RECCS

Ecological, Economic and Structural Comparison of Renewable Energy Technologies (RE) with Carbon Capture and Storage (CCS) — An Integrated Approach

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**Ecological, Economic and Structural Comparison
of Renewable Energy Technologies (RE)
with Carbon Capture and Storage (CCS) —
An Integrated Approach**

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Driving Forces and the Attitude of Relevant Groups Towards CO_2 Capture and Storage

- Climate protection is the most important reason for developing CO_2 capture and storage. In particular sectors of the economy other economic incentives to capture CO_2 already exist today (e.g. enhanced oil recovery).

- Attitudes towards the technology are not uniform in different groups of society. CCS is often described as a possible bridge to the era of renewable energy.

- Environmental organisations prioritise the further expansion of renewables and the full exploitation of energy-saving potentials. All environmental organisations reject the idea of storing CO_2 in the oceans. Adequate proof of long-term stability is demanded for all storage options.

CO_2 Capture Methods

- Today there are three technology options for CO_2 capture in the short to medium term. Capturing CO_2 from the flue gases of conventional power stations (*post-combustion* capture) leads to a significant increase in electricity generating costs, causes a considerable increase in fuel consumption and substantially reduces power station efficiency. In principle the technology is already available today, although it has yet to be demonstrated at the scale of commercial power plant.

- Capturing CO_2 *before* combustion (*pre-combustion* capture) in coal- or gas-fired power stations with integrated gasification (IGCC and natural gas combined cycle) is from today's perspective a more advantageous process than capturing CO_2 from flue gas. Implementing this CO_2 capture method would require considerable improvement and development, especially with regard to scaling it up to conventional power plant dimensions.

- The *oxyfuel* process involves burning fuel in pure oxygen and currently offers the best prospects for CO_2 capture in terms of the achievable overall efficiency of the process and possibly also the resulting costs, because the components involved are largely based on conventional power station technology. A precise evaluation is not yet possible, because the process is only at the beginning of the demonstration phase.

- Considerable additional costs must be factored in for capture at the power station, according to current estimates between €35/t and €50/t CO_2. Through research and demonstration projects and other technological improvements it is aimed to reduce the costs to less than €20/t CO_2.

- As well as planning new builds with integrated CO_2 capture it is in principle also possible to retrofit. Because of the strong increase in energy consumed internally, this only makes sense in power stations which start off with a sufficiently high level of efficiency. In terms of technology, flue gas scrubbing is the primary option for retrofitting from today's perspective. When power stations are planned today, the option of designing them to be 'capture ready' (prepared for retrofitting CO_2 capture) should be considered.

Methods for CO$_2$ Transport

- Energy efficiency, economic and ecological considerations mean that pipelines (onshore, possibly offshore too) and large tanker ships are the only relevant transport options for large-scale implementation of CCS.

- The decisive parameters for the source/sink relationship are in particular transport distance and capacity, but coordinating the timing of planning, approval and construction of power stations, pipelines and CO$_2$ sinks is also relevant. The high investment costs involved in establishing a CO$_2$ infrastructure necessitate forward-looking planning and coordination between the different parties involved.

- Both gas conditioning (liquefying CO$_2$ by compression, which reduces power station efficiency by up to 3.5 percentage points) and subsequent CO$_2$ transport themselves require a more than negligible additional amount of energy, which in turn causes additional CO$_2$ emissions (and other greenhouse gases and pollution).

- The range of cost estimates for CO$_2$ is – depending on transport distance and capacity – approx. €1/t to €10/t (for pipeline or ship transport) and represents about 10 % of the total costs of the CCS process (capture, compression, transport, storage).

- In relation to the other infrastructure costs (electricity transmission, fuel logistics) the cost of CO$_2$ transport is likely to be a secondary factor when selecting power station sites. Also, existing power station sites are often likely to be retained for reasons of public acceptance.

- Transport of fuel (oil, oil products, coal) already represents a large proportion of total freight transport in industrialised countries. Introducing CCS on a large scale would considerably increase transport volumes – to supply additional coal and remove CO$_2$. There would also be a risk of pipeline or shipping accidents, although the risk per ship or kilometre of pipeline is relatively small.

CO$_2$ Storage: Methods and Capacity

- For various reasons the storage possibilities for CO$_2$ are limited, both globally and nationally. Owing to the many uncertainties involved, current estimates of actual storage potential vary enormously. Global estimates show that although the potential is certainly considerable, in the long term it will certainly not be possible to solve the climate problem through CO$_2$ storage alone.

- Ecological, economic and capacity considerations mean that the only option e. g. for Germany is geological storage in empty gas fields and deep aquifers. Taking into consideration only the country's major point sources and factoring in an average increase in energy use for CCS of 30 %, the static range in Germany is between thirty and sixty years.

- Guaranteeing very low leakage rates is essential for the acceptance of underground storage. Corresponding evidence will have to be provided in a comprehensible form.

- Little is yet known about the behaviour of CO$_2$ in underground reservoirs. Research projects already under way should greatly improve knowledge of drilling and injection methods, distribution of gases in reservoirs and monitoring methods.

Comparative Life Cycle Assessments

- From a holistic perspective the terms *zero-carbon*, *zero-emissions* and *CO_2-free* are misleading regarding fossil fuelled electricity generation and hydrogen production. When the supply chain is taken into consideration and the usual assumptions are made about CO_2 capture rates at the power station (88 % for post-combustion and pre-combustion) the potential for net CO_2 reduction is found to be between 72 % and 78 %. If the full range of greenhouse gases is included, the reduction compared with a power station without CCS falls to a range of 67 % to 78 %. Higher CO_2 capture rates of up to 99.5 % (achievable with the oxyfuel process) allow in a coal-fired power station a net CO_2 reduction of 90 % and a net greenhouse gas reduction of 78 %.

- In this context it is more correct to speak of *low-CO_2* or *low-carbon* electricity generation. The CO_2 emissions from the 'best' fossil-fuelled power station from the climate protection perspective (natural gas combined cycle, NGCC) are 'only' 50 % higher than those from the 'worst' CCS power station (coal-fired thermal power station with post-combustion capture).

- The increased fuel consumption involved in CO_2 capture and storage always leads to a proportional worsening of the outcome in the other impact categories. There are, however, exceptions: with *post-combustion* capture other emissions are reduced through reaction with the solvent – acidification falls by 10 % and PM10 equivalents (particulate matter) increase by only about 2 %. On the other hand, eutrophication increases by 36 % and summer smog by 94 %, and demand for cooling water increases by up to 50 % (post-combustion).

- In comparison with CCS power stations, comparable large-scale renewable energy systems (e.g. solar thermal power stations, offshore wind farms) fare considerably better in all impact categories across all stages of the process. Innovative fossil-fuelled power station solutions like natural gas combined cycle (NGCC) including heat extraction and combined heat and power plant units (CHP) available today are comparably environmentally friendly as CCS plant are expected to be in 2020.

Other Ecological Assessment Factors for CCS

- As well as direct and indirect effects on the appearance of the landscape (e.g. caused by increased fuel consumption) and the negative consequences of increased transport volumes (of CO_2 and additional fuel), the greatest other ecological impact would be the potential unplanned release of stored CO_2 and the direct influence of the stored CO_2 on the immediate vicinity of the sink over the course of time.

- The different CO_2 storage options differ from one another – sometimes considerably – in terms of ecological and safety considerations. Geological sinks (e.g. saline aquifers) are considered to have comparatively high long-term stability, but there is still great uncertainty concerning the underground movement of CO_2 and the resulting consequences.

- Regarding CO_2 storage in oceans its impact on marine ecosystems is still largely unresearched, but the expectable risks are so great that most countries rule out even conducting further research into this storage option.

Economic Comparison of CCS and Renewable Energy Technologies

- In terms of electricity generation costs, a general structural difference must be noted when comparing CCS and renewables. Large or very large cost degression and learning effects are still to be expected in both fields, but in the case of CCS these will be counteracted by further rises in fuel prices. This effect is particularly strong in the case of gas-fired CCS power stations.

- It can be assumed that electricity from renewable energies will become economically competitive to fossil-fuel based electricity earlier with the introduction of CCS. By 2020 – the earliest point at which CCS technologies are likely to be commercially viable – a whole range of renewable energy technologies is likely to be able to supply electricity at cost conditions comparable to or better than fossil-fuelled power stations. In the longer term, renewables can be expected to have considerable cost advantages due to their independence from fuel price fluctuations.

- The relative profitability of CCS and renewables is currently still subject to many uncertainty factors. The aforementioned predictions for renewables are based on assumptions of dynamic market development on a global scale, allowing very substantial cost degression effects to be exploited through mass production and learning curve effects.

- When it comes to hydrogen, production using renewables cannot be expected to become competitive with production using fossil fuels (including CCS) in the foreseeable future. Whether or not this is the case, hydrogen is unlikely to become an important factor in the energy economy for several decades due to its generally high costs and the considerable infrastructure challenges associated with its introduction. But in principle this option represents an interesting strategic element for the transport sector – today still largely dependent on oil – and could potentially supplement biofuels as a diversifying element.

The Role of CCS in Industrialised Countries: the Example of the German Energy Supply System

- The energy systems of industrialised countries are characterised by a number of shared features. Firstly, there is great potential for energy efficiency measures, on both the supply and demand sides. Secondly, the growth in energy consumption, and consequently in energy-related greenhouse gas emissions, is in general much slower than in developing countries. The special case for Germany is that it faces the complex challenge of having to replace a large proportion of its power station capacity within the coming fifteen years. The following theses are formulated for Germany, but are also applicable to other industrialised countries:

- As the main element of a climate protection strategy (the CCSMAX scenario) CCS runs into structural and capacity limits. The earliest date when CCS technologies are expected to be ready for implementation is 2020, which is too late for the first wave of the necessary power station replacements, which has just begun. It would necessitate extremely rapid growth rates for CCS plant between 2020 and 2050 and speedy establishment of a hydrogen infrastructure.

- If a vigorous political course of promoting renewables and efficiency improvements is pursued over the next ten to fifteen years, the realisation of energy-saving potential and the successive expansion of renewables would be able to make a more rapid contribution to climate protection than CCS. Increasing energy productivity makes sense in purely economic terms, too. Both strategy elements are also associated with strong innovative stimuli for taking a share of growing global markets. Considerable increases in efficiency and the further expansion of renewables are absolute preconditions for effective climate protection. If a sustained high rate of implementation is maintained, as described in the NaturschutzPlus (NATP) scenario, the use of CCS technologies is not absolutely necessary for meeting even ambitious climate protection targets. The strategy outlined in NATP is the best for the economy as a whole in the medium to long term, and should therefore be an aim of energy policy.

- The period until 2020 should be used to thoroughly explore the development and cost-cutting potentials of CCS technologies and to demonstrate the technological feasibility. If that process proves successful, CCS would offer the possibility, as described in the BRIDGE scenario, of switching to a climate-friendly path even if it has not proved possible to sustain the ambitious pace of implementation of efficiency potentials and renewables over time. In view of the real interests involved in the field of energy, especially in the global context (where energy saving efforts are counteracted by substantial growth trends), this constellation may well become reality.

- The successive introduction of CCS after 2020 (presuming the availability of suitable sinks with long-term stability) can act as an ancillary element helping to make it easier to maintain the sustained efforts that will be required to further improve efficiency and expand renewables. In this situation CCS can attain significant importance in fulfilling a bridging function to the establishment of a renewable energy economy. Consequently, it would appear that further development efforts for CCS are necessary and in the international context of climate protection indeed unavoidable. But this must not occur at the expense of R&D efforts in the field of efficiency and renewables.

- Overall it must be ensured that measures for establishing a CCS infrastructure are compatible with the further expansion of renewables and that permanent structural commitments and use conflicts (for example with geothermal energy or decentralised CHP) are avoided.

- If CCS is included as a climate protection element, upcoming power station planning processes must already begin considering the possibility of future implementation of CCS. The idea of designing new builds 'capture ready' is central here, and is reinforced by discussions at the EU level about possibly making 'capture ready' status obligatory for all new power stations in the medium term.

CCS in the International Context

- Above all at the global level CCS could, from today's perspective, make a noticeable contribution to meeting ambitious climate protection goals alongside renewables and energy efficiency. Under plausible assumptions CCS could also help to reduce the economic costs of climate protection if today's expectations about its technological development (especially the cost-cutting possibilities) prove to be realistic. Including CCS in an integrated overall concept seems to be one option to stabilise the CO_2 concentration in the atmosphere at 450 ppm with an acceptable level of loss of economic growth. This applies in particular if the alternative investment required in measures to adapt to the looming climate change is taken into account.

- Internationally too, CCS can fulfil a 'bridging function' to an emission-free energy system, but only if the technologies are available in time for large-scale implementation and the costs of fossil fuels do not rise too steeply.

- The large-scale introduction of CCS presupposes that an institutional framework will be established (preferably at the international level) to sensibly regulate responsibility for the risks stemming from CCS (giving consideration to the precautionary and polluter pays principles) and offer involved parties an incentive to guarantee the safety of storage.

- Plausible proposals already exist for the shape of such an institutional framework (e.g. carbon sequestration bonds), that could be integrated in the existing climate protection regime and via market mechanisms involve the public in decisions about the use of CCS.

- Further research – and also political decisions – are required concerning the development and discussion of the institutional framework, especially integration in the mechanisms of the UN Framework Convention on Climate Change, the development of liability mechanisms and the implementation of legal provisions to restrict local risks associated with CCS.

- In upcoming climate protection negotiations CCS could improve the chances of persuading more states (e.g. United States, China) to undertake firm obligations on emissions, because it would allow them to retain their familiar structures and their domestic primary energy base.

- Ultimately, for reasons of capacity (limited storage potential and finite fossil energy resources), CCS cannot obviate the global need for further expansion of renewables and a considerable increase in energy efficiency. But under particular conditions CCS can help in meeting ambitious climate protection targets while at the same time extending the time available for the necessary restructuring of the energy system.

Summary

Background and Introduction

In recent years the discussion about carbon capture and storage (CCS) has moved steadily up the agenda in many countries as well as globally in the context of meeting climate protection targets – even more so as oil and gas prices have risen sharply and the increasingly urgent debate over security of energy supplies has swung towards greater use of coal.

Carbon capture and storage technologies are not fundamentally new. Some of them are already used on an industrial scale and finds commercial application in oil extraction (enhanced oil recovery to increase the extraction rate of oil fields) or for conditioning natural gas (separating off the accompanying CO_2). However, for the much larger volumes that would generally be involved in application in power stations or for centralised hydrogen production numerous questions still remain unanswered. That also applies to the field of transport, to the possible configurations of a CO_2 infrastructure and to storage. Demonstration projects (e.g. in Germany: 30 MW_{th} pilot plant using the oxyfuel process, planned start of operation 2008) and the first semi-commercial test facilities (the German company RWE Power AG plans to construct a coal-fired power station with integrated gasification, CO_2 capture and storage with a net output of 360 MW_{el} by 2014) aim to achieve significant progress in developing the technologies at the scale required for power stations.

Studies so far conducted in this field have concentrated largely on the technical feasibility of carbon capture and storage. There has not yet been a detailed investigation of the ecological, economic and social impact across all stages of the process (e.g. energy balance, cumulative energy demand, environmental impact, resource consumption, risks and costs) of the kind that is today a matter of course for other new energy technologies, in particular renewable enery technologies. Only after such a study has been completed will it be possible to decide how environmentally beneficial the CCS option really is, what its benefits and drawbacks are compared to renewables and what contribution it can make to a sustainable economic structure. Including carbon capture and storage in the fossil fuel cycle makes it possible for the first time to conduct a comparison with renewables on equal terms (with respect to climate policy). Such a comparison, made on the basis of a comprehensive set of criteria, is the main object of the present study, answering the following questions:

- What are the conceivable paths for carbon capture and storage (technologies, infrastructures) and how do they fit on the time axis (development periods)?

- How do the LCAs of these processes look, and how does low-CO_2 fossil electricity generation compare with CO_2-free options (especially renewables) in this respect?

- What role can carbon capture and storage play for climate protection in comparison with other relevant options, and when (systematic comparison on the basis of significant criteria such as cost, window of opportunity, ecological restrictions, etc.)?

- What role can carbon capture and storage play at the national and international levels as a possible bridge to a renewable energy system?

Driving Forces and the Attitudes of Relevant Groups towards Carbon Capture and Storage

Several different motivations are central to the development of technologies for capturing, transporting and storing CO_2. Alongside climate protection as the overriding motivation, questions of security of supply, technological aspects, and in some cases also very real commercial considerations (e.g. measures in the field of enhanced oil recovery in countries with a CO_2 tax such as Norway) play a decisive role. Technology that can generate progress in international climate protection negotiations is of particular importance. Among the supporters of CCS are – above all – those states that have so far adopted a rejectionist or wait-and-see stance in the international climate protection process, such as the United States. The United States has also made CCS a central priority of the Asian Pacific Partnership (APP), a more technology-oriented climate protection agreement that represents a counterpole to the Kyoto Protocol.

Not least for these reasons, carbon capture and storage has become the subject of a broad range of networks at the international level, such as the Carbon Sequestration Leadership Forum (CSLF), which was initiated by the United States in 2003.

The attitudes of actors in society towards CCS differ rather widely. Across the world environmental and nature conservation **NGOs** (non-governmental organisations) – with very few exceptions – agree on the following points and demands concerning CCS:

- CO_2 must not be stored in ecosystems (namely, oceans),

- Long-term stability of storage systems must be demonstrably proven and guaranteed,

- Development of CCS must not be at the expense of R&D funding for renewables, and

- Renewable energy sources and more rational use of energy are preferable to CO_2 storage, and their implementation should be stepped up.

That is as far as the consensus extends internationally. German NGOs, for example, are generally at the more sceptical end of the international spectrum in their attitudes to CO_2 storage.

Political parties, too, differ in their positions on the technology. In Germany, for example, they range from the expectation that low-CO_2 fossil-fuelled power stations will represent 'an important pillar' of energy policy (the conservative CDU) to the call for a coordinated research campaign (the social democratic SPD) or clear rejection (the left-wing Die Linke).

The positions of the different German **ministries and expert committees** can be summarised as follows: The Federal Ministry of Economics (BMWi) is supporting carbon capture and storage through the COORETEC research programme. This wide-ranging research programme is designed to allow the process of replacing and expanding capacity in the fossil-fuelled power sector that will begin around 2010 to be conducted at a high technological standard. The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) and the Federal Environment Agency (UBA) believe that there are still many unanswered questions to be resolved before CCS can be regarded as a safe long-term option that is acceptable in social, ecological and economic terms. In a comprehensive investigation the UBA has examined carbon capture and storage in terms of sustainability criteria, and has come to the conclusion that CCS is a set of non-sustainable technologies that can at best represent a transitional solution.

In its position paper the Council for Sustainable Development calls carbon capture and storage a potentially important bridge 'to the era of renewable energy supplies'. To this end, it believes, CO_2 capture technologies should be integrated in highly efficient power stations, but only from the point of view of economic efficiency. The German government's Advisory Council on Global Change (WBGU) has taken a firm stance in favour of storing carbon dioxide, referring in this connection to an 'end-of-pipe technology' that can make a contribu-

tion to climate protection for a limited period of time. It rejects the storage options in ocean waters (ecological reservations and missing long-term effect), biomass (lack of potential for expansion) and saline aquifers (no guarantee of safety and long-term storage). Exhausted oil and gas fields could be used temporarily, but only if a sufficient retention period can be guaranteed. In terms of storage period, the WBGU has called for secure sequestration for at least 10,000 years. The WBGU believes storage under the seabed to be permissible only under certain conditions. The Advisory Council on the Environment (SRU) believes that carbon capture and storage may be too expensive in comparison with other CO_2 avoidance options, and that the technologies may also come too late for the upcoming expansion and replacement of power station capacity.

Industrial Associations are definitely positive about CCS as a long-term option, but often prioritise improving the efficiency of the power station process as a contribution to climate protection. Capture of CO_2, as previously mentioned, already offers opportunities for the oil and gas industry today.

CO_2 Capture Methods

This investigation of carbon capture and storage in the use of fossil fuels has restricted itself to the field of electricity generation in power stations and the potential future production of hydrogen by means of coal gasification – in other words to plants emitting particularly large amounts of CO_2 centrally (point sources). In terms of reducing CO_2 emitted through the use of fossil fuels, efficiency-improving technologies have previously been the main focus of attention. Applying these technologies quickly over the past decades has achieved a continuous increase in power station efficiency (despite stricter environmental regulations that have in some cases led to increased fuel requirement). The efficiency levels achievable today are 43 % for lignite-fired power stations and 46 % for coal-fired power stations, while for gas-fired power stations 58 % efficiency is now possible. For reasons of thermodynamics and materials technology this trend cannot continue forever. So a further significant reduction in CO_2 emissions from fossil electricity generation will require the application of CO_2 capture techniques (which are largely already known today) or a move to innovative new power station technologies that include CO_2 capture (e.g. chemical looping combustion).

CO_2 capture technologies are more likely to become available in the medium term (large-scale application is unlikely to occur before 2020) while the development of new, innovative power station concepts should be regarded more as a long-term option (see Fig. 1). Disadvantageous for CO_2 capture is the high energy requirement for the capture process itself, which leads to significant reductions in efficiency (in some cases 10 percentage points and more) and significantly reduces

Measures and goals for CO₂ reduction in the power generation sector

Short-term:
· Efficiency increases
· CO₂ capture from flue gas

Medium-term :
· Combustion with oxygen (Oxyfuel)
· Improved air separation
· IGCC with CO shift and gas separation with CO₂ absorber or H₂ membrane
· Combustion with O₂/CO₂ and components for CO₂ working process

Long-term :
· New power station concepts with process-integrated oxygen supply systems
· CO₂ capture without additional energy requirement

2010   2020   > 2030   **Year**

Fig. 1: Measures and goals for CO_2 reduction in the power generation sector

the levels of efficiency achieved today (roughly to the level of twenty or thirty years ago). This means that CO_2 capture would lead to a significant increase in electricity generating costs and cause a considerable increase in fuel consumption, the logistics of which must also be taken into account. For power stations constructed around 2020, estimates of the cost of CO_2 capture at the power station (which dominates the additional costs of carbon capture and storage) currently vary between €30 and €60/t CO_2. Various research, demonstration and pilot projects aim to significantly reduce these costs, with the goal of bringing the overall cost of the whole CCS process (including transport and storage) down below €20/t CO_2.

From today's (technology) perspective there are three relevant options for CO_2 capture in the short to medium term (see Fig. 2). **Flue gas scrubbing** will probably be an adequate option for retrofitting, especially if it turns out to be possible to reduce the energy required still further through new scrubbing agents. Implementing **integrated coal gasification** (IGCC) would require much greater availability, which is not yet adequate for the power station scale. The crucial point for the **oxyfuel** process will be to collect experience and successfully put the lessons learned into practice (e.g. through the demonstration project at Schwarze Pumpe in Germany, launched in 2006 by Vattenfall).

The method of **capturing CO_2 from flue gases** in conventional power stations (**post-combustion capture**) is basically available today, but has not yet been demonstrated on a commercial power station scale. In the longer term this technology is unlikely to become widely established unless its energy consumption can be reduced significantly.

Pre-combustion capture of CO_2 in coal- or gas-fired power stations with integrated gasification combined cycle (IGCC and natural gas combined cycle, NGCC) is from today's perspective a better method than flue gas capture of CO_2. Apart from its higher efficiency levels, the prime advantage of this technology lies in its flexibility both in terms of fuel (coal, biomass, substitute fuels) and in terms of product (electricity, hydrogen, synthetic gas and liquid fuel). The next step here is large-scale technical demonstration. The IGCC technology itself – without CO_2 capture – has already been tested in several plants (e.g. Buggenum in the Netherlands and Puertollano in Spain). Before CO_2 capture is implemented there will be a need for improvement and development of individual components (e.g. hydrogen turbines). In Germany RWE Power intends to take the first step towards implementing this technology by building a full-scale IGCC power station with CO_2 capture (output (450 MW_{gross} / 360 MW_{net}) by 2014.

The **oxyfuel process** (combustion in pure oxygen) currently offers the best prospects for CO_2 capture in terms of achievable overall efficiency of the process (and also the resulting costs), because it is largely based on conventional power station components and technology. It is not yet possible to provide a precise assessment because the process is still at the beginning of the demonstration phase. At Schwarze Pumpe in eastern Germany Vattenfall Europe is building the world's first pilot plant for lignite combustion using the oxyfuel process. The Vattenfall pilot plant, which has an output of 30 MW (thermal), will be used for research and development purposes with the aim of developing the new technology to the point where it is commercially viable. It is scheduled to begin operation in 2008 after a construction phase lasting about three years. Initially the CO_2 will not be stored, but corresponding concepts (e.g. transport options) are being investigated.

Whether CO_2 capture technologies become relevant for power station replacement will depend on political and economic circumstances. The lack of incentives for retrofitting existing power stations with CO_2 capture has meant that this option has not been relevant to date. In order to be prepared for future developments it might make sense to build new power stations 'capture ready' (prepared for retrofitting with CO_2 capture). That discussion is already under way.

The space required for the additional components can place restrictions on the implementation of CO_2 capture and storage. Connection to suitable storage and transport infrastructures is also a significant location factor.

CO₂ capture processes

CO₂ separation **after** combustion (steam-turbine power stations)   ▮ = research required

Conventional power station with flue gas scrubbing

1) Post-combustion

Coal → Conventional steam turbine power station → Flue gas cleaning → CO₂ capture → ⊘ → CO₂
Air →

2) Oxyfuel

Air → Air separation → Coal → Boiler → Flue gas cleaning → CO₂ capture (condensation) → ⊘ → CO₂
O₂
CO₂ / H₂O

CO₂ capture **before** combustion (combined cycle power plant)

IGCC process (coal) or NGCC process (gas)

3) Pre-combustion

Air → Air separation → Fuel → Gasification → Gas cleaning CO₂ shift → CO₂ capture → Combined cycle with H₂ turbine
O₂
10m³/s, 45 % CO₂ (vol.) → ⊘ → CO₂

Source: Ewers, Renzenbrink 2005

Fig. 2: Methods of CO₂ capture at the power station

CO₂ Transport Methods

Because of the considerable transport volumes that occur with CCS, the main issue when analysing locations for sources and sinks is to reduce transport distances and costs to a minimum. Case studies show that the specific transport costs can vary very considerably from case to case. Even if the cost of transport appears small in comparison with the cost of CO₂ capture at the power station, the aspect of cost efficiency of CCS-related transport will have to be included when selecting locations for new sources.

Alongside transport distance, the question of the general accessibility of the various transport infrastructures that are suitable for CCS is an initial parameter for location analysis. Wherever it is possible to use existing bulk-capable means of transport and transshipment facilities there will be potential for reducing transport costs.

From the energy efficiency, economic and ecological perspectives the only relevant options for large-scale CO₂ transport are pipelines (onshore and possibly offshore) and large tanker ships (depending on the location conditions barges or seagoing vessels for offshore storage). The advantage of the pipeline is that it can transport very large quantities of CO₂ without interruption at relatively acceptable environmental and financial cost. But constructing a CO₂ pipeline infrastructure would be a time-consuming process and would tie up considerable capital; this would only

appear reasonable for long-term usage (> 20 to 30 years). Ships, on the other hand, are more flexible and more quickly available, but require intermediate storage facilities and loading/unloading infrastructure. With inland waterways the restrictions on availability during periods of low water levels must be taken into consideration. Transporting CO₂ by road and rail tanker is an option only for small quantities and will therefore probably only be relevant for the demonstration and launch phase (see Table 1).

The high investment costs involved make it especially important to coordinate the timing of planning, approval and construction of power stations, pipelines and CO₂ sinks. So establishing a CO₂ infrastructure necessitates forward-looking planning and coordination between the different parties involved.

Unlike the case of pipeline transport, there has so far been practically no experience in transporting CO₂ by ship. However, because CO₂ has similar physical properties to LPG (liquefied petroleum gas), experience with LPG transport is partially applicable to CO₂ transport.

Both the aforementioned transport options require gas conditioning in order to transport the CO₂ in the densest possible form (liquid or supercritical). Pipelines require conditioning to high pressure (approx. 80 to 120 bar), while tankers require very low temperatures at ambient pressure (low-temperature tankers) or temperatures below normal combined with pressure above normal (hybrid tankers).

Mode of transport	Capacity in Mt/a	Availability	Cost in €/t (250 km)	Infrastructure already exists at source/sink?	Comments
Seagoing tanker	< 50	Always	< 1	Almost never	Generally requires multi-mode transport
Inland waterways	< 10	Seasonally restricted (water levels)	approx. 1	Sometimes	Barges not seagoing, time restrictions
Pipeline	< 100	Always	approx. 1.5 (function of diameter)	Will almost always have to be constructed from scratch (largely investment)	25 year operating period, higher costs in built-up areas
Rail	< 1.2	Always	approx. 5	Generally	Noise
Road	< 0.5 Mt/a	Restricted in winter, congestion	approx. 25	Always	Cost, noise and emissions, acceptance, time restrictions

Table 1: Characteristics and suitability of different modes of transport for CO_2 transport

Both gas conditioning and CO_2 transport require quite a lot of energy, normally electricity for compression and/or cooling. According to current knowledge the energy required for CO_2 compression is equivalent to an efficiency loss at the power station of about 2 percentage points (for gas-fired power stations) to 3.5 percentage points (for coal-fired power stations). This additional energy requirement causes additional CO_2 emissions. Estimates of additional (energy-related) CO_2 emissions associated with CO_2 transport vary greatly, especially in relation to transport distance and capacity. Here additional (energy-related) emissions of 1 % to 4 % per 1,000 km are expected for ship transport and 1 % to 2 % per 1,000 km for pipeline transport.

The range of average cost estimates for CO_2 transport by pipeline or ship is between about €1 and €10/t (depending on mode of transport, distance and capacity) and represents about a 10 % share of the overall costs of the CCS process (comprising capture, compression, transport and storage). In relation to the other infrastructure costs (electricity transmission, fuel logistics) the cost of CO_2 transport is likely to be a secondary factor when selecting power station sites. Also, existing power station sites are often likely to be retained for reasons of public acceptance.

Already today, fuel (oil, oil products, coal) represents a large share of goods transport. Introducing CCS on a large scale would increase freight volumes considerably, through the supply of additional coal to power stations and the removal of CO_2.

Safety statistics for existing CO_2 pipelines (in particular in the United States) show a smaller leakage risk than for pipelines carrying natural gas or hazardous substances; nonetheless, routes should avoid densely populated areas where possible for reasons of safety.

In populated areas safety measures against leakage and overpressure are required. Although the relative risk associated with ship transport is also predictable, large-scale introduction of CO_2 tankers for CCS would increase the absolute risk of shipping collisions and tanker accidents.

CO_2 Storage Methods and Capacity

There are various different ways to withdraw CO_2 from the atmosphere. A distinction must be made between utilisation for technical and chemical purposes (e.g. producing carbonic acid, dry ice and feedstock for polymer chemistry), storage in geological formations (e.g. saline aquifers), sequestering CO_2 in the marine environment either directly (e.g. depositing it in the ocean depths) or indirectly (e.g. algae formation) and withdrawing CO_2 from the atmosphere by intentionally growing biomass (e.g. forestation). A mineralisation process for binding CO_2 to silicates is also under discussion (especially in the United States) but it is still in the early stages of development and is associated with very high energy requirement and very large amounts of material to be disposed of. Fig. 3 shows an overview of storage projects currently under way across the world.

For various reasons the storage possibilities for CO_2 are restricted at both the national and global levels. The many uncertainty factors lead to a very wide range of estimates about the extent of existing capacity, and the same applies to the question of the fundamental suitability of the various storage options, where ultimately a case-by-case analysis will be required to obtain practically relevant results.

CO₂ storage projects operating worldwide

Fig. 3: CO₂ storage projects operating worldwide (IEA database)

Estimates made in 2004 put global storage potential in the range between 476 and 5,880 Gt CO_2 (with a probable potential of 1,660 Gt CO_2). By comparison, global CO_2 emissions in 2005 were 27.3 Gt CO_2. This shows that the potential of CCS is certainly considerable but that regardless of other factors, the limited storage capacity alone means that it will not be possible to achieve a lasting solution to the climate problem through CCS. Table 2 shows the storage capacity and a selection of assessment criteria, for the example of Germany.

According to current information the theoretical storage potential in Germany is between 19 and 48 Gt CO_2. The largest and – in view of the numerous as yet unresolved issues affecting storage in deep coal seams (e.g. concerning permeability) – most important share relates to deep saline aquifers, supplemented by the more limited possibilities for storage in depleted gas fields. A calculation focusing on these two storage options and taking into account an average extra energy requirement for CCS of 30 % comes up with a static range of between thirty and sixty years for CO_2 point emission sources in Germany (2005: 393 Mt/a).[1]

In principle the storage of CO_2 in geological structures can draw on many methods and technological proc-

esses currently in use in the oil and gas industry and in the disposal of liquid wastes. However, drilling and injection methods, computer simulations of the distribution of gas in reservoirs and monitoring methods will have to be adapted to the special requirements of CO_2 storage. Here there is still a great need for research and development. In Germany the EU-funded CO2SINK project will significantly increase knowledge about the behaviour and controllability of CO_2 in underground reservoirs.

Criteria for a Systematic Assessment of CCS

A systematic comparison of various CCS technologies with other technology options such as energy efficiency and renewables requires a comprehensive catalogue of criteria. The criteria used here can be categorised as follows:

Ecological criteria
- Environmental impact as per life cycle assessment (LCA)
- Energetic efficiency
- Other ecological impacts, ecological restrictions, consequences and risks (direct and indirect)

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1   Taken together these two storage options have a potential of 14.3 to 30.5 Gt CO_2.

Option	Capacity [Gt]	Long-term stability	Costs*	Available technologies	Utilisation conflicts	General risks
Depleted gas fields	+ 2.3–2.5**	+	+	+ (+)	−	+
Deep saline aquifers	+ + 12–28**	+	− −	+	−	(+)
Deep coal seams	+ (+) 3.7–16.7	+	− −	−	−	−
Depleted oil fields	− − 0,11	+	+ +	+ +	−	+
Salt caverns	− − 0.04	− −	k. A.	+	− −	− −
Disused coal mines	+ 0.78	− −	− −	− −	− −	−

*   Cost estimate contains only storage costs without capture, compression or transport (after ECOFYS 2004, BGR, authors' additions)

**   Figures after May et al (2006a)

Criteria:

− −   Negative or very problematic

−   Fundamental difficulties still exist, but may be resolvable

+   Good, or few obstacles

+ +   Very good

()   Parentheses indicate uncertainties or places where each individual case will have to be assessed

Table 2:
Assessment of geological storage options in Germany using selected criteria

Economic criteria
- Generation costs and CO_2 avoidance costs (specific investment costs, resulting electricity and hydrogen production costs)

Other criteria
- Timeframe for application (possible time of implementation) and market readiness and/or R&D still required
- Compatibility with power plant replacement needs
- Acceptance
- Compatibility with existing structure and possible future development trajectories
- (Technological) stimuli for global climate protection
- Industrial policy opportunities
- Transferability to developing countries (not applicable for Germany)
- Compatibility with other climate protection strategies (decentralised options)
- Impact on import dependency
- Security policy implications

Comparative Life Cycle Assessments

For the ecological evaluation of selected system configurations (process chains from natural gas and coal to low-CO_2 electricity and hydrogen) the life cycle assessment method (LCA) defined by ISO 14.040ff was used. This integrative approach analyses the material and energy flows required to produce a kilowatt-hour of electricity or hydrogen and calculates their environmental impact.

For *electricity generation* the environmental impact of the following fossil fuel conversion paths were investigated: post-combustion (with coal- and lignite-fired thermal power plant and natural gas CC), pre-combustion (coal-fired IGCC) and oxyfuel (with coal). The Ruhr region (a densely populated industrial region in western Germany) was selected as the location of the power stations and an empty gas field 300 km away in northern Germany as the sink. For purposes of comparison with renewable energy paths, electricity generated by solar thermal power stations (in Algeria) and by wind power (in the German North Sea) was also modelled. In order to have the same reference location as with the fossil-fuelled options, the electricity was assumed to be transported to the Ruhr region using high-voltage DC lines. The following central conclusions can be drawn:
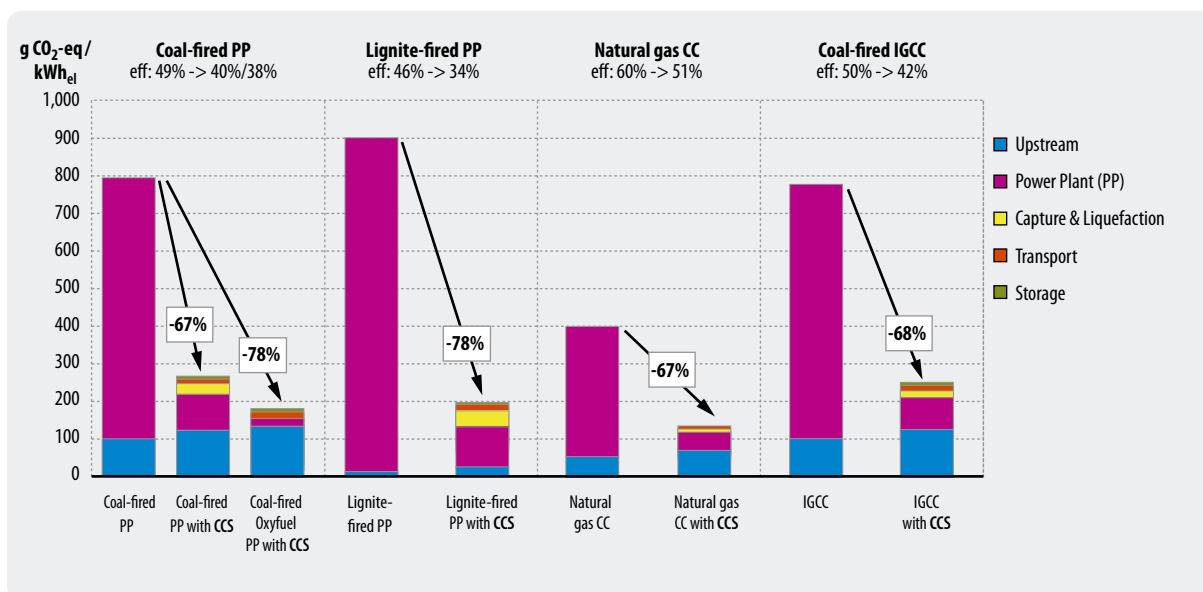
Fig. 4: LCAs of CCS plant in comparison with selected renewables (here: greenhouse gases)

The high rates of CO_2 reduction generally cited in the CCS discussion (capture rates of 88 % and more) relates only to CO_2 emissions directly in power station operation. If we take a holistic approach, 5 % of the CO_2 emissions already occur in the supply chain both with coal-fired thermal power stations and with natural gas CC. Reduced efficiency also causes higher consumption of primary energy and thus a 'larger' coal or natural gas supply chain. Taken together, these factors mean that with a capture rate of 88 % actual CO_2 emissions can not be reduced by 88 %, but only by 72–78 %. In view of this fact it is unjustified to speak of 'CO_2-free' or 'zero-carbon' power stations. Even if the capture rate at the power station can be increased still further in future, the designation 'low-CO_2' is more pertinent.[2]

The discussion to date has also neglected to consider that greenhouse gas emissions as a whole – and not only CO_2 emissions – have to be reduced. The Kyoto Protocol requires Germany, for example, to reduce a total of six greenhouse gases (and not just CO_2) by 21 % by 2012. If the effects of CO_2 capture on greenhouse gas emissions are calculated, it is found that the potential reduction is less than proportional. For example, with a CO_2 capture rate of 88 % (at the power plant) greenhouse gases as a whole can only be reduced by 67–78 % (see Fig. 4).[3] The reasons for this are again the considerably increased primary energy consumption and the methane emissions associated with fuel extraction and transport, which can be relatively high depending on the fuel and its source. Under the given assumpti-

ons these have a disproportionately large impact on the greenhouse effect. Improvements in the supply chain (e.g. collecting and using mine gas) could strongly improve the results. From a holistic perspective this lessens the reduction achievable through CCS power stations. With 396 g CO_2 equivalent per kWh the 'best' power station (in climate terms) without CCS (natural gas CC) has only 51 % more greenhouse gas emissions than the 'worst' power station with CCS (coal-fired thermal power station with 262 g CO_2 equivalent per kWh). Of all the fossil-fuelled power stations considered, oxyfuel produced the best greenhouse gas results under the given assumptions. Physical capture of almost 100 % of the CO_2 allows net rates of reduction of 90 % for CO_2 emissions and 78 % for greenhouse gas emissions.

Fig. 5 shows this in comparison with selected technologies from the field of renewables, whose impact by contrast are very small (resulting from manufacturing of the plant).

Overall, CO_2 capture requires additional energy consumption of 20 to 44 %, depending on the process. The higher energy consumption is felt directly and proportionately in various impact categories in the LCA. This applies, for example, to photo-oxidant formation, eutrophication, acidification of soil and water, and particle emissions (PM10). On the other hand, individual emissions such as SO_2, NO_2 or dust are reduced through reactions with the solvent, which in overall terms causes a reduction or at least a reduced increase in individual impact categories. Fig. 6 shows this effect for the example of the modelled lignite-fired power station (post-combustion).

The 44 % increased energy consumption initially causes a proportional increase in all impact categories. But overall the aforementioned influences cause a reduction

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2   For example, future capture rates of up to 99.5 % are expected through the oxyfuel process. For a coal-fired power station this would result in a net CO_2 reduction of 90 %.

3   Even with the oxyfuel method the net greenhouse gas reduction for a coal-fired power station would not be greater than 78 % (despite the higher capture rate of 99.5 %).
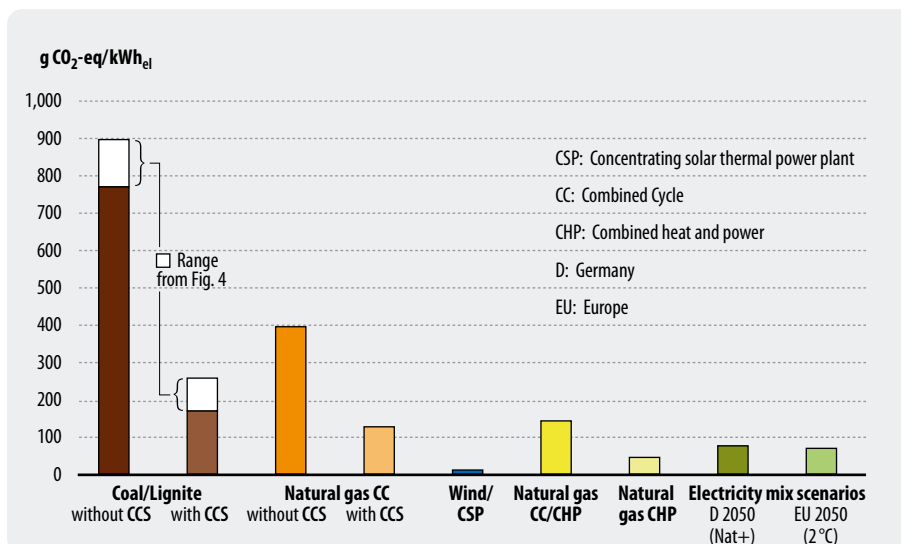
of 3 % in the acidification category, and PM10 equivalents rise by only approx. 24 %; on the other hand eutrophication rises by 40 % and photo-oxidant formation by 524 %.

A comparative analysis, however, showed the investigated renewable energy options to have considerably better values than the fossil-fuelled power stations with CO_2 capture. Even when electricity transmission is included, the CO_2 emissions, greenhouse gases (see Fig. 4) and cumulative energy demand of solar thermal electricity and electricity from wind power is just 2 to 3 % of the corresponding figures for fossil-fuelled CCS plant.

For *hydrogen production* the environmental impact of steam reforming of natural gas and coal gasification were investigated. The Ruhr region was again selected as

the location. Renewable hydrogen production was modelled as electrolysis using electricity from solar thermal power stations in Algeria and offshore wind farms in the North Sea (as modelled for electricity generation). The location for electrolysis was the Ruhr region; again high-voltage DC lines were used for transmission. The following central conclusions can be drawn:

As with the case of power stations, we cannot speak of 'CO$_2$-free' production of hydrogen. It would be more pertinent to use the term 'low-CO$_2$' hydrogen. When the supply chain is taken into account, even with a capture rate of 88 % (coal gasification) it would only be possible to reduce CO_2 emissions by 81 %.

With natural gas steam reforming, reduction rates of only 39/52 % (CO_2 emissions, depending on different
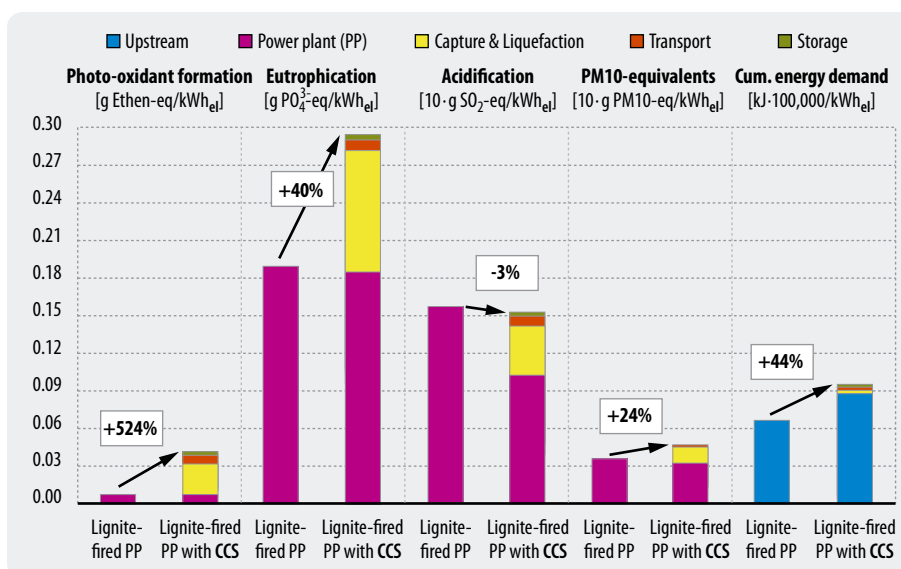
reforming technologies) and 36/49 % (greenhouse gas emissions) are possible from today's perspective, if it is assumed that only the CO_2 emissions from the synthesis gas can be captured at reasonable cost, and not those that occur beforehand when natural gas is burned to produce process heat.

Other Ecological Assessment Factors for CCS

The systematic approach of the LCA does not cover every ecological criterion. As well as direct and indirect influences on the landscape (e.g. through increased fuel usage) and the negative consequences of increased transport volume through the construction of a CO_2 infrastructure, the greatest impact would result from the possibility of unplanned release of stored CO_2 and the direct influence of the stored CO_2 on the surroundings of the sink over the course of time.

The various storage options differ – in some cases considerably – in terms of ecological and safety aspects. The risk of leakage is present in all geological storage options. Whereas storage in exhausted oil and gas fields and use in oil production (enhanced oil recovery, EOR) appear relatively safe for the population and the environment, injecting CO_2 into disused coal seams could pose considerably greater risks. Saline aquifers are regarded as relatively stable long-term sinks, although there is still a great need for research into the underground movement of CO_2 (mechanisms of dissemination and activity). Such aquifers have so far generally only been explored in the vicinity of hydrocarbon deposits so there is a shortage of comprehensive data and assessments of their petrophysical properties. The introduction of CO_2 leads to acidification of the water in the aquifer. Through its corrosive properties the acidic water could cause changes to the surrounding strata (especially carbonates) and to unprotected borehole seals.

The use of deep (currently uneconomic) coal seams bears the ecological risk of the extracted methane escaping (methane is a considerably more potent greenhouse gas than CO_2, by a factor of 21).

Marine storage options are associated with very great uncertainties and risks. Direct cause and effect relationships have so far only been demonstrated in certain cases. Acidification of seawater shifts the carbonate equilibrium: the shells of calcifying organisms become thinner and can even dissolve, interrupting food chains or at least altering them with inestimable consequences. CO_2 lakes on the ocean floor affect more than the local ecosystems. Many aspects of the behaviour of the ocean floor – submarine slides, undersea quakes, etc. – may be understood, but they remain unpredictable. Fundamentally it must be noted that storage in the oceans would not lead to permanent sequestration of the CO_2. Dissolving CO_2 in the ocean depths leads to delayed re-emission into the atmosphere after a few hundred years at the latest, when oceanic circulation brings the water masses into contact with the atmosphere again. In view of the unclarified consequences of marine storage options they are categorically rejected by the environmental organisations and are being pursued in any form in only a very few countries (in particular Japan).

Fixing CO_2 in biomass by planting forests and growing monocultures brings with it multifarious ecological problems. It must also be emphasised that this form of storage is only a temporary one, with delayed release. When a period of several generations is considered, the reduction effect is nil. Additionally, monocultures displace other species and alter biotopes.

The construction and operation of renewable energy technologies – e.g. constructing wind farms, hydroelectric dams and solar thermal power stations – can in certain cases be associated with considerable ecological consequences and disfiguration of the landscape. Within a social and energy system guided by sustainability principles, decisions would have to be made about which interventions are acceptable for the population and the natural environment and which should be avoided. Whereas the impact of using renewables is largely known and understood, decision-making with respect to CCS is from today's perspective still hampered by numerous uncertainties and open questions.

Economic Comparison of CCS and Renewables

If the capture and storage of CO_2 emissions from fossil-fuelled power stations can be demonstrated successfully, electricity generating costs (at power station) of between 6.5 and 7 ct/kWh can be expected on the basis of CCS power stations commercially available in 2020 (interest rate 10 %/a). In view of the fuel price rises expected in the longer term, a further rise in costs to between 7 ct/kWh (coal) and 8 ct/kWh (natural gas) is probable by 2040. In coal-fired power stations the fuel price effects could potentially be largely balanced out by further technical progress. Our calculations put CO_2 avoidance costs at between €35 and €50/t CO_2 in 2020, when the same power station without CCS is taken as the reference for comparison. Here coal-fired power stations are towards the bottom end of the range, gas-fired towards the top. This is less than the cost range assumed today and assumes that significant learning processes will already have occurred by then, but is still significantly higher than the costs of about €20/t CO_2 that the energy business is aiming at for the process as a whole.

Renewables, which – on the basis of a representative mix – today still involve electricity generating costs of approx. 13 to 14 ct/kWh (again assuming interest rate 10 %/a) can also achieve that level of costs by 2020 if their market introduction continues at a similar pace to now. With a continuing global increase in market penetration and learning effects significant cost degres-

Electricity generating costs in ct/kWh
DLR 2005 price forecast with CO_2 penalty; interest rate 10%/a
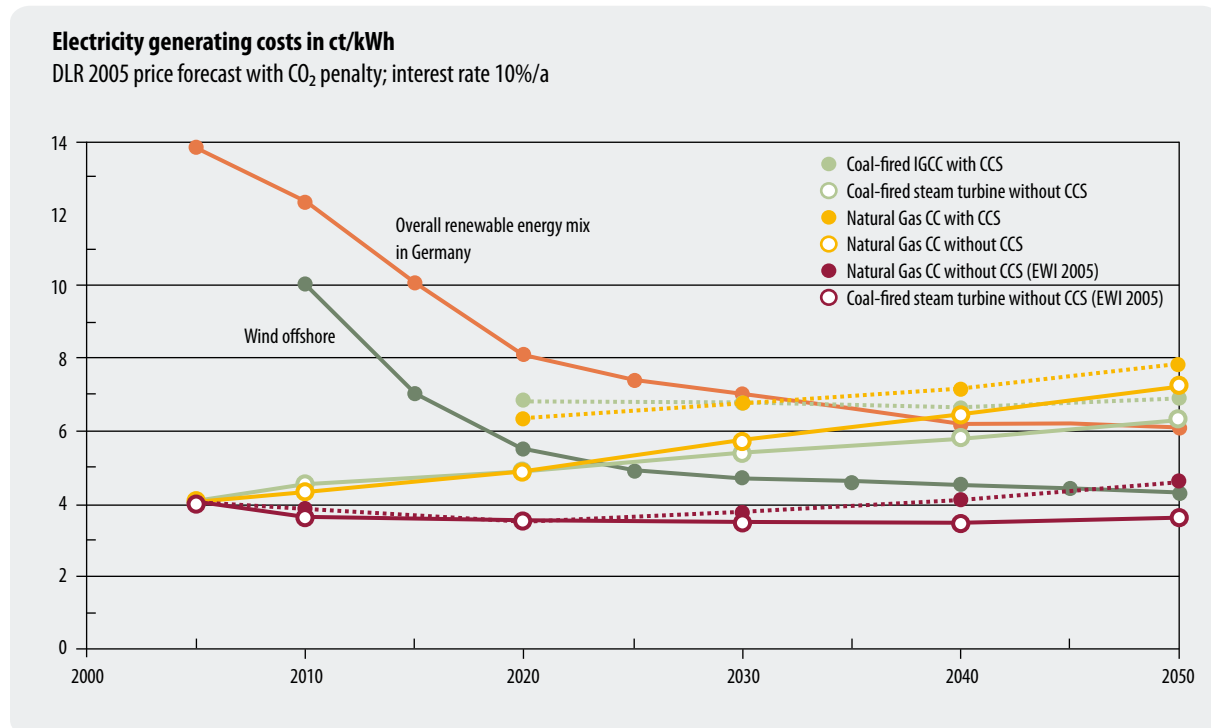
Fig. 7: Development of electricity generation costs (for new plant) for renewables, conventional gas- and coal-fired power stations and CCS power stations. Fuel prices after "DLR 2005" and for conventional power stations without CCS after EWI 2005 given for comparison

sions can still be expected for renewables in future, so that by 2050 the level of costs for generating electricity from renewables in the characteristic mix under consideration could fall to 6 ct/kWh. Individual technologies could achieve electricity costs of approx. 4 ct/kWh if a continuing expansion of global markets allows the learning curve to continue to be exploited (see Fig. 7).

If the pace of expansion of renewables in the electricity sector remains fast – as in the various scenarios that describe a switch to a climate-friendly energy supply based on a combination of stepping up the expansion of renewables and energy efficiency (e.g. the Naturschutzplus scenario) – at the time when the first CCS power stations might be coming on stream some technologies (e.g. wind offshore) could already be offering cheaper electricity generation costs and further increase that advantage over the course of time. Here significant cost-reduction effects come through the global market effects, so even if renewables in Germany were to grow less dynamically, cost parity between CCS and individual renewables can be expected. Only if fuel price rises were to be very small or cost reductions in the CCS process were to surpass the foreseeable effects would the situation be more favourable for CCS plant. This would not negate the general effect, but would push back the point on the time axis where renewables become relatively competitive.

Under the given assumptions there is neither a compelling economic reason to give CCS technologies preference over a further expansion of renewables for elec-

tricity generation. Nor, though, do they represent a prohibitively expensive option and if successfully commercialised under suitable conditions (inexpensive, stable long-term storage options, good infrastructure, cheap coal) could become part of the future electricity generating regime in some world regions.

In an economic comparison of low-CO_2 and largely CO_2-free options for hydrogen production (CCS versus renewables) the fossil option comes off best. By 2020 hydrogen from coal gasification with CO_2 capture will cost approx. €12.50/GJ (4.50 ct/kWh, upper heating value, at plant), or about twice the cost of today's hydrogen from natural gas reforming. Further fuel price rises until 2050 increase the cost to about €14/GJ (5.04 ct/kWh). Only electrolytic hydrogen via electricity from cheap hydropower can compete with this, but the available capacity is small. Only in the longer term costs of around €16–18/GJ for electrolytic hydrogen from wind or solar electricity can be expected; around 2020 the cost will probably be about €19–20/GJ. In the medium term the cost of generating hydrogen will always be at least double the cost of natural gas. So for economic reasons hydrogen will not be implemented as a fuel before 2030. Regardless of the way it is produced, it will probably be several decades before hydrogen becomes important in the energy sector in relevant quantities because of the considerable infrastructure challenges associated with its introduction.

The Role of CCS in Industrialised Countries – the Example of the German Energy Supply System

In this study three different scenarios were developed for the future energy supply in Germany (as a representative industrialised country) in order to analyse the role of CCS in the energy sector in comparison to renewables. In all three scenarios energy-related CO_2 emissions were reduced to 240 million t/a by 2050, which corresponds to a reduction of about 75 % compared with 1990. The **scenarios** are based on the following assumptions:

- **CCSMAX**: CCS as the main element of a climate protection strategy with 'maximum' use of CCS technologies within the framework of a development that otherwise largely follows current trends for energy consumption and expansion of renewables (relatively small mobilisation of efficiency potentials, limited implementation of the expansion potentials of renewables).

- **NATP**: Concentration on across-the-board exploitation of energy saving potentials and vigorous expansion of renewable energy technologies, as described in the 'NaturschutzPlus' scenarios prepared for the Federal Environment Ministry (after BMU 2004 and BMU 2005). In this scenario CCS is not required.

- **BRIDGE**: CCS as a bridge to further expansion of renewables while at the same time increasing energy efficiency and expanding renewables more strongly than in the reference case but less than in NATP. In this scenario the two strategy elements are insufficient to achieve the climate target unaided, so the use of CCS is required.

Various key findings can be drawn from the scenario analyses. Emission-reducing measures in the field of electricity generation alone will simply not be enough to meet the climate protection target. Similarly comprehensive measures in the heating and vehicle fuel sectors are also required. As well as expanding renewables, the exploitation of efficiency potential will have to make a very considerable contribution. If greater use is made of fossil resources, the alternative of generating hydrogen by gasifying coal with carbon capture and storage is always an option.

As the main element of a climate protection strategy CCS runs into structural and capacity limits (**CCSMAX scenario**). The earliest date when CCS technologies are expected to be ready for implementation is 2020, which is too late for the first wave of the power station replacement needs, which has just begun. This scenario would necessitate extremely rapid growth rates for CCS plant between 2020 and 2050 and speedy establishment of a hydrogen infrastructure. With 5,900 PJ/a the demand for coal in CCSMAX rises to three times today's level. By 2050 hydrogen would be the dominant form of energy, supplying 47 % of final demand. The amount of

CO_2 to be captured and stored in 2050 would amount to about 600 million t CO_2/a (Fig. 8). At that level the storage capacity available in Germany would last for just one or two decades. Cost advantages for energy produced using CCS are either non-existent (for electricity) or marginal (for hydrogen) so there is no decisive economic incentive for such a prominent preference for CCS. The high level of funding already required today in the form of R&D and demonstration plant for such a strong expansion of CCS technologies would probably demand a major turn away from support for efficiency strategies and strategies for expanding renewables. A great challenge in view of the very many questions that are still open is that the lead times involved mean that it would be necessary relatively quickly to achieve a very high level of certainty about the ecological impact and long-term stability of the potential CO_2 sinks.

A climate protection strategy following the **NATP** scenario, which manages without CCS, would not yet develop of its own accord. As well as maintaining the current dynamic rate of expansion of renewables in the electricity sector and extending their use to the heat sector on a significant scale, considerable additional support measures to encourage much greater efficiency in use and conversion of energy would be required if the 2050 climate protection target is to be met on time by this strategy. Expanding renewables and increasing efficiency are measures that take effect relatively quickly, so as long as the necessary support measures impact fast, they allow the restructuring process to run more harmoniously than in the CCSMAX case described above. Major conversion of energy infrastructures would be required, but this could be realised in stages. A strategy concentrating especially on energy productivity also makes sense in broader economic terms because many of the efficiency measures represent the most economic option for climate protection regardless of what measures are taken on the supply side. If external costs were included the overall economic situation would be even more favourable. To that extent this scenario represents an 'ideal strategy' but one which demands that very effective energy policy decisions be taken quickly, especially a clear rationalisation and expansion of energy efficiency policy. In the longer term this scenario necessitates considerable structural changes, increasing the network and system integration of renewables on the electricity side, integrating energy import structures (e.g. electricity from solar thermal power plant in North Africa) and greatly expanding district heating systems.

To pursue both strategies 'at full steam' until 2020 (efficiency and expansion of renewables following NATP until 2020; CCS development as in CCSMAX), but then to largely drop one of the options would not seem to be a sensible way to proceed. Consequently, the third scenario discusses the extent to which the two strategies could be combined compatibly in a forward-looking strategy.

In a development corresponding with the **BRIDGE scenario** the timeframe for introducing CCS technologies and a hydrogen infrastructure is more relaxed than in CCSMAX because until 2030 the contribution

CO$_2$ reduction scenarios for Germany

Legend:
- Renewables (yellow)
- Natural gas (green)
- Mineral oil (orange)
- Other coal (light grey)
- Coal for CCS-H$_2$ (grey)
- Lignite (brown)
- Nuclear (red)

Primary energy, PJ/a

Scenario	Value
2000	14,387
2005	14,269
CCSMAX	12,484
BRIDGE	10,419
NATP	8,122

2050

CO$_2$ storage in mio. t/a:

	CCSMAX	BRIDGE	NATP
	586	328	0
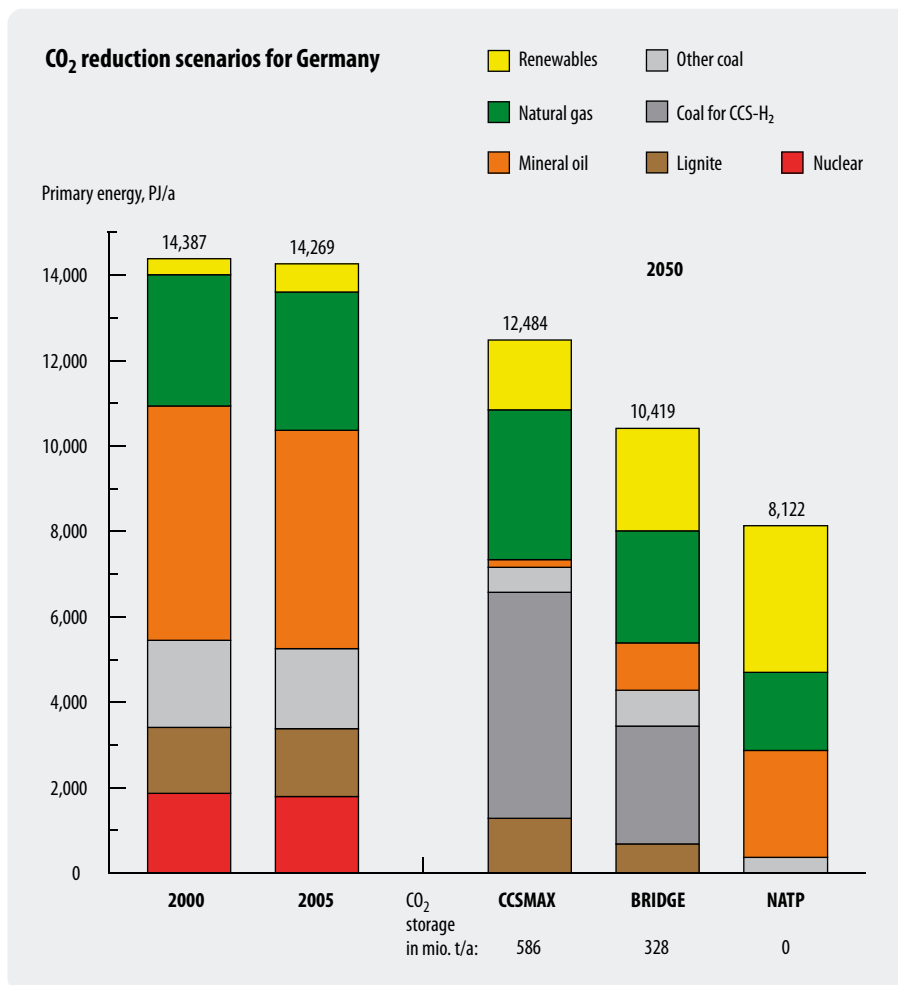
Fig. 8:
Primary energy structure today and in the scenarios for 2050

required from this option can remain relatively small. In the event that CCS technologies turn out to be a sensible and ecologically sustainable energy option, even the level of expansion required by 2050 does not encounter any fundamental barriers concerning required plant capacity, infrastructure modifications or sink capacity. In this case about 330 million t CO$_2$/a would have to be captured and stored in 2050. For this, however, fossil-fuelled power stations built before 2020 must also be suitable for retrofitting with CCS, if the electricity sector is to make a substantial contribution to reducing CO$_2$. This should be taken into account in current ongoing power station planning, and where possible plant should be designed to be 'capture ready'.

An energy policy following the BRIDGE strategy will definitely demand a general intensification of energy policy in all the listed fields if long-term climate protection goals are seriously to be achieved. So including 'CCS technologies' as an additional climate protection option should not serve as an excuse for neglecting the strategy elements of 'energy efficiency' and 'renewables' as the process intensifies. Instead these should be mobilised by 2020 at least to the extent that they can continue to 'take off' thereafter if CCS technologies should turn out to be unworkable on the desired scale in the

energy sector. At the same time, this timeframe offers the opportunity to explore the development and cost potentials of CCS technologies thoroughly and without massive pressure of time. But the successive introduction of CCS could help as an ancillary element to make it easier to maintain the sustained impetus for further efficiency increases and a greater expansion of renewables than would possibly be the case with the significantly higher hurdles in the NATP scenario. This could identify ways to soften resistance and to offset obstacles that remain insurmountable despite massive support and energy policy intervention. In view of the real constellations of interests and different evaluations of technology options in the field of energy, especially in the global context, a development following the BRIDGE scenario can be regarded as a 'pragmatic' strategy.

A cost comparison of renewables and CCS technologies for electricity and hydrogen production shows no economic advantages for the CCS option at the point of its possible introduction around 2020. The latter would then require CO$_2$ prices between €40 and €50/t CO$_2$ if it is to be attractive to private investors in place of conventional electricity generation from fossil fuels. Even after 2020 renewable energy technologies will probably continue to have exploitable cost degression potentials,

whereas the cost of generating electricity from coal with CCS will probably remain roughly constant, assuming a corresponding degree of technical development. If we factor in the external costs, we find further advantages for the development path building on renewables and energy efficiency. From today's perspective, the relative profitability of CCS and renewables is associated with diverse imponderables. The above assessments for renewables work on an assumption of dynamic global market developments allowing very considerable cost degression potentials to be exploited via mass production and learning curve effects.

One obstacle to a comprehensive CCS strategy could also be that a strategy building largely on CCS would require the earlier introduction of (low-CO_2) hydrogen on a broad scale, which is associated with great infrastructure challenges, whereas a strategy orientated on NATP would not require this on an appreciable scale until the middle of the century.

From the aforementioned aspects it follows that a rigorous strategy based on the NATP scenario could also represent the more favourable option in broader economic terms in the medium to long term and should thus be the aim of energy policy. At the same time, it would be recommendable to continue to subject the CCS option to thorough scrutiny and in particular a realistic practical demonstration, in order to possess after a decade more precise knowledge of the potential and limits of this set of technologies. If it then turned out that in terms of efficiency and expanding renewables the restructuring of the global energy supply can 'only' proceed at the intensity described in BRIDGE, then CCS would be available as an additional climate protection option.

Requirements for Successful International Implementation of CCS

The concluding part of the study broadens the perspective to examine whether CCS is necessary from a global perspective in order to meet ambitious climate protection targets and how an institutional framework can be established to sensibly regulate the risks of CCS.

The role of CCS in the context of other technology options – i.e. in particular the expansion of renewables – was analysed by means of an economic scenario analysis. Models to maximise global social welfare for a given limitation of the atmospheric CO_2 concentration were chosen by simulating the progress over time of implementation of the three named options (and in the process including the technological learning effects). Central uncertainty factors that have a strong influence on the implementation of CCS and on the costs of climate protection were identified and interpreted by means of sensitivity analyses:

- Learning rates for CCS and renewables influence the cost reduction curve of the technologies and thus their application. The quicker the cost-cutting potential of renewables is realised and the slower that of CCS takes effect, the less CCS will be used. However, in both fields of technology as yet unforeseeable development leaps and costs that cannot be reduced through learning effects (e.g. for fuels) could have a strong influence on their respective future market shares.

- Leakage rates (quantifying the slow escape of CO_2 from storage formations) must be well below 0.1 % per year if CCS is to be used efficiently at all.

- The discount rate determines the weighting of consumption over the course of the planning period. If a high discount rate is chosen – giving welfare in the present a higher weight and consequently resulting in less being invested in renewables – CCS gains and greater use of renewables is shifted back to a later date. This occurs above all when realising learning rates in renewables requires high initial investment compared with CCS.

- The rising cost of exploration and extraction associated with possible shortages of fossil resources has a strong effect on the role of CCS. Because of the attractiveness of fossil fuels, if their costs of do not rise until relatively late, CCS will be used extensively in order to meet the set climate protection target at all. But under 'peak oil' scenarios, which predict rapidly rising costs due to depletion of oil reserves, the substitution of various fossil fuels could occur considerably earlier, which would reduce the demand for CCS. However, the timeframe and interrelationships of these effects are not yet fully understood.

- The use of CCS is worthwhile even if the time when CCS technologies become available for large-scale application is delayed by several decades. But if CCS were not available until 2050 the amount of CO_2 stored to meet climate protection targets would be reduced considerably because it would then be more worthwhile to step up implementation of renewables from the outset.

The outcome of the economic scenario analysis is that at the global level CCS can make a tangible contribution to meeting ambitious climate protection targets. CCS can fulfil a 'bridging function' of avoiding emissions on a scale that renewables and efficiency improvements cannot achieve on their own, and in that context the two technology options can complement one another. There can be no doubt, however, that in the long term a sustainable reduction of climate change is achievable in the energy sector only through renewables and high energy efficiency.

Overall, according to the calculations, keeping the atmospheric concentration of CO_2 below 450 ppm over the course of the twenty-first century could be achieved with a relative loss of 0.6 % of global GDP compared with the business-as-usual trajectory, in the process of which a total of approx. 456 GtC (or 1,672 Gt CO_2) would have to be captured and stored. These results should be understood as plausible mid-range figures – assuming a leakage rate of 0.05 % per year and a learning rate for renewables of 15 %. The precise figure for cumulative storage and the cost reduction will depend on the development of the investigated uncertainty factors. The model calculations show that with a combination of both measures (renewables plus increased efficiency *and* CCS) it would be possible to achieve ambitious global climate protection targets at a relatively small loss of economic growth. The calculated growth losses are relativised still further if the necessary investments in measures for adapting to climate change are factored in.

Large-scale introduction of CCS presumes the implementation of an institutional framework that sensibly regulates the risks of CCS and offers incentives to use the safest possible storage options.

Many details of the national and international legal situation have yet to be clarified, and special frameworks for CCS have yet to be developed. In view of the long-term nature of CO_2 storage, the principles of environmental law require legislators to ensure there are suitable rules for dealing with future risks and to strike a suitable balance between business liability for harm caused and the ultimate responsibility of the state. Monitoring sinks and defining an appropriate leakage rate are particularly important here. Because of the transfrontier effects of CCS, international agreements are imperative.

As the economic analysis showed, it makes sense to embed CCS in international climate protection agreements. However, CCS is not yet included in the mechanisms of the UN Framework Convention on Climate Change. Guidelines for accounting for the emissions saved through CCS (and those that may be released again) have not yet been implemented. That would be an important precondition for being able to include CCS in the flexible mechanisms of the Framework Convention on Climate Change. With regard to the debate between the two fundamental approaches to climate protection agreements (cap and trade system and technology protocol) CCS, with its technological challenges that are yet to be mastered, could serve to illustrate that both approaches are possible and useful.

Regulating responsibility for risks from CCS could be achieved through tradable **carbon sequestration bonds,** which the operator of a CCS project would be obliged to purchase and which would be depreciated proportionately if leakage occurs. The bond system offers incentives for efficient limitation of harm caused by CO_2 leakage and involves the financial markets and

through them the public (via investment decisions for safe CCS projects) in the control of risks. State revenues through devaluation of bonds could be used to promote renewables, thus balancing out the delay in their development resulting from the use of an unsafe storage option.

Chapter 1

Status Quo and the Aims of the Study

Long-term scenarios on the development of energy systems show that the transition to a climate-friendly energy supply will in some way rule out coal. However, coal is the fossil fuel with the largest global reserves – distributed over many regions of the world – and is subject to fewer geopolitical risks than oil and gas.

This raises the question of how the use of coal could be made more climate-friendly. Alongside improvements in the efficiency of the various ways coal is used (primarily by increasing the conversion efficiency of power stations and expanding the use of combined heat and power) the technology option of carbon capture and storage (CCS) could also make a contribution. Its introduction could make it possible to produce 'low-CO_2' energy based on coal. The important fields in this context are electricity generation, and even more so the production of hydrogen as a universal storable fuel. The same also applies in principle to natural gas and oil, although from the climate perspective natural gas is a less critical issue owing to its lower carbon intensity.

There are still many unanswered questions today concerning the possibilities of capturing CO_2 and especially storing it safely for a very long time. These questions include not only how much safe, long-term storage capacity there actually is for CO_2 (and its regional distribution), but also what costs and ecological risks are involved. If CCS can be successfully introduced as a new technology option at reasonable cost and with acceptable ecological impacts, it could make a major contribution to providing a more secure and climate-friendly supply of energy.

Previous studies in this field have tended to concentrate on the general technical feasibility of the concept. There has not yet been a detailed examination of the ecological, economic and social impacts along the whole process chain (e.g. energy balance, cumulative energy demand, environmental impact, use of resources, risks, costs) of the kind that is a matter of course today for other new technologies, especially renewables. Only after such scrutiny will it be possible to decide how environmentally beneficial this technology option really is, what advantages and disadvantages it has compared with renewables and what contribution it can make to a sustainable economic structure. That is the focus of the present study.

This project is particularly relevant in view of recent political initiatives on international level for using the so-called 'clean coal' option, extensive research activities globally and the publication of the German Environ-ment Agency's assessment of CCS from the sustainability perspective in mid-2006.

More and more scientists, politicians, and NGOs are calling for investigation and consideration of 'clean coal' technology. The energy sector itself is planning to open various small CCS demonstration plant in 2008 and the following years mainly in Europe and USA.

The findings so far show that introducing carbon capture and storage only makes sense if done on a large scale. Given the great volume of investment required and the implications for other options for reducing greenhouse gases, the decision about whether CCS should be made a central pillar of energy policy will have to be thoroughly considered on a solid scientific basis. It is already recognised today that new technologies will have to satisfy numerous technological, structural, economic, ecological and social criteria before they can be regarded as viable options for a sustainable future energy supply. So they will be subjected to a rigorous selection process before their suitability as future key technologies is accepted. As well as detailed investigation of the potential, the achievable future costs, the implications for industrial policy and social impact of a technology, differentiated life cycle assessments (LCAs) of the whole system represent a suitable instrument for assessing the practicability of new technologies against various sustainability criteria. Very detailed LCAs are already available for the various technologies based on renewables, which represent one of the main other options for avoiding greenhouse gases. Suitable data for making a solid assessment of capability and environmental and system impact are also already available for numerous technologies in the field of efficiency (e.g. modern combined heat and power).

