12E-09	4.81E-10
	Lead	soil	kg	7.74E-11	8.05E-11	2.31E-11
	Mercury	soil	kg	1.87E-13	1.92E-13	5.47E-14
	Oils, unspecified	soil	kg	6.02E-06	6.38E-06	2.86E-06

Table 8.50 LCA results for year 2050, very optimistic development, “440 ppm-scenario”.

				electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	8.18E-01	8.18E-01	7.87E-01
	Coal, hard, unspecified, in ground	resource	kg	9.38E-04	1.06E-03	1.07E-03
	Gas, natural, in ground	resource	Nm3	1.07E-02	1.13E-02	1.20E-02
	Oil, crude, in ground	resource	kg	9.67E-04	1.07E-03	2.53E-03
	Uranium, in ground	resource	kg	5.71E-07	6.05E-07	5.23E-07
	Freshwater (lake, river, groundwater)	resource	m3	4.49E-03	4.52E-03	4.34E-03
	Occupation, agricultural and forestal area	resource	m2a	1.62E-03	1.68E-03	1.90E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.06E-03	1.09E-03	1.06E-03
Emissions to air						
	Ammonia	air	kg	2.22E-06	2.28E-06	2.37E-04
	Arsenic	air	kg	6.24E-09	6.28E-09	6.32E-09
	Cadmium	air	kg	5.41E-10	5.61E-10	1.04E-09
	Carbon dioxide, fossil	air	kg	1.77E-02	1.85E-02	9.81E-02
	Carbon monoxide, fossil	air	kg	1.76E-04	1.81E-04	1.76E-04
	Carbon-14	air	kBq	1.64E-03	1.73E-03	1.49E-03
	Chromium	air	kg	6.42E-08	7.04E-08	7.79E-08
	Chromium VI	air	kg	1.71E-09	1.86E-09	2.04E-09
	Dinitrogen monoxide	air	kg	2.00E-05	2.00E-05	1.93E-05
	Iodine-129	air	kBq	1.00E-06	1.06E-06	9.12E-07
	Lead	air	kg	1.03E-08	1.09E-08	1.18E-08
	Methane, fossil	air	kg	2.28E-04	2.30E-04	2.29E-04
	Mercury	air	kg	1.78E-08	1.80E-08	1.77E-08
	Nickel	air	kg	8.99E-09	9.35E-09	1.87E-08
	Nitrogen oxides	air	kg	2.59E-04	2.63E-04	6.32E-04
	NMVOC total	air	kg	2.98E-05	3.10E-05	3.68E-05
	thereof:					
	Benzene	air	kg	1.59E-06	1.59E-06	1.71E-06
	Benzo(a)pyrene	air	kg	5.90E-11	6.42E-11	6.58E-11
	Formaldehyde	air	kg	4.54E-07	4.56E-07	4.52E-07
	PAH	air	kg	1.32E-08	1.37E-08	1.32E-08
	PM2.5-10	air	kg	1.14E-05	1.21E-05	1.26E-05
	PM2.5	air	kg	5.57E-05	5.63E-05	5.50E-05
	PCDD/F (measured as I-TEQ)	air	kg	5.53E-14	5.59E-14	6.64E-14
	Radon-222	air	kBq	1.86E+01	1.97E+01	1.69E+01
	Sulfur dioxide	air	kg	1.18E-04	1.20E-04	1.31E-04
Emissions to Water						
	Ammonium, ion	water	kg	1.80E-07	1.91E-07	3.49E-06
	Arsenic, ion	water	kg	7.95E-07	7.97E-07	7.68E-07
	Cadmium, ion	water	kg	2.79E-08	2.92E-08	2.82E-08
	Carbon-14	water	kBq	4.33E-04	4.59E-04	3.95E-04
	Cesium-137	water	kBq	1.86E-04	1.97E-04	1.70E-04
	Chromium, ion	water	kg	2.76E-09	3.11E-09	2.83E-09
	Chromium VI	water	kg	6.83E-07	7.17E-07	6.90E-07
	COD	water	kg	3.59E-05	4.00E-05	1.20E-04
	Copper, ion	water	kg	8.56E-07	8.66E-07	8.58E-07
	Lead	water	kg	8.43E-07	8.46E-07	8.22E-07
	Mercury	water	kg	4.99E-09	5.20E-09	5.02E-09
	Nickel, ion	water	kg	1.63E-06	1.70E-06	1.67E-06
	Nitrate	water	kg	4.36E-07	4.62E-07	1.01E-05
	Oils, unspecified	water	kg	4.77E-06	5.29E-06	7.30E-06
	PAH	water	kg	1.97E-09	2.23E-09	2.48E-09
	Phosphate	water	kg	2.79E-05	2.80E-05	2.99E-05
Emissions to Soil						
	Arsenic	soil	kg	1.21E-10	1.23E-10	1.16E-10
	Cadmium	soil	kg	5.72E-12	6.36E-12	9.42E-12
	Chromium	soil	kg	1.57E-09	1.61E-09	1.66E-09
	Chromium VI	soil	kg	1.79E-08	1.91E-08	1.61E-08
	Lead	soil	kg	3.33E-11	3.68E-11	8.01E-11
	Mercury	soil	kg	8.15E-14	8.67E-14	1.97E-13
	Oils, unspecified	soil	kg	3.97E-06	4.38E-06	6.38E-06

Table 8.51 LCA results for year 2050, very optimistic development, "440 ppm-scenario".

				electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
				Total	Total	Total
				kWh	kWh	kWh
Resources						
	Coal, brown, in ground	resource	kg	7.87E-01	8.18E-01	8.18E-01
	Coal, hard, unspecified, in ground	resource	kg	1.18E-03	7.84E-04	9.07E-04
	Gas, natural, in ground	resource	Nm3	1.25E-02	4.88E-03	5.52E-03
	Oil, crude, in ground	resource	kg	2.62E-03	8.53E-04	9.56E-04
	Uranium, in ground	resource	kg	5.52E-07	2.55E-07	2.89E-07
	Freshwater (lake, river, groundwater)	resource	m3	4.37E-03	4.29E-03	4.32E-03
	Occupation, agricultural and forestal area	resource	m2a	1.96E-03	1.15E-03	1.21E-03
	Occupation, built up area incl. mineral extractio	resource	m2a	1.09E-03	1.04E-03	1.07E-03
Emissions to air						
	Ammonia	air	kg	2.37E-04	2.06E-06	2.12E-06
	Arsenic	air	kg	6.35E-09	6.03E-09	6.08E-09
	Cadmium	air	kg	1.06E-09	4.56E-10	4.76E-10
	Carbon dioxide, fossil	air	kg	9.88E-02	1.48E-02	1.56E-02
	Carbon monoxide, fossil	air	kg	1.80E-04	1.72E-04	1.77E-04
	Carbon-14	air	kBq	1.57E-03	7.27E-04	8.23E-04
	Chromium	air	kg	8.32E-08	6.00E-08	6.62E-08
	Chromium VI	air	kg	2.17E-09	1.61E-09	1.76E-09
	Dinitrogen monoxide	air	kg	1.94E-05	1.93E-05	1.93E-05
	Iodine-129	air	kBq	9.63E-07	4.45E-07	5.04E-07
	Lead	air	kg	1.23E-08	8.92E-09	9.53E-09
	Methane, fossil	air	kg	2.31E-04	2.13E-04	2.15E-04
	Mercury	air	kg	1.78E-08	1.77E-08	1.79E-08
	Nickel	air	kg	1.90E-08	8.05E-09	8.41E-09
	Nitrogen oxides	air	kg	6.35E-04	2.50E-04	2.54E-04
	NMVOC total	air	kg	3.79E-05	2.39E-05	2.52E-05
	thereof:					
	Benzene	air	kg	1.72E-06	1.58E-06	1.59E-06
	Benzo(a)pyrene	air	kg	7.03E-11	5.28E-11	5.80E-11
	Formaldehyde	air	kg	4.53E-07	4.46E-07	4.48E-07
	PAH	air	kg	1.36E-08	1.14E-08	1.18E-08
	PM2.5-10	air	kg	1.32E-05	1.10E-05	1.17E-05
	PM2.5	air	kg	5.55E-05	5.52E-05	5.57E-05
	PCDD/F (measured as I-TEQ)	air	kg	6.69E-14	5.45E-14	5.50E-14
	Radon-222	air	kBq	1.79E+01	8.28E+00	9.37E+00
	Sulfur dioxide	air	kg	1.32E-04	1.12E-04	1.13E-04
Emissions to Water						
	Ammonium, ion	water	kg	3.50E-06	9.31E-08	1.04E-07
	Arsenic, ion	water	kg	7.70E-07	7.94E-07	7.96E-07
	Cadmium, ion	water	kg	2.93E-08	2.73E-08	2.86E-08
	Carbon-14	water	kBq	4.17E-04	1.93E-04	2.18E-04
	Cesium-137	water	kBq	1.79E-04	8.30E-05	9.40E-05
	Chromium, ion	water	kg	3.13E-09	1.75E-09	2.10E-09
	Chromium VI	water	kg	7.19E-07	6.68E-07	7.01E-07
	COD	water	kg	1.23E-04	3.11E-05	3.52E-05
	Copper, ion	water	kg	8.67E-07	8.47E-07	8.57E-07
	Lead	water	kg	8.25E-07	8.36E-07	8.39E-07
	Mercury	water	kg	5.21E-09	4.90E-09	5.12E-09
	Nickel, ion	water	kg	1.73E-06	1.60E-06	1.67E-06
	Nitrate	water	kg	1.01E-05	2.23E-07	2.49E-07
	Oils, unspecified	water	kg	7.76E-06	4.18E-06	4.71E-06
	PAH	water	kg	2.71E-09	1.83E-09	2.09E-09
	Phosphate	water	kg	3.00E-05	2.78E-05	2.79E-05
Emissions to Soil						
	Arsenic	soil	kg	1.18E-10	4.83E-11	5.07E-11
	Cadmium	soil	kg	9.98E-12	5.30E-12	5.95E-12
	Chromium	soil	kg	1.69E-09	6.63E-10	7.01E-10
	Chromium VI	soil	kg	1.72E-08	6.27E-09	7.50E-09
	Lead	soil	kg	8.33E-11	3.01E-11	3.37E-11
	Mercury	soil	kg	2.01E-13	7.05E-14	7.57E-14
	Oils, unspecified	soil	kg	6.74E-06	3.56E-06	3.97E-06

Table 8.52 LCA results for year 2050, very optimistic development, "440 ppm-scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	3.27E-05	4.13E-01
Coal, hard, unspecified, in ground	resource	kg	3.23E-01	3.08E-04
Gas, natural, in ground	resource	Nm3	2.54E-03	1.07E-03
Oil, crude, in ground	resource	kg	3.97E-03	4.89E-04
Uranium, in ground	resource	kg	1.27E-07	5.56E-08
Freshwater (lake, river, groundwater)	resource	m3	5.87E-04	1.51E-03
Occupation, agricultural and forestal area	resource	m2a	1.49E-02	3.53E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.68E-03	7.11E-04
Emissions to air				
Ammonia	air	kg	1.36E-05	3.60E-07
Arsenic	air	kg	5.65E-08	5.47E-08
Cadmium	air	kg	7.45E-10	4.57E-10
Carbon dioxide, fossil	air	kg	6.21E-01	6.06E-01
Carbon monoxide, fossil	air	kg	1.18E-04	6.41E-05
Carbon-14	air	kBq	3.56E-04	1.56E-04
Chromium	air	kg	4.18E-08	3.52E-08
Chromium VI	air	kg	1.34E-09	1.14E-09
Dinitrogen monoxide	air	kg	2.63E-05	2.52E-05
Iodine-129	air	kBq	2.20E-07	9.62E-08
Lead	air	kg	3.00E-08	2.60E-08
Methane, fossil	air	kg	1.79E-03	1.11E-04
Mercury	air	kg	1.85E-08	1.79E-08
Nickel	air	kg	7.35E-08	1.26E-08
Nitrogen oxides	air	kg	4.03E-04	1.61E-04
NMVOC total	air	kg	4.64E-05	1.74E-05
thereof:				
Benzene	air	kg	1.12E-06	9.23E-07
Benzo(a)pyrene	air	kg	5.41E-11	2.27E-11
Formaldehyde	air	kg	2.60E-07	2.55E-07
PAH	air	kg	5.08E-08	4.35E-08
PM2.5-10	air	kg	1.30E-05	2.34E-06
PM2.5	air	kg	8.78E-06	1.83E-06
PCDD/F (measured as I-TEQ)	air	kg	4.32E-14	3.83E-14
Radon-222	air	kBq	4.13E+00	1.80E+00
Sulfur dioxide	air	kg	3.41E-04	1.87E-04
Emissions to Water				
Ammonium, ion	water	kg	3.54E-07	5.50E-08
Arsenic, ion	water	kg	7.70E-08	6.85E-08
Cadmium, ion	water	kg	1.18E-08	8.66E-09
Carbon-14	water	kBq	9.48E-05	4.15E-05
Cesium-137	water	kBq	4.10E-05	1.79E-05
Chromium, ion	water	kg	1.90E-09	6.95E-10
Chromium VI	water	kg	6.89E-07	6.09E-07
COD	water	kg	2.07E-04	1.54E-04
Copper, ion	water	kg	1.23E-06	1.21E-06
Lead	water	kg	3.14E-07	3.04E-07
Mercury	water	kg	4.67E-09	4.29E-09
Nickel, ion	water	kg	5.71E-07	4.56E-07
Nitrate	water	kg	1.17E-06	6.58E-07
Oils, unspecified	water	kg	1.76E-05	2.18E-06
PAH	water	kg	2.38E-09	9.21E-10
Phosphate	water	kg	6.71E-06	6.37E-06
Emissions to Soil				
Arsenic	soil	kg	5.15E-11	8.09E-12
Cadmium	soil	kg	6.32E-12	3.51E-12
Chromium	soil	kg	7.53E-10	1.61E-10
Chromium VI	soil	kg	2.35E-09	4.74E-10
Lead	soil	kg	4.92E-11	3.07E-11
Mercury	soil	kg	5.39E-13	1.76E-13
Oils, unspecified	soil	kg	1.78E-05	2.00E-06

Table 8.53 LCA results for year 2050, very optimistic development, “440 ppm-scenario”.

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.41E-05	4.53E-05	3.93E-05	4.04E-05
Coal, hard, unspecified, in ground	resource	kg	3.63E-01	3.63E-01	3.62E-01	3.63E-01
Gas, natural, in ground	resource	Nm3	1.04E-02	1.09E-02	5.34E-03	5.89E-03
Oil, crude, in ground	resource	kg	4.66E-03	4.75E-03	4.56E-03	4.65E-03
Uranium, in ground	resource	kg	5.53E-07	5.82E-07	2.78E-07	3.07E-07
Freshwater (lake, river, groundwater)	resource	m3	9.26E-04	9.52E-04	7.51E-04	7.76E-04
Occupation, agricultural and forestal area	resource	m2a	1.73E-02	1.74E-02	1.69E-02	1.69E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.15E-03	4.18E-03	4.13E-03	4.16E-03
Emissions to air						
Ammonia	air	kg	1.55E-05	1.55E-05	1.54E-05	1.54E-05
Arsenic	air	kg	7.01E-08	7.01E-08	6.99E-08	7.00E-08
Cadmium	air	kg	9.69E-10	9.86E-10	8.95E-10	9.12E-10
Carbon dioxide, fossil	air	kg	9.88E-02	9.94E-02	9.63E-02	9.69E-02
Carbon monoxide, fossil	air	kg	1.47E-04	1.51E-04	1.44E-04	1.48E-04
Carbon-14	air	kBq	1.58E-03	1.66E-03	7.87E-04	8.71E-04
Chromium	air	kg	5.69E-08	6.22E-08	5.32E-08	5.85E-08
Chromium VI	air	kg	1.78E-09	1.91E-09	1.69E-09	1.82E-09
Dinitrogen monoxide	air	kg	3.34E-05	3.35E-05	3.28E-05	3.28E-05
Iodine-129	air	kBq	9.66E-07	1.02E-06	4.83E-07	5.34E-07
Lead	air	kg	3.85E-08	3.90E-08	3.73E-08	3.78E-08
Methane, fossil	air	kg	2.03E-03	2.03E-03	2.02E-03	2.02E-03
Mercury	air	kg	2.31E-08	2.32E-08	2.30E-08	2.31E-08
Nickel	air	kg	8.50E-08	8.53E-08	8.42E-08	8.45E-08
Nitrogen oxides	air	kg	4.84E-04	4.88E-04	4.76E-04	4.80E-04
NMVOC total	air	kg	6.18E-05	6.29E-05	5.67E-05	5.78E-05
thereof:						
Benzene	air	kg	1.38E-06	1.38E-06	1.37E-06	1.37E-06
Benzo(a)pyrene	air	kg	7.14E-11	7.59E-11	6.60E-11	7.05E-11
Formaldehyde	air	kg	3.31E-07	3.33E-07	3.25E-07	3.26E-07
PAH	air	kg	6.46E-08	6.50E-08	6.30E-08	6.34E-08
PM2.5-10	air	kg	1.55E-05	1.61E-05	1.52E-05	1.57E-05
PM2.5	air	kg	1.09E-05	1.14E-05	1.05E-05	1.09E-05
PCDD/F (measured as I-TEQ)	air	kg	5.33E-14	5.38E-14	5.26E-14	5.31E-14
Radon-222	air	kBq	1.80E+01	1.89E+01	9.02E+00	9.97E+00
Sulfur dioxide	air	kg	4.13E-04	4.14E-04	4.07E-04	4.09E-04
Emissions to Water						
Ammonium, ion	water	kg	5.10E-07	5.19E-07	4.34E-07	4.44E-07
Arsenic, ion	water	kg	8.79E-08	8.95E-08	8.69E-08	8.84E-08
Cadmium, ion	water	kg	1.48E-08	1.59E-08	1.42E-08	1.54E-08
Carbon-14	water	kBq	4.18E-04	4.40E-04	2.09E-04	2.31E-04
Cesium-137	water	kBq	1.80E-04	1.89E-04	9.01E-05	9.96E-05
Chromium, ion	water	kg	3.63E-09	3.94E-09	2.76E-09	3.06E-09
Chromium VI	water	kg	8.09E-07	8.38E-07	7.96E-07	8.25E-07
COD	water	kg	2.39E-04	2.43E-04	2.35E-04	2.39E-04
Copper, ion	water	kg	1.38E-06	1.39E-06	1.38E-06	1.38E-06
Lead	water	kg	3.56E-07	3.59E-07	3.50E-07	3.53E-07
Mercury	water	kg	5.45E-09	5.63E-09	5.38E-09	5.56E-09
Nickel, ion	water	kg	7.27E-07	7.89E-07	7.00E-07	7.63E-07
Nitrate	water	kg	1.58E-06	1.60E-06	1.39E-06	1.42E-06
Oils, unspecified	water	kg	2.09E-05	2.13E-05	2.04E-05	2.08E-05
PAH	water	kg	3.03E-09	3.26E-09	2.92E-09	3.14E-09
Phosphate	water	kg	7.65E-06	7.77E-06	7.58E-06	7.70E-06
Emissions to Soil						
Arsenic	soil	kg	1.51E-10	1.53E-10	8.81E-11	9.02E-11
Cadmium	soil	kg	8.04E-12	8.60E-12	7.68E-12	8.24E-12
Chromium	soil	kg	2.02E-09	2.05E-09	1.23E-09	1.26E-09
Chromium VI	soil	kg	1.76E-08	1.87E-08	7.57E-09	8.64E-09
Lead	soil	kg	6.14E-11	6.45E-11	5.86E-11	6.17E-11
Mercury	soil	kg	6.19E-13	6.24E-13	6.10E-13	6.14E-13
Oils, unspecified	soil	kg	2.08E-05	2.11E-05	2.04E-05	2.08E-05

Table 8.54 LCA results for year 2050, very optimistic development, "440 ppm-scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.65E-01	4.65E-01	4.65E-01	4.65E-01
Coal, hard, unspecified, in ground	resource	kg	7.77E-04	9.11E-04	6.10E-04	7.44E-04
Gas, natural, in ground	resource	Nm3	1.07E-02	1.14E-02	4.40E-03	5.09E-03
Oil, crude, in ground	resource	kg	1.24E-03	1.35E-03	1.12E-03	1.23E-03
Uranium, in ground	resource	kg	5.84E-07	6.20E-07	2.40E-07	2.77E-07
Freshwater (lake, river, groundwater)	resource	m3	2.07E-03	2.10E-03	1.85E-03	1.88E-03
Occupation, agricultural and forestal area	resource	m2a	1.20E-03	1.27E-03	6.88E-04	7.57E-04
Occupation, built up area incl. mineral extractio	resource	m2a	1.14E-03	1.17E-03	1.12E-03	1.15E-03
Emissions to air						
Ammonia	air	kg	9.05E-07	9.73E-07	7.30E-07	7.98E-07
Arsenic	air	kg	4.88E-09	4.93E-09	4.66E-09	4.71E-09
Cadmium	air	kg	5.05E-10	5.26E-10	4.13E-10	4.35E-10
Carbon dioxide, fossil	air	kg	1.06E-01	1.07E-01	1.03E-01	1.04E-01
Carbon monoxide, fossil	air	kg	1.05E-04	1.10E-04	1.01E-04	1.06E-04
Carbon-14	air	kBq	1.66E-03	1.77E-03	6.77E-04	7.82E-04
Chromium	air	kg	5.08E-08	5.75E-08	4.62E-08	5.29E-08
Chromium VI	air	kg	1.35E-09	1.51E-09	1.24E-09	1.40E-09
Dinitrogen monoxide	air	kg	3.13E-05	3.14E-05	3.05E-05	3.06E-05
Iodine-129	air	kBq	1.02E-06	1.08E-06	4.17E-07	4.80E-07
Lead	air	kg	9.09E-09	9.75E-09	7.57E-09	8.23E-09
Methane, fossil	air	kg	1.53E-04	1.56E-04	1.37E-04	1.40E-04
Mercury	air	kg	1.32E-08	1.34E-08	1.31E-08	1.33E-08
Nickel	air	kg	6.66E-09	7.05E-09	5.65E-09	6.03E-09
Nitrogen oxides	air	kg	4.91E-04	4.96E-04	4.82E-04	4.86E-04
NMVOC total	air	kg	3.37E-05	3.51E-05	2.74E-05	2.88E-05
thereof:						
Benzene	air	kg	1.17E-06	1.17E-06	1.16E-06	1.16E-06
Benzo(a)pyrene	air	kg	4.48E-11	5.04E-11	3.81E-11	4.37E-11
Formaldehyde	air	kg	3.31E-07	3.33E-07	3.22E-07	3.24E-07
PAH	air	kg	5.73E-08	5.78E-08	5.53E-08	5.58E-08
PM2.5-10	air	kg	4.80E-06	5.53E-06	4.35E-06	5.07E-06
PM2.5	air	kg	3.99E-06	4.59E-06	3.38E-06	3.99E-06
PCDD/F (measured as I-TEQ)	air	kg	5.29E-14	5.35E-14	5.21E-14	5.27E-14
Radon-222	air	kBq	1.90E+01	2.01E+01	7.79E+00	8.98E+00
Sulfur dioxide	air	kg	7.08E-04	7.09E-04	7.01E-04	7.02E-04
Emissions to Water						
Ammonium, ion	water	kg	2.08E-07	2.20E-07	1.14E-07	1.25E-07
Arsenic, ion	water	kg	1.41E-06	1.41E-06	1.41E-06	1.41E-06
Cadmium, ion	water	kg	8.92E-08	9.06E-08	8.86E-08	9.00E-08
Carbon-14	water	kBq	4.41E-04	4.69E-04	1.80E-04	2.08E-04
Cesium-137	water	kBq	1.90E-04	2.02E-04	7.76E-05	8.95E-05
Chromium, ion	water	kg	2.80E-09	3.18E-09	1.70E-09	2.08E-09
Chromium VI	water	kg	9.04E-06	9.08E-06	9.03E-06	9.06E-06
COD	water	kg	2.02E-03	2.02E-03	2.01E-03	2.02E-03
Copper, ion	water	kg	6.52E-06	6.54E-06	6.52E-06	6.53E-06
Lead	water	kg	1.83E-06	1.83E-06	1.82E-06	1.82E-06
Mercury	water	kg	5.92E-08	5.94E-08	5.91E-08	5.94E-08
Nickel, ion	water	kg	3.90E-06	3.98E-06	3.87E-06	3.95E-06
Nitrate	water	kg	1.12E-06	1.14E-06	8.84E-07	9.13E-07
Oils, unspecified	water	kg	4.65E-06	5.22E-06	4.02E-06	4.59E-06
PAH	water	kg	1.63E-09	1.92E-09	1.49E-09	1.77E-09
Phosphate	water	kg	1.06E-04	1.07E-04	1.06E-04	1.07E-04
Emissions to Soil						
Arsenic	soil	kg	1.28E-10	1.31E-10	5.00E-11	5.26E-11
Cadmium	soil	kg	7.45E-12	8.14E-12	6.99E-12	7.69E-12
Chromium	soil	kg	1.71E-09	1.75E-09	7.27E-10	7.67E-10
Chromium VI	soil	kg	1.95E-08	2.08E-08	6.89E-09	8.22E-09
Lead	soil	kg	5.51E-11	5.90E-11	5.17E-11	5.56E-11
Mercury	soil	kg	2.28E-13	2.34E-13	2.16E-13	2.22E-13
Oils, unspecified	soil	kg	3.99E-06	4.44E-06	3.55E-06	4.00E-06

Table 8.55 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	1.14E-02	1.20E-02	1.09E-02	1.14E-02
Coal, hard, unspecified, in ground	resource	kg	5.30E-01	5.31E-01	5.30E-01	5.30E-01
Gas, natural, in ground	resource	Nm3	6.57E-03	6.91E-03	8.86E-03	9.17E-03
Oil, crude, in ground	resource	kg	7.21E-03	7.34E-03	9.03E-03	9.15E-03
Uranium, in ground	resource	kg	8.04E-07	8.46E-07	7.67E-07	8.05E-07
Freshwater (lake, river, groundwater)	resource	m3	2.97E-03	3.00E-03	2.99E-03	3.02E-03
Occupation, agricultural and forestal area	resource	m2a	2.59E-02	2.60E-02	2.61E-02	2.63E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.82E-03	5.86E-03	5.83E-03	5.87E-03
Emissions to air						
Ammonia	air	kg	2.41E-05	2.42E-05	2.49E-04	2.49E-04
Arsenic	air	kg	2.14E-08	2.17E-08	2.19E-08	2.21E-08
Cadmium	air	kg	2.62E-09	2.68E-09	3.23E-09	3.29E-09
Carbon dioxide, fossil	air	kg	8.49E-02	8.80E-02	1.78E-01	1.81E-01
Carbon monoxide, fossil	air	kg	2.12E-04	2.19E-04	2.16E-04	2.22E-04
Carbon-14	air	kBq	1.65E-03	1.74E-03	1.57E-03	1.65E-03
Chromium	air	kg	2.66E-07	2.74E-07	2.71E-07	2.78E-07
Chromium VI	air	kg	7.34E-09	7.51E-09	7.46E-09	7.62E-09
Dinitrogen monoxide	air	kg	4.30E-05	4.32E-05	4.31E-05	4.32E-05
Iodine-129	air	kBq	1.41E-06	1.49E-06	1.34E-06	1.41E-06
Lead	air	kg	8.86E-08	9.05E-08	9.06E-08	9.23E-08
Methane, fossil	air	kg	2.96E-03	2.96E-03	2.97E-03	2.97E-03
Mercury	air	kg	4.34E-08	4.36E-08	4.38E-08	4.41E-08
Nickel	air	kg	1.42E-07	1.43E-07	1.53E-07	1.54E-07
Nitrogen oxides	air	kg	6.82E-04	6.89E-04	1.03E-03	1.03E-03
NMVOC total	air	kg	7.86E-05	7.99E-05	8.83E-05	8.94E-05
thereof:						
Benzene	air	kg	2.54E-06	2.55E-06	2.76E-06	2.76E-06
Benzo(a)pyrene	air	kg	1.89E-10	1.97E-10	1.93E-10	2.00E-10
Formaldehyde	air	kg	6.25E-07	6.28E-07	6.38E-07	6.41E-07
PAH	air	kg	2.66E-08	2.71E-08	2.70E-08	2.74E-08
PM2.5-10	air	kg	2.91E-05	3.00E-05	3.02E-05	3.10E-05
PM2.5	air	kg	6.64E-05	6.72E-05	6.76E-05	6.84E-05
PCDD/F (measured as I-TEQ)	air	kg	9.16E-14	9.34E-14	1.04E-13	1.06E-13
Radon-222	air	kBq	2.61E+01	2.75E+01	2.49E+01	2.61E+01
Sulfur dioxide	air	kg	3.98E-04	4.00E-04	4.11E-04	4.14E-04
Emissions to Water						
Ammonium, ion	water	kg	1.18E-06	1.19E-06	5.14E-06	5.14E-06
Arsenic, ion	water	kg	1.76E-07	1.79E-07	1.77E-07	1.79E-07
Cadmium, ion	water	kg	1.83E-08	1.98E-08	1.85E-08	1.98E-08
Carbon-14	water	kBq	5.68E-04	5.98E-04	5.40E-04	5.67E-04
Cesium-137	water	kBq	2.64E-04	2.78E-04	2.51E-04	2.64E-04
Chromium, ion	water	kg	2.49E-08	2.53E-08	2.49E-08	2.53E-08
Chromium VI	water	kg	3.85E-07	4.24E-07	3.93E-07	4.28E-07
COD	water	kg	1.67E-04	1.72E-04	2.58E-04	2.63E-04
Copper, ion	water	kg	6.69E-07	6.81E-07	6.98E-07	7.09E-07
Lead	water	kg	3.02E-07	3.07E-07	3.04E-07	3.08E-07
Mercury	water	kg	4.05E-09	4.30E-09	4.16E-09	4.38E-09
Nickel, ion	water	kg	1.61E-06	1.69E-06	1.64E-06	1.72E-06
Nitrate	water	kg	3.46E-05	3.46E-05	4.57E-05	4.57E-05
Oils, unspecified	water	kg	3.16E-05	3.22E-05	3.43E-05	3.50E-05
PAH	water	kg	8.21E-09	8.53E-09	8.54E-09	8.82E-09
Phosphate	water	kg	4.19E-06	4.37E-06	7.19E-06	7.36E-06
Emissions to Soil						
Arsenic	soil	kg	1.96E-10	1.98E-10	1.95E-10	1.97E-10
Cadmium	soil	kg	1.00E-11	1.07E-11	1.39E-11	1.46E-11
Chromium	soil	kg	2.61E-09	2.64E-09	2.76E-09	2.79E-09
Chromium VI	soil	kg	2.42E-08	2.57E-08	2.29E-08	2.42E-08
Lead	soil	kg	7.61E-11	8.03E-11	1.28E-10	1.32E-10
Mercury	soil	kg	8.42E-13	8.54E-13	9.57E-13	9.68E-13
Oils, unspecified	soil	kg	3.18E-05	3.24E-05	3.45E-05	3.50E-05