The goal of this project is consequently to weigh up the range of technologies for carbon capture and storage currently under discussion in terms of their fundamental suitability for a future energy supply. We outline several reference systems and realistic system configurations for supplying electricity and hydrogen together with all the relevant data required to properly appraise and assess the options in the scope of an overall concept for a future sustainable energy supply. These make it possible to identify the fundamental potential of the proposed technologies, the technological advancements still required and the environmental impact. A systematic comparison with other options for a climate-friendly energy supply – especially the use of renew

ables – concludes the study. This is the context in which the discussion about the possible role of the CCS option in longer-term energy supply scenarios must be conducted, in which the timeframe of future development steps (establishing an infrastructure) must be considered and in which fundamental energy policy decisions must be addressed. This investigation supplies a sophisticated set of data for placing the carbon capture and storage option in the energy and especially the climate policy context. As such it can make an important contribution to energy policy decisions currently on the agenda.

The principle research questions can be summarised as follows:

- What are the conceivable routes for CCS (technologies, infrastructures, development timetables)?

- What does the overall life cycle assessment of these processes look like, and how does low-CO_2 fossil-based electricity compare with CO_2-free options, especially renewables (comparison on an equal footing)?

- What role can CCS play for climate protection in comparison with other relevant options, and when (systematic comparison on the basis of significant criteria such as cost, timeframe, ecological restrictions, etc.)?

- What role can CCS play as a possible bridge to a renewable energy system?

The report has **five parts**:

Part one (introduction and background) examines the driving forces behind CCS and the attitudes of relevant actors.

Part two takes a closer look at technological developments in the field of CO_2 capture (in electricity generation and hydrogen production) and at the individual steps involved in CO_2 capture, transport and storage.

The **third part** presents a comparative assessment of CCS and other relevant climate protection technologies on the basis of a comprehensive set of criteria. The life cycle assessment method (LCA) is used to conduct a thorough comparison of the ecological performance of CCS in comparison with continued expansion of renewables. The economic parameters are also examined in greater depth. Additional criteria are used to differentiate and expand the comparison with renewables.

Part four examines the significance of CCS for national energy sectors, including thorough system and scenario analyses. The significance of CCS and renewables for energy and climate policy are compared. The Germany energy system was chosen as an example.

Finally, **part five** turns to a more global perspective on CCS, showing the requirements and preconditions that have to be met for international implementation of this technology option.

Chapter 2

Terminology

Before proceeding to the body of the report, it would seem appropriate to examine the definitions of the fundamental concepts involved in carbon capture and storage.

In the literature on 'carbon capture and storage' we find divergent terminology being used.[1] The issue itself is often subsumed under the term 'low-emission/carbon-free (coal) power stations' or the catchword 'clean coal'.[2] The following table presents a selection of the terms commonly found in the literature. The first column lists the umbrella terms for the whole process from CO_2 separation through conversion and transport to storage, while the second and third columns respectively list synonyms for the individual processes of CO_2 capture and CO_2 storage.

Table 2-1: Terms relating to carbon capture and storage

Carbon capture and storage (CCS)	CO_2 capture	CO_2 Storage
CO_2 sequestration	Separation	Disposal
Carbon management		Discharge
		Injection
		Insertion
		Dumping
		Removal

It should be noted that the terms are applied with varying precision. For example 'storage' strictly speaking means to 'keep for the purpose of later retrieval'. This applies to the CO_2 issue only if 'storage' is indeed intended as a temporary solution (which, depending on the storage technology and the order of magnitude of the associated leakage rate, it may well be).

Certain of the terms listed in the 'CO_2 storage' column relate only to particular sinks. For example, 'dumping' refers to storing CO_2 in the sea.

It should also be noted that some of the terms are positively or negatively loaded. For example, the term 'storage' sounds rather positive, 'insertion' is more neutral, while the term 'dumping' may have more negative connotations, in particular due to its association with the controversy over dumping of radioactive waste at sea. Richter (2003) uses this phenomenon to classify the users of the different terms into supporters and opponents of 'CO_2 sequestration'.

In this report we primarily use the terms set in bold in the above table: 'carbon capture and storage' ('CCS'), 'capture' and 'storage'.

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1 'Sequestration', for example, is normally taken to mean the whole process from separation through transport to storage. However, some authors use the term to refer only to CO_2 separation at the power station, while others use it exclusively to designate storage, for example in a geological formation.

2 The terms 'emission-free', 'CO_2-free' and 'clean' are misleading, because with today's technology it is only possible to reduce CO_2 at the power station by about 80 to max. 95 % compared with conventional power stations. Additionally, depending on the technology, other pollutants (SO_2, NO_x, dust, etc.) may still be emitted (indeed, owing to the increased energy requirement possibly even in increased quantities).

Chapter 3

Driving Forces: The Attitudes of Relevant Groups to CO_2 Capture and Storage

The development of technologies for the capture, transport and storage of CO_2 is being promoted from various actors and driving forces. These include:

Global driving forces for climate protection: The necessity of reducing emissions of greenhouse gases, in particular CO2, has given a clear boost to CCS at the global level. This applies especially to those who doubt that long-term climate protection goals can be achieved at all or achieved quickly enough solely by expanding sources of renewable energy and significantly improving energy efficiency. In their view, as long as it gains sufficient acceptance by various actors, including the consumer, CCS could provide considerably more leeway for action and reduce the pressure for developing renewable energy and energy efficiency. For this reason some actors speak of CCS having a 'joker function'. Its advocates even include some states that have tended in the past to take a negative attitude to the international climate protection process. Here the United States in particular should be mentioned as a major promoter of CCS. A roadmap produced by the US Department of the Environment (DoE) envisages the first pilot and demonstration facilities being completed in 2018 (DoE 2003). In the few climate protection scenarios produced by the United States CCS is assigned a dominant role. Experts at the DoE believe that stabilising emissions at

the present level will only be possible if the overwhelming share of emissions reductions is achieved via CO_2 capture and storage (Fig. 3-1).

This 'enthusiasm' can be explained by the fear in the United States that the increased use of renewables and an increase in energy efficiency will place an unacceptable burden on the economy and will excessively limit the 'freedom' to use energy. In addition the strong lobbies of the oil and coal industries play a significant role in shaping US government policy on this issue. The United States has also made advancing CCS a major task of the Asia-Pacific Partnership.

But in other countries, too, CCS enjoys a strong measure of support in the context of climate protection. Examples include Japan, the Netherlands and Germany. In Germany, Vattenfall Europe has become the first energy supply company to begin building a low-CO_2 oxyfuel-based demonstration power station (30 MWth in the first phase of the project), and the Federal Ministry of Economics and Technology has launched a major research and development program in this field called COORETEC.

National energy security: The obligation to protect the climate in some respects clashes with requirements for

**Projection of
GHG Emissions Reductions (MMTCE) in the United States**

- Advanced Sequestration
- Value-Added Sequestration
- Non-CO_2 GHGs
- Forestation and Agriculture
- Efficiency and Renewables

Reductions rely on carbon sequestration developments

Reduction benefit shared with EPA/AG others

Reductions unrelated to sequestration, but includes coal
· Repowering
· Retrofit
· Vision 21

Fig. 3-1:
Emissions reduction requirements compared with the trend in stabilising CO_2 emissions in the United States (DoE 2003)

states and communities of states to maintain or improve their energy security (see the European Union green papers on Security of Supply and Energy Security [EU 2006, 2001]). For many countries a baseline contribution from fossil fuels (mainly coal) is essential, since they have their own reserves of these. In order to attain climate protection goals nonetheless, the argument goes, it is imperative to engage in CO_2 capture and storage while maintaining or even increasing the proportion of fossil fuels.

Many states, particularly India and China, are currently experiencing strong economic growth. In order to maintain their energy supply they believe it is essential to increase exploitation of domestic coal reserves, since other sources of energy cannot be tapped as easily, as quickly or as cheaply. Even if these countries have yet to enter into any quantitative climate protection obligations, the protection of the global climate plays an increasingly important role for them.

Technological innovation and export opportunities: Technological advancements have facilitated some aspects of capturing CO_2 in the power station process. This applies, for example, to coal-fired power stations with integrated coal gasification (integrated gasification combined cycle: IGCC), where the CO_2 produced during gasification can be separated from the resulting synthesis gas fairly easily prior to the combustion process. Subsequent storage of the CO_2 is then seen as a logical extension of the process for the purpose of climate protection. Here capturing CO_2 is seen not as the direct purpose of the new process – as it is for example when sulphur dioxide or nitrogen oxide is separated during flue gas cleaning – but rather as a side-effect.

Another, comparable issue is compatibility with a coal-based hydrogen economy (polygeneration of electricity, heat, synthesis gases and hydrogen). There is currently a fair degree of optimism about the future use of hydrogen as a fuel. Coal gasification represents one possibility for production of H_2. The rise in the prices of oil and gas is causing this approach to receive an increasing amount of attention. The same applies to the process of liquefying coal to provide fuel, known as coal-to-liquid (CTL). To make these processes compatible with protecting the climate, safe storage of the by-product CO_2 is necessary.

Plant engineering: Many power engineering businesses and component suppliers see the large-scale introduction of CO_2 capture processes as providing major economic opportunities not only to sell the additional components required to build new fossil-fuelled power stations but also generally to preserve the market for large-scale power stations. The large proportion of high-tech components required for coal power station processes involving CO_2 capture also means that exports of these technologies achieve correspondingly high added value. The building of a transport infrastructure for CO_2 would also open up new areas of business for suppliers in the pipeline construction sector.

Economic incentives: Several states such as Denmark and Norway have introduced a CO_2 tax. The economic incentives that this tax provides for avoiding CO_2 emissions were the main reason why the Norwegian oil company Statoil decided to launch what is to date the world's largest CO_2 storage project and to store in a geological formation approx. 1 million tonnes of CO_2 produced

Fig. 3-2:
Factors promoting CO_2 capture and storage worldwide
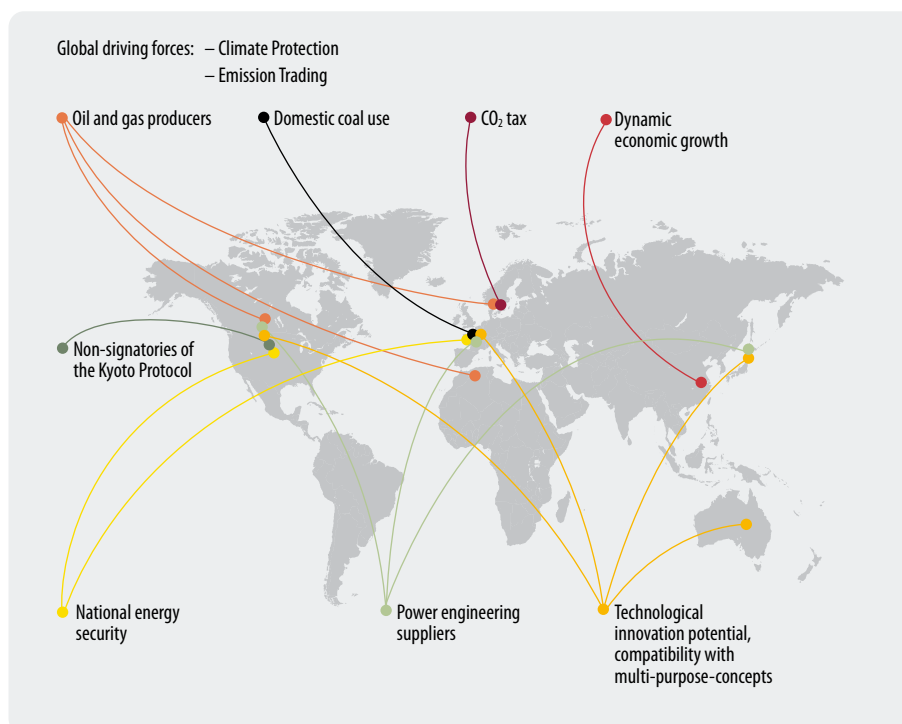
annually as an undesirable by-product in the extraction of natural gas from the Sleipner gas field (Statoil 2004). Oil companies also have an increasing interest in CO_2 capture, since in the process of enhanced oil recovery (EOR) CO_2 can increase the yield of oil extraction.

The various factors can be assigned differing degrees of importance depending on the region. The above diagram (Fig. 3-2) gives a broad overview of the major factors in various regions of the world.

3.1 International and German NGOs

Where non-governmental organisations (NGOs) are concerned, the process of developing positions on CCS has turned out to be very diverse and complex. Overall, NGOs (including those outside Europe) concur on only three points:

- They reject the storage of CO_2 in ecosystems – specifically oceans,

- Currently (February 2008) no campaigns against CO_2 disposal are planned,

- Renewable energy and more rational use of energy should be given priority over CO_2 storage and their implementation should be pushed.

There is no common position that goes beyond these three points. One major reason for this is that the positions of the national NGOs must always take into account the national energy situation (expected energy consumption trends, fuel mix, domestic energy resources, etc.). Another is that the focus of the individual groups and organisations varies considerably. Whereas some focus on climate protection and go into detail on the different solutions proposed, others have a broader range of goals and give more weight to issues such as local ecology and competition with renewables.

The World Wide Fund for Nature (WWF) advocates CO_2 storage under certain conditions (WWF 2005, 2004):

- No storage in oceans, open aquifers or lakes,

- International monitoring of storage must be introduced,

- Public funding of research into CO_2 storage should have no influence on the level of research funding for renewables,

- Emissions trading: only developed countries with 'CO_2 caps' should be allowed to offset 'carbon capture and storage',

- CCS should complement rather than substitute for the expansion of renewables.

Another reason why the WWF takes a positive view of the role of CO_2 storage is because it sees it as a stop-gap that can be used until other technologies have been developed sufficiently to be able to make a decisive contribution to CO_2 reduction.

Greenpeace generally rejects CCS, but in the event that CO_2 capture and storage should be introduced Greenpeace believes it should be used as an additional option and not as a substitute for expanding the use of renewables and introducing energy saving measures. In addition a number of 'essential conditions' must be fulfilled (Greenpeace 2004, 2007):

- CO_2 storage sites must be leak-proof for several thousand years,

- CO_2 should be stored only in disused oil or natural gas fields; no storage in oceans, coal seams or salt domes; storage in saline aquifers only after careful examination of safety aspects, potential utilisation conflicts and environmental impact,

- No use of CO_2 for EOR and EGR,

- Drawing up of national, European and international guidelines regulating CO_2 storage,

- CCS should not be offset under the Clean Development Mechanism (CDM),

- Emissions trading: still a need to discuss whether CO_2 storage should be included,

- Research and development: public research funding should be used exclusively for research into storage facilities (because safety is in the public interest),

- Export of the technology only after safe use in industrialised countries has been proven.

Above and beyond this Greenpeace sees no requirement for CCS in industrialised countries (Greenpeace 2005).

Climate Action Network (CAN) is an umbrella organisation of more than 350 NGOs active in climate protection world-wide. In May 2006 CAN Europe published its position on CCS, much of which corresponds with that of many other NGOs: no disposal of CO2 in the oceans, priority to be given to renewables and energy efficiency (e.g. in the area of research funding) and authorisation of CCS only after it has been proven that (geological) storage facilities are leak-proof in the long term. CAN also regards the development of a legal framework (operator liability for leaking storage facilities, no burden on public budgets) as an essential prerequisite for the introduction of CCS (CAN 2006).

Compared with those in other countries, German NGOs tend to take a rather sceptical attitude to the storage of CO2, but they have no uniform position on the matter. They all agree, however, that top priority must be given to expanding the use of renewables and to more rational energy use. This position stems from the fear that funds for CCS research might be made available at the expense of research in the fields of renewables and energy efficiency.

Specifically, the following reasons or fears have been named:

- CCS constitutes a classic 'end-of-pipe' approach, where problems higher up the process chain (those associated with the supply of fuel) are not only not solved, but tend to be aggravated (e.g. environmental damage caused by open-cast lignite mining) (NABU 2005).

- CCS offers 'no solution to the problem of providing a sustainable supply of energy' because of the large volume of additional energy required, an underestimation of the dangers of 'permanent disposal of CO_2,' and high costs. The use of CCS, it is argued, will prevent a switch of the energy system towards energy efficiency and renewable energies (BUND 2005, 2006; Robin Wood 2006).

- There are still too many open questions regarding the quality and quantity of storage sites. In addition the long periods of time that would have to be bridged until a large-scale system of storage is established make the actual contribution of CO_2 storage to a reduction in emissions seem questionable (Germanwatch 2004).

3.2 Industrial Associations and Companies

In a statement on capture-ready concepts the European Power Plant Suppliers Association (EPPSA 2006) gives recommendations for the use of CCS technology at power stations: 'Efficiency improvement is the least costly method for direct CO_2 reduction and also minimises the capital and operation costs for the CO_2 capture equipment by reducing the flue gas/ CO_2 volume that the equipment needs to handle … The authorisation process should allow the plant to run with or without CO_2 capture.'

Associations representing the interests of the coal industry in various countries fear that a reduction in supplies and market share motivated by environmental and climate protection considerations will have a negative effect on turnover and employment in the coal industry, so these traditional sectors of the energy economy are among the most active promoters of CO_2 capture and storage. The coal industries in Poland and Spain, for instance, are among those in a number of countries that advocate the use of large-scale technology for CO_2 storage.

Oil and gas producers see CO_2 capture and storage as a promising additional business opportunity in the future. For this reason companies like Shell, BP and Statoil are among the advocates of CO_2 capture and storage. Initial practical steps have already been taken; CO_2 is already being pumped into oil fields in order to raise the yield of oil.[1] This is made additionally profitable in some cases, as already explained, by the existing tax on CO_2. Thus in this respect CO_2 storage generates direct economic profits (Williams 2003). In addition today's oil and gas producers could in future become important suppliers of potential CO_2 storage sites in the form of disused oil and gas fields.

To date few German industrial associations have produced position papers stating their position on CO_2 storage. Those that have include the German Lignite Industry Association (DEBRIV), which advocates the capture and storage of CO_2, as well as the German Coal Mining Association (GVSt) and the Association of German Engineers (VDI). The GVSt and the VDI call for clarification of this 'long-term option', but their main priority is a maximum increase in the efficiency of the power plant process as a contribution to climate protection (RWE Rheinbraun / Vattenfall Europe 2003).

3.3 German Political Parties

Germany's political parties take different positions on CCS. The current governing coalition of conservatives (**CDU/CSU**) and social democrats (**SPD**) is positive about carbon capture and storage. The CDU sees CCS as a means of reducing carbon dioxide emissions worldwide and therefore advocates further research efforts in this field. Both the CDU and the CSU describe low-CO_2 fossil fuel power stations as 'important cornerstones' of their energy policy (Union 2002). The SPD calls for '… a co-ordinated research offensive for low-CO_2 or CO_2-free power stations (CO_2 capture)' (SPD 2003).[2] The liberal party, **FDP**, sees the capture and storage of carbon dioxide as an option for emissions reduction (FDP 2003). **Alliance 90/The Greens** believe that CCS is currently too immature a technology to provide any justification for increasing the number of coal-fired power stations in Germany (B90/Grüne 2003). **The Left Party**, on the other hand, comes to the conclusion that there is no place for 'coal-fired power stations, however "vision-

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1 As in the Norwegian Sleipner field, this CO_2 often appears as a by-product of oil and natural gas extraction and is injected back into the formation (EOR/EGR, enhanced oil/gas recovery).

2 'eine koordinierte Forschungsoffensive für CO_2-arme bzw. CO_2-freie Kraftwerke (CO_2-Abscheidung) …'

ary" their technology is' in its demand for a complete switchover to a renewable energy system by 2050 (PDS 2004).

3.4 German Ministries and Expert Committees

3.4.1 The Federal Ministry of Economics and Technology (BMWi)

The Federal Ministry of Economics and Technology is supporting carbon capture and storage with its research program COORETEC. This broad research programme is intended to provide a high-tech basis for meeting the need to replace old fossil-fuelled power stations by new ones. One branch of research in this programme is the long-term development of low-CO_2 power plants (misleadingly called 'zero emission power plants') (Rüggeberg 2004).

3.4.2 The Ministry for the Environment, Nature Conversation and Nuclear Safety (BMU) and the Federal Environment Agency (UBA)

Despite numerous research efforts, the Federal Ministry of the Environment and the Federal Environment Agency still have many open questions about the long-term safety and social, ecological and economic acceptability of CCS. Specifically there has so far been no systematic examination of CCS as a whole in the form of an ecological evaluation, an analysis of possible interaction with other aspects of the energy economy or a comparison with other measures for the reduction of CO_2 emissions – which is the main justification for the current research project. In August 2006 the Federal Environment Agency published a position paper entitled: 'Separation and Storage of CO_2 – only an interim solution – possible effects, potential and requirements', which examined the extent to which the introduction of CCS would be compatible with sustainability requirements, particularly in Germany (UBA 2006). In line with the guiding principles for sustainability issued by the Enquete Commission for the 'Protection of People and the Environment' of the thirteenth German Bundestag, the following theses were developed:

1. Climate protection can be achieved using renewables and energy efficiency. The technical capture and storage of CO_2, on the other hand, is not sustainable and is therefore at best an interim solution.

2. Capacity for CO_2 storage should be the main focus of discussion: in Germany this may be limited to forty years.

3. Technical capture and storage of CO_2 involves costs. Assuming ambitious climate protection goals, some projects will probably be economically viable.

4. CO_2 storage facilities should not exceed a leakage rate of 0.01 % per year. Dangers to health and environment should be avoided.

5. Storing CO_2 in the oceans and the 'artificial mineralisation' of CO_2 cannot be considered options.

6. A national and international legal framework must be developed for CCS.

7. The discussion should include environmental issues and questions of equity. Research, state regulation and demonstration projects should not be limited to technical aspects alone.

Altogether the UBA advocates initiating a more far-reaching discussion of sustainability issues in order to add a sustainability dimension to a 'discussion that to date has been conducted mainly with a view to technical aspects'. The results of the ecological and economic calculations done within the current project offer a preliminary basis for a concept of this kind and should be included in any fundamental discussion of sustainability.

3.4.3 The Council for Sustainable Development (RNE)

In a position paper the Council for Sustainable Development calls the capture and disposal of carbon dioxide a possible important bridge 'on the way to the era of renewable energy supplies'. Here it recommends integrating technology for CO_2 capture in high-efficiency power stations, only, however, from the point of view of economic efficiency. If this goal is not attainable, fossil-fuelled power stations should not be part of a long-term strategy for a sustainable energy supply. While the Council for Sustainable Development advocates research into technology paths of this kind, this must not compete for research funds in a way that might give priority to this end-of-pipe technology over research into renewables and improved energy efficiency. The Council for Sustainable Development lists CCS as a field of research along with research into renewables, energy efficiency and material efficiency (RNE 2004).

3.4.4 Advisory Council on Global Change (WBGU)

The Advisory Council on Global Change (WBGU) set up by the German government has taken up a clear position on the storage of carbon dioxide. It refers to CCS as an 'end-of-pipe technology' and states: 'Fossil fuels will continue to be the dominant source of energy in many countries for decades to come … Therefore the end-of-pipe technology for carbon storage provides … an option for climate protection'. (WBGU 2003). The criteria for evaluating various options include length of storage, storage safety and environmental impact. WBGU rejects as storage options disposal in the oceans (ecological reservations), terrestrial sinks/biomass

(lack of potential for expansion) and saline aquifers (no guarantee of safety and long-term storage). With regard to the length of storage the WBGU concludes in its most recent report (WBGU 2006): 'Sequestration … only represents an acceptable climate protection technology if it can be guaranteed that CO_2 will remain in a deposit for at least 10,000 years.'

Disused oil and gas fields could be used for interim storage, but only if the retention period mentioned above could be guaranteed. In the opinion of the WBGU there is a need for further research, above all on the permanent storage issue (WBGU 2003). Under certain conditions storage under the seabed might also be a feasible option. The WBGU recommends regulating CO_2 storage under the seabed and proposes a number of instruments for this purpose:

- The formulation of minimum standards,

- Direct volume limitations: in international climate protection agreements stored volumes of CO_2 should not be counted in full as avoided CO_2 emissions,

- The establishment of liability mechanisms.

In principle the WBGU advocates sequestration under the sea floor, however only for 'a transition period as an additional option to more sustainable emissions avoidance strategies' (WBGU 2006). It further recommends, 'clarifying the question of the compatibility of CO_2 storage under the sea floor with the London Convention or the London Protocol … in such a way that CO_2 sequestration in geological formations … is permissible' (WBGU 2006). At the same time the WBGU calls for such activities to be limited to a certain period of time (several decades), thus underlining its statement that CCS should only constitute an interim solution. The WBGU believes it would be sensible to apply flexible mechanisms to sequestrated CO_2 as well, although within the above-mentioned constraints.

3.4.5 Advisory Council on the Environment (SRU)

The Environmental Council believes that the capture and storage of carbon dioxide may be too expensive in comparison with other emissions avoidance options. An additional reservation is that 'even its advocates think that it will not be realisable until after 2020'. This would mean that this technology would come too late for the upcoming renewal and expansion of power station capacity (SRU 2004, 2000). The SRU is keeping track of this issue and continues to see a great need for action with regard to making a comprehensive evaluation of this technology (Hey 2006).

3.4.6 Office for the Assessment of the Impact of Technology of the German Bundestag (TAB)

As part of its monitoring of 'the sustainable supply of energy' the TAB has addressed the issue of 'CO_2 capture and storage for power stations'. A study surveyed the existing literature on the subject and a workshop of experts was held to identify critical gaps in knowledge and to 'define areas in which a more profound analysis can be undertaken' (TAB 2006).

Chapter 4

An Overview of CCS Processes

Because of the high costs and complex infrastructure involved, CO_2 capture and storage is by necessity suited primarily for centralised, large-scale power generation structures. CO_2 can in principle be separated from any point source, which means first and foremost from power stations and industrial plants. Electricity generation, which accounts for about one third of global CO_2 emissions, represents the largest source. Although CO_2 can in principle be filtered out of the atmosphere, this aspect is considered only in passing here. Feasible practical methods for the numerous smaller emissions sources (e.g. motor vehicles) are not as yet available.[1]

That said, it is possible to integrate CCS into decentralised structures at least indirectly, by linking the process to the introduction of the hydrogen energy economy. Hydrogen produced centrally in a process involving CO_2 separation (e.g. coal gasification or steam reforming of natural gas) could be distributed (through specially constructed pipeline networks) and used decentrally, for example to generate electricity and heat or in mobile energy consumers.[2] Although this would involve additional energy losses because it increases the number of steps in the process, the use of pure hydrogen applications would make high efficiency ratios possible, e.g. in fuel cell systems. So alongside the application of CCS in the field of power generation, we should also consider to what extent and in which applications and timeframes it would make sense to introduce a hydrogen energy economy using CCS, and whether this would lead to a sensible energy balance.

The CCS process chain consists of various steps, from CO_2 separation, through liquefaction of the separated CO_2 and transport, to permanent storage. In order to gain a full and complete picture of the process, the following fundamental aspects have to be differentiated:

- Type of fuel (largely natural gas and coal),

- General type of separation (pre-combustion/post-combustion),

- Type of electricity generation plant (steam turbines (ST) / gas turbines (GT) / natural gas combined cycle (NGCC) / power stations with integrated coal gasification (IGCC) / fuel cells (FC) / combined processes and hybrid versions / new cycles and methods, etc.),

- Type of separation technology (e.g. chemical absorption, physical absorption, membrane separation methods, adsorption on solid surfaces, cryogenic processes),

- Type of transport (e.g. pipeline, inland waterways) and transport state (liquid, solid, gaseous),

- Type of storage (e.g. geological etc.).

Just considering the levels of differentiation in the first step of the process – CO_2 separation – by different power generation technologies (Fig. 4-1) and different CO_2 separation methods (Fig. 4-2) shows clearly how complex the whole CCS process chain is (Fig. 4-3).

The next figure focuses on the separation and storage options currently under discussion, regardless of their prospects for implementation, the potential obstacles involved and the question of what restrictions they may face (including ecological repercussions).

The individual parts of the material flow diagram are described and discussed in more detail in the following chapters, including an analysis of the efficiencies, emissions and costs involved in CO_2 capture and storage. This relevance analysis identifies those options whose chances of implementation are especially high from today's perspective or where a market launch seems most likely. The analysis is based on studies and reports by BMWA (BMWA 2003), ECOFYS (ECOFYS 2004), Germanwatch (Germanwatch 2004), IEA (Gielen 2003, IEA 2003, 2004), IPCC (IPCC 2002, 2005) and WGBU (Ploetz 2003; WGBU 2003), as well as the authors' own experience.

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1 Given that the weight of the CO_2 produced by combustion is 3.67 times the weight of the carbon in the fuel, separation in the vehicle itself would be problematic and would automatically impact negatively on the energy balance.

2 It might be possible to use and expand existing infrastructure such as natural gas pipelines.
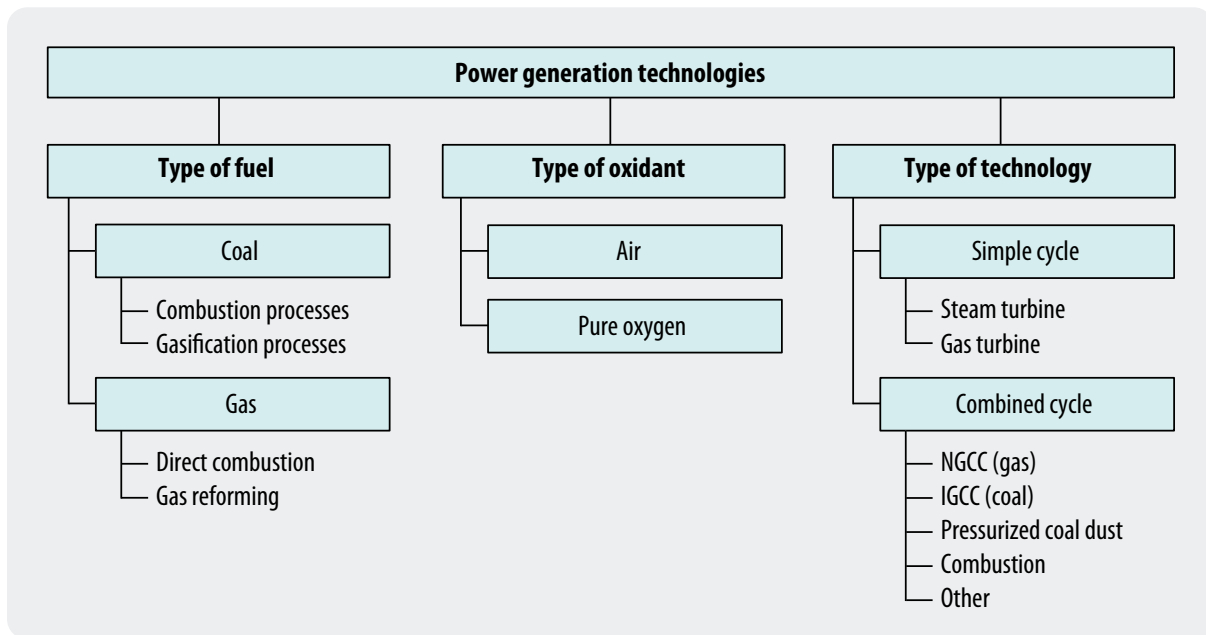
Fig. 4-1: The different types of fuel, oxidant and technology involved in power generation technology
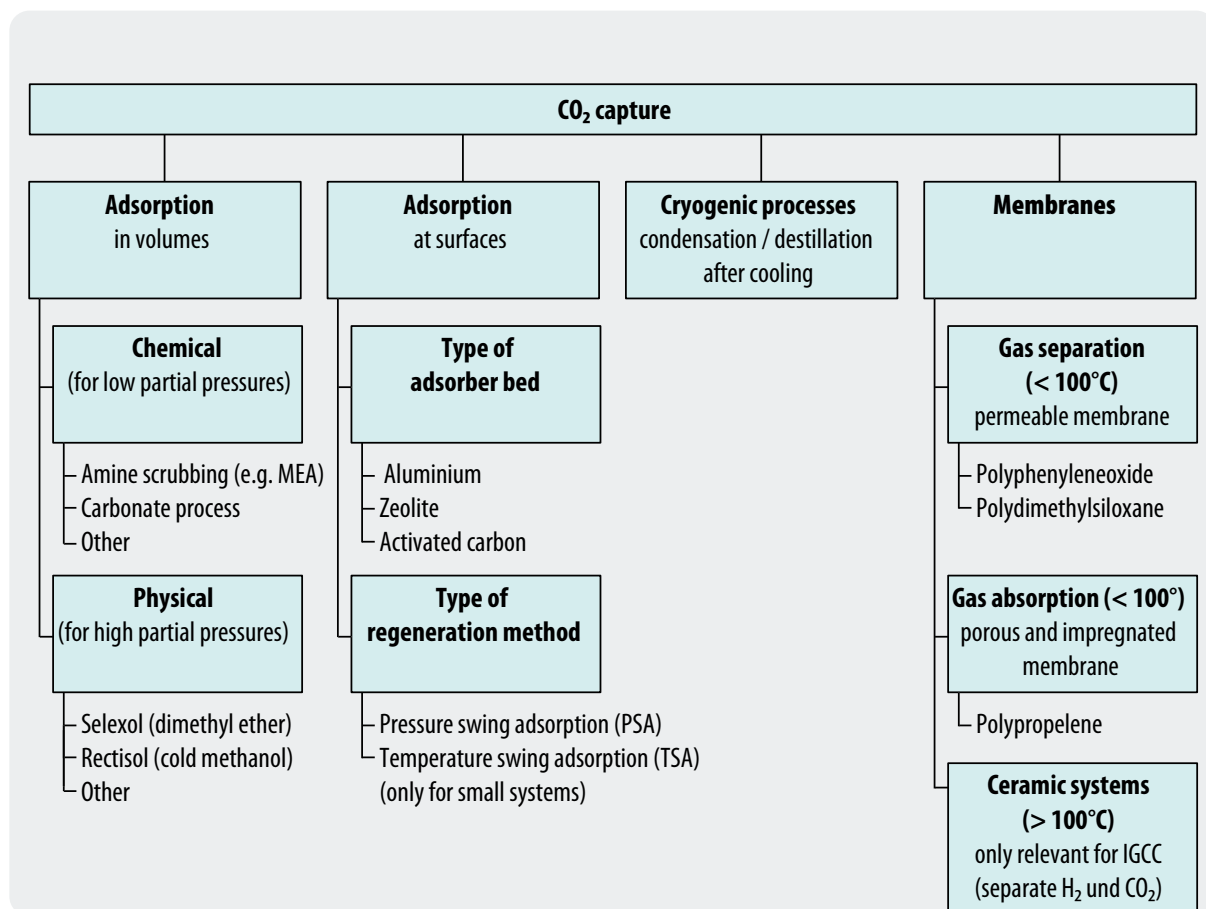
Fig. 4-2: Physical, chemical and membrane methods for CO_2 separation (Environmental Scientific Technologie 2002)

| CO$_2$ source / capture | CO$_2$ phase change | CO$_2$ transport | CO$_2$ storage[3] |

Fossil-fuelled power plants without CCS — coal, natural gas — ST / GT / CC

no phase change (gasous)

Atmosphere → Atmosphere → Biomass (plants & algae); Convection towers Absorber trees (CaO / Ca(OH)$_2$)

1. POST-Combustion
= Capture from flue gases

Absorptive washing from flue gases — coal, natural gas — ST / GT / CC — Atmosphere

Liquefaction (by pressure or cryogenic)

Atmosphere → **Pipeline**[2] → Atmosphere

Truck /ship /rail

Chemical recycling (mononuklear / polymer compound)

Fuel synthesis (e.g. methanol) from RES-H$_2$

2. PRE-Combustion
= Capture from synthetic gases
(physically active absorption
or membrane processes)

Mineralisation with magnesium silicates into carbonates / freezing (solid)

a) coal — **IGCC**[1] (coal gasification) with CO-shift + scrubbing

b) coal — **IGCC**[1] (coal gasification) with H$_2$ / CO$_2$ membrane

c) natural gas — **Natural gas reforming**[1] (steam reforming + CO-shift)

d) coal, natural gas — **HT-IGFC** (HT fuel cell with internal oxygen supply)

Ocean
a) Solution (>1,600 m)
b) CO$_2$-lake (>3,000 m)

Aquifers underground (onshore) or sea bed (offshore)

Enhanced oil /gas recovery (EOR / EGR)

Depleted oil / gas fields

Injection into methane-bearing coal seams (ECBM)

Injection into former coal or salt mines

3. Oxyfuel
= Combustion in pure oxygen
with flue gas recirculation
(capture from flue gases)

coal, natural gas — **O$_2$/CO$_2$ recirculation (Oxyfuel)** — ST / GT / IGCC[1]

Truck / ship / rail

Atmosphere → Dry ice disposal (ocean)

Carbonate disposal

Remarks: 1) Requires development of modified GT (working fluid CO$_2$/H$_2$O)
2) Transport at ca. 100 bar in supercritical state (p$_k$ = 73,8 bar)
3) All storage options as yet lack a comprehensive legal framework

Fig. 4-3: The process chain from CO$_2$ separation to storage

Chapter 5

CO_2 Capture Methods for Power Plant and Hydrogen Production

This chapter examines developments in power station concepts with CO_2 capture (new builds and retrofit) from the short-, medium- and long-term perspectives, and explains the various concepts and methods for hydrogen production with integrated CO_2 capture. The cost reduction potentials (learning curves) for both power generation and H_2 production are estimated, and finally the question of which of the considered technologies could be relevant in future is examined.

5.1 Developments in Power Station Concepts with CO_2 Capture

Fig. 5-1 shows the development status of measures for CO_2 capture in the power generation sector and the expected implementation timeframe for new power station concepts. The **short- to medium-term** options can mostly be assigned to the following fields:

- Post-combustion capture,
- Pre-combustion capture and
- Oxyfuel (combustion in oxygen).
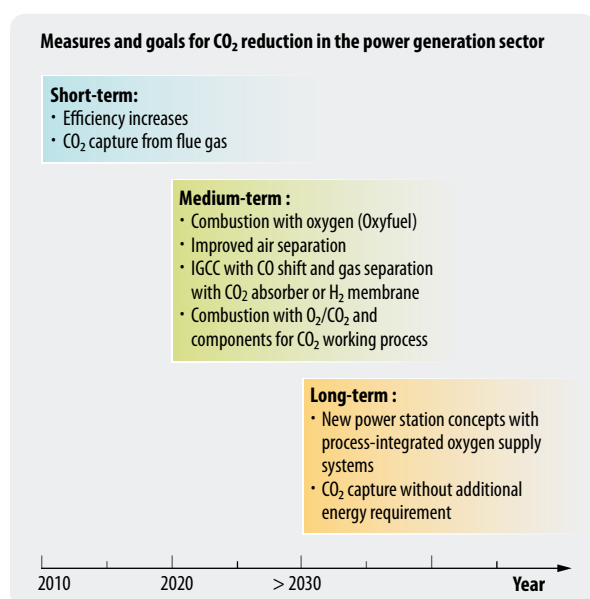
Fig. 5-1: Measures and goals for CO_2 reduction in the power generation sector

In the **longer term** power station concepts involving new combustion processes for energy conversion are under consideration, such as chemical looping combustion (CLC) or high-temperature fuel cells (MCFC and SOFC).

An overview of the main methods is provided below, including an outline of the current status of implementation and the development perspectives.

5.1.1 Short- to Medium-Term Options

As already indicated, there are numerous CO_2 capture methods, which have all reached different stages of development. The most promising short- and medium-term options are described below (timeframe 2020 to 2030).

CO_2 capture after combustion (flue gas decarbonisation / post-combustion)

In this method the CO_2 is captured from the power station's flue gas. Because the concentration of CO_2 in the flue gas is relatively low (3–15 %, fuel-dependent), a large volume of gas has to be treated. The use of large quantities of chemicals and energy increases costs accordingly and reduces overall effectiveness.

The least favourable conditions result from the application of CO_2 washers in conventional coal-fired power stations. When coal-fired power stations are retrofitted, efficiency losses of between 8 and 14 percentage points must be expected, with a 10 to 35 % increase in fuel consumption and additional investment costs of 30 to 150 %. In gas-fired power stations the situation is a little better (because the specific CO_2 emissions are lower compared with coal). The scrubbing fluids used are sensitive to flue gas impurities such as sulphur oxides (SO_x), nitrous oxides (NO_x > 10 ppmv), dust, oxygen (if > 1.5 vol. %), etc., so the flue gas must be cleaned before CO_2 capture. Most of the solvents used degrade over time, leading to losses and associated environmental problems. Potential is seen above all in the provision of stable scrubbing fluids with reduced corrosiveness and in the development of corrosion-resistant materials. In the medium term membranes are highly unlikely to play a role in CO_2 capture.

Washing processes are de facto the only possibility for retrofitting power stations without intervening in the existing process. Additionally, the separation of CO_2

Fig. 5-2:
Flue gas decarbonisation by amine scrubbing
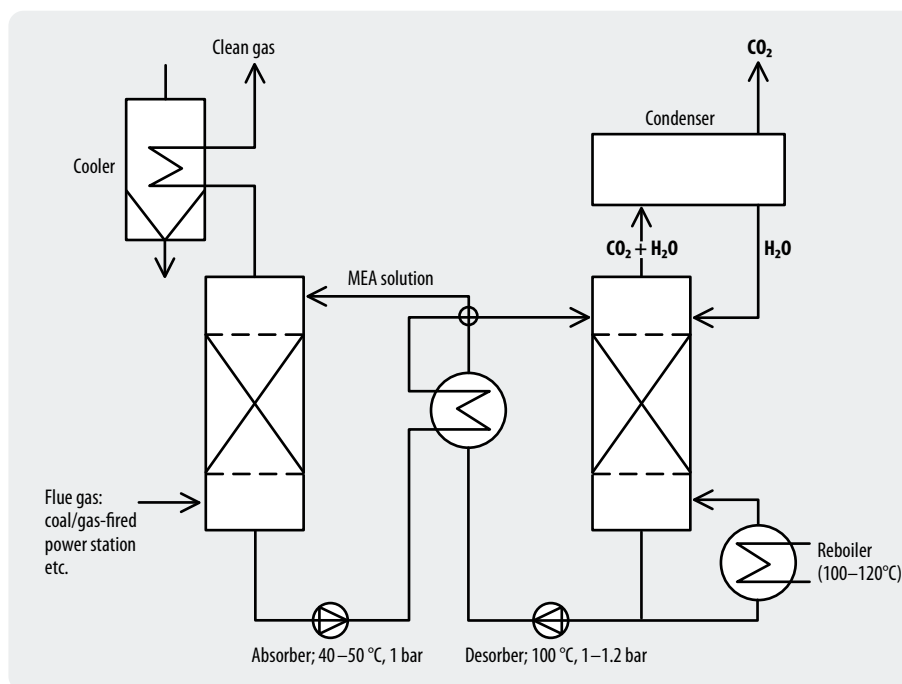
from flue gases is already an established chemical engineering process, albeit not yet on the power station scale.

There are already more than ten different technology lines for capturing CO₂ (BMWA 2003). One quickly available process is amine scrubbing, which functions similarly to flue gas scrubbing for desulphurisation. Also under development are membrane technologies (polymer-based, ceramic or metal-based), which are expected to reduce the cost of CO₂ capture in the medium to long term.

Amine scrubbing is an available and established process that has similarities to flue gas desulphurisation. Monoethanolamine (MEA, 30 vol. % solution in water) and methyldiethanolamine (MDEA, 40 vol. % solution in water activated with piperazine) are among the preferred amine solutions. MEA is a relatively strong base which strongly absorbs CO₂, so it is used where CO₂ concentrations are low or a high capture rate is required. Owing to its strong basicity MEA binds CO₂ very strongly, so regenerating the solution requires a great deal of energy. MDEA by contrast is a weaker base with a high capacity. It does not achieve high capture rates and is largely used where CO₂ content is high. Amine scrubbing for flue gas decarbonisation can be applied in both coal-fired and gas-fired power stations.

Fig. 5-2 shows a flow chart of a MEA system. Absorption takes place at approx. 40–50°C and 1 bar, desorption at 100°C, 1–1.2 bar. Amine solutions are stable at 100–120°C. The main components of a typical MEA system are the absorber and desorber columns.

Owing to the corrosiveness of amine solutions the equipment is made largely of high-grade stainless steel (e.g. 14571 or 14301). Where there is no oxygen in the flue gas carbon steel can also be used. Today's plant capacities range from 6 to approx. 1,000 tCO₂/d, but no problems are anticipated in building units with capacities up to 4,500 tCO₂/d (Chapel 1999). Plant design is largely determined by the volume of flue gas to be treated and the partial pressure of the CO₂. A unit for a typical coal-fired power station (1,000 MW) would have to cope with a flue gas volume of approx. 2 million Nm³/h or about 13,200 tCO₂/d, which is larger by a factor of three. Fig. 5-3 shows basic processes in a pulverised-coal-fired power station. The additional steps required for CO₂ capture are shaded grey in the figure.

The principles illustrated in Fig. 5-3 apply identically to CO₂ capture from flue gas in gas-fired power stations, but the specific quantity of CO₂ per kWh is smaller than in coal-fired power stations, which reduces the additional specific cost of CO₂ capture per kWh.[1] Consequently the negative effects of CO₂ capture on electrical efficiency and costs in gas-fired power stations are smaller than in coal-fired power stations.

Where this CO₂ capture technology is applied the additional costs and efficiency losses in the power stations are considerable, so widespread application in the future appears rather unlikely (although retrofitting is a possibility) on the one hand. On the other hand, flue gas scrubbing represents the only CO₂ capture method that is already ready for application today. The extent to which retrofitting is carried out will depend on numer-

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[1] In relation to the actual volume of CO₂ emissions, however, the picture is reversed, because the cost of the additional equipment stands in relation to a smaller volume flow of CO₂.
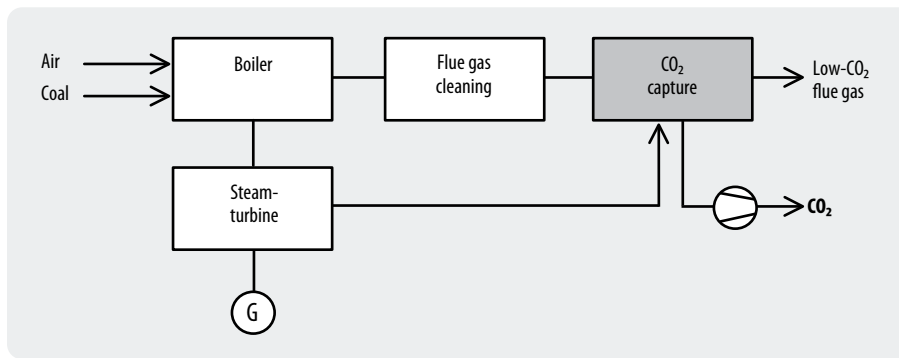
Fig. 5-3:
Pulverised-coal-fired power station with CO$_2$ scrubbing

ous factors, such as the speed at which climate protection regimes are introduced and the associated incentives for CO$_2$ reduction, the cost structure of other climate protection strategies and the development of other CO$_2$ capture methods.

CO$_2$ capture before combustion (fuel gas decarbonisation/pre-combustion)

Alternatives to flue gas scrubbing are currently attracting increasing attention. In very broad terms, we can speak of a 'hydrogen solution' and an 'oxygen solution'. In the hydrogen process described below CO$_2$ is captured before combustion. By means of gasification and steam reforming, solid coal is first converted into a gas largely made up of H$_2$, CO and CO$_2$. This synthesis gas can also be produced directly from natural gas by steam reforming. In a shift reactor steam is used to convert the CO into CO$_2$ and additional hydrogen. Then the CO$_2$ is captured and a hydrogen-rich gas becomes

available for combustion. Gasification and reforming are normally conducted under pressure (30–60 bar), producing a gas with high CO$_2$ partial pressure. This makes it possible to capture the CO$_2$ from the H$_2$/CO$_2$ mixture using physical scrubbing scrubbing(state of the art), which is considerably less energy-intensive than amine scrubbingscrubbing. In future membrane technology (hydrogen membranes) will also be an option for CO$_2$ capture, bringing with it the advantage of a further reduction of energy consumption. Another important aspect of fuel gas decarbonisation is that the combination of gasification (reforming) with CO$_2$ capture opens the way to a hydrogen economy. The generated hydrogen or synthesis gas can be used not only to generate electricity but also for other applications, for example methanol synthesis (co-production). Coal gasification without CO$_2$ capture is already used in a number of combined cycle power stations (IGCC, integrated gasification combined cycle), where the synthesis gas is burned directly in a gas turbine. With an additional reforming step, the same process can also be
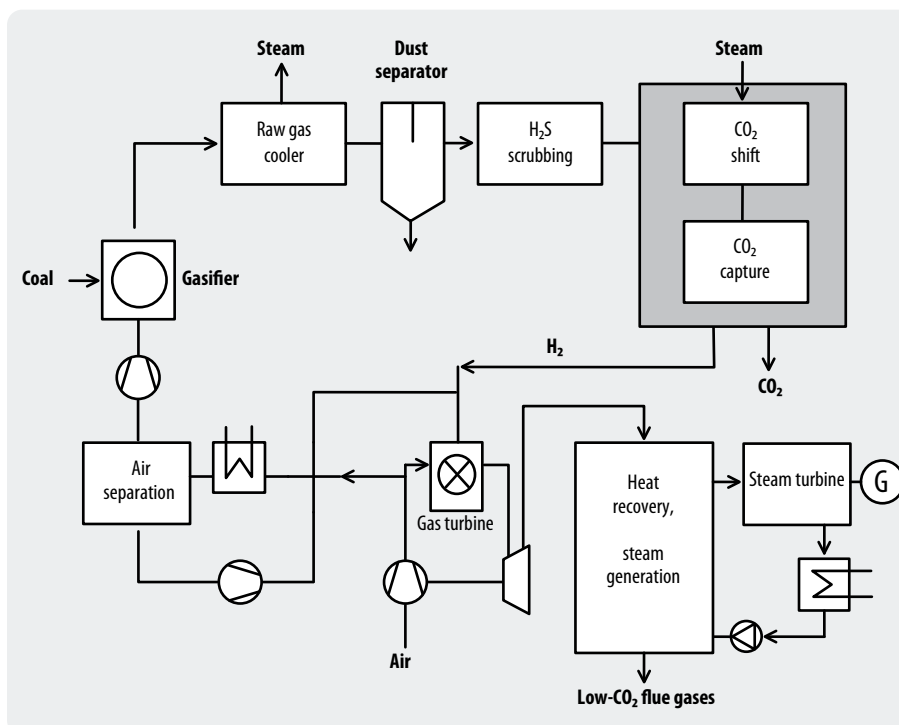
Fig. 5-4:
IGCC power station with CO shift and CO$_2$ capture (Rectisol scrubbing)

Fig. 5-5:
CO shift reactor for converting
CO and H_2O into H_2 and CO_2

Reactor 1: High-temperature shift stage, 350–530 °C **Reactor 2:** Low-temperature shift stage, 180–270° C
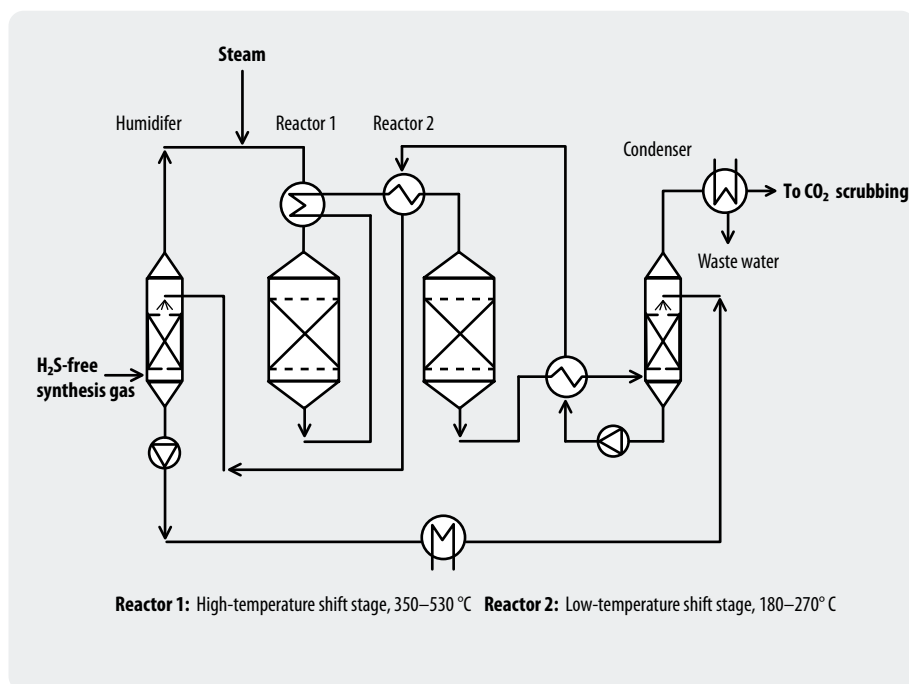
implemented in gas-fired combined cycle power stations (NGCC, natural gas combined cycle). IGCC with oxygen gasification offers a more economical way to achieve CO_2 capture than flue gas decarbonisation. The advantages of these pre-combustion processes lie in their clearly lower costs and higher levels of power station efficiency. The disadvantages are found in the lack of availability of IGCC power station technology. There is also a need for additional development work on individual components, such as the hydrogen turbines. As complete processes, IGCC and NGCC with CO_2 capture have yet to be demonstrated at the scale of real power stations. Fig. 5-4 shows the operating principles of an IGCC power station with CO_2 capture (physical scrubbing with Rectisol), while Fig. 5-5 illustrates the CO shift stage.

The pressurised IGCC process reduces the volume flow of gas to be treated and increases the CO_2 partial pressure. Both effects simplify CO_2 capture (because physical scrubbing or membrane technology can be used) and avoid the disadvantages of unpressurised capture processes such as amine scrubbing.

As an alternative to CO_2 capture, the hydrogen itself can be separated from the H_2/CO_2 gas mixture. The difference in size between H_2 and CO_2 molecules means that membrane methods can be used, which reduces the cost and energy consumption of the separation process. H_2 separation by membrane is close to commercial viability. Fig. 5-6 shows the basic processes in an NGCC power station with membrane separation of H_2 and afterburning of the retentate with O_2. In the illustrated example the conversion of natural gas into H_2 is accomplished by means of partial oxidation with a subsequent CO shift reactor and generally comprises a low-

temperature stage and a high-temperature stage. This is necessary in order to maximise CO conversion. Provision of oxygen for partial oxidation and afterburning is an important cost item in this concept.

Fig. 5-7 and Fig. 5-8 show the components of a physical scrubbing plant and a membrane separation system (H_2 membrane). Unlike chemical absorption processes (e.g. amine scrubbing), in physical scrubbing the absorption solution is regenerated by pressure release. The equipment for the membrane method is very simple and compact.

The oxyfuel process

The technology of combustion in pure oxygen represents another method to simplify CO_2 capture in the power station (the 'oxygen solution'). Here fuel is burned in pure oxygen rather than air, producing a much smaller volume of waste gas (owing to the absence of nitrogen). The flue gases contain primarily CO_2 (approx. 80 vol. %) and water vapour. Subsequently condensing out the water vapour allows the flow of CO_2 to be transferred to storage facilities without any additional technical complexities. Another advantage is that combustion in pure oxygen produces no nitrous oxides and there is no need for complex denitrification equipment. The large amount of energy required to produce the oxygen is a disadvantage. Before this CO_2 sequestration process can be implemented on a large scale significant improvements will be required, especially in the field of O_2 generation processes. Intensive research and development work on membrane separation technologies is currently in progress. Combustion in oxygen can in principle be applied in any power station type.
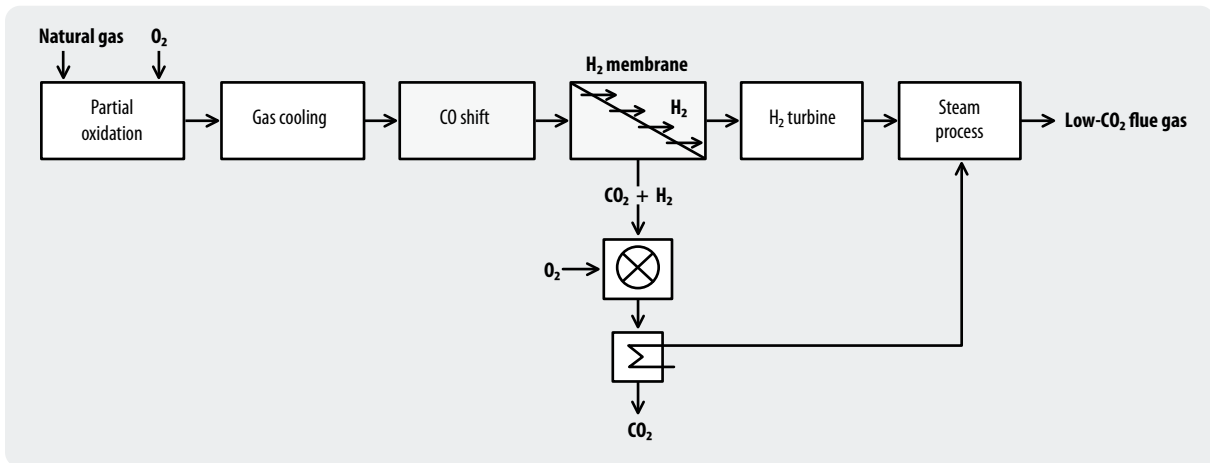
Fig. 5-6: NGCC power station with membrane separation of H_2 and afterburning of the retentate
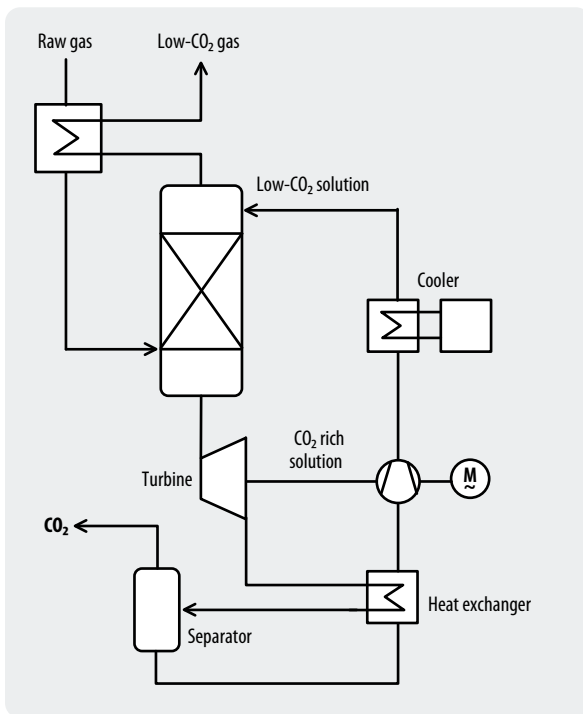
Fig. 5-7: Physical scrubbing
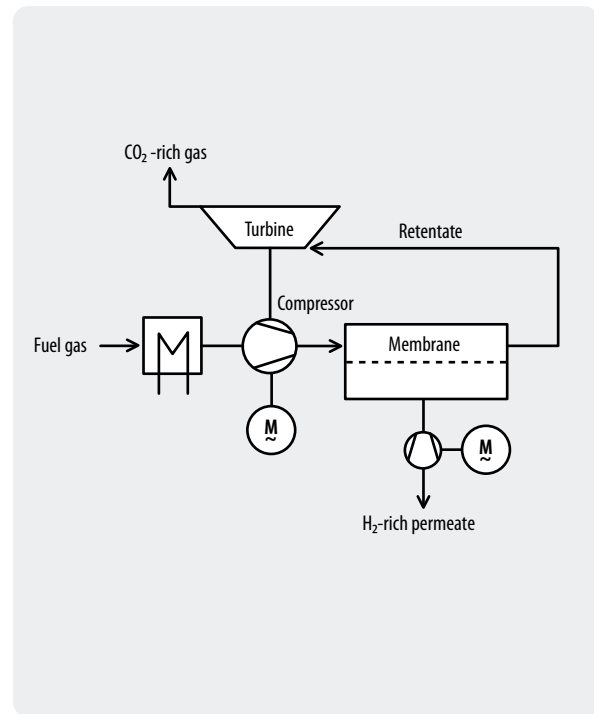
Fig. 5-8: CO_2 enrichment using membrane technology

Retrofitting is also possible, although this would be very expensive because both an air separation facility and a flue gas recirculation facility to regulate the combustion chamber temperature would be required.

The process can most simply be implemented in power stations with a steam boiler. Fig. 5-9 shows the operating principles of the oxyfuel process with a steam boiler. After combustion and gas cleaning, actual CO_2 capture involves no more than a condenser to remove the water and a compressor to compress the CO_2 for transport and storage.

For use with natural gas, further development work will be required not only on the provision of oxygen but also on the turbines to be used. High-temperature membranes for oxygen production represent an optimisation that could drastically reduce the energy required. Such special membranes capable of allowing ions and electrons to pass are not yet technologically viable. Overall, the oxyfuel process has yet to pass through the usual development phases from prototype to pilot plant to demonstration plant and will therefore only be able to achieve commercial viability in the medium to long term.
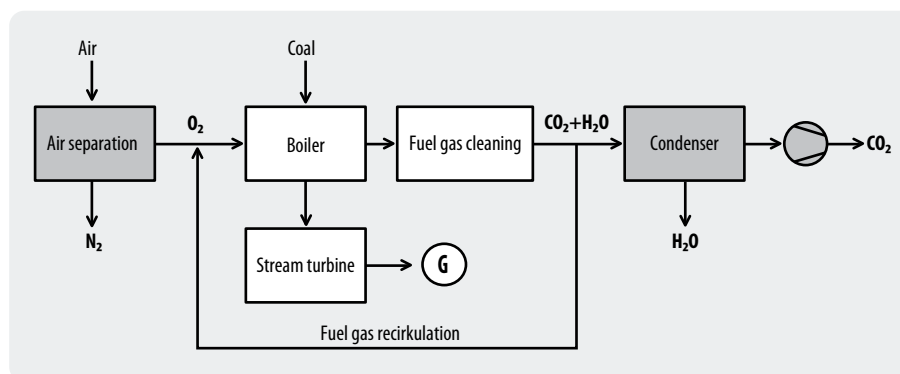
Summary of CO₂ capture technologies (short- to medium-term options)

- Separating CO_2 out of flue gases (**post-combustion**) in conventional power stations leads to a significant increase in electricity generation costs, causes considerable additional fuel consumption and substantially reduces power station efficiency (for details see chapters 10 and 12). The technology is available today, but has not yet been demonstrated in power stations on a commercial scale. In the longer term this technology is unlikely to become widely established unless climate protection regulations are tightened up considerably in the near future, in which case it could act as a stopgap while other processes are developed.

- **Pre-combustion capture** of CO_2 in IGCC and NGCC power stations is from today's perspective a more attractive method than flue gas separation of CO_2. The next step here is large-scale technical demonstration. The IGCC technology itself – without CO_2 capture – has already been tested in several plants. Before CO_2 capture can be implemented there will be a need for improvement and development of several components (e.g. hydrogen turbines). In Germany RWE Power intends to take the first step towards implementing this technology by building a full-scale IGCC power station with CO_2 capture (360 MWel output) by 2014.

- The **oxyfuel process** currently offers the best prospects for CO_2 capture in terms of achievable overall efficiency of the process as a whole (and also the resulting costs), because it is largely based on conventional power station components and technology. It is not possible to provide a precise assessment because the process is still at the beginning of the demonstration phase.

- At Schwarze Pumpe in eastern Germany Vattenfall Europe is building the world's first pilot plant for lignite combustion using the oxyfuel process. The Vattenfall pilot plant, which has an output of 30 MW (thermal), will be used for research and development purposes with the aim of developing the new technology to the point where it is com-

mercially viable. It is scheduled to begin operation in 2008 after a construction phase lasting about three years. Initially the CO_2 will not be stored, but corresponding concepts (e.g. transport options) are being investigated.

- TOTAL has announced that it will be starting up a pilot project in a combined cycle plant in Lacq in November 2008. Here CO_2 will be captured using the oxyfuel process and transported by pipeline to the disused gas field at Rousse (approx. 30 km from Lacq) where it will be injected through an existing borehole into an aquifer at a depth of 4,500 m.

The processes and methods available for short- to medium-term measures are summarised in Table 5-1 along with assessments of their development status.

5.1.2 Long-term Options

Application of the short- to medium-term options for CO_2 capture described in Table 5-1 is in all cases associated with a relatively high energy requirement. Innovative separation processes combined with new power station types could minimise energy use and thus make CO_2 capture more efficient. The principal options here are power station concepts where high-temperature fuel cells (SOFC, MCFC) are used to generate electricity or new power station concepts that draw the oxygen required for combustion from the reduction of a metal oxide (chemical looping combustion). Both approaches offer the possibility of isolating CO_2 from the process without using additional energy. However, the feasibility of most of these technology combinations has yet to be demonstrated.

CO₂ capture with fuel cells

In principle any type of fuel cell can be combined with pre- or post-cell CO_2 capture in various configurations. The most interesting is the concept of combining a high-temperature SOFC (solid oxide fuel cell) with a WGSMR afterburner (water gas shift membrane reactor). The residual anode off-gas, still containing

Table 5-1: Development status of CO$_2$ capture methods

CO$_2$-capture	State of development	Comments
Post Combustion a) Absorptive flue gas scrubbing b) Adsorption c) CO$_2$ membrane	a) Technology available, some commercial applications for CO$_2$ capture in energy sector, established technology for other purposes, e.g. flue gas desulphurisation b) Ready, to date only for small gas flows c) Current technology suffers from very poor membrane selectivity, not ready for CO$_2$ separation from flue gas	Post-combustion systems normally use a liquid solvent (e.g. MEA) for separation from flue gas with small proportion of CO$_2$ (typically 3–15 %) a) Technology close to application, but currently still very expensive and subject to efficiency losses; can in principle be retrofitted to existing power stations b) c) High specific energy requirement more or less excludes application for CO$_2$ capture from flue gas
Pre Combustion a) Coal gasification (IGCC) b) Natural gas reforming (NGCC) c) Coal/natural gas fuel cell (HT-IGFC) d) Physical CO$_2$ scrubbing e) H$_2$ membrane separation f) High-temperature separation (e.g. in situ binding of CO$_2$ at CaO)	a) b) d) Technology in principle available for large-scale application (with the exception of the H$_2$ turbine) c) Development stage (high long-term potential, 20–50 years) e) Development stage, close to commercial application but still expensive f) Development timeframe 10–20 years, very high research intensity (especially Japan and Norway)	In pre-combustion systems the fuel gas is first subjected to thermo-chemical conversion (e.g. gasification, reforming) using steam, oxygen or air to create a synthesis gas (primarily comprising CO, H$_2$, CO$_2$, with air gasification also N$_2$). In a shift reactor CO and H$_2$O are converted into more H$_2$ and CO$_2$. Before combustion the mixture is separated into flows of H$_2$ and CO$_2$. In the mixture the CO$_2$ is already present at a high concentration (15–60 %) and may also be under pressure. Physical scrubbing can be used to separate the CO$_2$, or membranes to separate the H$_2$. Another option is to capture the CO$_2$ earlier, during the thermochemical conversion process, using high-temperature sorbents (e.g. CaO). a) Potential for lower costs and higher efficiency; options for beginning implementation of H$_2$ technology; availability still inadequate/problems with load changes c) Allows CO$_2$ capture within process
Oxyfuel Combustion with oxygen a) combustion with flue gas recirculation b) in gas turbine	a) b) Development of O$_2$ membranes to replace cryogenic air separation (takes 15 to 20 years) b) Development of modified turbines required (working fluid CO$_2$/H$_2$O)	BIn the oxyfuel process combustion is conducted with pure oxygen rather than air. The waste gas is made up principally of CO$_2$ and water vapour, which is then condensed out by cooling. Apart from condensation, further cleaning may be required to make the CO$_2$ storable. Most concepts require oxygen at a purity > 95 %, which is generated by air separation. For coal the process is in the demonstration phase. Gas turbines for oxyfuel operation are still in the development phase.

30–35 % unused fuel gas, is passed to a shift reactor with a hydrogen membrane where the hydrogen diffuses through the membrane and is combusted with air in a turbine on the permeate side. After the water has been condensed out of the retentate the CO$_2$ is compressed and transported away. The electrolyte of the SOFC fuel cell also has the function of separating the O$_2$ from the N$_2$. Air is fed to the cathode under pressure. The oxygen ions diffuse from the cathode side of the electrolyte to the anode side, where they react with the fuel (H$_2$, CO, CH$_4$).

The residual anode off-gas is made up only of CO$_2$ and uncombusted fuel gas. In order to use the energy of the anode off-gas the gas must be passed to an afterburner. This concept is being investigated at ECN in the Netherlands and is illustrated in Fig. 5-10 (Dijkstra 2002). The calculated electrical efficiency of combined cycle power stations with SOFC and CO$_2$ capture is about 60 %. However, high-temperature fuel cells for power stations will probably not be available before 2030.

Fig. 5-10:
CO$_2$ capture in an SOFC fuel cell with WGSMR afterburner

The ZECA process combines high-temperature fuel cell technology with hydrating coal gasification and a calcium oxide/calcium carbonate cycle. In this process (Fig. 5-11) the coal is converted into CH$_4$ through hydrating pressure gasification with H$_2$. In the next step steam in the presence of CaO converts CH$_4$ into H$_2$ and CaCO$_3$. Half the hydrogen is fed to the hydrogasification process, while the other half is used to generate electricity in an SOFC. The waste heat from the SOFC is used to regenerate the CaO (through thermal decomposition of CaCO$_3$ into CaO and CO$_2$). Pure CO$_2$ leaves the reactor at 1 bar.

The key component of the process is the SOFC, which operates at a pressure of 30 bar. Fuel cells of this type with the output required for power stations will probably be available in 25–30 years (Lackner 2001). There are also still many unresolved issues, such as how to connect up systems operating at different pressure levels (gasifier 60 bar, calciner 1 bar, SOFC 30 bar). Problems are also still raised by incomplete substance con-

version and stability of the sorbents, etc. The electrical efficiency of the system is estimated at 70 %, but if today's technologies are used, this concept achieves an efficiency of 'only' 39 %. Research on this process is primarily being conducted by the ZECA Corporation in North America (formerly the Zero Emission Coal Alliance), a collaboration of power companies, the coal industry and research institutes.

The AZEP concept

The AZEP process (**A**dvanced **Z**ero **E**mission **P**ower Plant) developed as part of an EU project in its 5th Research Framework Programme is based on a power station concept with gas turbine, combustion in oxygen and CO$_2$ retention (Fig. 5-12). The key element in this concept is a reactor with an integrated ceramic high-temperature oxygen membrane. Unlike the oxyfuel process, where oxygen is produced in a separate air separation facility, in the AZEP concept oxygen sepa-

Fig. 5-13: Chemical looping combustion: basic processes (left) and material flows (right)

ration occurs directly in the combustion chamber. The fuel (natural gas) is burnt in oxygen, and the waste gases largely comprise CO_2 and water and are fed into a conventional steam process. Then the water is condensed out and separated from the CO_2. Calculations show that in the AZEP concept the efficiency loss in the power station is only 2–5 % compared to approx. 10 % for conventional CO_2 capture. After the water has been condensed out, the waste gases are made up of concentrated CO_2, so there is no need for complex, expensive separation processes.

Chemical Looping Combustion process (CLC)

In this process a metal oxide is used to oxidise the fuel rather than oxygen. This avoids direct contact between the fuel and the air supplied for combustion. The waste gases produced by combustion are composed largely of CO_2 and water, which means that it is easy to separate the CO_2 by condensing out the water – in the same way as in the oxyfuel process. Fig. 5-13 shows the flow chart (Lyngfelt 2001). Gaseous materials are suitable as fuel; solids such as coal would have to be gasified first. The system principally comprises two reactors. In the first the carrier metal (e.g. Fe, Cu, Ni, Co, etc.) is oxidised in air. The oxide then passes to the second reactor where it reacts with the gaseous fuel (e.g. natural gas, H_2, synthesis gas, etc.) to form CO_2 and water.

The crucial issue in the CLC process is to develop an oxygen carrier that can withstand repeated chemical oxidation/reduction cycles and is resistant to physical and chemical degradation. Generally a metal oxide is used as the oxygen carrier.
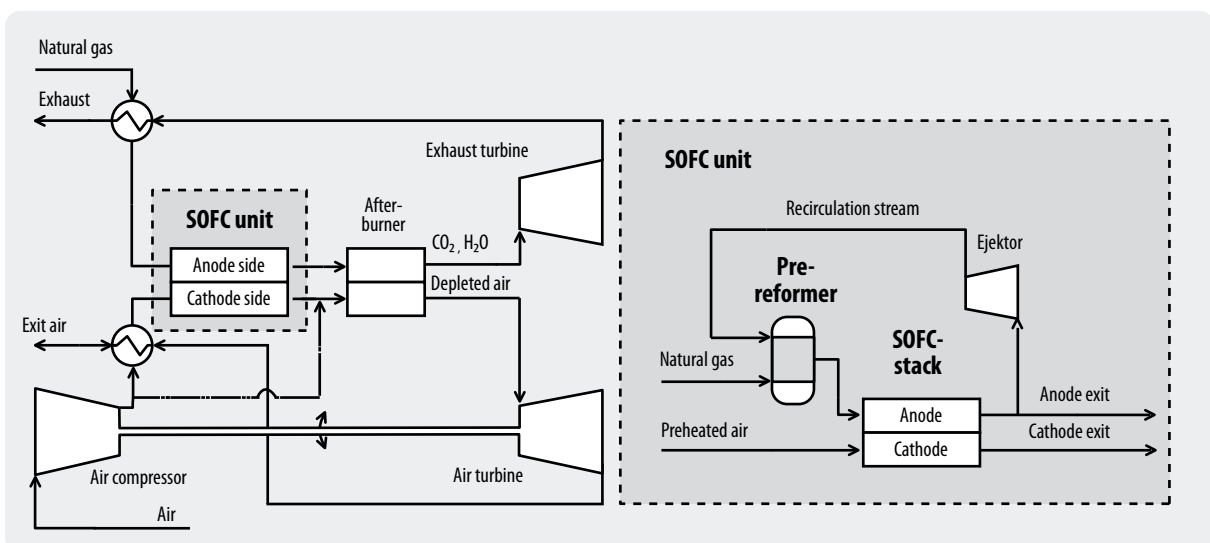
Fig. 5-14: CO_2 capture in an SOFC fuel cell with gas turbine and afterburner (Source: Maurstad et al. 2005)

At Chalmers University in Gothenburg an experimental 10 kW plant using nickel was operated for 100 hours in 2004 (Greenhouse Issues 2004).

New high-efficiency power station concepts

One highly efficient concept for generating electricity from natural gas is the combination of a high-temperature fuel cell with a gas turbine (see Fig. 5-14, Maurstad et al. 2005). Operating with integrated CO$_2$ capture this system can theoretically achieve efficiencies of up to 65 % on the basis of the following principles:

With SOFCs the theoretically achievable efficiency is not restricted by the Carnot process, as is the case for example with pure gas turbine and steam turbine processes.

Endothermic reforming (in the high-temperature fuel cell or a pre-reformer) converts thermal energy (waste heat) into chemical energy (fuel).