Table 8.56 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	5.81E-03	6.40E-03	5.78E-03	6.32E-03
Coal, hard, unspecified, in ground	resource	kg	5.23E-01	5.24E-01	5.23E-01	5.24E-01
Gas, natural, in ground	resource	Nm3	3.68E-03	4.02E-03	6.25E-03	6.55E-03
Oil, crude, in ground	resource	kg	6.94E-03	7.07E-03	8.78E-03	8.90E-03
Uranium, in ground	resource	kg	4.12E-07	4.53E-07	4.12E-07	4.50E-07
Freshwater (lake, river, groundwater)	resource	m3	2.75E-03	2.78E-03	2.79E-03	2.82E-03
Occupation, agricultural and forestal area	resource	m2a	2.48E-02	2.49E-02	2.51E-02	2.52E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.72E-03	5.76E-03	5.75E-03	5.78E-03
Emissions to air						
Ammonia	air	kg	2.35E-05	2.36E-05	2.48E-04	2.48E-04
Arsenic	air	kg	2.01E-08	2.03E-08	2.06E-08	2.09E-08
Cadmium	air	kg	2.22E-09	2.28E-09	2.87E-09	2.92E-09
Carbon dioxide, fossil	air	kg	6.06E-02	6.38E-02	1.56E-01	1.59E-01
Carbon monoxide, fossil	air	kg	2.04E-04	2.11E-04	2.09E-04	2.15E-04
Carbon-14	air	kBq	8.45E-04	9.30E-04	8.41E-04	9.19E-04
Chromium	air	kg	2.59E-07	2.67E-07	2.65E-07	2.72E-07
Chromium VI	air	kg	7.16E-09	7.34E-09	7.30E-09	7.46E-09
Dinitrogen monoxide	air	kg	4.16E-05	4.18E-05	4.18E-05	4.20E-05
Iodine-129	air	kBq	7.21E-07	7.95E-07	7.18E-07	7.84E-07
Lead	air	kg	8.36E-08	8.56E-08	8.61E-08	8.78E-08
Methane, fossil	air	kg	2.90E-03	2.91E-03	2.92E-03	2.92E-03
Mercury	air	kg	4.26E-08	4.29E-08	4.32E-08	4.34E-08
Nickel	air	kg	1.37E-07	1.38E-07	1.48E-07	1.49E-07
Nitrogen oxides	air	kg	6.54E-04	6.61E-04	1.00E-03	1.01E-03
NMVOC total	air	kg	7.42E-05	7.55E-05	8.42E-05	8.54E-05
thereof:						
Benzene	air	kg	2.50E-06	2.51E-06	2.72E-06	2.72E-06
Benzo(a)pyrene	air	kg	1.77E-10	1.85E-10	1.82E-10	1.89E-10
Formaldehyde	air	kg	6.08E-07	6.11E-07	6.23E-07	6.26E-07
PAH	air	kg	2.54E-08	2.59E-08	2.59E-08	2.63E-08
PM2.5-10	air	kg	2.83E-05	2.91E-05	2.95E-05	3.02E-05
PM2.5	air	kg	6.47E-05	6.55E-05	6.60E-05	6.68E-05
PCDD/F (measured as I-TEQ)	air	kg	8.89E-14	9.07E-14	1.02E-13	1.03E-13
Radon-222	air	kBq	1.34E+01	1.47E+01	1.33E+01	1.46E+01
Sulfur dioxide	air	kg	3.80E-04	3.83E-04	3.96E-04	3.98E-04
Emissions to Water						
Ammonium, ion	water	kg	1.11E-06	1.12E-06	5.07E-06	5.08E-06
Arsenic, ion	water	kg	1.67E-07	1.70E-07	1.69E-07	1.71E-07
Cadmium, ion	water	kg	1.74E-08	1.89E-08	1.77E-08	1.91E-08
Carbon-14	water	kBq	2.90E-04	3.19E-04	2.88E-04	3.15E-04
Cesium-137	water	kBq	1.35E-04	1.49E-04	1.34E-04	1.47E-04
Chromium, ion	water	kg	2.34E-08	2.38E-08	2.35E-08	2.39E-08
Chromium VI	water	kg	3.64E-07	4.03E-07	3.74E-07	4.09E-07
COD	water	kg	1.60E-04	1.65E-04	2.52E-04	2.56E-04
Copper, ion	water	kg	6.47E-07	6.60E-07	6.78E-07	6.90E-07
Lead	water	kg	2.86E-07	2.91E-07	2.89E-07	2.93E-07
Mercury	water	kg	3.92E-09	4.17E-09	4.04E-09	4.26E-09
Nickel, ion	water	kg	1.56E-06	1.64E-06	1.59E-06	1.67E-06
Nitrate	water	kg	3.40E-05	3.41E-05	4.51E-05	4.52E-05
Oils, unspecified	water	kg	3.03E-05	3.10E-05	3.32E-05	3.38E-05
PAH	water	kg	7.97E-09	8.28E-09	8.31E-09	8.60E-09
Phosphate	water	kg	3.89E-06	4.07E-06	6.92E-06	7.09E-06
Emissions to Soil						
Arsenic	soil	kg	1.19E-10	1.21E-10	1.26E-10	1.28E-10
Cadmium	soil	kg	9.45E-12	1.01E-11	1.34E-11	1.40E-11
Chromium	soil	kg	1.64E-09	1.67E-09	1.89E-09	1.92E-09
Chromium VI	soil	kg	1.05E-08	1.20E-08	1.05E-08	1.18E-08
Lead	soil	kg	6.90E-11	7.32E-11	1.22E-10	1.25E-10
Mercury	soil	kg	7.60E-13	7.72E-13	8.83E-13	8.94E-13
Oils, unspecified	soil	kg	3.06E-05	3.12E-05	3.34E-05	3.39E-05

Table 8.57 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	2.37E-03	2.36E-03	2.36E-03
Coal, hard, unspecified, in ground	resource	kg	4.10E-01	4.10E-01	4.10E-01
Gas, natural, in ground	resource	Nm3	1.84E-03	1.83E-03	1.83E-03
Oil, crude, in ground	resource	kg	5.29E-03	5.30E-03	5.30E-03
Uranium, in ground	resource	kg	1.71E-07	1.70E-07	1.70E-07
Freshwater (lake, river, groundwater)	resource	m3	2.06E-03	2.06E-03	2.06E-03
Occupation, agricultural and forestal area	resource	m2a	1.90E-02	1.90E-02	1.90E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.43E-03	4.40E-03	4.40E-03
Emissions to air					
Ammonia	air	kg	2.00E-05	2.00E-05	2.00E-05
Arsenic	air	kg	1.48E-08	1.46E-08	1.46E-08
Cadmium	air	kg	1.56E-09	1.52E-09	1.52E-09
Carbon dioxide, fossil	air	kg	7.40E-01	7.40E-01	7.40E-01
Carbon monoxide, fossil	air	kg	1.51E-04	1.50E-04	1.50E-04
Carbon-14	air	kBq	3.49E-04	3.47E-04	3.47E-04
Chromium	air	kg	1.54E-07	1.37E-07	1.37E-07
Chromium VI	air	kg	4.38E-09	4.00E-09	4.00E-09
Dinitrogen monoxide	air	kg	3.22E-05	3.22E-05	3.22E-05
Iodine-129	air	kBq	2.97E-07	2.96E-07	2.96E-07
Lead	air	kg	6.06E-08	6.00E-08	6.00E-08
Methane, fossil	air	kg	2.27E-03	2.27E-03	2.27E-03
Mercury	air	kg	3.30E-08	3.30E-08	3.30E-08
Nickel	air	kg	1.06E-07	1.05E-07	1.05E-07
Nitrogen oxides	air	kg	7.60E-04	7.60E-04	7.60E-04
NMVOC total	air	kg	5.60E-05	5.60E-05	5.60E-05
thereof:					
Benzene	air	kg	1.94E-06	1.94E-06	1.94E-06
Benzo(a)pyrene	air	kg	1.19E-10	1.15E-10	1.15E-10
Formaldehyde	air	kg	4.71E-07	4.70E-07	4.70E-07
PAH	air	kg	1.90E-08	1.89E-08	1.89E-08
PM2.5-10	air	kg	2.09E-05	2.07E-05	2.07E-05
PM2.5	air	kg	4.92E-05	4.90E-05	4.90E-05
PCDD/F (measured as I-TEQ)	air	kg	6.70E-14	6.70E-14	6.70E-14
Radon-222	air	kBq	5.54E+00	5.50E+00	5.50E+00
Sulfur dioxide	air	kg	5.49E-04	5.50E-04	5.50E-04
Emissions to Water					
Ammonium, ion	water	kg	8.20E-07	8.20E-07	8.20E-07
Arsenic, ion	water	kg	1.24E-07	1.23E-07	1.23E-07
Cadmium, ion	water	kg	1.15E-08	1.13E-08	1.12E-08
Carbon-14	water	kBq	1.19E-04	1.19E-04	1.19E-04
Cesium-137	water	kBq	5.56E-05	5.50E-05	5.50E-05
Chromium, ion	water	kg	1.67E-08	1.66E-08	1.66E-08
Chromium VI	water	kg	2.36E-07	2.30E-07	2.30E-07
COD	water	kg	1.18E-04	1.17E-04	1.17E-04
Copper, ion	water	kg	4.65E-07	4.60E-07	4.60E-07
Lead	water	kg	1.99E-07	1.96E-07	1.94E-07
Mercury	water	kg	2.69E-09	2.67E-09	2.67E-09
Nickel, ion	water	kg	9.80E-07	9.20E-07	9.20E-07
Nitrate	water	kg	2.52E-05	2.52E-05	2.52E-05
Oils, unspecified	water	kg	2.31E-05	2.30E-05	2.30E-05
PAH	water	kg	5.08E-09	4.70E-09	4.70E-09
Phosphate	water	kg	2.77E-06	2.75E-06	2.75E-06
Emissions to Soil					
Arsenic	soil	kg	6.46E-11	6.40E-11	6.40E-11
Cadmium	soil	kg	6.70E-12	6.60E-12	6.60E-12
Chromium	soil	kg	9.20E-10	9.20E-10	9.20E-10
Chromium VI	soil	kg	2.97E-09	2.95E-09	2.95E-09
Lead	soil	kg	4.93E-11	4.90E-11	4.90E-11
Mercury	soil	kg	5.63E-13	5.60E-13	5.60E-13
Oils, unspecified	soil	kg	2.34E-05	2.34E-05	2.34E-05

Table 8.58 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	1.12E+00	1.12E+00	1.12E+00
Coal, hard, unspecified, in ground	resource	kg	1.56E-02	1.66E-02	1.48E-02
Gas, natural, in ground	resource	Nm3	6.48E-03	6.88E-03	9.26E-03
Oil, crude, in ground	resource	kg	1.63E-03	1.79E-03	3.77E-03
Uranium, in ground	resource	kg	8.35E-07	8.84E-07	7.90E-07
Freshwater (lake, river, groundwater)	resource	m3	6.07E-03	6.11E-03	6.08E-03
Occupation, agricultural and forestal area	resource	m2a	3.46E-03	3.62E-03	3.75E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.61E-03	1.66E-03	1.62E-03
Emissions to air					
Ammonia	air	kg	3.66E-06	3.80E-06	2.40E-04
Arsenic	air	kg	1.36E-08	1.39E-08	1.41E-08
Cadmium	air	kg	2.19E-09	2.26E-09	2.96E-09
Carbon dioxide, fossil	air	kg	6.85E-02	7.22E-02	1.77E-01
Carbon monoxide, fossil	air	kg	2.54E-04	2.62E-04	2.59E-04
Carbon-14	air	kBq	1.72E-03	1.82E-03	1.62E-03
Chromium	air	kg	9.31E-08	1.02E-07	9.90E-08
Chromium VI	air	kg	2.49E-09	2.70E-09	2.63E-09
Dinitrogen monoxide	air	kg	2.83E-05	2.85E-05	2.83E-05
Iodine-129	air	kBq	1.47E-06	1.56E-06	1.39E-06
Lead	air	kg	3.33E-08	3.55E-08	3.56E-08
Methane, fossil	air	kg	3.90E-04	3.98E-04	4.02E-04
Mercury	air	kg	2.54E-08	2.58E-08	2.60E-08
Nickel	air	kg	2.72E-08	2.84E-08	4.11E-08
Nitrogen oxides	air	kg	3.59E-04	3.67E-04	9.23E-04
NMVOC total	air	kg	3.57E-05	3.72E-05	4.70E-05
thereof:					
Benzene	air	kg	2.23E-06	2.24E-06	2.49E-06
Benzo(a)pyrene	air	kg	1.27E-10	1.36E-10	1.31E-10
Formaldehyde	air	kg	6.30E-07	6.33E-07	6.46E-07
PAH	air	kg	1.64E-08	1.70E-08	1.68E-08
PM2.5-10	air	kg	1.66E-05	1.76E-05	1.79E-05
PM2.5	air	kg	7.83E-05	7.92E-05	7.97E-05
PCDD/F (measured as I-TEQ)	air	kg	8.52E-14	8.74E-14	9.79E-14
Radon-222	air	kBq	2.71E+01	2.87E+01	2.56E+01
Sulfur dioxide	air	kg	1.49E-04	1.52E-04	1.66E-04
Emissions to Water					
Ammonium, ion	water	kg	1.91E-07	2.03E-07	4.85E-06
Arsenic, ion	water	kg	1.09E-06	1.09E-06	1.09E-06
Cadmium, ion	water	kg	3.82E-08	4.00E-08	3.84E-08
Carbon-14	water	kBq	5.91E-04	6.26E-04	5.57E-04
Cesium-137	water	kBq	2.75E-04	2.91E-04	2.59E-04
Chromium, ion	water	kg	4.47E-09	4.99E-09	4.47E-09
Chromium VI	water	kg	9.34E-07	9.79E-07	9.42E-07
COD	water	kg	5.41E-05	6.01E-05	1.57E-04
Copper, ion	water	kg	1.18E-06	1.20E-06	1.22E-06
Lead	water	kg	1.16E-06	1.16E-06	1.16E-06
Mercury	water	kg	6.85E-09	7.15E-09	6.97E-09
Nickel, ion	water	kg	2.25E-06	2.35E-06	2.28E-06
Nitrate	water	kg	1.29E-06	1.37E-06	1.40E-05
Oils, unspecified	water	kg	7.76E-06	8.55E-06	1.10E-05
PAH	water	kg	2.91E-09	3.28E-09	3.30E-09
Phosphate	water	kg	3.81E-05	3.83E-05	4.11E-05
Emissions to Soil					
Arsenic	soil	kg	1.50E-10	1.52E-10	1.49E-10
Cadmium	soil	kg	7.21E-12	8.00E-12	1.18E-11
Chromium	soil	kg	1.96E-09	2.00E-09	2.15E-09
Chromium VI	soil	kg	2.49E-08	2.66E-08	2.33E-08
Lead	soil	kg	4.90E-11	5.39E-11	1.10E-10
Mercury	soil	kg	2.50E-13	2.65E-13	3.75E-13
Oils, unspecified	soil	kg	6.94E-06	7.60E-06	1.01E-05

Table 8.59 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	1.12E+00	1.12E+00	1.12E+00
Coal, hard, unspecified, in ground	resource	kg	1.57E-02	7.49E-03	1.37E-02
Gas, natural, in ground	resource	Nm3	9.62E-03	3.08E-03	7.14E-03
Oil, crude, in ground	resource	kg	3.91E-03	1.31E-03	4.35E-02
Uranium, in ground	resource	kg	8.34E-07	3.73E-07	6.20E-07
Freshwater (lake, river, groundwater)	resource	m3	6.12E-03	5.81E-03	6.42E-03
Occupation, agricultural and forestal area	resource	m2a	3.89E-03	2.12E-03	3.05E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.67E-03	1.49E-03	3.23E-03
Emissions to air					
Ammonia	air	kg	2.41E-04	2.96E-06	5.00E-06
Arsenic	air	kg	1.44E-08	1.20E-08	1.91E-08
Cadmium	air	kg	3.03E-09	1.71E-09	6.55E-09
Carbon dioxide, fossil	air	kg	1.80E-01	4.00E-02	1.71E-01
Carbon monoxide, fossil	air	kg	2.66E-04	2.45E-04	6.13E-04
Carbon-14	air	kBq	1.71E-03	7.66E-04	1.25E-03
Chromium	air	kg	1.07E-07	8.51E-08	1.21E-07
Chromium VI	air	kg	2.82E-09	2.28E-09	2.94E-09
Dinitrogen monoxide	air	kg	2.85E-05	2.66E-05	3.20E-05
Iodine-129	air	kBq	1.46E-06	6.56E-07	1.04E-06
Lead	air	kg	3.77E-08	2.74E-08	1.07E-07
Methane, fossil	air	kg	4.09E-04	3.26E-04	4.71E-04
Mercury	air	kg	2.62E-08	2.46E-08	3.04E-08
Nickel	air	kg	4.23E-08	2.07E-08	6.67E-08
Nitrogen oxides	air	kg	9.31E-04	3.26E-04	9.21E-04
NMVOC total	air	kg	4.83E-05	3.04E-05	3.41E-04
thereof:					
Benzene	air	kg	2.50E-06	2.18E-06	6.04E-06
Benzo(a)pyrene	air	kg	1.39E-10	1.12E-10	5.24E-10
Formaldehyde	air	kg	6.49E-07	6.10E-07	6.42E-07
PAH	air	kg	1.73E-08	1.51E-08	3.09E-08
PM2.5-10	air	kg	1.87E-05	1.56E-05	3.88E-05
PM2.5	air	kg	8.05E-05	7.62E-05	1.12E-04
PCDD/F (measured as I-TEQ)	air	kg	9.98E-14	8.20E-14	1.25E-13
Radon-222	air	kBq	2.70E+01	1.21E+01	2.00E+01
Sulfur dioxide	air	kg	1.69E-04	1.29E-04	3.19E-04
Emissions to Water					
Ammonium, ion	water	kg	4.86E-06	1.05E-07	4.22E-07
Arsenic, ion	water	kg	1.09E-06	1.08E-06	1.13E-06
Cadmium, ion	water	kg	4.00E-08	3.72E-08	7.47E-08
Carbon-14	water	kBq	5.89E-04	2.64E-04	4.15E-04
Cesium-137	water	kBq	2.74E-04	1.23E-04	1.94E-04
Chromium, ion	water	kg	4.94E-09	2.71E-09	2.61E-08
Chromium VI	water	kg	9.83E-07	9.10E-07	1.68E-06
COD	water	kg	1.62E-04	4.59E-05	6.39E-04
Copper, ion	water	kg	1.23E-06	1.16E-06	1.47E-06
Lead	water	kg	1.17E-06	1.14E-06	1.25E-06
Mercury	water	kg	7.24E-09	6.69E-09	1.13E-08
Nickel, ion	water	kg	2.37E-06	2.19E-06	2.98E-06
Nitrate	water	kg	1.40E-05	6.12E-07	2.33E-06
Oils, unspecified	water	kg	1.18E-05	6.28E-06	1.70E-04
PAH	water	kg	3.63E-09	2.62E-09	1.81E-08
Phosphate	water	kg	4.13E-05	3.77E-05	4.06E-05
Emissions to Soil					
Arsenic	soil	kg	1.52E-10	5.93E-11	5.13E-10
Cadmium	soil	kg	1.25E-11	6.53E-12	1.49E-09
Chromium	soil	kg	2.18E-09	8.18E-10	2.17E-08
Chromium VI	soil	kg	2.48E-08	8.82E-09	1.70E-08
Lead	soil	kg	1.15E-10	4.07E-11	7.89E-09
Mercury	soil	kg	3.88E-13	1.53E-13	1.08E-12
Oils, unspecified	soil	kg	1.07E-05	5.54E-06	1.73E-04

Table 8.60 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	1.12E+00	1.12E+00	8.70E-01
Coal, hard, unspecified, in ground	resource	kg	7.53E-03	8.46E-03	2.41E-03
Gas, natural, in ground	resource	Nm3	6.19E-03	6.55E-03	1.25E-03
Oil, crude, in ground	resource	kg	3.48E-03	3.62E-03	8.40E-04
Uranium, in ground	resource	kg	3.73E-07	4.18E-07	1.12E-07
Freshwater (lake, river, groundwater)	resource	m3	5.85E-03	5.88E-03	4.44E-03
Occupation, agricultural and forestal area	resource	m2a	2.54E-03	2.68E-03	1.03E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.52E-03	1.56E-03	1.07E-03
Emissions to air					
Ammonia	air	kg	2.40E-04	2.40E-04	5.08E-06
Arsenic	air	kg	1.27E-08	1.29E-08	8.20E-09
Cadmium	air	kg	2.53E-09	2.60E-09	1.12E-09
Carbon dioxide, fossil	air	kg	1.51E-01	1.55E-01	8.50E-01
Carbon monoxide, fossil	air	kg	2.51E-04	2.58E-04	1.77E-04
Carbon-14	air	kBq	7.61E-04	8.52E-04	2.30E-04
Chromium	air	kg	9.19E-08	9.96E-08	4.08E-08
Chromium VI	air	kg	2.44E-09	2.63E-09	1.15E-09
Dinitrogen monoxide	air	kg	2.68E-05	2.70E-05	2.03E-05
Iodine-129	air	kBq	6.51E-07	7.29E-07	1.96E-07
Lead	air	kg	3.03E-08	3.24E-08	1.52E-08
Methane, fossil	air	kg	3.44E-04	3.52E-04	2.29E-04
Mercury	air	kg	2.52E-08	2.55E-08	1.86E-08
Nickel	air	kg	3.53E-08	3.64E-08	1.46E-08
Nitrogen oxides	air	kg	8.94E-04	9.01E-04	6.70E-04
NMVOC total	air	kg	4.22E-05	4.36E-05	2.09E-05
thereof:					
Benzene	air	kg	2.44E-06	2.45E-06	1.69E-06
Benzo(a)pyrene	air	kg	1.17E-10	1.26E-10	5.80E-11
Formaldehyde	air	kg	6.28E-07	6.31E-07	4.70E-07
PAH	air	kg	1.56E-08	1.61E-08	1.05E-08
PM2.5-10	air	kg	1.70E-05	1.79E-05	1.03E-05
PM2.5	air	kg	7.78E-05	7.87E-05	5.80E-05
PCDD/F (measured as I-TEQ)	air	kg	9.50E-14	9.69E-14	6.00E-14
Radon-222	air	kBq	1.20E+01	1.35E+01	3.64E+00
Sulfur dioxide	air	kg	1.47E-04	1.50E-04	1.26E-04
Emissions to Water					
Ammonium, ion	water	kg	4.77E-06	4.78E-06	4.49E-08
Arsenic, ion	water	kg	1.08E-06	1.08E-06	8.40E-07
Cadmium, ion	water	kg	3.75E-08	3.91E-08	2.58E-08
Carbon-14	water	kBq	2.62E-04	2.93E-04	7.90E-05
Cesium-137	water	kBq	1.22E-04	1.36E-04	3.67E-05
Chromium, ion	water	kg	2.88E-09	3.35E-09	1.01E-09
Chromium VI	water	kg	9.20E-07	9.62E-07	6.30E-07
COD	water	kg	1.49E-04	1.55E-04	2.75E-05
Copper, ion	water	kg	1.19E-06	1.21E-06	8.80E-07
Lead	water	kg	1.14E-06	1.15E-06	8.70E-07
Mercury	water	kg	6.82E-09	7.09E-09	4.79E-09
Nickel, ion	water	kg	2.23E-06	2.32E-06	1.52E-06
Nitrate	water	kg	1.34E-05	1.34E-05	2.12E-07
Oils, unspecified	water	kg	9.71E-06	1.04E-05	3.89E-06
PAH	water	kg	3.03E-09	3.36E-09	1.28E-09
Phosphate	water	kg	4.08E-05	4.10E-05	2.93E-05
Emissions to Soil					
Arsenic	soil	kg	6.76E-11	6.98E-11	1.27E-11
Cadmium	soil	kg	1.12E-11	1.19E-11	3.82E-12
Chromium	soil	kg	1.12E-09	1.15E-09	2.13E-10
Chromium VI	soil	kg	8.73E-09	1.03E-08	6.50E-10
Lead	soil	kg	1.03E-10	1.07E-10	2.52E-11
Mercury	soil	kg	2.88E-13	3.01E-13	7.90E-14
Oils, unspecified	soil	kg	8.87E-06	9.47E-06	3.61E-06

Table 8.61 LCA results for year 2025, pessimistic development, “BAU-scenario”.

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	1.98E-03	4.34E-01
Coal, hard, unspecified, in ground	resource	kg	3.41E-01	1.69E-03
Gas, natural, in ground	resource	Nm3	1.37E-03	6.24E-04
Oil, crude, in ground	resource	kg	4.24E-03	1.07E-03
Uranium, in ground	resource	kg	1.44E-07	7.13E-08
Freshwater (lake, river, groundwater)	resource	m3	6.12E-04	1.61E-03
Occupation, agricultural and forestal area	resource	m2a	1.58E-02	4.98E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.87E-03	1.04E-03
Emissions to air				
Ammonia	air	kg	1.44E-05	6.37E-07
Arsenic	air	kg	6.43E-08	6.55E-09
Cadmium	air	kg	1.58E-09	1.14E-09
Carbon dioxide, fossil	air	kg	6.57E-01	7.94E-01
Carbon monoxide, fossil	air	kg	1.30E-04	8.53E-05
Carbon-14	air	kBq	2.94E-04	1.45E-04
Chromium	air	kg	4.39E-08	3.56E-08
Chromium VI	air	kg	1.42E-09	9.69E-10
Dinitrogen monoxide	air	kg	2.77E-05	2.54E-05
Iodine-129	air	kBq	2.50E-07	1.21E-07
Lead	air	kg	4.23E-08	1.40E-08
Methane, fossil	air	kg	1.89E-03	1.27E-04
Mercury	air	kg	2.05E-08	1.15E-08
Nickel	air	kg	8.34E-08	9.95E-09
Nitrogen oxides	air	kg	4.30E-04	4.07E-04
NMVOC total	air	kg	4.85E-05	2.10E-05
thereof:				
Benzene	air	kg	1.23E-06	1.02E-06
Benzo(a)pyrene	air	kg	9.51E-11	4.15E-11
Formaldehyde	air	kg	2.87E-07	2.81E-07
PAH	air	kg	5.53E-08	4.77E-08
PM2.5-10	air	kg	1.38E-05	3.48E-06
PM2.5	air	kg	9.89E-06	2.85E-06
PCDD/F (measured as I-TEQ)	air	kg	5.13E-14	4.81E-14
Radon-222	air	kBq	4.67E+00	2.31E+00
Sulfur dioxide	air	kg	3.63E-04	5.89E-04
Emissions to Water				
Ammonium, ion	water	kg	3.63E-07	5.91E-08
Arsenic, ion	water	kg	8.29E-08	1.33E-06
Cadmium, ion	water	kg	1.23E-08	8.21E-08
Carbon-14	water	kBq	1.00E-04	4.86E-05
Cesium-137	water	kBq	4.68E-05	2.27E-05
Chromium, ion	water	kg	2.11E-09	9.20E-10
Chromium VI	water	kg	7.21E-07	8.48E-06
COD	water	kg	2.19E-04	1.90E-03
Copper, ion	water	kg	1.29E-06	6.13E-06
Lead	water	kg	3.31E-07	1.71E-06
Mercury	water	kg	4.90E-09	5.55E-08
Nickel, ion	water	kg	5.99E-07	3.57E-06
Nitrate	water	kg	1.33E-06	7.76E-07
Oils, unspecified	water	kg	1.87E-05	3.31E-06
PAH	water	kg	2.52E-09	1.13E-09
Phosphate	water	kg	7.09E-06	1.00E-04
Emissions to Soil				
Arsenic	soil	kg	5.18E-11	1.09E-11
Cadmium	soil	kg	6.54E-12	5.88E-12
Chromium	soil	kg	7.63E-10	2.24E-10
Chromium VI	soil	kg	2.58E-09	7.27E-10
Lead	soil	kg	5.24E-11	4.51E-11
Mercury	soil	kg	5.84E-13	2.03E-13
Oils, unspecified	soil	kg	1.90E-05	3.04E-06