5.1.3 Possibilities and Limits of Retrofitting CO$_2$ Capture at Power Stations

In the next twenty years many fossil fuel-fired power stations in Germany (and in many other countries in Europe and overseas) will come up for replacement. Given the long service life of a power station (approx. forty years) and the necessity of achieving a long-term reduction in CO$_2$ emissions from electricity generation, today's investment decisions should take into account the possibility of later retrofitting with CO$_2$ capture technology. Power stations where the possibility of later retrofitting is taken into account at the planning and construction stages are designated 'capture ready'.

For upcoming generating capacity replacement programmes economic considerations dictate that only modern conventional power station types in the upper output class with blocks of up to 1,000 MW$_{el}$ and load factors of 25–100 % come into question (Fischedick et al. 2006). Additionally, rising fuel prices are causing R&D efforts to focus on maximising efficiency, which in itself brings about a reduction in specific CO$_2$ emissions (gCO$_2$/kWh$_{el}$).

There are two possibilities for retrofitting CO$_2$ capture in existing power stations. One is post-combustion CO$_2$ capture from the flue gas, e.g. by MEA scrubbing; the other involves converting the combustion process to pure oxygen (oxyfuel). Both involve considerable modifications to the power station infrastructure. In the case of MEA scrubbing this means first and foremost the provision of substantial additional space for the flue gas scrubbers and the column for regenerating the scrubbing fluid, as well as the associated storage facilities. In the case of retrofitting as an oxyfuel power station, an air separation facility is required for the necessary oxygen supply, and a conversion of this type involves major rebuilding work in the furnace, for example to allow the recirculation of CO$_2$ from the flue

gas, in order to control the temperature of combustion. There are also simpler forms of retrofitting (in the form of pre-combustion technology) if the route of gasification technology is chosen from the outset. Here the initial costs are greater than for conventional power station technology, but the additional cost of retrofitting is less.

Even where the technical and local conditions allow retrofitting at all, retrofitted CO$_2$ capture will always cause a loss in efficiency, which will have to be made up in extra fuel if the electrical output is to remain constant. The consequential increase in electricity generation costs means that CO$_2$ capture is not economical under today's conditions. However, if the overall conditions were to change (e.g. through the introduction of CO$_2$ certificate trading) retrofitting CO$_2$ capture could become an economic proposition within a few years, and it is this that explains the fundamental interest in the retrofitting option. This has already led certain companies to think about ways they can build plant so that it is 'capture ready', in other words to take suitable measures to prepare plant for later retrofitting.

Sekar et al. (2005) examine future regulatory frameworks for CO$_2$ and current investment in the electricity generating sector. In North America they identify two main technologies that are being considered today for new coal-fired power stations: PC (pulverised coal) technology and IGCC (integrated coal gasification combined cycle). They investigate the effects of future costs of CO$_2$ regimes, of retrofitting CO$_2$ capture and of a possible emissions levy. Using the key data (e.g. CO$_2$ tax) they compare the economic viability of the two concepts and determine the point at which it becomes worthwhile, for example, to retrofit CO$_2$ capture.

In the following we examine some of the preconditions for retrofitting existing power stations. Process integration is particularly important in order to minimise the efficiency losses that several studies predict for post-combustion CO$_2$ capture (in the range > 10 %). Gibbins et al. (2004) propose six rules for retrofitting, and explain them using examples. The aim of their work was to maximise the effectiveness of post-combustion solutions and to identify potential for improvement over and above earlier studies that previously failed to take into consideration optimised process integration.

- One of the most important preconditions for retrofitting CO$_2$ capture at the power station is the considerable additional space requirement, which can act as a limiting factor (initial estimates put the additional space requirement at about 50 to 100 %).

- If power stations are retrofitted with CO$_2$ capture they should demonstrate a good level of efficiency or else the power generation process itself must be modernised. It makes no economic sense to retrofit flue gas CO$_2$ capture in a power station that is operating at an efficiency of 30 %.

● With CO_2 capture from flue gas, the expense in terms of equipment and energy increases disproportionately as the CO_2 concentration in the flue gas diminishes. This means that partial CO_2 capture may be the most economic solution.

5.2 Concepts for Moving towards Large-Scale Production of H$_2$

Large-scale generation of hydrogen from fossil fuels can be accomplished by reforming natural gas, partial oxidation of hydrocarbons and gasification of coal. Hydrogen can also be produced as a secondary product via electrolysis of water (e.g. as a by-product of chlorine production). Electrolysis of water can function without using primary fuels and is regarded as a long-term pillar of a renewable hydrogen economy.

5.2.1 Large-scale H$_2$ Production Today (Steam Reforming of Natural Gas)

One of the largest producers of hydrogen is the German firm of Linde, which also manufactures H_2 synthesis plant in capacities up to 100,000 $m_N{}^3$/h (approx. 300 MW). In the Leuna/Bitterfeld region major customers are supplied via a pipeline network, and the gas is distributed in bottled form through eight hundred dealers across Germany.

In the first step of the steam reforming process natural gas and steam are heated to high temperatures in a reactor to generate hydrogen, carbon monoxide and carbon dioxide. In the second step steam is used to convert the carbon monoxide to carbon dioxide and water (CO shift stage). Finally, the hydrogen is separated from the residual gas using pressure swing adsorption (PSA). As well as CO_2, the residual gas also contains up to 60 % combustible elements and is used to heat the reformer.

5.2.2 Possibilities for CO$_2$ Capture and Expense Involved (in H$_2$ Generation)

In large-scale H_2 production CO_2 can be captured using MEA scrubbing, as outlined in Fig. 5-15 (Vagnetti 2005). In the outlined arrangement the CO_2

cannot be captured completely because the residual gas and part of the natural gas are used to heat the reformer, and the waste gas produced there also contains CO_2. Vagetti (2005) assumed a CO_2 capture rate of 71 %. The effort of CO_2 capture is comparable with that of amine-based post-combustion systems for capturing CO_2 from the flue gases of coal-fired power stations. In order to generate base data for life cycle assessments the above process was modelled using IPSE-Pro process simulation software. Here a CO_2 capture rate of 51 % was found, which is lower than that found by Vagnetti (2005).

5.2.3 Hydrogen Production by Gasification of Solids

Currently approx. 83 % of total hydrogen production originates from natural gas reforming and approx. 14 % from naphtha reforming in oil refinery processes. Only approx. 3 % is produced through the gasification of heavy hydrocarbon residues (see simplified process flow chart in Fig. 5-16). The process is also fundamentally suited for producing H_2 from coal. A pumpable slurry of hydrocarbon residues or coal is gasified with oxygen and steam. Alongside H_2 and other components (CO_2, H_2S, COS) the raw gas also contains up to approx. 50 % CO, which has to be converted using steam to H_2 and CO_2 in a shift stage. The main steps of the process are:

● Air separation and oxygen compression
● Entrained-flow gasification (multi-purpose gasification, MPG) quench configuration
● Raw gas for CO conversion
● Desulphurisation
● H_2 separation (not illustrated in Fig. 5-16)

The gasification part and the gas conditioning stages of the described process for generating H_2 from coal are largely the same as those in an IGCC power station with CO_2 capture before combustion in a gas turbine. H_2 separation is not shown in the simplified process flow chart. Depending on the quality requirements for the generated hydrogen, the following possibilities are available for separating the H_2:

● For a high degree of purity of H_2 separation by pressure swing adsorption (PSA) is an option. The remainder is a mixture of CO_2, residual H_2, CO and residual gases.
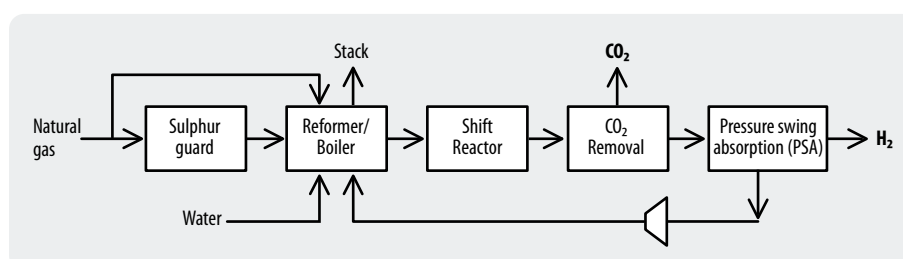
Fig. 5-15:
Hydrogen production from natural gas by steam reforming and CO$_2$ capture (MEA scrubbing)

Fig. 5-16:
Simplified process flow chart for gasification of carbonaceous slurries for H$_2$ production (Ullmann 2002)
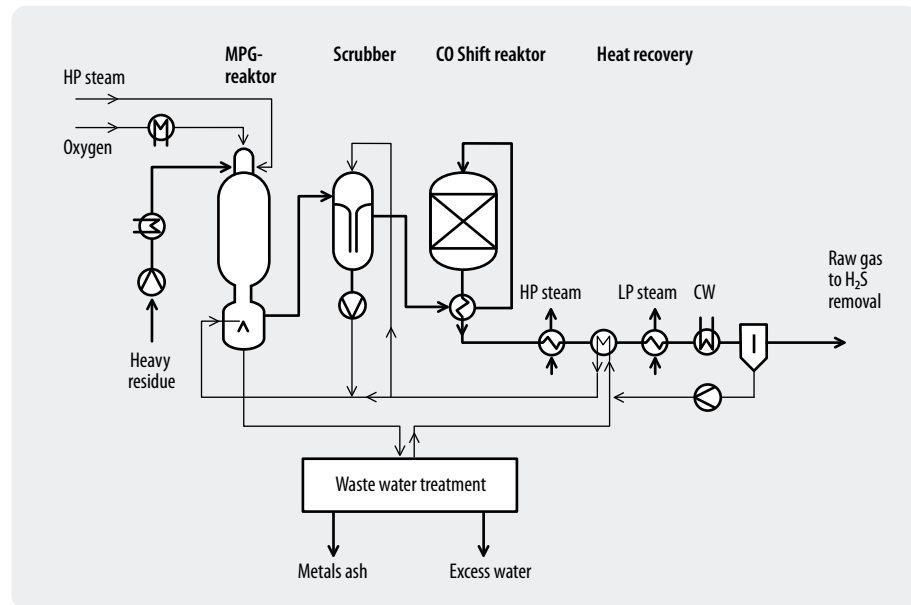
- CO$_2$ can be captured from the product gas in the same way as in the IGCC power station concept (physical scrubbing, e.g. Rectisol). The remaining gas consists largely of hydrogen (but not in the highly pure form), which in an IGCC power station would be burnt in a special H$_2$ gas turbine.

5.2.4 CO$_2$-free Concepts for Generating H$_2$

Since the early 1980s Kværner Engineering S.A. of Norway has been working on a process for CO$_2$-free generation of hydrogen that bears the company's name (Kværner Carbon Black and Hydrogen Process). In this process hydrocarbons (natural gas, crude oil) are separated into activated carbon (pure carbon) and hydrogen in a plasma torch at approx. 1600°C. A pilot plant that has been operating in Canada since 1992 uses 1,000 m$_N^3$/h natural gas and 2,100 kW$_{el}$ electrical energy to generate 1,000 kW hot steam, about 500 kg/h activated carbon and 2,000 m$_N^3$/h of hydrogen. Taking into consideration all the useable products, the plant achieves an efficiency of 93 %. Approx. 50 % of this is represented by the hydrogen, about 40 % by the activated carbon and 10 % by the hot steam.

5.3 Learning Curves and Possible Cost Degressions

Estimates of possible cost degressions for economic goods often use the Boston model, according to which doubling the volume can be expected to result in cost degressions in the range of 10–30 %. In principle this model can also be applied to estimate the costs of future technologies for reducing CO$_2$ in the electricity generation sector, as described in detail by Riahi et al. (2006) and applied to estimate the future costs of power station concepts with CCS. Here, the basis of an expected cost reduction is a continuous improvement in the tech-

nology with each new generation manufactured, gains in experience to apply technologies more efficiently and rationalisation gains in manufacturing of greater volumes. These effects produce learning curves that describe changing plant costs as a function of cumulative installed capacity. When we consider different scenarios these learning curves allow us to take account of a dynamic cost reduction resulting from an assumed implementation of the technology under consideration.

In order to predict possible future trends concerning power station costs with CO$_2$ capture Rubin et al. (2006) examined the historical cost development of power station components such as flue gas desulphurisation and de-nitrification as well as classical power station components. The learning rates they found for power station engineering components are listed in Table 5-2.

It is interesting to note here that the learning rates achieved for desulphurisation correspond to other power station engineering learning rates, but were only achieved because legal measures forced the installation of the volume of capacity required to cause cost reductions (Riahi et al. 2004). This fact somewhat relativises the applicability to other fields. Another interesting point regarding learning rates for CCS technology is found in an uncertainty analysis prepared by Gielen (2003), who concludes that when comparing scenarios learning effects play only a subsidiary role compared to other uncertainties.

For the CCS-specific components we can draw on comparable learning rates from the field of flue gas cleaning. But for investment costs for conventional power station technology learning curves can be regarded as relatively small (e.g. pulverised-coal-firing). On the one hand, we are dealing here with highly developed technologies and manufacturing processes, on the other the demand for continuing increases in efficiency often also results in increasing manufacturing costs and the

Table 5-2: Learning rates for capital and running costs for power station technologies, after Rubin et al. (2006)

Technology	Learning rate*	
	Capital costs	**Running costs**
Flue gas desulphurisation	0.11	0.22
SCR denitrification (selective catalytic reduction)	0.12	0.13
Combined cycle)	0.10	0.06
Coal dust firing	0.05	0.07–0.30
LNG production (liquefied natural gas)	0.14	0.12
Qxygen production	0.10	0.05
Hydrogen production (SMR, steam methane reforming)	0.27	0.27

* Proportional reduction in costs caused by a doubling of capacity

use of expensive materials. Increasing efficiency with unchanged investment costs can also reduce the costs of electricity generation.

The learning effects discussed here for CCS components and conventional power station components were used when determining the electricity generation costs of CCS power stations and are explained in detail in chapter 12. Taking as the base line reference technologies defined as 'commercially viable' by 2020, we define there a technology status of 'perfected CCS power stations' for 2040 that will have realised efficiency gains and improved CO_2 capture rates and therefore reduced specific investment costs.

5.4 Relevant Applications for Energy Systems, Case Study Germany

Our examination of the question of capture and storage of carbon dioxide has been restricted (apart from the examination of hydrogen production) to the field of electricity generation in power stations, because there large quantities of CO_2 are emitted centrally. The highest specific CO_2 emissions per generated kWh_{el} are found with coal-fired power stations (especially lignite), which should not, however, be taken to mean that there is no case for CO_2 capture in gas-fired power stations.

In Germany, for example, about half of net electricity output is currently based on coal. The scenarios for future energy supply assume various degrees of reduction in coal's share in Germany's electricity generating capacity. Despite this reduction it is forecast that Ger-

many will need to replace approx. 40 GW_{el} of installed power station capacity by 2030 (Fischedick et al. 2006), which partially – or depending on changed overall conditions (cf. Prognos and EWI 2006) possibly largely – will have to be covered by coal-fired power stations. Worldwide it is expected that large numbers of coal-fired power stations will be built (mainly in China and India). Even if CCS technology is not applied in replacement German power stations in the next two decades, the technology is relevant for Germany because leading manufacturers and exporters of power station technology are based here.

With regard to reducing CO_2 when using fossil fuels, the main interest is on technologies that increase efficiency. In recent decades – due to more stringent environmental regulations (which in some cases have led to increased fuel consumption) – it has been possible to achieve a continuous increase in power station efficiency. For reasons of thermodynamics and material technology this trend cannot continue for ever. So a further significant reduction in CO_2 from electricity generation using fossil fuels requires the application of CO_2 capture methods that currently cause efficiency losses or new power station concepts. While CO_2 capture technologies will be available in the medium term, the development of new power station concepts should be regarded rather as a long-term matter.

From today's perspective we cannot say which of the CO_2 capture processes that will in principle become available in the short to medium term will have the best chances of implementation. From the technological point of view, all three options could become relevant in the future. Flue gas scrubbing will probably be an adequate option for retrofitting, especially if it turns out to be possible to reduce the energy required still further through new scrubbing agents. IGCC technology is not yet ready for implementation in the electricity generating process, but there is significant room for improvement. For the oxyfuel process it will depend on whether the demonstration projects that have recently been initiated manage to collect worthwhile experience and successfully put the lessons learned into practice.

Whether CO_2 capture technologies become relevant for power station replacement will depend on political and economic circumstances. Without corresponding incentives retrofitting existing power stations with CO_2 capture will not be relevant. In order to be prepared for future developments it might make sense to build new power stations 'capture ready' (prepared for retrofitting with CO_2 capture).

With regard to choice of location, above all the space required for the additional components will be a decisive variable. But connection to suitable storage structures could also represent a significant factor (cf. chapter 8). Good chances for the introduction of CCS technologies exist for power station locations in connection with a specific demand for CO_2, for example for enhanced oil/gas recovery (EOR/EGR).

Chapter 6

CO$_2$ Transport

This chapter takes a closer look at the technical and thermodynamic characteristics of CO$_2$ which are relevant for transport and estimating the energy required to transport CO$_2$ in different physical states and by different means (section 6.1). It then goes on to examine the various transport options available for CO$_2$ and their specific advantages and disadvantages (section 6.2). Finally, in section 6.3, we compare specific transport costs for various transport options cited in a number of scientific studies.

6.1 Physical State for Transport and Energy Required for Compression and Transport

When CO$_2$ is transported by road, rail or water it is usually under high pressure in a liquid or supercritical state (exception: dry ice). For pipeline transport the CO$_2$ is brought to a supercritical pressure higher than 74 bar at a density of approx. 1,100 kg/m^3.[1] The advantage of the supercritical state over the liquid state is that stability is greater and problems with cavitation in pumps, com-

pressors, etc. are not to be expected.[2] Gaseous transport is less attractive, because the density – and consequentially the possible throughput – is very much lower.

Transport of solid CO$_2$ (dry ice) is only relevant for dry ice applications and plays no role for CO$_2$ storage, because the production of dry ice is extremely energy-intensive. VGB (2002) cites a direct specific energy requirement of approx. 375 kWh/t$_{CO_2}$ for producing dry ice and transporting it two hundred miles, while the same source cites 106 kWh/t$_{CO_2}$ for transporting liquid CO$_2$ one hundred kilometres by pipeline (of which 93 kWh/t$_{CO_2}$ is required simply for liquefaction) and 26 kWh/t$_{CO_2}$ for transport in the gaseous state. In his detailed early CCS study Göttlicher (1999) cites specific energy requirements of 111–113 kWh/t for compressing CO$_2$ to a pressure of 110 bar (corresponding to an energy requirement of approx. 3.5 % in relation to coal fuel H$_l$), 160 kWh/t for cryogenic liquefaction (5.2 %) and 260–420 kWh/t for dry ice production (8.4–13.5 %).

Fig. 6-1 shows the direct and indirect energy requirements per tonne of CO$_2$ for dry ice production and
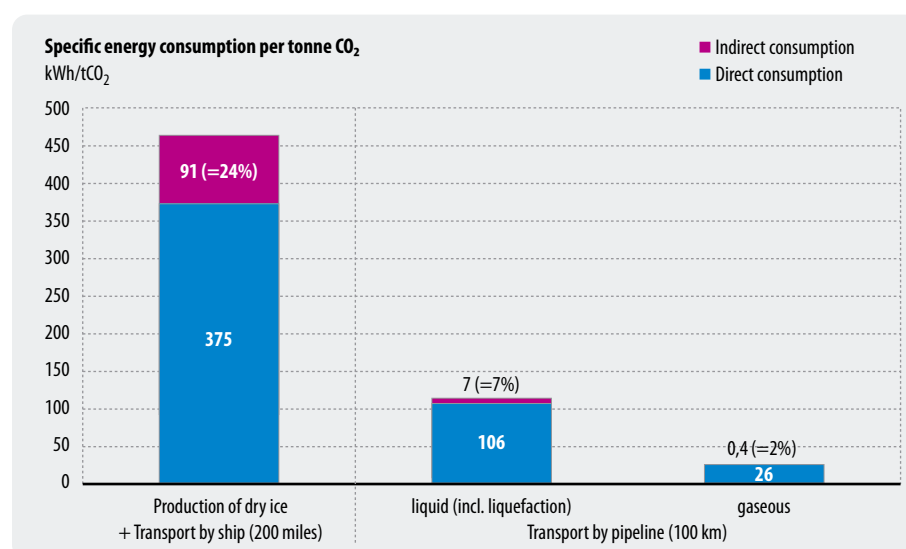
Specific energy consumption per tonne CO$_2$
kWh/tCO$_2$

■ Indirect consumption
■ Direct consumption

Production of dry ice + Transport by ship (200 miles): 375, 91 (=24%)

liquid (incl. liquefaction): 106, 7 (=7%)

gaseous: 26, 0,4 (=2%)

Transport by pipeline (100 km)

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1 In thermodynamics, the term 'supercritical' is used to describe a very dense state above the 'critical point', where a clear distinction between the liquid and gaseous states is no longer possible.

2 'Cavitation' is the formation of gas bubbles in a liquid caused by local negative pressure. The pressure surges caused by sudden vapourisation and subsequent implosion of gas bubbles can be very harmful to surrounding materials and equipment.

for pipeline transport in the form of a bar chart, the indirect energy requirements here being understood as the energy required for preceding and subsequent process steps (data for *direct* consumption from VGB 2002). The chart clearly shows how dry ice production (including two hundred miles of sea transport) involves additional indirect energy consumption amounting to about a quarter of the direct energy requirement, and corresponding additional CO_2 emissions.[3] For pipeline transport the indirect energy consumption and emissions are much lower, at about 7 % (liquid) and 2 % (gaseous). The lower energy requirement for gaseous transport is relativised, however, because the CO_2 will probably have to be compressed for subsequent storage.

Ship transport involves higher specific CO_2 emissions than offshore pipelines because of the additional energy required by the liquefaction plant and the fuel required by the tankers. The IEA estimates the additional emissions for ship transport to be at least 2.5 % (for a distance of 200 km) up to a maximum of 18 % (for a distance of 12,000 km). By comparison the specific emissions for pipelines (according to IEA 2004) are only approx. 1 to 2 % per 1,000 km. The authors of the IPCC study (2005) state specific additional emissions of 3 to 4 % per 1,000 km for ship transport through cargo vaporisation losses and CO_2 emissions from the ship's engines, which they believe could be reduced to 1 to 2 % per 1,000 km by collecting and reliquefying the vaporised CO_2. However, they do not give figures for the energy required for cooling and (re)liquefaction.

For transport, CO_2 is generally first compressed to 8 to 12 MPa for transport on land and up to 20 MPa for offshore transport (and thus liquefied). Of the studies under consideration here, only the ECOFYS study (2004) itemises the costs for in detail. As an example, the ECOFYS study calculated the costs for the following plant:

- Output of CO_2: 50 kg/s

- Full load hours: 7,500 hours/year

- Annuity: 13 % (discount rate 10 % over an operating period of fifteen years)

- Electricity price: 0.04 EUR/kWh$_{el}$

The following pie chart (Fig. 6-2) shows that the electricity consumption alone represents more than half of the cost of compression, followed by depreciation and running costs.

Breakdown of compression costs

Running costs 12%
Electricity 57%
Depreciation 31%
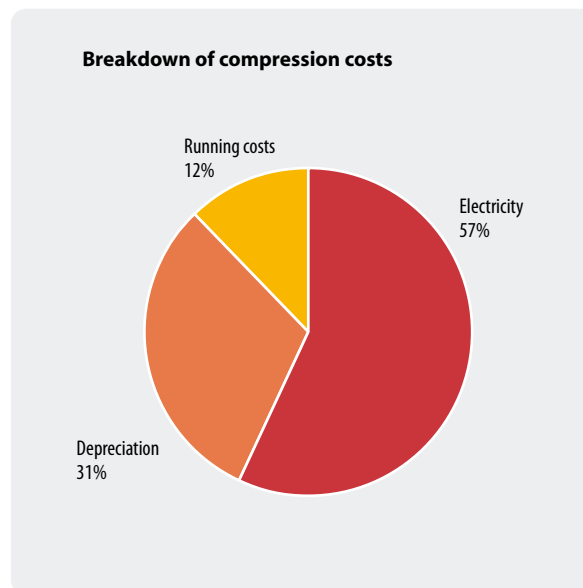
Fig. 6-2: Breakdown of compression costs (ECOFYS 2004)

Fig. 6-3 shows the cost curves in relation to throughput (kg/s) for different levels of annual utilisation (100 % = 8,760 hours). Clearly, the cost of compression depends strongly on the flow rate, which means that on the cost side there is a strong incentive to centralise CO_2 compression – which is more or less automatically the case where CO_2 is captured at the power station.

Gerling (2004), citing figures from the GESTCO Summary Report (2003), gives a range of EUR 3.5 to EUR 26.1/t of captured CO_2 for the cost of compression (with a mean of EUR 8.4/t CO_2).

According to ECOFYS the costs of compression amount to between EUR 6 and EUR 10/t of captured CO_2, assuming the compressor output is greater than 100 kg/s. These figures concur with the findings of the GESTCO project. The electricity required for compression reduces the efficiency of the overall process by a further 2 to 2.7 percentage points for gas-fired power stations and 3 to 4 percentage points for coal-fired ones (Göttlicher 2003a).

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3 Assumed CO_2 emissions factor: 0.65 kg/kWh (electricity, current energy mix).

Compression costs (EUR/t CO_2)
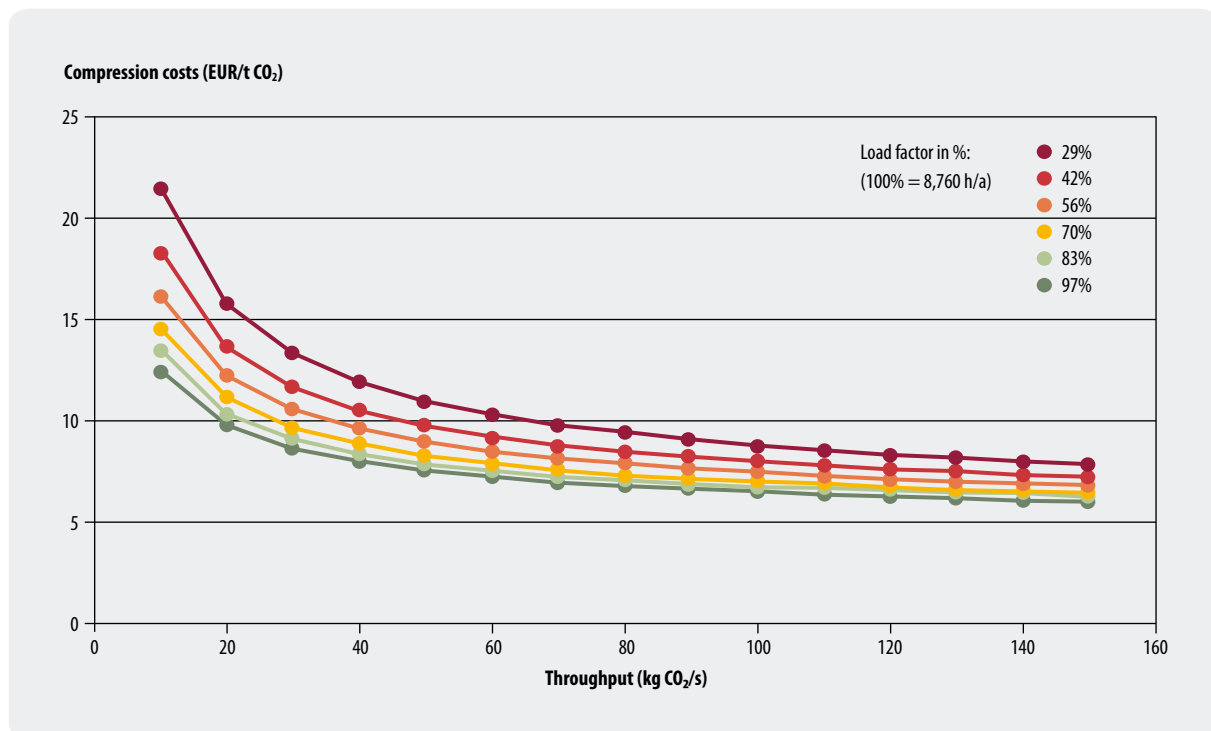
Fig. 6-3: Compression costs as a function of compressor throughput and load factor (ECOFYS 2004)

6.2 Transport Options

The following three parameters are crucial when selecting a suitable means of transport for CO_2:

- Transport capacity,
- Distance (from source to sink),
- Sink location (onshore/offshore).

The most important means of transport for handling large quantities of gases in general – and CO_2 in particular – is the pipeline. Of all the non-pipeline transport options, the ship is the only one that could sensibly be used. Other CO_2 transport options (road tanker, pressurised cylinders, dry ice) are only relevant on a small scale (e.g. for breweries and the food industry in volumes of a few 100,000 t/a) or for the introduction phase of a CCS infrastructure. In the following sections we examine the individual transport options in greater detail before moving on – in section 6.3 – to estimate the respective costs involved.

6.2.1 Pipeline Transport

Onshore
On land pipelines represent the only sensible alternative for bulk transport. Inland waterways, rail and road transport are conceivable as alternatives only for a transitional period (while a CO_2 pipeline infrastructure is being built).

Offshore:
Offshore pipelines are well suited for handling high-volume capacities at low cost, but first the infrastructure must be constructed, which is time-consuming and expensive. Ships, on the other hand, can be used more flexibly and are available more quickly, but they require temporary storage facilities and loading/unloading infrastructure.

Considerable experience has already been gathered in gas pipeline construction and operation both for onshore pipelines (generally laid at depths of at least one metre) and offshore (down to a depth of 2,200 m).

For onshore pipeline transport over greater distances or in hilly terrain compressor stations may be required along the pipeline. If the initial pressure is sufficient and/or transport speed is slow (with large pipe diameter) the resulting smaller pressure losses may make it possible to do without expensive intermediate compressor stations.[4] The usual transport speed is approx. 1 to 5 m/s, the usual operating parameters are one hundred to several hundred bar pressure and a maximum temperature of 50°C.

So pipeline design is a matter of optimising the most important parameters: diameter, wall thickness and pressure loss. The quality (purity) of the CO_2 being transported also requires adequate material selection

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4   For example the 328-kilometre Weyburn Pipeline in the United States operates without intermediate compressor stations.

and corrosion protection. For example, for dry CO_2 with an H_2O proportion under 50 ppm simple carbon steel is sufficient.[5]

The main parameters relevant for pipeline design are listed below:

Design parameters

- Pressure, temperature,
- Diameter, length, wall thickness,
- Impurities / purity of CO_2 ® corrosion protection requirements,
- Number of compressors and measuring stations
- Terrain and infrastructure: topography, composition of ground, settlements, obstacles (water bodies, roads, pipelines …), nature reserves,
- Vegetation, geothermal and seismic activity,
- Offshore: restrictions through fishing activities (nets), currents, shipping (anchors).

Safety aspects for CO_2 pipelines

Because CO_2 is not combustible there is no risk of explosion – unlike natural gas, for example, which is already transported in large quantities by pipeline. Nonetheless, certain safety precautions must still be taken, because CO_2 leads to death by asphyxiation in high concentrations (> 40,000 ppm) – and it is colourless and odourless.[6] Additionally, CO_2 is heavier than air, which means that it would collect at high concentrations in depressions. It may also be necessary to take account of the effects of unwanted impurities. For example, NIOSH puts the toxicity threshold for H_2S at 100 ppm.[7]

EOR statistics indicate a smaller leakage risk than for pipelines carrying natural gas or hazardous substances, but safety considerations still dictate that pipelines should be routed away from densely populated areas wherever possible. In populated areas safety measures against leakage and overpressure are required, the latter because if the temperature increases suddenly above the allowable level the CO_2 gas may move from the liquid/supercritical state to the gaseous state, which can cause a sudden and very large increase in pressure.

Pipeline monitoring can be external (outside the pipeline) or internal. Onshore pipelines can be monitored externally on foot or from vehicles, or from the air, while at sea special ships or remotely operated submersibles can be used. Fixed monitoring devices and 'pipeline pigs' (cylindrical automatic cleaning and inspection devices propelled through a pipeline by pressure) are possible methods of internal monitoring.

Offshore pipelines are especially vulnerable to damage by ships' anchors and fishing nets. The potential ecological impacts of a marine pipeline leak have not yet been investigated.

The inherent risk of military and/or terrorist attack on pipeline infrastructures is held to be relevant enough to have already made it the subject of various conferences.

Risk studies for onshore *natural gas* pipelines found a statistical accident frequency of less than 0.02 accidents per 100 kilometres per year for Western Europe in 2002. Larger pipelines (> 500 mm) present an even smaller risk (< 0.005/100 km/year). An analysis of accidents in the United States between 1986 and 2002 (Guijit 2004) found a statistical risk of 0.011 accidents/100 km/year. When comparing figures it must be remembered that the thresholds and definitions for 'accidents' in the different studies are not necessarily identical. Gale (2002) reports ten accidents between 1990 and 2002 in the onshore CO_2 pipelines that already exist in the United States, which corresponds to an accident rate of 0.032 accidents/100 km/year.[8] Damage amounting to US $470,000 was recorded, but no deaths or injuries. Because CO_2 pipelines have to date overwhelmingly been laid in thinly populated regions, it can be expected that the risks associated with accidents will increase when future infrastructure is built in densely populated areas too.

Experience with CO_2 pipeline transport

There is much experience with on- and offshore pipeline transport of large quantities of gas, oil, condensate and water over distances up to more than 1,000 km, with pipelines crossing deserts, mountains, densely populated regions, the Arctic, and oceans (in oceans with pipeline diameter up to 1,400 mm and at depths down to 2,200 m). Worldwide there are seven large onshore high-pressure CO_2 pipelines in three countries (five in the United States, most of them in the Permian Basin, one from the United States to Canada and one in Turkey) with a total transport capacity of approx. 50 Mt/a and a total length of approx. 2,600 km. The oldest is the Canyon Reef Carriers Pipeline, which the American firm Kinder Morgan has been operating since 1972. It supplies 5.2 Mt CO_2 annually from a coal gasification plant to consumers 225 km away. The largest facility, which opened in 1984, is also in the United States, supplying CO_2 from a natural source in the McElmo Dome through an 808-km pipeline with an annual capacity of 19.3 Mt. Oil producers who use carbon dioxide to boost production (EOR) pay about US $9–18/tonne for CO_2 supplied to the injection wells. All the main pipelines are made of ordinary carbon steel.

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5   Example for a specification: CO_2 > 95 %$_{Mol}$, no free H_2O, H_2O_{vapour} < 50 ppm, H_2S < 1,500 ppm.

6   For this reason there are proposals to odourise the CO_2 gas to make it detectable, as is already done with household natural gas supplies.

7   NIOSH: National Institute for Occupational Safety and Health, USA.

8   For a 500-km pipeline this would correspond to one accident approx. every six years.

There has not yet been any experience with offshore CO$_2$ pipeline operation, but it is held to be feasible in principle (see also the CENS infrastructure project).[9] The expense involved is roughly proportional to the product of water depth and pipeline diameter.

6.2.2 Transport by Ship

Gas transport by ship is more flexible and more quickly available than pipeline transport, but suffers the drawback that temporary storage and loading/unloading facilities are required. There is also the challenge of competition with other shipping traffic. Additional traffic is also associated with undesirable side effects (e.g. increased risk of collisions at sea, harmful emissions through combustion of heavy fuel oil).

As described above, only transport of CO$_2$ in the liquid state is relevant, for reasons of logistics and energy efficiency. We distinguish three different types of tank structure for this form of transport:

1. **Pressure tank**
   CO$_2$ compressed at high pressure at ambient temperature (for small-scale applications)

2. **Low-temperature tank**
   Refrigerated CO$_2$ at atmospheric pressure (for bulk transport, this type is already used for LPG and LNG)

3. **Hybrid tank, semi-refrigerated tank**
   CO$_2$ pressurised and cooled (adapted to different loading and unloading conditions)

The hybrid type is seen as the most economical version for future large-scale CO$_2$ transport. A design combining temperatures around –50°C and pressure of 6 to 8 bar would be close to the triple point of CO$_2$. A design study has been prepared for a capacity of approx. 20,000 m^3 ($\approx$ 22,000 t CO$_2$).

External heating would create carbon dioxide vapour in the tank and increase the pressure so the vapour would have either to be vented into the atmosphere (neither harmful nor dangerous, but worsens the CO$_2$ balance) or – like with LPG tankers – re-liquefied by recooling. The latter is an energy-intensive process and is therefore also associated with CO$_2$ emissions.

Approx. 1 to 2 years must be allowed simply for the construction of tankers.

Safety aspects of CO$_2$ tankers

A safety assessment of gas tankers by Lloyds Maritime Information Service for the period from 1978 to 2000 found the following (IPCC 2005):

LPG (number of tankers in 2000: 982):
20 serious accidents ➞ 0.00091 accidents/ship/year
LNG (number of tankers in 2000: 121):
one serious accident ➞ 0.00037 accidents/ship/year

Most accidents are inherent to the system or occur due to human error; safety regulations are often ignored. The types of accident include collision, running aground, sinking and fire. The only way to ensure that risk is minimised is to maintain high safety standards of equipment and navigation (including monitoring of the same) and adequate crew training.

The behaviour of CO$_2$ leaking from a ship's tank and spreading on the surface of the sea has not yet been investigated. The possible consequences include local ecological effects on marine organisms and – given high concentrations and unfavourable weather conditions – danger to the crew and engine failure through lack of oxygen.

The provisions of the following international conventions will apply to transboundary and marine transport of CO$_2$:

- UN Law of the Sea Convention,
- London Convention,
- ESPOO Convention (Convention on Environmental Impact Assessment in a Transboundary Context),
- OSPAR Convention (for the Protection of the Marine Environment of the North-East Atlantic),
- Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal.

National (and possibly also regional) rules and regulations will also have to be observed (see IEA 2003a). The legal applicability of the different treaties and conventions has not yet been finally clarified; one of the open questions is whether CO$_2$ is to be classified as waste.

Experience with ship transport of CO$_2$

There has so far been little experience with CO$_2$ transport by ship. In 2004 there were only four small tankers (of the hybrid type) in operation worldwide transporting food-quality CO$_2$ from CO$_2$ point sources in northern Europe (e.g. ammonia plants) to consumers. On the other hand, a great deal of experience has already been gathered with LPG (liquefied petroleum gas, principal components propane and butane) and LNG (liquefied natural gas), with tankers up to 145,000 m^3 capacity. LPG in particular has similar physical properties to liquefied CO$_2$, which means that comparable transport conditions prevail. Design studies for larger tankers

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9 CENS (CO$_2$ for EOR in the North Sea) is a joint project operated by the Danish electricity generator Elsam and the American CO$_2$ company Kinder Morgan and coordinated by the Norwegian company CO$_2$-Norway.

including the necessary peripherals (liquefaction plant, temporary storage facilities) are currently under preparation in Norway and Japan.

6.2.3 Transport by Rail and Road Tanker

As already mentioned at the beginning of this chapter, environmental and capacity considerations mean that neither rail transport, nor still less road tankers, will be in a position to make any appreciable contribution to handling very large quantities of CO_2. A limited use of these two means of transport might be relevant only for pilot and demonstration projects and possibly as a stop-gap while pipeline infrastructure is established.

In technical terms, CO_2 transport by road or rail would be accomplished in a cooled pressure tank at approx. 20 bar and -20°C (IPCC 2005). Other sources quote a pressure range of 12–17 bar and a temperature of -50 to -70°C (Air Liquide 2005). With a permissible gross weight of 40 t, an articulated lorry has a capacity of approx. 20 t CO_2, while a complete freight train carrying 1,300 to 3,000 t CO_2 can transport considerably greater quantities.

6.3 Transport Costs

The transport costs can be itemised into investment costs, running costs, and repair and maintenance costs (including spending on health and safety and environmental protection).

In the following we estimate the costs of transport in relation to distance, means of transport (pipeline or ship) and transport capacity. The data originates primarily from four sources (including studies quoted by them): VGB (2004), ECOFYS (2004), GESTCO (2004) and IPCC (2005).

Source 1: VGB (2004)

With costs of more than €25/t_{250} km for road transport and more than €5 €/$t_{250 km}$ for rail these two options are (very) expensive and therefore suitable only for small-
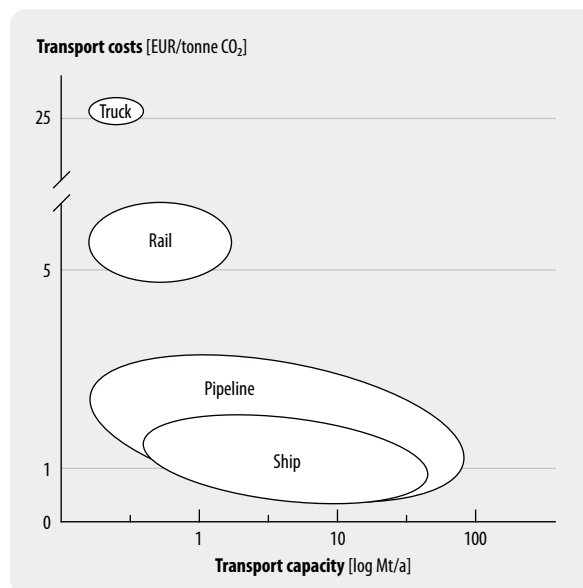
Fig. 6-4: Cost and capacity ranges for various CO_2 transport alternatives (250 km distance) (Odenberger and Svensson 2003, in VGB 2004)

scale transport requirements or for a possible CCS start-up phase.

Pipelines (€1–3/$t_{250 km}$) and **ships** (approx. €1/$t_{250 km}$) are considerably more economical and are suitable for high (and very high) volumes. However, it is first necessary – especially for pipelines – to construct an extremely cost-intensive infrastructure. Hilly terrain adds about 50 % to the cost of pipeline construction, while a supplement of 100 % must be allowed for crossing densely populated areas and nature reserves, and 40 to 70 % for laying offshore pipelines.

The figures listed above for non-pipeline transport options by road, rail or water (cf. Fig. 6-4) do not include the costs of the necessary **temporary storage.** Two main technologies come into question for storage:

1. *Underground storage*
   suitable for large quantities, cheap, already used for LPG but not yet for CO_2
2. *Steel tanks*
   suitable for small quantities, expensive, state of the art

Table 6-1: Costs of temporary storage facilities (steel tanks and rock shelters) after Odenberger and Svensson 2003, in VGB 2004

	Size (m³)	Investment cost (EUR)	Annual charge (EUR/y)	Throughput (t/y)	Specific costs (EUR/t CO_2)
Steel tanks	3,000	6,500,000	460,000	1,000,000	0.46
Rock shelter	120,000	17,000,000	1,200,000	20,000,000	0.06
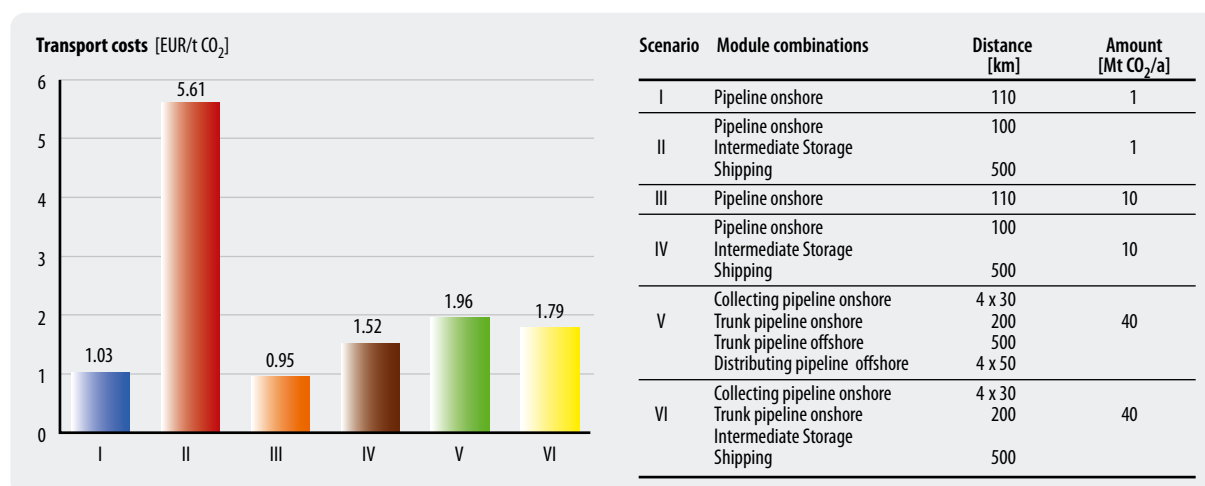
Fig. 6-5: Accumulated costs for transport scenarios I to VI (Odenberger and Svensson (2003) in VGB (2004).
Cost data *includes* transport, reloading and temporary storage, but *not* costs of necessary gas conditioning (pressure and temperature) in order to make CO$_2$ transportable/storable.

The estimated costs of temporary storage facilities are listed in Table 6-1.

Fig. 6-5 itemises six different **transport scenarios** that differ in terms of capacity (1 Mt/a, 10 Mt/a, 40 Mt/a), distance (30 km to 500 km), means of transport (pipeline, ship or combination of both) and pipeline type (collecting/trunk/distributing, onshore/offshore). The spectrum of costs is accordingly broad, ranging from 0.95 €/t (scenario 3 for 110 km and 10 Mt/a) to 5.61 €/t (scenario 2 for 600 km and 1 Mt/a).

The capacities selected in the scenarios are those associated with typical power station sizes. For example, in a CCS start-up phase a 200 MW$_{el}$ pilot plant with 1 Mt annual CO$_2$ emissions would be expected to have transport costs of approx. € 1/t (onshore permanent storage close to the power station location) up to €6/t (offshore sink). In a fully developed CCS infrastructure (several 1,000 MW$_{el}$ power stations with 40–300 Mt/a) transport costs could be expected to fall to approx. € 2/t (offshore).

The cost calculations are based on the following assumptions:

- Depreciation over 25 years,
- Interest rate 5 %,
- Costs of CO$_2$ liquefaction NOT included in calculation!
- Costs of CO$_2$ intermediate compressor stations along pipeline are included,
- Power station locations selected so as to minimise CO$_2$ transport distances,
- Mature technologies.

Source 2: ECOFYS (2004)

ECOFYS (2004) defined five 'cost windows' to allow the transport costs to be estimated for different scenarios (and distances), and found costs in relation to distance as shown in Table 6-2.

Taking these cost windows as the starting point, ECOFYS (2004) estimated the transport costs for various regions, distinguishing in each case between storage in aquifers, in onshore and offshore oil and gas fields and in coal seams. For Western Europe transport costs of €3/t CO$_2$ (aquifers, offshore oil and gas fields, coal seams) to €5/t CO$_2$ (onshore oil and gas fields) were found (ECOFYS 2004). The study stressed, however, that this represents only a very rough approximation.

In fact the figures appear to have been estimated very optimistically, because elsewhere in the same study costs of €1 to 6/t CO$_2$ are given for a distance of 100 km, depending on the capacity and flow rate (ECOFYS 2004).

Table 6-2: Transport costs for different 'cost windows', after ECOFYS (2004)

Distance Source-sink	Average distance (km)	Average cost (EUR/t CO$_2$)
Short	< 50	1
Medium	50–200	3
Long	200–500	5
Very long	500–2,000	10
Exceptionally long	> 2,000	30

Table 6-3: Costs for CO_2 capture, transport and storage in €/tonne after GESTCO (2004)

Country		Belgium	Denmark		Germany			Greece	
Project		Langerloo	Havnso	Tyra	Greifsw. B.I	Greifsw. B.II	Afeld-Elze	N. Karvali	Komotini
Plant typ		NGCC	Coal ST	Coal ST	Gas ST	Gas ST	Sugar	NH_3 plant	NGCC
Capture process		Post	Post	Post	Pre	Post	Post	CO_2 source	Post
Storage method		Coal seam	Aquifer	Oil-/Gas field	Aquifer	Aquifer	Aquifer	Aquifer	Aquifer
Costs (EUR/t)	Capture	82.1	21.5	25.3	33.2	26.6	75.5	0.6	76.3
	Compression	12.8	7.4	7.4	4.4	6.1	15.9	7.2	13.5
	Transport	3.5	1.4	14.8	1.1	1.1	1.1	3.4	13.0
	Storage	4.0	1.3	4.1	0.6	0.6	8.3	2.6	2.5
	Total	102.4	31.6	51.6	39.3	34.4	100.8	13.8	105.3

Country		United Kingdom		Netherlands				Norway		
Project		King's Lynn	Eggborough	Rijnmond I	Rijnmond II	Eemshaven I	Eemshaven II	Mongstad I	Mongstad II	Skogn
Plant typ		Coal ST	NGCC	H_2 prod.	NH_3 plant	NGCC	NGCC	Oil-Refinary	Oil-Refinary	NGCC
Capture process		Post	Post	CO_2 source	CO_2 source	Pre	Post	Post	Post	Pre
Storage method		Aquifer	Aquifer	Gas field	Gas field	Gas field	Gas field	Aquifer	Aquifer	Aquifer
Codsts (EUR/t)	Capture	38.4	35.1	0.7	0.6	32.5	32.2	27.5	27.5	38.7
	Compression	8.5	9.1	7.8	7.2	4.6	8.0	7.4	7.4	5.0
	Transport	6.5	4.4	9.7	11.6	1.7	3.0	6.7	2.6	7.4
	Storage	13.2	2.6	12.2	33.8	1.1	1.5	8.3	8.0	7.2
	Total	66.6	51.2	30.4	53.2	39.9	44.7	49.9	45.5	58.3

Source 3: GESTCO (2004)

The GESTCO project (2004) investigated seventeen case studies from seven European countries. In particular, estimates were made for the individual processes of CO_2 capture, compression, transport and storage. The analysis covered six different types of plant (NGCC, coal steam turbine (ST), H_2 production, natural gas ST, oil refinery, NH_3 production) for four different products (electricity 330–3,134 MW_{el}, oil 9,285 kt/a, NH_3 15.2–138 kt/a, H_2 17.6 kt/a) with three different capture processes (post-combustion, pre-combustion, pure CO_2 sources) and three different storage options (aquifer, oil/gas field, coal mine) (see Table 6-3).
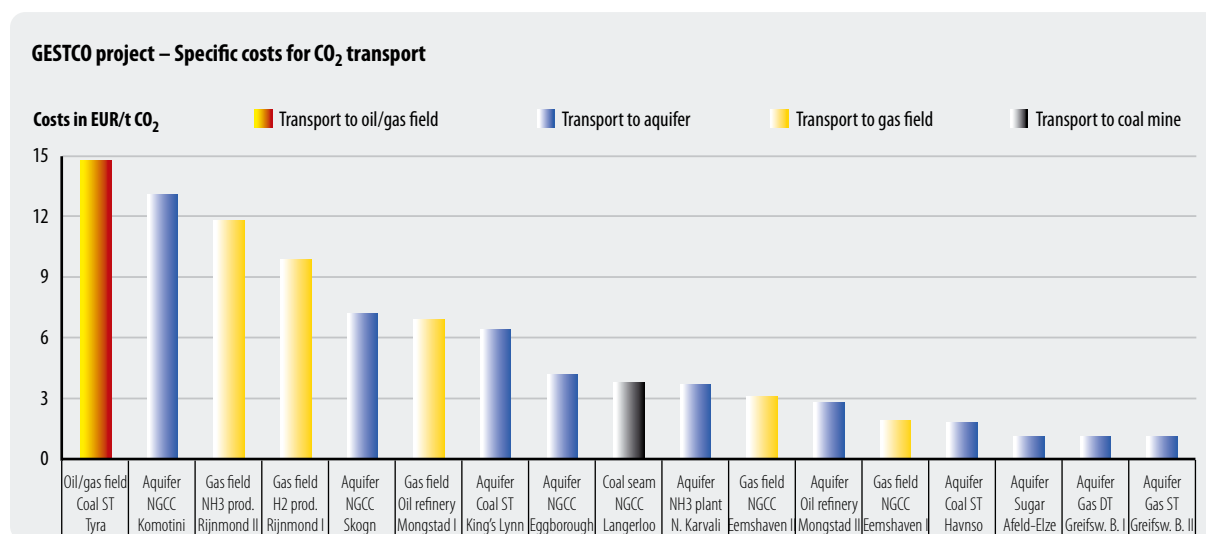
Fig. 6-6: Evaluation of transport costs from seventeen European case studies in the GESTCO project
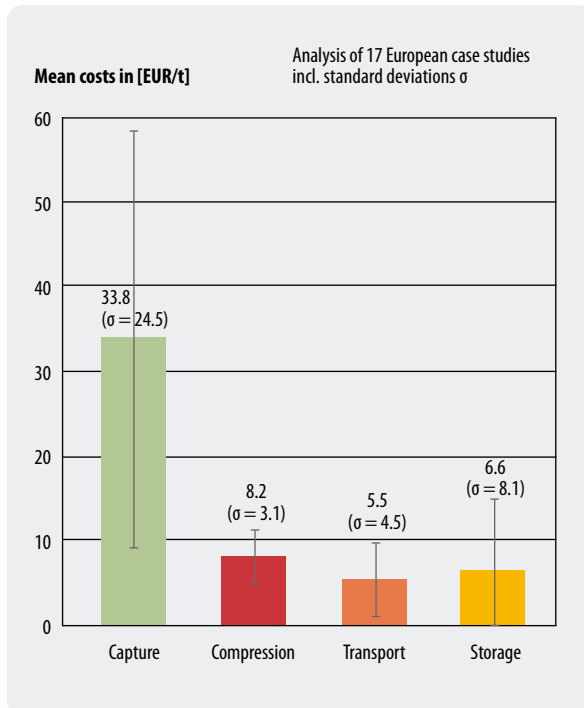
Fig. 6-7: Mean costs for capture, compression, transport and storage (GESTCO project)

Fig. 6-9: Span of CO$_2$ transport costs for a 250-km onshore or offshore pipeline as a function of capacity (IPCC 2005)

Fig. 6-6 shows the resulting transport costs as a bar chart. As can be seen, the variation in transport costs between the best case (€1.10/t) and the worst (€14.80/t) is very large.

Fig. 6-7 shows the mean costs and their spread (standard deviation σ) for the individual steps of the process. The mean value for transport cost is € 5.50/t with a large standard deviation of € 4.50/t (absolute) or 81 % (relative).

Fig. 6-8 shows a breakdown of the relative costs of the four steps of the overall CCS process. It shows that at 10 % of the mean overall costs of about €54.00/t in the case studies investigated in the GESTCO project, transport had the smallest share.

Source 4: IPCC (2005), Hendriks et al. (2003), Bock (2003), IEA (2002)[10]

The specific investment costs for **pipelines** with small diameters (200 mm) are approximately $0.2 million/km (onshore) to $0.3 million/km (offshore) and for larger diameters (1.00 m) approx. $0.8 million/km (onshore) to $1.2 million/km (offshore) (IEA 2002; Hendriks et al. 2003; Bock 2003). Transport costs for a 250-km small diameter pipeline were estimated at approx. $5/t (onshore) and > $8/t (offshore) and for a large-diameter pipeline approx. $1.2/t (onshore) and $1.8/t (offshore). For this distance the IPCC report gives typical pipeline transport costs of $1–8/t. Fig. 6-9 shows how transport costs depend strongly on the mass flow rate.

The investment costs for the EOR Weyburn Pipeline (length 330 km, diameter 300 to 350 mm, capacity 1.8 Mt/a, pressure 152 bar), for example, amounted to a total of $110 million or $330,000/km.

For **ship transport,** as well as the cost of the tanker itself, additional costs for loading/unloading, temporary storage and liquefaction facilities must be calculated.

Fig. 6-8: Distribution of CCS costs for capture, compression, transport and storage in the GESTCO project Analysis of 17 European case studies

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10 The transport chapter in the IPCC report refers to other sources (in particular IEA, Hendriks et al., Bock) so all four sources are addressed together here.

Ship transport is only economical for long distances. The break-even distance where the CO_2 tanker begins to have an advantage over offshore pipelines lies (assuming an annual volume of 6 Mt) in the range of approx. 500 to 2,000 km. Other influencing factors that may mitigate for or against offshore pipelines include water depth, seabed stability, existing pipeline routes and fuel costs.

There has not yet been any practical experience with the complete marine transport chain for CO_2 in the order of magnitude relevant for CCS, but there are studies that make certain statements about the issues. The Norwegian company Statoil estimates that the costs for a CO_2 tanker would be approx. 30 to 50 % above those of a similarly sized LPG tanker (with a semi-refrigerated tank). It should be noted here that owing to the greater density of CO_2 (in transportable state approx. 1,100 kg/m^3 compared with just about 500 kg/m^3 for LPG and LNG) a tanker of the same size would be able to transport a greater mass of CO_2 than LPG.

The International Energy Agency estimates the costs of a 10 kt tanker (30 kt/50 kt) at $34 million ($60 million/$85 million) and the costs of a liquefaction plant with a capacity of 6.2 Mt/a at US $80 million or US $30 million if the carbon dioxide supplied is already at a pressure of 100 bar (IEA 2004).[11] Statoil estimates a cost of $50 to 70 million for a ship with a capacity of 20 to 30 kt and $35 to 50 million for a liquefaction plant (1 Mt/a) (IPCC 2005).

For a distance of 7,600 km with a 30 kt tanker the IEA gives specific transport costs of $35/t and for a 50 kt tanker $30/t, but there are still great uncertainties concerning possible economies of scale. Further, the actual costs are determined by conditions on the ground. In a study for a marine CO_2 transport system with a capacity of 5.5 Mt/a Statoil estimates costs between $34/t (without liquefaction) and $55/t (with liquefaction) (IPCC 2005).

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11 By way of comparison, the largest liquefaction plant currently in existence has a capacity of 0.35 Mt/a.

Chapter 7

CO$_2$ Storage

As well as natural sinks for carbon dioxide, various technical methods could be developed to open up additional CO$_2$ storage capacity (see Fig. 7-1).

7.1 Overview of Methods

There are various ways of withdrawing CO$_2$ from the atmosphere. The possible methods are outlined below.

7.1.1 Marine Storage

Isolated CO$_2$ (CO$_2$ lake)

Mathematical models show that if CO$_2$ is brought into the ocean at depths below 3,000 m, the water pressure would cause it to form a lake of liquid CO$_2$ on the seabed with a chlatrate layer separating the carbon dioxide from the seawater above and inhibiting dissolution of the CO$_2$.

Dispersed CO$_2$

When CO$_2$ is injected into the sea at depths below 500 m, bubbles form and the gas dissolves; models suggest that it would remain trapped below the oceanic thermocline. If carbon dioxide is injected at greater depths (between 500 and 3,000 m) a 'trail of droplets' forms, where the droplets should best be surrounded with hydrates to slow the rate of dissolution.

CO$_2$ in the form of dry ice

Solid CO$_2$ in the form of a block of dry ice is taken out to sea by ship and allowed to sink to the seabed. However, because this form of CO$_2$ storage is extremely costly and energy-intensive it will not be discussed any further here.

Algae

Here the ocean is seeded with iron to induce an algae bloom which increases the CO$_2$ take-up by the ocean as an ecological system. An initiated algae bloom would be possible above all in the southern oceans, which are undersupplied with iron compounds. However, trials and experiments conducted to date have not produced the hoped-for success, because no more than 1 % of the bound CO$_2$ sinks to the seabed (Smetacek 2004).

7.1.2 Geological Storage

Deep saline aquifers

Storage in salt-water-bearing porous geological strata requires deep sedimentary basins, which are found all over the world. However, because such structures have to date only been investigated in connection with hydrocarbon deposits, there has not yet been a comprehensive assessment of their extent or of their petrophysical properties such as pore volume (which determines gas saturation), fracturing and deformation processes (impermeability of overlying layers) and their chemical properties. Such data are necessary in order to assess the storage capacity of these geological structures (May et al. 2003).

Depleted oil and gas fields

In many countries exhausted oil fields offer only restricted capacity compared with gas fields, which promise large overall capacities world-wide. The productivity of oil and gas fields in the final stages of exploitation can be increased by injecting CO$_2$ (EOR/EGR, enhanced oil/gas recovery). This brings economic benefits and at the same time allows CO$_2$ to be stored in the geological structure.

Deep (presently unexploitable) coal seams

Storing carbon dioxide in deep coal seams where mining is currently not economic for technical reasons while at the same time extracting and using methane (ECBM, enhanced coal bed methane) is currently in the pilot phase. Here CO$_2$ replaces the methane in the coal seam (coal can absorb about twice as much CO$_2$ as CH$_4$) and is thus held there. This, however, presupposes that the coal has a suitable permeability, which varies from one type of coal to another and has not yet been investigated under the geological conditions of deep seams.

Closed coal mines

It is theoretically possible to store CO$_2$ in the branching tunnel systems of coal mines. However, because the workings of different mines often join up and mining
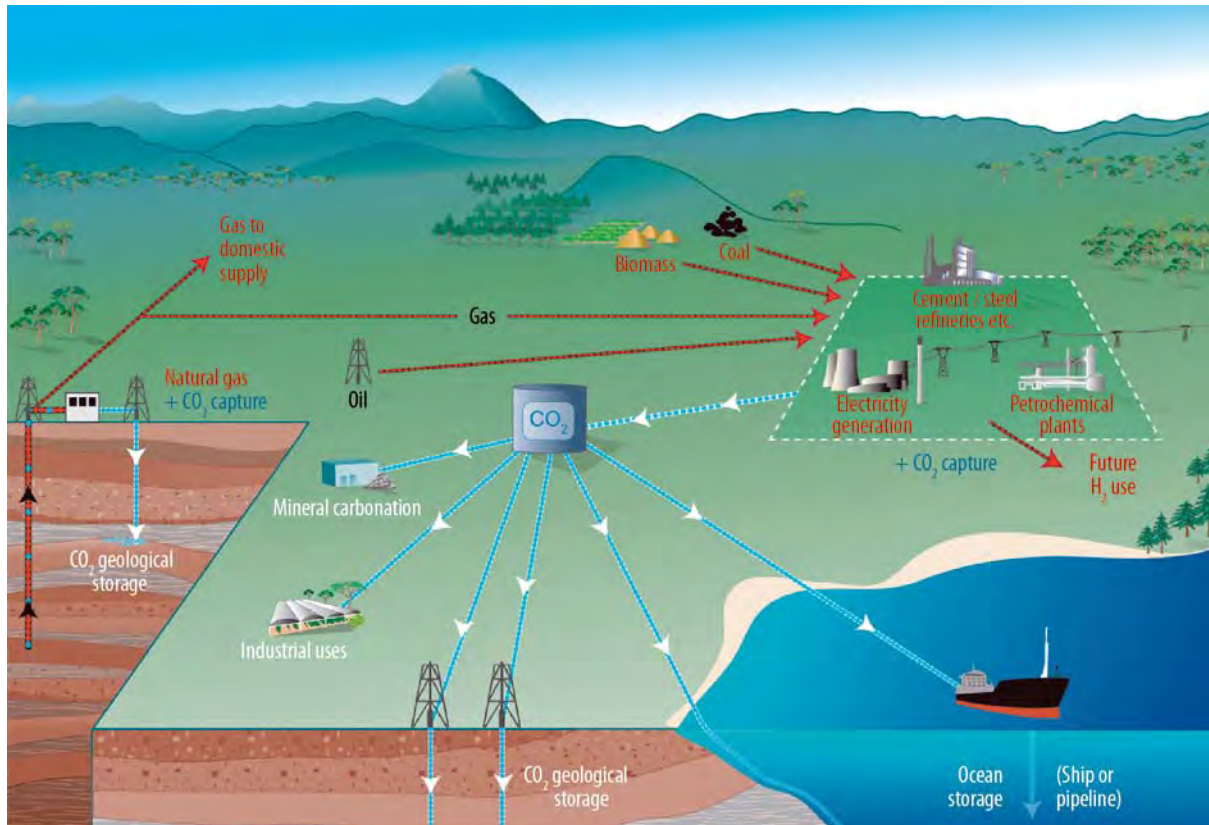
Fig. 7-1: Various conceivable options for storing CO_2 (IPCC 2005, courtesy of CO_2CRC)

continues in other parts of the complex, all the shafts and levels would have to be sealed before they were used for storage. Moreover, such sealing systems have yet to be developed and tested for long-term stability. In Germany some of these tunnel systems lie under heavily populated areas (Ruhr region and North Rhine-Westphalia) and the covering strata are in some cases relatively thin or strongly fractured.

Salt caverns

In comparison with other geological options, this alternative offers only very limited capacity and faces competition with other uses (e.g. waste dumping).

7.1.3 Other storage options

Biomass

Where carbon dioxide is fixed in trees, it can be stored temporarily, for example when the timber is used as a construction material. This allows the CO_2 to be stored for approx. 100–150 years in the timber construction elements.

Ways of fixing CO_2 using algae are also currently being researched. Like terrestrial plants, marine algae and seaweed convert carbon dioxide gas into biomass via photosynthesis using the energy of sunlight. To date power station flue gases contained too many other pollutants such as soot and nitrous oxides, but flue gas scrubbing allows these to be filtered out – with the result that the algae consume the remaining CO_2 gas. Biomass produced by algae can be turned into animal fodder, biodiesel or construction materials. Construction materials have the advantage that they allow CO_2 to be fixed as a form of organic carbon that will not decompose again quickly.[1]

Similar ideas have also been proposed for greenhouses, which could be heated using combined heat and power (electricity and heat from microturbines). The waste gases are CO_2-rich and relatively clean and can also be used to enrich the greenhouse atmosphere with CO_2 in order to increase biomass production.

Absorption in minerals

CO_2 can be bound permanently in magnesium silicate (e.g. olivine or serpentine), which is available globally in great quantities, forming magnesium carbonate. The

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1   See: http://www.radiobremen.de/magazin/wissenschaft/
    stadt-der-wissenschaft/themen/co2.html.

reaction takes place at high pressure (340 bar) and at a high temperature (500 °C) and is decisively influenced by particle size (the smaller the particles the faster the reaction). Per tonne of CO$_2$ the reaction produces 0.66 t quartz and 1.92 t magnesium carbonate, which can be disposed of, for example, in ore mines that produce serpentine as a by-product.

Chemical and technical uses

Using CO$_2$ in various industrial processes (e.g. as carbonic acid, for freeze-drying, in mononuclear and polymer compounds) in effect represents a way of recycling this 'waste product', although the storage period depends very much on the use to which the product in question is put (Breuer 2001). Estimates by the IPCC (2005) put the entire current global large-scale industrial use of CO$_2$ at approx. 104 Mt/a, which represents less than 0.5 % of current total global anthropogenic emissions. It is thought that rigorous conversion in the chemicals industry – driven particularly by research and development programmes – would make it possible to increase that figure to a maximum of 5 % (Plass 2002).

Fuel synthesis

Using chemical processes involving hydrogen, CO$_2$ can be converted into liquid fuels such as methanol (CH$_3$OH). This technology is still in the development/demonstration phase because it would require the supply system to be converted to provide hydrogen gained in environmentally friendly and climate-compatible ways, which means it can only be a medium- to long-term option. Direct use of renewable hydrogen is also considerably more efficient.

Ecological considerations are, of course, of special importance for the practicability of the listed storage methods. They include in particular the global and local risks of CO$_2$ leakages. The ecological restrictions for the respective storage options are listed in chapter 11.

7.2 Relevant Global Storage Options and their Potential

Estimates of existing storage potential currently differ enormously. The same applies to the fundamental suitability of the different storage options, where case-by-case examination will be required in order to gain clarity. Table 7-1 provides an overview of currently known CO$_2$ storage possibilities and lists a number of possible restrictions that could exclude possible future use (see also chapter 11).

The geological options of disused salt and coal mines are not taken into consideration by the authors cited in Table 7-1. This appears justified: in the case of salt

Table 7-1: Global CO$_2$ storage options and capacities (by comparison: global emissions rate in 2005 was 27.3 Gt** and rising)

Options	Capacity IPCC Gale (2002)	Capacity Hendricks + Turkenburg (1997)	Capacity Grimston et al. (2001)	Capacity ECOFYS (2004)	Restrictions
Geological:					Effects of CO$_2$ on soil organisms unresearched, possible danger to groundwater through leakages
Disused salt mines	n.a.	n.a.	n.a.	n.a.	Conflict with other uses
Disused coal mines	n.a.	n.a.	n.a.	n.a.	Risk of leakage, use conflicts with mine gas utilisation
Deep coal seams (ECBM)	40 Gt	n.a.	80–260 Gt	0-267-1480* Gt	Future use of deposits excluded, technology undergoing testing
Depleted oil fields	120 Gt (incl. EOR)	n.a.	(Oil and Gas together) 130–500 Gt	22-33-44* Gt onshore 20-60-107* Gt offshore	Risk of leakage relatively low
Enhanced oil recovery (EOR)	see above	40–100 Gt	20–65 Gt	9-112-734* Gt onshore 3-37-308* Gt offshore	Future use of deposits excluded
Depleted gas fields	690 Gt	90–400 Gt	see above	4-219-391* Gt onshore 20-20-32* Gt offshore	Risk of leakage
Enhanced gas recovery (EGR)	n.a.	n.a.	n.a.	219-391-925* Gt onshore 149-281-778* Gt offshore	Future use of deposits excluded

Options	Capacity IPCC Gale (2002)	Capacity Hendricks + Turkenburg (1997)	Capacity Grimston et al. (2001)	Capacity ECOFYS (2004)	Restrictions
Deep saline aquifers	400–10000 Gt	90/>1000 Gt	30–650 Gt	30-240-1081* Gt	Conceivable conflict with geothermal uses
Marine:	>1000 Gt	400/>1200 Gt	100–10,000 Gt based on total physical capacity 50–350 Gt after allowing for environmental constraints	n.a.	Apart from phytoplankton deposition, all technological concepts for marine methods are based exclusively on laboratory experiments and computer simulations. Knowledge of structure and function of deep ocean ecosystems is rudimentary at best (Germanwatch 2004)
Disperse and dissolve (max. depth 3,000 m)	n.a.	n.a..	n.a.	n.a.	At depths of less than 500 m retention period is only approx. 50 years. Problem of injecting liquid CO_2 into oceanic waters: reduction of pH value, dissolution of carbonates, substances involved in the CO_2 separation process continue to react, changes in specification of metals and ammonia (Germanwatch 2004)
CO_2 lake (water depth > 3,000 m)	n.a.	n.a.	n.a.	n.a.	Blankets seabed, causing high death rate of ecosystems there. Long-term geological risk of potential increase in rate of dissolution of carbonate sediment (Germanwatch 2004)
Dry ice dumping	n.a.	n.a.	n.a.	n.a.	Long-term geological risk of potential increase in rate of dissolution of carbonate sediment (Germanwatch 2004), logistically very complex and expensive (Herzog et al. 2001))
Bicarbonate dumping	n.a.	n.a.	n.a.	n.a.	
Phytoplankton	n.a.	n.a.	n.a.	n.a.	Requires iron seeding in southern-hemisphere oceans, increased photosynthesis rate warms oceanic surface waters with consequences for ocean circulation and climate, impact on atmospheric chemistry and climate (Lawrence 2002)
Biomass:					
Forestation	Worldwide by 2050 70 Gt in forests in addition to existing storage volume (IPCC 2001)	n.a.	n.a.	n.a.	Land use conflict with food production Possible monoculture Limited storage period
Other plants	Worldwide by 2050 30 Gt on agricultural land in addition to existing storage volume (IPCC 2001)	n.a.	n.a.	n.a.	Land use conflict with food production Possible monoculture Limited storage period

*   After ECOFYS (2004): low, best and high based on a set of assumptions, such as the number of undiscovered gas deposits, the exchange behaviour of CO_2 and methane in ECBM and the usable volume of oil deposits (40–80 %).

**   Data on rates of energy-related emissions after DIW (2006).

mines given the small potential capacity, in the case of coal mines because of the problematic issue of leakage. Furthermore, it must be pointed out that certain regions – such as South-East Asia and India – are as yet completely unresearched with regard to some of the listed options. Studies of storage capacity have been conducted largely in North America, Europe, Australia and Japan (Germanwatch 2004).

The analysis of potential capacity found great variance in the data for the global capacity of deep coal seams. This is because different types of coal absorb CO$_2$ to very varying extents. In the capacity data for CO$_2$ storage in exploitable oil and gas fields, on the other hand, the different authors give almost identical figures. The particularly large variance in the global capacity figures for saline aquifers stems from the very great uncertainty about their extent and technical potential, as well as specific problems of this storage option (structural complexity, varying thicknesses, varying porosity, saturation) (May et al. 2003).

When it comes to the marine options, usually only general figures are given, without differentiating between the individual technologies and methods. As a result these values also vary greatly from one author to another. Only one of the authors gives any figures at all for storage in the form of biomass.

Table 7-2: Overview of estimates of global CO$_2$ storage capacity, after ECOFYS (2004)

	Global CO$_2$ seq. potential [Gt]		
Estimate:	**Low**	**Best**	**High**
Remaining oil fields onshore	9	112	734
Remaining oil fields offshore	3	37	308
Depleted oil fields onshore	22	33	44
Depleted oil fields offshore	20	60	107
Oil fields (total)	**54**	**242**	**1,193**
Remaining gas fields onshore	219	391	925
Remaining gas sfieldss offshore	149	281	778
Depleted NG fields onshore	4	219	391
Depleted NG fields offshore	20	20	32
Gas fields (total)	**392**	**911**	**2,126**
ECBM	**0**	**267**	**1,480**
Aquifers	**30**	**240**	**1,081**
Total	**476**	**1,660**	**5,880**

Global CO$_2$ storage potential
(**Low** estimate: 476 Gt)

ECBM 0%
Oil fields (total) 11%
Aquifers 6%
Gas fields (total) 83%
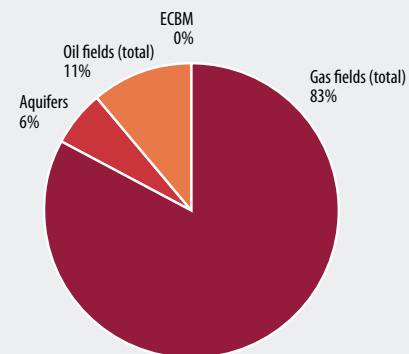
ECBM = Enhanced Coal Bed Methane Recovery

Global CO$_2$ storage potential
(**Best** estimate: 1,660 Gt)

ECBM 16%
Gas fields (total) 55%
Oil fields (total) 15%
Aquifers 14%
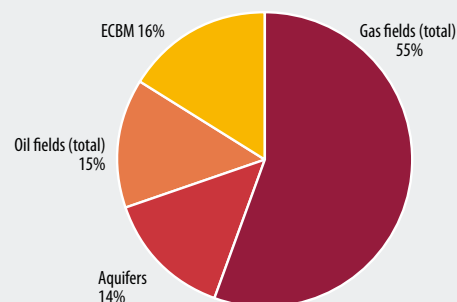
ECBM = Enhanced Coal Bed Methane Recovery

Global CO$_2$ storage potential
(**High** estimate: 5,880 Gt)

ECBM 25%
Gas fields (total) 37%
Oil fields 20%
Aquifers 18%
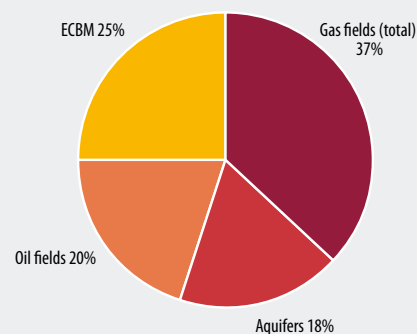
ECBM = Enhanced Coal Bed Methane Recovery

Fig. 7-2: Breakdown of 'low', 'best' and 'high' estimates of global CO$_2$ storage potential (data from ECOFYS 2004)

Table 7-3: European CO_2 storage options and capacities

By comparison: the annual rate of energy-related emissions in Europe (EU15) in 2005 was 3.5 Gt CO_2

Capacities	Deep coal seams (ECBM)	Depleted oil fields	Enhanced oil recovery (EOR)	Depleted Gas fields	Enhanced Gas recovery (EGR)	Deep saline aquifers
	0-1.7-9.9 Gt*					1.3-10.4-36.9 Gt
Onshore		0.4-0.6-0.8 Gt	0.1-1.0-6.2 Gt	0.2-7.6-14.3 Gt	7.6-14.3-23.5 Gt	
Offshore		3.4-10.3-18.2 Gt	0.3-4.0-39.9 Gt	10.3-10.1-13.3 Gt	12.9-26.8-111.9 Gt	

*   After ECOFYS (2004): low, best and high estimates are based on a series of assumptions, such as the number of undiscovered gas deposits, the exchange behaviour of CO_2 and methane for ECBM and the utilisable volume of oil deposits (40–80 %)

Taken together, the listed storage capacities are very considerable and represent many times the annual global CO_2 emissions generated by energy use, which amount to 27.3 Gt CO_2 (as of 2005: DIW 2006). A glance at the summary shown in Table 7-2 (ECOFYS 2004) shows the remaining uncertainties in the estimates. The low and high estimates of total storage capacity differ by as much as a factor of ten. The extent to which the listed options can actually be used to store CO_2 will have to be investigated in each individual case anyway.