Table 8.62 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	8.94E-03	9.42E-03	4.44E-03	4.92E-03
Coal, hard, unspecified, in ground	resource	kg	3.93E-01	3.93E-01	3.87E-01	3.88E-01
Gas, natural, in ground	resource	Nm3	5.00E-03	5.27E-03	2.69E-03	2.96E-03
Oil, crude, in ground	resource	kg	5.18E-03	5.29E-03	4.96E-03	5.07E-03
Uranium, in ground	resource	kg	6.30E-07	6.63E-07	3.16E-07	3.50E-07
Freshwater (lake, river, groundwater)	resource	m3	9.61E-04	9.88E-04	7.84E-04	8.10E-04
Occupation, agricultural and forestal area	resource	m2a	1.92E-02	1.93E-02	1.82E-02	1.84E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.48E-03	4.51E-03	4.40E-03	4.44E-03
Emissions to air						
Ammonia	air	kg	1.70E-05	1.71E-05	1.65E-05	1.66E-05
Arsenic	air	kg	8.16E-08	8.18E-08	8.05E-08	8.07E-08
Cadmium	air	kg	2.22E-09	2.27E-09	1.90E-09	1.95E-09
Carbon dioxide, fossil	air	kg	1.38E-01	1.40E-01	1.18E-01	1.21E-01
Carbon monoxide, fossil	air	kg	1.67E-04	1.73E-04	1.61E-04	1.66E-04
Carbon-14	air	kBq	1.29E-03	1.36E-03	6.49E-04	7.17E-04
Chromium	air	kg	6.22E-08	6.80E-08	5.68E-08	6.26E-08
Chromium VI	air	kg	1.97E-09	2.11E-09	1.82E-09	1.97E-09
Dinitrogen monoxide	air	kg	3.62E-05	3.64E-05	3.51E-05	3.52E-05
Iodine-129	air	kBq	1.11E-06	1.17E-06	5.54E-07	6.12E-07
Lead	air	kg	5.71E-08	5.87E-08	5.32E-08	5.47E-08
Methane, fossil	air	kg	2.20E-03	2.20E-03	2.15E-03	2.16E-03
Mercury	air	kg	2.65E-08	2.67E-08	2.59E-08	2.61E-08
Nickel	air	kg	1.02E-07	1.03E-07	9.76E-08	9.84E-08
Nitrogen oxides	air	kg	5.41E-04	5.46E-04	5.18E-04	5.24E-04
NMVOC total	air	kg	6.24E-05	6.34E-05	5.88E-05	5.98E-05
thereof:						
Benzene	air	kg	1.58E-06	1.58E-06	1.54E-06	1.55E-06
Benzo(a)pyrene	air	kg	1.25E-10	1.32E-10	1.15E-10	1.22E-10
Formaldehyde	air	kg	3.78E-07	3.80E-07	3.64E-07	3.66E-07
PAH	air	kg	6.98E-08	7.02E-08	6.89E-08	6.93E-08
PM2.5-10	air	kg	1.70E-05	1.77E-05	1.64E-05	1.71E-05
PM2.5	air	kg	1.37E-05	1.43E-05	1.23E-05	1.29E-05
PCDD/F (measured as I-TEQ)	air	kg	6.61E-14	6.75E-14	6.39E-14	6.54E-14
Radon-222	air	kBq	2.05E+01	2.15E+01	1.03E+01	1.14E+01
Sulfur dioxide	air	kg	4.55E-04	4.57E-04	4.41E-04	4.43E-04
Emissions to Water						
Ammonium, ion	water	kg	4.98E-07	5.06E-07	4.39E-07	4.47E-07
Arsenic, ion	water	kg	1.04E-07	1.06E-07	9.69E-08	9.92E-08
Cadmium, ion	water	kg	1.57E-08	1.69E-08	1.50E-08	1.62E-08
Carbon-14	water	kBq	4.45E-04	4.69E-04	2.23E-04	2.46E-04
Cesium-137	water	kBq	2.07E-04	2.18E-04	1.04E-04	1.14E-04
Chromium, ion	water	kg	4.36E-09	4.71E-09	3.17E-09	3.52E-09
Chromium VI	water	kg	8.54E-07	8.85E-07	8.38E-07	8.69E-07
COD	water	kg	2.56E-04	2.60E-04	2.50E-04	2.55E-04
Copper, ion	water	kg	1.47E-06	1.48E-06	1.46E-06	1.47E-06
Lead	water	kg	3.87E-07	3.91E-07	3.74E-07	3.78E-07
Mercury	water	kg	5.79E-09	5.99E-09	5.69E-09	5.88E-09
Nickel, ion	water	kg	7.87E-07	8.54E-07	7.45E-07	8.13E-07
Nitrate	water	kg	2.18E-06	2.24E-06	1.72E-06	1.78E-06
Oils, unspecified	water	kg	2.30E-05	2.35E-05	2.20E-05	2.25E-05
PAH	water	kg	3.33E-09	3.58E-09	3.13E-09	3.38E-09
Phosphate	water	kg	8.36E-06	8.51E-06	8.13E-06	8.27E-06
Emissions to Soil						
Arsenic	soil	kg	1.50E-10	1.51E-10	8.82E-11	8.99E-11
Cadmium	soil	kg	8.43E-12	8.97E-12	7.97E-12	8.51E-12
Chromium	soil	kg	2.01E-09	2.04E-09	1.24E-09	1.27E-09
Chromium VI	soil	kg	1.92E-08	2.04E-08	8.27E-09	9.43E-09
Lead	soil	kg	6.95E-11	7.28E-11	6.38E-11	6.72E-11
Mercury	soil	kg	7.57E-13	7.67E-13	6.91E-13	7.01E-13
Oils, unspecified	soil	kg	2.31E-05	2.36E-05	2.22E-05	2.26E-05

Table 8.63 LCA results for year 2025, pessimistic development, "BAU-scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	5.00E-01	5.01E-01	4.95E-01	5.00E-01
Coal, hard, unspecified, in ground	resource	kg	1.23E-02	1.31E-02	5.41E-03	1.23E-02
Gas, natural, in ground	resource	Nm3	5.07E-03	5.41E-03	2.18E-03	5.07E-03
Oil, crude, in ground	resource	kg	1.71E-03	1.85E-03	1.44E-03	1.71E-03
Uranium, in ground	resource	kg	6.67E-07	7.08E-07	2.74E-07	6.67E-07
Freshwater (lake, river, groundwater)	resource	m3	2.17E-03	2.20E-03	1.95E-03	2.17E-03
Occupation, agricultural and forestal area	resource	m2a	2.27E-03	2.41E-03	1.13E-03	2.27E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.32E-03	1.36E-03	1.22E-03	1.32E-03
Emissions to air						
Ammonia	air	kg	1.65E-06	1.77E-06	1.05E-06	1.65E-06
Arsenic	air	kg	9.70E-09	9.95E-09	8.36E-09	9.70E-09
Cadmium	air	kg	1.83E-09	1.89E-09	1.42E-09	1.83E-09
Carbon dioxide, fossil	air	kg	1.48E-01	1.51E-01	1.24E-01	1.48E-01
Carbon monoxide, fossil	air	kg	1.23E-04	1.30E-04	1.15E-04	1.23E-04
Carbon-14	air	kBq	1.37E-03	1.46E-03	5.61E-04	1.37E-03
Chromium	air	kg	5.60E-08	6.33E-08	4.92E-08	5.60E-08
Chromium VI	air	kg	1.51E-09	1.69E-09	1.33E-09	1.51E-09
Dinitrogen monoxide	air	kg	3.42E-05	3.44E-05	3.28E-05	3.42E-05
Iodine-129	air	kBq	1.17E-06	1.24E-06	4.78E-07	1.17E-06
Lead	air	kg	2.41E-08	2.60E-08	1.91E-08	2.41E-08
Methane, fossil	air	kg	2.28E-04	2.35E-04	1.73E-04	2.28E-04
Mercury	air	kg	1.57E-08	1.60E-08	1.50E-08	1.57E-08
Nickel	air	kg	1.96E-08	2.07E-08	1.41E-08	1.96E-08
Nitrogen oxides	air	kg	5.57E-04	5.64E-04	5.29E-04	5.57E-04
NMVOC total	air	kg	3.32E-05	3.44E-05	2.87E-05	3.32E-05
thereof:						
Benzene	air	kg	1.38E-06	1.39E-06	1.33E-06	1.38E-06
Benzo(a)pyrene	air	kg	7.00E-11	7.81E-11	5.73E-11	7.00E-11
Formaldehyde	air	kg	3.79E-07	3.82E-07	3.63E-07	3.79E-07
PAH	air	kg	6.21E-08	6.26E-08	6.09E-08	6.21E-08
PM2.5-10	air	kg	5.80E-06	6.65E-06	4.97E-06	5.80E-06
PM2.5	air	kg	6.41E-06	7.23E-06	4.66E-06	6.41E-06
PCDD/F (measured as I-TEQ)	air	kg	6.39E-14	6.57E-14	6.12E-14	6.39E-14
Radon-222	air	kBq	2.17E+01	2.30E+01	8.89E+00	2.17E+01
Sulfur dioxide	air	kg	7.71E-04	7.74E-04	7.54E-04	7.71E-04
Emissions to Water						
Ammonium, ion	water	kg	1.78E-07	1.88E-07	1.04E-07	1.78E-07
Arsenic, ion	water	kg	1.50E-06	1.50E-06	1.49E-06	1.50E-06
Cadmium, ion	water	kg	9.42E-08	9.58E-08	9.34E-08	9.42E-08
Carbon-14	water	kBq	4.70E-04	5.00E-04	1.92E-04	4.70E-04
Cesium-137	water	kBq	2.19E-04	2.33E-04	8.93E-05	2.19E-04
Chromium, ion	water	kg	3.53E-09	3.98E-09	2.04E-09	3.53E-09
Chromium VI	water	kg	9.54E-06	9.58E-06	9.52E-06	9.54E-06
COD	water	kg	2.13E-03	2.14E-03	2.13E-03	2.13E-03
Copper, ion	water	kg	6.90E-06	6.91E-06	6.88E-06	6.90E-06
Lead	water	kg	1.94E-06	1.94E-06	1.92E-06	1.94E-06
Mercury	water	kg	6.25E-08	6.28E-08	6.24E-08	6.25E-08
Nickel, ion	water	kg	4.14E-06	4.22E-06	4.09E-06	4.14E-06
Nitrate	water	kg	1.73E-06	1.80E-06	1.15E-06	1.73E-06
Oils, unspecified	water	kg	6.09E-06	6.76E-06	4.83E-06	6.09E-06
PAH	water	kg	1.90E-09	2.21E-09	1.65E-09	1.90E-09
Phosphate	water	kg	1.13E-04	1.13E-04	1.12E-04	1.13E-04
Emissions to Soil						
Arsenic	soil	kg	1.26E-10	1.29E-10	4.95E-11	1.26E-10
Cadmium	soil	kg	7.99E-12	8.66E-12	7.41E-12	7.99E-12
Chromium	soil	kg	1.70E-09	1.73E-09	7.28E-10	1.70E-09
Chromium VI	soil	kg	2.12E-08	2.27E-08	7.54E-09	2.12E-08
Lead	soil	kg	6.42E-11	6.84E-11	5.72E-11	6.42E-11
Mercury	soil	kg	3.53E-13	3.65E-13	2.71E-13	3.53E-13
Oils, unspecified	soil	kg	5.58E-06	6.14E-06	4.39E-06	5.58E-06

Table 8.64 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	3.79E-03	3.99E-03	3.54E-03	3.72E-03
Coal, hard, unspecified, in ground	resource	kg	4.39E-01	4.39E-01	4.29E-01	4.29E-01
Gas, natural, in ground	resource	Nm3	8.16E-03	8.58E-03	9.74E-03	1.01E-02
Oil, crude, in ground	resource	kg	5.99E-03	6.10E-03	7.38E-03	7.48E-03
Uranium, in ground	resource	kg	7.65E-07	8.04E-07	7.13E-07	7.49E-07
Freshwater (lake, river, groundwater)	resource	m3	2.49E-03	2.52E-03	2.45E-03	2.47E-03
Occupation, agricultural and forestal area	resource	m2a	2.15E-02	2.16E-02	2.13E-02	2.14E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.82E-03	4.85E-03	4.73E-03	4.76E-03
Emissions to air						
Ammonia	air	kg	2.03E-05	2.04E-05	2.44E-04	2.44E-04
Arsenic	air	kg	1.58E-08	1.59E-08	1.58E-08	1.59E-08
Cadmium	air	kg	1.76E-09	1.80E-09	2.20E-09	2.23E-09
Carbon dioxide, fossil	air	kg	5.23E-02	5.40E-02	1.30E-01	1.31E-01
Carbon monoxide, fossil	air	kg	1.69E-04	1.73E-04	1.69E-04	1.73E-04
Carbon-14	air	kBq	1.57E-03	1.65E-03	1.46E-03	1.53E-03
Chromium	air	kg	2.43E-07	2.49E-07	2.42E-07	2.47E-07
Chromium VI	air	kg	6.62E-09	6.77E-09	6.58E-09	6.71E-09
Dinitrogen monoxide	air	kg	3.57E-05	3.58E-05	3.51E-05	3.51E-05
Iodine-129	air	kBq	1.34E-06	1.41E-06	1.25E-06	1.31E-06
Lead	air	kg	6.29E-08	6.37E-08	6.28E-08	6.35E-08
Methane, fossil	air	kg	2.45E-03	2.45E-03	2.40E-03	2.40E-03
Mercury	air	kg	3.57E-08	3.59E-08	3.54E-08	3.55E-08
Nickel	air	kg	1.14E-07	1.15E-07	1.20E-07	1.21E-07
Nitrogen oxides	air	kg	5.67E-04	5.72E-04	8.26E-04	8.30E-04
NMVOC total	air	kg	6.73E-05	6.84E-05	7.37E-05	7.47E-05
thereof:						
Benzene	air	kg	2.10E-06	2.10E-06	2.23E-06	2.23E-06
Benzo(a)pyrene	air	kg	1.23E-10	1.29E-10	1.23E-10	1.28E-10
Formaldehyde	air	kg	5.18E-07	5.20E-07	5.17E-07	5.19E-07
PAH	air	kg	2.25E-08	2.29E-08	2.23E-08	2.26E-08
PM2.5-10	air	kg	2.40E-05	2.46E-05	2.44E-05	2.50E-05
PM2.5	air	kg	5.40E-05	5.46E-05	5.39E-05	5.44E-05
PCDD/F (measured as I-TEQ)	air	kg	7.00E-14	7.07E-14	8.10E-14	8.15E-14
Radon-222	air	kBq	2.48E+01	2.61E+01	2.31E+01	2.43E+01
Sulfur dioxide	air	kg	3.43E-04	3.44E-04	3.49E-04	3.50E-04
Emissions to Water						
Ammonium, ion	water	kg	9.77E-07	9.85E-07	4.21E-06	4.22E-06
Arsenic, ion	water	kg	1.46E-07	1.48E-07	1.44E-07	1.46E-07
Cadmium, ion	water	kg	1.58E-08	1.71E-08	1.56E-08	1.68E-08
Carbon-14	water	kBq	5.40E-04	5.69E-04	5.03E-04	5.28E-04
Cesium-137	water	kBq	2.51E-04	2.64E-04	2.34E-04	2.45E-04
Chromium, ion	water	kg	2.09E-08	2.12E-08	2.04E-08	2.07E-08
Chromium VI	water	kg	3.77E-07	4.12E-07	3.73E-07	4.04E-07
COD	water	kg	1.51E-04	1.55E-04	2.27E-04	2.32E-04
Copper, ion	water	kg	5.90E-07	6.01E-07	6.00E-07	6.10E-07
Lead	water	kg	2.58E-07	2.62E-07	2.54E-07	2.58E-07
Mercury	water	kg	3.70E-09	3.93E-09	3.70E-09	3.90E-09
Nickel, ion	water	kg	1.42E-06	1.50E-06	1.42E-06	1.49E-06
Nitrate	water	kg	2.85E-05	2.85E-05	3.73E-05	3.74E-05
Oils, unspecified	water	kg	2.63E-05	2.69E-05	2.81E-05	2.86E-05
PAH	water	kg	7.27E-09	7.53E-09	7.39E-09	7.62E-09
Phosphate	water	kg	3.84E-06	4.01E-06	6.74E-06	6.89E-06
Emissions to Soil						
Arsenic	soil	kg	1.70E-10	1.72E-10	1.66E-10	1.67E-10
Cadmium	soil	kg	9.63E-12	1.02E-11	1.27E-11	1.32E-11
Chromium	soil	kg	2.26E-09	2.30E-09	2.34E-09	2.37E-09
Chromium VI	soil	kg	2.04E-08	2.16E-08	1.89E-08	1.99E-08
Lead	soil	kg	6.56E-11	6.91E-11	1.08E-10	1.11E-10
Mercury	soil	kg	6.39E-13	6.45E-13	7.35E-13	7.41E-13
Oils, unspecified	soil	kg	2.64E-05	2.69E-05	2.82E-05	2.86E-05

Table 8.65 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	1.94E-03	2.13E-03	1.90E-03	2.07E-03
Coal, hard, unspecified, in ground	resource	kg	4.37E-01	4.37E-01	4.27E-01	4.27E-01
Gas, natural, in ground	resource	Nm3	4.43E-03	4.85E-03	6.44E-03	6.81E-03
Oil, crude, in ground	resource	kg	5.80E-03	5.91E-03	7.21E-03	7.31E-03
Uranium, in ground	resource	kg	3.90E-07	4.30E-07	3.82E-07	4.18E-07
Freshwater (lake, river, groundwater)	resource	m3	2.31E-03	2.34E-03	2.29E-03	2.31E-03
Occupation, agricultural and forestal area	resource	m2a	2.07E-02	2.08E-02	2.06E-02	2.07E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.78E-03	4.81E-03	4.70E-03	4.72E-03
Emissions to air						
Ammonia	air	kg	1.98E-05	1.99E-05	2.43E-04	2.43E-04
Arsenic	air	kg	1.51E-08	1.52E-08	1.52E-08	1.53E-08
Cadmium	air	kg	1.55E-09	1.58E-09	2.01E-09	2.04E-09
Carbon dioxide, fossil	air	kg	4.14E-02	4.30E-02	1.20E-01	1.22E-01
Carbon monoxide, fossil	air	kg	1.64E-04	1.69E-04	1.65E-04	1.69E-04
Carbon-14	air	kBq	8.01E-04	8.83E-04	7.81E-04	8.53E-04
Chromium	air	kg	2.38E-07	2.44E-07	2.37E-07	2.43E-07
Chromium VI	air	kg	6.50E-09	6.64E-09	6.47E-09	6.60E-09
Dinitrogen monoxide	air	kg	3.48E-05	3.49E-05	3.42E-05	3.43E-05
Iodine-129	air	kBq	6.84E-07	7.54E-07	6.67E-07	7.28E-07
Lead	air	kg	6.03E-08	6.11E-08	6.06E-08	6.13E-08
Methane, fossil	air	kg	2.42E-03	2.43E-03	2.38E-03	2.38E-03
Mercury	air	kg	3.54E-08	3.56E-08	3.51E-08	3.53E-08
Nickel	air	kg	1.11E-07	1.11E-07	1.18E-07	1.18E-07
Nitrogen oxides	air	kg	5.53E-04	5.58E-04	8.14E-04	8.18E-04
NMVOC total	air	kg	6.30E-05	6.41E-05	6.99E-05	7.09E-05
thereof:						
Benzene	air	kg	2.08E-06	2.09E-06	2.22E-06	2.22E-06
Benzo(a)pyrene	air	kg	1.15E-10	1.21E-10	1.16E-10	1.21E-10
Formaldehyde	air	kg	5.09E-07	5.10E-07	5.09E-07	5.11E-07
PAH	air	kg	2.13E-08	2.17E-08	2.12E-08	2.16E-08
PM2.5-10	air	kg	2.35E-05	2.41E-05	2.39E-05	2.45E-05
PM2.5	air	kg	5.33E-05	5.39E-05	5.33E-05	5.38E-05
PCDD/F (measured as I-TEQ)	air	kg	6.87E-14	6.94E-14	7.98E-14	8.04E-14
Radon-222	air	kBq	1.27E+01	1.40E+01	1.24E+01	1.35E+01
Sulfur dioxide	air	kg	3.31E-04	3.33E-04	3.39E-04	3.40E-04
Emissions to Water						
Ammonium, ion	water	kg	9.21E-07	9.29E-07	4.16E-06	4.17E-06
Arsenic, ion	water	kg	1.40E-07	1.42E-07	1.38E-07	1.40E-07
Cadmium, ion	water	kg	1.50E-08	1.63E-08	1.49E-08	1.61E-08
Carbon-14	water	kBq	2.75E-04	3.03E-04	2.68E-04	2.93E-04
Cesium-137	water	kBq	1.28E-04	1.41E-04	1.25E-04	1.36E-04
Chromium, ion	water	kg	1.96E-08	2.00E-08	1.93E-08	1.97E-08
Chromium VI	water	kg	3.36E-07	3.71E-07	3.38E-07	3.69E-07
COD	water	kg	1.40E-04	1.44E-04	2.18E-04	2.22E-04
Copper, ion	water	kg	5.60E-07	5.71E-07	5.73E-07	5.84E-07
Lead	water	kg	2.44E-07	2.48E-07	2.42E-07	2.45E-07
Mercury	water	kg	3.45E-09	3.68E-09	3.48E-09	3.67E-09
Nickel, ion	water	kg	1.38E-06	1.45E-06	1.39E-06	1.45E-06
Nitrate	water	kg	2.83E-05	2.83E-05	3.71E-05	3.72E-05
Oils, unspecified	water	kg	2.54E-05	2.60E-05	2.73E-05	2.78E-05
PAH	water	kg	7.09E-09	7.35E-09	7.23E-09	7.46E-09
Phosphate	water	kg	3.44E-06	3.61E-06	6.39E-06	6.54E-06
Emissions to Soil						
Arsenic	soil	kg	1.03E-10	1.05E-10	1.07E-10	1.08E-10
Cadmium	soil	kg	9.17E-12	9.78E-12	1.23E-11	1.28E-11
Chromium	soil	kg	1.42E-09	1.45E-09	1.60E-09	1.63E-09
Chromium VI	soil	kg	8.90E-09	1.01E-08	8.67E-09	9.74E-09
Lead	soil	kg	6.17E-11	6.52E-11	1.05E-10	1.08E-10
Mercury	soil	kg	6.10E-13	6.16E-13	7.09E-13	7.15E-13
Oils, unspecified	soil	kg	2.56E-05	2.61E-05	2.74E-05	2.78E-05

Table 8.66 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	8.57E-04	8.53E-04	8.52E-04
Coal, hard, unspecified, in ground	resource	kg	3.68E-01	3.68E-01	3.68E-01
Gas, natural, in ground	resource	Nm3	2.24E-03	2.22E-03	2.22E-03
Oil, crude, in ground	resource	kg	4.75E-03	4.73E-03	4.73E-03
Uranium, in ground	resource	kg	1.72E-07	1.72E-07	1.72E-07
Freshwater (lake, river, groundwater)	resource	m3	1.86E-03	1.86E-03	1.86E-03
Occupation, agricultural and forestal area	resource	m2a	1.71E-02	1.71E-02	1.71E-02
Occupation, built up area incl. mineral extractio	resource	m2a	3.98E-03	3.98E-03	3.98E-03
Emissions to air					
Ammonia	air	kg	1.80E-05	1.80E-05	1.80E-05
Arsenic	air	kg	1.23E-08	1.22E-08	1.22E-08
Cadmium	air	kg	1.22E-09	1.19E-09	1.19E-09
Carbon dioxide, fossil	air	kg	6.65E-01	6.64E-01	6.64E-01
Carbon monoxide, fossil	air	kg	1.32E-04	1.31E-04	1.31E-04
Carbon-14	air	kBq	3.53E-04	3.51E-04	3.51E-04
Chromium	air	kg	1.52E-07	1.35E-07	1.35E-07
Chromium VI	air	kg	4.27E-09	3.85E-09	3.85E-09
Dinitrogen monoxide	air	kg	2.90E-05	2.90E-05	2.90E-05
Iodine-129	air	kBq	3.01E-07	2.99E-07	2.99E-07
Lead	air	kg	4.86E-08	4.82E-08	4.82E-08
Methane, fossil	air	kg	2.03E-03	2.03E-03	2.03E-03
Mercury	air	kg	2.97E-08	2.97E-08	2.97E-08
Nickel	air	kg	9.28E-08	9.26E-08	9.26E-08
Nitrogen oxides	air	kg	6.82E-04	6.82E-04	6.82E-04
NMVOC total	air	kg	5.08E-05	5.07E-05	5.07E-05
thereof:					
Benzene	air	kg	1.75E-06	1.75E-06	1.75E-06
Benzo(a)pyrene	air	kg	8.30E-11	7.99E-11	8.00E-11
Formaldehyde	air	kg	4.25E-07	4.24E-07	4.24E-07
PAH	air	kg	1.71E-08	1.70E-08	1.70E-08
PM2.5-10	air	kg	1.87E-05	1.85E-05	1.85E-05
PM2.5	air	kg	4.39E-05	4.37E-05	4.37E-05
PCDD/F (measured as I-TEQ)	air	kg	5.67E-14	5.65E-14	5.64E-14
Radon-222	air	kBq	5.60E+00	5.57E+00	5.57E+00
Sulfur dioxide	air	kg	4.94E-04	4.93E-04	4.93E-04
Emissions to Water					
Ammonium, ion	water	kg	7.35E-07	7.34E-07	7.34E-07
Arsenic, ion	water	kg	1.12E-07	1.11E-07	1.11E-07
Cadmium, ion	water	kg	1.06E-08	1.04E-08	1.03E-08
Carbon-14	water	kBq	1.21E-04	1.20E-04	1.20E-04
Cesium-137	water	kBq	5.62E-05	5.60E-05	5.59E-05
Chromium, ion	water	kg	1.51E-08	1.50E-08	1.50E-08
Chromium VI	water	kg	2.27E-07	2.22E-07	2.21E-07
COD	water	kg	1.08E-04	1.07E-04	1.07E-04
Copper, ion	water	kg	4.28E-07	4.24E-07	4.24E-07
Lead	water	kg	1.83E-07	1.79E-07	1.78E-07
Mercury	water	kg	2.51E-09	2.49E-09	2.49E-09
Nickel, ion	water	kg	9.37E-07	8.75E-07	8.73E-07
Nitrate	water	kg	2.27E-05	2.27E-05	2.27E-05
Oils, unspecified	water	kg	2.07E-05	2.07E-05	2.07E-05
PAH	water	kg	4.84E-09	4.49E-09	4.49E-09
Phosphate	water	kg	2.59E-06	2.57E-06	2.57E-06
Emissions to Soil					
Arsenic	soil	kg	5.96E-11	5.93E-11	5.93E-11
Cadmium	soil	kg	6.79E-12	6.62E-12	6.61E-12
Chromium	soil	kg	8.53E-10	8.48E-10	8.48E-10
Chromium VI	soil	kg	2.69E-09	2.67E-09	2.67E-09
Lead	soil	kg	4.71E-11	4.61E-11	4.61E-11
Mercury	soil	kg	4.97E-13	4.95E-13	4.95E-13
Oils, unspecified	soil	kg	2.11E-05	2.10E-05	2.10E-05

Table 8.67 LCA results for year 2025, very optimimistic development, "renewable scenario".

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.34E-01	9.34E-01	9.13E-01
Coal, hard, unspecified, in ground	resource	kg	4.92E-03	5.28E-03	4.67E-03
Gas, natural, in ground	resource	Nm3	8.21E-03	8.70E-03	1.01E-02
Oil, crude, in ground	resource	kg	1.30E-03	1.43E-03	3.06E-03
Uranium, in ground	resource	kg	7.94E-07	8.41E-07	7.35E-07
Freshwater (lake, river, groundwater)	resource	m3	5.08E-03	5.11E-03	4.98E-03
Occupation, agricultural and forestal area	resource	m2a	2.64E-03	2.76E-03	2.84E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.27E-03	1.30E-03	1.26E-03
Emissions to air					
Ammonia	air	kg	3.10E-06	3.21E-06	2.38E-04
Arsenic	air	kg	9.27E-09	9.40E-09	9.42E-09
Cadmium	air	kg	1.26E-09	1.30E-09	1.84E-09
Carbon dioxide, fossil	air	kg	3.77E-02	3.96E-02	1.28E-01
Carbon monoxide, fossil	air	kg	2.05E-04	2.11E-04	2.05E-04
Carbon-14	air	kBq	1.63E-03	1.73E-03	1.51E-03
Chromium	air	kg	8.25E-08	8.96E-08	8.58E-08
Chromium VI	air	kg	2.19E-09	2.36E-09	2.26E-09
Dinitrogen monoxide	air	kg	2.33E-05	2.34E-05	2.28E-05
Iodine-129	air	kBq	1.40E-06	1.48E-06	1.29E-06
Lead	air	kg	1.79E-08	1.89E-08	1.92E-08
Methane, fossil	air	kg	2.82E-04	2.86E-04	2.86E-04
Mercury	air	kg	2.06E-08	2.09E-08	2.07E-08
Nickel	air	kg	1.71E-08	1.78E-08	2.80E-08
Nitrogen oxides	air	kg	2.98E-04	3.04E-04	7.40E-04
NMVOC total	air	kg	3.13E-05	3.26E-05	3.98E-05
thereof:					
Benzene	air	kg	1.84E-06	1.84E-06	2.01E-06
Benzo(a)pyrene	air	kg	8.74E-11	9.42E-11	8.85E-11
Formaldehyde	air	kg	5.22E-07	5.24E-07	5.24E-07
PAH	air	kg	1.40E-08	1.45E-08	1.40E-08
PM2.5-10	air	kg	1.37E-05	1.45E-05	1.44E-05
PM2.5	air	kg	6.41E-05	6.48E-05	6.39E-05
PCDD/F (measured as I-TEQ)	air	kg	6.46E-14	6.53E-14	7.57E-14
Radon-222	air	kBq	2.58E+01	2.73E+01	2.38E+01
Sulfur dioxide	air	kg	1.33E-04	1.36E-04	1.47E-04
Emissions to Water					
Ammonium, ion	water	kg	1.47E-07	1.56E-07	3.98E-06
Arsenic, ion	water	kg	9.16E-07	9.19E-07	8.97E-07
Cadmium, ion	water	kg	3.30E-08	3.45E-08	3.24E-08
Carbon-14	water	kBq	5.62E-04	5.95E-04	5.19E-04
Cesium-137	water	kBq	2.61E-04	2.77E-04	2.41E-04
Chromium, ion	water	kg	3.77E-09	4.20E-09	3.70E-09
Chromium VI	water	kg	8.47E-07	8.89E-07	8.33E-07
COD	water	kg	5.66E-05	6.21E-05	1.45E-04
Copper, ion	water	kg	1.02E-06	1.04E-06	1.03E-06
Lead	water	kg	9.80E-07	9.85E-07	9.60E-07
Mercury	water	kg	6.12E-09	6.38E-09	6.07E-09
Nickel, ion	water	kg	1.92E-06	2.01E-06	1.91E-06
Nitrate	water	kg	5.51E-07	5.84E-07	1.14E-05
Oils, unspecified	water	kg	6.35E-06	7.00E-06	8.99E-06
PAH	water	kg	2.54E-09	2.84E-09	2.81E-09
Phosphate	water	kg	3.24E-05	3.26E-05	3.47E-05
Emissions to Soil					
Arsenic	soil	kg	1.31E-10	1.33E-10	1.28E-10
Cadmium	soil	kg	6.73E-12	7.45E-12	1.04E-11
Chromium	soil	kg	1.71E-09	1.75E-09	1.83E-09
Chromium VI	soil	kg	2.10E-08	2.24E-08	1.92E-08
Lead	soil	kg	4.02E-11	4.43E-11	9.08E-11
Mercury	soil	kg	1.31E-13	1.39E-13	2.48E-13
Oils, unspecified	soil	kg	5.53E-06	6.06E-06	8.11E-06