Table 7–3 provides an overview of potential capacity of geological storage in Europe. The broad range of the capacity figures for deep coal seams results from uncertainty about exchange behaviour and permeability of the different types of coal.[2] Here there is a great need for research, which has already been initiated in various projects (e.g. RECOPOL, see the Overview of Global CCS Projects. The CO_2-EOR method is an option for Europe – and one that may become profitable in view of rising oil prices and trading in CO_2 certificates. European gas fields (e.g. in the Netherlands and Norway) also represent an attractive option for CO_2 storage with respect to technical and economic aspects and their relatively precisely quantifiable capacity. For deep saline aquifers in Europe (as at the global level) there is a considerable lack of research into quality and volume.

Taking ECOFYS's best estimate as a guide puts the total potential capacity in Europe at about 87 Gt CO_2. That is little more than twenty times the current annual emission rate of 4.114 Gt CO_2 in the EU25, which means that under these assumptions the application of CO_2 capture and storage technology as a central element of climate protection is a rather limited option.

7.3   Assessment of the Storage Options in Germany as an Example of an Industrialised Country

Table 7-4 gives volume estimates and quality criteria for the storage options in Germany. The assessment is based on a matrix developed by the Federal Institute for Geosciences and Natural Resources (BGR), to which criteria of cost, technology and general risks have been added.

information the theoretical storage potential in Germany is between 19 and 48 Gt CO_2. The largest and – in view of the numerous as yet unresolved issues affecting storage in deep coal seams (e.g. concerning permeability) – most important share relates to deep saline aquifers, supplemented by the more limited possibilities for storage in depleted gas fields. A calculation focusing on these latter two storage options and taking into account an average extra energy requirement of 30 % comes up with a static range of between thirty and sixty years for CO_2 point emission sources in Germany (2005: 393 Mt/a).[3]

In principle the storage of CO_2 in geological structures can draw on many methods and technological processes currently in use in the oil and gas industry and in the disposal of liquid wastes. However, drilling and injection methods, computer simulations of the distribution of gas in reservoirs and monitoring methods will have to be adapted to the special requirements of CO_2 storage. Here there is still a great need for research and development. In Germany the EU-funded CO_2SINK project will significantly increase knowledge about the behaviour and controllability of CO_2 in underground reservoirs.

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2   Deep coal seams cannot currently be mined for technical and economical reasons. However, injecting CO_2 might make it possible to extract the methane they contain, while at the same time ensuring that the CO_2 remained underground. The theoretical storage capacity of this option is greater than most other possibilities.

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3   Taken together these have a potential of 14.3 to 30.5 Gt CO_2.

Table 7-4:
Assessment of geo-
logical storage options
in Germany using
selected criteria

Option	Capacity in [Gt]	Long-therm stability	Costs*	State of the Technology	Utilisation conflicts	General Risks
Depleted gas fields	+ 2.3–2.5**	+	+	+ (+)	–	+
Deep saline aquifers	+ + 12–28**	+	– –	+	–	(+)
Deep coal seam	+ (+) 3.7–16.7	+	– –	–	–	–
Depleted oil fields	– – 0.11	+	+ +	+ +	–	+
Salt caverns	– – 0.04	– –	k. A.	+	– –	– –
Disused coal mines	+ 0.78	– –	– –	– –	– –	–

* Cost estimate contains only storage costs without capture, compression or transport (after ECOFYS 2004, BGR, authors' additions)
** Figures after May et al. (2005)

Criteria:
– – Negative or very problematic
– Fundamental difficulties stil exist, but may be resolvable
+ Good, or few obstacles
+ + Very good
() Parentheses indicate uncertainties or places where each individual case will have to be assessed

Chapter 8

Central Aspects of CO_2 Transport Infrastructure

Setting up a transport infrastructure will be a major cost factor in any future CCS regime. Consequently, questions concerning transport infrastructure will play a central role in location decisions for power stations and sinks. This is a classical **optimisation problem,** which can be resolved by defining one or more of the following target parameters:

- Minimise CO_2 transport,
- Minimise electricity transport,
- Minimise fuel transport,
- Minimise transport costs,
- Minimise ecological/social impact.

The following questions are decisive for configuring capture location, transport structure and storage location (see section 8.5):

- Where will future CO_2 sinks be? Onshore/offshore? Domestic/abroad?

- When can they be developed?

- When will they be exhausted?

- Where will power stations be located? Close to consumers/fuel/sinks? Centralised/decentralised?

- What will be transported? CO_2/electricity/H_2/SNG (synthtic natural gas)?

- Mode of transport? Pipeline/rail/road/ship?

- What kind of infrastructure will be required? Pipelines, compressors, collectors, intermediate storage, ports, …

Fig. 8-1 shows a possible CO_2 transport scenario (for Germany). In this example CO_2 is collected from point sources in North Rhine-Westphalia (e.g. large power stations), taken by branch pipelines to a main pipeline, compressed, and taken to onshore sinks in a neighbouring state (from North Rhine Westfalia to Lower Saxony in the example). For offshore storage (not illustrated here) the CO_2 would have to be transferred from the pipeline to ships using the corresponding infrastructure (port, loading facility, intermediate storage).

Fig. 8-2 shows the elements of the CO_2 transport infrastructure.

An estimate of the spectrum of transport costs for different transport scenarios (i.e. depending on level of development, capacity, distance and means of transport) has already been provided in chapter 6 (see especially figures 6–5 and 6–6).

8.1 Interdependency between Energy Use and Freight Transport

Transporting fossil fuels used primarily for energy purposes still represents a high proportion of freight transport. This applies in particular to shipping, but also to bulk transport on land. The high proportion of fossil fuels in international shipping cargoes is surprising given that public discussion of the transport issue is dominated by the internationalisation of production networks and the associated trade in complex industrial products (globalisation). In 2003 industrial manufactured products ('other goods') represented nearly 30 % of the tonne-kilometres transported by ship, while crude oil, oil products and coal still made up a good 53 % – although with a slight downward trend. Gas, crude oil and oil products account for almost 100 % of pipeline transport.

Growth in demand is a significant reason for the increase in pollution through freight transport, so initiatives to decouple demand for freight transport from economic growth have gained at least theoretical and political importance. In the energy sector especially, there is significant potential to reduce freight transport intensity (Pastowski 1997).

On the other hand, capturing and storing the CO_2 produced by burning fossil fuels has a tendency to increase freight transport intensity, because the CO_2 has to be transported to a sink. Thus, the reduced emissions and resulting climate protection effect obtained through the application of CCS – in the energy sector and elsewhere – would be counterbalanced by the increase in CO_2 emissions and other environmental costs associated with additional freight transport. In order to minimise these trade-offs and to cost-optimise the implementation of a CCS system, it is necessary to take a closer look at the consequences in the freight sector.

CO$_2$ sources (power plant)
Mt CO$_2$/a

- 0.0 - 2.5
- 2.6 - 5.0
- 5.1 - 7.5
- 7.6 - 10.0
- 10.1 - 12.5
- 12.6 - 15.0
- 15.1 - 17.5
- 17.6 - 20.0
- 20.1 - 22.5
- 22.6 - 25.0
- 25.1 - 27.0
- aquifers Germany
- aquifers NRW
- natural gas pipelines
- state boundaries
- CO$_2$ pipelines
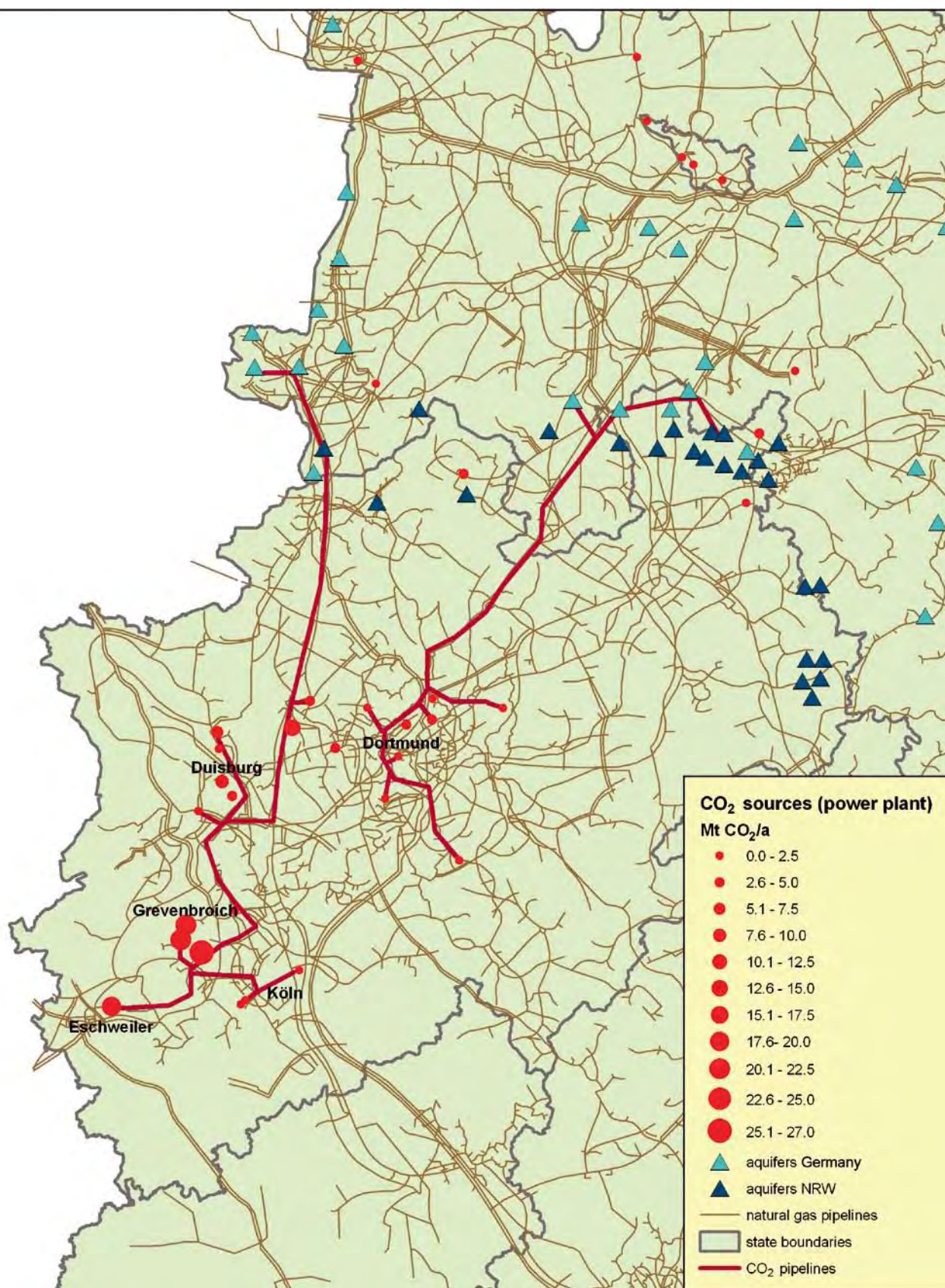
Fig. 8-1: Example of a possible CO$_2$ transport scenario in Germany
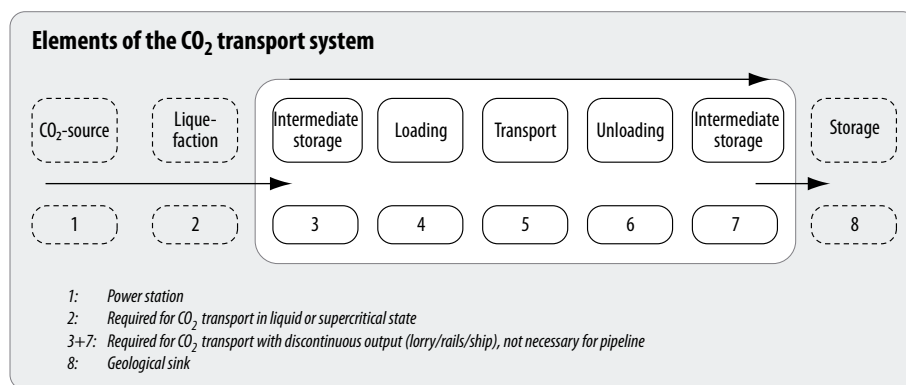
8.2 Determinants of Additional Freight Transport with CCS

The total extra transport required by CO_2 capture and storage can be determined through a with/without analysis, where the additional transport required for CCS is examined, and each case is analysed in terms of a series of determinants. The cost of transport is determined by the quantities transported, the distances involved and the means of transport used. Table 8-1 provides an overview of the relevant factors, which are described in more detail below.

Technical capture method

The relative and absolute quantities to be transported are influenced primarily by the choice of technical process for capture. CO_2 capture requires energy, so the fuel consumed by the power station increases to feed the same amount of electricity into the grid. Some capture methods also require additional materials (e.g. amine scrubbing agent), which also have to be transported. Table 8-2 shows the quantities of CO_2 and additional fuel that would have to be transported for various types and sizes of power station. In the case of MEA scrubbing, amine is required, some of which is lost or degraded during operation and has to be replaced. However, for a 700 MW power station, the latter represents an annual estimated quantity of 3,000 to 3,500 tonnes, which is negligible compared to the additional fuel requirement and the amount of CO_2 to be stored.[1]

Plant size and efficiency

The quantities of materials are also determined by the size of the plant. Here the efficiency of the respective plant – which may also depend on the size – also plays a role. The quantities of materials and CO_2 that have to be transported are known. At the same time, the size and location of the plant also determines the required

transport of electricity and other products. The quantities of materials and CO_2 are relevant for the choice of means of transport because sufficient transport capacity must always be available in the immediate vicinity of the plant. Otherwise the required capacity will have to be created. As Table 8-2 shows, even just for individual power stations CCS will involve considerable transport requirements.

For reasons of cost, the coal burnt in power stations is largely supplied by barge or rail. In Germany, for example, these two modes of transport together transported 87.4 million tonnes of coal in 2003 (BMVBW 2004). Even just at the level of individual power stations of the types and sizes under consideration, the additional fuel consumption caused by CCS is not negligible (approx. 0.23 to 1.6 million tonnes annually). Even more significant are the quantities of CO_2 to be transported, amounting to 3.4 to 5.1 million tonnes/year (for coal-fired power stations). So it must be assumed that if extensive capture and storage of CO_2 were implemented, considerable bulk transport capacity would have to be provided at the power station alone.

Location of sources and sinks

Alongside the additional quantities of material to be transported for CCS, the transport distance between sources and sinks will play a decisive part in determining the total transport cost. At the same time, particular conditions determine the use of particular modes of transport. An existing power station or sink may be far from the nearest waterway, thus allowing water transport only in a multi-modal context, where trans-shipment causes additional costs. It can be assumed that many of the plants that are suitable for CCS will already have rail or waterway links to supply them with materials such as coal. And with new plants these factors can be taken into account in location selection and planning. The choice of sink locations depends largely on their natural distribution. In the case of CO_2 storage in gas fields, it would sometimes be possible to make use of existing transport infrastructure.

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1   Note, however, that MEA (monoethanolamine) is a corrosive liquid that must be handled as a hazardous substance.

Table 8-1: Relevant factors for transport cost for CCS

Technical capture method	Plant size	Geographical location of source	Means of transport	Geographical location of sink	Technical method of storage
Transport quantity of CO$_2$, separating agent, additional fuel	Capacity and efficiency	Transport distance and access	Capacity, efficiency and ccosts	Transport distance and access	Accessibility, especially with offshohre storage

Availability of means of transport at the locations

Fundamentally, the use of pipelines, barges, ocean-going ships, freight trains and road tankers to transport CO$_2$ is conceivable. However, some of these are subject to restrictions where very large quantities are involved. Road transport quickly reaches the capacity limits of the road network, and in rail transport too, very large freight volumes can lead at least to local overloading of the network, which can only be avoided by expanding capacity. For many of the potential sources a connection to waterways and/or the railway network will already exist. In these cases the decisive question will simply be whether there is enough spare capacity for the transport required by CCS. Pipeline transport will almost always involve building new pipelines, with a potentially detrimental effect on costs in comparison to other options that make use of existing infrastructure.

Technical method of storage

The selected technical method of storage is relevant for transport to the extent that it determines the location and influences the maximum transportable volumes. Offshore storage involves special additional com-

plications, because here the CO$_2$ can only be supplied by pipeline or ship (ocean-going or coaster). Whereas pipeline transport from source to sink is feasible in principle, ocean-going ships or coasters will in many cases only represent one link in a transport chain where the CO$_2$ has to be transported to the coast/port by pipeline, barge or rail and transferred between the different modes of transport involved.

8.3 Technical Aspects of Bulk Transport Capacity

CO$_2$ transport is technically possible with all the available modes of transport. There are, however, relevant differences associated with the physical state of the CO$_2$, the continuous nature of its production at sources such as power stations and the considerable quantities involved.

Because new pipelines generally have to be built specially for the purpose of transporting CO$_2$, they can be dimensioned accordingly. Their capacity should be calculated so as to make intermediate storage unnecessary.

Table 8-2: Additional annual transport required by CCS in electricity or hydrogen production (capture rate: 88 %; 99.5 % for oxyfuel and 71 % for natural gas reforming) (Wuppertal Institute's calculations (for details see tables A 3 and A 4 in the Appendix))

Power station type	Net output [MW$_{el}$]	Efficiency [%] without CCS	Efficiency [%] with CCS	Full load hours [h/a]	Additional fuel [kt$_{coal}$/a]	Additional fuel [m$^3_{gas}$/a]	CO$_2$ to store [kt/a]
Lignite steam turbine	700	46	34	7,000	1,574		5,114
Coal • steam turbine • steam turbine (oxyfuel) • IGCC	700 700 700	49 49 50	40 38 42	7,000 7,000 7,000	276 343 229		3,570 4,249 3,400
Natural gas combined cycle	700	60	51	7,000		143,044,811	1,705
H$_2$: Coal gasification	560	59	55	8,000	68		2,374
H$_2$: Natural gas reforming	350	74	69	8,000		24,590,628	580

With other modes of transport – ocean-going ships, barges, railway and road – CO_2 will generally be transported in pressurised vessels. We should assume that it will be transported in liquefied form (like LPG and LNG) because transport in the gaseous state would require too much transport capacity (volume). The CO_2 will be loaded at a temperature and pressure that ensures that the maximum operating pressure of the vessel will not be exceeded before the destination is reached. To prevent heating and to ensure that the operating pressure remains within safety limits during the journey, the pressure vessels will be shaded by sunscreens, and in some cases pressure vessels insulated with polyurethane can be used. To maintain the required temperatures in ships, which travel considerably more slowly, active cooling systems can be used.

In the case of road transport, articulated road tankers are usually used to supply CO_2. With a maximum permitted weight of 40 tonnes (in Germany), they can load 20 tonnes of CO_2, which is transported at a pressure of 12–17 bar and a temperature between -50 and -70° C (Air Liquide 2005).

The smaller the individual transport vessels, the more difficult it becomes to ensure continuous filling at the source and unloading at the sink. While tanker ships can themselves serve as buffer stores during loading, in the case of rail and road transport in pressurised vessels, the small capacity of each individual vessel means that a large number of vehicles would be required. At the same time, handling is more costly and time-consuming, because each of these vessels has to be filled individually. Today there is a system called the 'block train' where all the tank wagons in a train are connected together and can be filled at one go (VTG 2005a) but this technique is available only for transporting unpressurised liquids where the tank can be filled from above. A solution of this kind is not available for tank wagons containing liquefied gases because of the high pressures involved and because the loading/unloading connections have to be underneath. To reduce the time required to fill tanks with liquefied gases, loading facilities that allow several tank wagons to be filled or emptied simultaneously are usually used (Transpetrol 2005).

Table 8-3: Transport capacities of different modes of transport, summarised by the Wuppertal Institute

	Capacity [t]
Pipeline	as required
Gas tanker	10,000–135,000
Barge	400–6,000
Trainload CO_2	1,000–3,000
Trainload coal	800–1,400
Road tanker	20

As well as the size of the individual containers and the number of individual tank wagons that can be joined to form a train, the speed must also be taken into account when considering the time factor in transport capacity. Although a ship possesses an impressive capacity as an individual vehicle, it moves considerably more slowly than a train or lorry, and this reduces its capacity per unit of time. This does not affect the number of vehicle movements required for transport, but it does influence the number of vehicles that actually have to be deployed. Table 8-3 compares the transport capacities of the modes of transport under consideration.

In the case of a **pipeline,** the dimensions usually correspond to the transport requirements, so a pipeline should always provide the required capacity. However, this is easier to ensure for a single pipeline than for a network, some parts of which will be used simultaneously for different transport connections and quantities, which may also be subject to change over time. In the case of other modes of transport a comparison of capacities is important, because – depending on the quantity of CO_2 to be transported – a large number of vehicle movements may be required. These will place a great strain not only on the respective transport network (waterways, rail, road) but also on residents living in the vicinity of the plant and routes in question. This may have a negative impact on practicability and acceptance.

With water-borne transport, inland waterways and – in the case of transport to offshore sinks – ocean-going ships come into consideration. **Ocean-going ships** offer considerable capacity but due to their dimensions their use on inland waterways is restricted or impossible. So ideally ocean-going vessels would be used to transport CO_2 to offshore sinks from sources located on appropriately dimensioned waterways – a combination that considerably reduces the possibilities. Another option for using ocean-going ships for maritime storage would be to build pipelines to ports that are capable of handling correspondingly dimensioned ships, or other forms of combined transport.

For transport on **inland waterways** tanker barges are available with the following dimensions: length 50–135 m, width 6.6–17.0 m, draught 2.2–4.0 m and capacity 400–6,000 tonnes. Apart from the quantity to be transported, the narrowest point in the respective waterway network will influence the selection. For barges this applies especially to width and draught. Maximum bridge clearance is insignificant for barges, but it does play a role with coasters whose superstructure protrudes higher out of the water.

Gas tankers are the usual means for transporting liquid gas by sea. There are different designs and specifications. A distinction can be made between designs with high pressure and moderately low temperature and less highly pressurised types with very low temperatures (semi-refrigerated versions). An example of the former would be similar to the tankers currently used to trans-

port liquefied gas at a temperature of -55 °C and a pressure of 6 bar. In the latter design liquefied natural gas is transported in a less highly pressurised form (max. 230 mbar) at a temperature of -164 to -161 °C.

In terms of capacity, a type II liquefied gas carrier (Det Norske Veritas classification) with a length of 145.7 m and a draught of 9.7 m, for example, provides a cargo capacity of 12,500 m³ (Thyssen-Nordseewerke 2005). The ships made by Thyssen offer capacities from approx. 10,000 to 55,000 m³, which at the temperatures and pressures involved here represent about the same in terms of tonnage. There are also considerably larger units for LNG transport. Alongside today's tankers with a total volume of 125,000–135,000 m³, ships with a capacity of up to 250,000 m³ are planned. However, their deployment will require correspondingly dimensioned ports and an appropriate volume of supply by other modes of transport, except where the CO$_2$ sources are located in the immediate vicinity of the port.

8.4 Networkability of Modes of Transport

Another decisive factor for the deployment of the various modes of transport is their networkability: The different densities of the respective transport networks determine whether a given means of transport can offer uninterrupted transport as well as determining the length of the actual route involved. The significance of networkability is smaller in the case of especially high transport costs, because here the transport requirements and costs will have already been given priority consideration in the choice of location. This is already the case for many facilities where CCS is an option, especially for power stations fired with solid fuels. It applies, however, in a special way for CO$_2$, because it almost never has any economic value, and instead its disposal costs money. Networkability has a particular influence on the choice of new locations for CO$_2$ sources, whereas in the case of sinks the choice is limited to a finite number of fundamentally suitable locations, which are better or less well connected by the respective modes of transport.

In most countries **roads** demonstrate the greatest networkability. Sources and sinks are very likely already connected to the road network. If they are not they can be connected at limited cost. However, transporting large quantities of CO$_2$ would mean placing a great strain on the affected sections of the road network; not only in terms of the number of vehicles, but also in road damage and nuisance to the environment through noise and emissions. Even without taking these factors into consideration, road transport of large quantities of CO$_2$ is unlikely simply because of the relatively high specific costs involved.

The **rail network** is considerably less dense than the road network, but it is reasonable to assume that many

CO$_2$ sources such as power stations will already possess a railhead. So for CO$_2$ transport by rail it is of primary importance whether the potential sinks have a rail connection or whether this can be created at reasonable cost. With regard to capacity, it should be noted that traffic on the main arteries of the rail network is sometimes already very dense, but freight traffic is generally handled at night, which allows routes and times with capacity problems to be avoided. On the other hand, depending on the location of the route, noise problems in inhabited areas can be exacerbated by night traffic, which can impair the acceptance of such traffic.

The extent of the network of viable navigable **waterways** differs from country to country, but is limited in many. While some existing CO$_2$ sources (e.g. coal-fired power stations) are often close to or directly beside waterways for supply with fuel and other materials, this applies only to a very limited extent to sinks. Furthermore, the navigability within the network is not homogeneous, but the possibilities differ depending on the type and size of vessel: In the smaller branches of the network of rivers and canals it is often only possible to use smaller types of barge. Because transport by ship can be accomplished relatively inexpensively, much speaks in favour of this mode of transport as long as the location of sources and sinks allows access. There are also advantages in terms of local environmental factors (compared with road or rail transport) because waterways do not normally run directly through densely populated areas and noise remains less significant. Attempts would have to be made to reduce emissions of air pollutants primarily by technical means in the same way as for road vehicles.

Overall we can say that the modes of transport with the best bulk carrying capacity present drawbacks when it comes to networkability and the optimal connection of sources and sinks (in the case of pipelines to date not at all). In particular cases this may necessitate either increased investment to connect to networks or the use of several different modes of transport, at correspondingly increased cost. Of all the modes of transport, pipelines suitable for CO$_2$ currently demonstrate the lowest networkability. So, while transporting large quantities of CO$_2$ by lorry is problematic owing to the lack of bulk carrying capacity and the high cost and environmental impact, a pipeline network for large-scale transport of CO$_2$ between different sources and sinks would have to be created from scratch in a concerted initiative that would require time and corresponding investment.

8.5 Conclusions

Here we provide answers (for the case study Germany) to the questions posed at the beginning of this chapter, to the extent that current knowledge allows.
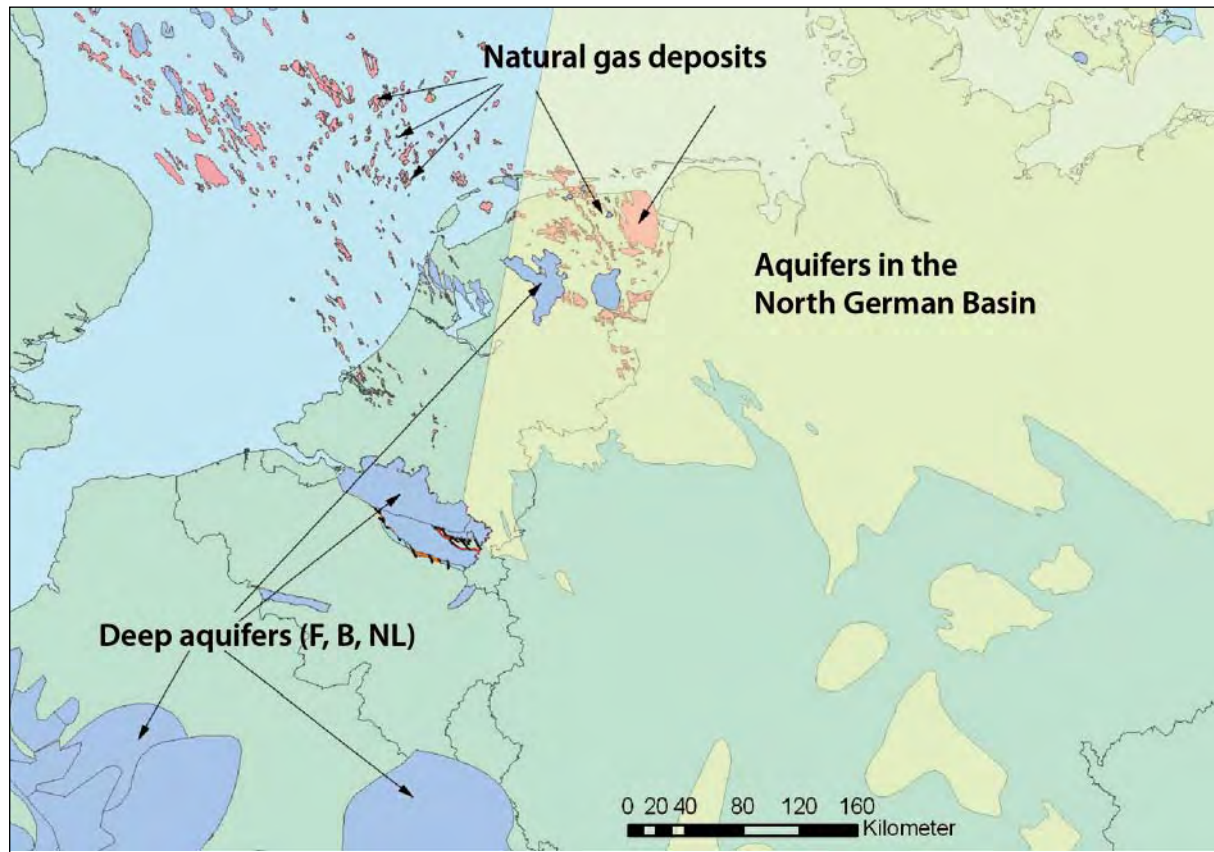
Fig. 8-3: Distribution of potential CO_2 storage formations
The beige area designates the general distribution of deep aquifers (> 1000 m) that would potentially be suitable for CO_2 storage. The blue areas designate deep aquifers in France and the Benelux countries. In addition, natural gas deposits are also shown for the Netherlands.
After GESTCO (2004)

Where will the future CO_2 sinks be?

The most obvious options for CO_2 storage in Germany are exhausted gas fields and saline aquifers, which are located above all in northern Germany: an east-west belt of gas fields approximately 100 km wide and saline aquifers located largely in the North German Basin. Fig. 8.3 also shows potential sinks in the western neighbouring countries of the Netherlands, Belgium and France. Here future cross-border cooperation on the use of sinks would certainly be conceivable, especially for the state of North Rhine-Westphalia. This is most relevant for the large point sources in the Ruhr region and in the Rhine lignite mining area.

When can future sinks be developed?

Some gas fields have already been exhausted, and some of these serve as natural gas storage facilities, for example WINGAS's underground gas storage facility at Rehden. This is the biggest gas storage facility in Western Europe, and represents about one fifth of existing natural gas storage capacity in Germany. Other fields will become exhausted during the next ten to twenty years and would then – assuming they are suitable – be able to serve as CO_2 sinks.

When will CO_2 sinks be full?

The storage potential of the exhausted natural gas fields and saline aquifers in Germany amounts to between 14 and 30 gigatonnes of CO_2 (see also chapter 7.3), which means there would be a range of times until all sinks are completely full. For example, if we take the annual emissions of all German industrial plant and power stations (combustion facilities > 50 MW) with an emissions rate of 1 megatonne per year, this would amount to a total of 343.4 $MtCO_2$ in 2004,[2] and a theoretical storage capacity of 41 to 87 years. However, this estimate neglects the increase in CO_2 emissions – approx. 30 % would currently appear realistic – caused by the additional energy required in the CCS process as a whole. Taking these additional CO_2 emissions into account would reduce maximum storage capacity to 31 to 67 years. Deep coal seams would be another option, but because it is currently completely unclear whether, when and to what extent it might be possible to use them, they have not been considered here.

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2   Source: European Pollutant Emission Register
    (EPER: www.eper.de)
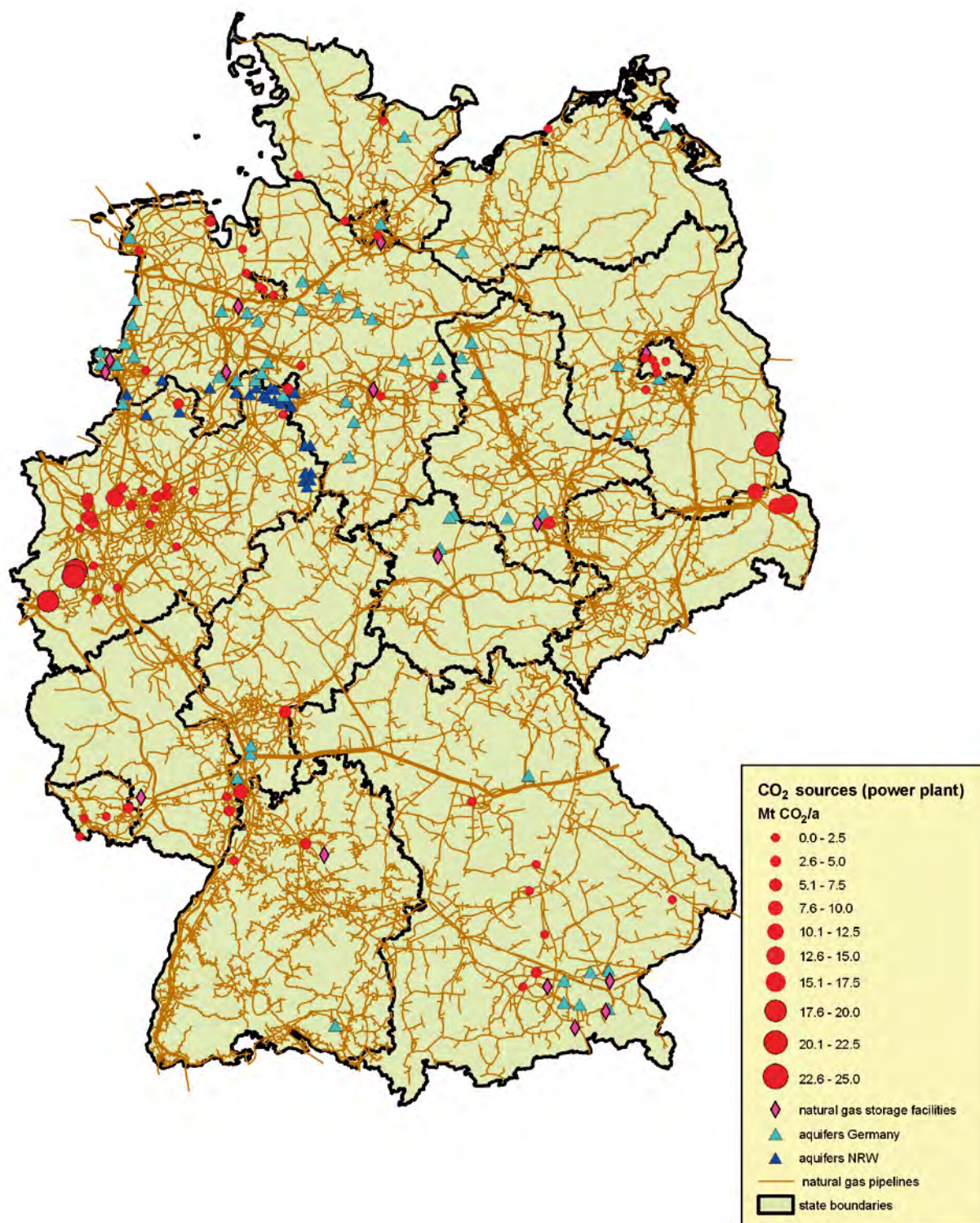
Fig. 8-4: CO$_2$ sources (power stations) and sinks (aquifers and natural gas storage facilities) in Germany and the existing gas pipeline network

Where will future power stations be located?
(Close to consumers/to transport networks/to sinks,
centralised/decentralised)?

Existing power station locations have been selected according to various optimisation parameters. Due to the high transport intensity of the fuel, for example, lignite-fired power stations are located in the lignite-mining areas of the Rhineland and Lausitz regions (identifiable in Fig. 8.4 as the biggest CO_2 point sources), because transporting low-calorific lignite over long distances is too expensive. Coal-fired power stations, on the other hand, are built closer to major electricity consumers (big cities and industrial regions, especially in the Ruhr region). They also generally depend on a good inland waterway connection for cost-effective bulk delivery of coal. Medium-sized and small power stations using efficient combined heat and power are located decentrally in the immediate vicinity of heat sinks (housing estates, urban districts, industrial plant). The distance to and location of CO_2 sinks comes into play as an additional parameter when selecting the location of future new CCS power stations. It remains to be seen what actual influence this will have on the selection of location, because the other factors outlined above (closeness to fuel and consumers, transport connections) will remain valid. Ultimately, weighing up the economic aspects will lead to a location decision. Questions of acceptance may also play a role and restrict the options for developing new power station locations.

What will be transported (CO_2, electricity, H_2)?

This question, too, will be answered primarily in terms of economic aspects. It is directly connected to the locational interrelationship between CO_2 source and sink. If the power station location remains close to the fuel (lignite-fired) or relatively close to the consumer (coal-fired), the CO_2 will have to be transported to potential sinks. If future power stations were to be built directly at CO_2 sinks, the amount of electricity to be transported would increase. If we take a third approach – decarbonisation of fuel at the CO_2 storage location (i.e. coal gasification or natural gas reforming to produce H_2) – this would eliminate or reduce the transport of CO_2 and electricity, but at the same time make it necessary to transport H_2. In SNG production the existing natural gas networks could be used for transport and distribution. As in the case of construction of new power stations, the question of acceptance can be of decisive importance when realising new transmission and pipeline infrastructure networks (electricity, CO_2, H_2, SNG). Experience in this matter has yet to be gathered.

How will CO_2 be transported?

From the economic, energy-efficiency and ecological perspectives, pipelines and ship transport are the first choices for CCS applications. Rail transport would require capacity to be expanded, and lorry transport would be acceptable only for a transitional period, for example for pilot projects, because of the small unit capacity, the environmental impact and the already crowded road network.

What infrastructure will be required?

For CO_2 transport by pipeline a completely new pipeline network would have to be constructed. In individual cases it might be possible to use existing natural gas pipelines or follow their routes. Depending on the pipeline length and initial pressure, individual compressor stations might be required. For ship transport new large-capacity tankers would have to be designed and the required loading/unloading infrastructure and intermediate storage facilities would have to be built at the port.

8.6   Case Study: Transport Options for a 700 MW Coal-fired Power Station

In order to generate estimates of the volume of freight transport demand created by CCS, it makes sense to start by estimating the transport requirments for an example power station. In this way the least promising transport options can be weeded out at the beginning.

The following example in Table 8-4 estimates the vehicle journeys required for CCS (for transporting CO_2 and the extra coal required) for a 700 MW_{el} IGCC power station (7,000 full load hours per year). The assumed annual transport volumes are approx. 3.4 million tonnes CO_2 and approx. 230,000 tonnes of additional coal (see Table 8-2). Where applicable, a range of figures is given to represent larger and smaller load capacities within each mode of transport.

The corresponding return journeys must also be taken into account, and these will generally be empty because appropriate loads will seldom be available. So ultimately the number of vehicle journeys will be nearly double. At the same time, the number of vehicle journeys says nothing about the transport distances involved, which will depend on the conditions in each individual case. The same applies to the number of vehicles required for transport, which will depend on the exact type of vehicle, distance, speed and other factors.

Table 8-4: Estimate of annual one way loaded vehicle journeys required for CCS for a 700 MW IGCC power station (7,000 full load hours per year), authors' own estimates

Mode of Transport	Capacity	Additional journeys per year	
	[t]	CO$_2$	Coal
Gas tanker	10,000	340	–
	135,000	25	–
Barge	400	8,500	–
	6,000	570	–
Trainload CO$_2$	1,000	3,400	–
	3,000	1,130	–
Trainload coal	800	–	289
	1,400	–	164
Road tanker	20	170,000	–

Here it already becomes apparent that road transport is not a plausible option – because of the high cost, but also because of the immense number of vehicle journeys which would cause traffic congestion at the sources and sinks and along the routes in-between. Every day there would be about 930 heavy road tankers arriving at and leaving the sink and the source.

Transport using small barges with 400 t capacity would also lead to considerable congestion problems. Every day about 23 barges of this type would have to be loaded and unloaded. Consequently, such cases can be excluded from further analyses and scenarios. Compared with CO$_2$ transport, moving the additional coal will have less impact, because the quantities involved are smaller and deliveries are already supplied by ship, barge or train. Nonetheless, the additional transport volume involved here is not negligible (for one 700 MW$_{el}$ power station one additional trainload of coal every day or two).

The volume of amine that would have to be transported for MEA scrubbing is negligible by comparison, although unlike coal and CO$_2$, MEA would have to be transported as a hazardous substance.

Chapter 9

Criteria for a Comparative Assessment of CCS

As part of the study we drew up a catalogue of criteria to allow a systematic comparison of various CCS technologies with other, fundamentally different technology options such as energy efficiency and renewables. The various criteria can be categorised as follows:

● Ecological criteria
  – Environmental impact as per life cycle assessment (LCA)
  – Energy efficiency
  – Other ecological criteria, ecological restrictions, consequences and risks (direct and indirect)
  – Ecological impact

● Economic criteria
  – Cost

– Industry policy
– Applicability for developing countries
– Compatibility with existing energy infrastructure and possible future development paths
– Compatibility with other climate protection strategies (decentralised options)
– Impact on import dependency
– Security policy implications

In the following chapters some of these aspects are illustrated and examined in greater depth. A comprehensive criteria-based comparison of CCS with the potential renewable alternatives that are to be expected during a comparable development timeframe can be found in Table 9-1.

Scenarios:
REF: Reference
UWE: Conversion efficiency
RRO: Renewable energy/ energy efficiency campaign
FNE: Fossil/nuclear energy mix
WI: Scenarios of the Wuppertal Institute
IER: Scenarios of the Stuttgart University Institute of Energy Economics

Total net electricity generation [TWh/a]

Coal, Lignite, Heating oil, Natural gas, Nuclear power, Biomass/Biogas/Refuse, Geothermal, Hydrogen, Hydro-electric, Wind, Photovoltaics, Import of renewables
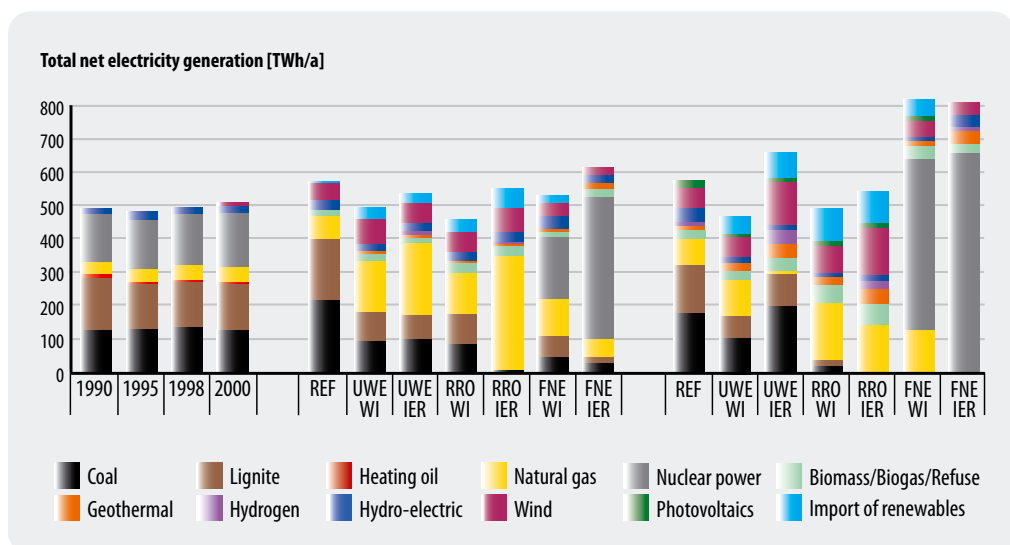
Fig. 9-1: Different development options for electricity generation considered by the Enquete Commssion "Sustainable Energy Supply" of the Germany Bundestag (Enquete 2002) for achieving ambitious climate protection goals in Germany

● Energy policy and other criteria
  – Timeframe for application (possible time of implementation) and market readiness and/or R&D still required
  – Compatibility with power plant replacement needs
  – Acceptance
  – (Technological) stimuli for global climate protection

As existing analyses show, large-scale CCS will probably not be technically ready for the power plant sector before 2020. This raises the question of which technologies CCS will actually be competing with, from the energy policy and climate protection perspectives. The Enquete Commission "Sustainable Energy Supply" of the German Bundestag outlined three different routes by which Germany could achieve ambitious climate protection goals by 2050 (see Fig. 9-1):

Fig. 9-2:
Climate protection options and their availability time-frames
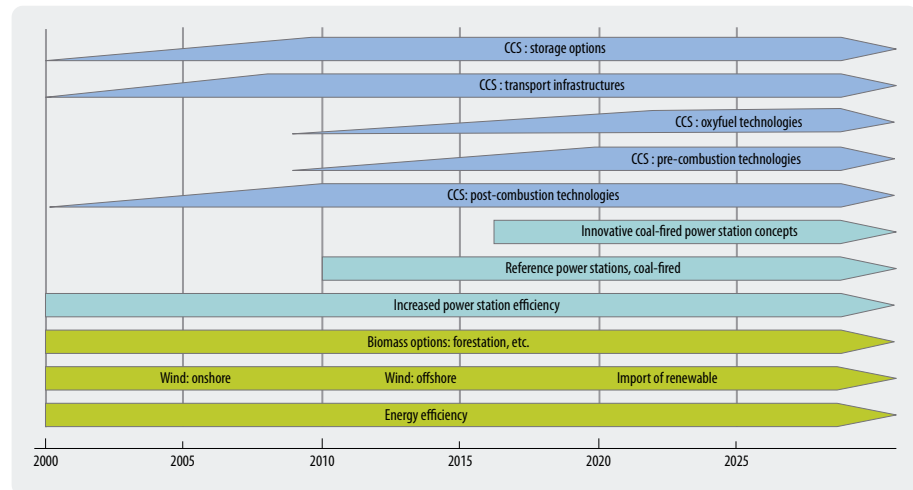
1. Large-scale implementation of CO_2 capture and storage,[1]

2. Implementation of a large-scale renewable energy system joining Western Europe and North Africa on the basis of large-scale renewable energy technologies for and the utilisation of decentralised renewable energy options as well as the exploitation of energy efficiency potentials,

3. A renaissance of nuclear power.

These are broadly focused strategies, of which only strategy 2 would achieve the required reduction in greenhouse gases. Scenarios 1 and 3 additionally assume a further expansion of renewables and the use of at least some of the potential for energy saving.

At the moment all fields still contain unresolved issues, which need to be clarified as quickly as possible. Even if the three named strategies can to some extent be combined, it would still appear that an early fundamental decision about the main direction of change in the energy system will be unavoidable, and that the pending power plant replacement needs will have to be handled accordingly. If we also assume that the current policy decision in Germany to phase out nuclear power will hold – which would appear justified in view of nuclear power's continuing lack of public acceptance – this would seems to imply competition primarily between CCS and large-scale generation of electricity from renewables (including imports from abroad).

The following chapters focus on the aforementioned criteria in the context of the following questions:

- When will large-scale technical solutions become available?

- How do the available technologies (development horizon) fit with the timeframe for power plant replacement?

- How will economic competitiveness of CCS with other options develop, how does the relationship change over time (for example as fossil fuel prices rise)?

- What stimuli can be generated by implementation at the international level?

Comparable questions also arise at the global level; these are analysed in greater detail in chapter 15.

Fig. 9-2 provides an overview of the possible timeframe for the availability of relevant climate protection options. With respect to the according timeframe the figure makes it clear that significant competition will rise above all between CCS and the large-scale development of offshore wind power as well as the introduction of renewable energy import systems (e.g. based on solar thermal power plant). The following chapters therefore concentrate mainly on a comparison with these technologies.

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1   For CO_2 capture and storage in Germany an annual volume of 202 to 260 million tonnes by 2050 was assumed. The cumulative amount of CO_2 to be stored by 2050 would be in the order of 2,020 to 4,500 million tonnes (Enquete 2002).

Table 9-1: Assessment criteria for various CO_2 avoidance options

Criterion	CCS	Renewables: wind offshore	Imported renewables: solar electricity from North Africa
Energy efficiency	Falls in comparison with conventional electricity generation (20–30 % loss of efficiency).		Transport losses (approx. 10 % over 3,000 km with high voltage transmission line)
Costs in ct$_{EUR}$/kWh	Depends on technology (approx. 6–8 €ct/kWh in 2020).	Current: 6–10 €ct/kWh, Future: 4–6 €ct/kWh	Current: ca. 15 €ct/kWh Future: 5–10 €ct/kWh
Environmental impact, ecological restrictions, consequences and risks (direct and indirect)	Intervention in ecosystems through increased extraction of fuels (especially coal) and construction of CO_2 pipelines; increased pollution through increase in energy and CO_2 transport (ships carrying coal, CO_2 etc.); environmental impact of toxic agents (e.g. MEA) in flue gas scrubbing.	Disruption to benthic ecosystems, possible dis-orientation of whales through infrasound; anthropo-centric argumentation: creation of new ecosystems could have positive effect on fish stocks (hard substrates offer new habitats for shellfish, etc.; undisturbed zone in wind farms can serve as breed-ing grounds for marine organisms; no-fishing zone). Laying cables involves intervention in benthic fauna.	Plant location: Intervention in desert eco-systems. High voltage transmission line: Interven-tion comparable with other power lines, primarily affects the appearance of the landscape.
Resource and material consumption	Depending on the technology: increased energy consumption, increased use of materials due to add-on charac-ter of post-combustion technologies. Expansion of fossil fuel production has repercussions for production dynamics (availability).	Insignificant during operation. Use of materials for plant construction and grid connection.	Insignificant during operation. Use of materials for plant construction and grid connection.
Window of opportunity (time of possible imple-mentation) and market-readiness and/or R&D requirements	Not before 2020	Systems are market-ready and offshore wind farms already exist; problems may be caused by bottle-necks in financing and in some cases also by official approval procedures. No long-term experience with large offshore facilities. Connecting system and grid is a complex matter.	In technological terms systems are market-ready (solar thermal power stations). Higher generation costs and high level of subsidies for fossil fuels in the targeted countries have to date made financing difficult (low returns in compari-son with conventional power station with conservative estimate of future fuel procurement costs). Planning of high-tension transmission routes takes several years, so long-distance electricity transport will not be available before 2010–2015. Tech-nology could, however, be implemented earlier to supply domestic demand in the states where solar thermal power stations are built
Compatibility with power station replacement needs, case study Germany	Availability will be too late for the first wave of power station replacements (a large proportion of Germany's existing capacity will already have been replaced by 2020)	Could cover part of replacement demand according to BMU expansion strategy (25 GW by 2020–2030)	BIf implemented immediately it might be possible to cover some part of the capacity replacement need using renewable elec-tricity imports

Potentials and their geographical distribution	Resource potential depends on:
	   geological availability
	   possibility of production within timeframe
	   acceptable side-effects (pollu-tion, etc.)
	   individual analyses required (cover-ing supplying country and infra-structure)
	   regional differences in availability of CO_2 storage
		25,000 MW for Germany	By European standards unlimited
			
			Area of desert theoretically required to cover Germany's electricity needs in full: 45 km^2
			
			Theoretical total potential in the Magh-reb states: many times global electricity demand

Criterion	CCS	Renewables: wind offshore	Imported renewables: solar electricity from North Africa
Acceptance	So far unclear, will depend to an extent on the argumentation strategy	High (even in holiday regions, contrary to the fears of the tourism branch)	So far unclear but acceptance of renewables is very high; little public knowledge or discussion of renewable electricity imports, possible acceptance problems with construction of high voltage transmission lines
Feasibility	At the moment there is still uncertainty about the regulatory framework (including integration in international emissions trading) and legal aspects	Some locational and infrastructure issues still unresolved	Uncertainties concerning sites. Implementation of solar thermal power plant began in the 1980s (> 350 MW in the United States), further expansions under way or planned (Spain > 100 MW under construction , several solar thermal facilities at planning stage in North Africa)
a) Technical challenges	Technically feasible within the afore-mentioned timeframe	Already being implemented. First reports on technological aspects available but no long-term studies yet. Grid connection problematic	Technically realisable in the aforementioned timeframe. The development of dry cooling systems will be required later for opening up further potential (sites without cooling water supply)
b) Legal framework	Legal status of CO_2 not yet properly clarified: classification of CO_2 as waste would restrict storage	Approval processes in progress, implementation under way	Unresolved problems: Power lines cross numerous countries. Owing to low level of environmental problems, legal and regulatory questions should be of little relevance, acceptance of grid infrastructure unclear
c) Other	Some problems expected with: lack of space at power stations (no room to build capture unit) CO_2 pipeline routes difficult to find in highly populated regions	Some conflicts with environmental protection (cable-laying in nature reserves). Otherwise compatible with regulatory framework (permits already granted).	
(Technological) Stimuli for global climate protection	Present	Great potential for widespread use in developing countries. Plant maintenance may be complex	Large-scale introduction e.g. of solar thermal power opens up opportunities for initiating a renewable H_2 economy. Other stimuli through combination with seawater desalination or other use of waste heat (e.g. solar cooling and solar process heat)
Industry policy opportunities	Technology manufacture will probably remain restricted to big corporations (Siemens, Linde, Alstom, etc.)	Strong medium-sized companies have grown up; increasing trend to concentration in market	With solar thermal power stations Spanish, US- and German companies are among the leaders
Transferability to developing countries	Possible but questionable whether technologies are robust enough to function properly in developing countries (where engineers may be less highly trained, etc.)	Integration of developing countries as export markets would offer great opportunities for co-operation between developing and industrialised countries	Integration of developing countries as export markets would offer great opportunities for co-operation between developing and industrialised countries. Technologies are comparable with conventional power stations (plus collector fields, whose operation and servicing are relatively simple). Very high potential for application in developing countries especially in combination with use of waste heat for seawater desalination.
Compatibility with existing infrastructure (e.g. load cycle response) and with possible future developments	Despite growing experience and increasing plant reliability, CCS technologies will curtail the flexibility of the electricity supply system (counteracting the increase in flexibility brought about by integrating renewable electricity). IGCC using storable gases could represent an exceptio	Throws up challenges concerning expansion of power grid from coasts to main centres of demand. Limited suitability for base load, requires storage technologies (storing as H2 or other options; initiation of renewable H2 economy structurally possible)	Suitability for base load through use of heat storage. Without storage: auxiliary fuelling with natural gas ensures base load supply. Good coincidence of electricity supply and demand (load peak caused by air-conditioning demand in importing countries is especially high when solar radiation is strong)

Criterion	CCS	Renewables: wind offshore	Imported renewables: solar electricity from North Africa
Compatibility with other climate protection strategies (decentralised options)	As a centralised generating option only partly compatible with decentralised or fluctuating generation. The controllability of CCS power stations will be the determining factor.	As a centralised generating option only partly compatible with decentralised generation. The controllability of offshore wind farms will be the determining factor	As a centralised generating option only partly compatible with decentralised generation. The controllability of solar thermal power facilities will be the determining factor; local consumers in the country itself would also have to be taken into account
Effect on import dependency	Dependency on imported fossil fuels will increase even more strongly than is already the case	Reduced import dependency depending on level of expansion	Rather than reducing import dependency, shifts it from primary fuels (coal, natural gas, possibly oil) to electricity. Severity of dependency will depend on the kinds of new forms of cooperation that are agreed
Security implications	Vulnerability of the energy system as a whole increases. Pipelines and shipping lanes are attractive targets for terrorist attacks	Electricity system becomes intrinsically more secure through use of numerous small generators in wind farms (few MW per generator). Attractiveness as a target for terrorist attacks low	Vulnerability of the energy system as a whole may increase. High voltage power lines could offer attractive targets for terrorist attacks. Interruption of supply: acute if solar thermal generators or power lines affected
Other aspects		Risk of failure through shipping accidents	Case study Germany: Fundamentally a discussion must be conducted about whether the high voltage transmission line would really have to be constructed all the way through to Germany or whether a simple meshed infeed at the extremities of the European grid would be adequate (the cost of infrastructure would be considerably less in the latter case)

Chapter 10
Life Cycle Assessments for Selected CCS Processes

10.1 Methodology

10.1.1 Goals of Life Cycle Assessment

For our ecological evaluation of selected systems configurations (from natural gas and coal to low-CO_2 electricity and hydrogen) we used the life cycle assessment method (LCA) according to ISO 14.040ff. The first step of a life cycle assessment compares the material and energy flows that enter a system, are converted there and leave it in a different form (input/output balance, inventory analysis). A product LCA thus examines all the material and energy flows caused by a single product, beginning with the extraction and processing of the raw materials and following the process through manufacturing and use to the product's eventual disposal ('cradle-to-grave' approach). The next step is to calculate the environmental impact of the assessed flows. Here it is necessary to '*weigh up, aggregate, or generalise flows of different materials in different environmental media with different environmental impacts*' (Schmidt and Häuslein 1997). One of the environmental impact categories is the greenhouse effect, to which atmospheric emissions of CO_2, methane and N_2O contribute to differing degrees. In this chapter we describe LCAs for the different paths of electricity generation and hydrogen production and assess their impact on the environment.

For inventory analysis the individual processes were modelled using Umberto® life cycle software (IFEU and IFU 2005). LCAs were conducted with the following goals:

- First of all, individual analyses were conducted for the different CO_2 capture and storage options. This made it possible to identify the plant components and life cycle phases that contribute significantly to the overall result. Also, where some of these technologies are still in the development stage, it was possible to make suggestions as to how the plant could be optimised from the environmental perspective.

- In a second step the different options for CO_2 capture and storage were compared with one another in order to identify the advantages and drawbacks of the different technologies.

- Finally, the options for electricity generation and hydrogen production were compared, in order to identify the differences between fossil fuels and renewables regarding climate protection.

The analysis involved several subsequent steps:

- Existing LCAs for parts of the processes under consideration were assessed.

- Specific plant types were described, including the source of the data.

- LCAs were conducted according to ISO 14.040ff (see e.g. Guinée 2002), while the steps of the processes were abridged ('Screening LCA'). In contrast to conventional studies that assess existing systems, we had to consider and assess future plant that have not yet come onto the market: We selected central parameters and modified them to take account of future developments (e.g. modifying power station efficiency from today's level to the probable level of 2020). Of course, such a 'prospective LCA' cannot be regarded as a detailed assessment of a future system, but it does at least reflect a trend.

- The material and energy flows were modelled using the material flow networks methodology implemented in Umberto, forming the basis for the inventory and impact analyses. The impact analyses were conducted using the UBA (German Federal Environment Agency) method of impact categories, which is also implemented in Umberto. The result is 'complete' LCAs (including environmental impact analyses) for CCS-based electricity and hydrogen.

- The results of the impact analysis were split up according to the different life cycle phases and components in order to allow detailed further analyses.

10.1.2 The Methodology of Material Flow Networks

When conducting LCAs, Umberto® uses the methodology of material flow networks (MFN) as a particularly flexible and powerful approach. MFN are capable of modelling the material and energy flows between the elements of a particular section of a real system (e.g. within an industrial process or a power station). It is
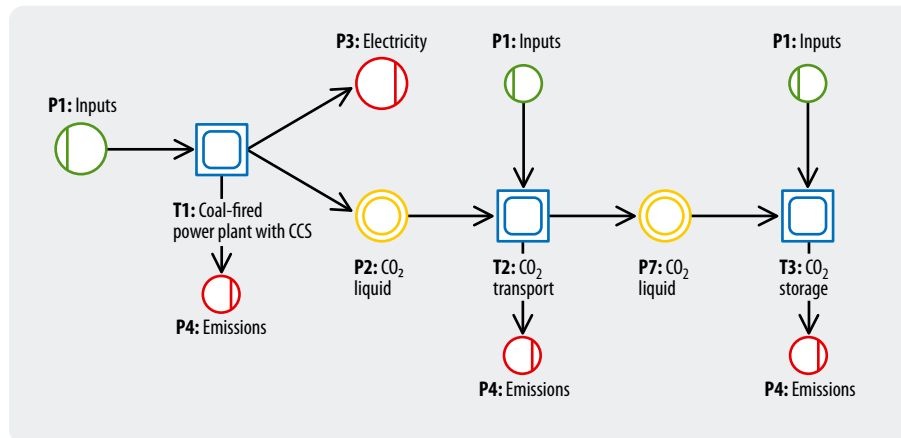
possible to analyse products (differentiated into supply chains, production, use and disposal) or services (e.g. transport of CO_2). The corresponding input and output flows then form the basis for creating LCAs. Fig. 10-1 shows the basic model we used for assessing CO_2 capture and storage techniques.

Material flow networks consist of three types of element: transitions, places and flows. *Transitions* (represented by squares) are processes transforming material and energy (e.g. *T1: Coal-fired power plant with CCS* or *T3: CO_2 Storage* in Fig. 10-1). They play a central role in material flow networks, because all the material and energy flows depend on the transformation processes they represent. The second fundamental element of every material flow network are the *places*, represented by circles (e.g. *P1: Inputs*, *P3: Electricity*). Places separate the transitions from one another and thus make it possible to analyse individual transitions. Finally, *flows* show the paths taken by material and energy between transitions and places (Möller et al. 2001).

The CO_2 sequestration model illustrated above shows the paths of the material flows from the input side to the output side. At transition *T1: Coal-fired power plant with CCS*, a particular amount of coal produces electricity, and CO_2 is emitted. The output flows to places *P3: electricity* and *P2: CO2, liquid*. However, coal is not the only input at transition *T1*. The others represent the 'infrastructure' (manufacture of the power plant and the equipment for CO_2 capture and compression) and the consumables used, altogether. The required inputs are taken from place *P1: Inputs*.

Finally the liquid CO_2 is transported via transition *T2: CO_2 transport* to a sink where it is stored via *T3: CO_2 storage*. Additional inputs of material and energy also appear at these transitions (for example for pipeline manufacture and construction) and each of the processes produces emissions.

The transitions with a double border represent another characteristic of material flow networks. Every transi-
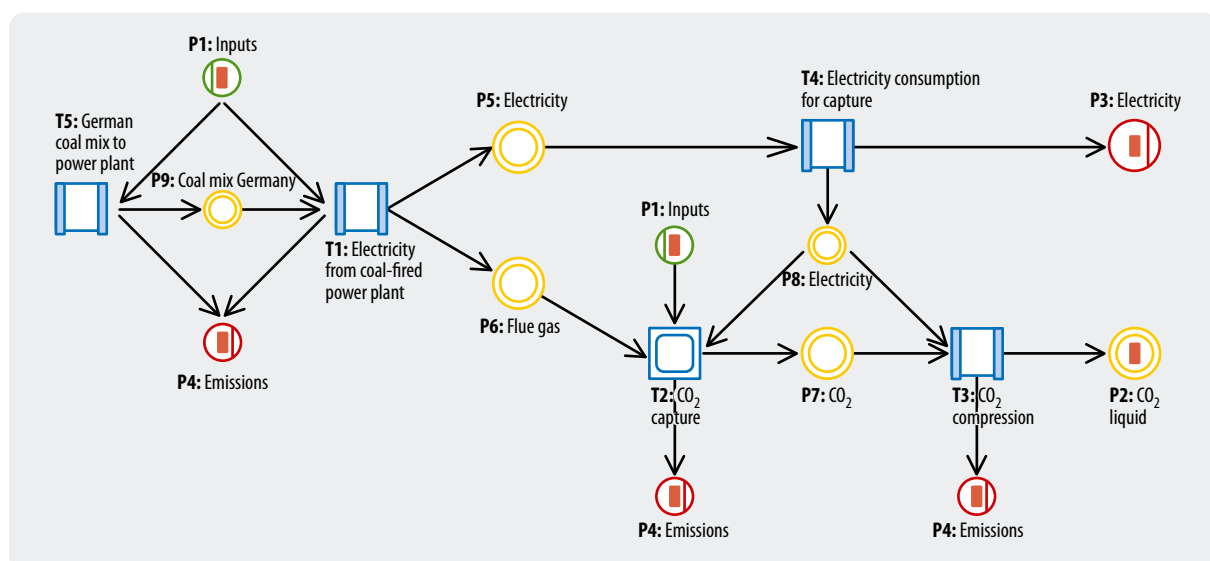
Fig. 10-2: Second-level subnet of T1: Coal-fired power plant with CCS from Fig 10-1

MEA Scrubbing

P9: Inputs P8: Electricity

P6: Flue gas T1: MEA scrubbing P7: CO$_2$

P9

P4: Emissions

P9: Inputs T2: MEA plant
4,500 tonnes CO$_2$/d
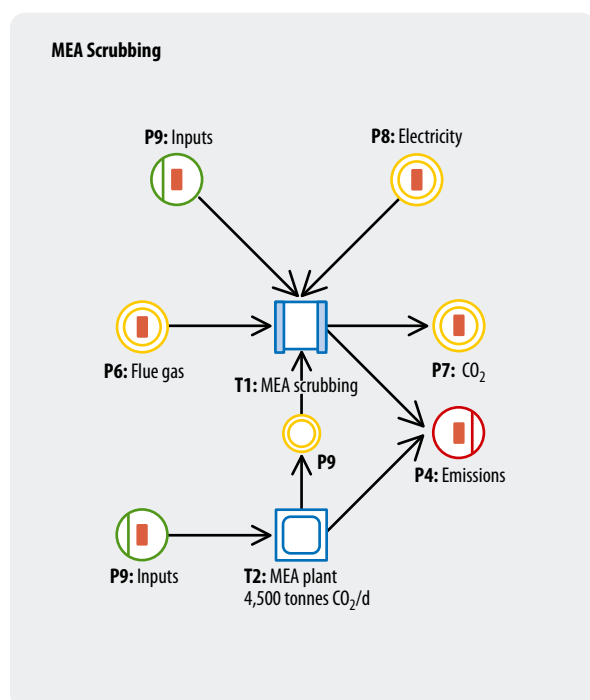
Fig. 10-3: Third-level subnet T2 (CO$_2$ capture)

tion represents a generalisation of another more detailed material flow network (known as a *subnet*). This allows us to create a hierarchical structure with any number of nested networks. Fig. 10-2 shows the refinement of transition *T1: CCS-based coal-fired power station* from Fig. 10-1.

The detailed process of burning coal to generate electricity (based on the German power mix) is represented within transition *T1: Electricity from coal-fired power plant*. The flue gas flows to place *P6: Flue gas* and passes to transition *T2: CO$_2$ capture*. After transition *T3: CO$_2$ compression* the liquefied carbon dioxide leaves the subnet and is now analysed further in the material flow network of level 1. The net electricity output (place *P3*) ultimately comprises the electricity generated in the power station (place *P5*) minus the electricity required for CO$_2$ capture and compression at place *P8*.

The detailed post-combustion capture technology itself is modelled in the level-three subnet T2. Fig. 10-3 shows the corresponding subnet for mono ethanol amine (MEA) scrubbing.

Other subnetworks at the same level as this one model the transport and storage of the captured carbon dioxide.

10.1.3 Scope of LCAs and Underlying Assumptions

Different Types of Power Plants

For *electricity generation* we investigated the environmental impact of various paths (Table 10-1). They included three capture technologies for fossil fuels: post-combustion (with coal- and lignite-fired steam turbine power plant and natural-gas-fired combined cycle NGCC), pre-combustion (coal-fired IGCC) and coal-fired steam turbine power plant with oxyfuel. The Ruhr region (a major industrial region in western Germany) was selected as the location of the power stations and an empty gas field 300 km away in northern Germany as the sink.

For purposes of comparison with renewables, electricity generated by solar thermal power plants (in Algeria) and by wind power (in the North Sea) was also modelled. In order to have the same reference location as with the fossil-fuelled options, the electricity was transported to the Ruhr region using high-voltage direct current lines. Fig. 10-4 shows the process chains modelled.

For *hydrogen production* the environmental impacts of the paths listed in Table 10-2 were investigated. On the fossil fuel side they include steam reforming of natural gas and coal gasification, which currently contribute to global industrial hydrogen production with 33 % and 10 % respectively (alongside 53 % from partial oxidation of crude oil and 4 % from electrolysis). The Ruhr region was again selected as the location.

Table 10-1: Selected systems configurations for electricity generation

Path name	Plant	Capture technology	Location
Low-CO$_2$ electricity from fossil-fuelled power stations with CO$_2$ capture and storage			
EL_CCS_1_STK	Coal-fired steam turbine	Post-combustion (MEA scrubbing)	Ruhr region
EL_CCS_2_NG	Natural gas combined cycle	Post-combustion (MEA scrubbing)	Ruhr region
EL_CCS_3_OXY	Coal-fired steam turbine with oxyfuel	Oxyfuel combustion	Ruhr region
EL_CCS_4_IGCC	Coal-fired IGCC	Pre-combustion (Rectisol scrubbing)	Ruhr region
EL_CCS_5_BRK	Lignite-fired steam turbine	Post-combustion (MEA scrubbing)	Ruhr region
CO$_2$-free electricity from renewables			
EL_REG_1_SEGS	Solar thermal type SEGS	–	Algeria + HVDC to Ruhr region[a]
EL_REG_2_Wind	Wind offshore	–	North Sea + HVDC to Ruhr region
a) HVDC = High-voltage direct-current transmission			
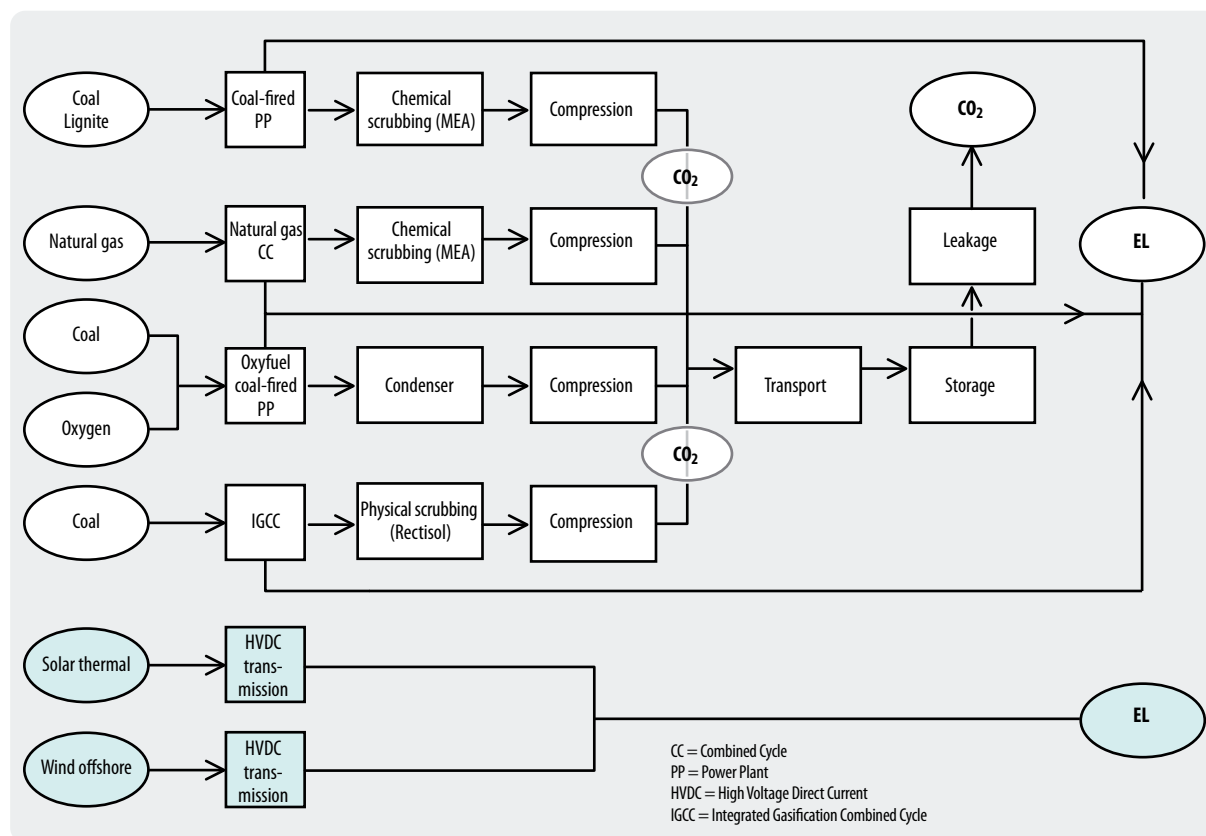
Fig. 10-4: Assessment steps for the electricity generation configurations

Renewable hydrogen production was modelled as electrolysis using electricity from solar thermal power stations in Algeria and offshore wind farms in the North Sea. The location for electrolysis was the Ruhr region; again high-voltage direct-current lines were used for transmission.

Fig. 10-5 shows the process chains modelled.

Table 10-2: Selected systems configurations for hydrogen production

Path name	Plant	Capture technology	Location
Low-CO_2 hydrogen from fossil fuels including CO_2 capture and storage			
H2_CCS_1_NG	Steam reforming (natural gas)	Chemical scrubbing (MEA)	Ruhr region
H2_CCS_2_STK	Coal gasification	Physical scrubbing (Rectisol)	Ruhr region
CO_2-free hydrogen from renewables			
H2_REG_1_SEGS	Electrolysis (solar thermal)	–	Algeria + HVDC to Ruhr region[a]
H2_REG_2_Wind	Electrolysis (wind, offshore)	–	North Sea + HVDC to Ruhr region
a) HVDC = High-voltage direct-current transmission			

Functional Unit

The functional unit for electricity generation is chosen to be 1 kWh_{el}, for hydrogen production it is 1 kWh_{th}. In both cases this means 1 kWh leaving the plant. These system boundaries were selected intentionally because electricity distribution is characterised by considerable data uncertainty and there is as yet no infrastructure for hydrogen distribution.