Table 8.68 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.13E-01	9.32E-01	9.32E-01
Coal, hard, unspecified, in ground	resource	kg	5.00E-03	2.68E-03	3.05E-03
Gas, natural, in ground	resource	Nm3	1.06E-02	3.82E-03	4.31E-03
Oil, crude, in ground	resource	kg	3.17E-03	1.08E-03	1.21E-03
Uranium, in ground	resource	kg	7.77E-07	3.54E-07	4.01E-07
Freshwater (lake, river, groundwater)	resource	m3	5.01E-03	4.87E-03	4.90E-03
Occupation, agricultural and forestal area	resource	m2a	2.94E-03	1.69E-03	1.81E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.29E-03	1.22E-03	1.26E-03
Emissions to air					
Ammonia	air	kg	2.39E-04	2.57E-06	2.68E-06
Arsenic	air	kg	9.53E-09	8.47E-09	8.60E-09
Cadmium	air	kg	1.87E-09	1.01E-09	1.05E-09
Carbon dioxide, fossil	air	kg	1.30E-01	2.49E-02	2.68E-02
Carbon monoxide, fossil	air	kg	2.09E-04	2.00E-04	2.06E-04
Carbon-14	air	kBq	1.59E-03	7.28E-04	8.24E-04
Chromium	air	kg	9.21E-08	7.67E-08	8.38E-08
Chromium VI	air	kg	2.41E-09	2.04E-09	2.21E-09
Dinitrogen monoxide	air	kg	2.29E-05	2.22E-05	2.23E-05
Iodine-129	air	kBq	1.36E-06	6.23E-07	7.05E-07
Lead	air	kg	2.00E-08	1.50E-08	1.59E-08
Methane, fossil	air	kg	2.90E-04	2.53E-04	2.57E-04
Mercury	air	kg	2.09E-08	2.03E-08	2.05E-08
Nickel	air	kg	2.87E-08	1.35E-08	1.43E-08
Nitrogen oxides	air	kg	7.45E-04	2.82E-04	2.87E-04
NMVOC total	air	kg	4.09E-05	2.62E-05	2.75E-05
thereof:					
Benzene	air	kg	2.01E-06	1.82E-06	1.82E-06
Benzo(a)pyrene	air	kg	9.45E-11	7.83E-11	8.51E-11
Formaldehyde	air	kg	5.26E-07	5.11E-07	5.13E-07
PAH	air	kg	1.44E-08	1.27E-08	1.31E-08
PM2.5-10	air	kg	1.51E-05	1.31E-05	1.39E-05
PM2.5	air	kg	6.45E-05	6.32E-05	6.39E-05
PCDD/F (measured as I-TEQ)	air	kg	7.63E-14	6.30E-14	6.37E-14
Radon-222	air	kBq	2.52E+01	1.15E+01	1.30E+01
Sulfur dioxide	air	kg	1.49E-04	1.20E-04	1.22E-04
Emissions to Water					
Ammonium, ion	water	kg	3.99E-06	8.17E-08	9.04E-08
Arsenic, ion	water	kg	8.99E-07	9.09E-07	9.11E-07
Cadmium, ion	water	kg	3.37E-08	3.20E-08	3.35E-08
Carbon-14	water	kBq	5.48E-04	2.50E-04	2.83E-04
Cesium-137	water	kBq	2.55E-04	1.16E-04	1.32E-04
Chromium, ion	water	kg	4.08E-09	2.32E-09	2.75E-09
Chromium VI	water	kg	8.70E-07	8.00E-07	8.41E-07
COD	water	kg	1.50E-04	4.37E-05	4.92E-05
Copper, ion	water	kg	1.04E-06	9.89E-07	1.00E-06
Lead	water	kg	9.64E-07	9.63E-07	9.68E-07
Mercury	water	kg	6.30E-09	5.82E-09	6.09E-09
Nickel, ion	water	kg	1.99E-06	1.87E-06	1.96E-06
Nitrate	water	kg	1.14E-05	2.80E-07	3.13E-07
Oils, unspecified	water	kg	9.56E-06	5.26E-06	5.91E-06
PAH	water	kg	3.08E-09	2.33E-09	2.63E-09
Phosphate	water	kg	3.49E-05	3.19E-05	3.21E-05
Emissions to Soil					
Arsenic	soil	kg	1.30E-10	5.24E-11	5.47E-11
Cadmium	soil	kg	1.10E-11	6.19E-12	6.91E-12
Chromium	soil	kg	1.87E-09	7.24E-10	7.62E-10
Chromium VI	soil	kg	2.05E-08	7.45E-09	8.88E-09
Lead	soil	kg	9.44E-11	3.57E-11	3.98E-11
Mercury	soil	kg	2.55E-13	9.72E-14	1.05E-13
Oils, unspecified	soil	kg	8.58E-06	4.56E-06	5.08E-06

Table 8.69 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.11E-01	9.11E-01	7.88E-01
Coal, hard, unspecified, in ground	resource	kg	2.70E-03	3.02E-03	1.04E-03
Gas, natural, in ground	resource	Nm3	6.27E-03	6.71E-03	1.52E-03
Oil, crude, in ground	resource	kg	2.86E-03	2.97E-03	7.49E-04
Uranium, in ground	resource	kg	3.47E-07	3.88E-07	1.14E-07
Freshwater (lake, river, groundwater)	resource	m3	4.80E-03	4.82E-03	4.02E-03
Occupation, agricultural and forestal area	resource	m2a	2.00E-03	2.10E-03	9.10E-04
Occupation, built up area incl. mineral extractio	resource	m2a	1.22E-03	1.25E-03	9.61E-04
Emissions to air					
Ammonia	air	kg	2.38E-04	2.38E-04	4.59E-06
Arsenic	air	kg	8.72E-09	8.83E-09	6.54E-09
Cadmium	air	kg	1.62E-09	1.65E-09	7.56E-10
Carbon dioxide, fossil	air	kg	1.17E-01	1.19E-01	7.61E-01
Carbon monoxide, fossil	air	kg	2.00E-04	2.05E-04	1.57E-04
Carbon-14	air	kBq	7.08E-04	7.93E-04	2.35E-04
Chromium	air	kg	8.07E-08	8.70E-08	4.00E-08
Chromium VI	air	kg	2.13E-09	2.28E-09	1.11E-09
Dinitrogen monoxide	air	kg	2.18E-05	2.20E-05	1.83E-05
Iodine-129	air	kBq	6.05E-07	6.78E-07	2.00E-07
Lead	air	kg	1.65E-08	1.74E-08	9.57E-09
Methane, fossil	air	kg	2.61E-04	2.64E-04	2.01E-04
Mercury	air	kg	2.04E-08	2.06E-08	1.67E-08
Nickel	air	kg	2.49E-08	2.56E-08	1.11E-08
Nitrogen oxides	air	kg	7.26E-04	7.31E-04	6.03E-04
NMVOC total	air	kg	3.53E-05	3.65E-05	1.92E-05
thereof:					
Benzene	air	kg	1.99E-06	1.99E-06	1.52E-06
Benzo(a)pyrene	air	kg	8.05E-11	8.65E-11	4.49E-11
Formaldehyde	air	kg	5.14E-07	5.16E-07	4.25E-07
PAH	air	kg	1.28E-08	1.32E-08	9.43E-09
PM2.5-10	air	kg	1.39E-05	1.46E-05	9.33E-06
PM2.5	air	kg	6.31E-05	6.37E-05	5.22E-05
PCDD/F (measured as I-TEQ)	air	kg	7.43E-14	7.50E-14	5.13E-14
Radon-222	air	kBq	1.12E+01	1.25E+01	3.72E+00
Sulfur dioxide	air	kg	1.35E-04	1.37E-04	1.12E-04
Emissions to Water					
Ammonium, ion	water	kg	3.92E-06	3.93E-06	3.86E-08
Arsenic, ion	water	kg	8.90E-07	8.93E-07	7.60E-07
Cadmium, ion	water	kg	3.16E-08	3.29E-08	2.37E-08
Carbon-14	water	kBq	2.43E-04	2.73E-04	8.05E-05
Cesium-137	water	kBq	1.13E-04	1.27E-04	3.75E-05
Chromium, ion	water	kg	2.41E-09	2.80E-09	9.38E-10
Chromium VI	water	kg	7.92E-07	8.28E-07	5.87E-07
COD	water	kg	1.33E-04	1.38E-04	2.66E-05
Copper, ion	water	kg	9.97E-07	1.01E-06	8.01E-07
Lead	water	kg	9.45E-07	9.49E-07	7.91E-07
Mercury	water	kg	5.81E-09	6.04E-09	4.41E-09
Nickel, ion	water	kg	1.87E-06	1.94E-06	1.39E-06
Nitrate	water	kg	1.11E-05	1.12E-05	1.18E-07
Oils, unspecified	water	kg	8.03E-06	8.60E-06	3.54E-06
PAH	water	kg	2.62E-09	2.89E-09	1.23E-09
Phosphate	water	kg	3.43E-05	3.44E-05	2.65E-05
Emissions to Soil					
Arsenic	soil	kg	5.82E-11	6.03E-11	1.24E-11
Cadmium	soil	kg	9.94E-12	1.06E-11	3.83E-12
Chromium	soil	kg	9.58E-10	9.91E-10	2.06E-10
Chromium VI	soil	kg	7.23E-09	8.49E-09	6.02E-10
Lead	soil	kg	8.67E-11	9.04E-11	2.40E-11
Mercury	soil	kg	2.18E-13	2.25E-13	6.26E-14
Oils, unspecified	soil	kg	7.25E-06	7.72E-06	3.24E-06

Table 8.70 LCA results for year 2025, very optimimistic development, “renewable scenario”.

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	7.58E-04	4.17E-01
Coal, hard, unspecified, in ground	resource	kg	3.27E-01	6.49E-04
Gas, natural, in ground	resource	Nm3	1.83E-03	7.53E-04
Oil, crude, in ground	resource	kg	4.06E-03	5.17E-04
Uranium, in ground	resource	kg	1.55E-07	6.79E-08
Freshwater (lake, river, groundwater)	resource	m3	5.87E-04	1.52E-03
Occupation, agricultural and forestal area	resource	m2a	1.51E-02	4.18E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.72E-03	7.20E-04
Emissions to air				
Ammonia	air	kg	1.38E-05	4.14E-07
Arsenic	air	kg	5.87E-08	5.69E-08
Cadmium	air	kg	1.14E-09	8.46E-10
Carbon dioxide, fossil	air	kg	6.30E-01	6.13E-01
Carbon monoxide, fossil	air	kg	1.20E-04	6.53E-05
Carbon-14	air	kBq	3.18E-04	1.39E-04
Chromium	air	kg	4.24E-08	3.55E-08
Chromium VI	air	kg	1.36E-09	1.15E-09
Dinitrogen monoxide	air	kg	2.66E-05	2.54E-05
Iodine-129	air	kBq	2.70E-07	1.18E-07
Lead	air	kg	3.39E-08	2.96E-08
Methane, fossil	air	kg	1.81E-03	1.14E-04
Mercury	air	kg	1.89E-08	1.82E-08
Nickel	air	kg	7.72E-08	1.53E-08
Nitrogen oxides	air	kg	4.10E-04	1.63E-04
NMVOC total	air	kg	4.65E-05	1.74E-05
thereof:				
Benzene	air	kg	1.14E-06	9.42E-07
Benzo(a)pyrene	air	kg	6.89E-11	2.75E-11
Formaldehyde	air	kg	2.65E-07	2.60E-07
PAH	air	kg	5.15E-08	4.42E-08
PM2.5-10	air	kg	1.32E-05	2.40E-06
PM2.5	air	kg	9.00E-06	1.91E-06
PCDD/F (measured as I-TEQ)	air	kg	4.42E-14	3.91E-14
Radon-222	air	kBq	5.04E+00	2.20E+00
Sulfur dioxide	air	kg	3.47E-04	1.91E-04
Emissions to Water				
Ammonium, ion	water	kg	3.47E-07	5.11E-08
Arsenic, ion	water	kg	7.96E-08	7.00E-08
Cadmium, ion	water	kg	1.20E-08	8.76E-09
Carbon-14	water	kBq	1.08E-04	4.75E-05
Cesium-137	water	kBq	5.05E-05	2.21E-05
Chromium, ion	water	kg	2.02E-09	7.47E-10
Chromium VI	water	kg	7.05E-07	6.19E-07
COD	water	kg	2.12E-04	1.56E-04
Copper, ion	water	kg	1.25E-06	1.22E-06
Lead	water	kg	3.20E-07	3.08E-07
Mercury	water	kg	4.78E-09	4.36E-09
Nickel, ion	water	kg	5.80E-07	4.62E-07
Nitrate	water	kg	1.19E-06	6.68E-07
Oils, unspecified	water	kg	1.80E-05	2.28E-06
PAH	water	kg	2.43E-09	9.38E-10
Phosphate	water	kg	6.89E-06	6.48E-06
Emissions to Soil				
Arsenic	soil	kg	5.09E-11	7.65E-12
Cadmium	soil	kg	6.43E-12	3.50E-12
Chromium	soil	kg	7.47E-10	1.56E-10
Chromium VI	soil	kg	2.49E-09	5.30E-10
Lead	soil	kg	5.02E-11	3.10E-11
Mercury	soil	kg	5.50E-13	1.79E-13
Oils, unspecified	soil	kg	1.82E-05	2.12E-06

Table 8.71 LCA results for year 2025, very optimimistic development, "renewable scenario".

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	3.36E-03	3.54E-03	1.68E-03	1.86E-03
Coal, hard, unspecified, in ground	resource	kg	3.69E-01	3.70E-01	3.68E-01	3.68E-01
Gas, natural, in ground	resource	Nm3	7.11E-03	7.49E-03	3.73E-03	4.11E-03
Oil, crude, in ground	resource	kg	4.88E-03	4.98E-03	4.70E-03	4.80E-03
Uranium, in ground	resource	kg	6.80E-07	7.16E-07	3.41E-07	3.77E-07
Freshwater (lake, river, groundwater)	resource	m3	9.09E-04	9.34E-04	7.45E-04	7.70E-04
Occupation, agricultural and forestal area	resource	m2a	1.81E-02	1.82E-02	1.74E-02	1.75E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.23E-03	4.26E-03	4.19E-03	4.22E-03
Emissions to air						
Ammonia	air	kg	1.62E-05	1.63E-05	1.58E-05	1.58E-05
Arsenic	air	kg	7.34E-08	7.35E-08	7.28E-08	7.29E-08
Cadmium	air	kg	1.56E-09	1.59E-09	1.37E-09	1.40E-09
Carbon dioxide, fossil	air	kg	1.15E-01	1.16E-01	1.05E-01	1.06E-01
Carbon monoxide, fossil	air	kg	1.51E-04	1.55E-04	1.47E-04	1.51E-04
Carbon-14	air	kBq	1.40E-03	1.47E-03	7.00E-04	7.74E-04
Chromium	air	kg	5.89E-08	6.44E-08	5.44E-08	5.99E-08
Chromium VI	air	kg	1.84E-09	1.97E-09	1.73E-09	1.86E-09
Dinitrogen monoxide	air	kg	3.42E-05	3.43E-05	3.34E-05	3.34E-05
Iodine-129	air	kBq	1.20E-06	1.26E-06	5.97E-07	6.61E-07
Lead	air	kg	4.44E-08	4.51E-08	4.21E-08	4.28E-08
Methane, fossil	air	kg	2.07E-03	2.07E-03	2.05E-03	2.05E-03
Mercury	air	kg	2.38E-08	2.40E-08	2.36E-08	2.38E-08
Nickel	air	kg	9.19E-08	9.24E-08	8.92E-08	8.97E-08
Nitrogen oxides	air	kg	5.00E-04	5.04E-04	4.87E-04	4.91E-04
NMVOC total	air	kg	6.03E-05	6.13E-05	5.64E-05	5.74E-05
thereof:						
Benzene	air	kg	1.42E-06	1.43E-06	1.41E-06	1.41E-06
Benzo(a)pyrene	air	kg	9.06E-11	9.59E-11	8.37E-11	8.89E-11
Formaldehyde	air	kg	3.41E-07	3.43E-07	3.33E-07	3.34E-07
PAH	air	kg	6.48E-08	6.51E-08	6.37E-08	6.40E-08
PM2.5-10	air	kg	1.59E-05	1.65E-05	1.54E-05	1.60E-05
PM2.5	air	kg	1.15E-05	1.20E-05	1.08E-05	1.13E-05
PCDD/F (measured as I-TEQ)	air	kg	5.53E-14	5.59E-14	5.41E-14	5.47E-14
Radon-222	air	kBq	2.21E+01	2.33E+01	1.11E+01	1.22E+01
Sulfur dioxide	air	kg	4.28E-04	4.29E-04	4.17E-04	4.19E-04
Emissions to Water						
Ammonium, ion	water	kg	4.66E-07	4.72E-07	4.15E-07	4.22E-07
Arsenic, ion	water	kg	9.78E-08	9.99E-08	9.22E-08	9.43E-08
Cadmium, ion	water	kg	1.53E-08	1.65E-08	1.46E-08	1.57E-08
Carbon-14	water	kBq	4.81E-04	5.06E-04	2.40E-04	2.66E-04
Cesium-137	water	kBq	2.23E-04	2.35E-04	1.12E-04	1.23E-04
Chromium, ion	water	kg	4.13E-09	4.47E-09	3.01E-09	3.35E-09
Chromium VI	water	kg	8.62E-07	8.94E-07	8.26E-07	8.58E-07
COD	water	kg	2.54E-04	2.58E-04	2.44E-04	2.48E-04
Copper, ion	water	kg	1.44E-06	1.45E-06	1.41E-06	1.42E-06
Lead	water	kg	3.73E-07	3.77E-07	3.60E-07	3.64E-07
Mercury	water	kg	5.81E-09	6.01E-09	5.58E-09	5.79E-09
Nickel, ion	water	kg	7.57E-07	8.22E-07	7.18E-07	7.83E-07
Nitrate	water	kg	1.64E-06	1.66E-06	1.43E-06	1.46E-06
Oils, unspecified	water	kg	2.18E-05	2.23E-05	2.09E-05	2.14E-05
PAH	water	kg	3.16E-09	3.39E-09	2.99E-09	3.23E-09
Phosphate	water	kg	8.30E-06	8.45E-06	7.93E-06	8.09E-06
Emissions to Soil						
Arsenic	soil	kg	1.47E-10	1.49E-10	8.64E-11	8.82E-11
Cadmium	soil	kg	8.23E-12	8.79E-12	7.82E-12	8.37E-12
Chromium	soil	kg	1.98E-09	2.00E-09	1.21E-09	1.24E-09
Chromium VI	soil	kg	1.84E-08	1.95E-08	7.92E-09	9.02E-09
Lead	soil	kg	6.36E-11	6.68E-11	6.01E-11	6.33E-11
Mercury	soil	kg	6.57E-13	6.63E-13	6.30E-13	6.36E-13
Oils, unspecified	soil	kg	2.18E-05	2.22E-05	2.11E-05	2.15E-05

Table 8.72 LCA results for year 2025, very optimimistic development, "renewable scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.73E-01	4.70E-01	4.71E-01	4.72E-01
Coal, hard, unspecified, in ground	resource	kg	4.25E-03	4.60E-03	2.09E-03	2.45E-03
Gas, natural, in ground	resource	Nm3	7.29E-03	7.80E-03	3.06E-03	3.53E-03
Oil, crude, in ground	resource	kg	1.49E-03	1.61E-03	1.27E-03	1.39E-03
Uranium, in ground	resource	kg	7.18E-07	7.60E-07	2.94E-07	3.39E-07
Freshwater (lake, river, groundwater)	resource	m3	2.06E-03	2.09E-03	1.86E-03	1.89E-03
Occupation, agricultural and forestal area	resource	m2a	1.89E-03	2.00E-03	9.70E-04	1.08E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.19E-03	1.23E-03	1.15E-03	1.18E-03
Emissions to air						
Ammonia	air	kg	1.47E-06	1.57E-06	9.60E-07	1.07E-06
Arsenic	air	kg	7.03E-09	7.20E-09	6.26E-09	6.39E-09
Cadmium	air	kg	1.14E-09	1.18E-09	8.98E-10	9.38E-10
Carbon dioxide, fossil	air	kg	1.23E-01	1.25E-01	1.11E-01	1.13E-01
Carbon monoxide, fossil	air	kg	1.08E-04	1.14E-04	1.03E-04	1.08E-04
Carbon-14	air	kBq	1.48E-03	1.57E-03	6.03E-04	6.96E-04
Chromium	air	kg	5.28E-08	6.00E-08	4.72E-08	5.41E-08
Chromium VI	air	kg	1.41E-09	1.58E-09	1.27E-09	1.43E-09
Dinitrogen monoxide	air	kg	3.21E-05	3.23E-05	3.11E-05	3.12E-05
Iodine-129	air	kBq	1.26E-06	1.34E-06	5.14E-07	5.93E-07
Lead	air	kg	1.46E-08	1.55E-08	1.17E-08	1.26E-08
Methane, fossil	air	kg	1.76E-04	1.80E-04	1.48E-04	1.52E-04
Mercury	air	kg	1.38E-08	1.40E-08	1.35E-08	1.37E-08
Nickel	air	kg	1.30E-08	1.37E-08	9.70E-09	1.03E-08
Nitrogen oxides	air	kg	5.09E-04	5.10E-04	4.94E-04	4.99E-04
NMVOC total	air	kg	3.20E-05	3.33E-05	2.72E-05	2.84E-05
thereof:						
Benzene	air	kg	1.23E-06	1.23E-06	1.21E-06	1.21E-06
Benzo(a)pyrene	air	kg	5.38E-11	6.00E-11	4.51E-11	5.17E-11
Formaldehyde	air	kg	3.41E-07	3.40E-07	3.31E-07	3.33E-07
PAH	air	kg	5.73E-08	5.80E-08	5.60E-08	5.64E-08
PM2.5-10	air	kg	5.09E-06	5.80E-06	4.52E-06	5.27E-06
PM2.5	air	kg	4.50E-06	5.10E-06	3.66E-06	4.31E-06
PCDD/F (measured as I-TEQ)	air	kg	5.50E-14	5.60E-14	5.35E-14	5.42E-14
Radon-222	air	kBq	2.33E+01	2.48E+01	9.60E+00	1.10E+01
Sulfur dioxide	air	kg	7.27E-04	7.30E-04	7.14E-04	7.16E-04
Emissions to Water						
Ammonium, ion	water	kg	1.58E-07	1.66E-07	9.40E-08	1.03E-07
Arsenic, ion	water	kg	1.43E-06	1.44E-06	1.43E-06	1.43E-06
Cadmium, ion	water	kg	9.06E-08	9.20E-08	8.97E-08	9.11E-08
Carbon-14	water	kBq	5.07E-04	5.40E-04	2.07E-04	2.38E-04
Cesium-137	water	kBq	2.36E-04	2.51E-04	9.60E-05	1.11E-04
Chromium, ion	water	kg	3.32E-09	3.70E-09	1.92E-09	2.34E-09
Chromium VI	water	kg	9.19E-06	9.20E-06	9.10E-06	9.18E-06
COD	water	kg	2.05E-03	2.06E-03	2.04E-03	2.05E-03
Copper, ion	water	kg	6.63E-06	6.60E-06	6.60E-06	6.61E-06
Lead	water	kg	1.86E-06	1.86E-06	1.84E-06	1.85E-06
Mercury	water	kg	6.02E-08	6.00E-08	5.99E-08	6.01E-08
Nickel, ion	water	kg	3.97E-06	4.00E-06	3.92E-06	4.00E-06
Nitrate	water	kg	1.17E-06	1.21E-06	9.10E-07	9.45E-07
Oils, unspecified	water	kg	5.48E-06	6.10E-06	4.44E-06	5.06E-06
PAH	water	kg	1.76E-09	2.05E-09	1.55E-09	1.85E-09
Phosphate	water	kg	1.08E-04	1.08E-04	1.08E-04	1.08E-04
Emissions to Soil						
Arsenic	soil	kg	1.24E-10	1.27E-10	4.86E-11	5.09E-11
Cadmium	soil	kg	7.72E-12	8.40E-12	7.20E-12	7.88E-12
Chromium	soil	kg	1.67E-09	1.70E-09	7.12E-10	7.48E-10
Chromium VI	soil	kg	2.03E-08	2.16E-08	7.20E-09	8.58E-09
Lead	soil	kg	5.79E-11	6.20E-11	5.35E-11	5.75E-11
Mercury	soil	kg	2.64E-13	2.72E-13	2.31E-13	2.39E-13
Oils, unspecified	soil	kg	4.95E-06	5.50E-06	4.01E-06	4.51E-06

Table 8.73 LCA results for year 2050, pessimistic development, “BAU scenario”.

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	1.00E-02	1.06E-02	9.32E-03	9.78E-03
Coal, hard, unspecified, in ground	resource	kg	4.68E-01	4.69E-01	4.57E-01	4.57E-01
Gas, natural, in ground	resource	Nm3	5.16E-03	5.43E-03	7.08E-03	7.31E-03
Oil, crude, in ground	resource	kg	6.32E-03	6.44E-03	7.79E-03	7.90E-03
Uranium, in ground	resource	kg	6.39E-07	6.72E-07	5.96E-07	6.26E-07
Freshwater (lake, river, groundwater)	resource	m3	2.61E-03	2.63E-03	2.56E-03	2.59E-03
Occupation, agricultural and forestal area	resource	m2a	2.30E-02	2.31E-02	2.27E-02	2.28E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.13E-03	5.16E-03	5.03E-03	5.07E-03
Emissions to air						
Ammonia	air	kg	2.13E-05	2.14E-05	2.45E-04	2.45E-04
Arsenic	air	kg	1.85E-08	1.87E-08	1.90E-08	1.92E-08
Cadmium	air	kg	2.25E-09	2.31E-09	2.81E-09	2.86E-09
Carbon dioxide, fossil	air	kg	7.03E-02	7.31E-02	1.54E-01	1.56E-01
Carbon monoxide, fossil	air	kg	1.84E-04	1.90E-04	1.86E-04	1.91E-04
Carbon-14	air	kBq	1.31E-03	1.38E-03	1.22E-03	1.28E-03
Chromium	air	kg	2.05E-07	2.11E-07	2.47E-07	2.52E-07
Chromium VI	air	kg	5.73E-09	5.88E-09	6.74E-09	6.88E-09
Dinitrogen monoxide	air	kg	3.80E-05	3.81E-05	3.71E-05	3.73E-05
Iodine-129	air	kBq	1.12E-06	1.18E-06	1.04E-06	1.09E-06
Lead	air	kg	7.66E-08	7.83E-08	7.88E-08	8.03E-08
Methane, fossil	air	kg	2.61E-03	2.62E-03	2.56E-03	2.56E-03
Mercury	air	kg	3.81E-08	3.84E-08	3.78E-08	3.80E-08
Nickel	air	kg	1.25E-07	1.26E-07	1.32E-07	1.33E-07
Nitrogen oxides	air	kg	6.13E-04	6.19E-04	8.84E-04	8.89E-04
NMVOC total	air	kg	6.88E-05	6.99E-05	7.58E-05	7.67E-05
thereof:						
Benzene	air	kg	2.24E-06	2.25E-06	2.38E-06	2.39E-06
Benzo(a)pyrene	air	kg	1.60E-10	1.68E-10	1.70E-10	1.76E-10
Formaldehyde	air	kg	5.50E-07	5.52E-07	5.51E-07	5.53E-07
PAH	air	kg	2.33E-08	2.37E-08	2.34E-08	2.37E-08
PM2.5-10	air	kg	2.53E-05	2.61E-05	2.62E-05	2.69E-05
PM2.5	air	kg	5.81E-05	5.89E-05	5.84E-05	5.91E-05
PCDD/F (measured as I-TEQ)	air	kg	8.04E-14	8.20E-14	9.18E-14	9.33E-14
Radon-222	air	kBq	2.08E+01	2.19E+01	1.93E+01	2.03E+01
Sulfur dioxide	air	kg	3.62E-04	3.64E-04	3.69E-04	3.71E-04
Emissions to Water						
Ammonium, ion	water	kg	1.03E-06	1.03E-06	4.41E-06	4.42E-06
Arsenic, ion	water	kg	1.53E-07	1.56E-07	1.53E-07	1.55E-07
Cadmium, ion	water	kg	1.57E-08	1.70E-08	1.61E-08	1.72E-08
Carbon-14	water	kBq	4.51E-04	4.75E-04	4.19E-04	4.40E-04
Cesium-137	water	kBq	2.10E-04	2.21E-04	1.95E-04	2.05E-04
Chromium, ion	water	kg	2.16E-08	2.20E-08	2.13E-08	2.16E-08
Chromium VI	water	kg	3.28E-07	3.62E-07	3.42E-07	3.72E-07
COD	water	kg	1.45E-04	1.49E-04	2.27E-04	2.31E-04
Copper, ion	water	kg	5.81E-07	5.92E-07	6.03E-07	6.12E-07
Lead	water	kg	2.59E-07	2.63E-07	2.63E-07	2.67E-07
Mercury	water	kg	3.52E-09	3.75E-09	3.59E-09	3.78E-09
Nickel, ion	water	kg	1.31E-06	1.38E-06	1.46E-06	1.53E-06
Nitrate	water	kg	3.04E-05	3.05E-05	3.95E-05	3.96E-05
Oils, unspecified	water	kg	2.76E-05	2.82E-05	2.96E-05	3.01E-05
PAH	water	kg	6.61E-09	6.89E-09	7.63E-09	7.87E-09
Phosphate	water	kg	3.64E-06	3.80E-06	6.61E-06	6.75E-06
Emissions to Soil						
Arsenic	soil	kg	1.71E-10	1.73E-10	1.67E-10	1.69E-10
Cadmium	soil	kg	8.55E-12	9.13E-12	1.19E-11	1.24E-11
Chromium	soil	kg	2.28E-09	2.31E-09	2.37E-09	2.39E-09
Chromium VI	soil	kg	2.11E-08	2.24E-08	1.95E-08	2.06E-08
Lead	soil	kg	6.34E-11	6.69E-11	1.09E-10	1.12E-10
Mercury	soil	kg	7.12E-13	7.21E-13	8.06E-13	8.14E-13
Oils, unspecified	soil	kg	2.79E-05	2.84E-05	2.97E-05	3.02E-05

Table 8.74 LCA results for year 2050, pessimistic development, "BAU scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	5.08E-03	5.60E-03	4.96E-03	5.42E-03
Coal, hard, unspecified, in ground	resource	kg	4.62E-01	4.63E-01	4.51E-01	4.52E-01
Gas, natural, in ground	resource	Nm3	2.92E-03	3.18E-03	5.10E-03	5.33E-03
Oil, crude, in ground	resource	kg	6.08E-03	6.20E-03	7.58E-03	7.69E-03
Uranium, in ground	resource	kg	3.27E-07	3.60E-07	3.22E-07	3.51E-07
Freshwater (lake, river, groundwater)	resource	m3	2.42E-03	2.44E-03	2.40E-03	2.42E-03
Occupation, agricultural and forestal area	resource	m2a	2.19E-02	2.20E-02	2.17E-02	2.18E-02
Occupation, built up area incl. mineral extractio	resource	m2a	5.04E-03	5.08E-03	4.96E-03	4.99E-03
Emissions to air						
Ammonia	air	kg	2.08E-05	2.09E-05	2.44E-04	2.44E-04
Arsenic	air	kg	1.73E-08	1.75E-08	1.80E-08	1.82E-08
Cadmium	air	kg	1.89E-09	1.95E-09	2.50E-09	2.55E-09
Carbon dioxide, fossil	air	kg	4.91E-02	5.18E-02	1.35E-01	1.38E-01
Carbon monoxide, fossil	air	kg	1.78E-04	1.84E-04	1.80E-04	1.85E-04
Carbon-14	air	kBq	6.71E-04	7.39E-04	6.55E-04	7.15E-04
Chromium	air	kg	1.99E-07	2.05E-07	2.41E-07	2.47E-07
Chromium VI	air	kg	5.56E-09	5.72E-09	6.60E-09	6.74E-09
Dinitrogen monoxide	air	kg	3.67E-05	3.68E-05	3.60E-05	3.62E-05
Iodine-129	air	kBq	5.72E-07	6.31E-07	5.59E-07	6.10E-07
Lead	air	kg	7.21E-08	7.38E-08	7.49E-08	7.64E-08
Methane, fossil	air	kg	2.56E-03	2.57E-03	2.51E-03	2.52E-03
Mercury	air	kg	3.75E-08	3.77E-08	3.72E-08	3.74E-08
Nickel	air	kg	1.20E-07	1.21E-07	1.28E-07	1.29E-07
Nitrogen oxides	air	kg	5.88E-04	5.94E-04	8.62E-04	8.67E-04
NMVOC total	air	kg	6.50E-05	6.61E-05	7.24E-05	7.34E-05
thereof:						
Benzene	air	kg	2.20E-06	2.21E-06	2.34E-06	2.35E-06
Benzo(a)pyrene	air	kg	1.49E-10	1.56E-10	1.60E-10	1.66E-10
Formaldehyde	air	kg	5.35E-07	5.37E-07	5.38E-07	5.40E-07
PAH	air	kg	2.22E-08	2.27E-08	2.24E-08	2.28E-08
PM2.5-10	air	kg	2.46E-05	2.53E-05	2.56E-05	2.62E-05
PM2.5	air	kg	5.65E-05	5.73E-05	5.70E-05	5.77E-05
PCDD/F (measured as I-TEQ)	air	kg	7.79E-14	7.95E-14	8.96E-14	9.11E-14
Radon-222	air	kBq	1.06E+01	1.17E+01	1.04E+01	1.13E+01
Sulfur dioxide	air	kg	3.47E-04	3.49E-04	3.55E-04	3.57E-04
Emissions to Water						
Ammonium, ion	water	kg	9.66E-07	9.74E-07	4.36E-06	4.36E-06
Arsenic, ion	water	kg	1.46E-07	1.48E-07	1.46E-07	1.48E-07
Cadmium, ion	water	kg	1.50E-08	1.63E-08	1.54E-08	1.66E-08
Carbon-14	water	kBq	2.30E-04	2.53E-04	2.25E-04	2.45E-04
Cesium-137	water	kBq	1.07E-04	1.18E-04	1.05E-04	1.14E-04
Chromium, ion	water	kg	2.04E-08	2.07E-08	2.02E-08	2.05E-08
Chromium VI	water	kg	3.10E-07	3.45E-07	3.26E-07	3.57E-07
COD	water	kg	1.39E-04	1.43E-04	2.22E-04	2.26E-04
Copper, ion	water	kg	5.62E-07	5.73E-07	5.86E-07	5.96E-07
Lead	water	kg	2.45E-07	2.49E-07	2.51E-07	2.55E-07
Mercury	water	kg	3.41E-09	3.63E-09	3.49E-09	3.68E-09
Nickel, ion	water	kg	1.26E-06	1.34E-06	1.42E-06	1.49E-06
Nitrate	water	kg	2.99E-05	3.00E-05	3.91E-05	3.91E-05
Oils, unspecified	water	kg	2.66E-05	2.72E-05	2.87E-05	2.92E-05
PAH	water	kg	6.39E-09	6.67E-09	7.43E-09	7.67E-09
Phosphate	water	kg	3.38E-06	3.54E-06	6.38E-06	6.52E-06
Emissions to Soil						
Arsenic	soil	kg	1.04E-10	1.06E-10	1.08E-10	1.10E-10
Cadmium	soil	kg	8.02E-12	8.60E-12	1.14E-11	1.19E-11
Chromium	soil	kg	1.43E-09	1.46E-09	1.62E-09	1.64E-09
Chromium VI	soil	kg	9.15E-09	1.04E-08	8.92E-09	1.00E-08
Lead	soil	kg	5.80E-11	6.15E-11	1.04E-10	1.07E-10
Mercury	soil	kg	6.54E-13	6.63E-13	7.55E-13	7.63E-13
Oils, unspecified	soil	kg	2.69E-05	2.73E-05	2.88E-05	2.93E-05

Table 8.75 LCA results for year 2050, pessimistic development, “BAU scenario”.

			electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	2.22E-03	2.21E-03	2.21E-03
Coal, hard, unspecified, in ground	resource	kg	3.85E-01	3.80E-01	3.80E-01
Gas, natural, in ground	resource	Nm3	1.60E-03	1.59E-03	1.59E-03
Oil, crude, in ground	resource	kg	4.97E-03	5.00E-03	5.00E-03
Uranium, in ground	resource	kg	1.45E-07	1.45E-07	1.45E-07
Freshwater (lake, river, groundwater)	resource	m3	1.93E-03	1.93E-03	1.93E-03
Occupation, agricultural and forestal area	resource	m2a	1.79E-02	1.79E-02	1.79E-02
Occupation, built up area incl. mineral extractic	resource	m2a	4.17E-03	4.20E-03	4.20E-03
Emissions to air					
Ammonia	air	kg	1.88E-05	1.87E-05	1.87E-05
Arsenic	air	kg	1.40E-08	1.38E-08	1.38E-08
Cadmium	air	kg	1.48E-09	1.44E-09	1.44E-09
Carbon dioxide, fossil	air	kg	6.96E-01	7.00E-01	7.00E-01
Carbon monoxide, fossil	air	kg	1.42E-04	1.41E-04	1.41E-04
Carbon-14	air	kBq	2.97E-04	2.96E-04	2.96E-04
Chromium	air	kg	1.53E-07	1.36E-07	1.36E-07
Chromium VI	air	kg	4.33E-09	3.90E-09	3.90E-09
Dinitrogen monoxide	air	kg	3.03E-05	3.03E-05	3.03E-05
Iodine-129	air	kBq	2.53E-07	2.52E-07	2.52E-07
Lead	air	kg	5.75E-08	5.70E-08	5.70E-08
Methane, fossil	air	kg	2.13E-03	2.13E-03	2.13E-03
Mercury	air	kg	3.11E-08	3.10E-08	3.10E-08
Nickel	air	kg	1.00E-07	9.90E-08	9.90E-08
Nitrogen oxides	air	kg	7.20E-04	7.10E-04	7.10E-04
NMVOC total	air	kg	5.26E-05	5.20E-05	5.20E-05
thereof:					
Benzene	air	kg	1.83E-06	1.83E-06	1.83E-06
Benzo(a)pyrene	air	kg	1.14E-10	1.10E-10	1.10E-10
Formaldehyde	air	kg	4.44E-07	4.40E-07	4.40E-07
PAH	air	kg	1.80E-08	1.78E-08	1.78E-08
PM2.5-10	air	kg	1.97E-05	1.95E-05	1.95E-05
PM2.5	air	kg	4.64E-05	4.60E-05	4.60E-05
PCDD/F (measured as I-TEQ)	air	kg	6.31E-14	6.30E-14	6.30E-14
Radon-222	air	kBq	4.72E+00	4.70E+00	4.70E+00
Sulfur dioxide	air	kg	5.16E-04	5.20E-04	5.20E-04
Emissions to Water					
Ammonium, ion	water	kg	7.70E-07	7.60E-07	7.60E-07
Arsenic, ion	water	kg	1.16E-07	1.16E-07	1.16E-07
Cadmium, ion	water	kg	1.09E-08	1.07E-08	1.07E-08
Carbon-14	water	kBq	1.02E-04	1.01E-04	1.01E-04
Cesium-137	water	kBq	4.73E-05	4.70E-05	4.70E-05
Chromium, ion	water	kg	1.57E-08	1.56E-08	1.56E-08
Chromium VI	water	kg	2.24E-07	2.18E-07	2.18E-07
COD	water	kg	1.11E-04	1.10E-04	1.10E-04
Copper, ion	water	kg	4.39E-07	4.30E-07	4.30E-07
Lead	water	kg	1.89E-07	1.85E-07	1.84E-07
Mercury	water	kg	2.54E-09	2.52E-09	2.52E-09
Nickel, ion	water	kg	9.60E-07	8.90E-07	8.90E-07
Nitrate	water	kg	2.37E-05	2.37E-05	2.37E-05
Oils, unspecified	water	kg	2.17E-05	2.16E-05	2.16E-05
PAH	water	kg	4.94E-09	4.60E-09	4.60E-09
Phosphate	water	kg	2.61E-06	2.59E-06	2.59E-06
Emissions to Soil					
Arsenic	soil	kg	6.04E-11	6.00E-11	6.00E-11
Cadmium	soil	kg	6.19E-12	6.10E-12	6.10E-12
Chromium	soil	kg	8.60E-10	8.60E-10	8.60E-10
Chromium VI	soil	kg	2.74E-09	2.72E-09	2.72E-09
Lead	soil	kg	4.54E-11	4.50E-11	4.50E-11
Mercury	soil	kg	5.23E-13	5.20E-13	5.20E-13
Oils, unspecified	soil	kg	2.20E-05	2.20E-05	2.20E-05

Table 8.76 LCA results for year 2050, pessimistic development, “BAU scenario”.

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.84E-01	9.85E-01	9.61E-01
Coal, hard, unspecified, in ground	resource	kg	1.42E-02	1.51E-02	1.34E-02
Gas, natural, in ground	resource	Nm3	5.03E-03	5.34E-03	7.39E-03
Oil, crude, in ground	resource	kg	1.39E-03	1.53E-03	3.27E-03
Uranium, in ground	resource	kg	6.59E-07	6.98E-07	6.13E-07
Freshwater (lake, river, groundwater)	resource	m3	5.32E-03	5.35E-03	5.22E-03
Occupation, agricultural and forestal area	resource	m2a	3.18E-03	3.33E-03	3.44E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.40E-03	1.45E-03	1.41E-03
Emissions to air					
Ammonia	air	kg	3.26E-06	3.38E-06	2.39E-04
Arsenic	air	kg	1.17E-08	1.19E-08	1.23E-08
Cadmium	air	kg	1.85E-09	1.92E-09	2.58E-09
Carbon dioxide, fossil	air	kg	5.96E-02	6.28E-02	1.53E-01
Carbon monoxide, fossil	air	kg	2.19E-04	2.26E-04	2.22E-04
Carbon-14	air	kBq	1.36E-03	1.44E-03	1.25E-03
Chromium	air	kg	7.35E-08	8.11E-08	8.94E-08
Chromium VI	air	kg	1.99E-09	2.17E-09	2.37E-09
Dinitrogen monoxide	air	kg	2.50E-05	2.51E-05	2.45E-05
Iodine-129	air	kBq	1.16E-06	1.23E-06	1.07E-06
Lead	air	kg	2.79E-08	2.99E-08	3.14E-08
Methane, fossil	air	kg	3.42E-04	3.49E-04	3.45E-04
Mercury	air	kg	2.23E-08	2.26E-08	2.24E-08
Nickel	air	kg	2.32E-08	2.43E-08	3.57E-08
Nitrogen oxides	air	kg	3.31E-04	3.38E-04	7.94E-04
NMVOC total	air	kg	3.08E-05	3.21E-05	4.02E-05
thereof:					
Benzene	air	kg	1.97E-06	1.98E-06	2.15E-06
Benzo(a)pyrene	air	kg	1.03E-10	1.11E-10	1.17E-10
Formaldehyde	air	kg	5.53E-07	5.56E-07	5.58E-07
PAH	air	kg	1.43E-08	1.47E-08	1.47E-08
PM2.5-10	air	kg	1.41E-05	1.50E-05	1.56E-05
PM2.5	air	kg	6.87E-05	6.95E-05	6.87E-05
PCDD/F (measured as I-TEQ)	air	kg	7.42E-14	7.61E-14	8.66E-14
Radon-222	air	kBq	2.14E+01	2.27E+01	1.98E+01
Sulfur dioxide	air	kg	1.42E-04	1.45E-04	1.57E-04
Emissions to Water					
Ammonium, ion	water	kg	1.54E-07	1.63E-07	4.17E-06
Arsenic, ion	water	kg	9.59E-07	9.62E-07	9.41E-07
Cadmium, ion	water	kg	3.27E-08	3.43E-08	3.35E-08
Carbon-14	water	kBq	4.67E-04	4.94E-04	4.32E-04
Cesium-137	water	kBq	2.17E-04	2.30E-04	2.01E-04
Chromium, ion	water	kg	3.65E-09	4.10E-09	3.73E-09
Chromium VI	water	kg	8.02E-07	8.42E-07	8.19E-07
COD	water	kg	4.49E-05	5.02E-05	1.40E-04
Copper, ion	water	kg	1.03E-06	1.05E-06	1.05E-06
Lead	water	kg	1.01E-06	1.02E-06	1.00E-06
Mercury	water	kg	5.93E-09	6.19E-09	6.04E-09
Nickel, ion	water	kg	1.93E-06	2.01E-06	1.99E-06
Nitrate	water	kg	1.14E-06	1.21E-06	1.23E-05
Oils, unspecified	water	kg	6.58E-06	7.28E-06	9.57E-06
PAH	water	kg	2.34E-09	2.66E-09	2.94E-09
Phosphate	water	kg	3.35E-05	3.37E-05	3.58E-05
Emissions to Soil					
Arsenic	soil	kg	1.30E-10	1.32E-10	1.28E-10
Cadmium	soil	kg	5.94E-12	6.61E-12	1.03E-11
Chromium	soil	kg	1.70E-09	1.73E-09	1.84E-09
Chromium VI	soil	kg	2.16E-08	2.31E-08	1.98E-08
Lead	soil	kg	3.91E-11	4.32E-11	9.41E-11
Mercury	soil	kg	1.86E-13	1.97E-13	3.04E-13
Oils, unspecified	soil	kg	5.95E-06	6.52E-06	8.77E-06

Table 8.77 LCA results for year 2050, pessimistic development, "BAU scenario".

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.61E-01	9.79E-01	9.79E-01
Coal, hard, unspecified, in ground	resource	kg	1.42E-02	6.75E-03	7.69E-03
Gas, natural, in ground	resource	Nm3	7.66E-03	2.41E-03	2.71E-03
Oil, crude, in ground	resource	kg	3.39E-03	1.12E-03	1.26E-03
Uranium, in ground	resource	kg	6.47E-07	2.94E-07	3.33E-07
Freshwater (lake, river, groundwater)	resource	m3	5.24E-03	5.10E-03	5.13E-03
Occupation, agricultural and forestal area	resource	m2a	3.57E-03	1.89E-03	2.05E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.44E-03	1.30E-03	1.34E-03
Emissions to air					
Ammonia	air	kg	2.39E-04	2.67E-06	2.79E-06
Arsenic	air	kg	1.25E-08	1.03E-08	1.05E-08
Cadmium	air	kg	2.64E-09	1.43E-09	1.50E-09
Carbon dioxide, fossil	air	kg	1.56E-01	3.47E-02	3.79E-02
Carbon monoxide, fossil	air	kg	2.29E-04	2.11E-04	2.18E-04
Carbon-14	air	kBq	1.32E-03	6.04E-04	6.84E-04
Chromium	air	kg	9.60E-08	6.63E-08	7.39E-08
Chromium VI	air	kg	2.53E-09	1.80E-09	1.98E-09
Dinitrogen monoxide	air	kg	2.46E-05	2.35E-05	2.37E-05
Iodine-129	air	kBq	1.13E-06	5.17E-07	5.85E-07
Lead	air	kg	3.32E-08	2.26E-08	2.46E-08
Methane, fossil	air	kg	3.52E-04	2.85E-04	2.92E-04
Mercury	air	kg	2.26E-08	2.15E-08	2.18E-08
Nickel	air	kg	3.67E-08	1.76E-08	1.87E-08
Nitrogen oxides	air	kg	8.00E-04	3.02E-04	3.09E-04
NMVOC total	air	kg	4.14E-05	2.64E-05	2.77E-05
thereof:					
Benzene	air	kg	2.16E-06	1.92E-06	1.93E-06
Benzo(a)pyrene	air	kg	1.24E-10	8.93E-11	9.77E-11
Formaldehyde	air	kg	5.61E-07	5.36E-07	5.39E-07
PAH	air	kg	1.51E-08	1.30E-08	1.35E-08
PM2.5-10	air	kg	1.64E-05	1.33E-05	1.41E-05
PM2.5	air	kg	6.95E-05	6.68E-05	6.77E-05
PCDD/F (measured as I-TEQ)	air	kg	8.82E-14	7.13E-14	7.32E-14
Radon-222	air	kBq	2.09E+01	9.56E+00	1.08E+01
Sulfur dioxide	air	kg	1.60E-04	1.25E-04	1.28E-04
Emissions to Water					
Ammonium, ion	water	kg	4.18E-06	8.47E-08	9.41E-08
Arsenic, ion	water	kg	9.43E-07	9.50E-07	9.53E-07
Cadmium, ion	water	kg	3.48E-08	3.19E-08	3.34E-08
Carbon-14	water	kBq	4.56E-04	2.08E-04	2.35E-04
Cesium-137	water	kBq	2.12E-04	9.66E-05	1.09E-04
Chromium, ion	water	kg	4.12E-09	2.20E-09	2.65E-09
Chromium VI	water	kg	8.55E-07	7.81E-07	8.21E-07
COD	water	kg	1.44E-04	3.80E-05	4.32E-05
Copper, ion	water	kg	1.06E-06	1.01E-06	1.02E-06
Lead	water	kg	1.01E-06	9.97E-07	1.00E-06
Mercury	water	kg	6.27E-09	5.79E-09	6.05E-09
Nickel, ion	water	kg	2.07E-06	1.87E-06	1.96E-06
Nitrate	water	kg	1.24E-05	5.38E-07	6.06E-07
Oils, unspecified	water	kg	1.02E-05	5.32E-06	6.01E-06
PAH	water	kg	3.23E-09	2.08E-09	2.40E-09
Phosphate	water	kg	3.60E-05	3.32E-05	3.34E-05
Emissions to Soil					
Arsenic	soil	kg	1.29E-10	5.12E-11	5.33E-11
Cadmium	soil	kg	1.09E-11	5.32E-12	5.99E-12
Chromium	soil	kg	1.87E-09	7.03E-10	7.37E-10
Chromium VI	soil	kg	2.11E-08	7.60E-09	9.08E-09
Lead	soil	kg	9.77E-11	3.27E-11	3.68E-11
Mercury	soil	kg	3.14E-13	1.19E-13	1.30E-13
Oils, unspecified	soil	kg	9.28E-06	4.75E-06	5.32E-06

Table 8.78 LCA results for year 2050, pessimistic development, "BAU scenario".

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	9.56E-01	9.56E-01	8.20E-01
Coal, hard, unspecified, in ground	resource	kg	6.80E-03	7.63E-03	2.38E-03
Gas, natural, in ground	resource	Nm3	5.07E-03	5.34E-03	1.09E-03
Oil, crude, in ground	resource	kg	3.02E-03	3.15E-03	7.90E-04
Uranium, in ground	resource	kg	2.90E-07	3.24E-07	9.60E-08
Freshwater (lake, river, groundwater)	resource	m3	5.02E-03	5.05E-03	4.18E-03
Occupation, agricultural and forestal area	resource	m2a	2.30E-03	2.43E-03	1.01E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.31E-03	1.35E-03	1.01E-03
Emissions to air					
Ammonia	air	kg	2.38E-04	2.38E-04	4.76E-06
Arsenic	air	kg	1.10E-08	1.13E-08	7.80E-09
Cadmium	air	kg	2.21E-09	2.27E-09	1.07E-09
Carbon dioxide, fossil	air	kg	1.31E-01	1.34E-01	7.90E-01
Carbon monoxide, fossil	air	kg	2.16E-04	2.22E-04	1.67E-04
Carbon-14	air	kBq	5.90E-04	6.61E-04	1.96E-04
Chromium	air	kg	8.30E-08	8.97E-08	4.05E-08
Chromium VI	air	kg	2.20E-09	2.36E-09	1.13E-09
Dinitrogen monoxide	air	kg	2.32E-05	2.33E-05	1.91E-05
Iodine-129	air	kBq	5.05E-07	5.65E-07	1.67E-07
Lead	air	kg	2.68E-08	2.86E-08	1.47E-08
Methane, fossil	air	kg	2.96E-04	3.02E-04	2.16E-04
Mercury	air	kg	2.17E-08	2.19E-08	1.75E-08
Nickel	air	kg	3.07E-08	3.17E-08	1.38E-08
Nitrogen oxides	air	kg	7.69E-04	7.75E-04	6.30E-04
NMVOC total	air	kg	3.63E-05	3.75E-05	1.97E-05
thereof:					
Benzene	air	kg	2.10E-06	2.11E-06	1.59E-06
Benzo(a)pyrene	air	kg	1.05E-10	1.12E-10	5.70E-11
Formaldehyde	air	kg	5.43E-07	5.45E-07	4.43E-07
PAH	air	kg	1.36E-08	1.40E-08	9.90E-09
PM2.5-10	air	kg	1.48E-05	1.56E-05	9.80E-06
PM2.5	air	kg	6.71E-05	6.78E-05	5.47E-05
PCDD/F (measured as I-TEQ)	air	kg	8.40E-14	8.57E-14	5.66E-14
Radon-222	air	kBq	9.34E+00	1.05E+01	3.10E+00
Sulfur dioxide	air	kg	1.41E-04	1.44E-04	1.18E-04
Emissions to Water					
Ammonium, ion	water	kg	4.11E-06	4.12E-06	4.07E-08
Arsenic, ion	water	kg	9.33E-07	9.35E-07	7.90E-07
Cadmium, ion	water	kg	3.27E-08	3.41E-08	2.45E-08
Carbon-14	water	kBq	2.03E-04	2.27E-04	6.70E-05
Cesium-137	water	kBq	9.44E-05	1.06E-04	3.12E-05
Chromium, ion	water	kg	2.45E-09	2.84E-09	9.40E-10
Chromium VI	water	kg	8.01E-07	8.37E-07	6.00E-07
COD	water	kg	1.34E-04	1.38E-04	2.63E-05
Copper, ion	water	kg	1.03E-06	1.04E-06	8.30E-07
Lead	water	kg	9.87E-07	9.92E-07	8.20E-07
Mercury	water	kg	5.92E-09	6.15E-09	4.52E-09
Nickel, ion	water	kg	1.94E-06	2.02E-06	1.44E-06
Nitrate	water	kg	1.18E-05	1.19E-05	2.01E-07
Oils, unspecified	water	kg	8.46E-06	9.07E-06	3.69E-06
PAH	water	kg	2.71E-09	3.00E-09	1.25E-09
Phosphate	water	kg	3.56E-05	3.57E-05	2.75E-05
Emissions to Soil					
Arsenic	soil	kg	5.79E-11	5.98E-11	1.18E-11
Cadmium	soil	kg	9.73E-12	1.03E-11	3.64E-12
Chromium	soil	kg	9.60E-10	9.90E-10	1.99E-10
Chromium VI	soil	kg	7.42E-09	8.72E-09	5.80E-10
Lead	soil	kg	8.85E-11	9.21E-11	2.37E-11
Mercury	soil	kg	2.45E-13	2.54E-13	7.10E-14
Oils, unspecified	soil	kg	7.71E-06	8.21E-06	3.41E-06

Table 8.79 LCA results for year 2050, pessimistic development, "BAU scenario".

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	1.95E-03	4.30E-01
Coal, hard, unspecified, in ground	resource	kg	3.38E-01	1.44E-03
Gas, natural, in ground	resource	Nm3	1.24E-03	4.91E-04
Oil, crude, in ground	resource	kg	4.20E-03	5.45E-04
Uranium, in ground	resource	kg	1.29E-07	5.64E-08
Freshwater (lake, river, groundwater)	resource	m3	6.03E-04	1.57E-03
Occupation, agricultural and forestal area	resource	m2a	1.57E-02	4.71E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.84E-03	7.44E-04
Emissions to air				
Ammonia	air	kg	1.42E-05	4.34E-07
Arsenic	air	kg	6.32E-08	6.13E-08
Cadmium	air	kg	1.57E-09	1.26E-09
Carbon dioxide, fossil	air	kg	6.51E-01	6.32E-01
Carbon monoxide, fossil	air	kg	1.29E-04	6.93E-05
Carbon-14	air	kBq	2.64E-04	1.15E-04
Chromium	air	kg	4.37E-08	3.64E-08
Chromium VI	air	kg	1.41E-09	1.19E-09
Dinitrogen monoxide	air	kg	2.75E-05	2.62E-05
Iodine-129	air	kBq	2.24E-07	9.80E-08
Lead	air	kg	4.17E-08	3.57E-08
Methane, fossil	air	kg	1.87E-03	1.22E-04
Mercury	air	kg	2.01E-08	1.93E-08
Nickel	air	kg	8.26E-08	1.87E-08
Nitrogen oxides	air	kg	4.26E-04	1.70E-04
NMVOC total	air	kg	4.79E-05	1.80E-05
thereof:				
Benzene	air	kg	1.21E-06	1.00E-06
Benzo(a)pyrene	air	kg	9.45E-11	3.54E-11
Formaldehyde	air	kg	2.82E-07	2.76E-07
PAH	air	kg	5.44E-08	4.67E-08
PM2.5-10	air	kg	1.37E-05	2.55E-06
PM2.5	air	kg	9.82E-06	2.24E-06
PCDD/F (measured as I-TEQ)	air	kg	5.06E-14	4.30E-14
Radon-222	air	kBq	4.19E+00	1.83E+00
Sulfur dioxide	air	kg	3.60E-04	1.98E-04
Emissions to Water				
Ammonium, ion	water	kg	3.58E-07	5.29E-08
Arsenic, ion	water	kg	8.22E-08	7.20E-08
Cadmium, ion	water	kg	1.22E-08	8.94E-09
Carbon-14	water	kBq	9.00E-05	3.93E-05
Cesium-137	water	kBq	4.19E-05	1.83E-05
Chromium, ion	water	kg	2.05E-09	7.56E-10
Chromium VI	water	kg	7.14E-07	6.31E-07
COD	water	kg	2.17E-04	1.60E-04
Copper, ion	water	kg	1.28E-06	1.25E-06
Lead	water	kg	3.28E-07	3.16E-07
Mercury	water	kg	4.85E-09	4.45E-09
Nickel, ion	water	kg	5.95E-07	4.72E-07
Nitrate	water	kg	1.32E-06	7.33E-07
Oils, unspecified	water	kg	1.85E-05	2.36E-06
PAH	water	kg	2.50E-09	9.61E-10
Phosphate	water	kg	7.02E-06	6.63E-06
Emissions to Soil				
Arsenic	soil	kg	5.11E-11	7.29E-12
Cadmium	soil	kg	6.32E-12	3.37E-12
Chromium	soil	kg	7.51E-10	1.52E-10
Chromium VI	soil	kg	2.50E-09	5.19E-10
Lead	soil	kg	5.07E-11	3.10E-11
Mercury	soil	kg	5.74E-13	1.88E-13
Oils, unspecified	soil	kg	1.88E-05	2.20E-06

Table 8.80 LCA results for year 2050, pessimistic development, “BAU scenario”.