Geographical Scope and Timeframe

The geographical reference is Germany; i.e. we used LCA modules that cover technologies in Germany or Europe.

Within the project the reference year was 2020 because as yet there are only pilot projects for CO_2 sequestration and capture technologies for use in large power stations have still to be developed. 2020 was also selected as the reference year for the LCAs. For the most important processes such as electricity mix, steelmaking and aluminium smelting, LCA modules projected to 2010 exist, making it possible to conduct a 'dynamic' assessment. That means that product manufacture was assessed not according to the current state of the art but instead approximating production conditions in 2010. This applies, for example, to changes in the electricity mix or increased recycling rates in steel and aluminium production.

Fig. 10-5: Assessment steps for hydrogen production configurations

Table 10-3: Impact categories and assessment parameters considered in this study

Impact category	Assessment parameter	Aggregated impact parameter	Ratio
Resource consumption	Cumulative energy demand	MJ (inventory parameter)	
Global warming potential[a]	CO_2 CH_4 N_2O	g CO_2-equivalent	1 21 310
Acidification	SO_2 NO_X NH_3 HCl	mg SO_2-equivalent	1 0.7 1.88 0.88
Eutrophication	NO_X NH_3	mg PO_4^{3-}-equivalent	0.13 0.33
Photo-oxidant formation	NMHC CH_4	mg ethene equivalent	0.416 0.007
Particles and dust	Airborne particles (PM10) Sekundary aerosol SO_2 Sekundary aerosol NO_X as NO_2 Sekundary aerosol NMVOC Sekundary aerosol NH_3	kg PM10-equivalent	1 0.087 0.216 0.012 0.159
[a] time horizon 100 years			

System boundaries

The *scope* of the assessment comprised the exploration, extraction, preparation and transport of power station fuels (especially for coal and gas) including the provision of the required infrastructure (pipelines, buildings, etc.), the production process (including provision of the required materials and use of energy and consumables) and the construction of power stations and the emissions caused by operation and disposal. For manufacture and operation a distinction was made between conventional power stations and power stations with post-combustion capture technologies (to cover different types of flue gas decarbonisation).

Recycling was assessed according to the closed loop approach decribed in ISO 14.041, i.e. it was assumed that recycled material can replace a certain share of primary material (closed loop approach). Hence on the input side a mix of primary and secondary materials was modelled, using the following recycling shares for the processes: steel (2010), 46 %; aluminium (2010), 85 %; copper, 80 %.

Impact Categories and Assessment Parameters

The impact category method prescribed by ISO 14.042 was used for the inventory analysis, in the specific form of the 'UBA method' developed by the German Federal Environment Agency (UBA) (UBA 1995, 1999) and implemented in Umberto® as the 'UBA method'. The inventory analysis parameters (Table 10-3) were selected to match the impact categories under consideration (Pehnt 2002).

Standardisation

In order to evaluate the improvement yielded by using renewables and applying CO_2 capture and storage to fossil fuels, the results of the LCAs were compared with competing conventional systems. For each scenario under consideration a reference electricity generating system and a widespread type of hydrogen production were selected and compared using the same impact categories.

10.1.4 Data Sources and Quality

In order to conduct an LCA it is necessary to have the inventory data for the individual processes under consideration: material and energy consumption figures for manufacture, operation and disposal of the respective power plant types. Different levels of detail are possible depending on the data available. The data were drawn from various sources. The right-hand column in Table 10-4 shows which LCAs had to be drawn up completely from scratch from literature investigation or our own modelling. Existing LCAs were modified to reflect the CO_2 capture situation.

Estimates of environmental data for renewable energy systems always involve uncertainties. The following quality gradients generally apply (Pehnt 2002):

- Energy consumption data and factors for consumption-related emissions (especially CO_2) are more reliable than factors for emissions unrelated to consumption;

- Factors for emissions from production of infrastructure are less reliable than those for emissions from operation;

- Data for infrastructure of the power stations themselves are more reliable than data for infrastructure of upstream energy supply chains (for example natural gas supply);

- Data for the infrastructure of renewable energy systems are more reliable than those for the infrastructure of fossil-fuelled systems with which they are compared (because in the former case they often represent the only environmental impact);

- Factors for controlled emissions (e.g. NO_x, CO, hydrocarbons) are more reliable than factors for non-restricted emissions.

Differences that arise within impact categories when comparing different technologies can be regarded as insignificant as long as they remain under 5 % for energy consumption and global warming potential, under 20 % for eutrophication and under 30 % for particles and dust.

Table 10-4: Data sources of processes under consideration

Process	Data source	Existing LCA	New LCA prepared
Electricity generation and CO_2 capture			
Natural gas and coal-fired power stations	Umberto, ecoinvent	X	
MEA-scrubbing	Mariz 1998 Chapel and Mariz 1999 Rao and Rubin 2002 Ecoinvent	X	X
IGCC power station	Briem et al. 2004		X
Oxyfuel power station	Göttlicher 1999		X
Electricity from renewables (wind, solar thermal)	DLR database	X	
HVDC transmission	DLR database	X	
Hydrogen production and CO_2 capture			
Coal gasification with/ without CCS	data from IGCC used		X
Natural gas steam reforming	Pehnt 2002		X
Natural gas steam reforming with CCS	ZSW DOE 2002		X X
Electrolysis	DLR database	X	
Compression	Göttlicher 1999		X
Transport			
Pipeline	Ecoinvent	X	
Storage	–		

10.2 Mathematical Methodology – Captured versus Avoided CO_2

Fig. 10-6 shows the derivation of the *captured* and *avoided* amounts of CO_2 per kWh for the example of a coal-fired power station (efficiency 49 %, gross CO_2 emissions 710 g/kWh_{el}).

Bar 1 shows the CO_2 emissions from the power station *without* capture, divided into upstream chain (pre-processes) and operation. Capturing CO_2 requires additional electricity to be generated – and consequently causes additional emissions. The emissions associated with the *additional demand* are also shown, divided into upstream chain and power station operation (bar 2). The capture rate is 88 %, both from the regular operation emissions (assigned to the final product 1 kWh electricity) and those from emissions that arise through capture (bar 3). In bar 4 the respective captured and remaining emissions are added together. Then the CO_2 emissions from transport and storage are added (bar 5). Bar 5 thus brings together all the residual emissions: from the original upstream chain, from original power
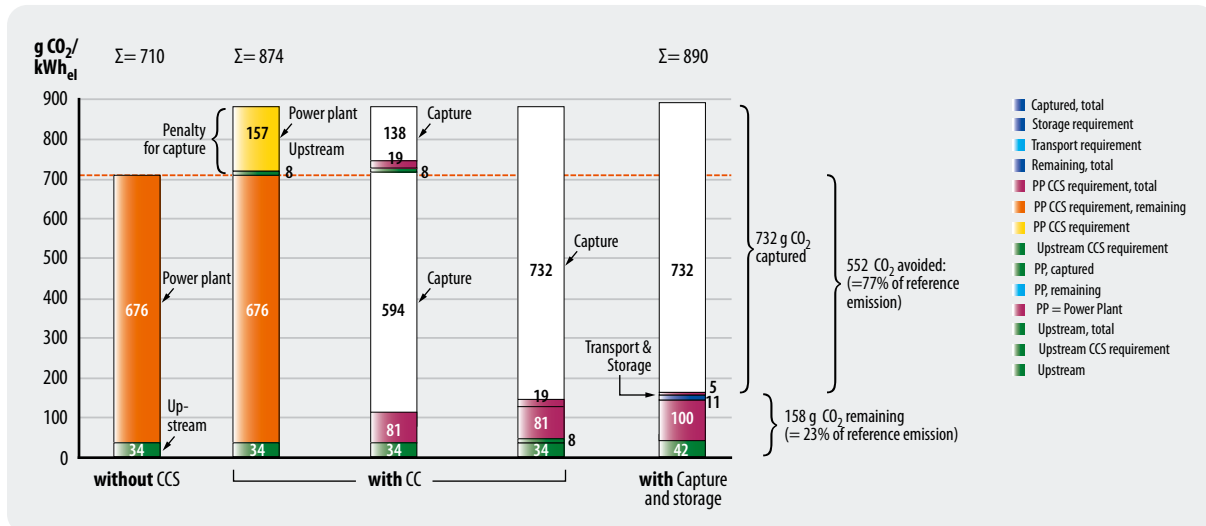
Fig. 10-6: Methodology for calculating captured and avoided CO_2 for the example of a coal-fired power station with and without CCS (CC = carbon capture only, without transport and storage). Efficiency without CCS = 49 %, with CCS = 40 %, capture rate = 88 %

station operation without CCS, from the additional demand and its upstream chain, and from transport and storage (small bracket). Altogether owing to the additional energy demand the gross emissions of 710 g/kWh_{el} initially rise considerably to 913 g/kWh_{el} – which means that the real *avoided* CO_2 emissions (medium-sized bracket) are actually a good deal less than the *captured* CO_2 (large bracket).

10.3 Plant and Processes for Conventional Electricity Generation with CCS

10.3.1 Reference Power Stations

Table 10-5 shows the basic data of the reference power stations without and with CO_2 capture. They are compatible with the data used for the economic calculations and refer to 2020.

In each case the most up-to-date modules for power stations and the supply chain were used to model the LCA. The power station modules are projected through to 2020 by modifying the efficiency according to the values in the table above. The LCA modules came from various sources (see Table 10-6):

- **Coal-fired power plant:** The module describes a coastal coal-fired power station using imported coal in the early 1990s. A flue gas desulphurisation plant, a $DeNO_x$ unit and an electric filter are included to reduce emissions. Flue gas desulphurisation operates using the wet process with pulverised limestone sorbent ($CaCO_3$) and a stoichio-

metric relationship of limestone to SO_2. It reduces SO_2 emissions by 90 %, dust emissions by 90 % and HCl and HF emissions by 95 %.[1] The $DeNO_x$ unit operates using the SCR process (selective catalytic reduction) with ammonia as the sorbent in a stoichiometric relationship, and cuts NO_x emissions by 85 %. The electric filter further reduces dust emissions, resulting in an overall reduction of 99.5 %.

- **Coal-fired IGCC:** The module describes a coal-fired IGCC power station modelling the operating conditions of 2010. There are relatively few IGCC pilot plants in operation worldwide, and there were no LCAs for IGCC until Briem et al. (2004) modelled a future 450 MW plant by taking certain components from existing power stations (gas turbine, generator, coaling plant, et al.) and scaling up others from smaller plants. For components where there were no existing materials data from known plants (e.g. air separation facility, Claus plant, gasification system, et al.), estimates based on materials data of other known components were used.

- **Natural gas CC:** The module describes a combined cycle power plant in Germany in 1994 with low-NO_x combustor. One third of the power comes from the steam turbine, using wet re-cooling via a cooling tower with a water requirement of 190 t/TJ.

- **Lignite-fired power plant:** The module describes averaged data for the lignite-fired power stations in the German public electricity supply, based on the situation at the end of the 1990s (largely 1998). It models mill-drying, boiler (dust firing, fluidised bed firing), steam turbine (national mix rather than

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1 SO_2 content of 222 ppmv calculated from the volume flows and specific SO_2 emissions.

Table 10-5: Basic data for fossil-fired reference power stations without and with CO_2 capture

		Lignite-fired power plant	Coal-fired power plant		Coal-fired IGCC [a]	Natural gas CC [b]
A) Without CO_2 capture						
Output	MW$_{el}$	700	700		700	700
Full load hours	h	7,000	7,000		7,000	7,000
Efficiency	%	46	49		50	60
CO_2-intensity of fuel	g CO_2/MJ [c]	112	92		92	56
	g CO_2/kWh	403	331		331	202
CO_2-intensity of electricity	g CO_2/kWh$_{el}$	849	676		662	337
B) With CO_2 capture						
Capture method		Post-combustion	Post-combustion	Oxyfuel	Pre-combustion	Post-combustion
Scrubbing method		Chemical (MEA) [d]	Chemical (MEA) [d]	Condensation only	Physikal (Rectisol)	Chemical (MEA) [d]
Output	MW	517	570	543	590	600
Efficiency	%	34	40	38	42	51
Loss	% points	12	9	11	8	9
Capture rate	%	88	88	99,5	88	88
CO_2 to store	t/a	5,113,525	3,570,336	4,249,383	3,400,320	1,704,508

a) IGCC = integrated gasification combined cycle (coal gasification)

b) CC = Combine cycle

c) Source: UBA 2003

d) MEA = monoethanolamine

Table 10-6: Sources for the LCA modules for the fossil-fired reference power stations

Power station type	Output [MW]	Functional unit	Efficiency (net) [%]	Source	Modul name	Year
Coal-fired power plant	500	1 kWh$_{el}$	43.5	Umberto	KW SK D (Küste)	Early 1990s
Coal-fired IGCC	450	1 kWh$_{el}$	51.5	Briem et al. 2004	New	2010
Lignite-fired power plant	500	1 kWh$_{el}$	30.1	Umberto	BrkKW o.V	Late 1990s
Natural gas CC	450	1 kWh$_{el}$	55	Umberto	KW Erdgas (D, GuD, 450 MW)	1994

individual plant) and flue gas scrubbing (as actually implemented in overall capacity). Flue gas scrubbing includes dust filtering (electric filter) and flue gas desulphurisation (80 % wet, 15 % quasi-dry, 5 % dry; 70 % with pulverised limestone, 30 % with quicklime; approach derived from ecoinvent). $DeNO_x$ catalytic converters are not usually fitted in lignite-fired power stations but NO_x emissions are reduced to 250 mg/m³ by primary measures.

10.3.2 Supply Chains

The LCA modules for the supply chains come from the following sources (Table 10-7) and cover all steps from raw material extraction to local distribution:

- **Coal:** From unmined coal in deposits to delivered coal at power stations and industrial plant in Germany. The mix of coal sources used was: Germany, 62.1 %; Poland (and Eastern Europe), 12.5 %; South Africa, 10.2 %; Columbia/Canada/USA, 7.8 %; Australia,: 4.1 %; Netherlands (and rest of Western Europe), 3.3 % (Statistik der Kohlenwirtschaft e.V. 2000).

- **Natural gas:** Includes exploration and development of reserves, extraction and conditioning, long-distance transport and regional and local distribution. Most of the natural gas used in Germany is imported, so the supply was divided among the most important supplying regions (Germany, Russia, Norway, Netherlands). Pehnt (2002) projects the current situation described in Umberto for a probable import mix in 2010: Germany, 13 %; Netherlands, 19 %; Norway, 33 %; CIS, 35 %. Finally, the greenhouse gas emissions for Russian natural gas were modified according to the results of a study where the Wuppertal Institute and the Max Planck Institute of Chemistry investigated and updated the greenhouse gas emissions for the Russian natural gas export pipelines (WI and MPI 2004).

- **Lignite:** From unmined lignite to delivery at power stations and industrial plants. The lignite used in Germany is mined almost exclusively in Germany. We distinguished between the western, central and

Table 10-7: Sources for LCA modules for fossil fuel supply chains

Fuel	Functional unit	Source	Modul name	Year
Coal	1 kg	Umberto	Steinkohle-Mix D frei KW/In	2000
Lignite	1 kg	Umberto	Braunkohle-Mix D frei KW/In	1998
Natural gas	1 kJ	Umberto, Pehnt 2002, WI and PMI 2004	Vorkette_ Erdgas_D_2010	2010

eastern deposits to reflect the different complaces of the lignite in those areas. The 1998 mix according to Statistik der Kohlenwirtschaft e.V. (2000) was taken as the basis.

10.3.3 CO_2 Capture Methods

The following methods were used to separate the carbon dioxide:

CO_2 Capture *after* Combustion

Coal-fired power plants and natural gas CC were combined with flue gas decarbonisation, which is an obvious option for retrofitting existing power stations (chemical scrubbing). A capture rate of 88 % was assumed. The modelled method was the Econamine process developed by FluorDaniel of Canada, which works with a 30 % MEA (mono ethanol amine) solution (Mariz 1998; Chapel and Mariz 1999). According to Mariz (1998) consumption of *cooling water* and *electricity* is proportional to the CO_2 content of the flue gas, whereas the the consumption of *steam* and *chemicals* depends only on the *amount of captured CO_2* (and to an extent also on other emissions).

Based on Göttlicher (1999), the following values for CO_2 content were used when determining the variables:

- Coal-fired power plant
  11.2 % CO_2 in flue gas
- Natural gas CC
  3.2 % CO_2 in flue gas

The following values for consumption and emissions were used for modelling capture; unless otherwise indicated they derive from Chapel and Mariz (1999), who modelled a coal-fired power station with MEA capture and a capacity of 1,000 t CO_2/day and assumed that the SO_2 content would be reduced from 250 ppmv to a maximum of 10 ppmv.

Energy consumption

The following energy consumption figures were used for MEA capture:[2]

- Electricity (coal-fired power plant)
  177 MJ_{el}/t CO_2 or 49 kWh_{el}/t CO_2
- Electricity (natural gas CC)
  526 MJ_{el}/t CO_2 or 146 kWh_{el}/t CO_2
- Steam (both power station types)
  4,200 MJ_{th}/t CO_2 or 1,166 kWh_{th}/t CO_2

In modelling terms the steam appears in the LCA as a loss of electricity, which could not be generated by the

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2 Chapel and Mariz (1999) use the American short ton (te) so all the figures they cite had to be multiplied by 1.1023 to give values in metric tonnes (t).

Table 10-8: Modelled residual efficiency of the steam turbine process

Power station type	Residual efficiency of the steam turbine process [%]	Lost turbine output [kWhel/t CO₂]	Direct electricity consumption [kWhel/t CO₂]
Coal-fired power plant	13	187	49
Lignite-fired power plant	15.5	128	49
Natural gas CC	22.5	385	146

steam turbine (lost turbine output). However, because the required steam is taken out as saturated steam (i.e. in one of the later steps of the process), we cannot assume that all the relevant steam turbine energy (about 40 % of energy input) is 'lost' for electricity generation. So instead we use a 'residual efficiency' (Table 10-8) that is determined by adding the directly required electricity to the overall efficiency loss of the reference power stations (8 to 12 % points, see Table 10-5) and placing the remainder in relation to the required steam. We found the following residual efficiencies of the steam turbine process (column 2), from which we were then able to calculate the amount of electricity lost (column 3). Column 4 shows the directly used electricity.

Chemicals

- The solvent MEA must be constantly topped up because a proportion of the original volume is lost through degradation, vaporisation and leaks. Here an average consumption of 1.76 kg/t CO_2 (1.6 kg/te CO_2) was assumed. Any residual SO_x in the flue gas will react with the MEA causing further losses. Additional MEA consumption of 0.49 kg/t CO_2 (0.446 kg/te CO_2) is factored in to account for the assumed residual content of about 10 ppmv SO_x (plus additional SO_3) for a coal-fired steam turbine (see below).

- Owing to lack of data it was impossible to assess the manufacture of the plant for chemical scrubbing, which comprises absorption and desorption columns, three heat exchangers, condensers, pump and fan. However, in comparison with process energy and consumables, manufacturing probably represents a marginal factor.

- Activated carbon and sodium hydroxide (NaOH) are also required for the capture process. The following consumption figures were used: activated carbon 0.0826 kg/t CO_2 (0.077 kg/te CO_2), NaOH 0.152 kg/t CO_2 (0.137 kg/te CO_2).

- Neither the Umberto nor the ecoinvent database includes an LCA module for activated carbon, so it has not yet been possible to model its consumption.

Cooling water

The following values were used for consumption of cooling water for capture:

- Coal-fired power plant
  83.2 m³/t CO_2 (75.5 m³/te CO_2)
- Electricity (natural gas CC)
  121.7 m³/t CO_2 (110.4 m³/te CO_2)

Emissions

- SO_2 in power station flue gas needs to be reduced to a residual content of 10 ppmv in order to minimise the amount of SO_2 that can react with the MEA. The coal-fired power station modules we used in Umberto already specify a 90 % reduction in SO_2 emissions through flue gas scrubbing, which produces a residual content of 222 ppmv. So power station SO_2 emissions were reduced further in a ratio of 220:10 but the costs of this additional flue gas desulphurisation could not be modelled.

- The SO_2 emissions from natural gas CC plant are low anyway so the values were left unaltered.

Table 10-9: Consumption and emissions data used for modelling the MEA capture process

Power station type		Coal-fired power plant	Natural gas CC
CO₂ content of flue gas	%	11.2	3.2
Consumption for MEA capture			
Electricity consumption for capture	kWhel/t CO₂	49	146
Steam consumption for capture	kWhth/t CO₂	1,166	1,166
MEA consumption	kg/t CO₂	1.76 + 0.49	1.76
Activated carbon	kg/t CO₂	0.0826	0.0826
Sodium hydroxide (NaOH)	kg/t CO₂	0.152	0.152
Cooling water	m³/t CO₂	83.2	121.7
Changes in power station emissions			
SO₂ emissions	%	− 99.5	−
NOₓ emissions	%	− 2.5	− 2.5
Dust emissions	%	− 50	− 50
Hydrogen chloride (HCl)	%	− 95	− 95

- NO_2 in flue gas can corrode steel and degrade the solvent so it should also be reduced. Because NO_2 represents only 10 % of NO_x emissions and in turn only 25 % of these emissions can be reduced (Rao und Rubin 2002), power station NO_x emissions overall are reduced by 2.5 %. The costs of this additional cleaning were also impossible to model.

- Dust and hydrogen chloride react with the solvent, allowing dust emissions to be reduced by 50 % and HCl emissions by 95 % (Rao and Rubin 2002).

Table 10-9 gives an overview of the figures used.

CO_2 Capture *before* Combustion

In coal-fired IGCC, the CO_2 is captured before combustion (fuel gas decarbonisation) using physical scrubbing to separate the CO_2 from a H_2/CO_2 mixture. Existing literature specifies only the electricity consumption required for the individual steps of this process (Göttlicher 1999, Fig. 3.45), which meant that it was not possible to model in detail the CO shift and the physical scrubbing. A capture rate of 88 % was assumed.

Electricity consumption CO shift	125 kWh$_{el}$/t CO$_2$
Electricity consumption physical scrubbing	48 kWh$_{el}$/t CO$_2$
Lost turbine output	30 kWh$_{el}$/t CO$_2$
Total	203 kWh$_{el}$/t CO$_2$

Oxyfuel Process

The oxyfuel process involves burning coal in pure oxygen rather than in air. Here it is applied to the reference coal-fired power station. The advantage of combustion in oxygen is that the volume of waste gas is much smaller, and the flue gases consist largely of CO_2 (about 80 % by volume) which means that the CO_2 can be captured simply by condensing out the water. No chemical or physical scrubbing is required. The disadvantage is the very large amount of electricity used by the air separation facility to produce the oxygen.

For this project an air separation facility is added to the coal-fired power station, without more detailed modelling of the material flows. The following data were used:

- The air separation facility was taken from the coal-fired IGCC model in Briem et al. (2004) which assumes the conditions of application for 2010. A facility dimensioned for a 450 MW$_{el}$ power station was linearly scaled up for the power station output of 700 MW$_{el}$ required here.

- The waste gas is condensed in the SO_x scrubber, meaning that only power stations with wet desulphurisation can be used here (as implemented in

the coal-fired power station used in the Umberto module). However, the captured CO_2 still has a residual moisture content of approx. 1 %. If dry gas is to be generated it must be cooled further to condense out the remaining water. This additional cost is ignored here, making the calculation for capture a conservative one.

- On the other hand, an oyxfuel power station can dispense with the standard denitrification equipment because most of the nitrogen oxides in the standard process originate from the oxidation of atmospheric nitrogen, which is absent here. The lower internal consumption at the oxyfuel power station resulting from the absence of denitrification equipment is also excluded here.

- It has not yet been possible to model the nitrogen oxide emissions, so the old values for the original power station (which are too high) were used.

- Apart from the air separation facility the only extra cost was for liquefying the carbon dioxide.

- A CO_2 capture rate of 99.5 % was assumed according to Göttlicher (1999) who stated that 'considerably more than 99 %' of the CO_2 could be retained.

- Göttlicher (1999) gives 2.7 kg O_2/kg fuel as the mean oxygen requirement for a coal-fired oyxfuel power station.

- For the electricity required by the air separation facility, a mean was calculated using the data given by Göttlicher (1999); the figure found was 0.2245 kWh$_{el}$/kg O_2. Here oxygen is produced at a high purity of 96–97 %, which requires more energy. However, this at the same time reduces the work of the compressor because less inert gas has to be liquefied along with the CO_2 (Göttlicher 1999).

10.3.4 CO_2 Liquefaction

For initial compression to 110 bar (and thus liquefaction of the CO_2) we took a figure of 110 kWh$_{el}$/t CO_2 (Göttlicher 1999), for multi-stage compression starting from 1 bar with intermediate cooling to 30°C.

10.3.5 CO_2 Transport

The transport and storage of CO_2 was modelled for a single power station, taking the Ruhr region as the origin and an exhausted gas field (no further specified) in northern Germany as the destination. An arbitrary transport distance of 300 km was chosen, and it was assumed that the pipeline would have to be built specially for this power station because only in exceptional circumstances it will be possible to use existing (natural gas) pipelines. This transport and storage scenario was applied to all the reference power stations defined above (see Table 10-10).

Table 10-10:
CO_2 transport scenarios for power stations

Scenario	Location of CO₂ source	Power station type and electrical output	Captured CO₂ [Mt/a] [a]	[t/d] [d]	Pipeline land [b] + ship [km]	Pipeline diameter [c] [mm]	Storage location
1	Ruhr region	Coal 700 MW	3.57	9,781	300 + 0	400	Gas field onshore
2	Ruhr region	Lignite 700 MW	5.11	14,010	300 + 0	450	Gas field onshore
3	Ruhr region	Natural gas CC 700 MW	1.70	4,670	300 + 0	305	Gas field onshore
4	Ruhr region	IGCC 700 MW	3.4	9,316	300 + 0	380	Gas field onshore
5	Ruhr region	Coal oxyfuel 700 MW	4.25	11,642	300 + 0	400	Gas field onshore

[a]	Calculated with 7,000 h/a base load capacity, capture rate 88 %
	Coal-fired power station: CO₂ emissions = 676 g/kWh_el, efficiency 49 % → 40 %
	Lignite-fired power station: CO₂ emissions = 849 g/kWh_el, efficiency 46 % → 34 %
	Natural gas CC: CO₂ emissions = 337 g/kWh_el, efficiency 60 % → 51 %
	Coal IGCC: CO₂ emissions = 662 g/kWh_el, efficiency 50 % → 42 %
	Coal oxyfuel: CO₂ emissions = 676 g/kWh_el, efficiency 49 % → 38 %
[b]	Including a gas-turbine-powered turbo-compressor
[c]	Estimated after data in Bock et al. (2001)
[d]	Calculated with 365 d/a

Transport was modelled using existing LCA modules for natural gas pipelines from the ecoinvent database (see Table 10-11). Pipelines for CO_2 and natural gas are comparable in terms of construction and operation, i.e. data for material, land use, monitoring and dismantling and can be taken from natural gas pipelines. There are marginal differences in operating energy (compressor output for transporting a particular quantity of CO_2 over a particular distance) but these can be ignored for the moment. To model larger scale transport scenarios it might be necessary to take into account a port infrastructure (for ship-transport) and/or intermediate storage facilities.

If we compare the transport requirement of the transport scenarios (300 km Ruhr region to northern Germany with max. 14,000 t CO_2 per day) with the capacities of the long-distance pipeline modules, we find that the 'Onshore, low capacity' type (Table 10-11) is sufficient. With an annual capacity of 5 Mt it might at first seem overdimensioned for the natural gas CC option, but it must be remembered that all costs are calculated in terms of tonne-kilometres transported, so if the quantity of material flowing in the pipeline is smaller the material and energy flows will be smaller too.

10.3.6 CO₂ Storage

Due to the lack of sources it has not yet been possible to identify data for the required material and energy consumption for storage, but for a similar case Hendriks et al. (2004) give transport costs of \$5/t CO_2 and storage costs of \$1.1–3.6/t CO_2 depending on storage depth. So if we take the average figure of \$2.35/t CO_2, the storage costs amount to about half the transport costs. This relation is also used for the initial storage LCA, where 50 % of the values for transport were used to calculate emissions and cumulative energy demand.

No expert has yet been able to prove that the storage options on offer will be 100 % leak-proof, so an LCA must also address the question of possible leakage rate. The following questions arise here:

Table 10-11:
Long-distance natural gas pipeline modules in the ecoinvent database (ecoinvent 2005)

Type	Diameter [mm]	Wall thickness [mm]	Average transport capacity [Mio. Nm³/h]	[Mt/a] [a]	[t/d]	Pressure [bar]	Service life [a]
Onshore, low capacity	950	10	0.8	5	13,824	65–100	50
Onshore, high capacity	1,220	12	1.1	7	19,008	65–100	50
Offshore, high capacity	1,000	25 + 100 for concrete casing	1.6	10	27,648	65–100	50

[a]	Calculated with 0,72 kg CH₄/Nm³

Compressors: Pipelines have a gas-turbine-powered turbo-compressor (10 MW) every 150 km.

- Which leakage rate should be modelled?

- Will leakage occur from the outset or only at a later stage?

- Will it be possible to seal leaks or will all the CO_2 escape?

- Which period must be considered for leakage?

Given these still unresolved questions, the following models initially take a leakage rate of 0 % in order to determine the 'best case'. Then different leakage rates are applied in a sensitivity analysis (see section 10.7.1).

10.4 Plant for Generating Electricity from Renewables

Fossil-fired power stations were compared with those types of power plant using renewables that will be available in 2020. Because the transport scenarios described above took the Ruhr region as the location for the fossil-fuelled power stations, the plant using renewables was also modelled on the basis of delivery of electricity to the Ruhr region. Table 10-20 shows the power plant modelled:

- **Solar thermal:** It is likely that by 2020 electricity will be generated by solar thermal plant in North Africa and transported to Europe using high-voltage DC transmission lines. Through the use of thermal storage, solar electricity could even be used as base load in the German and European electricity grids (DLR 2006). For purposes of comparison with conventional power stations we took a solar thermal power plant in Algeria with high-voltage transmission to the Ruhr region, using the LCA for a solar thermal plant with 200 MW output designed for solar-only operation. This is possible through thermal storage which stores excess heat during the day and releases it again at night. The SEGS plant was originally modelled by Viebahn (2004) for 80 MW output at a location in Egypt and scaled up to 200 MW by May (2005) for a location in Algeria (with greater solar radiation intensity).

- **Wind:** By 2020 large offshore wind farms will be operating in the North Sea generating electricity that can also be transported to the Ruhr region

using high-voltage lines. The applied LCA uses a 1.5 MW wind generator from Pick (1998). Both Briem et al. (2004) and Chataignere and le Boulch (2003) have demonstrated that the environmental impact of an onshore wind generator is not much different from that of a much larger offshore facility (e.g. 4.5 MW). Wind conditions are considerably better offshore, but much greater amounts of steel and concrete are required for construction. The two effects roughly balance each other out, making it possible to use the existing LCA for the onshore facility.

For the transport of electricity generated in North Africa or the North Sea by high-voltage line to the Ruhr region reference location we used an LCA by May (2005), modelled a 10 GW overhead line (800 kV double bipole system on two separate lines with aluminium-steel cable) and a 10 GW undersea cable (800 kV earthing cable with central copper conductor). The following distances were applied in this study:

- **Solar thermal**, Algeria to Ruhr region: high-voltage transmission via 3,100 km overhead line and 18 km undersea cable.

- **Wind** offshore, North Sea to Ruhr region: high-voltage transmission via 500 km overhead line and 30 km undersea cable.

10.5 Analyses of Individual Electricity Generating Systems

10.5.1 Conventional Power Stations

In the following we use the example of the coal-fired steam power station to show a) which contributions the individual steps of CO_2 capture and storage make to the overall result and b) how the emissions and cumulative energy demand change when CCS is used (see Fig. 10-7).

- When power stations are modelled in LCAs we generally distinguish between power station operation itself and the supply chain of the raw materials used, especially fuel. As can be seen in the following figure, the coal upstream chain represents only a small proportion of the CO_2 emissions (5 %) but a not inconsiderable share of total greenhouse gas emissions (13 %) (bars 1 and 3).

Plant	Output [MW]	Fuctional unit	Efficiency [%]	Source	Comments
Solar thermal (type SEGS)	200	1 kWh	17.6	Viebahn 2004, May 2005	
Wind offshore	5	1 kWh		Pick 1998	Onshore plant equated with offshore after Chataignere and le Boulch (2003)

Table 10-12:
Reference power plant using renewables

Fig. 10-7:
Comparison of CO_2 emissions, total greenhouse gases and cumulative energy demand for the coal-fired power station without and with CCS
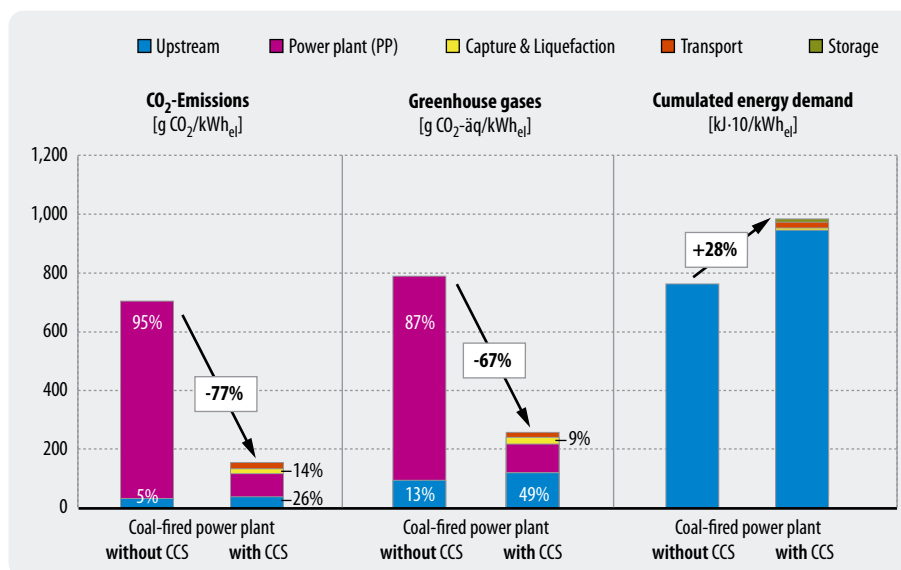
This Screening LCA models emissions of the three greenhouse gases CO_2, methane (CH_4) and N_2O (nitruous oxide). Methane emissions during mining are a particular issue in the coal supply chain, while in the natural gas supply chain leakages during transport are one of the main causes of emissions (WI and MPI 2004). As well as these impacts from the supply chain, the application of CCS also includes emissions from capture, transport and storage, as can be seen in the second, fourth and sixth bars. While the capture step represents a relevant proportion of emissions (9 % of greenhouse gases and 14 % of CO_2 emissions), transport and storage each represent only a minimal share of the overall CCS process. Capture also includes liquefaction (compression to 110 bar).

- For the coal-fired power plant, as for the other reference power stations, we took a CO_2 capture rate of 88 %. But the CO_2 emissions of the process as a whole only decrease by 77 % because we have to add the additional (indirect) emissions from the capture process and to a small extent from transport and storage too (compare bars 1 and 2). The impact from the upstream and downsteam chains cannot be reduced by means of CO_2 capture. The overall result is significantly worse if we consider greenhouse gas emissions in total, which can only be reduced by 67 % (bars 3 and 4). Here an important role is played in particular by the high level of methane emissions in the supply chain, which cause the supply chain's share to rise to 49 % for the CCS power station (bar 4). Cumulative energy demand ultimately rises to 9,870 kJ/kWh$_{el}$, or 128 % of the original figure of 7,740 kJ/kWh$_{el}$, largely because of the additional energy required for capture (bars 5 and 6).

Fig. 10-8:
Comparison of the shares of power plant and high-voltage DC transmission for emissions and cumulative energy demand
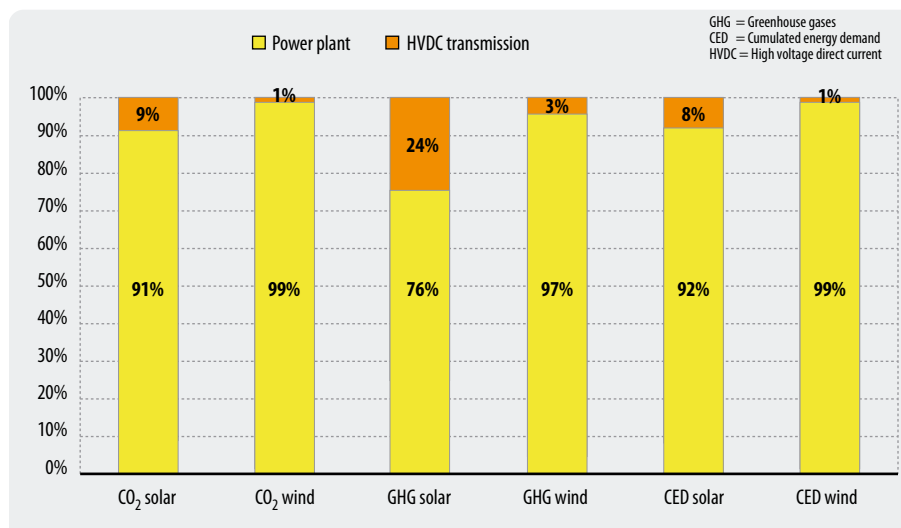
10.5.2 Power Plant Using Renewables

With power plant using renewables there is no comparison with an alternative system because in comparison with fossil-fuelled power stations the emissions are very small from the outset (see below). With the wind- and solar-powered plant under consideration here, a distinction between supply chain and power plant is not generally made because there are no fuel supply chains to model.

What is relevant in this study, however, is the distinction between power plant and electricity transport, because as explained above, electricity is transported by high-voltage line from Algeria or the North Sea to the Ruhr region. As Fig. 10-8 clearly shows, with wind the high-voltage line represents only 1–3 % of overall emissions and energy, but for solar thermal the figure is between 8 and 24 %. The figures for greenhouse gases are generally somewhat higher because N_2O emissions occur during operation through ionisation of air molecules on the transmission line (May 2005). The share is generally higher for solar thermal because the transmission line (3,120 km) is much longer than for wind (530 km).

10.6 Comparison of Energy Generation Systems

10.6.1 Greenhouse Gases and Cumulative Energy Demand

The approach described above was applied to all the fossil-fuelled power station types under consideration. The following figures begin by comparing the four fossil-fuelled reference power station types

- coal (steam),
- lignite (steam),
- natural gas CC and
- coal IGCC

with their respective CCS versions. As well as CO_2 emissions (Fig. 10-9) and greenhouse gas emissions (Fig. 10-11), cumulative energy demand is also shown (Fig. 10-13). The climate-relevant emissions of the CCS power stations are also compared with a selection of other options (Fig. 10-10 and Fig. 10-12):

- **renewables** (solar thermal and wind power) and
- **advanced fossil-fuelled combined heat and power (CHP)** technologies (natural gas and natural gas CC)

Other impact categories are considered in section 10.6.2.

In the comparison with CCS versions it should be noted that a capture rate of 88 % was applied for power stations with pre- and post-combustion CO_2 capture, but 99.5 % for the oxyfuel power station.

The following conclusions can be drawn from the comparison of CO_2 emissions in Fig. 10-9:

- If we first consider only the power stations with pre- and post-combustion technology, a reduction in CO_2 emissions by 72 % to 78 % can be achieved in all four power station types under the given assumptions. Relatively speaking, the natural gas CC power station does worst (–72 %) because in relative terms the upstream chain emissions are highest in relation to the other emissions (and cannot be reduced by capture technology).

Fig. 10-9: Comparison of CO_2 emissions from fossil-fuelled reference power stations without and with CCS

Fig. 10-10:
Comparison of CO_2 emissions from CCS power stations with selected plant from the fields of renewables and advanced fossil-fuelled CHP technologies
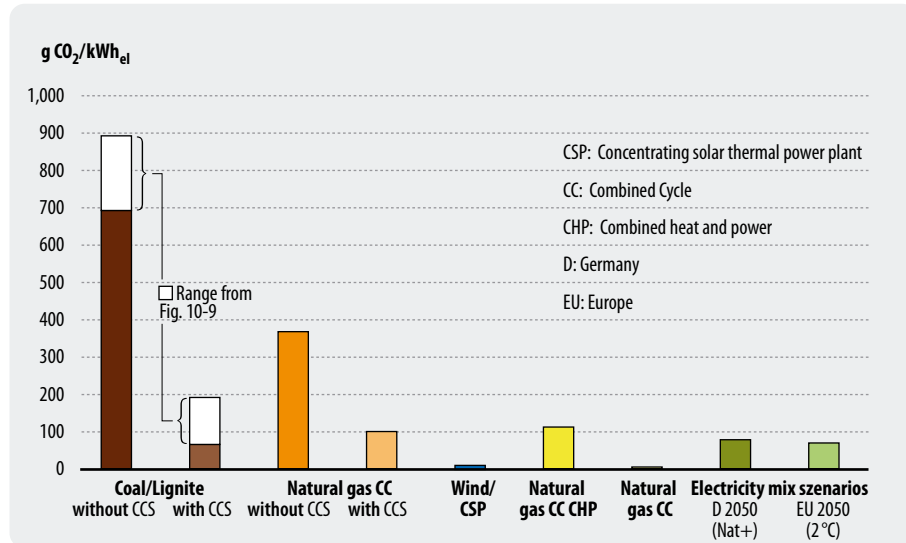
If we compare the actual reduction (72 % to 78 %) with the selected capture rate (88 %), we find a difference of 10 to 16 percentage points. This is caused by the emissions produced in the supply chain and the higher specific energy consumption caused by capture.

The coal-fired power station with oxyfuel technology achieves a 90 % reduction in CO_2 emissions. This is 10 percentage points less than the high initial capture rate of 99.5 %, and here too the causes are upstream chain emissions and higher energy consumption for both capture and transport (larger quantities to transport).

Fig. 10-10 compares electricity generated in CCS power stations (coal and natural gas) with renewables (offshore wind and solar thermal) and advanced CHP technologies (natural gas, natural gas CC). The comparison also shows possible electricity mixes for Germany and Europe for 2050, whose feasibility has been demonstrated by various studies conducted by DLR.[3] While the impact of renewables is very small (resulting from the manufacture and construction of plant), the figures for fossil technologies and future electricity mixes (without CCS) are only a little higher than for power stations with CCS.

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3   Sources: CHP with natural gas, natural gas CC: Fritsche et al. (2007); electricity mix Germany: Nitsch (2007); electricity mix EU: Greenpeace and EREC (2007)
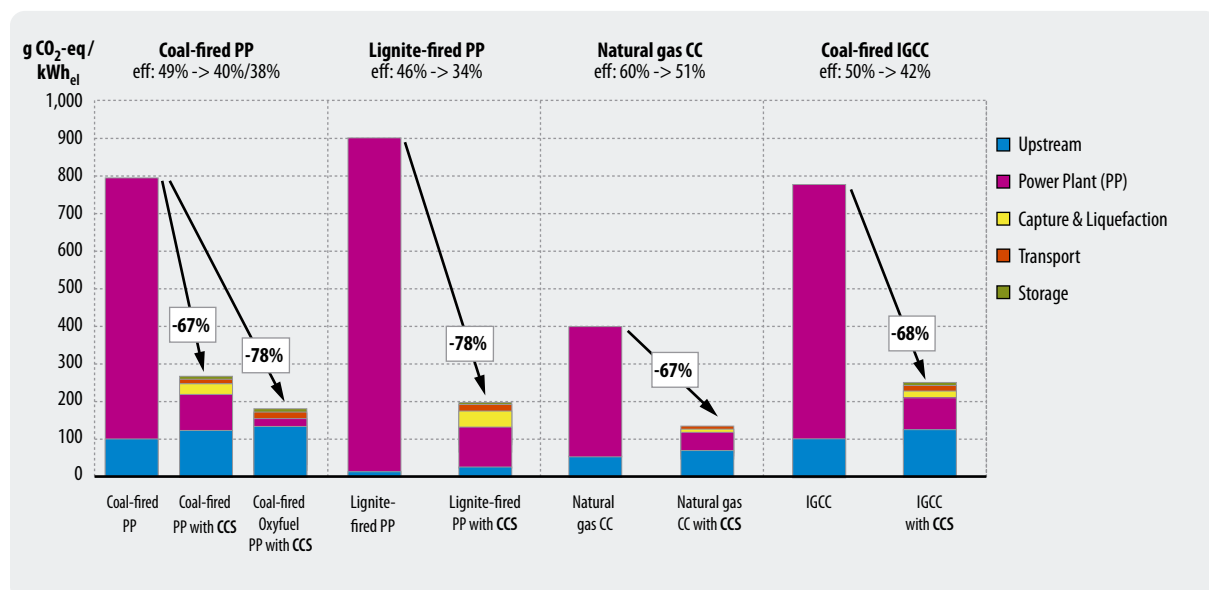
Fig. 10-11: Comparison of greenhouse gas emissions from fossil-fuelled reference power stations without and with CCS

We find similar conclusions when greenhouse gas emissions are compared (Fig. 10-11). As greenhouse gases we included the CO_2 equivalents for CO_2 itself, CH_4 and N_2O, weighted according to the factors in Table 10-3.

- The relative reductions in greenhouse gas emissions are smaller than just for CO_2 emissions, because as well as carbon dioxide, methane and N_2O also contribute to the global warming potential.

- In power stations with pre- and post-combustion technology a reduction in greenhouse gas emissions of 67 % to 78 % can be achieved. Because of the low level of supply chain emissions the lignite-fired power station does best here

(minus 78 %). With natural gas CC, and especially the coal-fired power station, methane emissions contribute to a higher greenhouse effect (pipeline leakage and release during mining).

- Despite the high CO_2 capture rate of 99.5 %, the coal-fired power station with oxyfuel technology achieves only a 78 % reduction in greenhouse gas emissions, putting it close to the lignite-fired power station with post-combustion CCS in both relative and absolute terms. The reason for this is again the methane emissions associated with coal mining.

- The best power station without CCS (natural gas CC) has, with 396 g CO_2 equivalent per kWh, only
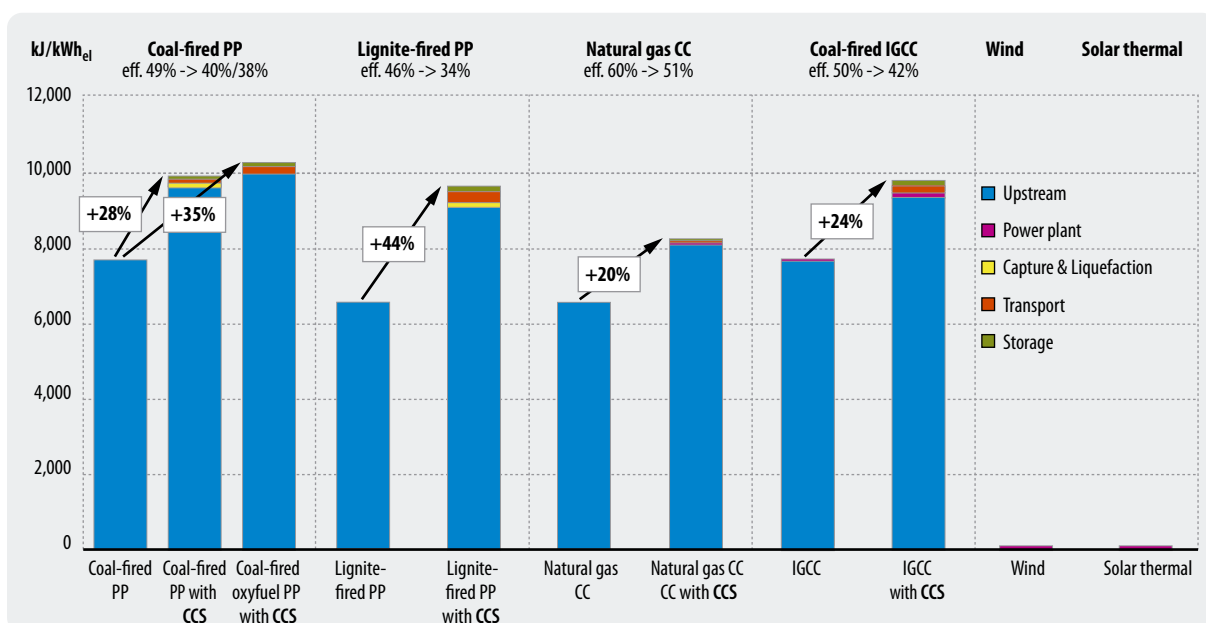
Fig. 10-13: Comparison of cumulative energy demand for reference power plant using fossil fuels and renewables without and with CCS
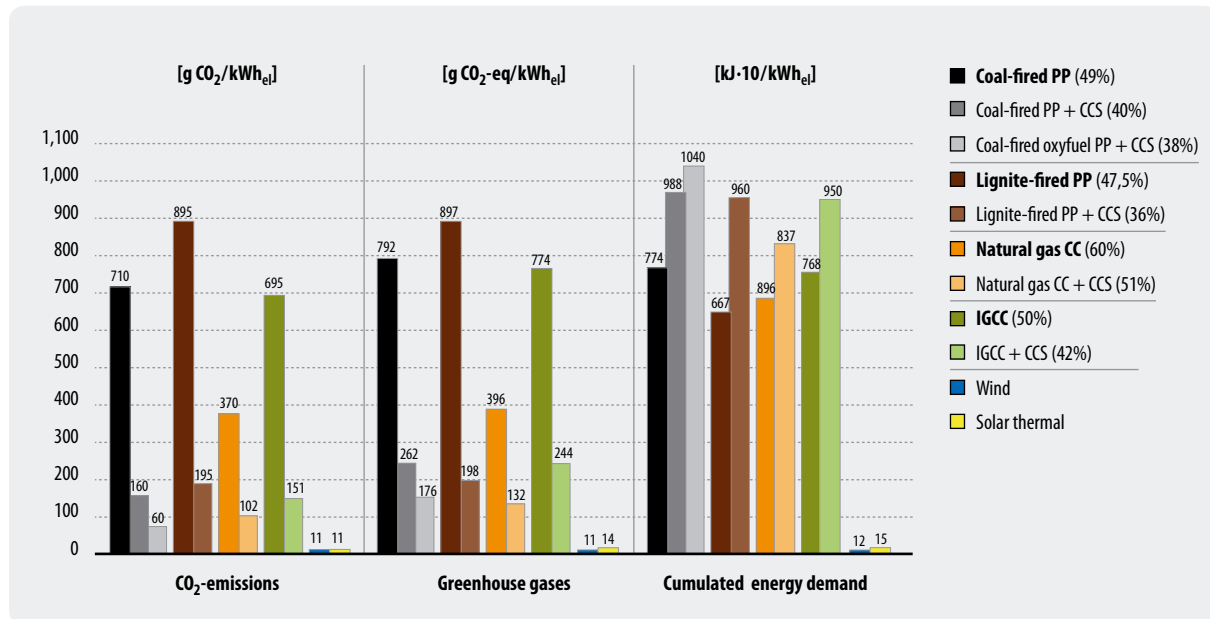
Fig. 10-14: Comparison of absolute CO_2 emissions, total greenhouse gases and cumulative energy demand for reference power plant using fossil fuels and renewables without and with CCS

51 % more emissions than the worst power station with CCS (coal-fired steam power station with post-combustion CO_2 capture and 262 g CO_2 equivalent per kWh).

As in the case of the CO_2 emissions, the total greenhouse gas emissions from electricity generated from wind or solar thermal plant are negligible (Fig. 10-12). Even more than for CO_2 emissions alone, overall greenhouse gas emissions for advanced CHP technologies and future electricity mixes (without CCS) are roughly

equivalent to those for power stations using CCS. This means that with CHP using natural gas and natural gas CC, there are technologies on the market today that are already as green as the target for CCS power stations in 2020.

The following conclusions can be drawn for cumulative energy demand (Fig. 10-13):

- The increases in energy demand are between 20 % and 44 %. The higher the specific CO_2 emissions
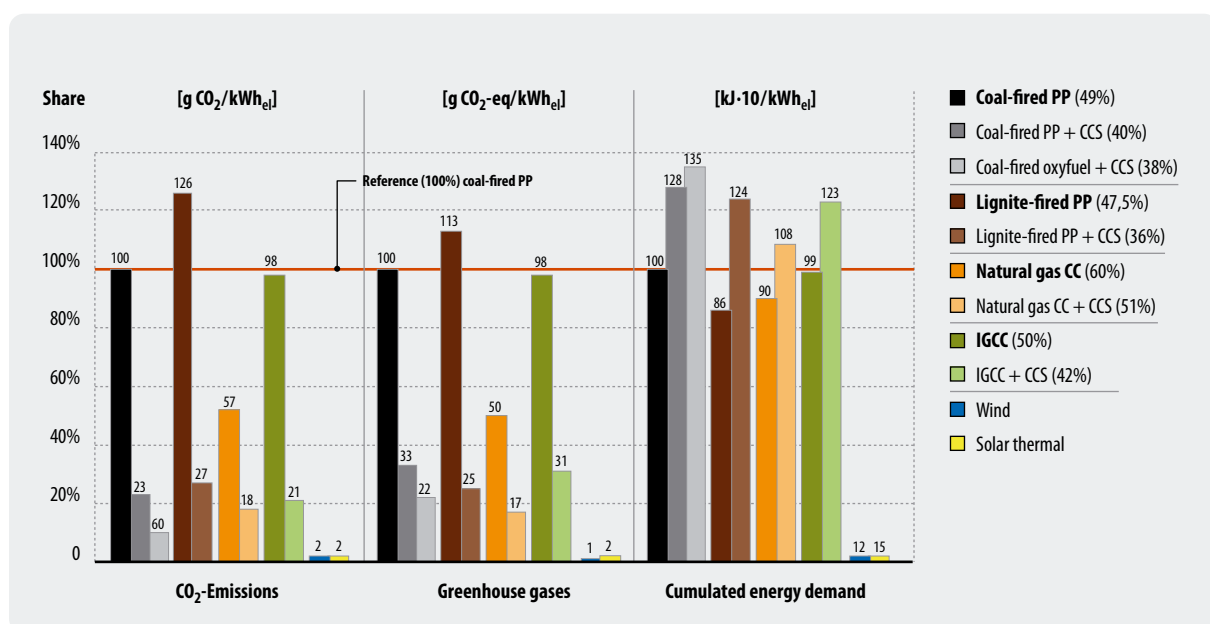
Fig. 10-15: Comparison of relative CO_2 emissions, total greenhouse gases and cumulative energy demand for reference power plant using fossil fuels and renewables without and with CCS (relative to coal-fired steam power station)
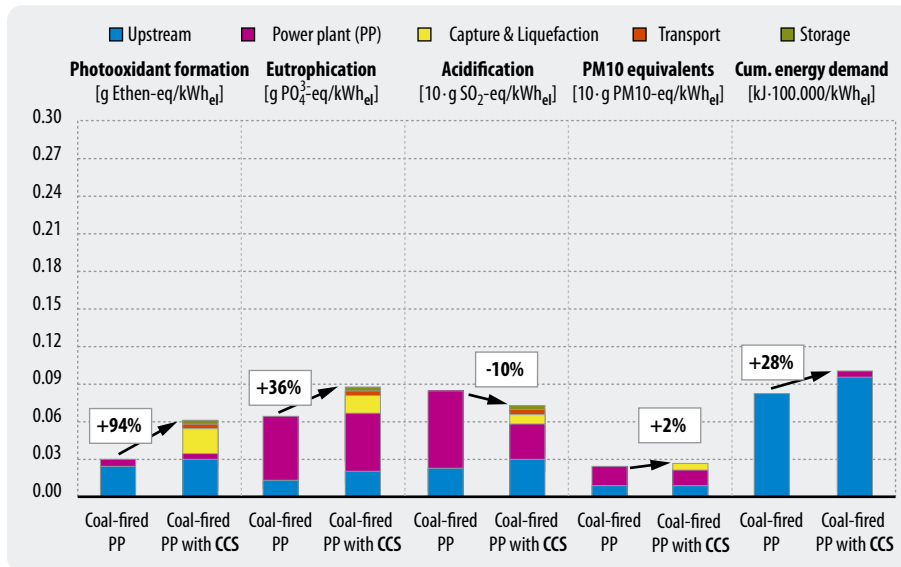
Fig. 10-16:
Comparison of other impact categories for coal-fired steam power station without and with CCS (post-combustion)

of the reference power station (without CCS) the greater the increase, because if emissions are higher more CO_2 is captured and consequently more energy is required. Accordingly the lignite-fired steam power station has the largest increase in cumulative energy demand, natural gas CC the smallest.

- The cumulative energy demand for electricity from wind power and solar thermal is again negligible (about 2 % of the cumulative energy demand of the coal-fired reference power station).

The next two figures provide two different illustrations of these relationships. Fig. 10-14 shows the *absolute* figures, while Fig. 10-15 gives the values relative to the *reference coal-fired steam power station* (= 100 %).

10.6.2 Other Impact Categories

As described in the methodology (section 10.1.3), other impact categories are also analysed in an LCA apart from global warming potential and cumulative energy demand. These are photo-oxidant formation, eutrophication, acidification, and dust and particles. They play a role especially when CO_2 capture not only brings about increased energy consumption (in which case they would increase in a linear fashion like CO_2 or methane emissions), but other materials and substances are used too, for example the production of monoethanolamine (MEA) for post-combustion capture. Furthermore, as explained above, certain emissions are reduced by reactions with the solvent, which can cause a relative reduction in particular impact categories.
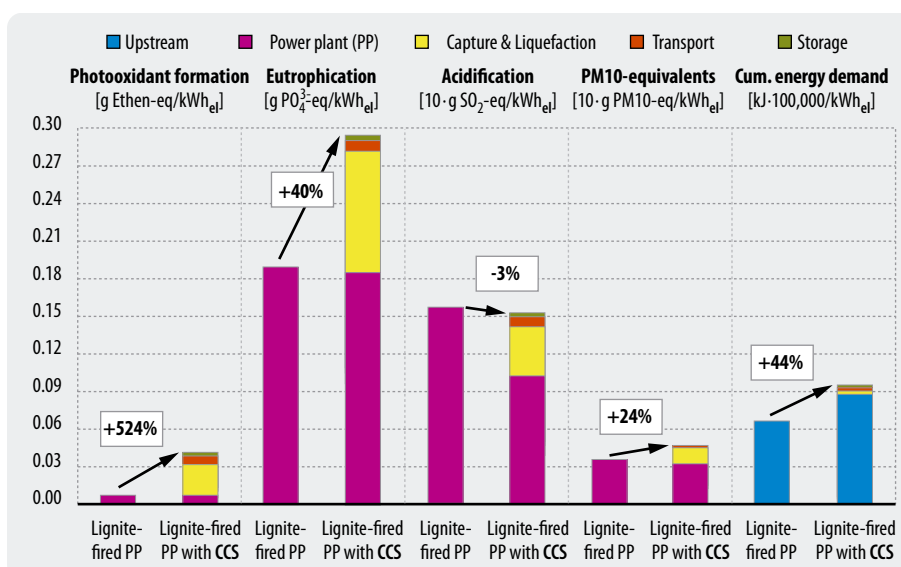
Fig. 10-17:
Comparison of other impact categories for the lignite-fired power station without and with CCS (post-combustion)

Fig. 10-16 shows the change in the impact categories for the example of the coal-fired power station without and with CCS. The 28 % increase in energy consumption for capture, transport and storage initially causes a proportional increase in all the impact categories. But the following influences must also be noted:

- The disproportionate rise in *photo-oxidant formation* by an additional 66 percentage points (total increase 94 %) is caused by the production of monoethanolamine for the capture process (and to a lesser extent also the required sodium hydroxide).

- The additional increase in *eutrophication* is also due to production of chemicals, but it is somewhat ameliorated because the NO_x emissions that contribute to eutrophication are also (slightly) reduced by the CO_2 capture process.

- The overall balance of *acidification* is negative because of the almost complete elimination of SO_2 emissions from operation. But because other substances such as NO_x emissions also contribute to acidification, and the supply chain, transport and storage must also be factored in, the overall reduction is only 10 %.

- Similarly, even though particle emissions from operation are halved, there is still a 2 % overall increase in *PM10 equivalents*.

Overall it must be remembered that it has not yet been possible to fully model the capture process using MEA, so the results should not yet be regarded as conclusive.

Similar effects are found with the lignite-fired power station (Fig. 10-17), except that the values are a good deal higher than for the coal-fired power station (the scales are identical).

- In absolute terms the rise in *photo-oxidant formation* is slightly larger than for the coal-fired power station (because the greater CO_2 emissions mean there is more CO_2 to capture and more MEA is used). But in relative terms the effect is much greater (+ 524 %) because there are only minimal emissions from the supply chain.

- Because the lignite-fired power station has higher operating emissions, emissions associated with capture are also considerably higher. And the emissions from chemicals production come on top of this too. Because in the power station without CCS the supply chain plays a relatively small role, the overall increase is greater than for the coal-fired power station.

Finally, Fig. 10-18 compares the impact categories of photo-oxidant formation, acidification and eutrophication for all the analysed power stations plus electricity from renewables. All the figures are given in relation to the coal-fired steam power station. The figure shows in particular the great differences in emissions between coal and lignite. It should be noted that detailed modelling of individual emissions has not yet been conducted for the oxyfuel and IGCC (pre-combustion) power stations; instead a proportional increase corresponding to the additional energy demand was assumed.
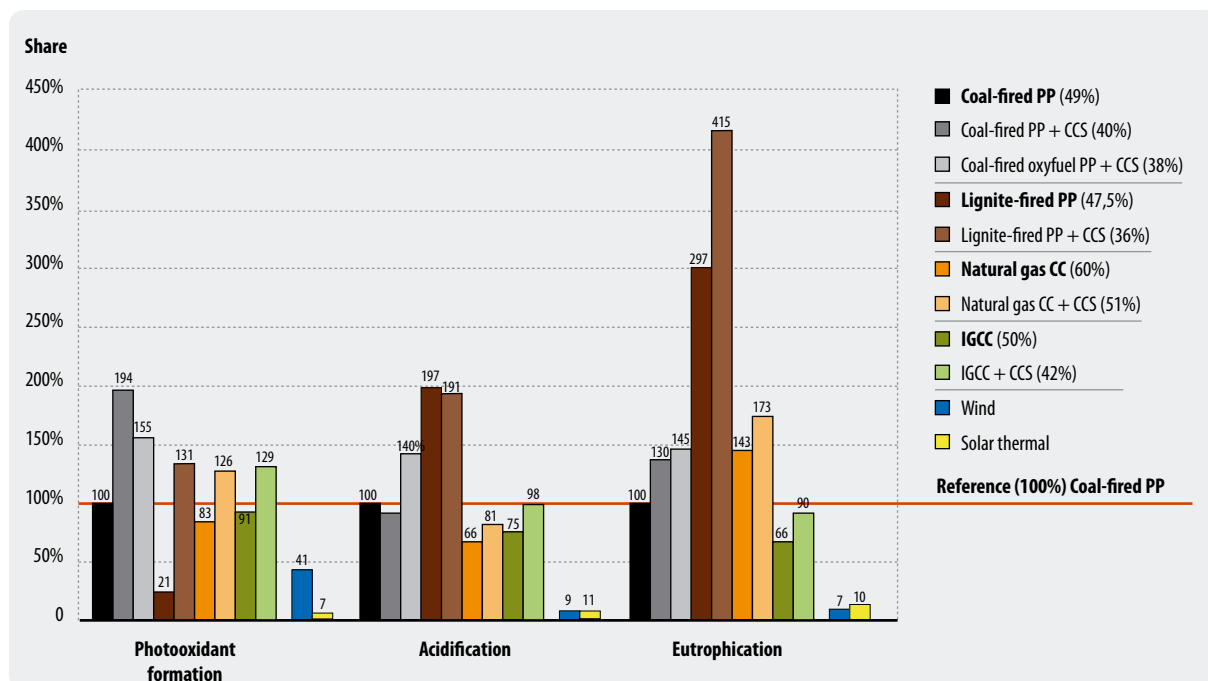
Fig. 10-18: Comparison of impact categories photooxidant formation, acidification and eutrophication in relative form for reference power plant using fossil fuels and renewables without and with CCS (relative to coal-fired steam power station)

Wind power and solar power plant also score worse here than they do for greenhouse gas emissions and cumulative energy demand, but remain well below the values for fossil-fuelled power stations. These emissions result largely from the manufacture and construction of the power plant. A detailed interpretation of the wind power analyses is found in Bruno (2003) and Chataignere and le Boulch (2003), and of the solar thermal plant data in Viebahn (2004).

10.7 Sensitivity Analyses of Electricity Generating Systems

Table 10-13 below shows the sensitivity analyses conducted as part of the LCA.

10.7.1 Sensitivity Analysis 1: Variation in Leakage Rate

Basis
No expert has yet been able to prove that the available sinks will be one hundred percent leak-proof, so any LCA must also include the question of leakage rate. Although there is no reliable information about possible leakage rates, in its special report on CCS the IPCC found that if continuous leakage were to occur this would at least partially negate the benefits for climate protection (IPCC 2005b). So it makes sense to take a look at the effects of possible leakage by means of a sensitivity analysis.

Method
The following assumptions were made for modelling leakage:

Table 10-13: Sensitivity analyses (electricity generation)

Variation	Sensitivity case		Unit	Baseline	Variation
1	1–4	Leakage rate of sink	%/a	0	0.0001 – 0.1
2	6–9	Capture rate, variable costs	%	88	90–96 with corresponding rise in resource consumption
3	6a–9a	Capture rate, fixed costs	%	88	90–96 with fixed resource consumption
4	14–17	Methane emissions during coal mining	kg/TJ	454	363–91

Storage potential and leakage (1%/a)
over 100 years
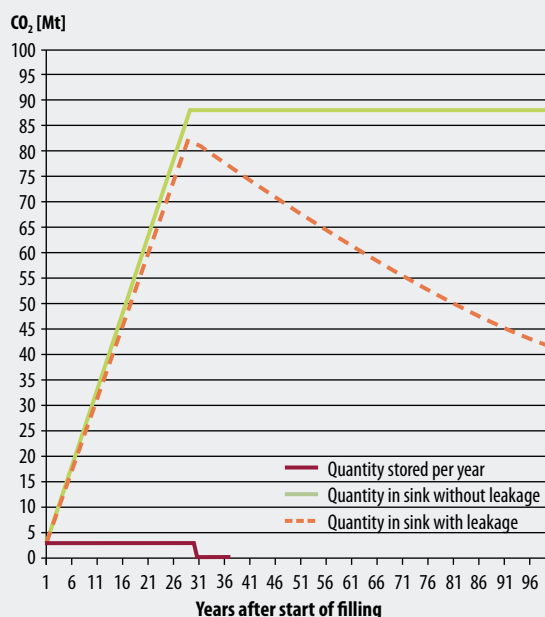
Fig. 10-19: Stored quantity and leakage over the first 100 years with a leakage rate of 1 %/a, for the example of a coal-fired power station

- Four different CO_2 leakage rates were selected for modelling, in order to cover the range of uncertainty (0.1 / 0.01 / 0.001 / 0.0001 %/a). From today's perspective it would appear unlikely that sinks with leakage rates potentially higher than that would be put into operation – and this would in any case be rather pointless in economic terms.

- Leakage begins in the first year of storage, but the actual annual leakage rates are calculated in relation to the level of CO_2 in the sink. The less full a sink is, the smaller the actual leakage rate. The full rate is not reached until the point where the sink is full.

- In the model the imaginary sink is full in year 41, while the service life of the power station is 30 years. During the remaining ten years the sink could be filled from another power station.

- The calculations were conducted using the example of the 700 MW coal-fired power station.

The following two figures show the development of stored quantities. Fig. 10-19 shows the development over the first one hundred years. To illustrate the principle clearly we calculated using a leakage rate of 1 % here, but that figure is not used otherwise. The figure clearly shows how very little CO_2 escapes during the first 30 years. The effect of the full leakage rate only begins to be felt after year 41.

Fig. 10-20 shows the trend over 40,000 years with a leakage rate of 0.01 %/a. During the first 40 years – while

Storage potential and leakage (0,01%/a)
over 40,000 years
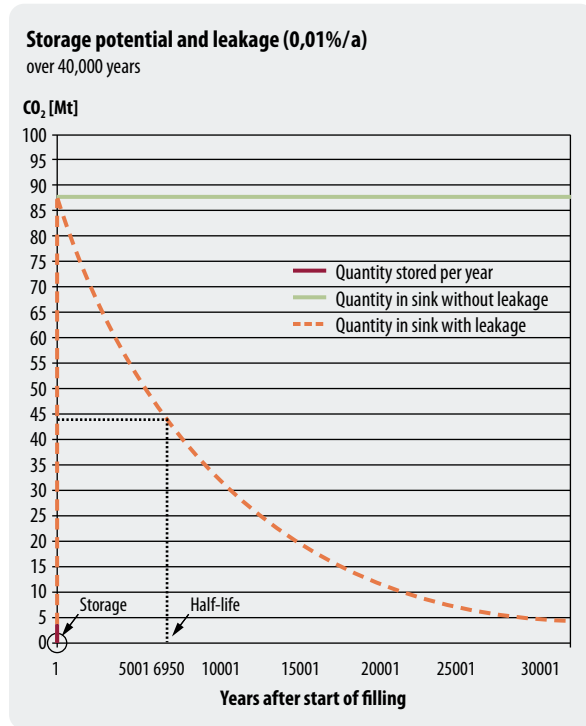
Fig. 10-20: Stored quantity and leakage over the first 100 years with a leakage rate of 0.01 %/a, for the example of a coal-fired power station

Storage potential and leakage (different leakage rates)
over the first 1,000 years
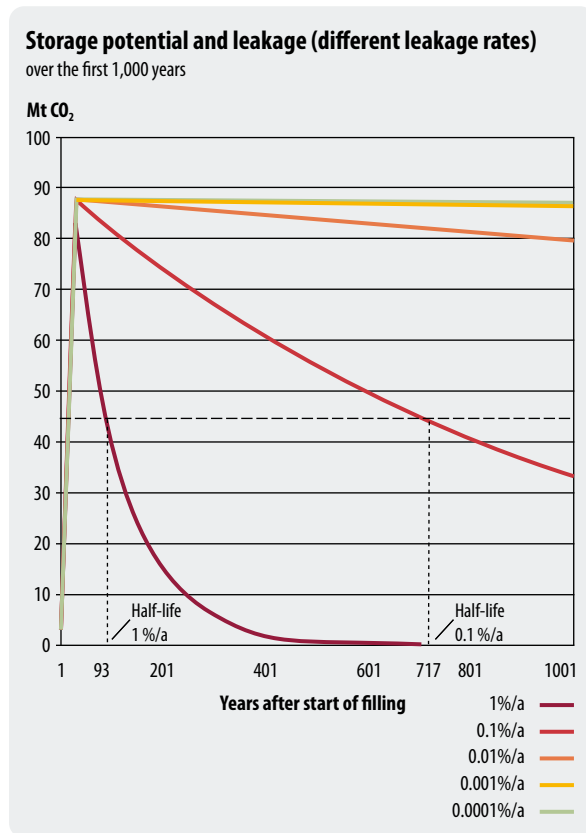
Fig. 10-21: Sink content over the first 1,000 years with leakage rates of 1 % to 0.0001 %/a, for the example of a coal-fired power station

the sink is filling – almost no CO_2 is released. Continuous leakage begins in year 41 and follows an exponential curve until almost all the stored CO_2 has escaped again after 40,000 years.[4] The 'half-life', the time taken for 50 % of the stored CO_2 to escape, is 6,950 years in this case.

Mathematical derivation
If L_rate is the assumed annual leakage rate and t_{full} the time when the sink is full, then the actual leakage rate is

$$actual\_Leakage\_rate\_in\_year\_i = \begin{cases} L\_rate * \dfrac{i}{t_{full}} & if & i < t_{full} \\ L\_rate & if & i \geq t_{full} \end{cases} \quad (1)$$

Accordingly, for a given sink volume V(t) the level of leakage L(t) in year t is

$$L(t) = \begin{cases} V(t) * L\_rate * \dfrac{i}{t_{full}} & if & i < t_{full} \\ V(t) * L\_rate & if & i \geq t_{full} \end{cases} \quad (2)$$

The volume in the sink in year t, V(t), is the volume in the sink in year t-1, plus the amount added to the sink, Add(t), minus the leakage L(t-1):

$$V(t) = \begin{cases} V(t-1) + Ein(t) - L(t-1) & falls & i < t_{voll} \\ V(t-1) - L(t-1) & falls & i \geq t_{voll} \end{cases} \quad (3)$$

The cumulative leakage L_total in year t

$$L\_total(t) = \sum_{i=0}^{t} L(i)$$

is then calculated from (2) and (3)

$$L\_total(t) = \sum_{i=1}^{t_{full}-1} V(t-1) + Add(t) - L(t-1) + \sum_{i=t_{full}}^{t} V(t-1) - L(t-1)$$

applied to the quantities *before* time t_{full} and *after* time t_{full}. The leakage amount at any time t can be calculated exactly by solving this iterative equation.

Life cycle analysis
For the purposes of the LCA the released CO_2 emissions are divided (rather arbitrarily) into medium-term and long-term emissions, depending on whether they occur in the next 10,000 years or after that. But this raises the problem of how current and future emissions and impacts are to be weighed up against one another and how events in the future can be discounted. In general LCAs do not distinguish between different times of emission. But this would mean that even the smallest leakage rate would result in all the CO_2 escaping into the atmosphere. So unless sinks could be guaranteed 100 % leak-proof the introduction of CO_2 capture would automatically lead to a general 25 % increase in CO_2 emissions.

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4 The last 8,000 years are not shown, because Excel can only show the first 32,000 data points.
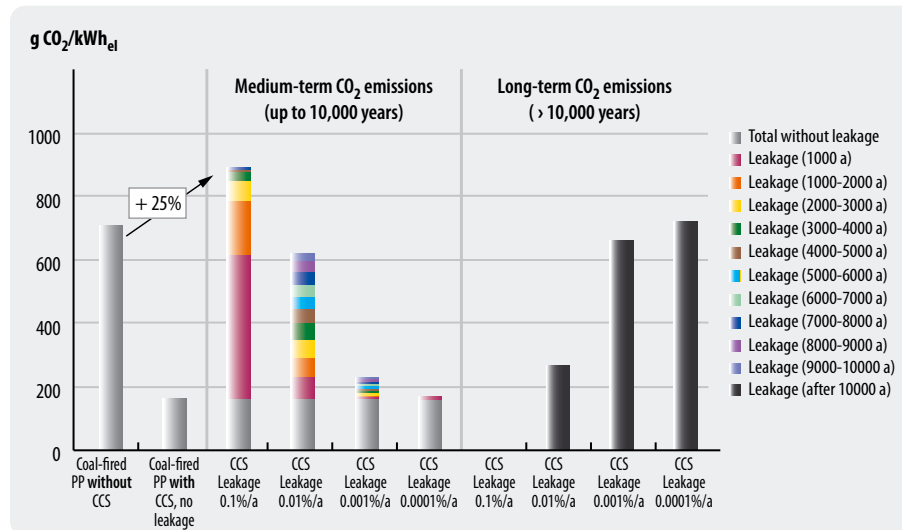
Fig. 10-22:
CO_2 emissions for the coal-fired power station with different CO_2 leakage rates, divided into medium-term (up to 10,000 years in 1,000-year steps) and long-term emissions (>10,000 years)

This means that for LCA research it is necessary to develop a method for discounting the climate effects of future greenhouse gas emissions. So far such work has only been completed for waste disposal, where short-term emissions from incinerators have been weighed against long-term emissions from dumps (Hellweg et al. 2003).