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	8.79E-03	9.26E-03	4.37E-03	4.83E-03
Coal, hard, unspecified, in ground	resource	kg	3.89E-01	3.90E-01	3.83E-01	3.84E-01
Gas, natural, in ground	resource	Nm3	4.40E-03	4.64E-03	2.39E-03	2.63E-03
Oil, crude, in ground	resource	kg	5.11E-03	5.22E-03	4.90E-03	5.01E-03
Uranium, in ground	resource	kg	5.61E-07	5.91E-07	2.82E-07	3.12E-07
Freshwater (lake, river, groundwater)	resource	m3	9.38E-04	9.64E-04	7.69E-04	7.95E-04
Occupation, agricultural and forestal area	resource	m2a	1.91E-02	1.92E-02	1.81E-02	1.83E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.44E-03	4.47E-03	4.36E-03	4.39E-03
Emissions to air						
Ammonia	air	kg	1.67E-05	1.68E-05	1.63E-05	1.64E-05
Arsenic	air	kg	8.00E-08	8.02E-08	7.89E-08	7.91E-08
Cadmium	air	kg	2.20E-09	2.25E-09	1.88E-09	1.93E-09
Carbon dioxide, fossil	air	kg	1.36E-01	1.38E-01	1.17E-01	1.19E-01
Carbon monoxide, fossil	air	kg	1.64E-04	1.70E-04	1.59E-04	1.64E-04
Carbon-14	air	kBq	1.15E-03	1.21E-03	5.79E-04	6.40E-04
Chromium	air	kg	6.20E-08	6.78E-08	5.65E-08	6.23E-08
Chromium VI	air	kg	1.95E-09	2.09E-09	1.81E-09	1.95E-09
Dinitrogen monoxide	air	kg	3.59E-05	3.60E-05	3.47E-05	3.49E-05
Iodine-129	air	kBq	9.85E-07	1.04E-06	4.94E-07	5.46E-07
Lead	air	kg	5.64E-08	5.79E-08	5.24E-08	5.39E-08
Methane, fossil	air	kg	2.17E-03	2.18E-03	2.13E-03	2.14E-03
Mercury	air	kg	2.60E-08	2.62E-08	2.54E-08	2.56E-08
Nickel	air	kg	1.01E-07	1.02E-07	9.64E-08	9.73E-08
Nitrogen oxides	air	kg	5.34E-04	5.40E-04	5.13E-04	5.18E-04
NMVOC total	air	kg	6.13E-05	6.22E-05	5.79E-05	5.89E-05
thereof:						
Benzene	air	kg	1.55E-06	1.55E-06	1.51E-06	1.52E-06
Benzo(a)pyrene	air	kg	1.25E-10	1.31E-10	1.14E-10	1.21E-10
Formaldehyde	air	kg	3.71E-07	3.73E-07	3.57E-07	3.59E-07
PAH	air	kg	6.86E-08	6.89E-08	6.76E-08	6.80E-08
PM2.5-10	air	kg	1.69E-05	1.76E-05	1.62E-05	1.69E-05
PM2.5	air	kg	1.36E-05	1.43E-05	1.22E-05	1.28E-05
PCDD/F (measured as I-TEQ)	air	kg	6.52E-14	6.66E-14	6.29E-14	6.44E-14
Radon-222	air	kBq	1.82E+01	1.92E+01	9.17E+00	1.01E+01
Sulfur dioxide	air	kg	4.50E-04	4.52E-04	4.36E-04	4.38E-04
Emissions to Water						
Ammonium, ion	water	kg	4.82E-07	4.89E-07	4.29E-07	4.36E-07
Arsenic, ion	water	kg	1.03E-07	1.05E-07	9.59E-08	9.82E-08
Cadmium, ion	water	kg	1.55E-08	1.67E-08	1.49E-08	1.61E-08
Carbon-14	water	kBq	3.96E-04	4.17E-04	1.98E-04	2.19E-04
Cesium-137	water	kBq	1.84E-04	1.94E-04	9.23E-05	1.02E-04
Chromium, ion	water	kg	4.17E-09	4.50E-09	3.06E-09	3.40E-09
Chromium VI	water	kg	8.45E-07	8.76E-07	8.29E-07	8.60E-07
COD	water	kg	2.53E-04	2.57E-04	2.48E-04	2.52E-04
Copper, ion	water	kg	1.46E-06	1.47E-06	1.44E-06	1.45E-06
Lead	water	kg	3.83E-07	3.87E-07	3.70E-07	3.74E-07
Mercury	water	kg	5.73E-09	5.93E-09	5.63E-09	5.82E-09
Nickel, ion	water	kg	7.81E-07	8.48E-07	7.39E-07	8.06E-07
Nitrate	water	kg	2.17E-06	2.22E-06	1.71E-06	1.76E-06
Oils, unspecified	water	kg	2.27E-05	2.32E-05	2.17E-05	2.22E-05
PAH	water	kg	3.31E-09	3.55E-09	3.11E-09	3.35E-09
Phosphate	water	kg	8.27E-06	8.41E-06	8.04E-06	8.18E-06
Emissions to Soil						
Arsenic	soil	kg	1.47E-10	1.48E-10	8.66E-11	8.82E-11
Cadmium	soil	kg	8.18E-12	8.69E-12	7.71E-12	8.22E-12
Chromium	soil	kg	1.98E-09	2.00E-09	1.22E-09	1.24E-09
Chromium VI	soil	kg	1.87E-08	1.99E-08	8.06E-09	9.19E-09
Lead	soil	kg	6.62E-11	6.93E-11	6.14E-11	6.45E-11
Mercury	soil	kg	7.23E-13	7.31E-13	6.71E-13	6.80E-13
Oils, unspecified	soil	kg	2.28E-05	2.33E-05	2.19E-05	2.23E-05

Table 8.81 LCA results for year 2050, pessimistic development, "BAU scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.95E-01	4.95E-01	4.89E-01	4.90E-01
Coal, hard, unspecified, in ground	resource	kg	1.27E-02	1.36E-02	5.56E-03	6.46E-03
Gas, natural, in ground	resource	Nm3	4.43E-03	4.72E-03	1.92E-03	2.21E-03
Oil, crude, in ground	resource	kg	1.68E-03	1.81E-03	1.42E-03	1.55E-03
Uranium, in ground	resource	kg	5.93E-07	6.30E-07	2.44E-07	2.81E-07
Freshwater (lake, river, groundwater)	resource	m3	2.13E-03	2.16E-03	1.92E-03	1.95E-03
Occupation, agricultural and forestal area	resource	m2a	2.42E-03	2.57E-03	1.19E-03	1.34E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.32E-03	1.36E-03	1.22E-03	1.26E-03
Emissions to air						
Ammonia	air	kg	1.59E-06	1.70E-06	1.02E-06	1.14E-06
Arsenic	air	kg	9.58E-09	9.82E-09	8.24E-09	8.49E-09
Cadmium	air	kg	1.81E-09	1.87E-09	1.41E-09	1.47E-09
Carbon dioxide, fossil	air	kg	1.46E-01	1.49E-01	1.23E-01	1.26E-01
Carbon monoxide, fossil	air	kg	1.20E-04	1.27E-04	1.13E-04	1.20E-04
Carbon-14	air	kBq	1.22E-03	1.29E-03	5.01E-04	5.77E-04
Chromium	air	kg	5.59E-08	6.31E-08	4.90E-08	5.62E-08
Chromium VI	air	kg	1.50E-09	1.68E-09	1.32E-09	1.50E-09
Dinitrogen monoxide	air	kg	3.38E-05	3.40E-05	3.24E-05	3.26E-05
Iodine-129	air	kBq	1.04E-06	1.11E-06	4.26E-07	4.91E-07
Lead	air	kg	2.39E-08	2.58E-08	1.89E-08	2.08E-08
Methane, fossil	air	kg	2.25E-04	2.32E-04	1.71E-04	1.78E-04
Mercury	air	kg	1.54E-08	1.57E-08	1.47E-08	1.50E-08
Nickel	air	kg	1.94E-08	2.04E-08	1.40E-08	1.50E-08
Nitrogen oxides	air	kg	5.50E-04	5.57E-04	5.22E-04	5.29E-04
NMVOC total	air	kg	3.23E-05	3.35E-05	2.81E-05	2.93E-05
thereof:						
Benzene	air	kg	1.35E-06	1.36E-06	1.31E-06	1.32E-06
Benzo(a)pyrene	air	kg	7.00E-11	7.79E-11	5.71E-11	6.50E-11
Formaldehyde	air	kg	3.72E-07	3.75E-07	3.55E-07	3.58E-07
PAH	air	kg	6.09E-08	6.13E-08	5.97E-08	6.01E-08
PM2.5-10	air	kg	5.76E-06	6.59E-06	4.93E-06	5.76E-06
PM2.5	air	kg	6.41E-06	7.23E-06	4.64E-06	5.46E-06
PCDD/F (measured as I-TEQ)	air	kg	6.30E-14	6.48E-14	6.02E-14	6.20E-14
Radon-222	air	kBq	1.93E+01	2.05E+01	7.93E+00	9.14E+00
Sulfur dioxide	air	kg	7.62E-04	7.65E-04	7.45E-04	7.48E-04
Emissions to Water						
Ammonium, ion	water	kg	1.64E-07	1.73E-07	9.85E-08	1.07E-07
Arsenic, ion	water	kg	1.48E-06	1.49E-06	1.47E-06	1.48E-06
Cadmium, ion	water	kg	9.32E-08	9.47E-08	9.24E-08	9.39E-08
Carbon-14	water	kBq	4.18E-04	4.45E-04	1.71E-04	1.97E-04
Cesium-137	water	kBq	1.95E-04	2.07E-04	7.97E-05	9.19E-05
Chromium, ion	water	kg	3.33E-09	3.76E-09	1.95E-09	2.37E-09
Chromium VI	water	kg	9.44E-06	9.47E-06	9.42E-06	9.45E-06
COD	water	kg	2.11E-03	2.12E-03	2.10E-03	2.11E-03
Copper, ion	water	kg	6.82E-06	6.83E-06	6.80E-06	6.81E-06
Lead	water	kg	1.92E-06	1.92E-06	1.90E-06	1.91E-06
Mercury	water	kg	6.18E-08	6.21E-08	6.17E-08	6.19E-08
Nickel, ion	water	kg	4.10E-06	4.18E-06	4.04E-06	4.13E-06
Nitrate	water	kg	1.72E-06	1.78E-06	1.14E-06	1.21E-06
Oils, unspecified	water	kg	5.95E-06	6.61E-06	4.74E-06	5.40E-06
PAH	water	kg	1.88E-09	2.19E-09	1.63E-09	1.94E-09
Phosphate	water	kg	1.11E-04	1.12E-04	1.11E-04	1.11E-04
Emissions to Soil						
Arsenic	soil	kg	1.24E-10	1.26E-10	4.84E-11	5.04E-11
Cadmium	soil	kg	7.72E-12	8.36E-12	7.13E-12	7.78E-12
Chromium	soil	kg	1.66E-09	1.69E-09	7.11E-10	7.43E-10
Chromium VI	soil	kg	2.07E-08	2.21E-08	7.35E-09	8.76E-09
Lead	soil	kg	6.08E-11	6.47E-11	5.48E-11	5.87E-11
Mercury	soil	kg	3.21E-13	3.32E-13	2.57E-13	2.67E-13
Oils, unspecified	soil	kg	5.46E-06	6.01E-06	4.31E-06	4.85E-06

Table 8.82 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, hard coal plant 500MW class oxyf CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class oxyf CCS, 400km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 200km & 2500m deplet gasfield	electricity, hard coal plant 500MW class post CCS, 400km & 2500m deplet gasfield
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	5.17E-05	5.26E-05	6.52E-05	6.60E-05
Coal, hard, unspecified, in ground	resource	kg	3.83E-01	3.84E-01	3.68E-01	3.68E-01
Gas, natural, in ground	resource	Nm3	3.83E-03	4.02E-03	5.38E-03	5.55E-03
Oil, crude, in ground	resource	kg	5.03E-03	5.12E-03	6.21E-03	6.29E-03
Uranium, in ground	resource	kg	1.06E-08	1.08E-08	1.30E-08	1.32E-08
Freshwater (lake, river, groundwater)	resource	m3	1.92E-03	1.93E-03	1.88E-03	1.89E-03
Occupation, agricultural and forestal area	resource	m2a	2.14E-02	2.17E-02	2.07E-02	2.09E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.24E-03	4.26E-03	4.10E-03	4.12E-03
Emissions to air						
Ammonia	air	kg	1.81E-05	1.82E-05	2.41E-04	2.41E-04
Arsenic	air	kg	1.24E-08	1.24E-08	1.22E-08	1.22E-08
Cadmium	air	kg	1.12E-09	1.14E-09	1.50E-09	1.51E-09
Carbon dioxide, fossil	air	kg	3.14E-02	3.22E-02	1.03E-01	1.04E-01
Carbon monoxide, fossil	air	kg	1.44E-04	1.48E-04	1.43E-04	1.46E-04
Carbon-14	air	kBq	1.93E-05	1.96E-05	2.06E-05	2.09E-05
Chromium	air	kg	1.99E-07	2.05E-07	2.34E-07	2.39E-07
Chromium VI	air	kg	5.46E-09	5.60E-09	6.31E-09	6.43E-09
Dinitrogen monoxide	air	kg	3.20E-05	3.21E-05	3.09E-05	3.10E-05
Iodine-129	air	kBq	1.43E-08	1.46E-08	1.55E-08	1.57E-08
Lead	air	kg	5.09E-08	5.15E-08	5.05E-08	5.10E-08
Methane, fossil	air	kg	2.12E-03	2.12E-03	2.05E-03	2.05E-03
Mercury	air	kg	3.12E-08	3.13E-08	3.05E-08	3.06E-08
Nickel	air	kg	9.44E-08	9.46E-08	9.86E-08	9.88E-08
Nitrogen oxides	air	kg	5.08E-04	5.13E-04	7.18E-04	7.22E-04
NMVOC total	air	kg	5.69E-05	5.77E-05	6.18E-05	6.25E-05
thereof:						
Benzene	air	kg	1.82E-06	1.82E-06	1.91E-06	1.91E-06
Benzo(a)pyrene	air	kg	9.07E-11	9.55E-11	9.43E-11	9.85E-11
Formaldehyde	air	kg	4.42E-07	4.43E-07	4.38E-07	4.39E-07
PAH	air	kg	1.87E-08	1.89E-08	1.85E-08	1.87E-08
PM2.5-10	air	kg	2.09E-05	2.15E-05	2.13E-05	2.18E-05
PM2.5	air	kg	4.71E-05	4.76E-05	4.67E-05	4.71E-05
PCDD/F (measured as I-TEQ)	air	kg	6.29E-14	6.35E-14	7.34E-14	7.40E-14
Radon-222	air	kBq	3.33E-01	3.39E-01	3.56E-01	3.62E-01
Sulfur dioxide	air	kg	3.02E-04	3.03E-04	3.05E-04	3.06E-04
Emissions to Water						
Ammonium, ion	water	kg	8.22E-07	8.26E-07	3.61E-06	3.62E-06
Arsenic, ion	water	kg	1.19E-07	1.20E-07	1.17E-07	1.19E-07
Cadmium, ion	water	kg	1.34E-08	1.45E-08	1.35E-08	1.45E-08
Carbon-14	water	kBq	5.59E-06	5.69E-06	6.03E-06	6.11E-06
Cesium-137	water	kBq	2.73E-06	2.78E-06	2.94E-06	2.98E-06
Chromium, ion	water	kg	1.64E-08	1.66E-08	1.60E-08	1.62E-08
Chromium VI	water	kg	2.85E-07	3.14E-07	2.94E-07	3.19E-07
COD	water	kg	1.18E-04	1.21E-04	1.90E-04	1.93E-04
Copper, ion	water	kg	4.83E-07	4.91E-07	4.95E-07	5.02E-07
Lead	water	kg	2.01E-07	2.04E-07	2.04E-07	2.06E-07
Mercury	water	kg	2.94E-09	3.13E-09	2.96E-09	3.12E-09
Nickel, ion	water	kg	1.19E-06	1.25E-06	1.31E-06	1.37E-06
Nitrate	water	kg	2.49E-05	2.50E-05	3.24E-05	3.25E-05
Oils, unspecified	water	kg	2.21E-05	2.25E-05	2.35E-05	2.39E-05
PAH	water	kg	6.03E-09	6.26E-09	6.86E-09	7.07E-09
Phosphate	water	kg	2.79E-06	2.91E-06	5.74E-06	5.85E-06
Emissions to Soil						
Arsenic	soil	kg	1.41E-10	1.42E-10	1.36E-10	1.37E-10
Cadmium	soil	kg	9.88E-12	1.05E-11	1.28E-11	1.33E-11
Chromium	soil	kg	1.90E-09	1.93E-09	1.96E-09	1.98E-09
Chromium VI	soil	kg	1.83E-08	1.94E-08	1.66E-08	1.75E-08
Lead	soil	kg	7.42E-11	7.82E-11	1.12E-10	1.16E-10
Mercury	soil	kg	7.51E-13	7.67E-13	8.21E-13	8.35E-13
Oils, unspecified	soil	kg	2.22E-05	2.25E-05	2.35E-05	2.38E-05

Table 8.83 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, hard coal power plant 500MW class oxyf CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class oxyf CCS, 400km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 200km & 800m aquifer	electricity, hard coal power plant 500MW class post CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.94E-05	5.03E-05	6.32E-05	6.40E-05
Coal, hard, unspecified, in ground	resource	kg	3.83E-01	3.83E-01	3.68E-01	3.68E-01
Gas, natural, in ground	resource	Nm3	2.19E-03	2.39E-03	3.97E-03	4.14E-03
Oil, crude, in ground	resource	kg	4.96E-03	5.05E-03	6.15E-03	6.23E-03
Uranium, in ground	resource	kg	1.02E-08	1.04E-08	1.27E-08	1.29E-08
Freshwater (lake, river, groundwater)	resource	m3	1.89E-03	1.90E-03	1.86E-03	1.86E-03
Occupation, agricultural and forestal area	resource	m2a	1.95E-02	1.97E-02	1.90E-02	1.92E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.20E-03	4.22E-03	4.07E-03	4.09E-03
Emissions to air						
Ammonia	air	kg	1.76E-05	1.77E-05	2.40E-04	2.40E-04
Arsenic	air	kg	1.21E-08	1.22E-08	1.20E-08	1.20E-08
Cadmium	air	kg	1.05E-09	1.06E-09	1.43E-09	1.44E-09
Carbon dioxide, fossil	air	kg	2.71E-02	2.80E-02	9.91E-02	9.98E-02
Carbon monoxide, fossil	air	kg	1.41E-04	1.45E-04	1.41E-04	1.44E-04
Carbon-14	air	kBq	1.88E-05	1.92E-05	2.02E-05	2.05E-05
Chromium	air	kg	1.90E-07	1.96E-07	2.27E-07	2.32E-07
Chromium VI	air	kg	5.24E-09	5.38E-09	6.13E-09	6.25E-09
Dinitrogen monoxide	air	kg	3.09E-05	3.10E-05	2.99E-05	3.00E-05
Iodine-129	air	kBq	1.40E-08	1.42E-08	1.52E-08	1.54E-08
Lead	air	kg	4.93E-08	4.99E-08	4.91E-08	4.96E-08
Methane, fossil	air	kg	2.12E-03	2.12E-03	2.04E-03	2.04E-03
Mercury	air	kg	3.10E-08	3.12E-08	3.04E-08	3.05E-08
Nickel	air	kg	9.37E-08	9.40E-08	9.80E-08	9.82E-08
Nitrogen oxides	air	kg	4.94E-04	4.98E-04	7.06E-04	7.09E-04
NMVOC total	air	kg	5.41E-05	5.50E-05	5.94E-05	6.01E-05
thereof:						
Benzene	air	kg	1.82E-06	1.82E-06	1.90E-06	1.90E-06
Benzo(a)pyrene	air	kg	8.15E-11	8.63E-11	8.63E-11	9.05E-11
Formaldehyde	air	kg	4.40E-07	4.41E-07	4.36E-07	4.37E-07
PAH	air	kg	1.81E-08	1.84E-08	1.80E-08	1.82E-08
PM2.5-10	air	kg	2.04E-05	2.10E-05	2.09E-05	2.14E-05
PM2.5	air	kg	4.65E-05	4.69E-05	4.62E-05	4.66E-05
PCDD/F (measured as I-TEQ)	air	kg	6.09E-14	6.15E-14	7.17E-14	7.22E-14
Radon-222	air	kBq	3.24E-01	3.31E-01	3.49E-01	3.54E-01
Sulfur dioxide	air	kg	2.97E-04	2.98E-04	3.01E-04	3.02E-04
Emissions to Water						
Ammonium, ion	water	kg	7.90E-07	7.95E-07	3.59E-06	3.59E-06
Arsenic, ion	water	kg	1.18E-07	1.19E-07	1.16E-07	1.18E-07
Cadmium, ion	water	kg	1.28E-08	1.39E-08	1.30E-08	1.40E-08
Carbon-14	water	kBq	5.44E-06	5.54E-06	5.90E-06	5.99E-06
Cesium-137	water	kBq	2.66E-06	2.71E-06	2.88E-06	2.92E-06
Chromium, ion	water	kg	1.62E-08	1.65E-08	1.59E-08	1.60E-08
Chromium VI	water	kg	2.69E-07	2.98E-07	2.80E-07	3.05E-07
COD	water	kg	1.14E-04	1.18E-04	1.87E-04	1.90E-04
Copper, ion	water	kg	4.71E-07	4.80E-07	4.85E-07	4.92E-07
Lead	water	kg	1.99E-07	2.02E-07	2.02E-07	2.04E-07
Mercury	water	kg	2.86E-09	3.05E-09	2.89E-09	3.05E-09
Nickel, ion	water	kg	1.14E-06	1.20E-06	1.27E-06	1.33E-06
Nitrate	water	kg	2.48E-05	2.48E-05	3.23E-05	3.23E-05
Oils, unspecified	water	kg	2.17E-05	2.22E-05	2.32E-05	2.36E-05
PAH	water	kg	5.81E-09	6.04E-09	6.67E-09	6.88E-09
Phosphate	water	kg	2.71E-06	2.83E-06	5.68E-06	5.78E-06
Emissions to Soil						
Arsenic	soil	kg	8.61E-11	8.75E-11	8.86E-11	8.97E-11
Cadmium	soil	kg	8.94E-12	9.55E-12	1.20E-11	1.25E-11
Chromium	soil	kg	1.21E-09	1.23E-09	1.35E-09	1.37E-09
Chromium VI	soil	kg	7.95E-09	9.04E-09	7.64E-09	8.58E-09
Lead	soil	kg	6.32E-11	6.71E-11	1.03E-10	1.06E-10
Mercury	soil	kg	6.33E-13	6.49E-13	7.19E-13	7.32E-13
Oils, unspecified	soil	kg	2.19E-05	2.23E-05	2.33E-05	2.36E-05

Table 8.84 LCA results for year 2050, very optimimistic development, “renewable scenario”.

			electricity, hard coal, at power plant 350 MW	electricity, hard coal, at power plant 600 MW	electricity, hard coal, at power plant 800 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	4.58E-05	4.44E-05	4.19E-05
Coal, hard, unspecified, in ground	resource	kg	3.36E-01	3.36E-01	3.35E-01
Gas, natural, in ground	resource	Nm3	1.29E-03	1.28E-03	1.25E-03
Oil, crude, in ground	resource	kg	4.29E-03	4.27E-03	4.25E-03
Uranium, in ground	resource	kg	8.77E-09	8.65E-09	8.42E-09
Freshwater (lake, river, groundwater)	resource	m3	1.64E-03	1.64E-03	1.63E-03
Occupation, agricultural and forestal area	resource	m2a	1.62E-02	1.62E-02	1.62E-02
Occupation, built up area incl. mineral extractid	resource	m2a	3.64E-03	3.64E-03	3.63E-03
Emissions to air					
Ammonia	air	kg	1.65E-05	1.65E-05	1.65E-05
Arsenic	air	kg	1.05E-08	1.05E-08	1.04E-08
Cadmium	air	kg	9.28E-10	9.18E-10	9.00E-10
Carbon dioxide, fossil	air	kg	6.04E-01	6.04E-01	6.03E-01
Carbon monoxide, fossil	air	kg	1.19E-04	1.19E-04	1.18E-04
Carbon-14	air	kBq	1.63E-05	1.61E-05	1.57E-05
Chromium	air	kg	1.52E-07	1.36E-07	1.06E-07
Chromium VI	air	kg	4.24E-09	3.82E-09	3.08E-09
Dinitrogen monoxide	air	kg	2.66E-05	2.66E-05	2.66E-05
Iodine-129	air	kBq	1.22E-08	1.20E-08	1.17E-08
Lead	air	kg	4.22E-08	4.20E-08	4.15E-08
Methane, fossil	air	kg	1.85E-03	1.85E-03	1.85E-03
Mercury	air	kg	2.71E-08	2.70E-08	2.70E-08
Nickel	air	kg	8.28E-08	8.27E-08	8.25E-08
Nitrogen oxides	air	kg	6.23E-04	6.23E-04	6.22E-04
NMVOC total	air	kg	4.59E-05	4.58E-05	4.56E-05
thereof:					
Benzene	air	kg	1.59E-06	1.59E-06	1.59E-06
Benzo(a)pyrene	air	kg	6.37E-11	6.13E-11	5.72E-11
Formaldehyde	air	kg	3.85E-07	3.84E-07	3.82E-07
PAH	air	kg	1.54E-08	1.53E-08	1.51E-08
PM2.5-10	air	kg	1.72E-05	1.70E-05	1.66E-05
PM2.5	air	kg	4.01E-05	3.99E-05	3.96E-05
PCDD/F (measured as I-TEQ)	air	kg	5.21E-14	5.19E-14	5.15E-14
Radon-222	air	kBq	2.81E-01	2.77E-01	2.71E-01
Sulfur dioxide	air	kg	4.47E-04	4.47E-04	4.47E-04
Emissions to Water					
Ammonium, ion	water	kg	6.62E-07	6.62E-07	6.61E-07
Arsenic, ion	water	kg	1.00E-07	9.96E-08	9.85E-08
Cadmium, ion	water	kg	9.77E-09	9.55E-09	9.17E-09
Carbon-14	water	kBq	4.75E-06	4.69E-06	4.58E-06
Cesium-137	water	kBq	2.32E-06	2.29E-06	2.23E-06
Chromium, ion	water	kg	1.34E-08	1.33E-08	1.32E-08
Chromium VI	water	kg	2.03E-07	1.97E-07	1.87E-07
COD	water	kg	9.63E-05	9.53E-05	9.35E-05
Copper, ion	water	kg	3.87E-07	3.83E-07	3.76E-07
Lead	water	kg	1.65E-07	1.61E-07	1.55E-07
Mercury	water	kg	2.24E-09	2.22E-09	2.18E-09
Nickel, ion	water	kg	9.03E-07	8.41E-07	7.31E-07
Nitrate	water	kg	2.07E-05	2.07E-05	2.07E-05
Oils, unspecified	water	kg	1.87E-05	1.87E-05	1.85E-05
PAH	water	kg	4.69E-09	4.34E-09	3.71E-09
Phosphate	water	kg	2.25E-06	2.23E-06	2.19E-06
Emissions to Soil					
Arsenic	soil	kg	5.28E-11	5.25E-11	5.20E-11
Cadmium	soil	kg	7.01E-12	6.77E-12	6.35E-12
Chromium	soil	kg	7.66E-10	7.60E-10	7.50E-10
Chromium VI	soil	kg	2.52E-09	2.50E-09	2.47E-09
Lead	soil	kg	4.91E-11	4.78E-11	4.55E-11
Mercury	soil	kg	5.01E-13	4.99E-13	4.95E-13
Oils, unspecified	soil	kg	1.90E-05	1.90E-05	1.89E-05

Table 8.85 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, lignite plant 800 MW class oxyf CCS, 200km & 2500m depl. gasfield	electricity, lignite plant 800 MW class oxyf CCS, 400km & 2500m depl. gasfield	electricity, lignite plant 800 MW class post CCS, 200km & 2500m depl. gasfield
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	8.18E-01	8.18E-01	7.87E-01
Coal, hard, unspecified, in ground	resource	kg	1.93E-03	2.12E-03	1.98E-03
Gas, natural, in ground	resource	Nm3	3.70E-03	3.93E-03	5.62E-03
Oil, crude, in ground	resource	kg	9.15E-04	1.01E-03	2.49E-03
Uranium, in ground	resource	kg	5.34E-09	5.59E-09	8.46E-09
Freshwater (lake, river, groundwater)	resource	m3	4.19E-03	4.20E-03	4.07E-03
Occupation, agricultural and forestal area	resource	m2a	4.90E-03	5.16E-03	4.89E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.11E-03	1.14E-03	1.10E-03
Emissions to air					
Ammonia	air	kg	2.99E-06	3.10E-06	2.38E-04
Arsenic	air	kg	6.36E-09	6.41E-09	6.42E-09
Cadmium	air	kg	5.53E-10	5.74E-10	1.06E-09
Carbon dioxide, fossil	air	kg	2.14E-02	2.24E-02	1.01E-01
Carbon monoxide, fossil	air	kg	1.75E-04	1.79E-04	1.75E-04
Carbon-14	air	kBq	9.28E-06	9.69E-06	1.14E-05
Chromium	air	kg	7.46E-08	8.14E-08	8.73E-08
Chromium VI	air	kg	1.97E-09	2.13E-09	2.27E-09
Dinitrogen monoxide	air	kg	2.10E-05	2.12E-05	2.03E-05
Iodine-129	air	kBq	7.05E-09	7.35E-09	8.83E-09
Lead	air	kg	1.12E-08	1.18E-08	1.26E-08
Methane, fossil	air	kg	2.17E-04	2.19E-04	2.19E-04
Mercury	air	kg	1.79E-08	1.81E-08	1.78E-08
Nickel	air	kg	8.69E-09	9.03E-09	1.85E-08
Nitrogen oxides	air	kg	2.73E-04	2.78E-04	6.45E-04
NMVOC total	air	kg	2.51E-05	2.61E-05	3.25E-05
thereof:					
Benzene	air	kg	1.59E-06	1.59E-06	1.71E-06
Benzo(a)pyrene	air	kg	6.72E-11	7.28E-11	7.32E-11
Formaldehyde	air	kg	4.45E-07	4.46E-07	4.43E-07
PAH	air	kg	1.11E-08	1.15E-08	1.13E-08
PM2.5-10	air	kg	1.18E-05	1.25E-05	1.29E-05
PM2.5	air	kg	5.60E-05	5.66E-05	5.52E-05
PCDD/F (measured as I-TEQ)	air	kg	5.81E-14	5.88E-14	6.89E-14
Radon-222	air	kBq	1.62E-01	1.69E-01	1.99E-01
Sulfur dioxide	air	kg	1.18E-04	1.19E-04	1.30E-04
Emissions to Water					
Ammonium, ion	water	kg	9.00E-08	9.53E-08	3.40E-06
Arsenic, ion	water	kg	7.95E-07	7.97E-07	7.68E-07
Cadmium, ion	water	kg	2.81E-08	2.94E-08	2.84E-08
Carbon-14	water	kBq	2.75E-06	2.86E-06	3.44E-06
Cesium-137	water	kBq	1.34E-06	1.40E-06	1.68E-06
Chromium, ion	water	kg	1.31E-09	1.57E-09	1.50E-09
Chromium VI	water	kg	6.90E-07	7.24E-07	6.96E-07
COD	water	kg	3.40E-05	3.80E-05	1.18E-04
Copper, ion	water	kg	8.64E-07	8.74E-07	8.65E-07
Lead	water	kg	8.35E-07	8.38E-07	8.14E-07
Mercury	water	kg	5.01E-09	5.23E-09	5.05E-09
Nickel, ion	water	kg	1.67E-06	1.74E-06	1.70E-06
Nitrate	water	kg	3.86E-07	4.09E-07	1.00E-05
Oils, unspecified	water	kg	4.43E-06	4.94E-06	7.00E-06
PAH	water	kg	2.18E-09	2.46E-09	2.68E-09
Phosphate	water	kg	2.79E-05	2.80E-05	2.99E-05
Emissions to Soil					
Arsenic	soil	kg	1.06E-10	1.07E-10	1.03E-10
Cadmium	soil	kg	6.95E-12	7.66E-12	1.05E-11
Chromium	soil	kg	1.40E-09	1.43E-09	1.51E-09
Chromium VI	soil	kg	1.87E-08	2.00E-08	1.69E-08
Lead	soil	kg	5.08E-11	5.54E-11	9.61E-11
Mercury	soil	kg	3.09E-13	3.28E-13	4.04E-13
Oils, unspecified	soil	kg	3.77E-06	4.16E-06	6.20E-06