Results
The 'best case' is the baseline assumption of a leakage rate of 0 %, because all the sensitivity analyses result in higher emissions of CO_2. Fig. 10-22 shows how they change. The first bar represents the reference power station without CCS, the second the reference CCS power station (without leakage) and the following bars the four sensitivity cases under consideration. The first group shows medium-term emissions (first 10,000 years), the second the long-term emissions after 10,000 years. In the case of the (relatively high) leakage rate of 0.1 %/a all the CO_2 stored underground would be released into the atmosphere within 6,000 years. The smaller the assumed leakage rate, the more emissions are shifted to the period after 10,000 years.

10.7.2 Sensitivity Analysis 2: Variation in Capture Rate (Variable Cost)

Basis
So far in the study a capture rate of 88 % has been assumed for CO_2 emissions directly at the power station, which is generally the state of the art cited in the literature. Post-combustion capture using MEA consumes electricity and steam – in proportion to the amount of CO_2 captured – which significantly reduces the net efficiency of the power station. Because the models are based on current state of the art and future values for capture rate and resource consumption with MEA capture are not known, it makes sense to use sensitivity analyses to assess their influence. For example, the effect of

increasing CO_2 capture through a higher capture rate could be negated if the efficiency were to fall disproportionately through higher consumption of electricity and steam.

Method
The following assumptions were made for modelling capture rate:

- The CO_2 capture rate increases successively from the baseline (88 %) to 90, 92, 94 and 96 % (Sens_6 to Sens_9).

- The consumption of electricity, steam and MEA used in MEA capture is variable, i.e. consumption per kg of captured carbon dioxide is the same as in the baseline case.

- Calculations were conducted for the example of a 700 MW coal-fired power station (representative for the post-combustion capture power stations).

Results
As Fig. 10-23 shows, specific CO_2 emissions and greenhouse gases (per kilowatt hour) fall continuously as capture rate rises. Again, the first bar represents the reference power station without CCS, the second the reference CCS power station (88 % capture) and bars 3 to 6 the four sensitivity cases under consideration.

The findings result from four partly contradictory developments:

- The specific emissions of the supply chain increase because altogether more energy is consumed.

- The specific emissions of operation fall continuously because of the increased capture rates.
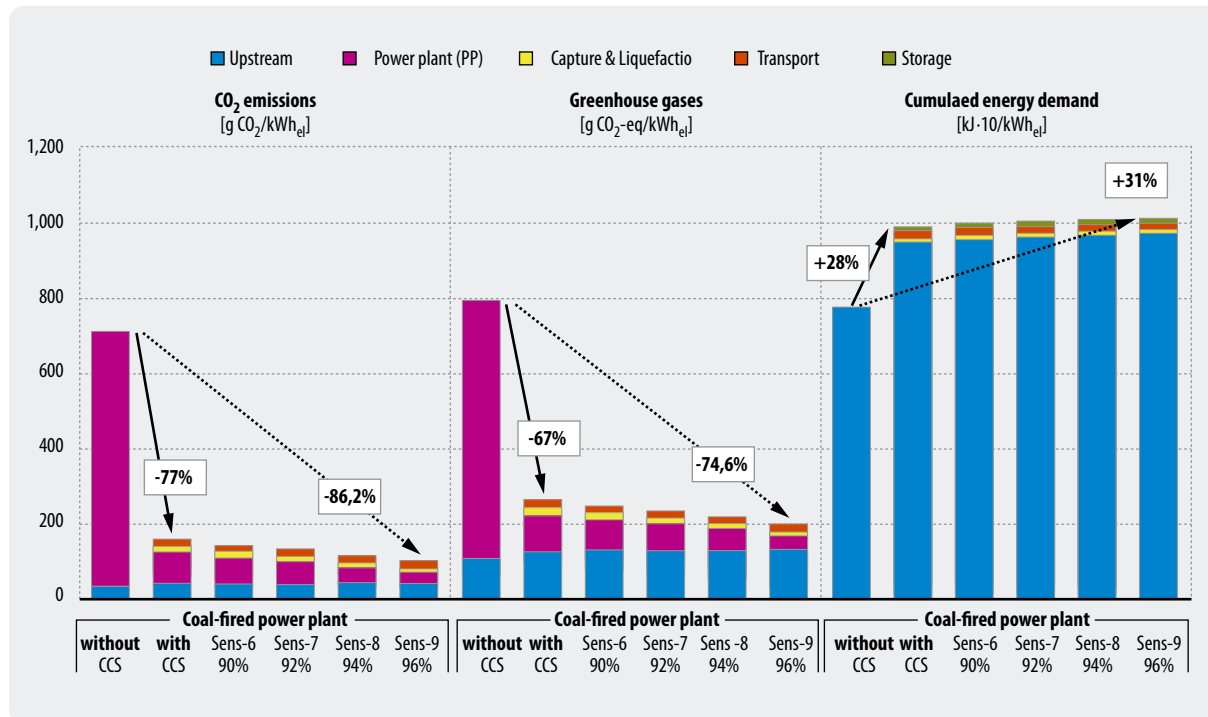
Fig. 10-23: CO_2 emissions, total greenhouse gases and cumulative energy demand for the coal-fired power station with various CO_2 capture rates (variable capture costs)

- The specific emissions attributable to capture also fall continuously. Because of the higher capture rate more electricity, steam and MEA are used (which increases emissions) but this is more than compensated by the increased quantity of CO_2 captured, resulting in a net fall in emissions per kWh.

- Emissions from transport and storage increase continuously because they are directly proportional to the amount of carbon dioxide to be transported and stored.

Energy demand, on the other hand, rises continuously because capture, transport and storage all require more energy.

10.7.3 Sensitivity Analysis 3: Variation in Capture Rates (Fixed Cost)

Method
This time the capture costs were kept constant for the sensitivity analysis (meaning that a capture rate of 96 % requires exactly the same amount of electricity, steam and MEA as a capture rate of 88 %). This simulates possible technical advances in MEA capture.

- As above, the CO_2 capture rate was increased successively from the baseline case (88 %) to 90, 92, 94 and 96 % (Sens_6a to Sens_9a).

- The amounts of electricity, steam and MEA required for MEA capture were kept constant.

- Calculations were again conducted for the example of a 700 MW coal-fired power station (representative for the post-combustion capture power stations).

Results
As Fig. 10-24 shows, specific CO_2 emissions and greenhouse gases (per kilowatt hour) again fall continuously as the capture rate rises. The specific emissions from capture fall even further than in the previous case because no additional cost was modelled, so overall emissions are also slightly lower. At the highest capture rate CO_2 emissions fall to 13.6 % (from 13.8 %) and greenhouse gases fall to 25.0 % (from 25.4 %). The energy costs are also smaller (increase of 29 % rather than 31 % at highest capture rate). The first bar again represents the reference power station without CCS, the second bar the reference CCS power station (88 % capture) and bars 3 to 6 the four sensitivity cases under consideration.

From the second and third sensitivity analyses we can conclude that increasing the CO_2 capture rate leads to a continuous fall in specific CO_2 and greenhouse gas emissions. Although the greater consumption of electricity, steam and MEA initially increases emissions, this is more than compensated by the greater amounts of CO_2 captured. If the cost of the capture process is kept constant a further marginal reduction in CO_2 and greenhouse gas emissions is possible.
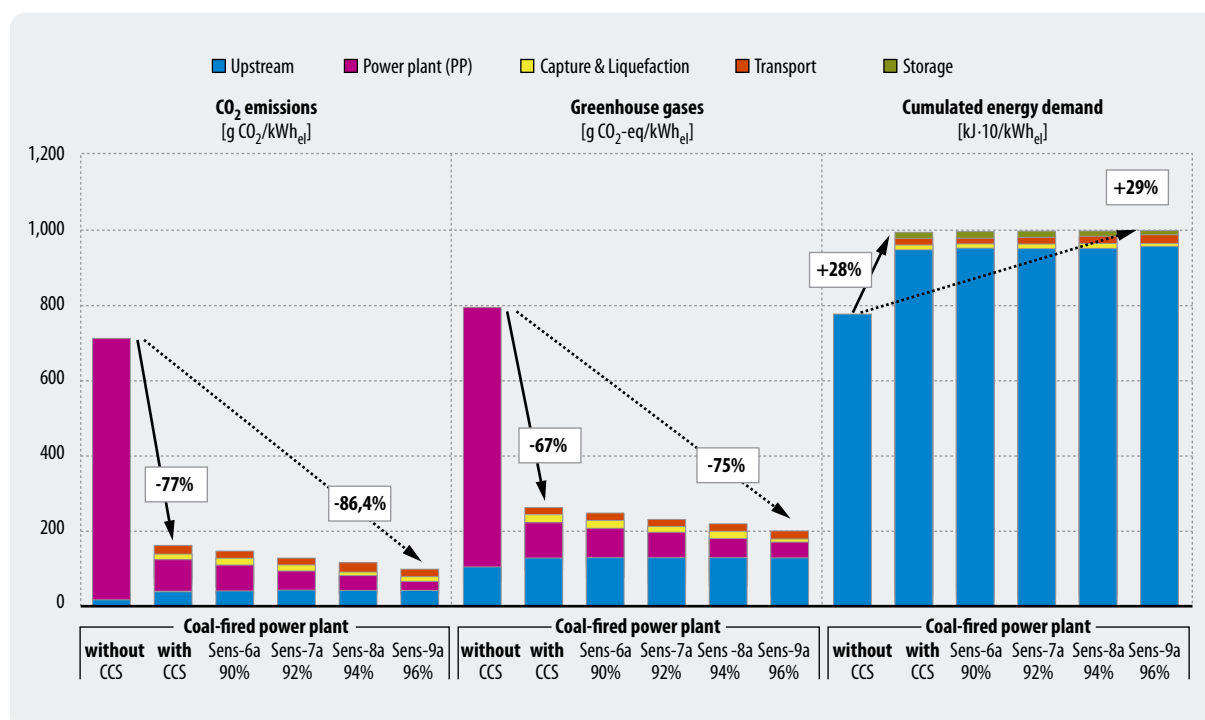
Fig. 10-24: CO_2 emissions, total greenhouse gases and cumulative energy demand for the coal-fired power station with various CO_2 capture rates and fixed capture costs

10.7.4 Sensitivity Analysis 4: Variation in Methane Emissions During Coal Mining

Basis
In the models so far we have used the coal supply chain 'Steinkohle-Mix D frei KW/In', which models the German coal mix in 2000 (see section 10.3.2). In comparison to lignite and natural gas, methane emissions from coal mining are relatively high, as Table 10-14 shows:

Only for lignite are the upstream emissions negligible, because here the CO_2 emissions associated with energy consumption for transport are almost the only factor to play a role. Whereas both energy used to transport the gas and the release of gas through leaks are relevant with natural gas, the major factors in the coal supply chain are energy consumption for transport and above all the release of mine gas (WI and MPI 2004).

Table 10-14: Methane emissions of the primary energy supply chains

Primary energy	Umberto module	Year	Methane emissions in kg/TJ
Coal	Steinkohle-Mix D frei KW/In	2000	454
Lignite	Braunkohle-Mix D frei KW/In	2000	2
Natural gas	Vorkette_Erdgas_D_2010	2010	154

Mine gas has been covered by the Renewable Energy Act since 2000, with the result that in Germany it is increasingly being extracted from working and closed mines and used to power CHP units. The installed capacity for using mine gas in the Ruhr coalfield has grown quickly from just 800 kW$_{el}$ in 1999 to 90 MW$_{el}$ in 2003 (Backhaus et al. 2003) and 158 MW$_{el}$ by the end of 2005 (Landesinitiative 2006). In each of the years 2003 and 2004 about 160 million m^3 of methane gas were used to generate 600 GWh of electricity (SteinkohlePortal.de 2006, Geologischer Dienst NRW 2006), and in 2005 the figure rose to 885 GWh (Landesinitiative 2006).

The German coal mix used in Umberto comprises the following sources: Germany (62.1 %); Poland and eastern Europe (12.5 %); South Africa (10.2 %); Colombia, Canada and the United States (7.8 %); Australia (4.1 %); and the Netherlands (and other western Europe) (3.3 %). The high proportion of German coal means that utilising the methane for power also influences the methane emissions of the overall mix. Although detailed data are not yet available, lower emissions than in 2000 should be applied here, especially for the post-2020 period modelled in this case. This sensitivity analysis examines the influence of reduced methane emissions in the coal supply chain on the overall result.

Fig. 10-25:

Comparison of total green-house gases at various levels of methane emissions in the coal supply chain for the fossil-fuelled reference power stations
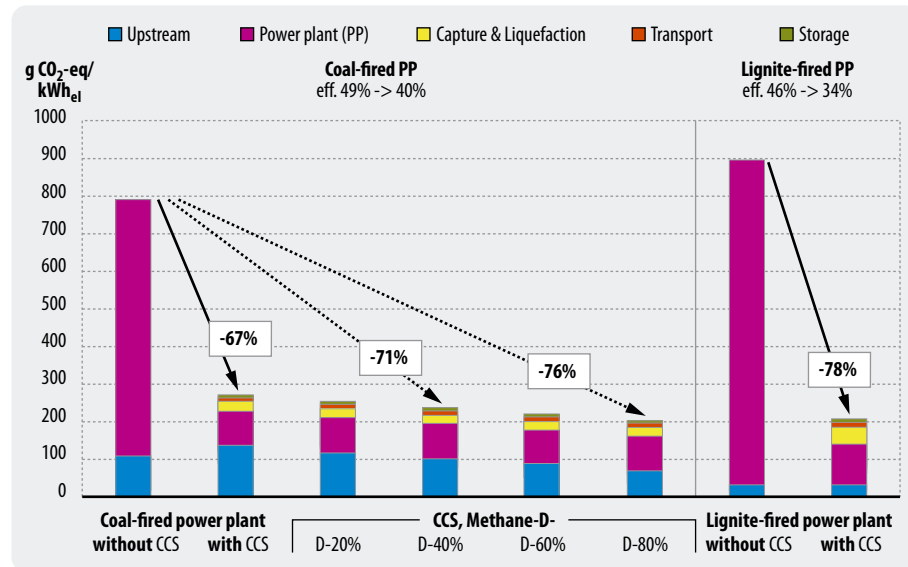
Method

The following assumptions were made for modelling methane emissions:

- In the Umberto module 'Steinkohle-Mix D frei KW/In' the methane emissions of 454 kg/TJ were reduced to 80, 60, 40 and 20 % of that value in four sensitivity cases.

- The calculations were again conducted for the example of the 700 MW coal-fired power stations, and the results were compared with those for lignite-fired and natural-gas-fired power stations.

Results

The first bar in Fig. 10-25 shows the reference power station without CCS, the second bar the reference CCS power station (100 % methane emissions), and bars 3 to 6 show the four sensitivity cases under consideration. Because the coal supply chain causes CO_2 emissions as well as methane emissions, the greenhouse gas emissions of the supply chain as a whole only fall by 87 to 46 %. In relation to the power station process as a whole (including CO_2 capture), we found a reduction in greenhouse gas emissions of 67 % (baseline) to 76 % (sensitivity case 4 with 20 % methane emissions). That brings the coal-fired power station with CCS close to the values for the lignite-fired power station with CCS that is included on the right for comparison.

10.8 Conclusions for Electricity Generation

- Although a capture rate of, for example, 88 % would suggest that *total* CO_2 emissions are reduced by 88 %, the rate of CO_2 capture cited by the industry relates only to the CO_2 emissions directly in power

station operation. If we take an integrated approach, five percent of the CO_2 emissions already occur in the supply chain both with coal-fired steam power stations and with natural gas CC. Reduced efficiency also causes higher consumption of primary energy and thus a 'larger' coal or natural gas supply chain. Taken together, these factors mean that with a capture rate of 88 % actual CO_2 emissions can be reduced not by 88 %, but only by 72–78 %. In view of this fact it would seem unjustified to speak of 'CO_2-free' power stations. Even if the capture rate at the power station can be increased still further, the designation 'low-CO_2' is more pertinent.

- The discussion to date has also neglected to consider that greenhouse gas emissions as a whole – and not only CO_2 emissions – have to be reduced. The Kyoto Protocol requires Germany to reduce a total of six greenhouse gases (and not just CO_2 emissions) by 21 % by 2012. If we calculate the effects of CO_2 capture on greenhouse gas emissions, we find that the potential reduction is less than proportional. For example, with a CO_2 capture rate of 88 % greenhouse gases can only be reduced by 67–78 %. The reasons for this are the considerably increased primary energy consumption and the methane emissions associated with fuel extraction and transport, which can be relatively high in some cases. These have a disproportionately large effect on the greenhouse effect.

- With 396 g CO_2 equivalent per kWh the best power station without CCS (natural gas CC) has only 51 % more greenhouse gas emissions than the worst power station with CCS (coal-fired steam power station with 262 g CO_2 equivalent per kWh).

- If methane emissions from coal mining were to be reduced by up to 80 % from today's value, this would result in greenhouse gas emissions from the

coal-fired power station with CCS being reduced by up to 76 %, compared with the same power station without CCS. Here the capture rate was kept constant at 88 %. This brings the coal-fired power station with CCS close to the values for the lignite-fired power station with CCS, but still exceeds the greenhouse gas emissions of natural gas CC by about 50 %.

- Of all the fossil-fired power stations considered, oxyfuel combustion was best. Physical capture of almost 100 % of the CO_2 allows net rates of reduction of 90 % for CO_2 emissions and 78 % for greenhouse gas emissions.

- Overall, CO_2 capture requires additional energy consumption of 20 to 44 %, depending on the process. Even if the extent of deposits would present no obstacle to increased use of coal, many other aspects must be taken into consideration in connection with coal mining. Fell (2003) names, for example, destruction of landscapes, subsidence, falling water tables, human rights violations in the mining industry and ecological harm caused by burning coal seams in China. These aspects are not registered by an LCA but should not be neglected.

- The considerably higher energy consumption also contributes to a change in the other environmental impact categories. But with the *post-combustion approach* the MEA solvent also captures other emissions as well as CO_2 so the picture is more complex here. In the category of acidification there is a slight reduction in absolute terms; PM10 equivalents (dust emissions) rise slightly, while considerable increases are found for eutrophication and summer smog. For *pre-combustion* and *oxyfuel combustion* an overall increase must be expected in the impact categories, but precise modelling was not possible due to lack of data.

- The renewables considered all exhibited better values than the fossil-fuelled power stations with CO_2 capture. Even including electricity transport, solar thermal and wind-generated electricity produce only 2 to 3 % of the CO_2 emissions, greenhouse gases and cumulative energy demand of fossil-fuelled power stations, and in the other impact categories the values for renewables are also way below those for fossil-fuelled systems.

- If we include advanced power generation concepts based on fossil fuels, we find that with CHP systems (natural gas and natural gas CC) there are already technologies on the market that are as green as the target to be achieved by CCS power stations in 2020.

- While the CO_2 capture process itself represents a relevant share of total emissions (about 22 %), transport and storage play only a secondary role. Further modelling is required for these parts of the process, however, because the basic data are still incomplete.

- The question of discounting future emissions is of more than academic interest. Like in the field of waste disposal, if we assume a leakage rate greater than zero, emissions will occur thousands of years later and have to be discounted if energy systems are to be compared. With the exception of one study, this question has not yet been examined using the LCA methodology, so a simplified approach had to be adopted for the sensitivity analysis.

- From the sensitivity analyses about capture rate and capture cost we can conclude that higher CO_2 capture rates contribute to continuous reductions in specific CO_2 and greenhouse gas emissions. The greater consumption of electricity, steam and MEA initially increases emissions, but this is more than compensated by increases in the amount of captured CO_2. If the cost of the capture process is kept constant, a further marginal reduction in CO_2 and greenhouse gas emissions is possible.

10.9 Plant and Processes for Conventional Hydrogen Production with CCS

10.9.1 Reference Plant

Table 10-15 shows the basic data of the reference hydrogen production processes used in the study with and without CO_2 capture. They are compatible with the data used for the economic calculations. All values given relate to lower heating value (LHV).

In each case the most up-to-date available modules for existing technologies and supply chains were used to model the LCA. The modules were projected through to 2020 by modifying the efficiency according to the values in the table above. The LCA modules came from the following sources (Table 10-16).

- **Natural gas steam reforming:** Pehnt (2002) models the classical natural gas steam reforming process on the basis of a modern production facility built by Lurgi with a relatively small output (8,000 Nm^3/h or 24 MW_{th}), using data supplied by the manufacturer. When he compared the data with a literature source for a large-scale Linde plant he found that the values were almost identical. For this reason, here we used the data given by Pehnt and modelled them accordingly in Umberto. The efficiency of the plant under consideration is 72 % if the steam is not used (and 81 % if steam is exported) and was projected to 74 % in 2020. The plant was modelled with a credit for the steam by offsetting a natural gas condensing boiler, although part of the steam is required to generate the electricity required for the plant itself. Nevertheless, external electricity is

Table 10-15: Basic data for hydrogen production from fossil fuels without and with CO_2 capture

A) Without CO_2 capture			
		Natural gas steam reforming	Coal gasification
Output	MW	350	560
Full load hours	h/a	8,000	8,000
Efficiency[a]	%	73.6	59
CO_2 intensity of fuel	g CO_2/MJ [b]	56	92
	g CO_2/kWh	202	331
CO_2 intensity of hydrogen (without emissions for electricity)	g CO_2/kWh$_{th}$	274	561
External electricity demand	kWh$_{el}$/kWh$_{th}$	0.005	–
Steam export	kg/kWh$_{th}$	0.158	–
B) With CO_2 capture			
		Natural gas steam reforming	Coal gasification
		Lurgi/ZSW model[c]	DOE model[d]	
Output	MW	325	329	522
Efficiency [a]	%	68.4	69.1	55
Reduction	% points	5,2	4.5	4
External electricity demand	kWh$_{el}$/kWh$_{th}$	0.005	0.0125	–
Steam export	kg/kWh$_{th}$	0.079	0	–
Capture rate	%	53	71	88
CO_2 to dispose of	t/a	437,389	580,001	2,374,042

[a] In terms of calorific value, without export steam
[b] Source: UBA 2003
[c] Source: Küppers 2006, [d] Source: DOE 2002

still needed as well. The required heat is generated by burning part of the supplied natural gas and the residual gases produced in the process. This produces a waste gas with the usual composition of combusted gas (including 3–15 % CO_2).

- **Coal IGCC:** As the basic module we used the same coal-fired IGCC-power station as for the electricity LCA and substituted the corresponding efficiency value for hydrogen production. Separation of the hydrogen from the synthesis gas has not yet been modelled.

10.9.2 Supply Chains

The LCA modules used for the supply chains were taken from the sources given in Table 10-17. In steam reforming they were used both for hydrogen production itself and for the natural gas boiler credit.

- **Coal:** The same coal supply chain was used as for electricity generation (see section 10.3.2).

- **Natural gas**: The same natural gas supply chain was used as for electricity generation (see section 10.3.2).

10.9.3 CO_2 Capture

In contrast to CO_2 capture in power stations, for hydrogen production it was not possible to use 'ready-made' plant modules and supplement them with CO_2 capture components. Instead the plant had to be remodelled with CCS. When preparing the LCAs the following approach was chosen.

Coal Gasification

For coal gasification the CO_2 is separated from a H_2/CO_2 mixture by installing a physical scrubbing facility between the shift reactor and the PSA unit (see e.g. Parsons 2002). For reasons of time it was not possible to model that for this study. Instead, for coal gasification, we used the reference module for IGCC electricity generation and reduced the efficiency according to the figure listed above. The plant's additional consumption was assigned to physical capture. A capture rate of 88 %

Table 10-16: Sources for the LCA modules for hydrogen production from fossil fuels

Process	Output [MW]	Functional unit	Efficiency [a] [%]	Source	Module name	Year
Natural gas steam reforming	24	1 Nm³ H_2	72	Pehnt 2002	New	1998
Coal gasification (coal IGCC)	450	1 kWh$_{el}$ [b]	51.5	Briem et al. 2004	New	2010

a)   In relation to calorific value

b)   The existing IGCC module is only for electricity generation.

Table 10-17: Sources of the LCA modules for the fossil fuel supply chains

Fuel	Functional unit	Source	Module name	Year
Coal	1 kg	Umberto	Steinkohle-Mix D frei KW/ln	2000
Natural gas	1 kJ	Umberto, Pehnt 2002, WI and PMI 2004	Vorkette_Erdgas_D_2010	2010

was assumed, as for IGCC electricity generation (see also the explanatory notes concerning electricity generation in section 10.3.3).

Natural Gas Steam Reforming

Natural gas steam reforming with CO_2 capture was modelled according to two different sources:

1. In the first case the project partner ZSW simulated natural gas steam reforming on the basis of the Lurgi process as the reference system and integrated CO_2 capture by means of chemical scrubbing (MEA process). The reference plant corresponds to the values given by Pehnt (2002) (see section 10.9.1). The plant complete with CO_2 capture is illustrated in Fig. 10-26 and exhibits the following differences from the reference case:
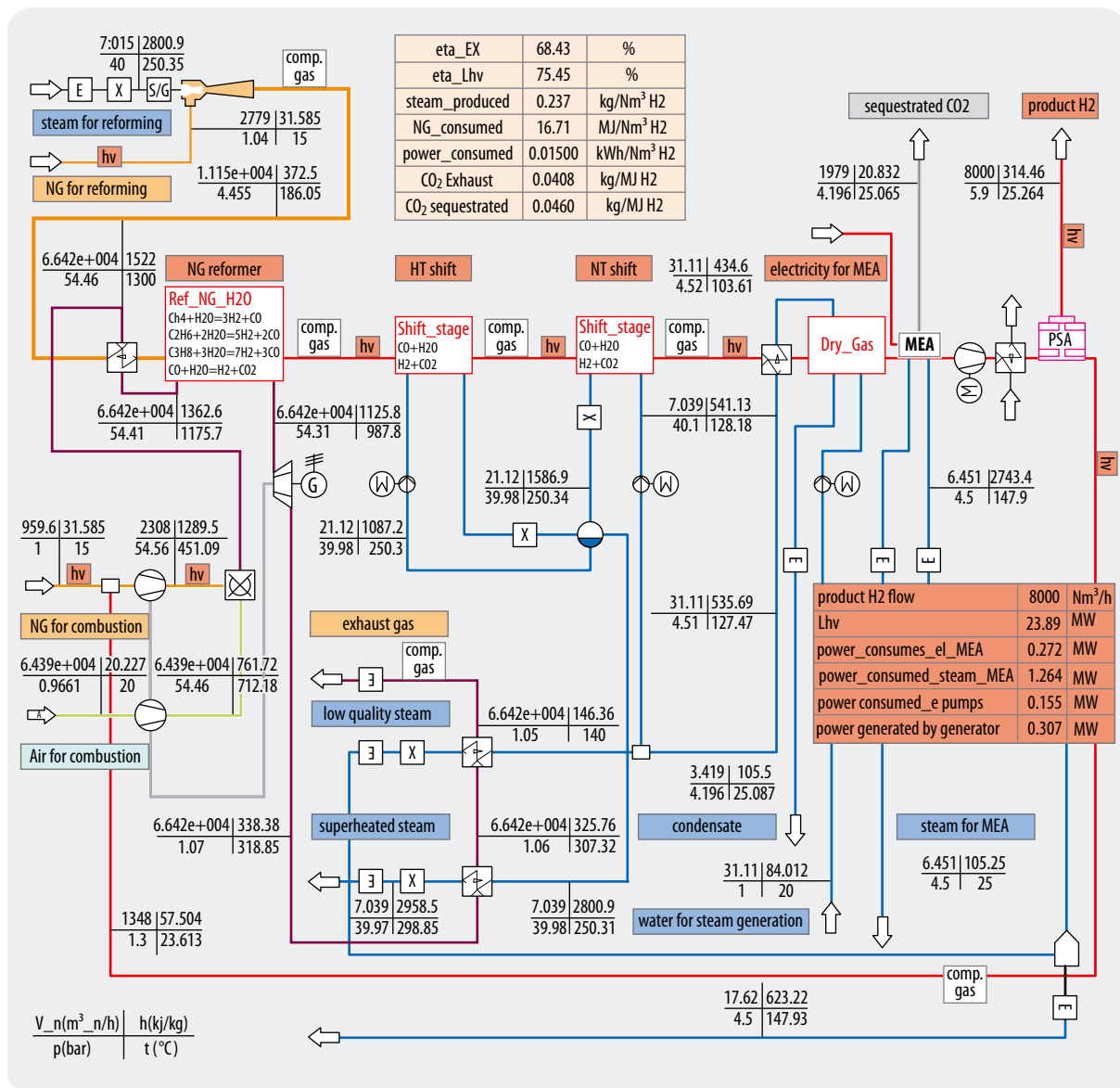
Fig. 10-26: Classical steam reforming plus CO_2 capture using chemical scrubbing (MEA solution) (Küppers 2006)

- Chemical scrubbing using MEA involves consumption of a certain amount of steam and electricity. Part of the excess steam is used for this purpose. In order to avoid increasing the use of external electricity the additional electricity consumption is generated internally, causing the efficiency to fall by 5.2 percentage points. Net export steam falls by about half, so the natural gas boiler credit is correspondingly smaller.

- The net CO_2 capture rate is 53 %, because capture is carried out in the reformer *before* the PSA. It would also be technically possible – as in the coal-fired power station – to capture almost all the CO_2 from the reformer waste gas, but this would be less favourable in terms of energy.

2. The ZSW model was compared with a similar model described by DOE (2002). It uses all the excess steam so none is available for export and no credit is given. External electricity demand is also 150 % higher. But the plant achieves a net CO_2 capture rate of 71 % (with 99 % capture using amines) with a reduction in efficiency amounting to 4.5 percentage points. The assumptions on which this model is based could not be verified because the source cited published only the final results.

In future another process might become available, solar steam reforming. This process – currently under development by the German Aerospace Center – would draw the heat required to produce hydrogen entirely from solar sources (Möller et al. 2006). This would reduce the consumption of natural gas by 40 %. The relevant research projects are still in progress so it was not possible to include the process in this study.

10.9.4 CO_2 Liquefaction

For initial compression to 110 bar (and thus the liquefaction of the CO_2) we took the same figure as for electricity generation: 110 kWh$_{el}$/t CO_2 (Göttlicher 1999), for multi-stage compression starting from 1 bar with intermediate cooling to 30°C.

10.9.5 CO_2 Transport Scenarios

The transport and storage of CO_2 was modelled for a single power station, taking the Ruhr region as the origin and an exhausted gas field (not further spedified) in northern Germany as the destination (Table 10-18). An arbitrary transport distance of 300 km was chosen, and it was assumed – as for electricity generation – that the pipeline would have to be built specially for this power station because it will not necessarily be possible to use existing (natural gas) pipelines.

As for electricity, transport was modelled using the existing LCA module 'Onshore, low capacity'. With an annual capacity of 5 Mt it might at first seem overdimensioned, but it must be remembered that all costs are calculated in terms of the transported tonne-kilometres, so if the quantity of material flowing in the pipeline is smaller the material and energy flows will be smaller too.

Table 10-18: CO_2 transport scenarios for hydrogen technologies

Scenario	Location of CO_2 Source	Plant type and H_2 output	Captured CO_2 [Mt/a] [a]	Captured CO_2 [t/d] [d]	Pipeline land [b] + ship [km]	Pipeline-diameter [c] [mm]	Storage location
1	Ruhr region	Natural gas steam reforming 350 MW (ZSW)	0.44	1,198	300 + 0	200	Gas field onshore
2	Ruhr region	Natural gas steam reforming 350 MW (DOW)	0.58	1,589	300 + 0	200	Gas field onshore
3	Ruhr region	Coal gasisfication 560 MW	2.37	6,504	300 + 0	330	Gas field onshore

[a] Calculated with 8,000 h/a

Steam reforming (ZSW): efficiency 74 % → 68 %, capture rate 53 %, CO_2 emissions (without CCS, without external electricity supply) = 274 g/kWh$_{th}$

Steam reforming (DOE): efficiency 74 % → 69 %, capture rate 71 %, CO_2 emissions (without CCS, without external electricity supply) = 274 g/kWh$_{th}$

Coal gasification: efficiency 59 % → 55 %, capture rate 88 %, CO_2 emissions (without CCS) = 561 g/kWh$_{th}$

[b] Including a gas-turbine-powered tubo-compressor

[c] Estimated according to data in Bock et al. 2001

[d] Calculated with 365 d/a

10.9.6 CO₂ Storage

As for electricity generation, the costs of storage were initially estimated via the relationship between storage and transport costs, taking a rough approximation of 50 % of the transport values for emissions and cumulative energy demand.

10.10 Plant for Producing Hydrogen Using Renewables

10.10.1 Reference Plant

As with the power stations, hydrogen production from fossil fuels was compared with plant for producing hydrogen using renewables that will be available in 2020. The technology used is electrolysis powered by electricity generated in solar thermal plant and offshore wind farms. Because the transport scenarios described above took the Ruhr region as the location for the fossil-fired power stations, the plant using renewables was also modelled on the basis of delivery of electricity to the Ruhr region. It was assumed that the electrolysis plant is in the Ruhr region and the required electricity is transported there by high-voltage DC lines from Algeria (solar thermal) and the North Sea (offshore wind power).

To model the LCA we used the latest available module for electrolysis (see Table 10-19):

Pehnt (2002) models hydrogen production by means of alkaline electrolysis (output 200-400 Nm³/h or 0.6–1.2 MW_{H2}), taking account of potential for optimisation compared with state of the art. Data about operational plant were available from the literature and various

manufacturers. For the efficiency of energy conversion we took the value of 70 % given by Pehnt, which already takes account of the optimised plant.

In future other methods which promise higher efficiencies will become available (Krewitt and Schmid 2004). These include membrane electrolysers (structured like a PEM fuel cell) and high-pressure electrolysers (like SOFC fuel cells, using high-temperature ceramics at operating temperatures of 900 °C). However, in view of the lack of operating data from these new processes we worked on the basis of improved alkaline electrolysis.

10.10.2 Supply Chains

The LCA modules for the electricity generation supply chains came from the sources (given in Table 10-20) and are described in section 10.4.

For the transport of electricity generated in North Africa or the North Sea by high-voltage line to the Ruhr region reference location we again used the LCA by May (2005).

10.11 Individual Analyses of Hydrogen Production Systems

10.11.1 Conventional Plant

Coal Gasification

Fig. 10-27 shows the impact of CO₂ capture on greenhouse gas emissions and energy consumption for hydrogen production by coal gasification.

Process	Output [MW]	Functional unit	Efficiency [a)] [%]	Source	Module name	Year
(Alkaline) elektrolysis	0.6 – 1.2	1 Nm³ H₂	70	Pehnt 2002		2002
a) In relation of heating value.						

Table 10-19:
Sources of the LCA modules for production of hydrogen using renewables

Process	Output [MW]	Functional unit	Efficiency [%]	Source	Comments
Solar thermal (type SEGS)	200	1 kWh	17.6	Viebahn 2004, May 2005	
Wind offshore	5	1 kWh		Pick 1998	Onshore plant equated with offshore after Chataignere and le Boulch (2003)

Table 10-20:
Reference power plant for renewables

- **CO₂ emissions:** With gasification by means of IGCC the coal supply chain contributes 5 % to the CO₂ emissions while the plant itself is responsible for 95 % of the emissions. With a CO₂ capture rate of 88 % total CO₂ emissions are only reduced by about 81 %. Of the remaining emissions 6 % originate from capture and 25 % from the supply chain.

- **Greenhouse gas emissions:** As well as CO₂ emissions, methane emissions also contribute to the supply chain, with the result that their share of greenhouse gas emissions (13 %) is higher than that of CO₂ emissions. CO₂ capture reduces overall greenhouse gas emissions by 72 %. Of the remaining emissions again 6 % originate from capture and 47 % from the supply chain. This shows again the need to reduce supply chain emissions too if we are to achieve a 'clean coal' solution.

- **Cumulative energy demand:** CO₂ capture causes cumulative energy demand to rise by 11 %, most of which is attributable directly to capture.

Natural Gas Steam Reforming

The situation is somewhat different for the natural gas steam reforming models (see Fig. 10-28).

- CO₂ emissions: In natural gas steam reforming the natural gas supply chain contributes 10 % to the CO₂ emissions while plant itself is responsible for 90 %. Operating emissions comprise the direct emissions from the plant and indirect emissions attributable to use of electricity from the grid. If we

consider the models selected for CO₂ capture, only those emissions that occur directly in the plant can be captured (and efficiently only those CO₂ emissions that are present in the synthesis gas). Emissions caused by increased use of electricity are not captured. So with a net CO₂ capture rate of 53 % (ZSW) overall emissions are only reduced by 39 %; with a net CO₂ capture rate of 71 % (DOE) the figure is 52 %. Of the remaining emissions 11 % (ZSW) or 14 % (DOE) are attributable to capture. The share of the supply chain rises to 18 % (ZSW) or 22 % (DOE).

- Greenhouse gas emissions: As well as the CO₂ emissions, methane emissions also contribute to the supply chain, so the supply chain share of greenhouse gas emissions (without capture) (15 %) is half as much again as the CO₂ emissions (10 %). Overall greenhouse gas emissions are reduced by the CO₂ capture process by 36 % (ZSW) or 49 % (DOE). Of the remaining emissions 10 % (ZSW) or 13 % (DOE) are attributable to capture. The share of the supply chain rises to 25 % (ZSW) or 30 % (DOE).

- Cumulative energy demand: CO₂ capture causes cumulative energy demand to rise by 22 % (ZSW) or 20 % (DOE), most of which is directly attributable to capture. Contributing factors here are the reduction in efficiency and the additional electricity required.

Overall it was found that the DOE model has a higher external electricity requirement and because all the steam produced is used internally no credit can be given. But through the higher efficiency (or lower loss

Fig. 10-27:
Comparison of CO₂ emissions, total greenhouse gases and cumulative energy demand for coal gasification by IGCC without and with CCS
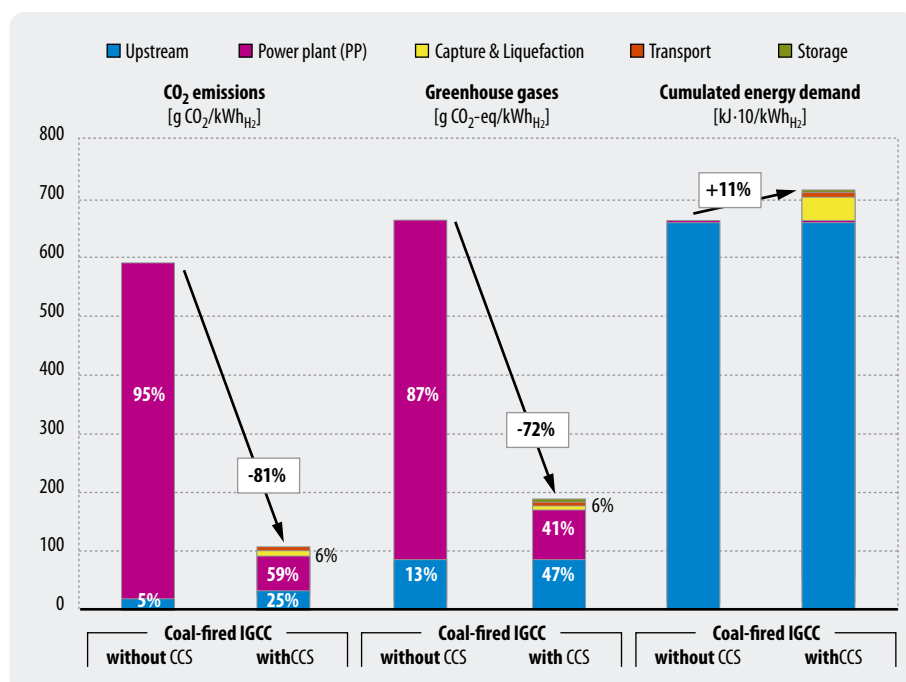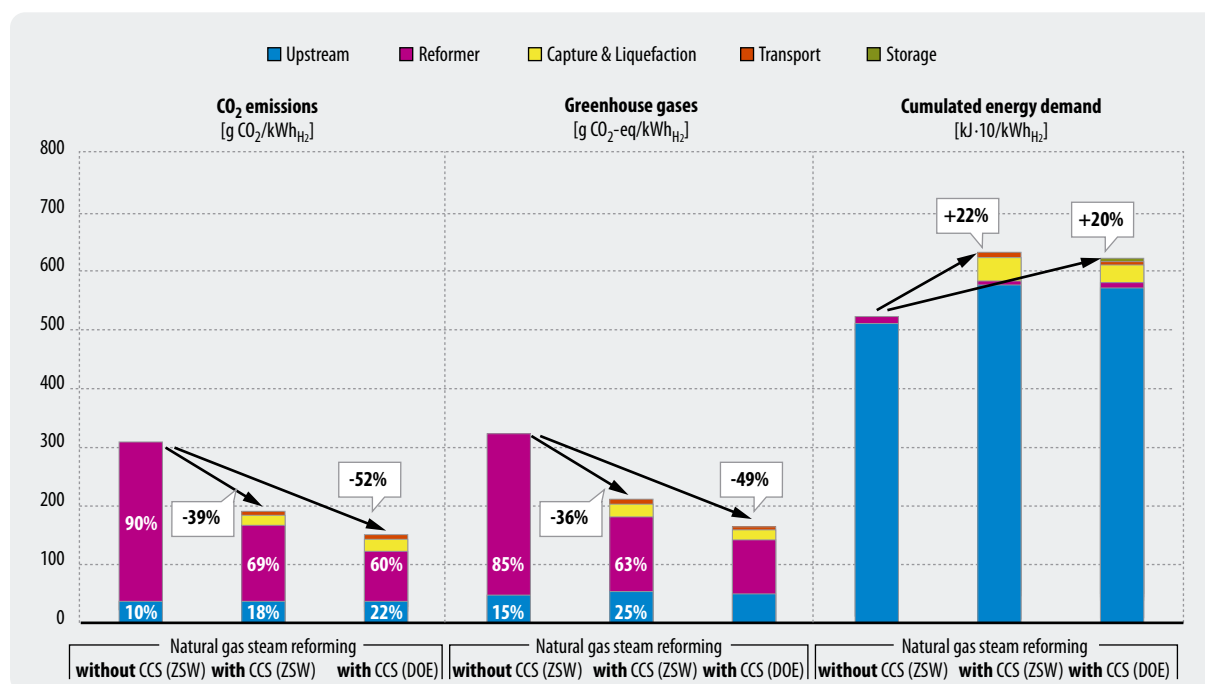
Fig. 10-28: Comparison of CO_2 emissions, total greenhouse gases and cumulative energy demand for natural gas steam reforming (ZSW and DOE methods) without and with CCS

of efficiency) that is possible and the higher capture rate, these drawbacks – compared to the ZSW model – are more than balanced out, with the result that overall greater emissions reductions and lower cumulative energy demand are possible.

10.11.2 Plant Using Renewables

The processes using renewables (electrolysis with electricity from solar thermal and wind power) are not described in detail here. For details see the direct comparison with hydrogen production from fossil fuels (section 10.10).

10.12 Comparison of Hydrogen Production Systems

10.12.1 Greenhouse Gases and Cumulative Energy Demand

Fig. 10-29 compares the fossil fuel processes with electrolysis using solar thermal and wind power. Although in the reference case hydrogen production from coal produces considerably higher CO_2 emissions than natural gas steam reforming, when CO_2 capture is applied it achieves (with 114 g CO_2/kWh$_{H2}$) lower values than natural gas (186 or 145 g CO_2/kWh$_{H2}$). The reason for this is the higher CO_2 capture rate with coal gasification.

If we consider greenhouse gases in total, the relationship between coal gasification and reforming changes.

Because of the high methane emissions from the supply chain it is only possible to achieve a reduction to 185 g CO_2 equivalent/kWh$_{H2}$ for coal, whereas the natural gas processes achieve 205 or 164 g CO_2 equivalent/kWh$_{H2}$. So the figure for coal gasification lies between those for the two natural gas processes. In terms of cumulative energy demand, coal gasification with 7.2 MJ/kWh$_{H2}$ does worse than the two natural gas processes (6.29 and 6.17 MJ/kWh$_{H2}$).

With hydrogen production from renewables both CO_2 emissions and overall greenhouse gas emissions are about 3–6 % of the values for fossil fuel processes. Cumulative energy demand is 3–4 % of the fossil fuel systems.

10.12.2 Other Impact Categories

In the other impact categories the renewable processes do not score as well as with greenhouse gas emissions, but still remain far below the values for the fossil fuel systems they are compared with. Fig. 10-30 shows this for the examples of photo-oxidant formation, acidification and eutrophication. The emissions involved are caused largely by the manufacture of the power plant itself, but in the wind power alternative the manufacture of electrolysers also takes a share of about 10 %. With the solar version the long transmission distance by high-voltage line also contributes about 10 % to emissions. The relatively high values in the acidification category are caused by the SO_x emissions in steelmaking, which are significant because of the relatively high consumption of steel in both wind farms and solar thermal plant.

Fig. 10-29:
Comparison of *absolute* CO_2 emissions, total greenhouse gases and cumulative energy demand for hydrogen production using fossil fuels and renewables
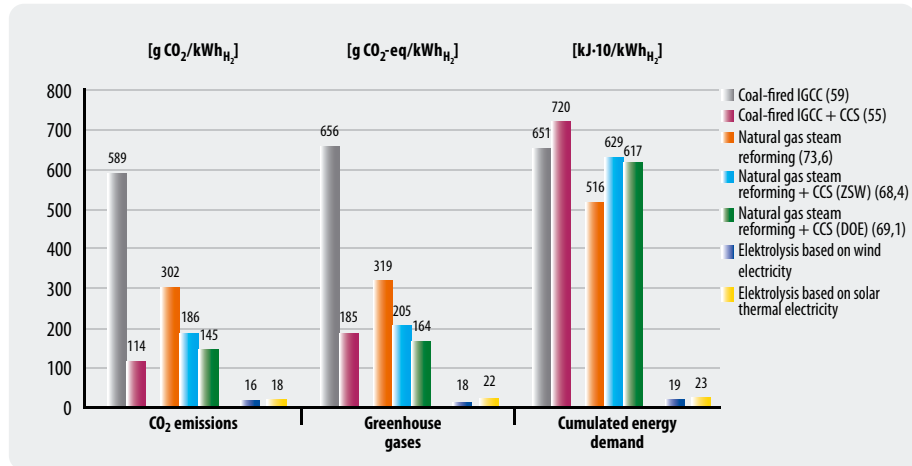
10.13 Conclusions for Hydrogen Production

- As with the case of power stations, we cannot speak of 'CO$_2$-free' or 'zero-CO$_2$' production. It would be more pertinent to use the term 'low-CO$_2$' hydrogen. Even with a capture rate of 88 % (coal gasification) it will only be possible to reduce CO_2 emissions by 81 %.

- Depending on the different methods of ZSW and DOE, with natural gas steam reforming reduction rates of CO_2 emissions of only 39 % and 52 % and of greenhouse gas emissions of 36 and 49 % respectively are possible. This is because only the CO_2 emissions from the synthesis gas can be captured at reasonable cost but not those that occur beforehand during natural gas combustion.

- Total greenhouse gas emissions can only be reduced less than proportionally because of the considerably increased primary energy consumption and the relatively high methane emissions associated with raw material extraction (coal mining) and transport (natural gas). These have a disproportionate influence on the greenhouse effect (supply chain share of 47 % for coal gasification with CCS and 25 % or 30 % for natural gas steam reforming with CCS).

- According to the literature the CO_2 capture process itself as a whole requires less additional energy than in the case of electricity generation. But the costs of transport and storage remain.

Fig. 10-30:
Comparison of impact categories photooxidant formation, acidification and eutrophication for hydrogen production using fossil fuels and renewables
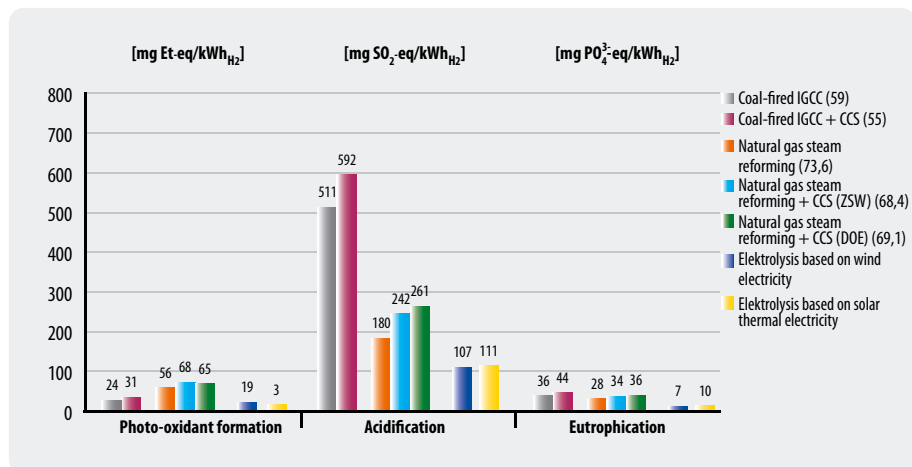
Chapter 11

Other Ecological Assessment Criteria for CCS

The previous chapter presented LCAs for CO_2 capture (using various technologies), liquefaction and transport. As we showed there, environmental problems associated with the other impact categories – such as acidification and eutrophication of soils and water bodies, summer smog and particle emissions – increase too, in particular because of the large amount of energy required for CO_2 capture. However, when assessing a field of technology as complex as CO_2 capture we need to cover and assess much more than the criteria included in an LCA. That expanded ecological perspective is addressed in the present chapter.

Concern about preserving the natural environment is increasingly reflected in the self-image of many businesses and individuals, as well as politicians and other actors in society. It has also found its way into environmental law, which treats the natural habitats of flora and fauna as goods worth preserving. A broad-based examination of the different CO_2 sequestration paths must therefore be conducted in that light. Anyway, given the influence environmental organisations have today, environmentally unacceptable solutions would be difficult to implement at all. Public opinion – partly influenced by the environmental lobby – is a decisive factor here.

The safety aspect should be seen as complementary to the ecological. Whereas ecological risks – as understood here – relate to flora and fauna, safety in general also addresses the hazards for people. One concept of safety applies primarily to specific one-off events; i.e., in connection with direct risks such as accidents caused by sudden pipeline leaks. The second meaning of the term 'safety' is defined in terms of long-term safety and thus poses the question of how 'safe' storage options are; i.e., how efficiently and permanently CO_2 will remain in the sink. This aspect was already touched on in the discussion of storage options.

11.1 CO$_2$ Capture

The ecological problems of the capture phase were largely dealt with in the LCAs. An issue not included there was the significant amount of additional space needed at power station sites – e.g. for installing CO_2 flue gas scrubbers.

11.2 CO$_2$ Transport

The conceivable transport methods for CO_2 are: pipeline (liquid or supercritical CO_2), rail or road tanker, ship (liquid CO_2 or the special case of dry ice for deep ocean storage). Another special case is ocean seeding, where the seeding agent (iron sulphate or iron oxide) would be transported to the place of dispersal in the ocean. The possible risks of the different transport options are discussed below.

Transport of liquid or solid CO$_2$ by road, rail or ship

The extent to which the transport network (road or rail) would have to be expanded for vehicle transport is not yet apparent. But this is the variable on which the direct ecological consequences ultimately depend (in terms of land use, habitat loss, etc.). Increased pollution emissions from the vehicles (diesel combustion in lorries and locomotives or electricity production for locomotives) would affect ecosystems and people directly. Anyway, road or rail transport appears relevant only for the start-up phase of a CO_2 infrastructure.

In the case of large-scale marine CO_2 storage, increased release of pollutants from ships (which usually run on heavy fuel oil) would probably lead to perceptible harm to ecosystems. But there are not yet any specific calculations on this.

Transport of solid CO_2 (dry ice) is fairly safe. For example, after an accident dry ice can be recovered almost without danger and reloaded. However, producing dry ice from captured CO_2 (to store in the deep oceans simply by tipping it into the sea) is an extremely energy-intensive process (see chapter 6) where all the ecological impact associated with increased use of energy would have to be taken into account. It can be assumed that dry ice will not represent a relevant transport option.

Transport by CO$_2$ pipeline

Building pipelines disrupts the ecosystems they pass through. During operation leakages or breakages suddenly releasing large amounts of CO_2 could have grave local effects on nearby ecosystems because in high concentrations CO_2 acts as a respiratory toxin. After completion of construction and following closure it is not always possible to fully restore the original ecosystems.
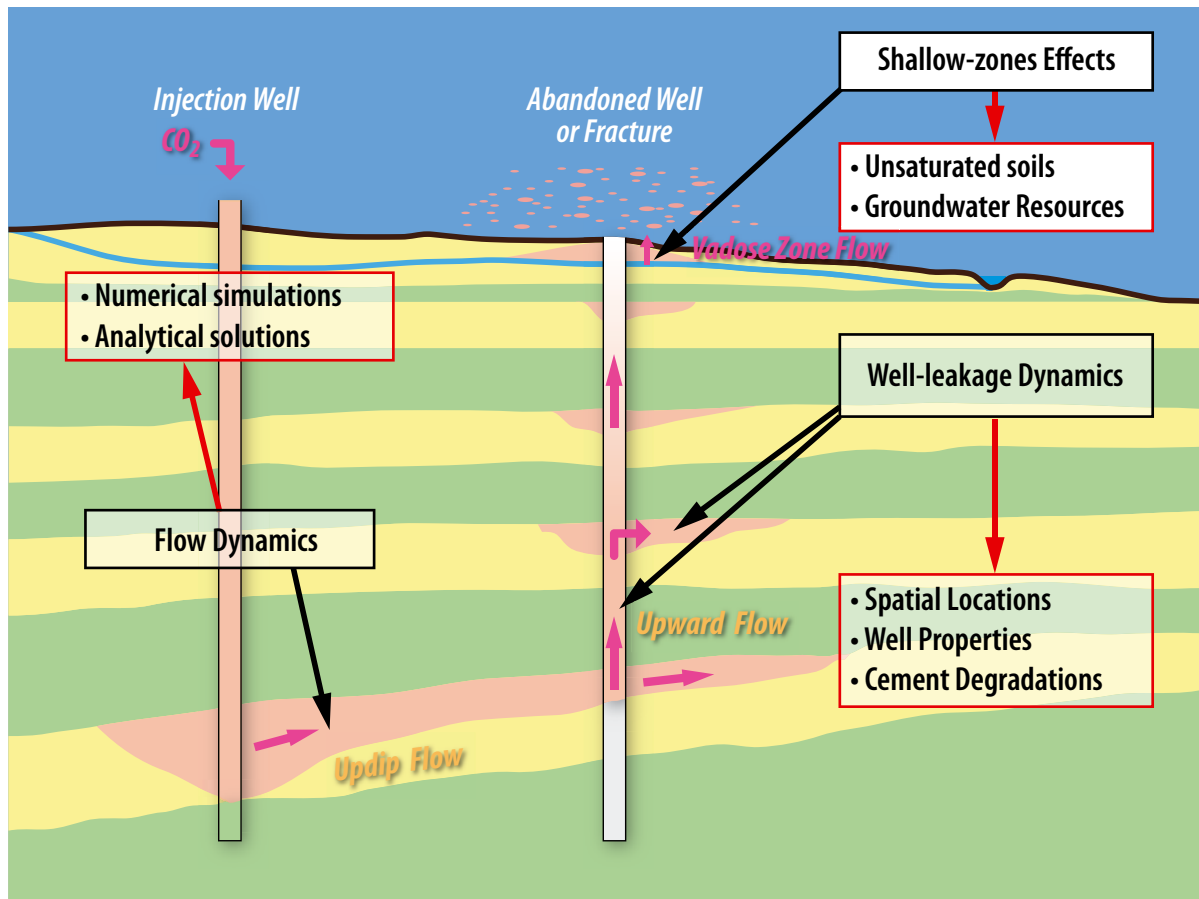
Fig. 11-1: CO_2 injection wells and possible leakages (Celia and Scherer 2004)

Pipelines are associated with various risks. Accidents (e.g. breakage) can occur through material fatigue, but can also be caused by external influences such as vehicle collision or deliberate destruction. Both cases would lead to CO_2 escaping, but a quantitative assessment of the risks cannot be provided here. However, the damage would probably be small, and current knowledge and experience with natural gas pipelines suggests that such incidents are rather unlikely.

Transport of iron sulphate or iron oxide for ocean seeding

Iron sulphate and iron oxide occur as by-products in numerous industrial processes. So depending on the scale on which ocean seeding was conducted it might be possible to supply the seeding agent without additional energy use. It is not presently possible to say anything more precise about this option, because the efficiency of ocean seeding has not been sufficiently clarified. If ocean seeding was introduced on a large scale, increased shipping could affect ecosystems (including regions away from the major shipping routes). Transporting iron compounds presents no particular problems in terms of transport safety. Protective clothing would be required when applying the substances.

11.3 Storing CO_2

Geological options

All the geological storage options are subject to the risk of leaks through unsealed or inadequately sealed boreholes, tunnels and shafts (oil and gas fields, coal mines), through new or previously unknown faults and fractures in the storage formation, or through seismic activity. All of these can allow the carbon dioxide to escape to the surface or to enter other geological strata, such as strata containing groundwater (see Fig. 11-1). This safety aspect of long-term stability is also important in relation to possible recognition of CO_2 storage projects under the clean development mechanism of the Kyoto Protocol (see also chapter 15).

All living creatures (human, animal, plant, microorganism) above and below the earth's surface would be affected by the toxic effects of CO_2 in high concentrations.

a. Deep saline aquifers
Storing CO_2 in porous salt-water-bearing strata requires deep sedimentary basins. These structures have so far generally only been explored in the vicinity of hydrocarbon deposits so there is a lack of comprehensive

data and assessments of their petrophysical properties. This applies, for example, to pore volume (which determines gas saturation), fracture and deformation processes, and chemistry (tightness of overlying layers), all of which are required to estimate the storage capacities of these geological structures and their safety risks in relation to possible leakage (May et al. 2003). Possible effects on microbiological processes in the geological formations are also still unclarified. Furthermore, the introduction of CO_2 leads to acidification of the water in the aquifer. Through its corrosive properties the acidic water could cause changes to the surrounding strata (especially carbonates) and to unprotected borehole seals (Ploetz 2002).

b. Exhausted oil and gas fields
When considering this option it should be noted that carbon dioxide possesses different chemical properties than substances stored to date. Globally, exhausted gas fields offer greater capacity than oil fields (cf. Table 7–2 and Fig. 7–2). As mentioned above, these options are subject to ecological restrictions to the extent that existing boreholes penetrating the covering layers could serve as escape paths for the CO_2 if sealing measures fail (May et al. 2003). There is no currently known type of cement that can be continuously exposed to high concentrations of CO_2 without corroding (Greenpeace 2004).

c. Deep unmineable coal seams (currently uneconomic)
This option poses the ecological risk of the extracted methane (which has a considerably higher greenhouse gas potential than CO_2) escaping.

d. Closed coal mines
The risk of gas escaping through leaks in densely populated areas (e.g. the Ruhr region in Germany) is very high because the covering layers are often thin, there are complex branching tunnel and shaft systems with connections to still operating areas, and sometimes there are also 'forgotten' tunnels and unrecorded subsidence (Ploetz 2002).

Marine options

For all marine storage options it should be noted that to date scientific investigation of the deep sea regions in general and their ecosystem structures has been very fragmentary, and the effects of CO_2 storage in these areas have so far only been studied in small-scale experiments or computer simulations. For these reasons, and because the physical state of the CO_2 can change as it sinks, any assessment of consequences can only be provisional.

In particular, the issue of seawater acidification should be noted, with its negative influences on physical/chemical and metabolic/physiological processes in both the abiotic and biotic spheres (Germanwatch 2004). As acidification increases calcifying organisms add less calcium carbonate to their shells, causing them to become thinner. Eventually acidification can even lead to the dissolution of calcium carbonate structures. This would affect shellfish, corals and many plankton organisms such as Foraminifera; Pteropoda are already affected (Feely et al. 2004; Wolf-Gladrow 2004; Wolf-Gladrow et al. 1999). Because many marine organisms react very sensitively to changes in pH, it is doubtful whether the marine biota would be capable of responding quickly enough to a fast anthropogenic change in living conditions, because adaptation to changing environmental conditions usually occurs over much longer periods (Knutzen 1981; Omori et al. 1998; Yamada and Ikeda 1999). If these organisms were to disappear food chains would be severed (or at least changed), with as yet unforeseeable consequences.

Oceanic storage would not lead to permanent sequestration of the CO_2. If CO_2 were to be dissolved in the ocean depths it would begin to escape back into the atmosphere after a few hundred years at the latest, when the water masses involved came into contact with the atmosphere again.

An induced algal bloom resulting from large-scale iron seeding would also have unforeseeable effects on marine ecosystems. A large part of the algae would be ingested by krill, for example, and thus pass up the food chain so that in the medium term the CO_2 would be released again (e.g. through breathing). The dead remainder would sink to the depths where it would be degraded (consuming oxygen) into gases such as methane and nitrous oxide (N_2O) which contribute proportionally much more to the greenhouse effect than does CO_2.

An increased photosynthesis rate of phytoplankton would lead to warming of the oceanic surface waters with consequences for oceanic circulation. This would also affect atmospheric chemistry and climate, for example because the phytoplankton produces dimethyl sulphide which forms cloud condensation nuclei (Lawrence 2002).

Other options

Biomass: Primary forests and wetlands are almost impossible to expand as sinks because many of the areas are limited in extent and threatened. So the foremost goal must be to protect the diversity of existing virgin and primary forests and to manage them sustainably. An end must also be put to clear-felling because the carbon already stored in old trees is quickly released, e.g. via the paper industry, which uses much of such timber (Forum Umwelt und Entwicklung 2001). Medium-term storage could be achieved by using timber for construction because wooden elements can last 100 to 150 years (Pro REGENWALD 1998).

Through their fast growth tree plantations quickly bind large quantities of CO_2 (between 1.4 and 15 t carbon/ha, natural forests 7–8 t/ha), but after just a few years or decades growth drops considerably and all that is left is depleted soil that is scarcely of any use for further cultivation.

Furthermore, the planting of fast-growing, non-native monocultures leads to the reduction and displacement of the natural species. Monocultures are also very susceptible to pests, and the application of fertilisers and pesticides worsens the greenhouse gas balance (Pro REGENWALD 1998). Plantations often compete for land with food production and in the process displace small-scale agricultural structures, above all in developing countries. They also exacerbate soil erosion and cause groundwater levels to fall through irrigation measures. Planting genetically modified trees has been proposed in connection with CO_2 storage. This would risk altering existing ecosystems through gene transfer with as yet unknown effects (Umweltinstitut München 2004). Storing CO_2 in trees represents only a temporary storage option.

Absorption in minerals: As things currently stand, binding CO_2 to magnesium silicate requires a very large energy input and large quantities of water for the reaction, when the whole process is considered. Capturing and binding the CO_2 from a 1 GW power station would require 400 MW of heat energy (Kohlmann 2001). The land used for mining the magnesium silicate and the emissions involved in transporting and disposing of the reaction product are problematic factors (Herzog 2002).

11.4 A Comparison of Strategies

Table 11–2 summarises the ecological effects of the CCS processes and compares them with renewables and energy efficiency. Both strategy options – renewables and energy efficiency – bear ecological burdens that have to be taken into account for integrated technology assessment. The examples of wind power and solar thermal power serve to illustrate the point:

Wind farms can alter local biospheres because both their foundations and the required access roads represent interventions in ecosystems. Offshore construction leads to the death of local benthic (bottom-living) fauna during the building phase. Towers create new habitats (artificial reefs), which change the composition of flora and fauna. However, this is often regarded as a positive effect because the area within the wind farm has weaker currents and no fishing and is used by many animals for resting and reproduction (nursing grounds).

The installation of solar thermal power plant, for example in Spain or in desert regions of North Africa, could cause harm to habitats because the great amount of space required would change conditions on the ground. This change is brought about not, however, by soil sealing, but primarily by the shading of the ground.

The broad range of ecological effects is listed in Table 11-1.

Table 11-1: Overall assessment of various climate protection options (criterion: ecological impact)

Technology	Ecological impact		
	During construction/ introduction (short-term)	During use	After use (long-term)
CO₂ capture and storage			
Process chain in general		• Energy consumption: seriously increased for all options, consequent increase in all material flows and associated strain on ecosystems • Increased demand for coal: increased ecological stress through mining and increased shipping • Increased other emissions: e.g. methane and N_2O, atmospheric pollutants, dust • Increased demand for natural gas: increased production and pipeline transport increases existing safety risks	
Capture processes		• Considerable increase in fuel use in comparison to existing processes through longer process chain (flue gas scrubbing) or introduction of new process lines (IGCC, oxyfuel) (for consequences see above)	
Flue gas scrubbing	• Greater material requirement because flue gas scrubbing requires numerous additional components	• The most energy-intensive method of CO_2 capture, increases energy required by up to 40 %; all associated environmental impacts increase accordingly • Possible consequences of release of toxic scrubbing agent	
Integrated gasification combined cycle (IGCC)	• Additional material requirement through introduction of IGCC not yet assessable	• Apart from increased energy requirement and associated environmental impacts (see above) negative ecological consequences will not be much greater than for existing conventional power stations	
Oxyfuel process	• Additional material requirement through introduction of the oxyfuel process not yet estimable	• Ecological consequences for the oxyfuel process itself cannot yet be estimated because the process is still under development. Apart from increased energy requirement and associated environmental impacts (see above) negative ecological consequences will not be much greater than for existing conventional power stations	
Transport		• Transporting CO_2 in any form is energy-intensive and therefore increases material flows; especially when conditioning the CO_2 (compressing, liquefying)	
Pipeline	• Intervention in all ecosystems along pipeline route	• Leaks and accidents (breakage etc.) can lead to elimination of ecosystems	• Restoration of original ecosystems along closed pipeline route is questionable
Dry ice: by ship and/ or rail		• Producing dry ice is extremely energy-intensive	• Rail: none, because existing transport routes used • Ship: destruction of ecosystems through increased release of pollutants into water
Iron sulphate or oxide, transport by ship		• Energy-intensive process, resulting strain on ecosystems	• Owing to increase in shipping possible destruction of ecosystems through increased release of pollutants into water

Technology	Ecological impact		
	During construction/ introduction (short-term)	**During use**	**After use (long-term)**
Storage			
Terrestrial storage option			
Forestation	• Creation of plantations may involve clearing of natural woodland and trees	• Plantations generally store less CO_2 than mixed forests and natural woodland • Monocultures compete with food production • Monocultures are susceptible to disease and pests • Primary forest sinks are practically unexpandable • Various woodland ecosystems have different levels of potential storage capacity • Use of genetically modified (GM) plants could harm wild species or displace them with monocultures	• Forestation should be seen more as a temporary storage option with delayed CO_2 release. CO_2 released later contributes to climate change because it is fixed only for a few decades during the tree's growth phase • Biomass/algae: strictly limited potential after consideration of ethical and ecological aspects
Geological storage options			
Closed coal mines		• Ecosystems may be strongly endangered through high leakage risk	• Ecosystems may be strongly endangered through high leakage risk
Deep coal seams (unmineable)		• Escaping methane may increase the greenhouse effect	• Permanent storage of CO_2 not yet proven
Saline aquifers		• If insertion process is safe risks are low	• Long-term stability of CO_2 in aquifers not yet adequately clarified
Salt caverns		• Danger of sudden emptying if leakage occurs	• None, as long as leaks can be prevented
Mineralisation	• Mining of raw materials (reactants) uses land and causes destruction of ecosystems	• High energy consumption for mineralisation processes and transport • High transport intensity	• Large land requirement for depositing minerals displaces ecosystems
Marine storage options			
Induced algae blooms		• Surface waters: possible shifts in ecosystems in favour of other species • Warming of surface waters alters stratification, changes or even eliminates ecosystems • Seabed: degradation of sinking algae consumes oxygen creating low-O_2 or O_2-free zones. Consequence: elimination of ecosystems	• Long-term effects on ecosystems not yet predictable
Physical dissolution by pumping into seawater		• Long-term use would reduce the pH of seawater, harming ecosystems globally; calcifying organisms are affected first • Delayed re-release of CO_2	• Long-term application lowers pH of sea water, harming ecosystems globally
Sinking dry ice		• Organisms die in vicinity of sunk dry ice shipments • Delayed re-release of CO_2	• Organisms die in vicinity of sunk dry ice shipments
Creation of CO_2 lakes on ocean floor		• Organisms die in vicinity of lakes • Extensive destruction of whole ecosystems through possible slippage of sediments and subsequent uncontrolled spread of liquid CO_2	• Organisms die in vicinity of lakes • Extensive destruction of whole ecosystems through possible slippage of sediments and subsequent uncontrolled spread of liquid CO_2

Technology	Ecological impact		
	During construction/ introduction (short-term)	**During use**	**After use (long-term)**
Renewables			
Wind power onshore	• Foundations and access roads alter local abiotic environment, consequential alteration of natural biospheres	• Provokes avoidance behaviour in certain bird species, which may reduce size of habitat • Noise emissions • In some cases still flickering shadow problem, but largely eliminated by modern control technology	• None, complete restoration possible
Wind power offshore	North Sea and Baltic both intensively used for decades with wide-ranging consequences for ecological systems: intense utilisation as fishing grounds (overfishing), as shipping route (pollutants), as source of raw materials (gravel) and as dumping ground (waste dumping)		
	• During construction phase death of benthic communities locally • Foundations alter abiotic environment, consequential alteration of natural biospheres • Underwater noise during construction of foundations could damage hearing of marine mammals (no limits for noise exposure set yet)	• Provokes avoidance behaviour in certain bird species • Noise emissions • Possible positive effects: • Sheltered zones in and around wind parks can serve as nursing grounds for fauna • Foundations and towers serve as artificial reefs and offer a habitat for numerous groups of organisms (with consequences further up food chain)	• None, complete restoration possible
Biomass and Biogas Cultivation of 'energy plants' (renewable raw materials) Residual forest wood Loppings Sewage sludge Liquid manure		• Cultivation of monocultures reduces species diversity and so impairs natural control dynamics (applies only to energy crops) • Possible prospective use of genetically modified (GM) plants with unpredictable consequences (applies only to energy crops) • Displacement of natural biotopes (applies only to energy crops) • Depending on biofuel and combustion process, SO_2 and NO_x emissions	• Restoration of original ecosystems normally impossible (e.g. drained wetlands) • Possible unpredictable consequences of use of GM organisms
Hydropower a) Small river-flow plants b) Large river-flow plants c) Reservoir storage	• Grave intervention in surrounding ecosystems	• River-flow plants have extensive ecological and hydrological consequences: changes in quality, quantity and dynamic of run-off and sediment regime, diverse experience in dealing with consequences of damming • Disruption or prevention of fish migration and migration of macrozoobenthic organisms • Reservoirs cause direct loss of land and ecosystems	• Depends on post-closure use of hydroelectric plant, but restoration of original ecosystems normally impossible
Solar radiation I Photovoltaik on buildings on open spaces	• Minimal intervention during construction phase • Significant energy and material requirement depending on cell technology	• Land-use intensity can impair ecological habitats, e.g. through shading	• None on site because complete restoration possible • Depending on materials used complex disposal with possible environmental risks, especially with cadmium telluride and gallium arsenide cells (Cd and As are heavy metals)
Solar radiation II Solar thermal power plant		• Land-use intensity can impair ecological habitats, e.g. through shading	• None, complete restoration possible

Technology	Ecological impact		
	During construction/ introduction (short-term)	**During use**	**After use (long-term)**
Geothermal I near surface	• Small-scale harm to eco-systems through drilling		
Geothermal II deep	• Small-scale harm to eco-systems through drilling and access roads	• Rather small	
Ocean energy Tidal, wave power, currents, temperature gradients		• All systems apart from tidal power are currently in development stage, conclusive estimate of ecological consequences not yet possible • Tidal power station: possible impediment to animal movements	• Not yet sufficiently known
Energy efficiency			
Supply side measures: increase of generation efficiency	• Normally no increase in ecological stress in com-parison to less efficient technologies	• Normally no increase in ecological stress in comparison to less efficient technologies	• No increase in ecological stress in comparison with less efficient technologies
Demand side measures: efficiency of technolo-gies on consumer level	• In some cases greater material intensity	• None	• Possible increased disposal costs (e.g. insulat-ing materials)

Chapter 12

Development of Electricity and Hydrogen Generation Costs with CCS

12.1 Future Electricity Generation Costs Taking Account of Technological Developments, Fuel Price Rises and Cost of CO_2 Emission Certificates

12.1.1 Price Trends for Fuel and CO_2 Emission Certificates

If we are to correctly assess long-term investment decisions such as the construction of power stations that will be in operation for decades, one of the things we require are scenarios about future prices of fossil fuels. Such scenarios must cover a sufficiently broad range of possible developments and in particular take into consideration the fact that – as in the case of CCS plant – investment decisions may not have to be made until around 2020 but their effect will then last for thirty years and more. In the light of the recent hefty price rises for crude oil that have put an end to a good decade of very low prices and the medium-term prospect of this resource becoming scarce, it would also make sense to consider price developments that would have been regarded as improbable just a few years ago. In fact, these could now prove to be more likely than many of the low-price scenarios that served as the basis of numerous studies over the past five years. Here we use two price trajectories for fossil fuel prices that roughly cover this spectrum. The 'traditional' price scenario – referred to as 'EWI 2005' – is based on the scenarios in Energiereport IV (EWI and Prognos 2005). It is based on the comparatively low level of energy prices that still existed around 2002 and describes a price development through to 2030, which we have projected on to 2050. The second, referred to as 'DLR 2005', includes the most recent price rises and basically projects them into the future. It is based partly on the BMU's assumptions (2004) and has been updated accordingly.

Figure 12-1 compares the past development of the price of crude oil on the basis of annual averages (\$/bbl real 2000 prices) with these two price scenarios. Whereas the average price in 2002 was still \$$_{2000}$24/bbl, it rose to \$$_{2000}$36/bbl in 2004 and by 2005 (average January to September) had already reached \$$_{2000}$48/bbl. Nominal prices have already exceeded the price peaks of around 1982, although the real price level (annual average) is still lower. In 2006 there were already brief price peaks of around \$$_{2000}$70/bbl.

Starting from the price level of 2002, EWI 2005 reaches a real oil price of \$$_{2000}$37 /bbl in 2030 (nominal \$63/bbl) and \$$_{2000}$50/bbl in 2050 (nominal \$110/bbl), so throughout this whole period it is below the 2005 level. In other words, the current oil price would have to fall again considerably to reach those levels. The DLR 2005 scenario starts from the 2005 price level and assumes that there will be a further price increase, but a moderate one. Here a price of \$$_{2000}$65 /bbl (nominal \$110/bbl) is reached in 2030 and \$$_{2000}$72/bbl (nominal \$160/bbl) in 2050.