Table 8.86 LCA results for year 2050, very optimimistic development, “renewable scenario”.

			electricity, lignite plant 800 MW class post CCS, 400km & 2500m depl. gasfield	electricity, lignite power plant 800 MW class oxyf CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class oxyf CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	7.87E-01	8.18E-01	8.18E-01
Coal, hard, unspecified, in ground	resource	kg	2.14E-03	1.22E-03	1.41E-03
Gas, natural, in ground	resource	Nm3	5.82E-03	1.79E-03	2.02E-03
Oil, crude, in ground	resource	kg	2.57E-03	8.30E-04	9.30E-04
Uranium, in ground	resource	kg	8.67E-09	4.88E-09	5.12E-09
Freshwater (lake, river, groundwater)	resource	m3	4.08E-03	4.16E-03	4.17E-03
Occupation, agricultural and forestal area	resource	m2a	5.11E-03	2.60E-03	2.86E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.13E-03	1.07E-03	1.10E-03
Emissions to air					
Ammonia	air	kg	2.38E-04	2.40E-06	2.51E-06
Arsenic	air	kg	6.47E-09	6.09E-09	6.14E-09
Cadmium	air	kg	1.07E-09	4.62E-10	4.82E-10
Carbon dioxide, fossil	air	kg	1.02E-01	1.65E-02	1.74E-02
Carbon monoxide, fossil	air	kg	1.79E-04	1.72E-04	1.76E-04
Carbon-14	air	kBq	1.17E-05	8.72E-06	9.14E-06
Chromium	air	kg	9.32E-08	6.46E-08	7.14E-08
Chromium VI	air	kg	2.42E-09	1.72E-09	1.89E-09
Dinitrogen monoxide	air	kg	2.04E-05	1.97E-05	1.99E-05
Iodine-129	air	kBq	9.10E-09	6.62E-09	6.92E-09
Lead	air	kg	1.31E-08	9.30E-09	9.96E-09
Methane, fossil	air	kg	2.21E-04	2.08E-04	2.10E-04
Mercury	air	kg	1.79E-08	1.77E-08	1.79E-08
Nickel	air	kg	1.88E-08	7.92E-09	8.26E-09
Nitrogen oxides	air	kg	6.49E-04	2.57E-04	2.62E-04
NMVOC total	air	kg	3.34E-05	2.18E-05	2.28E-05
thereof:					
Benzene	air	kg	1.72E-06	1.58E-06	1.59E-06
Benzo(a)pyrene	air	kg	7.81E-11	5.64E-11	6.21E-11
Formaldehyde	air	kg	4.44E-07	4.42E-07	4.43E-07
PAH	air	kg	1.16E-08	1.05E-08	1.08E-08
PM2.5-10	air	kg	1.35E-05	1.12E-05	1.19E-05
PM2.5	air	kg	5.57E-05	5.53E-05	5.59E-05
PCDD/F (measured as I-TEQ)	air	kg	6.96E-14	5.57E-14	5.64E-14
Radon-222	air	kBq	2.05E-01	1.52E-01	1.59E-01
Sulfur dioxide	air	kg	1.31E-04	1.12E-04	1.13E-04
Emissions to Water					
Ammonium, ion	water	kg	3.41E-06	5.32E-08	5.85E-08
Arsenic, ion	water	kg	7.70E-07	7.94E-07	7.96E-07
Cadmium, ion	water	kg	2.95E-08	2.74E-08	2.87E-08
Carbon-14	water	kBq	3.55E-06	2.58E-06	2.70E-06
Cesium-137	water	kBq	1.73E-06	1.26E-06	1.32E-06
Chromium, ion	water	kg	1.74E-09	1.11E-09	1.37E-09
Chromium VI	water	kg	7.26E-07	6.71E-07	7.05E-07
COD	water	kg	1.21E-04	3.03E-05	3.42E-05
Copper, ion	water	kg	8.74E-07	8.50E-07	8.61E-07
Lead	water	kg	8.17E-07	8.32E-07	8.35E-07
Mercury	water	kg	5.23E-09	4.92E-09	5.13E-09
Nickel, ion	water	kg	1.77E-06	1.61E-06	1.69E-06
Nitrate	water	kg	1.01E-05	2.01E-07	2.24E-07
Oils, unspecified	water	kg	7.44E-06	4.04E-06	4.54E-06
PAH	water	kg	2.91E-09	1.92E-09	2.20E-09
Phosphate	water	kg	3.00E-05	2.78E-05	2.79E-05
Emissions to Soil					
Arsenic	soil	kg	1.04E-10	4.18E-11	4.34E-11
Cadmium	soil	kg	1.12E-11	5.84E-12	6.56E-12
Chromium	soil	kg	1.53E-09	5.89E-10	6.16E-10
Chromium VI	soil	kg	1.80E-08	6.63E-09	7.91E-09
Lead	soil	kg	1.00E-10	3.79E-11	4.25E-11
Mercury	soil	kg	4.20E-13	1.71E-13	1.90E-13
Oils, unspecified	soil	kg	6.54E-06	3.47E-06	3.87E-06

Table 8.87 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, lignite power plant 800 MW class post CCS, 200km & 800m aquifer	electricity, lignite power plant 800 MW class post CCS, 400km & 800m aquifer	electricity, lignite, at power plant 950 MW
			Total kWh	Total kWh	Total kWh
Resources					
Coal, brown, in ground	resource	kg	7.87E-01	7.87E-01	7.18E-01
Coal, hard, unspecified, in ground	resource	kg	1.36E-03	1.52E-03	6.13E-04
Gas, natural, in ground	resource	Nm3	3.96E-03	4.16E-03	8.82E-04
Oil, crude, in ground	resource	kg	2.41E-03	2.50E-03	6.60E-04
Uranium, in ground	resource	kg	8.05E-09	8.27E-09	4.11E-09
Freshwater (lake, river, groundwater)	resource	m3	4.04E-03	4.05E-03	3.62E-03
Occupation, agricultural and forestal area	resource	m2a	2.88E-03	3.11E-03	1.23E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.06E-03	1.09E-03	8.82E-04
Emissions to air					
Ammonia	air	kg	2.37E-04	2.37E-04	4.23E-06
Arsenic	air	kg	6.19E-09	6.23E-09	5.20E-09
Cadmium	air	kg	9.76E-10	9.94E-10	4.44E-10
Carbon dioxide, fossil	air	kg	9.72E-02	9.80E-02	6.93E-01
Carbon monoxide, fossil	air	kg	1.72E-04	1.76E-04	1.43E-04
Carbon-14	air	kBq	1.09E-05	1.12E-05	7.48E-06
Chromium	air	kg	7.86E-08	8.45E-08	4.08E-08
Chromium VI	air	kg	2.06E-09	2.20E-09	1.12E-09
Dinitrogen monoxide	air	kg	1.92E-05	1.93E-05	1.68E-05
Iodine-129	air	kBq	8.46E-09	8.72E-09	5.87E-09
Lead	air	kg	1.09E-08	1.15E-08	6.77E-09
Methane, fossil	air	kg	2.12E-04	2.13E-04	1.78E-04
Mercury	air	kg	1.76E-08	1.78E-08	1.52E-08
Nickel	air	kg	1.78E-08	1.81E-08	8.26E-09
Nitrogen oxides	air	kg	6.30E-04	6.35E-04	5.50E-04
NMVOC total	air	kg	2.97E-05	3.06E-05	1.72E-05
thereof:					
Benzene	air	kg	1.71E-06	1.71E-06	1.39E-06
Benzo(a)pyrene	air	kg	6.38E-11	6.88E-11	3.73E-11
Formaldehyde	air	kg	4.41E-07	4.42E-07	3.86E-07
PAH	air	kg	1.07E-08	1.10E-08	8.53E-09
PM2.5-10	air	kg	1.23E-05	1.29E-05	8.67E-06
PM2.5	air	kg	5.46E-05	5.51E-05	4.76E-05
PCDD/F (measured as I-TEQ)	air	kg	6.69E-14	6.75E-14	4.71E-14
Radon-222	air	kBq	1.90E-01	1.96E-01	1.31E-01
Sulfur dioxide	air	kg	1.25E-04	1.26E-04	1.01E-04
Emissions to Water					
Ammonium, ion	water	kg	3.37E-06	3.38E-06	2.95E-08
Arsenic, ion	water	kg	7.67E-07	7.69E-07	6.93E-07
Cadmium, ion	water	kg	2.78E-08	2.89E-08	2.19E-08
Carbon-14	water	kBq	3.30E-06	3.40E-06	2.29E-06
Cesium-137	water	kBq	1.60E-06	1.66E-06	1.11E-06
Chromium, ion	water	kg	1.33E-09	1.56E-09	6.08E-10
Chromium VI	water	kg	6.80E-07	7.09E-07	5.36E-07
COD	water	kg	1.15E-04	1.18E-04	2.27E-05
Copper, ion	water	kg	8.54E-07	8.63E-07	7.29E-07
Lead	water	kg	8.12E-07	8.15E-07	7.21E-07
Mercury	water	kg	4.96E-09	5.15E-09	4.01E-09
Nickel, ion	water	kg	1.66E-06	1.72E-06	1.29E-06
Nitrate	water	kg	9.87E-06	9.89E-06	9.49E-08
Oils, unspecified	water	kg	6.65E-06	7.09E-06	3.13E-06
PAH	water	kg	2.45E-09	2.69E-09	1.21E-09
Phosphate	water	kg	2.98E-05	3.00E-05	2.42E-05
Emissions to Soil					
Arsenic	soil	kg	4.70E-11	4.84E-11	1.02E-11
Cadmium	soil	kg	9.58E-12	1.02E-11	3.95E-12
Chromium	soil	kg	7.99E-10	8.22E-10	1.79E-10
Chromium VI	soil	kg	6.40E-09	7.51E-09	5.99E-10
Lead	soil	kg	8.48E-11	8.88E-11	2.56E-11
Mercury	soil	kg	2.84E-13	3.00E-13	8.77E-14
Oils, unspecified	soil	kg	5.94E-06	6.28E-06	2.83E-06

Table 8.88 LCA results for year 2050, very optimimistic development, “renewable scenario”.

			electricity, hard coal, at IGCC power plant 450MW	electricity, lignite, at IGCC power plant 450MW
			Total kWh	Total kWh
Resources				
Coal, brown, in ground	resource	kg	3.16E-05	4.13E-01
Coal, hard, unspecified, in ground	resource	kg	3.23E-01	3.99E-04
Gas, natural, in ground	resource	Nm3	1.07E-03	4.21E-04
Oil, crude, in ground	resource	kg	3.96E-03	4.84E-04
Uranium, in ground	resource	kg	8.80E-09	3.51E-09
Freshwater (lake, river, groundwater)	resource	m3	5.23E-04	1.48E-03
Occupation, agricultural and forestal area	resource	m2a	1.56E-02	6.55E-04
Occupation, built up area incl. mineral extractio	resource	m2a	3.69E-03	7.16E-04
Emissions to air				
Ammonia	air	kg	1.38E-05	4.31E-07
Arsenic	air	kg	5.65E-08	5.47E-08
Cadmium	air	kg	7.48E-10	4.58E-10
Carbon dioxide, fossil	air	kg	6.21E-01	6.06E-01
Carbon monoxide, fossil	air	kg	1.18E-04	6.40E-05
Carbon-14	air	kBq	1.64E-05	6.38E-06
Chromium	air	kg	4.40E-08	3.61E-08
Chromium VI	air	kg	1.39E-09	1.16E-09
Dinitrogen monoxide	air	kg	2.65E-05	2.53E-05
Iodine-129	air	kBq	1.20E-08	4.67E-09
Lead	air	kg	3.02E-08	2.61E-08
Methane, fossil	air	kg	1.79E-03	1.10E-04
Mercury	air	kg	1.85E-08	1.79E-08
Nickel	air	kg	7.35E-08	1.26E-08
Nitrogen oxides	air	kg	4.06E-04	1.62E-04
NMVOC total	air	kg	4.55E-05	1.69E-05
thereof:				
Benzene	air	kg	1.12E-06	9.23E-07
Benzo(a)pyrene	air	kg	5.58E-11	2.34E-11
Formaldehyde	air	kg	2.58E-07	2.55E-07
PAH	air	kg	5.04E-08	4.33E-08
PM2.5-10	air	kg	1.30E-05	2.37E-06
PM2.5	air	kg	8.84E-06	1.86E-06
PCDD/F (measured as I-TEQ)	air	kg	4.38E-14	3.86E-14
Radon-222	air	kBq	2.81E-01	1.10E-01
Sulfur dioxide	air	kg	3.41E-04	1.87E-04
Emissions to Water				
Ammonium, ion	water	kg	3.35E-07	4.67E-08
Arsenic, ion	water	kg	7.70E-08	6.85E-08
Cadmium, ion	water	kg	1.18E-08	8.67E-09
Carbon-14	water	kBq	4.67E-06	1.82E-06
Cesium-137	water	kBq	2.28E-06	8.89E-07
Chromium, ion	water	kg	1.59E-09	5.61E-10
Chromium VI	water	kg	6.90E-07	6.10E-07
COD	water	kg	2.07E-04	1.53E-04
Copper, ion	water	kg	1.23E-06	1.21E-06
Lead	water	kg	3.13E-07	3.04E-07
Mercury	water	kg	4.68E-09	4.29E-09
Nickel, ion	water	kg	5.80E-07	4.60E-07
Nitrate	water	kg	1.16E-06	6.53E-07
Oils, unspecified	water	kg	1.76E-05	2.15E-06
PAH	water	kg	2.43E-09	9.41E-10
Phosphate	water	kg	6.71E-06	6.37E-06
Emissions to Soil				
Arsenic	soil	kg	4.84E-11	6.74E-12
Cadmium	soil	kg	6.58E-12	3.62E-12
Chromium	soil	kg	7.18E-10	1.46E-10
Chromium VI	soil	kg	2.52E-09	5.49E-10
Lead	soil	kg	5.29E-11	3.23E-11
Mercury	soil	kg	5.87E-13	1.97E-13
Oils, unspecified	soil	kg	1.78E-05	1.99E-06

Table 8.89 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, hard coal IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, hard coal IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, hard coal IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, hard coal IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	3.92E-05	4.01E-05	3.69E-05	3.78E-05
Coal, hard, unspecified, in ground	resource	kg	3.64E-01	3.64E-01	3.63E-01	3.63E-01
Gas, natural, in ground	resource	Nm3	3.69E-03	3.89E-03	2.03E-03	2.23E-03
Oil, crude, in ground	resource	kg	4.61E-03	4.70E-03	4.54E-03	4.63E-03
Uranium, in ground	resource	kg	1.05E-08	1.07E-08	1.01E-08	1.03E-08
Freshwater (lake, river, groundwater)	resource	m3	6.32E-04	6.42E-04	6.06E-04	6.16E-04
Occupation, agricultural and forestal area	resource	m2a	2.04E-02	2.07E-02	1.84E-02	1.87E-02
Occupation, built up area incl. mineral extractio	resource	m2a	4.20E-03	4.22E-03	4.16E-03	4.18E-03
Emissions to air						
Ammonia	air	kg	1.62E-05	1.63E-05	1.57E-05	1.58E-05
Arsenic	air	kg	7.02E-08	7.03E-08	7.00E-08	7.00E-08
Cadmium	air	kg	9.80E-10	9.98E-10	9.01E-10	9.19E-10
Carbon dioxide, fossil	air	kg	1.02E-01	1.03E-01	9.80E-02	9.89E-02
Carbon monoxide, fossil	air	kg	1.46E-04	1.50E-04	1.43E-04	1.47E-04
Carbon-14	air	kBq	1.91E-05	1.95E-05	1.87E-05	1.90E-05
Chromium	air	kg	6.68E-08	7.27E-08	5.81E-08	6.40E-08
Chromium VI	air	kg	2.03E-09	2.17E-09	1.81E-09	1.95E-09
Dinitrogen monoxide	air	kg	3.44E-05	3.45E-05	3.33E-05	3.34E-05
Iodine-129	air	kBq	1.41E-08	1.43E-08	1.37E-08	1.40E-08
Lead	air	kg	3.93E-08	3.99E-08	3.77E-08	3.82E-08
Methane, fossil	air	kg	2.02E-03	2.02E-03	2.01E-03	2.01E-03
Mercury	air	kg	2.32E-08	2.33E-08	2.30E-08	2.32E-08
Nickel	air	kg	8.47E-08	8.50E-08	8.41E-08	8.44E-08
Nitrogen oxides	air	kg	4.98E-04	5.02E-04	4.83E-04	4.88E-04
NMVOC total	air	kg	5.73E-05	5.82E-05	5.45E-05	5.54E-05
thereof:						
Benzene	air	kg	1.38E-06	1.38E-06	1.37E-06	1.37E-06
Benzo(a)pyrene	air	kg	7.92E-11	8.42E-11	6.99E-11	7.48E-11
Formaldehyde	air	kg	3.22E-07	3.23E-07	3.20E-07	3.21E-07
PAH	air	kg	6.26E-08	6.29E-08	6.20E-08	6.23E-08
PM2.5-10	air	kg	1.58E-05	1.64E-05	1.53E-05	1.59E-05
PM2.5	air	kg	1.12E-05	1.17E-05	1.06E-05	1.11E-05
PCDD/F (measured as I-TEQ)	air	kg	5.60E-14	5.66E-14	5.39E-14	5.45E-14
Radon-222	air	kBq	3.29E-01	3.35E-01	3.21E-01	3.27E-01
Sulfur dioxide	air	kg	4.12E-04	4.13E-04	4.07E-04	4.08E-04
Emissions to Water						
Ammonium, ion	water	kg	4.24E-07	4.28E-07	3.92E-07	3.96E-07
Arsenic, ion	water	kg	8.81E-08	8.97E-08	8.69E-08	8.85E-08
Cadmium, ion	water	kg	1.49E-08	1.61E-08	1.43E-08	1.55E-08
Carbon-14	water	kBq	5.48E-06	5.58E-06	5.33E-06	5.44E-06
Cesium-137	water	kBq	2.68E-06	2.73E-06	2.61E-06	2.66E-06
Chromium, ion	water	kg	2.24E-09	2.47E-09	2.07E-09	2.30E-09
Chromium VI	water	kg	8.15E-07	8.45E-07	7.99E-07	8.28E-07
COD	water	kg	2.38E-04	2.41E-04	2.34E-04	2.38E-04
Copper, ion	water	kg	1.39E-06	1.40E-06	1.38E-06	1.39E-06
Lead	water	kg	3.49E-07	3.51E-07	3.47E-07	3.49E-07
Mercury	water	kg	5.47E-09	5.66E-09	5.39E-09	5.58E-09
Nickel, ion	water	kg	7.68E-07	8.32E-07	7.21E-07	7.85E-07
Nitrate	water	kg	1.53E-06	1.55E-06	1.37E-06	1.39E-06
Oils, unspecified	water	kg	2.05E-05	2.10E-05	2.02E-05	2.06E-05
PAH	water	kg	3.24E-09	3.48E-09	3.02E-09	3.25E-09
Phosphate	water	kg	7.65E-06	7.78E-06	7.58E-06	7.70E-06
Emissions to Soil						
Arsenic	soil	kg	1.37E-10	1.38E-10	8.12E-11	8.25E-11
Cadmium	soil	kg	9.21E-12	9.83E-12	8.26E-12	8.88E-12
Chromium	soil	kg	1.86E-09	1.88E-09	1.15E-09	1.18E-09
Chromium VI	soil	kg	1.84E-08	1.95E-08	7.96E-09	9.06E-09
Lead	soil	kg	7.82E-11	8.22E-11	6.69E-11	7.09E-11
Mercury	soil	kg	8.37E-13	8.53E-13	7.17E-13	7.34E-13
Oils, unspecified	soil	kg	2.06E-05	2.09E-05	2.03E-05	2.07E-05

Table 8.90 LCA results for year 2050, very optimimistic development, "renewable scenario".

			electricity, lignite IGCC plant 400MW, CCS, 200km & 2500m depleted gasfield	electricity, lignite IGCC plant 400MW, CCS, 400km & 2500m depleted gasfield	electricity, lignite IGCC power plant 400MW, CCS, 200km & 800m aquifer	electricity, lignite IGCC power plant 400MW, CCS, 400km & 800m aquifer
			Total kWh	Total kWh	Total kWh	Total kWh
Resources						
Coal, brown, in ground	resource	kg	4.65E-01	4.65E-01	4.65E-01	4.65E-01
Coal, hard, unspecified, in ground	resource	kg	1.78E-03	1.98E-03	1.01E-03	1.21E-03
Gas, natural, in ground	resource	Nm3	3.65E-03	3.90E-03	1.58E-03	1.83E-03
Oil, crude, in ground	resource	kg	1.19E-03	1.30E-03	1.10E-03	1.20E-03
Uranium, in ground	resource	kg	1.24E-08	1.27E-08	1.19E-08	1.22E-08
Freshwater (lake, river, groundwater)	resource	m3	1.76E-03	1.77E-03	1.73E-03	1.74E-03
Occupation, agricultural and forestal area	resource	m2a	4.51E-03	4.79E-03	2.01E-03	2.29E-03
Occupation, built up area incl. mineral extractio	resource	m2a	1.19E-03	1.22E-03	1.14E-03	1.17E-03
Emissions to air						
Ammonia	air	kg	1.68E-06	1.80E-06	1.04E-06	1.16E-06
Arsenic	air	kg	5.00E-09	5.06E-09	4.71E-09	4.76E-09
Cadmium	air	kg	5.17E-10	5.40E-10	4.18E-10	4.40E-10
Carbon dioxide, fossil	air	kg	1.10E-01	1.11E-01	1.04E-01	1.05E-01
Carbon monoxide, fossil	air	kg	1.04E-04	1.09E-04	1.00E-04	1.05E-04
Carbon-14	air	kBq	2.27E-05	2.31E-05	2.21E-05	2.25E-05
Chromium	air	kg	6.13E-08	6.86E-08	5.04E-08	5.78E-08
Chromium VI	air	kg	1.61E-09	1.79E-09	1.34E-09	1.52E-09
Dinitrogen monoxide	air	kg	3.24E-05	3.25E-05	3.10E-05	3.11E-05
Iodine-129	air	kBq	1.65E-08	1.68E-08	1.60E-08	1.63E-08
Lead	air	kg	9.95E-09	1.07E-08	7.91E-09	8.63E-09
Methane, fossil	air	kg	1.42E-04	1.44E-04	1.33E-04	1.34E-04
Mercury	air	kg	1.33E-08	1.35E-08	1.32E-08	1.33E-08
Nickel	air	kg	6.36E-09	6.73E-09	5.52E-09	5.89E-09
Nitrogen oxides	air	kg	5.06E-04	5.12E-04	4.88E-04	4.93E-04
NMVOC total	air	kg	2.90E-05	3.01E-05	2.55E-05	2.66E-05
thereof:						
Benzene	air	kg	1.17E-06	1.17E-06	1.16E-06	1.16E-06
Benzo(a)pyrene	air	kg	5.30E-11	5.92E-11	4.13E-11	4.75E-11
Formaldehyde	air	kg	3.22E-07	3.23E-07	3.19E-07	3.20E-07
PAH	air	kg	5.52E-08	5.55E-08	5.45E-08	5.48E-08
PM2.5-10	air	kg	5.14E-06	5.89E-06	4.48E-06	5.23E-06
PM2.5	air	kg	4.26E-06	4.88E-06	3.49E-06	4.11E-06
PCDD/F (measured as I-TEQ)	air	kg	5.58E-14	5.66E-14	5.32E-14	5.40E-14
Radon-222	air	kBq	3.86E-01	3.93E-01	3.75E-01	3.83E-01
Sulfur dioxide	air	kg	7.07E-04	7.08E-04	7.01E-04	7.02E-04
Emissions to Water						
Ammonium, ion	water	kg	1.17E-07	1.23E-07	7.73E-08	8.30E-08
Arsenic, ion	water	kg	1.41E-06	1.41E-06	1.41E-06	1.41E-06
Cadmium, ion	water	kg	8.94E-08	9.08E-08	8.87E-08	9.01E-08
Carbon-14	water	kBq	6.42E-06	6.55E-06	6.23E-06	6.36E-06
Cesium-137	water	kBq	3.14E-06	3.20E-06	3.05E-06	3.11E-06
Chromium, ion	water	kg	1.33E-09	1.61E-09	1.11E-09	1.40E-09
Chromium VI	water	kg	9.05E-06	9.09E-06	9.03E-06	9.07E-06
COD	water	kg	2.02E-03	2.02E-03	2.01E-03	2.02E-03
Copper, ion	water	kg	6.53E-06	6.54E-06	6.52E-06	6.53E-06
Lead	water	kg	1.82E-06	1.82E-06	1.82E-06	1.82E-06
Mercury	water	kg	5.92E-08	5.95E-08	5.91E-08	5.94E-08
Nickel, ion	water	kg	3.95E-06	4.03E-06	3.89E-06	3.97E-06
Nitrate	water	kg	1.07E-06	1.09E-06	8.64E-07	8.90E-07
Oils, unspecified	water	kg	4.31E-06	4.86E-06	3.88E-06	4.43E-06
PAH	water	kg	1.85E-09	2.15E-09	1.57E-09	1.87E-09
Phosphate	water	kg	1.06E-04	1.07E-04	1.06E-04	1.07E-04
Emissions to Soil						
Arsenic	soil	kg	1.14E-10	1.15E-10	4.41E-11	4.58E-11
Cadmium	soil	kg	8.68E-12	9.45E-12	7.49E-12	8.26E-12
Chromium	soil	kg	1.54E-09	1.57E-09	6.59E-10	6.89E-10
Chromium VI	soil	kg	2.03E-08	2.17E-08	7.22E-09	8.60E-09
Lead	soil	kg	7.28E-11	7.79E-11	5.88E-11	6.38E-11
Mercury	soil	kg	4.58E-13	4.78E-13	3.08E-13	3.28E-13
Oils, unspecified	soil	kg	3.79E-06	4.22E-06	3.47E-06	3.90E-06

Table 8.91 LCA results for year 2025, natural gas, realistic-optimistic development, "440 ppm-scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	1.26E-04	1.77E-04	1.22E-03	2.41E-04
Coal, hard, unspecified, in ground	resource	kg	9.44E-04	1.21E-03	2.41E-03	1.52E-03
Gas, natural, in ground	resource	Nm3	1.76E-01	2.54E-01	1.99E-01	2.23E-01
Oil, crude, in ground	resource	kg	8.32E-04	1.17E-03	1.95E-03	1.86E-03
Uranium, in ground	resource	kg	1.61E-08	2.20E-08	2.26E-07	3.25E-08
Freshwater (lake, river, groundwater)	resource	m3	3.05E-03	8.61E-05	3.52E-03	1.09E-04
Occupation, agricultural and forestal area	resource	m2a	1.47E-04	1.90E-04	9.39E-04	6.64E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.85E-04	2.49E-04	2.71E-04	3.40E-04
Emissions to air						
Ammonia	air	kg	1.87E-07	2.20E-07	1.49E-06	3.82E-07
Arsenic	air	kg	1.11E-09	9.17E-10	2.37E-09	2.45E-09
Cadmium	air	kg	4.57E-10	4.62E-10	1.06E-09	9.45E-10
Carbon dioxide, fossil	air	kg	3.67E-01	5.28E-01	9.50E-02	4.58E-01
Carbon monoxide, fossil	air	kg	8.78E-05	1.88E-04	1.09E-04	3.98E-04
Carbon-14	air	kBq	3.06E-05	4.21E-05	4.59E-04	6.02E-05
Chromium	air	kg	2.45E-08	5.80E-09	4.61E-08	8.94E-09
Chromium VI	air	kg	5.82E-10	1.04E-10	1.11E-09	1.73E-10
Dinitrogen monoxide	air	kg	6.45E-06	9.29E-06	7.94E-06	3.69E-05
Iodine-129	air	kBq	2.65E-08	3.64E-08	3.93E-07	5.02E-08
Lead	air	kg	6.66E-09	7.06E-09	1.21E-08	1.27E-08
Methane, fossil	air	kg	7.71E-04	1.14E-03	8.87E-04	2.23E-03
Mercury	air	kg	1.71E-09	2.29E-09	2.47E-09	2.59E-09
Nickel	air	kg	5.09E-09	5.83E-09	1.33E-08	7.54E-09
Nitrogen oxides	air	kg	1.82E-04	3.54E-04	1.85E-04	2.46E-04
NMVOC total	air	kg	1.63E-04	2.01E-04	1.90E-04	3.15E-04
thereof:						
Benzene	air	kg	2.96E-08	3.23E-08	1.56E-07	7.44E-08
Benzo(a)pyrene	air	kg	4.87E-11	4.99E-11	7.11E-11	6.43E-11
Formaldehyde	air	kg	1.98E-07	6.02E-09	2.34E-07	2.98E-08
PAH	air	kg	4.83E-08	2.05E-09	5.50E-08	2.19E-09
PM2.5-10	air	kg	3.66E-06	4.53E-06	5.68E-06	5.97E-06
PM2.5	air	kg	7.18E-06	5.68E-06	9.77E-06	6.43E-06
PCDD/F (measured as I-TEQ)	air	kg	6.60E-15	8.42E-15	1.19E-14	1.26E-14
Radon-222	air	kBq	5.11E-01	7.03E-01	7.27E+00	1.01E+00
Sulfur dioxide	air	kg	1.31E-04	1.88E-04	1.60E-04	2.07E-04
Emissions to Water						
Ammonium, ion	water	kg	3.47E-08	4.71E-08	1.67E-06	9.94E-08
Arsenic, ion	water	kg	1.24E-08	1.58E-08	1.84E-08	2.00E-08
Cadmium, ion	water	kg	7.85E-09	1.03E-08	1.07E-08	1.28E-08
Carbon-14	water	kBq	1.06E-05	1.46E-05	1.58E-04	2.00E-05
Cesium-137	water	kBq	4.95E-06	6.81E-06	7.35E-05	9.42E-06
Chromium, ion	water	kg	1.69E-09	2.27E-09	2.92E-09	2.65E-09
Chromium VI	water	kg	1.93E-07	2.50E-07	2.66E-07	3.33E-07
COD	water	kg	4.59E-05	6.27E-05	9.09E-05	8.60E-05
Copper, ion	water	kg	6.87E-08	8.35E-08	1.08E-07	1.25E-07
Lead	water	kg	2.51E-08	3.24E-08	3.82E-08	4.16E-08
Mercury	water	kg	1.16E-09	1.54E-09	1.62E-09	1.92E-09
Nickel, ion	water	kg	2.87E-07	2.59E-07	4.49E-07	3.34E-07
Nitrate	water	kg	7.31E-08	8.20E-08	4.23E-06	1.52E-07
Oils, unspecified	water	kg	8.15E-06	1.16E-05	1.13E-05	1.47E-05
PAH	water	kg	9.00E-10	6.87E-10	1.65E-09	9.13E-10
Phosphate	water	kg	8.49E-07	1.11E-06	1.74E-06	1.37E-06
Emissions to Soil						
Arsenic	soil	kg	3.32E-10	4.79E-10	4.17E-10	3.91E-10
Cadmium	soil	kg	2.24E-12	2.96E-12	4.65E-12	6.42E-12
Chromium	soil	kg	4.18E-09	6.02E-09	5.31E-09	4.96E-09
Chromium VI	soil	kg	1.05E-09	1.47E-09	9.35E-09	2.83E-09
Lead	soil	kg	1.36E-11	1.71E-11	3.96E-11	3.62E-11
Mercury	soil	kg	2.86E-14	2.62E-14	8.99E-14	4.54E-14
Oils, unspecified	soil	kg	3.44E-06	4.88E-06	5.84E-06	7.51E-06