For the further discussion the prices of natural gas and coal in particular are significant for power stations. Power stations in Germany are already subject to emissions trading, so future prices for CO_2 certificates are also of interest. They currently cost around €15–20/t, even though it was originally thought that the first phase of emissions trading (until 2007) would not see prices rising above €10/t CO_2. In both scenarios CO_2 prices rise continuously: in EWI 2005 only very slightly, from €5/t CO_2 in 2010 to €15/t CO_2 in 2030 (and projected on to €22.50/t CO_2 in 2050); in DLR 2005 somewhat more steeply, but still relatively moderately, from €7.50/t CO_2 in 2010 to €22.50/t CO_2 in 2030 and €35/t CO_2 in 2050. In the calculations for electricity generation costs cited in the following discussion these CO_2 prices are added to the fuel price according to the carbon content of the fuel.

The resulting power station fuel prices with and without CO_2 penalty are summarised in Fig. 12-2 and Table 12-1. In EWI 2005 the 2005 gas price is not reached again until 2025, the coal price not until 2045. A CO_2 penalty brings those dates a long way forward, to 2015 and 2010. In the DLR 2005 scenario fuel prices without CO_2 penalty in 2020 (the year when the first commercial CCS systems could come on stream) are about one third higher than in EWI 2005 and in 2050 about 45 % higher for gas and about 30 % higher for coal. The assumed CO_2 penalties make coal in particular considerably more expensive. In DLR 2005 the coal price in 2050 (including CO_2 penalty) is three times the 2005 price, while the natural gas price is 2.5 times higher. The lignite price is also given for comparison.

Oil price, real [US-$_{2000}/bbl]

Source: Massarat 2002; BMWA 2005; Tecson 2006; EWI/Prognos 2005; BMU 2004; own calculations
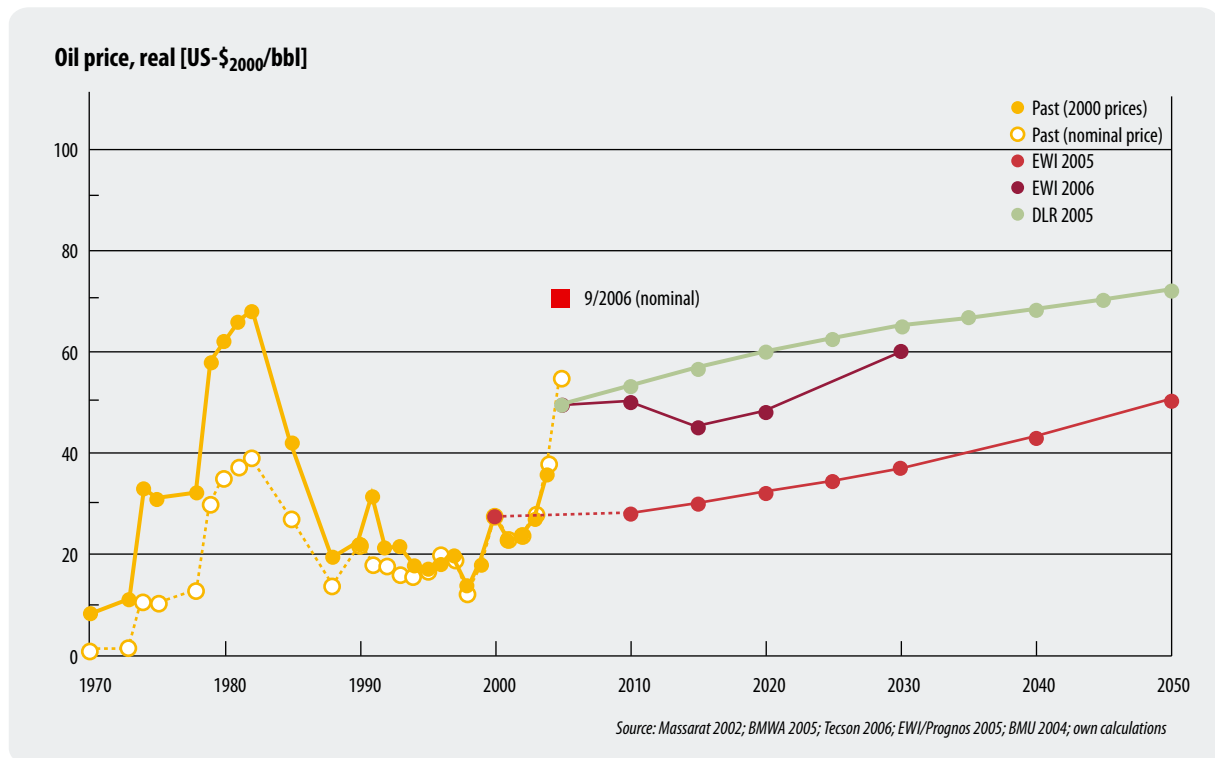
Fig. 12-1: Real ($_{2000}$) and nominal oil price since 1970; energy price scenarios (EWI 2005 and DLR 2005) in real prices until 2050 and (for comparison) the EWI 2006 scenario until 2030

Power plant fuel prices [EUR_{2000}/GJ]

Power plant fuel prices [EUR_{2000} G/J]
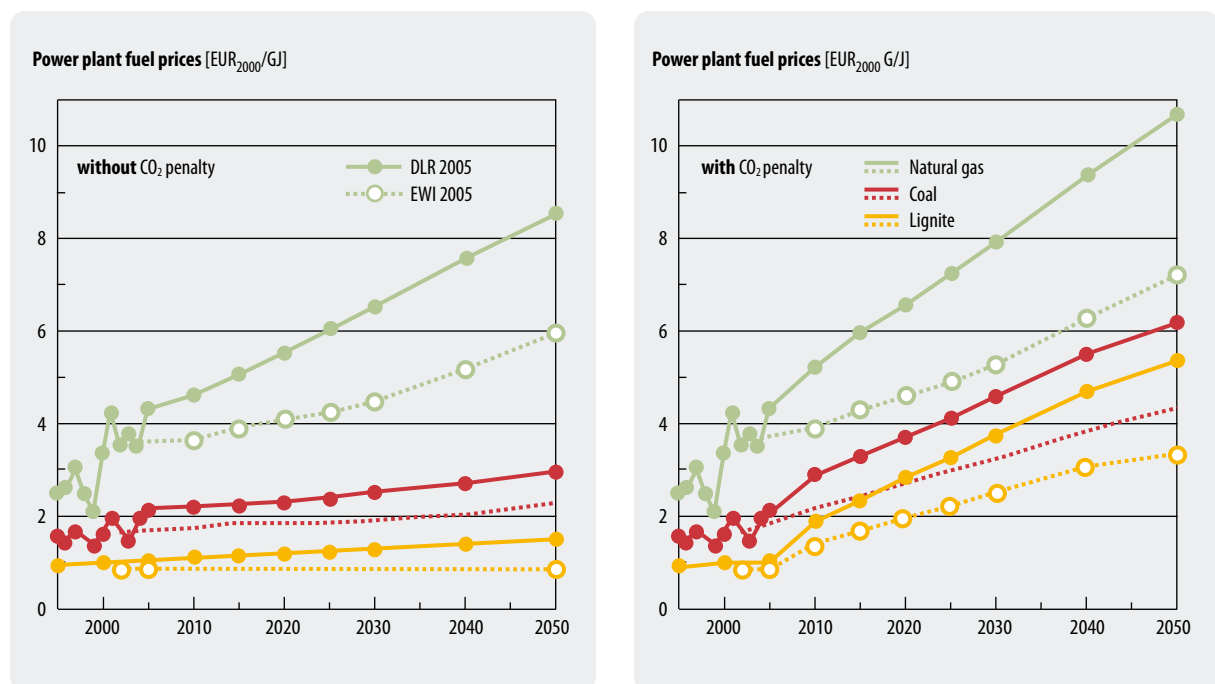
Fig. 12-2: Fuel prices at power station (in $_{2000}$/GJ) for natural gas, coal and lignite for price scenarios DLR 2005 (solid lines) and EWI 2005 (broken lines) without (left) and with (right) CO_2 penalty

Table 12-1: Fuel prices for power stations in two price scenarios (EWI 2005 and DLR 2005) without and with CO_2 penalty in $ct_{\text{€}2000}/kWh_{th}$ and in $\text{€}_{2000}/GJ$

				EWI					Projection				Mean	Inccrease by 2050
		2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	20-50	%/a
EWI 2005														
Natural gas														
	ct/kWh$_{th}$	1.27	**1.55**	1.30	1.40	1.46	1.52	1.60	1.72	1.85	1.98	2.15	**1.75**	1.59
	EUR/GJ	3.53	**4.31**	3.61	3.88	4.04	4.23	4.45	4.78	5.14	5.50	5.98	**4.87**	
Coal														
	ct/kWh$_{th}$	0.57	**0.76**	0.62	0.65	0.65	0.66	0.67	0.69	0.72	0.77	0.81	**0.71**	0.79
	EUR/GJ	1.59	**2.12**	1.72	1.82	1.82	1.84	1.86	1.93	2.00	2.13	2.25	**1.98**	
Lignite														
	ct/kWh$_{th}$	0.30	**0.30**	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	**0.30**	0.00
	EUR/GJ	0.83	**0.83**	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	**0.83**	
EWI 2005 + CO$_2$	EUR/t			5.00	7.50	10.00	12.50	15.00	17.50	20.00	21.25	22.50		
Natural gas														
	ct/kWh$_{th}$	1.27	**1.55**	1.40	1.55	1.66	1.77	1.91	2.08	2.26	2.43	2.61	**2.10**	1.90
	EUR/GJ	3.53	**4.31**	3.89	4.30	4.61	4.92	5.30	5.79	6.28	6.76	7.24	**5.84**	
Coal														
	ct/kWh$_{th}$	0.57	**0.76**	0.78	0.88	0.99	1.08	1.17	1.28	1.38	1.47	1.56	**1.27**	1.93
	EUR/GJ	1.59	**2.12**	2.18	2.46	2.74	2.99	3.24	3.55	3.85	4.09	4.33	**3.54**	
Lignite														
	ct/kWh$_{th}$	0.30	**0.30**	0.50	0.60	0.70	0.80	0.90	0.95	1.10	1.05	1.20	**0.96**	2.38
	EUR/GJ	0.83	**0.83**	1.39	1.67	1.95	2.22	2.50	2.64	3.06	2.92	3.34	**2.66**	
				DLR										
		2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	20-50	%/a
DLR														
Natural gas														
	ct/kWh$_{th}$	1.21	**1.55**	1.73	1.90	2.06	2.23	2.40	2.58	2.76	2.96	3.15	**2.59**	1.76
	EUR/GJ	3.35	**4.31**	4.81	5.27	5.73	6.20	6.67	7.17	7.67	8.21	8.76	**7.20**	
Coal														
	ct/kWh$_{th}$	0.57	**0.76**	0.79	0.81	0.84	0.87	0.90	0.94	0.98	1.03	1.08	**0.95**	0.97
	EUR/GJ	1.59	**2.12**	2.20	2.26	2.32	2.42	2.51	2.62	2.72	2.86	3.00	**2.64**	
Lignite														
	ct/kWh$_{th}$	0.34	**0.36**	0.38	0.40	0.41	0.43	0.45	0.47	0.49	0.51	0.52	**0.47**	0.86
	EUR/GJ	0.95	**1.00**	1.05	1.10	1.15	1.20	1.25	1.31	1.36	1.40	1.45	**1.30**	
DLR 2005 + CO$_2$	EUR/t			7.50	11.25	15.00	18.75	22.50	26.26	30.00	32.50	35.00		
Natural gas														
	ct/kWh$_{th}$	1.21	**1.55**	1.82	2.05	2.29	2.54	2.80	3.07	3.33	3.57	3.80	**3.06**	2.20
	EUR/GJ	3.35	**4.31**	5.05	5.70	6.37	7.06	7.78	8.52	9.26	9.91	10.56	**8.49**	
Coal														
	ct/kWh$_{th}$	0.57	**0.76**	1.03	1.17	1.32	1.48	1.64	1.80	1.96	2.09	2.22	**1.79**	2.27
	EUR/GJ	1.59	**2.12**	2.86	3.25	3.67	4.11	4.55	5.00	5.45	5.81	6.17	**4.97**	
Lignite														
	ct/kWh$_{th}$	0.34	**0.36**	0.68	0.85	1.02	1.19	1.35	1.52	1.69	1.81	1.93	**1.50**	2.97
	EUR/GJ	0.95	**1.00**	1.89	2.36	2.84	3.29	3.75	4.23	4.70	5.03	5.37	**4.17**	

Table 12-2:
Data used for calculating
electricity generation costs of
fossil-fuelled power stations

		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC [2] (2005)	Reference
Interest rate	%/a	12	10	10		**10**
Depreciation period	a	15	30	25		**25**
Annuity	%/a	15.0	10.6	11.0	11–17	**11.0**
Load factor	h/a	7,000	8,200	7,500	5,700–7,800	**7,000**
Influence on electricity generation costs in relation to reference		1.10	0.85	0.93	0.80–1.20	**1.00**
Fuel prices Natural gas Coal	€/GJ €/GJ	3.93 1.24	3.20 1.60	3.00 2.00	3.0–4.8 1.8–2.3	**4.0–5.7** [1] **1.8–2.3** [1]

1) Prices for 2020 without CO_2 penalty	2) Ranges from studies cited in IPCC 2005

The scenario price trends for fuel and CO_2 emission certificates have effects both on the cost differences between technologies with and without CO_2 capture (owing to the different levels of efficiency) and on competitiveness with CO_2-free technologies based on renewable energy sources.

12.1.2 Data Used for Cost Calculations and Electricity Costs in 2020

In the following we describe the cost information given by various relevant sources for future power stations with and without CO_2 capture. However, these costs were calculated on the basis of different economic data such as base year for prices, interest rates and depreciation periods, different plant lifetimes and in some cases very different fuel prices, so they are only partially comparable. The different assumptions about annuity and plant lifetimes alone (Table 12-2) cause differences of up to ± 20 % in the cost calculations. Different power station sizes can also lead to different specific investment costs. The differences in fuel prices are also considerable, although in general nothing was said about rates of increase during the plant's lifetime (e.g. between 2020 and 2050). In the following we contrast data from four important sources (Williams 2002, IEA 2003, ECOFYS 2004, IPCC 2005) on the basis of identical data for interest rate, depreciation period, annual full load hours and fuel costs and compare them with the four reference technologies defined here.

Table 12-3 shows the data for three types of power station that are particularly important for early introduction of CO_2 capture techniques (around 2020). These are

- efficient coal-fired thermal power stations
- coal-fired combined cycle power stations with integrated coal gasification and
- gas-fired combined cycle power stations.

They are covered by all the relevant sources. Only ECOFYS (2004) additionally investigates gas-fired thermal power stations. But because they have significantly lower efficiency than combined cycle power stations they are not of great interest for CO_2 capture. Considerable differences arise in the assessments for coal-fired thermal power stations, so the reference power station data take special account of the German situation. Accordingly, the data for the coal-fired thermal power station for 2020 were defined on the basis of the NRW reference power station (VGB 2004). With gas-fired combined cycle power stations the differences in the assumptions are smaller. Coal-fired IGCC power stations are in general still found to be considerably more expensive in 2020.

Under these assumptions the resulting electricity generation costs in 2020 for coal-fired thermal power stations are 3.51–3.87 ct/kWh$_{el}$ and for gas-fired combined cycle power stations 3.56–4.44 ct/kWh$_{el}$. So with the assumed cost relationships, efficient modern 'conventional' coal-fired power stations are more cost-effective than gas-fired combined cycle power stations. With coal gasification costs can be expected to be about 0.6 ct/kWh$_{el}$ higher. A CO_2 penalty of €15/t in 2020 (DLR 2005+CO_2) makes electricity generated from coal more expensive by 1 ct/kWh$_{el}$ and electricity from gas by 0.5 ct/kWh$_{el}$, which has the effect of inverting the cost relationship between the two options at that point in time.

If the electricity costs are calculated using the average fuel price over the whole period of operation (see Table 12-1, second-last column), the cost of electricity from coal is 0.3 ct/kWh$_{el}$ above those of 2020 and the cost of electricity from natural gas – due to steeper rates of

		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)[1]	Reference
Coal-fired thermal power station						
Output	MW	460	n.a.	500	n.a.	**700**
Efficiency	%	42.7	44	42	45.6	**49**
Investment	€/kW$_{el}$	1,425	1,086	1,085	870	**950**
Running and maintenance costs	€/kW,a	72.1	33.0	50.0	48.3[2]	**48.3**
Electricity costs 2020	ct/kWh$_{el}$	5.19	4.15	4.39	3.90	
• DLR 2005, without CO$_2$ penalty						**3.87**
• DLR 2005, with CO$_2$ penalty						**4.89**
• EWI 2005, without CO$_2$ penalty						**3.51**
Coal-fired IGCC power station						
Output	MW	425	n.a.	500	365	**700**
Efficiency	%	43.1	46	47	49.4	**50**
Investment	€/kW$_{el}$	1,557	1,335	1,685	1,100	**1,300**
Running and maintenance costs	€/kW,a	59.3	37.1	57.5	53.0[2]	**53.0**
Electricity costs 2020	ct/kWh$_{el}$	5.21	4.48	5.18	4.20	
• DLR 2005, without CO$_2$ penalty						**4.46**
• DLR 2005, with CO$_2$ penalty						**5.46**
• EWI 2005, without CO$_2$ penalty						**4.12**
Natural gas combined cycle power station						
Output	MW	385	n.a.	500	380	**700**
Efficiency	%	53.6	59	58	58.6	**60**
Investment	€/kW$_{el}$	590	424	480	700	**400**
Running and maintenance costs	€/kW,a	23.3	14.8	37.3	34.1[2]	**34.1**
Electricity costs 2020	ct/kWh$_{el}$	4.97	4.35	4.71	5.00	
• DLR 2005, without CO$_2$ penalty						**4.44**
• DLR 2005, with CO$_2$ penalty						**4.94**
• EWI 2005, without CO$_2$ penalty						**3.56**
1) Average values for 'advanced technologies' 2) Figure taken from reference						

Table 12-3:
Data for fossil-fuelled power stations *in 2020* and their electricity generation costs on the basis of the same data (*without* capture and final storage of CO$_2$); all costs in € or cents (2000 prices)

price increase and the generally greater proportional importance of fuel prices – 0.6 to 1.2 ct/ kWh$_{el}$ above those of 2020.

Table 12–4 shows the same comparison of these power stations but *with* CO$_2$ capture. With coal-fired thermal power stations and gas-fired combined cycle power stations this is CO$_2$ capture after combustion; with coal-fired IGCC power stations it is capture before combustion. The data shown in the 'Reference' column are 'best estimates' on the basis of all consulted sources, the reference power stations as per Table 12-3 and other findings from this study. In all cases it is assumed that the

plant in question has completed its pilot and demonstration phase and will be basically commercially available by 2020.

The resulting electricity generation costs in 2020 (using fuel prices without CO$_2$ penalty) for low-CO$_2$ coal-fired thermal power stations are between 5.52 and 5.95 ct/kWh$_{el}$. Low-CO$_2$ coal-fired power stations with IGCC have electricity costs between 5.88 and 6.46 ct/kWh$_{el}$. For low-CO$_2$ gas-fired combined cycle power stations the cost is between 5.04 and 6.08 ct/kWh$_{el}$ and thus within the cost range for coal-fired power stations at the same time. If we take the CO$_2$ penalties into account,

Table 12-4:
Data for fossil-fuelled power stations *in 2020* and their electricity generation costs on the basis of the same data (with capture, *without* final storage of CO_2); all costs in € or cents (2000 prices)

		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)[1]	Reference
Coal-fired thermal power station						
Output	MW	330	n.a.	385	n.a.	**570**
Efficiency	%	31.0	36.0	33.7	35.4	**40.0**
Investment	€/kW$_{el}$	2,385	1,823	1,880	1,470	**1,750**
Running and maintenance costs	€/kW,a	129	78.0	79.7	80.0 [2]	**80.0**
Electricity costs 2020	ct/kWh$_{el}$	8.06	6.29	6.48	5.78	
• DLR 2005, without CO_2 penalty						**5.95**
• DLR 2005, with CO_2 penalty						**6.13**
• EWI 2005, without CO_2 penalty						**5.52**
Coal-fired IGCC power station						
Output	MW	365	n.a.	385	360	**590**
Efficiency	%	37.0	40.0	42.2	40.3	**42.0**
Investment	€/kW$_{el}$	2,022	1,733	2,375	1,720	**2,000**
Running and maintenance costs	€/kW,a	72.0	55.0	87.5	85.0[2]	**85.0**
Electricity costs 2020	ct/kWh$_{el}$	6.56	5.57	6.95	6.00	
• DLR 2005, without CO_2 penalty						**6.28**
• DLR 2005, with CO_2 penalty						**6.46**
• EWI 2005, without CO_2 penalty						**5.88**
Natural gas combined cycle power station						
Output	MW	310	n.a.	440	330	**600**
Efficiency	%	43.3	51.0	52.0	50.6	**51.0**
Investment	€/kW$_{el}$	1,125	850	890	1,170	**900**
Running and maintenance costs	€/kW,a	52.8	35.0	51.7	54.0[2]	**54.0**
Electricity costs 2020	ct/kWh$_{el}$	7.12	5.77	5.99	6.59	
• DLR 2005, without CO_2 penalty						**6.08**
• DLR 2005, with CO_2 penalty						**6.16**
• EWI 2005, without CO_2 penalty						**5.04**

1) Average values for 'advanced technologies'   2) Figure taken from reference

the electricity costs of these power stations rise too – if only slightly – because the remaining CO_2 emissions from CCS power stations are only about 15 % of those from power stations without CCS (capture rate 88 %). Compression, transport and final storage of the CO_2 are not yet included in these costs.

Table 12-5 shows the efficiency losses resulting from CO_2 capture and the extra expense for market-ready CCS facilities in 2020. In the reference case CO_2 cap-

ture increases the cost of electricity from coal-fired thermal power stations by approx. 2 ct/kWh$_{el}$. The cost increase (1.8 ct/kWh$_{el}$) with CO_2 capture in IGCC power stations is somewhat smaller because gasification has already occurred in the power station without CO_2 capture. In relation to the lower-cost coal-fired thermal power station, however, the cost increase at this point in time rises to 2.6 ct/kWh$_{el}$ (values in parentheses in Table 12-5). The cost increases are smallest with gas-fired combined cycle power stations with values around

		Williams (2002)	IEA (2003)	ECOFYS (2004)	IPCC (2005)[1]	Reference (2005)
Coal-fired thermal power station						
Efficiency	% points	− 11.7	− 8.0	− 8.3	− 10.2	**− 9.0**
Avoided CO_2 emissions/original emissions	%	83.5	85.3	85.0	84.4	**85.3**
Additional investment costs	€/kW$_{el}$	+ 960	+ 737	+ 795	+ 600	**+ 800**
Electricity costs 2020	ct/kWh$_{el}$	2.87	2.14	2.09	1.88	
• DLR 2005, without CO_2 penalty						**2.08**
• DLR 2005 with CO_2 penalty						**1.24**
• EWI 2005, without CO_2 penalty						**2.01**
Range of other studies [3]						**2.1–4.2**
Coal-fired IGCC power station						
Efficiency	% points	− 6.1	− 6.0	− 4.8	− 9.0	**− 8.0**
Avoided CO_2 emissions/original emissions	%	86.0	86.2	86.6	91.1	**85.7**
Additional investment costs	€/kW$_{el}$	+ 465	+ 398	+ 690	+620	**+ 700**
Electricity costs 2020	ct/kWh$_{el}$	1.35 (1.37)	1.09 (1.42)	1.77 (2.56)	1.80 (2.10)	
• DLR 2005, without CO_2 penalty						**1.82 (2.41)[2]**
• DLR 2005 with CO_2 penalty						**1.00**
• EWI 2005, without CO_2 penalty						**1.76**
Range of other studies [3]						**1.3–2.7**
Natural gas combined cycle power station						
Efficiency	% points	− 10.3	− 8.0	− 6.0	− 8.6	**− 9.0**
Avoided CO_2 emissions/original emissions	%	85.1	86.1	86.6	94.1	**85.9**
Additional investment costs	€/kW$_{el}$	+ 535	+ 426	+ 410	+470	**+ 500**
Electricity costs 2020	ct/kWh$_{el}$	2.15	1.42	1.72	1.59	
• DLR 2005, without CO_2 penalty						**1.64**
• DLR 2005 with CO_2 penalty						**1.22**
• EWI 2005, without CO_2 penalty						**1.48**
Range of other studies [3]						**1.1–2.3**

1) Average values for 'advanced technologies'   2) In relation to coal-fired thermal power station without CO_2 capture
3) Figures according to ECOFYS 2004, approximately adjusted to above data with lowest and highest value omitted in each case

Table 12-5:
Difference in data of power stations *with* and *without* CO_2 capture (*without* transport and final storage of the CO_2), all costs in €ct (2000 prices)

1.6 ct/kWh$_{el}$. CO_2 penalties of €15/t – as included in the DLR 2005 plus CO_2 penalty price scenario – reduce the cost increase compared with power stations without CO_2 capture to about 1.2 ct/kWh$_{el}$.

If we compare the above values with the ranges determined by ECOFYS (2004) from ten other studies (the values given there were converted to be compatible with the economic reference data and the respective lowest and highest value was ignored) the refer-ence cost increases described here are at the low ends of the respective ranges. IPCC (2005) gives ranges of 1.7–4.2 ct/kWh$_{el}$ for coal-fired thermal power stations and 0.8–2.5 ct/kWh$_{el}$ for coal-fired IGCC and gas-fired combined cycle power stations. So the results for the electricity generation costs of the reference technologies selected here form a representative and reliable starting point for cost comparisons.

Table 12-6:
Comparison of 'market-ready' CCS power stations (2020) with 'mature' CCS power stations (2040) and their reference power stations without CCS

		Coal-fired thermal		Coal-fired IGCC		Natural gas CC	
		2020	2040	2020	2040	2020	2040
A) Without CO$_2$ capture							
Efficiency	%	49.0	52.0	50.0	54.0	60.0	62.0
Investment	€/kW$_{el}$	950	900	1,300	1,200	400	400
Running and maintenance	€/kW,a	48.3	45.0	53.0	49.0	34.1	32.0
CO$_2$ emissions, direct	g/kWh$_{el}$	673	635	660	611	337	326
Electricity costs (with fuel costs 2020, DLR scenario)	ct/kWh$_{el}$	3.87	3.60	4.46	4.12	4.44	4.32
B) With CO$_2$ capture							
Efficiency	%	40.0	44.0	42.0	46.0	51.0	55.0
Reduction	% points	9	8	8	8	9	7
Capture rate	%	88	90	88	92	88	92
Investment	€/kW$_{el}$	1,750	1,600	2,000	1,800	900	750
Difference	€/kW$_{el}$	800	700	700	600	500	350
Running and maintenance	€/kW,a	80.0	74.0	85.0	78.0	54.0	50.0
CO$_2$ emissions, direct	g/kWh$_{el}$	99	75	94	57	48	40
Avoided emissions/original emissions	%	85.3	88.2	85.7	90.6	85.9	91.0
Additional fuel used	%	22.5	18.2	19.0	17.4	17.6	12.7
Electricity costs (with fuel costs 2020, DLR scenario)	ct/kWh$_{el}$	5.95	5.43	6.28	5.74	6.08	5.50
Cost difference (CCS minus cost without CCS)	ct/kWh$_{el}$	2.08	1.83	1.82 (2.41)	1.62 (2.14)	1.64	1.18

12.1.3 Electricity Generation Costs with Changing Technology Parameters and Fuel Prices

Technologies undergo continuous improvements, which may also be reflected in cost reductions. Introduction on a broad scale also leads to cost reductions. Such cost reductions derived from 'learning curves' are especially suitable for large production runs of similar or identical energy converters, as is the case with renewables and motor cars. These mechanisms can also be applied to CCS power stations and their components (Rubin 2004; Riahi 2004). The reference technologies for power stations with and without CCS are defined as 'market-ready' technologies for the period around 2020, meaning that they have already achieved the cost reductions achievable through R&D and demonstration projects. But if they penetrate the energy market on a larger scale this automatically subjects them to a maturing process. For that reason a second status is defined, that of 'mature' plant for the period around 2040. An approximation of the aforementioned learning effects is included in these data, which are listed in Table 12-6 along with some CCS-specific figures.

Whereas conventional power stations without CCS are already highly developed before 2020 and consequently only relatively small changes are to be expected, the room for improvements in CCS plant could be greater because the CCS-specific components will still be more at the beginning of their learning curve in 2020. We assume that efficiency and CO$_2$ capture rate will increase considerably and that investment costs will also fall noticeably. Rubin (2004) found that doubling cumulative capacity would reduce the costs of typical CCS components (gas scrubbers) by 11–13 %. If we assume that that figure will apply to all CCS components and remember that the CCS-related additional costs make up about 30–40 % of total investment for CCS power stations, we can go on to estimate learning rates for complete CCS power stations. Technical improvements and reduced investment costs resulting from growing market volumes have a positive effect on electricity generation costs. While electricity costs from power stations without CCS (with constant fuel costs) fall by about 0.20 to 0.25 ct/kWh$_{el}$, those from CCS plant fall by 0.50 to 0.60 ct/kWh$_{el}$. The cost gaps between plant with and without CCS also close correspondingly (last row in Table 12-6).

Unlike plant using renewable sources of energy, fossil-fuelled plant is subject to rising prices of limited energy resources, and for plant with significant CO_2 emissions there are additional costs caused by the CO_2 emission certificate system. Both effects reduce or even reverse the aforementioned cost reduction potentials, whereby gas-fired power stations (due to their high proportion of fuel-related costs) respond more sensitively than coal-fired power stations. Figs. 12-3 and 12-4 show the results of these interrelationships, whereby the electricity costs are calculated using the fuel costs at the time of start-up.

For coal-fired power stations the electricity generation costs without CO_2 penalty remain roughly constant at approx. 4.0 ct/kWh. But a CO_2 penalty has a noticeable impact, increasing electricity costs in 2020 (€15/t) by 1.0 ct/kWh and in 2050 (€35/t) by 2.2 ct/kWh to a total of 6.3 ct/kWh. CCS power stations would then be competitive from around 2040 at about 6 ct/kWh (without including the cost of transporting and storing the CO_2, see below). By then rising fuel prices will be balanced out by falling capital and running costs. Because the additional costs caused by rising CO_2 penalties are also small, coal-fired power stations with CCS would be
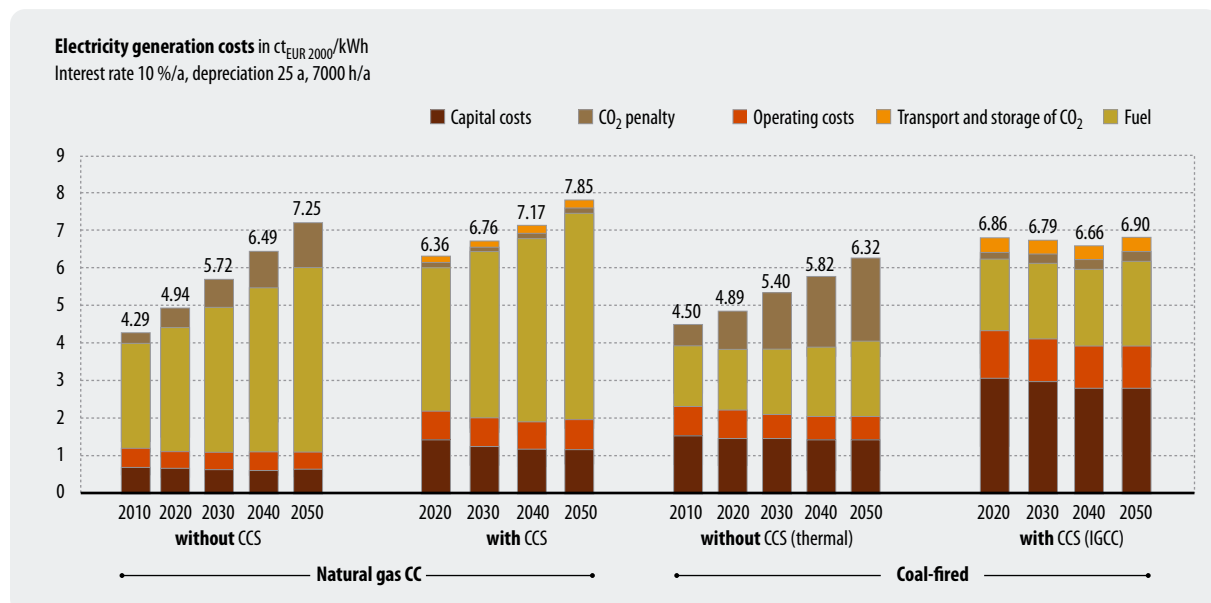
Fig. 12-4: Electricity costs of new gas-fired combined cycle and coal-fired power stations at the respective start-up time in relation to technological improvements, fuel prices and CO_2 penalties (CCS plant including costs for transport and storage of CO_2; DLR 2005 price scenario)

Fig. 12-5:
Comparison of CO$_2$ avoidance costs of CCS power stations (*without* transport and storage of CO$_2$) for *status 2020* (as reference also 2040) (DLR 2005 price scenario)
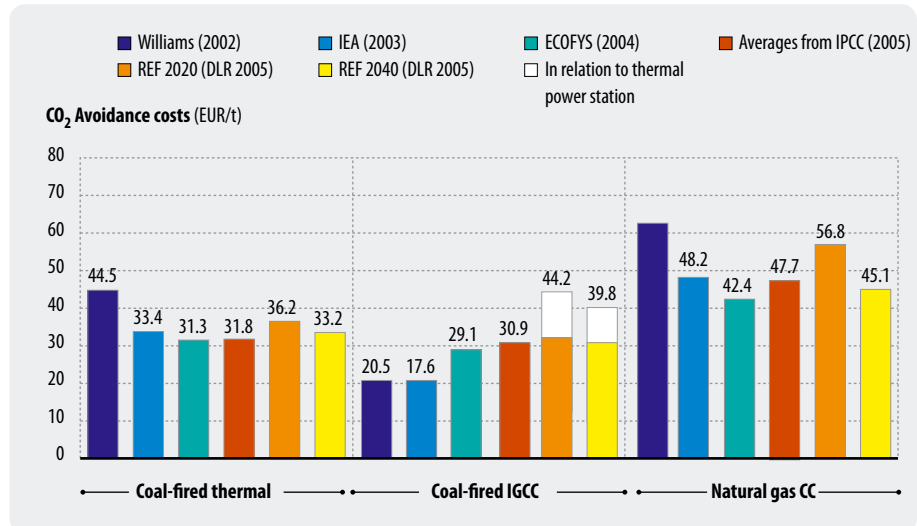
largely immune to possible rises in climate protection costs, see Fig. 12-3.

With gas-fired power stations, on the other hand, fuel price rises as described in Table 12-1 (DLR 2005 price scenario) cause considerable rises in electricity prices, which are amplified yet further by CO$_2$ penalties (Fig. 12-4). On the basis of the price scenarios used here this makes gas-fired combined cycle power stations considerably more expensive than coal-fired power stations as of 2030. Gas-fired CCS plant can, in contrast to coal-fired power stations with CCS, only compensate for a small part of the fuel price increase, so if the price of natural gas increases further we can expect a steady increase in electricity generation costs from CCS power stations too.

The above electricity costs were calculated using the fuel prices at the time the plant begins operation. But for a correct comparison with technologies that are little or not at all fuel-dependent (i.e. renewables) we need electricity generation costs calculated with fuel costs and CO$_2$ penalties averaged over the whole plant lifetime. For coal-fired power stations operating between 2020 and 2050 the cost differences are relatively small (0.3 to 0.5 ct/kWh), while for gas-fired power stations they are significantly higher (0.6–1.2 ct/kWh).

Finally, Fig. 12-5 shows the CO$_2$ avoidance costs for the CCS power stations considered here in 2020 (without transport and storage). It shows at which levels of CO$_2$ penalties these plants can be operated profitably in comparison with the respective reference power stations without CCS. For coal-fired thermal power stations the figures are around €32–36/t CO$_2$, for IGCC somewhat lower and for gas-fired combined cycle power stations around €50/t CO$_2$. For technology status 2040 the avoidance costs are about 10 % lower. If we compare coal-fired power stations using CCS generally with the lower-cost reference thermal power station the avoidance costs for IGCC plant rise to about €40/t CO$_2$. If we compare coal-fired power stations with

the gas-fired reference power station, the CO$_2$ avoidance costs roughly triple due to the then significantly smaller amount of avoided CO$_2$. So statements about CO$_2$ avoidance costs must always indicate the respective reference power station.

12.1.4 Including the Costs of Transporting and Storing CO$_2$

If we are to draw comparisons with other low-CO$_2$ and CO$_2$-free technologies, the costs of compression, transport and final storage must be added to those of capturing the CO$_2$. According to current research these additional costs for the typical transport distances in Germany of around 200 kilometres can be estimated at 0.20 ct/kWh$_{el}$ for gas-fired power stations and 0.40 ct/kWh$_{el}$ for coal-fired. It is assumed that they too will fall by about 10 % over the course of time.

The resulting overall costs for CCS power stations and the resulting additional costs compared with the respective reference power stations are listed in Table 12-7 for three different fuel price scenarios.

According to these calculations low-CO$_2$ electricity from gas-fired power stations will cost between 5.2 and 6.4 ct/kWh in 2020 and between 5.5 and 7.2 ct/kWh in 2040. For low-CO$_2$ electricity from coal-fired plant we find costs between 5.9 and 6.9 ct/kWh in 2020 and between 5.6 and 6.7 ct/kWh in 2040. This means that gas-fired CCS power stations are cheaper than coal-fired in 2020 and if fuel price rises remain moderate (EWI 2005) this even remains the case in 2040. But if prices rose more steeply (DLR 2005) coal-fired CCS power stations would have the lower costs after 2020. The resulting additional costs for CO$_2$ capture compared with the same power station type without CCS depend less strongly on the price scenarios. In 2020 they are between 1.7 and 2.5 ct/kWh and fall to values between 1.4 and 2.3 ct/kWh by 2040.

With CO_2 capture (with transport and storage)	Year of starting operation					
	2005	2010	**2020**	2030	2040	2050
Prices EWI 2005						
• Natural gas CC			**5.24**	5.27	5.46	6.00
• Coal-fired thermal			**5.92**	5.74	5.62	5.83
• Coal-fired IGCC			**6.28**	6.07	5.92	6.12
Prices DLR 2005						
• Natural gas CC			**6.28**	6.68	7.06	7.71
• Coal-fired thermal			**6.35**	6.32	6.17	6.37
• Coal-fired IGCC			**6.68**	6.57	6.44	6.64
Prices DLR 2005 + CO_2						
• Natural gas CC			**6.36**	6.77	7.17	7.84
• Coal-fired thermal			**6.53**	6.55	6.39	6.64
• Coal-fired IGCC			**6.86**	6.79	6.66	6.90

Additional cost of CO_2 capture (with transport and storage)	Year of starting operation					
	2005	2010	**2020**	2030	2040	2050
Prices EWI 2005						
• Natural gas CC			**1.68**	1.51	1.36	1.42
• Coal-fired thermal			**2.41**	2.26	2.17	2.21
• Coal-fired IGCC			**2.16**	2.05	2.00	2.03
Prices DLR 2005						
• Natural gas CC			**1.84**	1.71	1.54	1.61
• Coal-fired thermal			**2.48**	2.41	2.26	2.28
• Coal-fired IGCC			**2.22**	2.13	2.07	2.10
Prices DLR 2005 + CO_2						
• Natural gas CC			**1.42**	1.05	0.68	0.59
• Coal-fired thermal			**1.64**	1.15	0.57	0.32
• Coal-fired IGCC			**1.40**	0.991	0.44	0.20

Table 12-7:
Electricity generation costs ($ct_{€2000}/kWh_{el}$) of new CCS power stations at the time of starting operation *including* transport and storage for three price scenarios and the resulting additional costs compared with the same power station type without CO_2 capture

With CO_2 capture (with transport and storage)	Year of starting operation					
	2005	2010	**2020**	2030	2040	2050
Prices EWI 2005						
• Natural gas CC			**58.2**	51.5	45.8	47.8
• Coal-fired thermal			**42.0**	39.8	38.8	39.5
• Coal-fired IGCC			**38.2**	36.6	36.1	36.6
• Coal-fired IGCC (in relation to coal-fired thermal)			**47.8**	44.8	42.8	43.3
Prices DLR 2005						
• Natural gas CC			**63.7**	58.3	51.9	54.2
• Coal-fired thermal			**43.2**	42.5	40.4	40.7
• Coal-fired IGCC			**39.2**	38.1	37.4	37.9
• Coal-fired IGCC (in relation to coal-fired thermal)			**48.5**	46.0	43.8	44.1
Prices DLR 2005 + CO_2						
CO_2 penalty (EUR/t)	7.5		**15.0**	22.5	30.0	35.0
• Natural gas CC	'residual'		**49.2**	35.8	22.9	19.9
• Coal-fired thermal	advoidance costs		**28.5**	20.3	10.2	5.7
• Coal-fired IGCC			**24.7**	16.3	7.9	3.6
• Coal-fired IGCC (in relation to coal-fired thermal)			**34.0**	24.0	14.5	10.0

Table 12-8:
CO_2 avoidance costs of CCS power stations (*including* transport and storage) in $€_{2000}/t$ CO_2 for different fuel price scenarios and times of starting operation

Table 12-9: Development of the electricity costs of new renewable energy plant according to the NaturschutzPlus-new scenario (BMU 2005) with comparable economic data (interest rate 10 %, plant lifetime 20–25 years)

Electricity costs of new renewable energy (ct/kWh); annuity 0.11–0.126 (10 % interest, 20–25 years) according to the NaturschutzPlus-new scenario (BMU 2005, new plant)										
New plant:	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Wind offshore		10.10	6.50	5.00	4.85	4.70	4.60	4.50	4.40	4.30
Wind power (mix)	10.80	10.00	7.10	6.10	5.95	5.80	5.40	5.00	5.05	5.10
Hydropower (mix)	5.50	6.10	6.60	7.10	7.10	7.10	7.25	7.40	7.50	7.70
Geothermal	42.00	22.00	15.40	10.20	9.60	9.20	8.80	8.40	7.90	7.50
Solar thermal power stations (at border)			14.00	9.00	8.40	7.60	7.20	6.70	6.50	6.30
Photovoltaic (mix)	72.30	46.20	27.10	19.30	17.60	15.80	13.50	14.40	14.00	13.70
Solid biomass	10.90	12.50	14.00	12.00	11.20	10.40	9.70	9.00	8.30	7.70
Biogas	11.90	10.90	9.70	8.10	7.80	7.50	7.20	6.90	6.65	6.40
Typical mix	**13.80**	**12.30**	**10.10**	**8.10**	**7.50**	**7.00**	**6.60**	**6.20**	**6.15**	**6.10**

Using the DLR 2005+CO_2 price scenario the electricity costs of CCS power stations increase only slightly in comparison with those without CO_2 capture. The remaining additional costs in 2050 of 0.2–0.6 ct/kWh show that CCS power stations are almost competitive with their conventional counterparts – if we assume that by then CO_2 penalties will have reached €35/t. Table 12-8 shows the complete CO_2 avoidance costs of CCS power stations including the costs of transport and storage of the CO_2. Compared with those without these costs (cf. Fig. 12-5) they are €10–13/t higher and amount in 2020 to €40–45/t for coal-fired power stations and €60/t for gas-fired combined cycle power stations.

The current values published by IPCC (2005a) allow us to put these results into context. That publication gives the following values for CO_2 avoidance costs for the case of geological storage (Table S4; in relation to reference power station of same type): coal-fired thermal power station between $€_{2000}31$ and $€_{2000}73$/t CO_2; coal-fired IGCC between $€_{2000}21$ and 73 $€_{2000}$/t CO_2 and gas-fired combined cycle between $€_{2000}41$ and $€_{2000}94$/t CO_2. In other words, the costs calculated in the present study are close to the average values found by the IPCC studies, which confirms the suitability as reference plant of the CCS power stations defined here.

12.1.5 Cost Comparison with Plant Using Renewables

On the basis of the costs calculated above, a comparison with plant using renewables can be conducted. Table 12-9 lists their future electricity costs (BMU 2005) (annual interest rate 10 %). Starting from today's average of 13.8 ct/kWh the 'NaturschutzPlus-new' scenario finds the cost of a representative mix of new renewables plant in 2020 to be 8.1 ct/kWh with a range between

5.0 ct/kWh (wind offshore) and 19.3 ct/kWh (photovoltaic). Unlike fossil-fuelled plant, which is subject to fuel price increases, costs for renewable energy can be assumed to remain constant over the whole plant lifetime. By 2050 the cost of electricity from newly installed plant falls to about 6.1 ct/kWh (if the annual interest rate is assumed to be 6 %, as is the case in BMU 2005, the cost is 5.2 ct/kWh).

The learning curves on which the cost trend is based are documented by BMU (2005). The cost development calculated here assumes that the pace of construction of new plant stated in the 'NaturschutzPlus-new' scenario will be maintained over the whole period. In this scenario for Germany the contribution of renewables to the electricity supply in 2050 is about 64 %, and the level of new construction of plant capacity which that requires provides the market volumes required for a successful learning process. However, it is also assumed that the momentum of growth in renewables described there for Germany will also extend in the foreseeable future at least to the European markets, and better still to the global ones.

Fig. 12-6 shows the economic prospects of the two options – renewables and CCS – for a representative case, namely, Germany's energy supply. The development trend of electricity generation costs from fossil-fuelled power stations without CCS according to the EWI 2005 price scenario (broken lines) illustrates the general necessity of introducing effective climate protection instruments.

If they fail to take effect and at the same time fuel prices remain at a low level – as the EWI 2005 price scenario assumes – neither option would be an economic prospect in the long term. Further technological improvements in conventional power stations largely compensate for the rather small electricity price rises. Steeper

Electricity generation costs in ct/kWh
DLR 2005 price forecast with CO_2 penalty; interest rate 10%/a
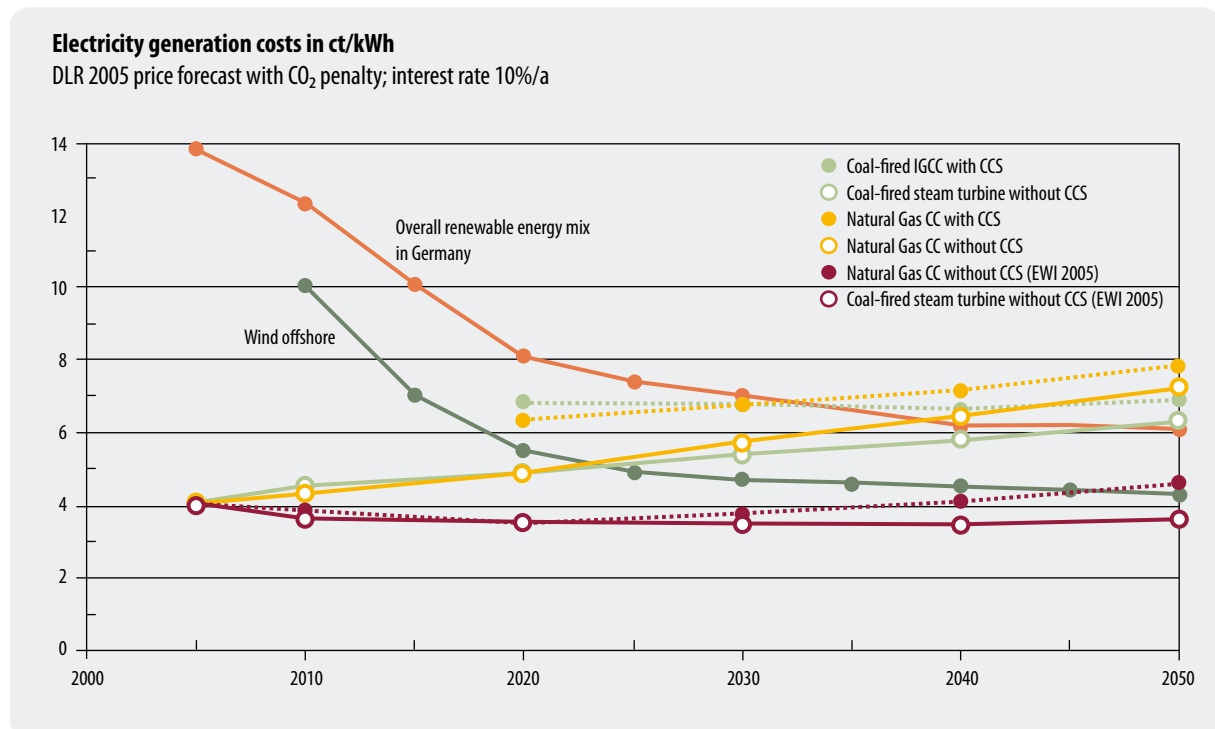
Fig. 12-6: Development of electricity generation costs (for new plant) for renewables, conventional gas- and coal-fired power stations and CCS power stations. Fuel prices after DLR 2005+CO_2 penalty; conventional power stations after EWI 2005 given for comparison.

price rises as per the DLR 2005 price scenario, and even more so a steady price increase for CO_2 emission certificates (here rising to €35/t CO_2 in 2050) increase the electricity generation costs of conventional power stations by 50 % by 2030 and by 65 % by 2050 to reach a level of 6.5 to 7.0 ct/kWh. Thus they reach a level of costs close to those of effective climate protection options. The price increase, which will of course probably continue after 2050, is relatively similar for coal-fired and gas-fired power stations. Whereas for the former the steadily increasing CO_2 penalty is most decisive, the rising gas price has the biggest effect for gas-fired power stations.

An effective reduction in CO_2 emissions from fossil-fuelled power stations requires (or causes) a level of electricity generation costs at the power station of between 7 and 8 ct/kWh, if, as assumed here, market-ready CCS power stations are ready for operation by 2020 and are developed further over the following decades. So in the longer term coal-fired power stations in particular are economically interesting. Renewables, which today still have mean electricity generation costs of 12 to 13 ct/kWh (at annual interest rates of 10 %), could also achieve that level of costs by 2020 if their expansion continues at a similar pace to now. Since about 1990 their cost reduction has been following learning curves with learning rates between 15 and 20 %. These will decrease in the course of time, but will still be sufficient to reduce their level of costs – if introduced on a broad basis according to the NaturschutzPlus scenarios according to BMU (2004) – to values of around 6 ct/kWh. If, as these sce-

narios assume, the momentum of expansion of renewables in the electricity sector remains strong then they will be able to compete with CCS power stations as soon as the latter come into operation and will subsequently actually widen the gap still further. If fuel price rises are very small the situation for CCS plant turns out to be a little more favourable (compare the approx. 0.5 ct/kWh cheaper electricity generation costs of CCS plant according to the EWI 2005 price scenario in Table 12-7). But if CCS is to become competitive at an early stage, significantly higher CO_2 certificate prices (of at least €40–50/t) would have to come into effect by 2020.

The above calculations are based on an annual interest rate of 10 %. If we calculate all the data with an annual interest rate of 6 % instead, the more capital-intensive renewable energy technologies do even better. Renewables would already cost less than CCS power stations by 2025 (overall renewables mix), and offshore wind power would already be clearly cheaper than CCS power stations by 2020.

12.2 Costs of Hydrogen Production from Fossil Resources with CO_2 Capture

12.2.1 Hydrogen Production with CO_2 Capture

Here we present cost comparisons – analogous to those for electricity in section 12.1.1 – for the production of hydrogen from natural gas (steam reforming) and coal (coal gasification) with identical economic data and uniform fuel prices. Table 12-10 lists the corresponding starting data. As was the case for electricity, data from IEA (2003) and Williams (2002) were used here too. Information from NREL (Padro and Putsche 1999) and ETH Zurich (Fahrni 2002) was also included. The DLR reference data originate largely from the EU research project CASCADE MINTS (Krewitt and Schmid 2004), where the DLR developed the technology database for hydrogen production technologies. The data are identical with those for electricity generation (see also Table 12-11 for the fuel prices). But with 8,000 h/a the reference load factor was set higher than that for electricity generation. All hydrogen-related data relate to the high heating value (HHV). In relation to the low heating value for hydrogen the efficiency figures would be lower by a factor of 1.18, investment and generation costs higher by the same factor.

Table 12-11 shows the available data for plant generating hydrogen from natural gas (steam reforming), coal (gasification) and electricity (electrolysis) *without* CO_2 capture, coming on stream in 2020. These are large-scale plants with several hundred MW of hydrogen production capacity. Only the data from Fahrni (2002; provided for comparison) relate to today's status.

The data are relatively uniform for *steam reforming of natural gas*, which is already practised on a large scale today. According to the data, at natural gas costs of €5.70/GJ (2020, DLR 2005 price scenario) hydrogen can be produced at a cost of around €8.50/GJ. Today's generation costs are around €6.50/GJ (gas price €4.30/GJ). For *coal gasification* the data are less consistent. The very favourable figures given by Williams (2002) and IEA (2003) (here only for facilities with CO_2 capture) contrast with much higher figures cited by Padro and Putsche (1999) and Fahrni (2002). This applies both to investment costs and to running costs, although in Fahrni (2002) the latter can only be derived indirectly. The reference data taken from Krewitt and Schmid (2004) lie roughly in the middle of the range and can therefore from today's perspective be regarded as relatively representative. Thus hydrogen from coal is available in 2020 for approx. €9.50/GJ (coal price = €2.30/GJ; DLR 2005 price scenario); at today's coal price (€1.80/GJ) the generation costs would amount to €8.50/GJ. For hydrogen from coal the dependency on the fuel price is considerably smaller than for hydrogen from natural gas, due to the higher capital costs.

The reference technology for *electrolysis* is medium/high-pressure alkaline electrolysis in a form that can

Table 12-10: Data for calculating the cost of generating hydrogen from fossil fuels

		IEA (2003)	Williams (2002)	NREL[1] (1999)	Reference[2] DLR (2004)
Interest rate	%/a	10	12	10	**10**
Depreciation period	a	30	15	20	**25**
Annuity	%/a	10.6	15.0	11.8	**11.0**
Load factor h/a	h/a	8,200	7,000	7,900	**8,000**
Approximate influence on electricity generation costs		0.95	1.15	1.04	**1.00**
Fuel prices Natural gas Coal	€/GJ €/GJ	3.20 1.60	3.93 1.24	3.00 2.00	**4.04 – 5.73 *)** **1.82 – 2.32 *)**

*) Range of energy price scenarios in 2020 (without CO_2 penalty)
1) Source: Padro and Putsche (1999)   2) Source: Krewitt and Schmid (2004)

be implemented in 2020. Although the sources used here differ little in their estimates of costs, there are still clear differences in their estimates of possible efficiency rates. But because today electrolysers already exhibit efficiencies of 65–70 % (LHV) or 77–84 % (HHV) (cf. Fahrni 2002), the efficiency figure for future reference technology was set at 77 % (LHV) or 91 % (HHV) following Krewitt and Schmid (2004). At an electricity cost of 4 ct/kWh$_{el}$ and a load factor of 8,000 h/a (e.g. with hydropower) it would be possible to achieve hydrogen costs of €14/GJ (or 5.04 ct/kWh$_{th}$). Table 12–12 compares in the same way the data for hydrogen production from natural gas and coal *with capture* of CO_2. As in the case of electricity generation, all data assume large-scale plant capable of coming on stream in 2020 after already having undergone a certain learning process. That would mean that pilot plants, whose costs would be higher, would have to be available by about 2010 if the necessary experience is to be gathered and translated into practice in time. By 2020 the cost of hydrogen from low-CO_2 natural gas reforming could be between €7/GJ and €8/GJ with a natural gas price of €4.10/GJ (EWI 2005) or between €9/GJ and €11/GJ with a natural gas price of €5.70/GJ (DLR 2005). Because the estimates for fixed and variable running costs differ widely, the degree of dependency of hydrogen costs on the natural gas price differs widely in the different sources. For low-CO_2 hydrogen from coal the range of estimates is relatively broad with €8–11/GJ (coal price €1.80/GJ; EWI 2005) or €9–12/GJ (coal price €2.30/GJ; DLR 2005). The selected reference case after Krewitt and Schmid (2004) lies roughly in the middle of that range.

		IEA (2003)	Williams (2002)	NREL[1] (1999)	ETH Zürich[2] (2002)[***]	Reference[3] DLR (2004)
Natural gas steam reforming						
Output	MW_{H2}		810	960	1 100	**350**
Efficiency	%		81	87[*]	90	**87**
Investment	$€/kW_{H2}$		251	377		**325**
Running and maintenance costs	% Inv./a		5	5		**5**
H_2 costs 2020 • EWI 2005 • DLR 2005 • DLR 2005 + CO_2	€/GJ		6.45 8.47	6.76 8.68	5.3–6.5	**6.47** **8.39** **9.13**
Coal gasification						
Output	MW_{H2}		560	600	1,100	**560**
Efficiency	%		70.3	70[*]	68–74	**70**
Investment	$€/kW_{H2}$		620	897		**755**
Running and maintenance costs	% Inv./a		5 [**]	7[**]		**7**[**]
H_2 costs 2020 • EWI 2005 • DLR 2005 • DLR 2005 + CO_2	€/GJ		7.09 8.16	9.27 10.34	13.2–16.3	**8.38** **9.45** **12.15**
Elektrolyse						
Output	MW_{H2}	n.a.	500		> 100	**500**
Efficiency	%	85	80		76 – 88	**91**
Investment	$€/kW_{H2}$ $€/kW_{el}$	420 355	425 340			**396** **360**
Running and maintenance costs	% Inv./a	3	3			**2**
H2 costs 2020 with electricity cost 4 ct/kWh	€/GJ	15.10	15.97		14 – 16.5	**14.01**

*) Figure taken from DLR reference
**) Plus variable running costs
***) Data for current technology; conversion to match DLR data only approximately possible
1) Source: Padro and Putsche (1999)   2) Source: Fahrni (2002)   3) Source: Krewitt and Schmid (2004)

Table 12-11:
Data for hydrogen production

Altogether the range of resulting costs is considerably greater than for conventional plant without CO_2 capture. Whereas IEA (2003) and Williams (2002) assume relatively favourable conditions for future plants, NREL estimates the costs considerably higher, as can also be seen from the additional costs. Capturing most of the CO_2 increases the cost of hydrogen by about €1.5 to 2/GJ (or by 20 to 25 % compared with plant without CO_2 capture) with no fundamental difference between gas-based and coal-based plants. A comparison with plant without CO_2 capture using the DLR 2005+CO_2 price scenario (in other words taking account of future CO_2 penalties) shows that for natural gas reforming, plant without capture is still cheaper (row 'DLR 2005+CO_2' in Table 12-13). In this case hydrogen from coal gasification with CO_2 capture would be cheaper because the CO_2 penalty for the conventional plant makes a much bigger difference (the additional costs for CCS hydrogen that arise due to the existence of residual emissions of CO_2 were ignored here).

Like in the case of electricity generation, here too the rising prices of fossil fuels must be taken into account for the longer-term perspective (Table 12-14 and Fig. 12-7 without CO_2 capture). Plant using natural gas is currently and in the medium term more cost-effective

Table 12-12:
Data for hydrogen generation plant using fossil feedstock in 2020 and their generation costs on the basis of the DLR data (*with* CO_2, capture, *without* transport and final storage); figures relate to high heating value (HHV = 3.55 kWh/Nm³)

		IEA (2003)	Williams (2002)	NREL[1] (1999)	Reference[2] DLR (2004)
Natural gas steam reforming					
Output	MW$_{H2}$	n.a.	780	n.a.	**335**
Efficiency	%	79	78	n.a.	**80**
Investment	€/kW$_{H2}$	260	460	660	**540**
Running and maintenance costs	% Inv./a	2.5 [*]	5	5	**5**
H$_2$ costs 2020	€/GJ				
• EWI 2005		6.36	7.76	8.81	**8.08**
• DLR 2005		8.47	9.90	10.92	**10.16**
Coal gasification					
Output	MW$_{H2}$	n.a.	540	n.a.	**520**
Efficiency	%	75	67.7	n.a.	**65**
Investment	€/kW$_{H2}$	880	770	1 220	**965**
Running and maintenance costs	% Inv./a	5 [*]	5	6 [*]	**6 [*]**
H$_2$ costs 2020	€/GJ				
• EWI 2005		8.59	7.20	13.47	**9.92**
• DLR 2005		9.45	7.78	14.34	**10.63**
1) Source: Padro and Putsche (1999) 2) Source: Krewitt and Schmid (2004)					

Table 12-13:
Difference in data of hydrogen generation plant with and without CO_2 capture (*without* transport and final storage of CO_2)

		IEA (2003)	Williams (2002)	NREL[1] (1999)	Reference[2] DLR (2004)
Natural gas steam reforming					
Efficiency	%		− 3,0	(−7,0)	**− 7,0**
Investment	€/kW$_{H2}$		+ 210	+ 283	**+ 215**
H$_2$ costs 2020	€/GJ	No data on plant without CO_2 capture			
• EWI 2005			+ 1,31	+ 2,05	**+ 1,61**
• DLR 2005			+ 1,43	+ 2,24	**+ 1,76**
• DLR 2005 + CO_2					**+ 1,03**
Coal gasification					
Efficiency	%		− 2,6	(− 5,0)	**− 5,0**
Investment	€/kW$_{H2}$		+ 150	+ 323	**+ 210**
H$_2$ costs 2020	€/GJ	No data on plant without CO_2 capture			
• EWI 2005			+ 0,94	+ 1,80	**+ 1,51**
• DLR 2005			+ 0,96	+ 1,85	**+ 1,57**
• DLR 2005 + CO_2					**− 1,13**
1) Source: Padro and Putsche (1999) 2) Source: Krewitt and Schmid (2004)					

Table 12-14: Hydrogen costs of reference plant (start-up 2020) in relation to fuel price; plant without CO_2 capture

Without CO_2 capture	2005	2020	2030	2040	2050
	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$
EWI 2005					
Natural gas-steam reforming	6.5	6.47	6.92	7.72	8.68
Coal gasification	8.5	8.38	8.61	9.06	9.28
DLR 2005					
Natural gas-steam reforming	6.5	8.39	9.48	10.63	11.87
Coal gasification	8.5	9.45	9.79	10.24	10.80
DLR 2005 + CO_2					
Natural gas-steam reforming	6.5	9.13	10.76	12.71	14.21
Coal gasification	8.5	12.15	13.95	15.75	17.21

than plant using coal. However, the clear sensitivity of steam reforming to rising natural gas prices is discernible as the most likely trend from today's perspective, especially when the DLR 2005 price scenario is used as the basis. Only if fossil fuels are burdened with the costs of their CO_2 emissions (DLR 2005+CO_2 price scenario) does steam reforming become the cheaper form of production in the longer term. If we assume that prices will follow the DLR 2005 scenario, today's hydrogen costs will roughly double.

When we turn to the corresponding figures for plant *with* CO_2 *capture* (Table 12-15) the natural gas and coal options move closer together. Because capital costs are higher, the relative influence of fuel costs is smaller. Assuming that corresponding large-scale commercial plant was to be available by 2020, low-CO_2 hydrogen from fossil sources could be made available at costs between €8.10 and 11.00/GJ. By 2050 these costs (for plant coming on stream in 2020) would increase to about €10.50 to 14.00/GJ. If price developments followed DLR 2005 hydrogen from coal – costing around €12.50/GJ – would then be a good deal cheaper than hydrogen from natural gas.

Hydrogen generation costs in EUR / GJ (HHV)

Legend:
- DLR + CO_2 (orange)
- DLR + CO_2 (dark blue)
- DLR 2005 (red)
- DLR 2005 (dark green)
- Natural gas steam reforming EWI 2005 (dark red)
- Coal gasification EWI 2005 (light green)
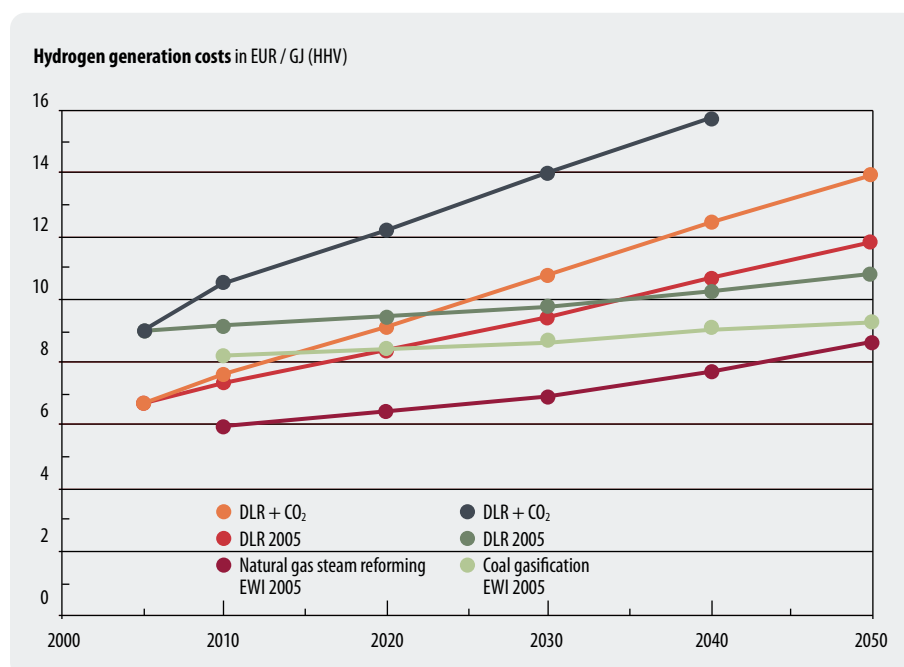
Fig. 12–7:
Hydrogen generation costs in relation to prices for natural gas and coal (three price variants through to 2050) for plant *without* CO_2 capture

Table 12-15: Hydrogen costs of reference plant (start-up 2020) in relation to fuel price; plant with CO_2 capture, without transport and final storage

With CO_2 capture	2020	2030	2040	2050
	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$
EWI 2005				
Natural gas steam reforming	8.08	8.57	9.43	10.48
Coal gasification	9.89	10.13	10.61	10.84
DLR 2005				
Natural gas steam reforming	10.16	11.35	12.60	13.95
Coal gasification	11.02	11.38	11.85	12.44

Table 12-16: Hydrogen costs of reference plant (start-up 2020) in relation to fuel price; plant with CO_2 capture, with transport and final storage

With CO_2 capture, with transport and final storage	2020	2030	2040	2050
	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$	€/GJ$_{HHV}$
EWI 2005				
Natural gas steam reforming	8.93	9.42	10.28	11.33
Coal gasification	11.59	11.83	12.31	12.54
DLR 2005				
Natural gas steam reforming	10.91	12.20	13.45	14.80
Coal gasification	12.72	13.08	13.55	14.14

12.2.2 Accounting for the Costs of Transport and Storage of CO_2

The costs of compressing, transporting and storing the captured CO_2 have not so far been included in the costs of CCS hydrogen production. Relying on the same data and assumptions as for power stations, we find that these costs will be in the range between €16 and 34/t CO_2. Steam reforming produces about 0.05 t CO_2 per GJ of hydrogen, while with coal gasification the figure is about 0.1 t CO_2 per GJ. In each case about 85 % is captured. So assuming disposal costs are a mid-range €20/t CO_2, the additional costs incurred are €0.85/GJ H_2 for steam reforming and €1.70/GJ H_2 for coal gasification. Table 12–16 shows the resulting total (ex works) hydrogen costs for steam reforming and coal gasification.

12.2.3 Cost Comparison with Hydrogen from Renewables

The costs thus determined can be compared with those for electrolytic hydrogen production using renewable sources of energy. Figure 12-8 first of all shows the cost of the reference electrolysis process for an electricity cost range of 2.5 to 8 ct/kWh$_{el}$ and load factors between 2,000 and 8,000 h/a. The achievable hydrogen costs corresponding to different electricity generation costs from renewables are indicated (see section 12.1.5).

By 2020 hydrogen can be produced using wind energy (e.g. offshore with 4,000 h/a) at about €19/GJ. Only if cheap hydropower is available (on a large scale) the generation costs could be reduced to €13–14/GJ. In 2020 electricity from solar thermal power stations would still produce considerably more expensive hydrogen. The lower broken line (status 2040) can be regarded as the longer-term achievable limit, showing that renewable hydrogen with €15/GJ (wind, 4,000 h/a) to €20/GJ

(solar electricity, 6,000 h/a) always remains a relatively expensive source of energy. In return it produces practically no CO_2 during its production, in contrast to ’low-CO_2‘ CCS hydrogen, which is still burdened with 0.017 million t CO_2/PJ hydrogen. There are no more resource problems either.

’Conventional‘ electricity (from nuclear power or low-CO_2 fossil-fuelled power stations) can also be used for electrolytic generation of CO_2-free or low-CO_2 hydrogen. Fig. 12-8 shows the resulting hydrogen generation costs. According to the calculated electricity generation costs (7–9 ct/kWh), the path of using ’fossil‘ electricity is considerably more expensive than producing hydrogen directly from coal or natural gas and can therefore be excluded. The option of electricity from nuclear power stations remains. If we follow the IEA’s figures , electricity from new nuclear power stations can be produced at a cost of around 3.0 to 3.5 ct/kWh (load factor about 8,000 h/a). That would make it possible to achieve hydrogen costs of around €12–14/GJ which would be comparable with those for hydrogen from hydropower in Fig. 12–8 below. If electricity from nuclear power was costed at about 5 ct/kWh (8,000 h/a) that would be comparable with wind power (4 ct/kWh, 4,000 h/a). So whether nuclear power can be an option for hydrogen production depends in the first place on the political assessment of nuclear power (keywords: risk assessment, external costs).

This is also demonstrated by a comparison of fossil and renewable generation options. Fig. 12-9 compares hydrogen production from natural gas and coal (costs as per Table 12-16) with electrolytic hydrogen production using wind and hydropower. However, the scarcity of the resource means that using hydropower to produce hydrogen will remain at best a market niche. Potential for large-scale renewable hydrogen production exists only via wind – and in the long term especially via

Hydrogen costs in EUR/GJ (HHV)
Elektrolysis status 2020: Efficiency 91% (HHV), 400 EUR/kWH$_2$ (HHV)
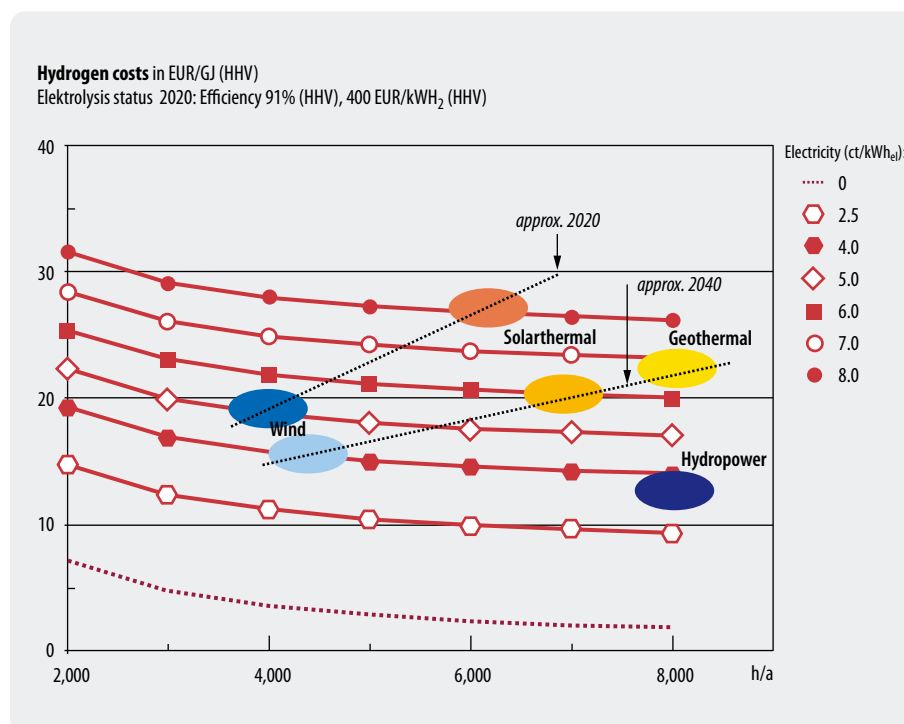
Fig. 12-8:
Cost of reference electrolysis and approximate hydrogen costs given use of wind-generated electricity (3,500–4,500 h/a), solar thermal power stations (6,000–7,000 h/a; electricity costs at border), and geothermal and hydropower (8,000 h/a) for 2020 and 2040

Hydrogen generation costs in EUR / GJ (HHV)
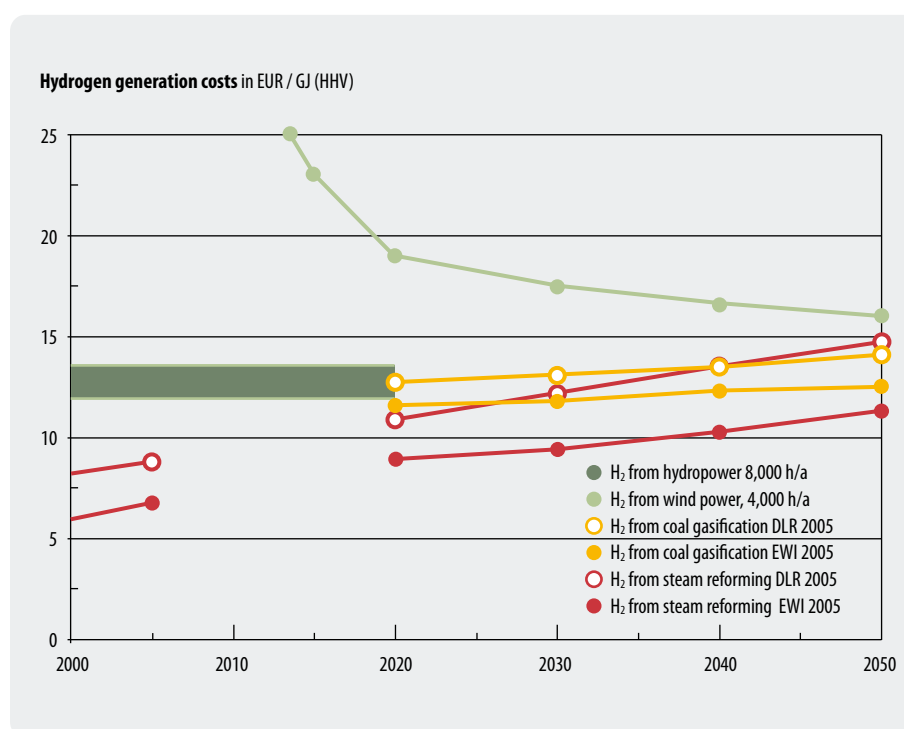
Fig. 12-9:
Cost comparison of hydrogen production from low-CO_2 plant using natural gas and coal (8,000 h/a) with electrolytic hydrogen from wind power and hydropower (todayís hydrogen costs are for fossil plant without CO_2 capture)

solar thermal electricity. In 2020 cheap hydrogen from renewable electricity (wind) will still be about twice as expensive. Compared with low-CO_2 hydrogen from natural gas the cost gap can close in the longer term. According to the cost assumptions used here, low-CO_2 hydrogen from coal remains cheaper in the longer term too because roughly equal costs would require electricity from renewable sources to cost about 3–3.5 ct/kWh. However, if fossil plant is operated for less than 8,000 h/a the hydrogen production costs rise accordingly.