Table 8.92 LCA results for year 2050, natural gas, realistic-optimistic development, "440 ppm-scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	5.59E-05	7.80E-05	7.00E-05	1.31E-04
Coal, hard, unspecified, in ground	resource	kg	8.59E-04	1.07E-03	2.00E-03	1.39E-03
Gas, natural, in ground	resource	Nm3	1.66E-01	2.35E-01	1.80E-01	2.13E-01
Oil, crude, in ground	resource	kg	7.89E-04	1.09E-03	1.70E-03	1.78E-03
Uranium, in ground	resource	kg	1.66E-08	2.23E-08	2.30E-07	3.32E-08
Freshwater (lake, river, groundwater)	resource	m3	2.91E-03	8.08E-05	3.20E-03	1.05E-04
Occupation, agricultural and forestal area	resource	m2a	1.30E-04	1.62E-04	7.00E-04	6.23E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.76E-04	2.32E-04	2.50E-04	3.26E-04
Emissions to air						
Ammonia	air	kg	1.72E-07	1.96E-07	1.30E-06	3.56E-07
Arsenic	air	kg	7.31E-10	6.14E-10	1.70E-09	1.56E-09
Cadmium	air	kg	3.50E-10	3.63E-10	8.00E-10	6.62E-10
Carbon dioxide, fossil	air	kg	3.46E-01	4.89E-01	8.00E-02	4.38E-01
Carbon monoxide, fossil	air	kg	7.89E-05	1.08E-04	9.00E-05	2.38E-04
Carbon-14	air	kBq	4.28E-05	5.78E-05	6.00E-04	7.92E-05
Chromium	air	kg	2.43E-08	5.49E-09	4.50E-08	8.55E-09
Chromium VI	air	kg	5.79E-10	9.94E-11	1.10E-09	1.66E-10
Dinitrogen monoxide	air	kg	6.09E-06	8.60E-06	7.00E-06	3.56E-05
Iodine-129	air	kBq	2.73E-08	3.69E-08	4.00E-07	5.16E-08
Lead	air	kg	3.94E-09	4.11E-09	7.00E-09	7.60E-09
Methane, fossil	air	kg	4.94E-04	7.25E-04	5.50E-04	1.62E-03
Mercury	air	kg	1.60E-09	2.08E-09	2.20E-09	2.43E-09
Nickel	air	kg	4.16E-09	4.95E-09	1.00E-08	5.49E-09
Nitrogen oxides	air	kg	1.30E-04	1.83E-04	1.60E-04	1.88E-04
NMVOC total	air	kg	1.50E-04	1.80E-04	1.70E-04	2.68E-04
thereof:						
Benzene	air	kg	2.75E-08	2.92E-08	1.40E-07	7.05E-08
Benzo(a)pyrene	air	kg	4.13E-11	4.33E-11	5.70E-11	5.67E-11
Formaldehyde	air	kg	1.89E-07	5.57E-09	2.10E-07	2.86E-08
PAH	air	kg	4.60E-08	1.76E-09	5.10E-08	1.89E-09
PM2.5-10	air	kg	3.46E-06	4.19E-06	5.20E-06	5.70E-06
PM2.5	air	kg	6.72E-06	5.15E-06	9.00E-06	5.97E-06
PCDD/F (measured as I-TEQ)	air	kg	3.75E-15	4.57E-15	7.00E-15	7.94E-15
Radon-222	air	kBq	5.28E-01	7.13E-01	7.00E+00	1.04E+00
Sulfur dioxide	air	kg	1.22E-04	1.72E-04	1.40E-04	1.96E-04
Emissions to Water						
Ammonium, ion	water	kg	3.38E-08	4.50E-08	1.60E-06	9.70E-08
Arsenic, ion	water	kg	1.17E-08	1.46E-08	1.60E-08	1.91E-08
Cadmium, ion	water	kg	7.49E-09	9.58E-09	1.00E-08	1.23E-08
Carbon-14	water	kBq	1.17E-05	1.58E-05	1.70E-04	2.17E-05
Cesium-137	water	kBq	5.09E-06	6.88E-06	7.00E-05	9.66E-06
Chromium, ion	water	kg	1.61E-09	2.11E-09	2.70E-09	2.55E-09
Chromium VI	water	kg	1.84E-07	2.33E-07	2.50E-07	3.20E-07
COD	water	kg	4.32E-05	5.78E-05	8.00E-05	8.18E-05
Copper, ion	water	kg	6.57E-08	7.78E-08	1.00E-07	1.21E-07
Lead	water	kg	2.38E-08	3.00E-08	3.50E-08	3.98E-08
Mercury	water	kg	1.11E-09	1.43E-09	1.50E-09	1.84E-09
Nickel, ion	water	kg	2.77E-07	2.42E-07	4.20E-07	3.21E-07
Nitrate	water	kg	7.00E-08	7.70E-08	3.90E-06	1.47E-07
Oils, unspecified	water	kg	7.75E-06	1.08E-05	1.00E-05	1.41E-05
PAH	water	kg	8.76E-10	6.41E-10	1.50E-09	8.73E-10
Phosphate	water	kg	8.07E-07	1.03E-06	1.60E-06	1.32E-06
Emissions to Soil						
Arsenic	soil	kg	3.12E-10	4.41E-10	3.80E-10	3.71E-10
Cadmium	soil	kg	2.04E-12	2.63E-12	4.10E-12	6.03E-12
Chromium	soil	kg	3.93E-09	5.54E-09	4.80E-09	4.70E-09
Chromium VI	soil	kg	9.84E-10	1.36E-09	8.00E-09	2.71E-09
Lead	soil	kg	1.26E-11	1.54E-11	3.60E-11	3.42E-11
Mercury	soil	kg	2.73E-14	2.44E-14	8.00E-14	4.37E-14
Oils, unspecified	soil	kg	3.26E-06	4.54E-06	5.10E-06	7.18E-06

Table 8.93 LCA results for year 2025, natural gas, pessimistic development, "BAU scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	2.80E-04	4.04E-04	3.88E-03	4.92E-04
Coal, hard, unspecified, in ground	resource	kg	1.17E-03	1.61E-03	5.87E-03	1.95E-03
Gas, natural, in ground	resource	Nm3	1.80E-01	2.75E-01	2.10E-01	2.35E-01
Oil, crude, in ground	resource	kg	8.52E-04	1.26E-03	2.08E-03	1.97E-03
Uranium, in ground	resource	kg	1.84E-08	2.64E-08	2.70E-07	3.73E-08
Freshwater (lake, river, groundwater)	resource	m3	3.13E-03	9.43E-05	3.73E-03	1.16E-04
Occupation, agricultural and forestal area	resource	m2a	1.55E-04	2.12E-04	1.06E-03	7.08E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.91E-04	2.71E-04	3.23E-04	3.64E-04
Emissions to air						
Ammonia	air	kg	1.98E-07	2.47E-07	1.68E-06	4.20E-07
Arsenic	air	kg	1.49E-09	1.26E-09	3.27E-09	3.51E-09
Cadmium	air	kg	5.64E-10	5.67E-10	1.30E-09	1.28E-09
Carbon dioxide, fossil	air	kg	3.77E-01	5.71E-01	1.08E-01	4.85E-01
Carbon monoxide, fossil	air	kg	9.37E-05	3.89E-04	1.21E-04	7.28E-04
Carbon-14	air	kBq	3.53E-05	5.07E-05	5.51E-04	6.97E-05
Chromium	air	kg	2.47E-08	6.21E-09	4.78E-08	9.58E-09
Chromium VI	air	kg	5.85E-10	1.12E-10	1.16E-09	1.86E-10
Dinitrogen monoxide	air	kg	6.64E-06	1.00E-05	8.53E-06	3.89E-05
Iodine-129	air	kBq	3.05E-08	4.38E-08	4.72E-07	5.83E-08
Lead	air	kg	9.39E-09	1.04E-08	1.74E-08	1.86E-08
Methane, fossil	air	kg	9.38E-04	1.46E-03	1.12E-03	2.63E-03
Mercury	air	kg	1.80E-09	2.54E-09	2.95E-09	2.81E-09
Nickel	air	kg	5.99E-09	6.77E-09	1.62E-08	9.98E-09
Nitrogen oxides	air	kg	2.11E-04	6.61E-04	2.10E-04	7.22E-04
NMVOC total	air	kg	1.70E-04	2.21E-04	2.03E-04	3.51E-04
thereof:						
Benzene	air	kg	3.17E-08	3.69E-08	1.86E-07	8.12E-08
Benzo(a)pyrene	air	kg	5.52E-11	5.73E-11	8.42E-11	7.35E-11
Formaldehyde	air	kg	2.03E-07	6.66E-09	2.50E-07	3.17E-08
PAH	air	kg	4.96E-08	2.38E-09	5.81E-08	2.55E-09
PM2.5-10	air	kg	3.77E-06	4.92E-06	6.17E-06	1.34E-05
PM2.5	air	kg	7.50E-06	6.31E-06	1.10E-05	7.05E-06
PCDD/F (measured as I-TEQ)	air	kg	9.47E-15	1.29E-14	1.68E-14	1.79E-14
Radon-222	air	kBq	5.86E-01	8.42E-01	8.73E+00	1.17E+00
Sulfur dioxide	air	kg	1.36E-04	2.05E-04	1.75E-04	2.22E-04
Emissions to Water						
Ammonium, ion	water	kg	3.67E-08	5.26E-08	1.78E-06	1.07E-07
Arsenic, ion	water	kg	1.28E-08	1.73E-08	2.27E-08	2.14E-08
Cadmium, ion	water	kg	8.00E-09	1.11E-08	1.13E-08	1.35E-08
Carbon-14	water	kBq	1.22E-05	1.76E-05	1.90E-04	2.33E-05
Cesium-137	water	kBq	5.70E-06	8.20E-06	8.82E-05	1.09E-05
Chromium, ion	water	kg	1.74E-09	2.46E-09	3.28E-09	2.82E-09
Chromium VI	water	kg	1.96E-07	2.69E-07	2.80E-07	3.52E-07
COD	water	kg	4.73E-05	6.82E-05	9.67E-05	9.16E-05
Copper, ion	water	kg	7.02E-08	9.02E-08	1.18E-07	1.32E-07
Lead	water	kg	2.59E-08	3.53E-08	4.45E-08	4.44E-08
Mercury	water	kg	1.18E-09	1.66E-09	1.72E-09	2.02E-09
Nickel, ion	water	kg	2.91E-07	2.79E-07	4.76E-07	3.53E-07
Nitrate	water	kg	8.80E-08	1.08E-07	4.70E-06	1.82E-07
Oils, unspecified	water	kg	8.30E-06	1.24E-05	1.20E-05	1.55E-05
PAH	water	kg	9.12E-10	7.38E-10	1.73E-09	9.69E-10
Phosphate	water	kg	8.71E-07	1.21E-06	1.92E-06	1.46E-06
Emissions to Soil						
Arsenic	soil	kg	3.41E-10	5.20E-10	4.41E-10	4.15E-10
Cadmium	soil	kg	2.31E-12	3.23E-12	5.00E-12	6.84E-12
Chromium	soil	kg	4.29E-09	6.53E-09	5.63E-09	5.27E-09
Chromium VI	soil	kg	1.07E-09	1.59E-09	9.86E-09	2.99E-09
Lead	soil	kg	1.42E-11	1.89E-11	4.38E-11	3.88E-11
Mercury	soil	kg	3.12E-14	3.11E-14	1.28E-13	5.10E-14
Oils, unspecified	soil	kg	3.52E-06	5.22E-06	6.28E-06	7.94E-06

Table 8.94 LCA results for year 2050, natural gas, pessimistic development, “BAU scenario”.

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	2.74E-04	3.84E-04	3.65E-03	4.71E-04
Coal, hard, unspecified, in ground	resource	kg	1.17E-03	1.56E-03	5.78E-03	1.89E-03
Gas, natural, in ground	resource	Nm3	1.77E-01	2.62E-01	1.99E-01	2.27E-01
Oil, crude, in ground	resource	kg	8.38E-04	1.20E-03	1.97E-03	1.89E-03
Uranium, in ground	resource	kg	1.67E-08	2.31E-08	2.31E-07	3.35E-08
Freshwater (lake, river, groundwater)	resource	m3	3.05E-03	8.95E-05	3.53E-03	1.12E-04
Occupation, agricultural and forestal area	resource	m2a	1.57E-04	2.08E-04	1.08E-03	6.88E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.89E-04	2.59E-04	3.09E-04	3.50E-04
Emissions to air						
Ammonia	air	kg	1.95E-07	2.35E-07	1.58E-06	4.02E-07
Arsenic	air	kg	1.49E-09	1.23E-09	3.19E-09	3.35E-09
Cadmium	air	kg	5.61E-10	5.57E-10	1.26E-09	1.23E-09
Carbon dioxide, fossil	air	kg	3.69E-01	5.44E-01	1.02E-01	4.67E-01
Carbon monoxide, fossil	air	kg	9.21E-05	2.84E-04	1.14E-04	7.01E-04
Carbon-14	air	kBq	3.17E-05	4.41E-05	4.69E-04	6.23E-05
Chromium	air	kg	2.46E-08	6.02E-09	4.71E-08	9.23E-09
Chromium VI	air	kg	5.85E-10	1.09E-10	1.14E-09	1.79E-10
Dinitrogen monoxide	air	kg	6.49E-06	9.57E-06	8.10E-06	3.74E-05
Iodine-129	air	kBq	2.74E-08	3.82E-08	4.02E-07	5.20E-08
Lead	air	kg	9.31E-09	1.00E-08	1.68E-08	1.79E-08
Methane, fossil	air	kg	9.22E-04	1.39E-03	1.06E-03	2.35E-03
Mercury	air	kg	1.77E-09	2.42E-09	2.82E-09	2.71E-09
Nickel	air	kg	5.95E-09	6.61E-09	1.56E-08	9.55E-09
Nitrogen oxides	air	kg	2.07E-04	5.44E-04	1.99E-04	6.96E-04
NMVOC total	air	kg	1.67E-04	2.10E-04	1.92E-04	3.16E-04
thereof:						
Benzene	air	kg	3.11E-08	3.51E-08	1.77E-07	7.78E-08
Benzo(a)pyrene	air	kg	5.45E-11	5.48E-11	8.12E-11	7.08E-11
Formaldehyde	air	kg	1.98E-07	6.43E-09	2.37E-07	3.05E-08
PAH	air	kg	4.85E-08	2.28E-09	5.50E-08	2.46E-09
PM2.5-10	air	kg	3.72E-06	4.70E-06	5.90E-06	1.29E-05
PM2.5	air	kg	7.37E-06	6.03E-06	1.05E-05	6.78E-06
PCDD/F (measured as I-TEQ)	air	kg	9.34E-15	1.23E-14	1.61E-14	1.72E-14
Radon-222	air	kBq	5.29E-01	7.36E-01	7.44E+00	1.05E+00
Sulfur dioxide	air	kg	1.34E-04	1.96E-04	1.66E-04	2.14E-04
Emissions to Water						
Ammonium, ion	water	kg	3.59E-08	4.98E-08	1.68E-06	1.02E-07
Arsenic, ion	water	kg	1.26E-08	1.65E-08	2.16E-08	2.06E-08
Cadmium, ion	water	kg	7.89E-09	1.06E-08	1.07E-08	1.30E-08
Carbon-14	water	kBq	1.10E-05	1.53E-05	1.62E-04	2.07E-05
Cesium-137	water	kBq	5.13E-06	7.13E-06	7.51E-05	9.76E-06
Chromium, ion	water	kg	1.71E-09	2.34E-09	3.05E-09	2.70E-09
Chromium VI	water	kg	1.94E-07	2.57E-07	2.66E-07	3.38E-07
COD	water	kg	4.66E-05	6.50E-05	9.17E-05	8.81E-05
Copper, ion	water	kg	6.92E-08	8.60E-08	1.12E-07	1.28E-07
Lead	water	kg	2.55E-08	3.37E-08	4.19E-08	4.27E-08
Mercury	water	kg	1.17E-09	1.58E-09	1.64E-09	1.94E-09
Nickel, ion	water	kg	2.88E-07	2.67E-07	4.58E-07	3.40E-07
Nitrate	water	kg	8.68E-08	1.03E-07	4.46E-06	1.75E-07
Oils, unspecified	water	kg	8.17E-06	1.19E-05	1.14E-05	1.49E-05
PAH	water	kg	9.05E-10	7.07E-10	1.68E-09	9.31E-10
Phosphate	water	kg	8.58E-07	1.15E-06	1.82E-06	1.40E-06
Emissions to Soil						
Arsenic	soil	kg	3.36E-10	4.95E-10	4.17E-10	4.00E-10
Cadmium	soil	kg	2.21E-12	2.99E-12	4.64E-12	6.46E-12
Chromium	soil	kg	4.22E-09	6.22E-09	5.32E-09	5.07E-09
Chromium VI	soil	kg	1.05E-09	1.51E-09	9.24E-09	2.87E-09
Lead	soil	kg	1.36E-11	1.74E-11	4.03E-11	3.66E-11
Mercury	soil	kg	3.00E-14	2.87E-14	1.11E-13	4.81E-14
Oils, unspecified	soil	kg	3.46E-06	5.00E-06	5.96E-06	7.63E-06

Table 8.95 LCA results for year 2025, natural gas, very optimistic development, "renewable scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	1.38E-04	1.93E-04	1.45E-03	1.54E-04
Coal, hard, unspecified, in ground	resource	kg	9.01E-04	1.15E-03	2.50E-03	1.48E-03
Gas, natural, in ground	resource	Nm3	1.72E-01	2.47E-01	1.94E-01	2.16E-01
Oil, crude, in ground	resource	kg	8.15E-04	1.14E-03	1.90E-03	1.80E-03
Uranium, in ground	resource	kg	1.94E-08	2.65E-08	2.84E-07	1.22E-08
Freshwater (lake, river, groundwater)	resource	m3	3.01E-03	8.45E-05	3.47E-03	9.87E-05
Occupation, agricultural and forestal area	resource	m2a	1.43E-04	1.81E-04	8.78E-04	6.90E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.82E-04	2.43E-04	2.68E-04	3.32E-04
Emissions to air						
Ammonia	air	kg	1.86E-07	2.17E-07	1.52E-06	3.91E-07
Arsenic	air	kg	8.48E-10	7.14E-10	1.85E-09	1.89E-09
Cadmium	air	kg	3.73E-10	3.86E-10	8.82E-10	7.27E-10
Carbon dioxide, fossil	air	kg	3.59E-01	5.13E-01	8.96E-02	4.45E-01
Carbon monoxide, fossil	air	kg	8.12E-05	1.38E-04	1.01E-04	3.12E-04
Carbon-14	air	kBq	3.75E-05	5.13E-05	5.79E-04	1.86E-05
Chromium	air	kg	2.45E-08	5.69E-09	4.60E-08	8.91E-09
Chromium VI	air	kg	5.81E-10	1.03E-10	1.11E-09	1.74E-10
Dinitrogen monoxide	air	kg	6.31E-06	9.03E-06	7.67E-06	3.60E-05
Iodine-129	air	kBq	3.23E-08	4.43E-08	4.96E-07	1.46E-08
Lead	air	kg	4.56E-09	4.70E-09	8.82E-09	9.18E-09
Methane, fossil	air	kg	6.09E-04	9.00E-04	6.97E-04	1.77E-03
Mercury	air	kg	1.65E-09	2.19E-09	2.40E-09	2.47E-09
Nickel	air	kg	4.54E-09	5.36E-09	1.22E-08	6.37E-09
Nitrogen oxides	air	kg	1.50E-04	2.55E-04	1.74E-04	2.04E-04
NMVOC total	air	kg	1.57E-04	1.91E-04	1.82E-04	2.75E-04
thereof:						
Benzene	air	kg	2.88E-08	3.11E-08	1.55E-07	7.21E-08
Benzo(a)pyrene	air	kg	4.52E-11	4.59E-11	6.57E-11	5.93E-11
Formaldehyde	air	kg	1.95E-07	5.87E-09	2.29E-07	2.90E-08
PAH	air	kg	4.74E-08	1.80E-09	5.38E-08	1.89E-09
PM2.5-10	air	kg	3.56E-06	4.39E-06	5.51E-06	1.19E-05
PM2.5	air	kg	6.94E-06	5.39E-06	9.36E-06	6.09E-06
PCDD/F (measured as I-TEQ)	air	kg	3.87E-15	4.80E-15	8.18E-15	8.10E-15
Radon-222	air	kBq	6.19E-01	8.47E-01	9.17E+00	3.55E-01
Sulfur dioxide	air	kg	1.27E-04	1.81E-04	1.56E-04	2.00E-04
Emissions to Water						
Ammonium, ion	water	kg	3.39E-08	4.58E-08	1.65E-06	9.79E-08
Arsenic, ion	water	kg	1.23E-08	1.56E-08	2.03E-08	1.94E-08
Cadmium, ion	water	kg	7.72E-09	1.00E-08	1.06E-08	1.25E-08
Carbon-14	water	kBq	1.30E-05	1.78E-05	1.99E-04	5.68E-06
Cesium-137	water	kBq	6.05E-06	8.28E-06	9.27E-05	2.77E-06
Chromium, ion	water	kg	1.67E-09	2.22E-09	3.03E-09	2.53E-09
Chromium VI	water	kg	1.90E-07	2.45E-07	2.78E-07	3.25E-07
COD	water	kg	4.48E-05	6.08E-05	9.25E-05	8.30E-05
Copper, ion	water	kg	6.83E-08	8.24E-08	1.19E-07	1.22E-07
Lead	water	kg	2.48E-08	3.18E-08	4.15E-08	4.01E-08
Mercury	water	kg	1.15E-09	1.51E-09	1.71E-09	1.87E-09
Nickel, ion	water	kg	2.83E-07	2.53E-07	4.50E-07	3.26E-07
Nitrate	water	kg	7.37E-08	8.25E-08	4.19E-06	1.66E-07
Oils, unspecified	water	kg	8.00E-06	1.13E-05	1.11E-05	1.43E-05
PAH	water	kg	8.91E-10	6.70E-10	1.63E-09	8.91E-10
Phosphate	water	kg	8.44E-07	1.10E-06	1.90E-06	1.34E-06
Emissions to Soil						
Arsenic	soil	kg	3.24E-10	4.64E-10	4.05E-10	3.78E-10
Cadmium	soil	kg	2.36E-12	2.95E-12	4.86E-12	6.38E-12
Chromium	soil	kg	4.08E-09	5.83E-09	5.17E-09	4.79E-09
Chromium VI	soil	kg	1.03E-09	1.43E-09	9.17E-09	2.76E-09
Lead	soil	kg	1.41E-11	1.70E-11	4.01E-11	3.70E-11
Mercury	soil	kg	2.96E-14	2.64E-14	9.17E-14	6.76E-14
Oils, unspecified	soil	kg	3.37E-06	4.75E-06	5.71E-06	7.30E-06

Table 8.96 LCA results for year 2050, natural gas, very optimistic development, "renewable scenario".

			electricity, natural gas, at combined cycle plant, 500MWe	electricity, natural gas, at turbine, 50MWe	electricity, natural gas, CC plant, 500MWe post CCS, 400km&2500m deplet gasfield	electricity, natural gas, at cogeneration 200kWe lean burn, allocation exergy
			Total	Total	Total	Total
			kWh	kWh	kWh	kWh
Resources						
Coal, brown, in ground	resource	kg	5.50E-05	7.63E-05	6.50E-05	1.27E-04
Coal, hard, unspecified, in ground	resource	kg	7.55E-04	9.41E-04	1.40E-03	1.21E-03
Gas, natural, in ground	resource	Nm3	1.63E-01	2.29E-01	1.76E-01	2.04E-01
Oil, crude, in ground	resource	kg	7.70E-04	1.06E-03	1.68E-03	1.70E-03
Uranium, in ground	resource	kg	3.07E-09	3.88E-09	5.09E-09	1.17E-08
Freshwater (lake, river, groundwater)	resource	m3	2.86E-03	7.01E-05	3.08E-03	9.15E-05
Occupation, agricultural and forestal area	resource	m2a	1.94E-04	2.46E-04	1.78E-03	7.02E-04
Occupation, built up area incl. mineral extrac	resource	m2a	1.73E-04	2.27E-04	2.51E-04	3.15E-04
Emissions to air						
Ammonia	air	kg	1.81E-07	2.07E-07	1.48E-06	3.61E-07
Arsenic	air	kg	3.18E-10	2.82E-10	7.17E-10	6.06E-10
Cadmium	air	kg	2.00E-10	2.40E-10	5.07E-10	2.88E-10
Carbon dioxide, fossil	air	kg	3.40E-01	4.77E-01	7.57E-02	4.22E-01
Carbon monoxide, fossil	air	kg	6.88E-05	9.37E-05	8.87E-05	1.92E-04
Carbon-14	air	kBq	3.88E-06	4.94E-06	5.22E-06	1.78E-05
Chromium	air	kg	2.45E-08	5.67E-09	4.81E-08	8.57E-09
Chromium VI	air	kg	5.82E-10	1.05E-10	1.16E-09	1.67E-10
Dinitrogen monoxide	air	kg	6.00E-06	8.41E-06	7.24E-06	3.44E-05
Iodine-129	air	kBq	3.52E-09	4.53E-09	4.57E-09	1.39E-08
Lead	air	kg	2.98E-09	3.33E-09	5.64E-09	5.50E-09
Methane, fossil	air	kg	3.91E-04	5.76E-04	4.28E-04	1.38E-03
Mercury	air	kg	1.56E-09	2.02E-09	2.12E-09	2.32E-09
Nickel	air	kg	3.33E-09	4.25E-09	8.37E-09	3.58E-09
Nitrogen oxides	air	kg	1.14E-04	1.59E-04	1.53E-04	1.63E-04
NMVOC total	air	kg	1.46E-04	1.72E-04	1.62E-04	2.49E-04
thereof:						
Benzene	air	kg	2.63E-08	2.75E-08	1.34E-07	6.69E-08
Benzo(a)pyrene	air	kg	3.77E-11	3.84E-11	5.54E-11	4.96E-11
Formaldehyde	air	kg	1.86E-07	5.18E-09	2.06E-07	2.73E-08
PAH	air	kg	4.52E-08	1.62E-09	4.91E-08	1.70E-09
PM2.5-10	air	kg	3.38E-06	4.07E-06	5.13E-06	1.12E-05
PM2.5	air	kg	6.57E-06	4.99E-06	8.55E-06	5.69E-06
PCDD/F (measured as I-TEQ)	air	kg	3.57E-15	4.32E-15	8.04E-15	7.46E-15
Radon-222	air	kBq	8.68E-02	1.13E-01	1.11E-01	3.39E-01
Sulfur dioxide	air	kg	1.19E-04	1.66E-04	1.37E-04	1.87E-04
Emissions to Water						
Ammonium, ion	water	kg	3.04E-08	4.03E-08	1.50E-06	8.92E-08
Arsenic, ion	water	kg	1.15E-08	1.42E-08	1.54E-08	1.84E-08
Cadmium, ion	water	kg	7.37E-09	9.36E-09	9.70E-09	1.19E-08
Carbon-14	water	kBq	1.37E-06	1.76E-06	1.78E-06	5.42E-06
Cesium-137	water	kBq	6.62E-07	8.52E-07	8.60E-07	2.64E-06
Chromium, ion	water	kg	1.55E-09	2.02E-09	2.08E-09	2.40E-09
Chromium VI	water	kg	1.81E-07	2.27E-07	2.43E-07	3.09E-07
COD	water	kg	4.19E-05	5.58E-05	7.96E-05	7.80E-05
Copper, ion	water	kg	6.46E-08	7.59E-08	9.86E-08	1.16E-07
Lead	water	kg	2.31E-08	2.89E-08	3.00E-08	3.79E-08
Mercury	water	kg	1.09E-09	1.40E-09	1.47E-09	1.78E-09
Nickel, ion	water	kg	2.74E-07	2.37E-07	4.30E-07	3.11E-07
Nitrate	water	kg	6.80E-08	7.40E-08	3.81E-06	1.40E-07
Oils, unspecified	water	kg	7.61E-06	1.05E-05	9.82E-06	1.36E-05
PAH	water	kg	8.70E-10	6.30E-10	1.60E-09	8.44E-10
Phosphate	water	kg	7.92E-07	1.00E-06	1.54E-06	1.27E-06
Emissions to Soil						
Arsenic	soil	kg	3.05E-10	4.28E-10	3.65E-10	3.55E-10
Cadmium	soil	kg	2.33E-12	2.74E-12	5.00E-12	6.02E-12
Chromium	soil	kg	3.84E-09	5.38E-09	4.66E-09	4.51E-09
Chromium VI	soil	kg	9.79E-10	1.34E-09	8.53E-09	2.64E-09
Lead	soil	kg	1.40E-11	1.60E-11	4.33E-11	3.42E-11
Mercury	soil	kg	3.35E-14	3.10E-14	1.58E-13	5.04E-14
Oils, unspecified	soil	kg	3.19E-06	4.42E-06	4.91E-06	6.89E-06