It should be pointed out that the cost comparison is not yet complete. In particular a comparison of additional infrastructure costs is still lacking. Production from fossil resources requires very large centralised plants, which requires a fully developed transport and distribution structure for hydrogen. Systems based on renewables could have advantages here, although they may also involve not insignificant additional costs (e.g. wind offshore). The option of producing hydrogen from biomass has not been considered here, but it must be assumed that the potential is very limited.

Overall, a comparison of low-CO_2 and CO_2-free options for hydrogen turns out quite differently than was the case for electricity generation. In the case of electricity the available data showed no cost advantage for the fossil option (section 12.1), whereas for hydrogen production the fossil option fared better. Before making a final assessment in this matter, however, it must be remembered that electricity is an established medium and that decisions about expanding climate-friendly technologies will have to be made relatively quickly. Hydrogen on the other hand will not be required as a fuel in relevant quantities before 2030 (probably not until 2050) (UBA 2006) so it will not be able to contribute to climate protection until then. That will probably be too late for the substantial climate protection efforts that are required by 2050. This also clearly reduces the potential economic advantage of low-CO_2 hydrogen from fossil sources and its importance for climate protection. The scenario analyses in chapter 14 go into this question in greater detail.

Chapter 13

Other Energy Sector Criteria

As well as considering the purely economic aspects of the costs of generating electricity and hydrogen, other aspects relating to the energy sector are also relevant for the implementation of CCS. Selected factors (listed in Table 9–1) are discussed in the following.

13.1 Social Acceptance

Numerous surveys and studies have examined the social acceptance of technologies for exploiting renewable sources of energy. Although there are now several hundred local campaigns against wind power in Germany as well as certain reservations against the use of biomass, a large majority of the German population nonetheless has a positive attitude towards the use of renewables. Comparable studies for CCS have not yet been conducted in Germany, and it must also be noted that public knowledge about CCS is still threadbare. To that extent the introduction of CCS does not encounter a preconceived public opinion. The general strategy and wording of argumentation could therefore be decisive in influencing public opinion for or against CCS. The extent to which, for example, the basic choice of vocabulary (for example 'CO$_2$-free'/'zero-carbon' versus 'low-CO$_2$' and 'CO$_2$ storage' versus 'CO$_2$ dumping') could have the effect of increasing or reducing acceptance has yet to be properly investigated.

13.2 Transferability of Technology to Developing Countries

Increasingly the criterion of transferability to developing countries is being used to measure the suitability of technologies for responding to climate change. Although the industrialised countries still have the highest share in total energy consumption – and produce the most CO$_2$ – it is expected that the situation will be reversed in the coming decades and that the developing countries will come to be the biggest energy consumers and biggest producers of CO$_2$ emissions (IEA 2004). That means that for a global emissions reduction strategy, technologies that can only be applied in the mature energy infrastructures of industrialised countries are automatically inferior to those that can be applied in developing countries. The level of complexity of a technology is measured not only by the controllability of the technology itself but also – especially – by whether it can be

integrated into the existing energy system. Criteria for this are:

- Controllability of the technology in the power station,
- Controllability of the technology in the overall system

Relevant criteria for controllability in the power station include the level of training of engineers and the availability of spare parts. In many developing countries these two factors are simply not available, and thus represent limiting factors.[1]

Where technical or economic circumstances represent limiting factors, technologies have to be as robust as possible; i.e. they must be designed to be as uncomplicated as possible in order not to themselves become a limiting factor within the system as a whole. The application of post-combustion technology – as an addition to conventional power station technology – represents an increase in the degree of complexity. In developing countries it would be necessary to test whether these additions can be reliably controlled by the local engineers and whether the low flexibility of such a system can be reconciled with the existing energy infrastructure. Partially or completely new technologies such as IGCC and oxyfuel may require even higher standards of knowledge and training than post-combustion technologies.

On the other hand, controlling offshore wind generators could possibly place lower requirements on training of skilled personnel even though the turbines are also high-technology products, and servicing in particular is a complex matter. The aspect of whether offshore wind farms are compatible with existing power grid infrastructures in developing countries – and whether they are controllable – appears problematic. New challenges would arise here, especially for generation and power grid planning.

Solar thermal power stations are comparable with conventional power stations; the difference is simply that the heat for operating the turbines is gained from solar radiation. To that extent solar thermal power stations do not fundamentally require any higher standards of training for skilled personnel than those required for normal operation of conventional power stations.

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1 At the same time, it must be emphasised that great progress has been made in some areas of technical training in developing countries.

13.3 Technology Leadership and Export Opportunities

In the field of CCS German and US-American companies and research institutes are important leaders. Relatively speaking, the United States already provides considerably more R&D funding than other countries. That means that promoting CCS in developing countries could benefit primarily American companies.

13.4 Import Dependency

Increasing dependency on energy imports is a general trend in very many countries. Here we describe the situation for Germany and the European Union, which is symptomatic for other countries. Germany is more than 70 % dependent on energy imports; for individual fuels the figures are: oil, approx. 97 %; natural gas, approx. 80 %; nuclear fuel, 100 % and coal more than 50 % (the latter determined not by the volume of domestic reserves but by the high cost of extraction). Only lignite is available domestically in sufficient quantities for electricity generation. Decreasing domestic production will cause import dependency to increase significantly in the coming years. This tendency can be observed in many industrialised countries, and import dependency is increasing at the EU level too. This is especially significant in relation to CCS because capturing CO_2 significantly reduces conversion efficiency.

The supply structure for coal is characterised by two main features:

- The number of suppliers is relatively large, and
- The exporting countries are generally politically stable.

Coal is available in sufficient quantities so we can assume that structural supply shortages will probably not occur in the coming decades. For the aforementioned reasons, import dependency can be treated as primarily a problem of market economics.

The situation for natural gas is more problematic than for coal. For natural gas the supplier structure – especially the distribution of economically exploitable resources – is less diverse than for coal. Germany's main suppliers are Russia, Norway and the Netherlands (see Fig. 13-1). Because the infrastructure is capital-intensive and requires long-term planning, in Germany in recent decades there has been a kind of 'natural monopoly' of various suppliers and of the various companies positioned between supplier and consumer (e.g. gas distributors). The capital intensity of the gas pipelines – which represent the biggest share of overall costs – was also the factor that has to date prevented suppliers from further afield from entering the market. For example, neither Germany nor the European Union imports natural gas from the Persian Gulf (except for small amounts of
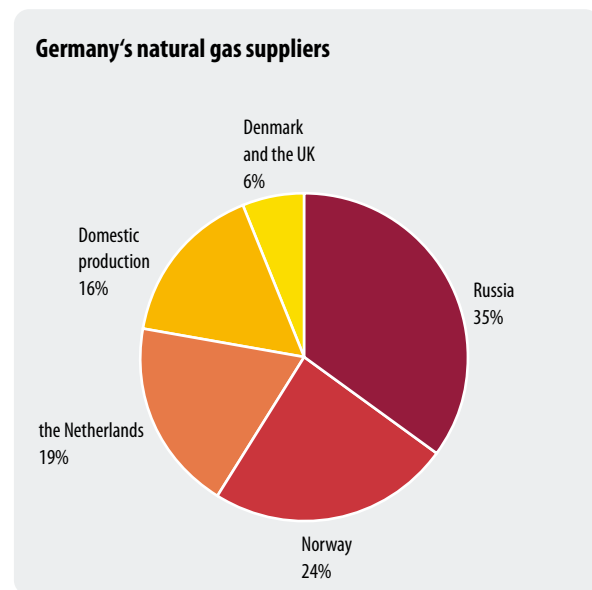
Fig. 13-1: Germany's natural gas suppliers (Ruhrgas 2005)

LNG/LPG). However, this could change in the coming years for two reasons:

- Gas prices have risen steeply, which would make it potentially profitable to build and operate longer pipelines,

- Rising prices make the use of liquefied natural gas (LNG) competitive, meaning that gas can also be transported by ship and taken flexibly to the markets.

Because of the restricted number of exporters, increasing import dependency, e.g. in the case of natural gas, is not only an economic problem but increasingly also a political one. By contrast, the use of domestic renewables can help to reduce dependency on fossil fuel imports and thus maintain political leverage.

Large-scale import of renewable electricity by contrast, would create new dependencies through the fixed transmission structures for international electricity transport. In the case of solar thermal electricity generation in North Africa the transmission lines would pass through several countries and could easily be disrupted (e.g. by terrorism).

13.5 Security Policy Implications

The influence of import dependencies on political leverage is closely tied to the ensuing security policy consequences. The greater the dependency on politically unstable states and hence the vulnerability to interruptions of supply, the more important the international dimension of security policy becomes. Vulnerability

to interruptions of supply arises when supply routes become extended and more difficult to protect. The EU Commission's green paper on 'Security of Energy Supply' addresses the security importance of energy supply and proposes possible first steps towards a comprehensive European response. These include developing a coherent European energy foreign policy (including setting up long-term energy cooperation arrangements with producers and transit countries), developing a political concept for safeguarding and diversifying energy supply, and other approaches (EU 2006).

At this point we can note that an increase in natural gas imports through the introduction of large-scale CCS would exacerbate security problems. Changes in dependency relationships through large-scale renewable electricity imports, on the other hand, would present new security challenges, because dependency on other states would arise (e.g. transit countries).

13.6 Vulnerability and Complexity of the System

In general terms, the vulnerability of technical systems to failure increases with increasing complexity, because the probability of failure of the system as a whole is the product of the individual failure probabilities of the system's components. Hence each additional vertical component (i. e. introducing more technological processes) increases the probability of failure of the system as a whole. In the case of CCS this applies in particular to the additional components for flue gas scrubbing (post-combustion), coal gasification (pre-combustion) and air separation (oxyfuel), because in each of these cases an additional step is added to the conventional power station process.

The lack of commercial readiness has been the reason why IGCC power stations have not become more widespread to date despite their higher efficiency. No relevant experience has yet been gathered with oxyfuel. But in general terms it can be said that in comparison with proven technologies newly launched and more complex technologies have initially demonstrated lower availability, because operating experience has yet to be gathered and new components often demonstrate their actual reliability only under everyday conditions – and are then subjected to ongoing optimisation efforts.

But in terms of the availability and thus also the reliability of the plant, the power station process itself is not the only relevant factor. Transporting CO_2 away from the power station further increases the level of complexity given the associated transport infrastructure. For example, if a pipeline were to fail, it would be necessary either to have corresponding buffer storage capacity on hand or to purchase CO_2 emission certificates. But experience from other network-based infrastructures (e.g. gas pipelines) shows that the risk of that eventuality is relatively low.
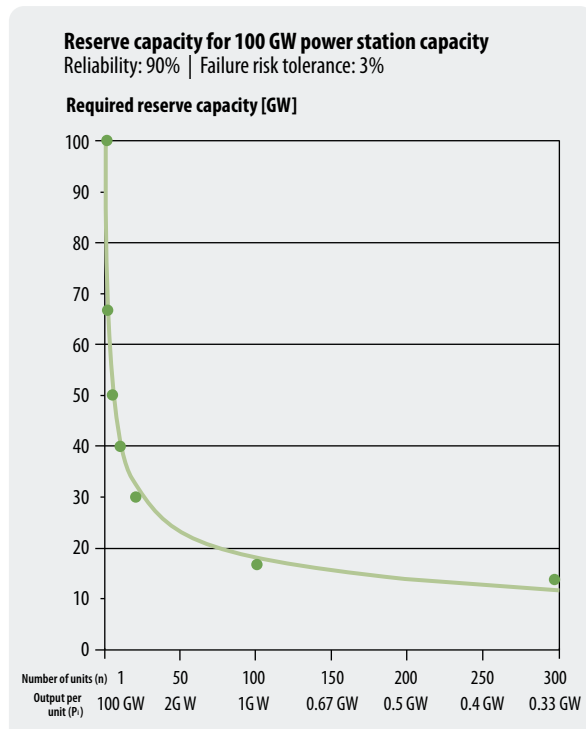
Fig. 13-2: Required reserve capacity as a function of unit output P_i (assuming identically sized units) for 100 GW generating capacity (Schüwer 1997)

For reasons of cost the large-scale introduction of the CCS option would only make sense for large power station units. This would lead to the preservation or expansion of centralised structures and thus further increase the probability of failure and the costs of maintaining reserve capacity. The reason for this is that if the reliability of individual systems remains constant, the probability of failure of the system as a whole (and thus the required reserve capacity) of a few large systems is always greater than that of many small ones (see Fig. 13–2). So more centralised structures tend to increase reserve capacity costs – for example in the form of dedicated reserve power stations or contracted reserve capacity.

The terrorism argument that has entered the debate in recent years (especially in connection with nuclear power stations) is probably less relevant for the case of CO_2 pipelines. However, because it is based on large-scale power stations, CCS automatically implies greater vulnerability and less flexibility than is the case with decentralised systems.

13.7 Conflicting Alternative Uses

In many decisions opportunity costs play an important role; in other words, the question of what has to be given up in order to obtain a particular thing. Opportunity costs are reflected in use conflicts: how should particular resources be treated – storage capacity, land use, etc.? There are two dimensions here. Firstly the horizontal dimension examining current use conflicts (spatial competition). Secondly the vertical dimension of future restrictions imposed by today's decisions. The latter especially is difficult to assess because the future is always difficult to predict. People today cannot precisely picture what future generations will regard as desirable or worthy of preservation.

For example storing CO_2 in salt caverns would make future use of the caverns – for the salt or as storage facilities for other substances – impossible for all time (in human terms). The same may apply to future geothermal applications for generating heat and electricity and to heat and cold storage, which could collide with the use of aquifers as CO_2 sinks. Use conflicts have already been addressed in the discussion of the different types of sink (Chapter 7).

Chapter 14

Systems Analysis of CCS Scenarios

The previous chapters discussed the technological basis of CCS and presented ecological and economic comparisons with renewable energy options; we now move on to analyse the significance of CCS for energy supply and climate policy in the overall context. After reviewing the general factors influencing the implementation of CCS we analyse a range of scenarios to show which of the future perspectives for CCS are plausible and sensible. The analysis is based on the German energy system, but some aspects are also in principle applicable to other countries, especially those planning similarly large power station replacement programmes.

14.1 CCS in the Energy Economy

The role of CCS in the energy economy as a whole is influenced by many factors. This chapter begins with an overview of these, starting by taking a more fundamental look at the compatibility of CCS with other climate protection measures.

14.1.1 General Factors Affecting CCS

Alongside technical, ecological and economic considerations, the availability of alternatives and social acceptance, the future role of CCS will be determined above all by the potential demand for power generation capacity over the period under consideration. From the energy economy perspective, the relationship between power station replacement demand and technological availability of CCS is the decisive factor that determines the limits of general applicability of CCS.

Initial rough estimates of the theoretical (demand-side) limits of CCS are found in Fig. 14-1. The starting point for the analyses here is a scenario where – under conditions otherwise identical to the reference scenario – all new fossil-fuelled power stations built after 2020 are fitted with CO_2 capture and storage.[1]

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1 Reference scenario from Energiereport IV in EWI and Prognos (2005).
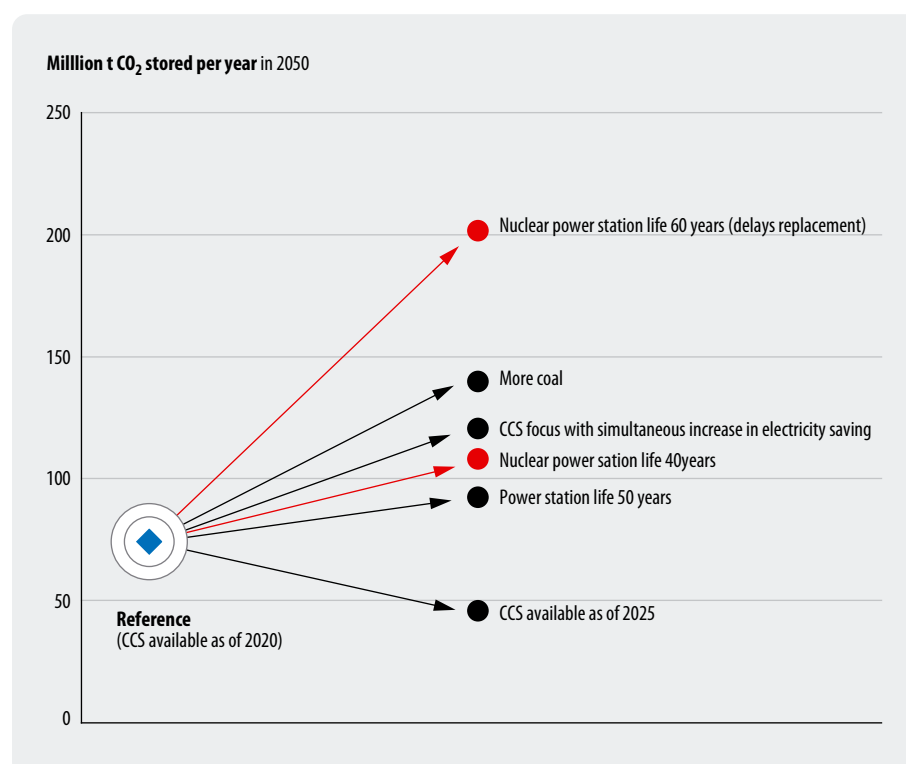
Fig. 14-1:
The main factors influencing future CO_2 capture and storage in Germany (analysis for 2050)
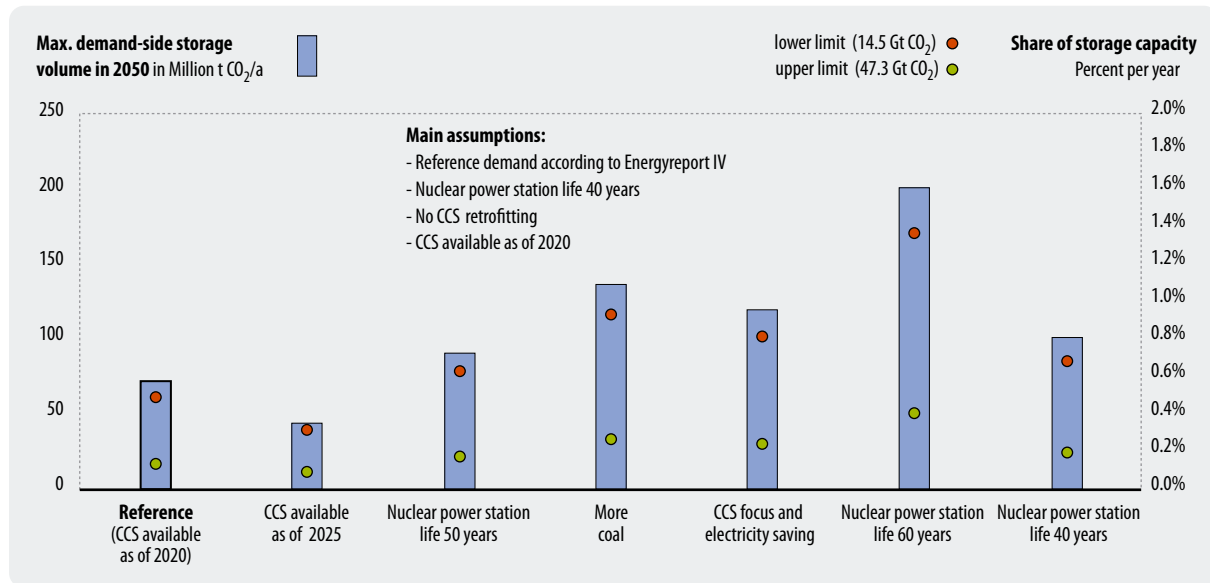
Fig. 14-2: Relationship between possible storage demand and available capacity

Taking this approach we find an annual storage demand of 73.1 million t CO_2 for the reference case. Various factors could influence this theoretical figure. A considerable proportion of power generation capacity will have to be replaced by 2025, so a five-year delay in getting CCS ready for implementation would (if we for the moment exclude the question of retrofitting) reduce the storage demand to 47.8 million t CO_2. Increases of the amount of CO_2 to be stored could result in particular from a change in the power station mix (larger share of coal compared to the reference case) but also from any change in the assumptions about nuclear power plant operating life that would delay the need to replace capacity. Increasing the operating lives of the fossil-fuelled power stations themselves (from 40 to 50 years) would have a comparable effect because it would also delay the need to replace capacity.

If we compare the resulting annual storage quantities (between just under 50 million t CO_2 and 200 million t CO_2) with the minimum and maximum figures for available storage capacity in Germany (see chapter 7), we find that capacity problems are not to be expected, at least where CCS is used as part of a transitional strategy.[2] This applies under the provison that the identified storage capacities also turn out to be viable – i.e., sufficient long-term stability, ecologically compatible, exploitable at acceptable cost. It also assumes that power stations can be connected to suitable sinks (through new CO_2 infrastructure) with enough capacity to allow storage during each power station's whole operating life.

Fig. 14-2 shows the respective shares of available storage capacity represented by annual storage demand, while Fig. 14-3 shows the corresponding static ranges for the storage capacity.

If we take the lower capacity figure as our measure, by 2050 the projected annual storage volume will have filled only between 0.3 % (best case) and 1.4 % (worst case) (Fig. 14-2).

The situation becomes even clearer when we consider the resulting static ranges. If we calculate the static range for the lower storage capacity figure we find – depending on the scenario – a possible storage period of 72 to 305 years (Fig. 14-3). As the figures show, the possible implementation of CCS in power stations will be largely determined by the need to replace increasingly ageing power stations, which is already enormous today. In this context the question of retrofitting CCS in existing power stations is highly significant and will be addressed in the next section (14.1.2). Equally significant is the potential expansion of CO_2 capture to include hydrogen production. Section addresses this aspect in greater detail in quantitative scenario analyses.

14.1.2 Power Station Retrofitting

There are two possibilities for retrofitting CO_2 capture in existing coal-fired power stations. Firstly, post-combustion CO_2 capture from the flue gas, e.g. by means of monoethanolamine scrubbing (MEA), and secondly, converting the combustion process to function with pure oxygen (oxyfuel). Both involve considerable infrastructure changes within the power station. In the case of MEA scrubbing the main factors are the considerable additional space required for the flue gas scrubbers and the column for regenerating the scrubbing solution

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2   For the calculations here we set the **lower limit** of national storage potential at **14.5 Gt CO_2** (sum of *minimum* capacity estimates for exhausted oil and gas fields and saline aquifers). For the **upper limit** we added together the *maximum* capacity estimates for oil and gas fields and saline aquifers, and also included deep coal seams (ECBM, enhanced coal bed methane recovery) to arrive at a total capacity of **47.3 Gt CO_2** (cf. Table 7–5).

Fig. 14-3: Static ranges of storage capacity for different power generation scenarios

(plus space for storage facilities required for the MEA). Additionally, it is still unclear how much further purification of the flue gas will be required for the process to function properly. For example, if amine scrubbing is used for CO_2 capture, the SO_2 and NO_x concentrations must be reduced further than required by the legal emission limits. Surplus oxygen after combustion also has a disruptive effect, but developing more stable solvents to replace conventional MEA could permit higher residual O_2 concentrations.

In the case of retrofitting as an oxyfuel power station an air separation facility is needed to supply pure oxygen. Such a conversion would also involve major rebuilding of the furnace, for example to allow the possibility to recirculate CO_2 from the waste gas (as required to control the temperature of combustion).

During the retrofit procedure power stations can only operate at limited or zero outputwith corresponding financial losses. Because of the large losses in efficiency involved, retrofitting only makes sense in power stations that have a high level of efficiency to start with. So from today's perspective (especially if we consider the residual operating life required to amortise the additional investment) retrofitting is probably only conceivable for power station new builds that are part of the forthcoming capacity replacement programme (Fischedick et al. 2006). For coal these include power stations operating comparable to the reference power station (with an electrical efficiency of 46 %) and potentially also power stations using new 700°C steam technology with conversion efficiency of possibly more than 50%.

Retrofitting must also take account of possible effects on plant operation performance. In the case of post-combustion CO_2 capture in a conventional power station probably no negative effects on dynamics and control are

to be expected, because the effects of MEA scrubbing will be comparable to the flue gas desulphurisation scrubbers that are normally already fitted. In the case of pre-combustion capture in an IGCC process, CO_2 capture represents a major process between gasification and gas turbine, which requires closely regulated interconnection of the different steps of the process. Because the steps cannot be operated independently of one another, CO_2 capture can be expected to have a system-relevant impact that does not fundamentally exclude retrofitting but does at least place restrictions on it. In comparison to pre- and post-combustion concepts for CO_2 capture, dynamics and control in an oxyfuel power station are influenced little or not at all by CO_2 capture. After combustion in pure oxygen the waste gas consists largely of CO_2 and H_2O, and rather than separating the CO_2 from the gas mixture the steam is separated out by condensation. The combustion and steam processes are largely separate.

There is growing research into the question of retrofitting power stations and the possibilities of implementing preparatory measures (capture-ready plant). Work is already under way, for example in the Dutch CATO programme, and studies for a capture-ready concept are currently also being prepared by the Canadian Clean Power Coalition and Sask Power for a 350 to 450 MW coal-fired power station. In Germany RWE Power is planning to build an IGCC plant with CO_2 capture by 2014 and also intends to work on retrofitting concepts (in cooperation with BASF and Linde). In the Netherlands there is already discussion about making capture-ready design obligatory for new power stations.

In terms of energy and climate policy retrofitting could be of great importance if current power station construction plans (without carbon capture) are implemented in full, and sooner or later a clear conflict with ambitious climate protection goals arises.
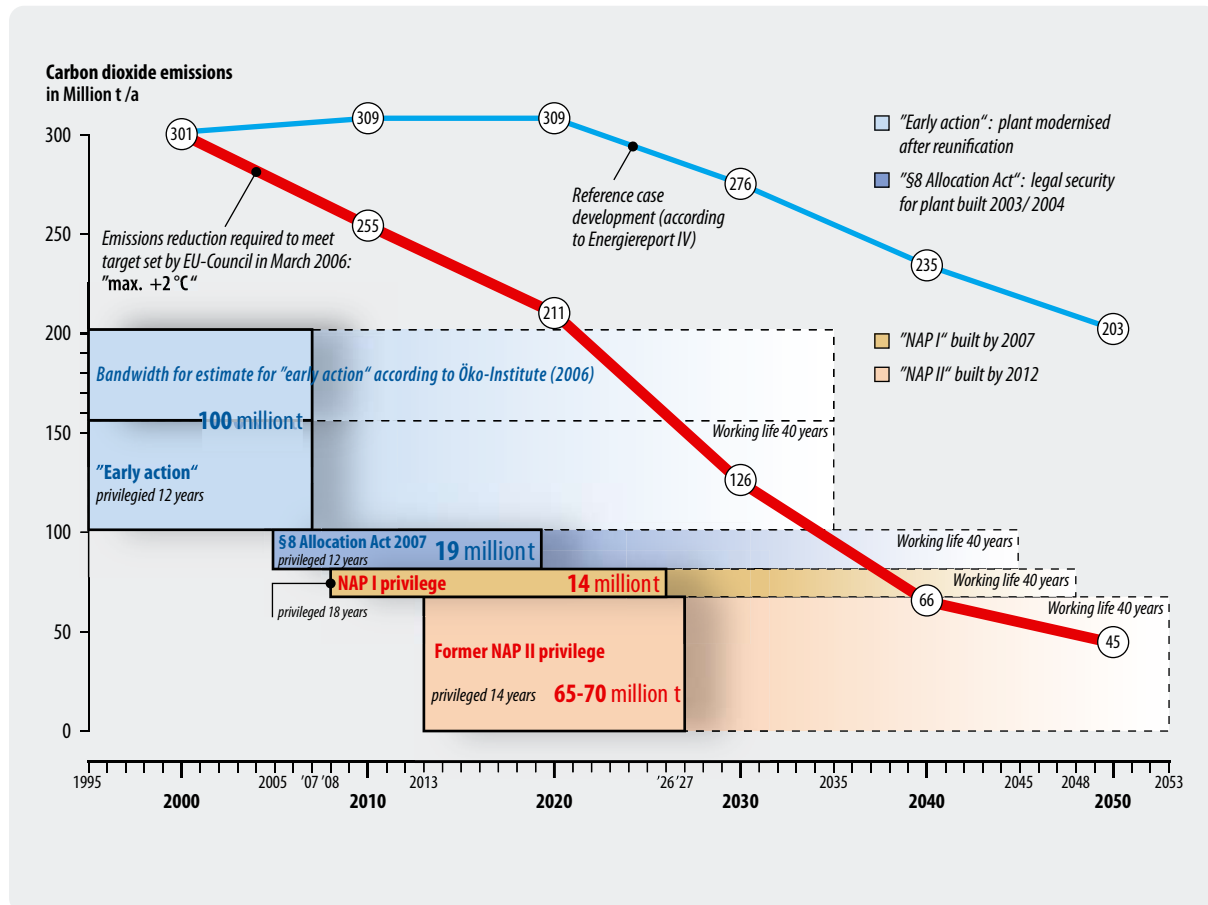
Fig. 14-4: Emissions from existing and planned power stations in relation to two emissions reduction trajectories in Germany (WI calculations)

The forthcoming investment programme doubtlessly contains many opportunities. It offers good prospects for economic and employment policy, represents sensible industrial policy, and will boost the German economy with respect to export markets. But it also represents a great opportunity for ecological modernisation. If we start from the existing plans for up to thirty-two power stations with an installed capacity of about 18 GW, and assume initially that these will merely replace existing power stations (with the same fuel but considerably worse fuel efficiency) we find a considerable theoretical CO_2 saving of 24 %.[3]

On the other hand, the announced new builds represent structural decisions with implications that extend far into the future and must therefore be examined for conflicts with future developments. This applies in particular to long-term responses to the climate policy challenge. The sum of all construction projects could thus prove incompatible with such goals, and even if new power stations are considerably more efficient than the existing ones they replace, the problem will remain. In times of climate change even 'much better' may prove to be 'not good enough'. Or put another way, for climate

protection not only the 'class of plant' but also the simple 'mass of plant' is relevant.

If we compare the new build plans with specific goals for CO_2 emissions (see Fig. 14-4) the potential conflict is obvious.

The figure shows that by the third decade of this century the new power stations already planned today will be coming into conflict with climate protection goals. Put another way, if all the power stations were to be built as planned, we would already have decided today that it will not be possible to apply a restrictive (but necessary) climate protection target to the power station sector that is proportionate to other sectors' targets. Consequently other sectors would have to be treated more strictly than the electricity generating sector if the overall target is to be met, and it is doubtful whether that could be sustained politically.

The general situation changed recently. In former years the NAP II privilege allowed more plans for new builds. After cancellation of the privilege the number of new builds will strongly depend on the developments of the European emissions trading scheme.

As already mentioned, the conflict stems in the first

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3   18 GW is a rather conservative figure. Various sources cite plans involving up to 40 GW.

place from the volume of planned new capacity. But this could be reduced considerably by targeted electricity saving measures (which are generally also very attractive in broader economic terms) and a further diversification of the range of renewables (see section 14.2). Assuming the power stations are built, it may prove necessary to retrofit them with CO_2 capture in the medium term. It would therefore be logical to equip today's new power stations with the possibility of retrofitting for CO_2 capture and storage (capture-ready). Corresponding incentive regimes are not yet in place, but they would be conceivable and are currently under discussion especially at the European level.

14.1.3 Compatibility of CCS with Other Climate Protection Measures

From the perspective of energy economics it is also relevant to know which fields of application CCS technologies relate to today and in the future and how they stand in relation to other climate protection strategies regarding compatibility with them and whether conflicts will arise.

Applications for CCS

Because of the high costs and infrastructure investment involved, CO_2 capture and storage is most obviously an option for the centralised structure of large power stations. It is not yet clear to what extent CO_2 capture and storage will remain restricted only to these central point sources or whether in future the many small-scale sources (e.g. fuel cells for stationary domestic supply, vehicles) could be included directly or indirectly (e.g. gasification prior to capture, CO_2 capture from the atmosphere).[4]

CCS for decentralised structures is possible at least indirectly through the introduction of a hydrogen economy where hydrogen would be produced centrally, distributed through new or existing pipeline systems (e.g. the natural gas pipeline network) and used locally, for example to generate electricity or heat or to power vehicles. On the one hand this would expand the length of the process and thus imply additional energy losses but on the other hand (pure) hydrogen applications in particular would allow high conversion efficiency rates. To what extent and in what applications and timeframes introducing a hydrogen economy makes sense and would lead to a rational energy balance remains to be investigated.

Compatibility or conflict

A further question that arises in any analysis of energy economics is the compatibility of CCS with other climate protection options. Table 14-1 provides an overview of compatibility testing of CCS with the climate protection strategies that play a decisive role in the NaturschutzPlus scenario (BMU 2004). The matrix identifies the possible negative interactions and (potential) positive synergies; it thus represents one of the main starting points for the process of defining scenarios described in section 14.2, and begins to address whether CCS stands in conflict with the expansion of renewables or represents a bridge to reaching that goal.

According to Table 14-1 the greatest competition is with the expansion of centralised renewable electricity generation (wind offshore, import of renewables). Compatibility problems arise above all with respect to decentralised combined heat and power. Synergy possibilities and combined solutions appear possible with respect to hydrogen production. For geothermal there are still open questions to resolve. Here there would seem to be both the possibility of competition and the potential to exploit synergy effects because both cases involve the use of underground structures. However, the number of potential CO_2 sinks is limited. Other conflicting interests could arise if compressed air storage gains in importance, for example to balance out fluctuations in electricity generated from renewables. Conflicting interests with natural gas storage are obvious, because in some cases deep aquifers are already used today.

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4 Given that the CO_2 produced by combustion weighs more than three times as much as the carbon in the mineral oil, capture in the vehicle is a problematic option and would automatically impact negatively on the energy balance.

Table 14-1: Interaction matrix for CCS (basic assumption: available from 2020/2025) and other relevant climate protection strategies (focus on electricity generation and fuel production, geographical scope: Germany)

Assumption CCS availability from 2020/2025					
Technology/ strategy	**Availability**	**Synergy potential with CCS**	**Conflict potential with CCS**	**Potentials**	**Conclusion: conflicting development?**
Fossil and nuclear electricity generation					
Efficient central-ised electricity generation	Immediately (700°C plant from 2015)	Efficiency increases create lee-way for CCS	Efficiency reduction; in combi-nation with renewables high flexibility required, probably not provided by CCS power stations (due to additional components)	Significantly reducing over time	
Centralised public and independ-ent CHP	Immediately		Normally gas-fired power sta-tions due to high electricity-to-heat-ratio (smaller CCS incentive), high equipment investment for independent operators (space requirement critical)	Replacement of existing power stations	
Decentralised CHP	Immediately	Via hydrogen fuel supply (best prospects with use of fuel cells)	CCS not practicable for decen-tralised applications (high costs	Significant expansion (16 % share of electricity gen-eration in 2050), later with fuel cells	(Yes)
Nuclear power	Immediately			No new builds – phase-out	Yes – but public accept-ance more important
Electricity generation from renewables					
Hydropower	Immediately			Maximum capacity installed	No
Wind energy (onshore)	Immediately		Intermittent renewables require high flexibility which is probably not provided by CCS power stations	Maximum capacity installed (but onshore repowering)	No
Wind energy (offshore)	2010		see above	Large contribution long-term, contribution of wind to total renewable electricity generation 33 % (of which > 2/3 offshore)	Yes
Imported renewables	From 2025			Share rising long-term (65 TWh in 2050, 13 % share of electricity generation by 2050)	Yes – strong conflict with CCS regarding date of deployment
Photovoltaics	Immediately		Intermittent renewables require high flexibility which is probably not provided by CCS power stations	Limited mid-termimpor-tance in Germany	(No)
Biomass	Gasification from 2015	Double dividend with CCS (negative emissions), multi-fuel use possible e.g. with co-combustion of biomass in power stations or combined gasification	Due to fuel logistics usually smaller plants, especially with CHP (< 20 MW)	High importance of biomass	Consider combined concepts
Geothermal (heat, electricity)	From 2015	Synergy projects possible (cf. RWTH project)[1]	Conflicts conceivable, espe-cially with heat supply, CCS at 800 m and deeper open question	Cautious estimate:14.5 TWh in 2050 corresponds to just over 3 %	

Technology/ strategy	Availability	Synergy potential with CCS	Conflict potential with CCS	Potentials	Conclusion: conflicting development?
Electricity generation from renewables					
Electricity saving	Immediately			High, saving in 2050 about 20 % compared with reference development	Yes – but efficiency technologies available earlier
Wärmeeinsparung	Immediately			In buildings very high (e.g. passive house standard compared to current German buildings standard ("EnEV")	(Yes – compared to CCS-H2, but efficient technologies are available earlier)
Fuel supply					
Biofuels				Limited use of biofuels (111 PJ in 2050[2])	No
Hydrogen (fuel, feed into natural gas network)		Low-CO2 hydrogen can be imported (CO2 separation at borehole), hydrogen production in IGCC plants, (combined cycle multi-purpose concepts)		Limited quantities of hydrogen in scenario (189 PJ in 2050) on basis of electricity from renewables	Think about combined concepts
Mineral oil		Enhanced oil recovery creates favourable economic framework			International first step for CCSS
Natural gas		Capture of CO2 as natural gas impurity			International first step for CCS
Storage systems					
Compressed air stores	In principle immediately, intense research under way		Competition for suitable geological storage formations, which are also of fundamental interest for compensating intermittent renewable contributions		(Yes)
Thermal energy stores (seasonal)	In principle immediately, intense research under way		Competition for suitable geological storage formations, seasonal stores are fundamentally of great importance for renewable heat storage		(Yes)

1   Integrating CO_2 in reflux water in geothermal projects (deep geothermal at depth of e.g. 1,500 m) – calcite formation

2   Very restricted use in NATP I scenario (largely in stationary applications), in NATP II scenario 300 PJ (here no use of renewable H_2), a comparable order of magnitude is also found in the UBA fuel scenario.

14.2 Scenario Analyses: Assessment of the Strategic Importance of CCS

The results of calculations in models are highly dependent on the assumptions on which the models are based. This applies in particular to the fundamental economic data of the available alternatives and the development of fuel prices. In the following we examine scenarios for Germany in order to elucidate – without the distractions of optimisation models – the strategic importance of CCS for reaching ambitious climate protection goals.

14.2.1 Storylines for Political Relevant CCS Scenarios

In the light of the interaction matrix described above (Table 14-1) and earlier studies dealing with ways to meet ambitious climate protection targets – as already presented in scenario studies conducted for the Federal Environment Ministry and the Federal Environment Agency (UBA 2006b, BMU 2004, WI/DLR 2002) – this study identifies three different scenarios[5] (name of scenario in brackets):

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5   Target: 80 % reduction in CO_2 emissions by 2050 compared to reference year 1990.

- **CCS as the main element of a climate protection strategy** with maximum application of CCS technologies, whereas development of renewables is derived from the reference trend (**CCSMAX**)

- **Avoidance of CCS as a result of** great success in increasing efficiency and through the ambitious expansion of technologies for using renewable energy as described for example in the NaturschutzPlus scenarios (BMU 2004, 2005) (**NATP**)

- **CCS as a bridge to renewable energies** in a scenario where increases in efficiency and expansion of renewables cannot be sufficiently mobilised to achieve the climate protection goal on their own in the envisaged time frame (**BRIDGE**)

Rather than developing completely new scenarios we based our work on the NaturschutzPlus scenario (modified and adapted to current conditions) (BMU 2004; UBA 2006b) and the reference forecast from the EWI/Prognos Energiereport IV.[6] All three scenarios either state a climate protection goal to be achieved by 2050 or else examine whether such a goal is achievable. The goal is specified by the NaturschutzPlus scenario: 242 million t CO_2 emissions in 2050. The scenarios are also shaped by specific storylines, which are described below. The principal results of the scenarios are described in the following.

CCS as the main climate protection strategy (CCSMAX scenario)

If CCS is chosen as the main strategic pillar of climate protection this can function on two different levels:

- *Central electricity generation* (largely condensation power plant). The driving forces here are that existing structures could be maintained (including operator structures), that coal (as the fossil fuel with the greatest reserves) could continue to be used, and that this option could represent an industrial policy model for other countries with significant coal reserves.

- *Central hydrogen production* (on the basis of coal gasification). Low-emission electricity generation alone will not be enough to achieve the required reduction in CO_2, and in the transport sector biofuels – alongside improving efficiency – can make only a limited contribution to climate protection. So here the driving force for expanding the CCS option would be to diversify the range of different fuels to include hydrogen for reasons of security of supply.

Because of the structural preconditions (strong focus on large-scale power station technology) it is logical to develop the scenario on the basis of the existing Energiereport IV (i.e. a 'business-as-usual' approach) with the goal of meeting comparable climate protection targets (80 % emissions reduction goal).

When expanding CCS, the existing age structure of the power stations initially has a restrictive effect, but it must also be taken into account that a hydrogen system cannot be established at the drop of a hat. Conceivable steps would be first to launch the system with a centralised supply for major consumers (e.g. airports), establishing 'stand-alone systems' and starting to feed into the natural gas network to certain shares. Then the successive creation of the first mixed gas structures could follow (including necessary modifications of application technology for mixed gas), and finally a gradual move (in both the temporal and geographical sense) to full-blown hydrogen systems.

CCS as a bridge to expanding renewables (BRIDGE scenario)

In this scenario CCS is understood as a complementary technology for a climate protection strategy that ultimately aims to further expand renewables and increase energy efficiency, but cannot implement these in the required intensity due to conflicts of interests and insurmountable obstacles.

In contrast to the idea of using CCS exclusively as a back-stop technology (a technology that is only applied when other measures fail to have sufficient effect), this development strategy integrates CCS as a strategic element from the outset and regards it as necessary for meeting the climate protection target in time. The foremost questions to be analysed here are firstly the extent to which the necessary expansion of renewables and the implementation of energy efficiency measures (including the expansion of decentralised CHP) can be spread over a longer period and secondly whether CCS can turn out to be a longer-term complementary and transitional option (compatible with the expansion of renewables) for the technologies that are strongly expanded in the NATP scenario.

14.2.2 Definitions and Parameters for the Scenarios

The required demographic and economic data for all the scenarios are taken from EWI and Prognos (2005), with modifications only with respect to the development of transport volume, where figures from UBA (2006) were used (Table 14-2). However, the reference development used here was determined on the basis of the 2005 situation. This means that for the near future (based on 2010) a number of deviations from the energy data in Energiereport IV arise. In all the scenarios the agreed phase-out of nuclear power is completed on schedule.

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6 In the course of an investigation of fuel strategies for the Environment Agency (UBA 2006b) the climate protection strategies developed for the Federal Environment Ministry (BMU 2004) were modified to account for changes in conditions (e.g. population trends) in accordance with the EWI/Prognos Energiereport IV.

Table 14-2: Demographic and economic data for the scenarios

Data	1996	1998	2000	2002	2005	2010	2020	2030	2040	2050
Population (million)	81.94	82.11	82.21	82.41	82.41	82.41	81.39	79.42	77.30	75.12
Employment (million)	37.27	37.62	38.75	38.67	38.76	38.92	38.95	37.50	37.00	35.80
Households (million)	37.30	37.60	38.15	38.76	39.15	39.67	40.02	39.72	39.20	38.50
Housing units (million)	36.10	36.80	37.06	37.27	37.60	38.20	39.80	40.85	39.50	38.50
Housing space (million m^2)	3,080	3200	3,281	3,347	3,450	3,615	4,010	4,406	4,560	4,510
Heated industrial space (million m^2)	1,310	1,385	1,458	1,465	1,485	1,514	1,539	1,500	1,480	1,432
GDP (€1,000 million. 2000)	1,870	1,934	2,030	2,050	2,110	2,306	2,691	3,050	3,355	3,600
Cars (million)	41.00	41.70	42.84	44.52	44.83	46.96	50.60	51.90	52.38	52.09
Passenger transport (1,000 million passenger-km)			1,169	1,186	1,220	1,285	1,433	1,511	1,560	1,536
Goods transport (1,000 million t-km)			490	496	535	607	748	843	918	980
Ratios										
Household size	2.20	2.18	2.15	2.13	2.11	2.08	2.03	2.00	1.97	1.95
Living space/head (m^2)	37.6	39.0	39.9	40.6	41.9	43.9	49.3	55.5	59.0	60.0
Size of housing unit (m^2)	85.3	87.0	88.5	89.8	91.8	94.6	100.7	107.9	115.4	117.1
Cars/household	1.10	1.11	1.12	1.15	1.15	1.18	1.26	1.31	1.34	1.35
Useful area/employee (m^2)	35.1	36.8	37.6	37.9	38.3	38.9	39.5	40.0	40.0	40.0
GDP/head (€2000)	22,822	23,554	24,692	24,875	25,603	27,982	33,062	38,403	43,402	47,923
Passenger transport/head (km)			14,219	14,391	14,804	15,593	17,606	19,025	20,181	20,447
Goods transport/head (km)			5,960	6,018	6,492	7,366	9,190	10,614	11,876	13,046
Index (2000 = 100)										
Population	99.7	99.9	100.0	100.2	100.2	100.2	99.0	96.6	94.0	91.4
Employment	96.2	97.1	100.0	99.8	100.0	100.4	100.5	96.8	95.5	92.4
Households	97.8	98.6	100.0	101.6	102.6	104.0	104.9	104.1	102.8	100.9
Housing units	97.4	99.3	100.0	100.6	101.5	103.1	107.4	110.2	106.6	103.9
Housing space	93.9	97.5	100.0	102.0	105.2	110.2	122.2	134.3	139.0	137.5
Heated useful area	89.8	95.0	100.0	100.5	101.9	103.8	105.6	102.9	101.5	98.2
GDP	92.1	95.3	100.0	101.0	103.9	113.6	132.6	150.2	165.3	177.3
Cars	95.7	97.3	100.0	103.9	104.6	109.6	118.1	121.1	122.3	121.6
Passenger transport	0.0	0.0	100.0	101.5	104.4	109.9	122.6	129.3	133.4	131.4
Goods transport	0.0	0.0	100.0	101.2	109.2	123.9	152.7	172.0	187.3	200.0
GDP growth (%/a)		1.68	2.42	0.49	0.96	1.78	1.54	1.25	0.95	0.70
Until 2030: according to EWI and Prognos (2005); WI projection through 2050 Transport and number of cars according to UBA 2006										

The overall economic and energy data in the Natur-schutzPlus I and II scenarios developed by BMU (2004) – which serve as the basis for our NATP scenario – are largely based on the year 2000. In the meantime considerable changes have occurred both in the energy market and in the development of renewables. Compared with the reference development presented by the Enquete Commission (expert commission of the German Bundestag) in 2002 (Enquete 2002), the energy market reference forecast for 2030 ('Energiewirtschaftliche Referenzprognose 2030') in Energiereport IV (EWI and Prognos 2005) already reaches quite different conclusions regarding probable trends. But even this relatively new study, based largely on data from 2002, does not include the latest energy price rises and the sharp increase in recent years in the contribution of renewables to electricity generation and liquid fuels. Upcoming power station new builds are included as per known planning of the electricity companies.

Table 14-3: Primary and final energy consumption and gross electricity generation in the three scenarios, itemised by energy source

	Total energy supply (PJ/a)						Electricity generation							
	Primary energy		Final energy		Renewables primary		Gross generation (TWh/a)				Installed capacity (GW)			
Year/ scenario	Total	of which fossil	Total	of which electricity	(PEV)	(END)	Total	Renewables	Nuclear	Fossil	Total	Renewables	Nuclear	Fossil
2005	14,238	11,833	9,118	1,836	658	572	613	62	163	387	131.2	26.9	21.3	83.0
2020														
CCSMAX	12,980	11,556	8,800	1,886	1,097	892	591	112	30	449	139.4	40.9	4.3	94.2
BRIDGE	12,565	10,861	8,531	1,796	1,377	1,072	575	127	30	418	144.3	51.3	4.3	88.7
NATP	12,071	10,174	8,291	1,710	1,570	1,230	551	159	30	362	147.7	61.1	4.3	82.3
2030														
CCSMAX	12,375	11,068	8,403	1,853	1,300	1,084	581	145	0	436	142.5	49.1	0.0	93.4
BRIDGE	11,699	9,957	7,977	1,746	1,742	1,392	559	168	0	391	147.5	61.2	0.0	86.3
NATP	10,534	8,237	7,689	1,638	2,297	1,886	529	265	0	264	158.4	87.1	0.0	71.3
2050														
CCSMAX	12,483	10,837	7,309	1,782	1,646	1,392	569	197	0	372	146.2	63.8	0.0	82.4
BRIDGE	10,419	8,010	6,523	1,598	2,409	2,002	542	245	0	297	148.3	74.2	0.0	74.1
NATP	8,122	4,696	6,025	1,512	3,426	2,881	534	384	0	150	158.3	111.5	0.0	46.8

The **NATP scenario** describes a development that gradually continues the expansion of renewables already initiated through energy policy and increasingly links it with growing contributions from more efficient energy conversion (CHP) and use (efficiency measures). It describes the short- to medium-term effects of the German government's current energy policy and projects this favourable framework into the future. It abides by the German government's climate protection goals and the agreed targets for expanding renewables. The required instruments remain effective in their current state (e.g. Renewable Energies Act, CHP Act, tax breaks, obligation to blend biofuels) or are strengthened (energy efficiency promotion in the heat market). Earlier and current studies (BMU 2004, 2006) have shown that the growth dynamic initiated in renewables must be maintained at least at the current extent for the foreseeable future if energy policy in this field is to successfully meet its goal of making renewables competitive in the energy market without further subsidies.

By consistently continuing to expand renewables until 2050 – and assuming a successful mobilisation of potential efficiency improvements in energy conversion and use – the NATP scenario leads to a clear reduction in use of fossil fuels and thus to a considerable reduction in CO_2 emissions. It largely follows the lower reduction path shown in Fig. 14-4. In 2050 about 240 million t CO_2/a will still be emitted, which represents a reduction of 76 % from the figure for the reference year 1990. Here the application of CCS technologies is not necessary for climate protection. This scenario is the archetype of an ambitious climate protection policy based on the strategies of efficiency and expanding renewa-

bles and thus serves as a yardstick for assessing the CO_2 emissions that have to be avoided by means of CCS in other scenarios.

We updated the original NaturschutzPlus scenario on this basis with 2005 as the baseline for all energy data.[7] The potential for improving efficiency in the electricity, heat and transport sectors and the combined heat and power subsegment was reassessed using the latest data. The most important alterations in these areas relate to expected short-term electricity consumption, and to the amount of electricity and heat currently actually produced by CHP and the perspectives for short-term expansion there. The figure for gross electricity generation taken as the starting point here – 613 TWh/a in 2005 (comparison 2000: 571 TWh/a) – is considerably higher than that used by BMU (2004). Electricity generated from fossil fuels in CHP has remained stagnant for about ten years at about 50–53 TWh/a. Recently, however – stimulated by rising electricity prices and trading in CO_2 certificates – a slight increase has been noted again. For 2005 we take 53 TWh/a as a staring point. Thanks to the favourable framework offered by the Renewable Energy Sources Act there is also about 10 TWh/a CHP electricity from biomass (including biogas).

The **CCSMAX scenario** continues current energy policy – on the basis of the energy market reference forecast by EWI and Prognos (2005) – and leads to a certain

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7   When the work was conducted some of the data for overall energy supply in 2005 were still provisional.
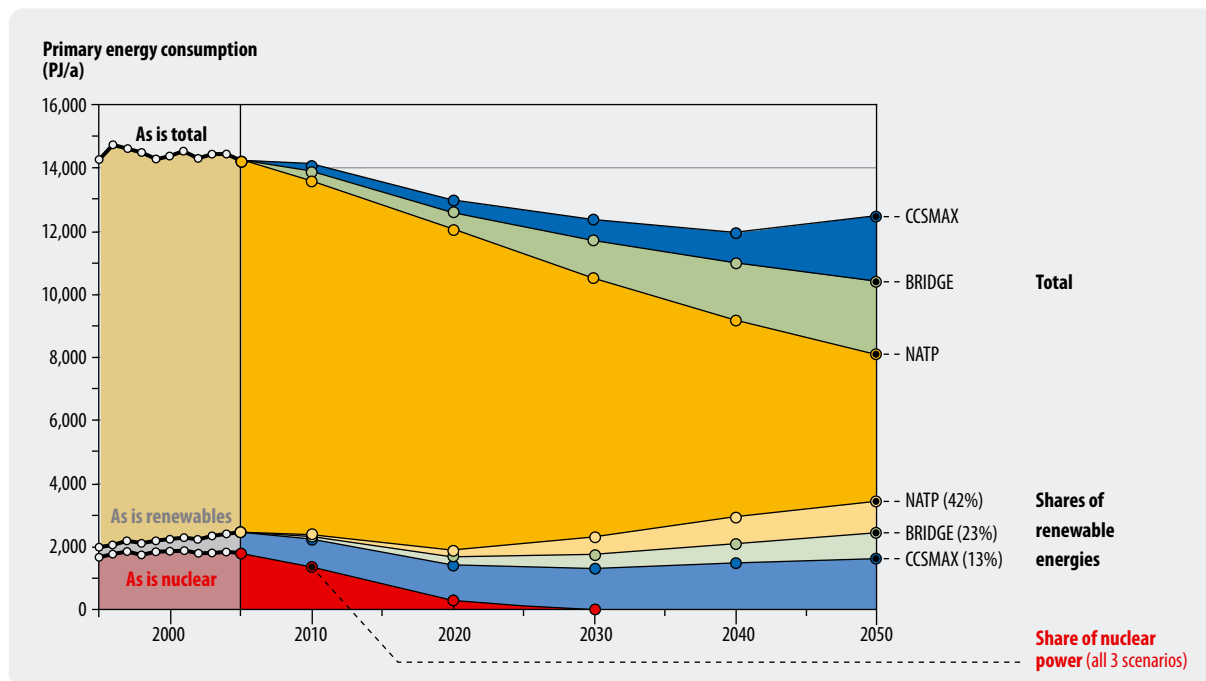
Fig. 14-5: Primary energy trends in the three scenarios showing the shares of nuclear and renewables

degree of progress in trends to increase dissemination of efficiency and renewable energy technologies. But the progress is far from being sufficient to meet existing climate protection goals. The scenario thus models a climate protection policy that will be inadequate in the medium term; one that would necessitate the use of CCS technologies from about 2020 if the 2050 climate protection target is to be met in time after all. It models from the demand side the maximum CCS contribution that the German energy supply system could require by 2050. It was assumed that development of efficiency and renewable energy technologies would not fall behind the levels assumed in the reference development.

Compared to the reference development, the **BRIDGE scenario** defines an accelerated climate protection policy that boosts efficiency and renewable energy strategies in comparison to the reference case. But because from the outset major players in energy policy and the energy business do not expect these two strategy elements to be enough to meet the 80 % emissions reduction target, CCS technologies are included here from about 2020 as part of an overall strategy for meeting climate protection targets.

Table 14-3 summarises the main data for overall energy supply – and in particular for electricity generation – based on the above assumptions. Fig. 14-5 shows structural differences in primary energy supply between the scenarios and the shares of different energy sources.

Even in the reference case, primary energy consumption shows a slight downward trend, (which is replicated in CCSMAX) because it is assumed that the trend

for continuous improvements in energy productivity can more than compensate the growth in energy services (expressed by growth in GDP). In the longer term falling population in Germany also has an effect. But only the NATP scenario exploits the great potential of structural technical efficiency improvements. Here only the economically viable options are considered at any particular time. Both the other scenarios assume that structural and institutional impediments will to differing degrees impede effective exploitation of these potentials.

In both scenarios *with* CCS the reduction in primary energy consumption slows after 2020 because of the increasing use of primary energy for low-CO_2 production of electricity and hydrogen. In the CCSMAX scenario this actually causes use of primary energy to rise again after 2040. So in this scenario the use of fossil energy in 2050 (10,837 PJ/a) is only 9 % less than today (11,830 PJ/a). In the BRIDGE scenario use of fossil primary energy falls considerably (by 33 %) and in the NATP scenario even further (by 60 %). Given that GDP grows by 75 % between 2005 and 2050, primary energy intensity falls in the NATP scenario to 34 % of today's value by 2050. That does not yet, however, reach the structural technical limits, which the Enquete Commission puts at a mean value of approx. 25 % ('Factor Four') (Enquete 2002). So there is still further potential for reduction especially in the transport sector and in utilisation of electricity.

The contribution from renewables increases in all scenarios. But measured against the speed of growth of the past five to seven years future growth slows significantly

Power station output, MW$_{el}$ Power stations built before 2001, working lifetime of large-scale power stations 40 years
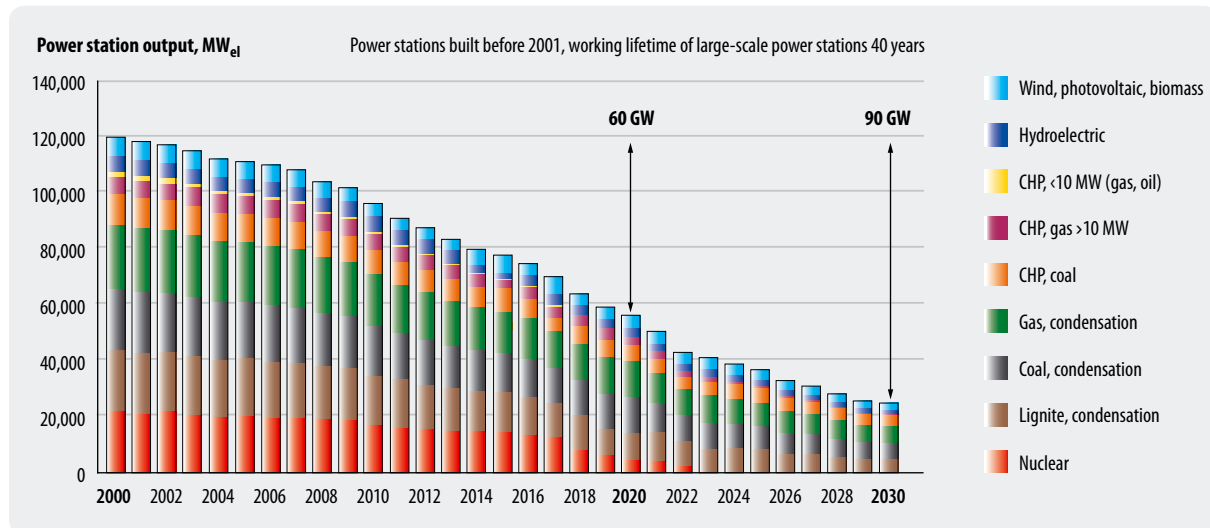
Fig. 14-6: Remaining output of power stations built before 2001 in Germany, itemised by type

in the CCSMAX scenario, reaching only 2.5 times today's value in 2050. That corresponds with a policy that allows existing funding instruments to expire in the foreseeable future and neglects to establish them in the first place in some fields (e.g. heat supply). In the other extreme case, the NATP scenario, the current speed of growth of renewables is maintained over the coming decades. How quickly the relative shares of renewables grow, will depend strongly on the development of primary energy consumption. In the NATP scenario in 2050 their contribution in absolute terms (3,426 PJ/a) is double that of the CCSMAX scenario, but their share (42 %) is more than three times higher.

14.2.3 Scenarios for Developing CCS Technologies in the Electricity Sector

The intensity of structural change in electricity generation is largely defined by the necessity of replacing ageing fossil-fuelled power stations. The decision to phase out nuclear power, the continuing growth in renewables and the development of electricity consumption also influence this transformation.

Fig. 14-6 shows the capacity retirement line for German power stations in the twenty-first century. If we assume that a large-scale power station has a working lifetime of forty years we can calculate the consequential replacement demand from the capacity retirement line. Of the power stations built before 2000, a total of 60 GW will have to be replaced by 2020: approx. 35 GW fossil-fuelled power stations (including approx. 8 GW in CHP plant), 8 GW plant using renewables and 18 GW nuclear power. By 2030 altogether 90 GW or 75 % of installed capacity in 2000 will have to be replaced.

In conjunction with the expansion of renewables and the expansion of CHP (especially decentralised), both of which are aims of energy policy, the potential 'market' for CCS power stations is defined. However, whereas

renewables and CHP already profit from the pre-2020 structural changes, which affect more than half of existing power station capacity, CCS plant will not be ready for this market (that being the assumption in the scenarios under consideration). The potential market volume for CCS plant could expand if it is possible to retrofit CCS technologies in fossil-fuelled power stations built between 2005 and 2020.

In electricity consumption too, a small reduction already occurs in the reference case (see Table 14-3).[8] But in the CCSMAX scenario for 2050 final demand for electricity is only 3 % less than the value for 2005 (and thus as high as consumption in 2000). Partial exploitation of potential for electricity savings in the NATP scenario increases the savings to 18 %. In all the scenarios production and supply of hydrogen using renewable energy begins in 2030, which requires in the CCSMAX scenario in 2050 an additional 22 TWh/a of electricity (in BRIDGE: 31 TWh/a; in NATP: 47 TWh/a).

In the electricity sector the interdependence with renewables is especially great because they already have a share of more than 10 % and current growth is most dynamic of all in that sector. But in the CCSMAX scenario electricity from fossil fuels still dominates in 2050 with a share of 65 %. In the BRIDGE scenario both energy sources are almost equally involved (fossil 56 %), while in the NATP scenario renewables (72 %) clearly outweigh fossil fuels.

The following assumptions were made when determining installable CCS capacity in the electricity sector:

- Commercial application begins in 2020, all large-scale power stations have a working lifetime of 40 years.

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8   However, the reference case is based on data from 2000 when gross electricity generation was 571 TWh/a (without pumped storage), and doesn't include the relatively steep increase to 2005.
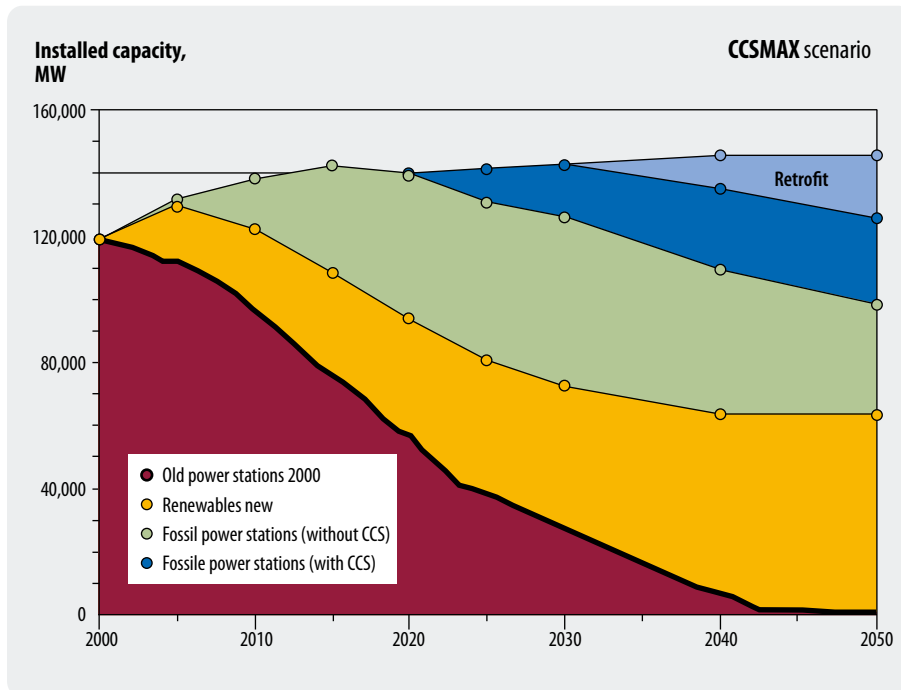
Fig. 14-7:
Installed output in the CCS-MAX scenario: old power stations, new renewable energy plant and new fossil-fuelled power stations with and without CCS
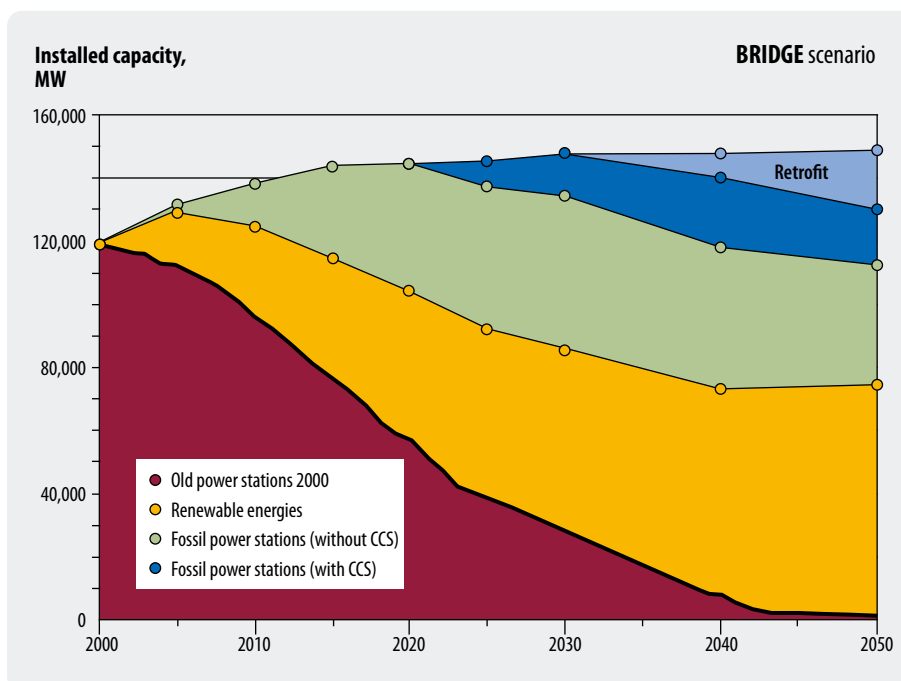
Fig. 14-8:
Installed output in the BRIDGE scenario: old power stations, new renewable energy plant and new fossil-fuelled power stations with and without CCS

- From then on 90 % of new condensation power stations and 50 % of large cogeneration plants (CHP) will be equipped with CCS technologkies.

- New power stations built between 2005 and 2010 will be replaced by new CCS plant between 2045 and 2050.

- New power stations built between 2011 and 2020 (large condensation power stations, large cogeneration plants) will be retrofitted with CCS technology after 2030, in the same proportions as new builds.

- The parameters of power stations without and with CCS are taken from chapter 12; only the direct CO_2 issions are considered;[9] in all scenarios fossil-fuelled power stations without CCS have the same parameters.

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9 So *indirect* CO_2 emissions (from upstream processes) and other greenhouse gases (e.g. methane) are not included here. The LCAs in chapter 10 show, however, that these emissions assume significant dimensions.
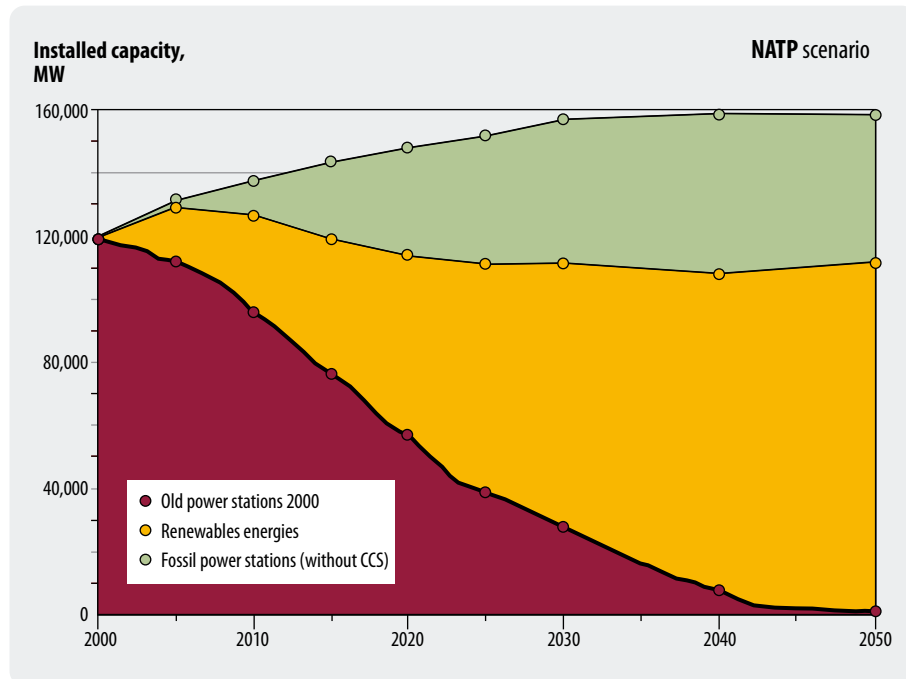
- Renewables and cogeneration plants will be expanded in the dimensions described above.

Fig. 14-7 to Fig. 14-9 show the output curves of the different power station types in the three scenarios (see also Table 14-3). In Fig. 14–7 and Fig. 14–8 the upper segment represents installed CCS capacity divided into new and retrofitted plant. By 2020 42 GW (CCSMAX), 36 GW (BRIDGE) or 30 GW (NATP) of new fossil-fuelled large scale power station capacity – which cannot initially be equipped with CCS technology – will already have to have been installed. On the basis of the assumed conditions the following maximum CCS capacities can be installed by 2050:

- **CCSMAX:** 47 GW (of which 7 GW coal, 14 GW lignite, 27 GW natural gas; power station structure until 2030 taken from Energiereport IV [EWI and Prognos 2005])

- **BRIDGE:** 36 GW (14 GW coal, 8 GW lignite, 14 GW natural gas)

The installed capacity of all renewables – currently 27 GW – rises through expansion measures to between 64 GW (CCSMAX) and 112 GW (NATP). Apart from biomass and thermal storage in conjunction with solar thermal and geothermal power, their capacity utilisation may fluctuate depending on conditions. The fossil-fuelled power station capacity required in the CCSMAX scenario rises slightly until 2020 before returning to about today's level with a figure of about 83 GW. It falls slightly until 2050 in BRIDGE to reach 74 GW and falls strongly in NATP to 47 GW. These figures also include a growing trend towards fossil-fuelled CHP capacity (currently 18 GW, in 2050 in CCSMAX 31 GW, in BRIDGE and NATP 36 GW).

To reflect the different power station structures the scenarios model a broad range of possible investment strategies. As a consequence the power station load factors are different too. In 2050 in the CCSMAX scenario 228 TWh/a of electricity are generated from CCS power stations (40 %) and in the BRIDGE scenario 146 TWh/a (27 %).

Fig. 14-10 and Fig. 14-11 show how these data fit into the overall generation structure. The CCSMAX scenario demands extremely fast growth of CCS technologies if the opportunities offered by power station replacement
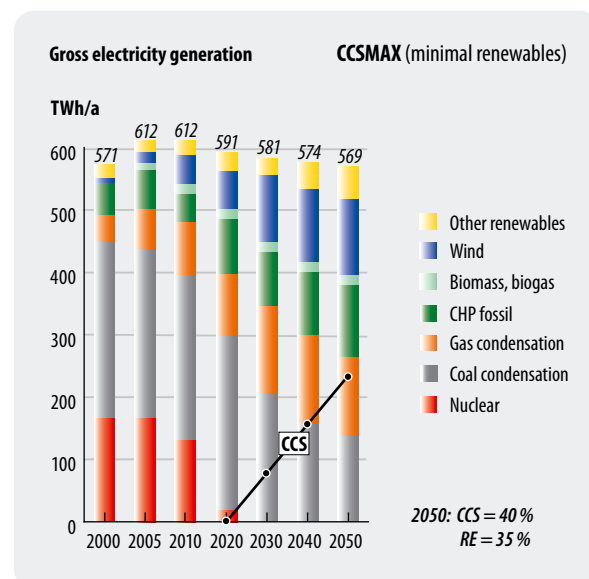
Fig. 14-10: Structure of gross electricity generation of CCSMAX scenario
RE = renewable energies
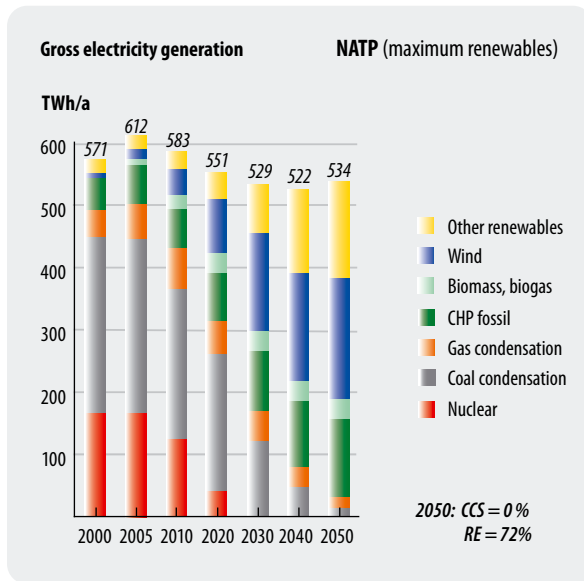
Fig. 14-11: Gross electricity generation in the NATP scenario
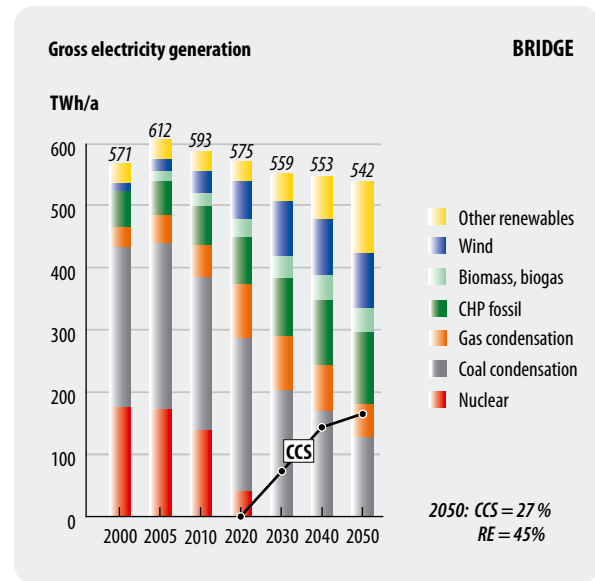
Fig. 14-12: Gross electricity generation in the BRIDGE scenario

demand are to be used to the full. Between 2020 and 2050 an average of 1,600 MW CCS power station capacity would have to come on stream every year (or after 2030 to be retrofitted). In BRIDGE it would be less at 1,200 MW/a, but still considerable.

In all three scenarios between 72 % and 75 % of electricity in 2050 is generated with low or no emissions with different shares in the two technology categories (Fig. 14-10 to 14-12). Because of the differences in total amount generated, the respective absolute amounts vary between 384 TWh/a (NATP: 72 % renewables + 0% CCS

out of total 534 TWh/a) and 425 TWh/a (CCSMAX: 35 % renewables + 40 % CCS out of total 569 TWh/a).

Fig. 14-11 clearly shows the effects of the investment strategies on CO_2 emissions from electricity generation. By 2020 the combination of ambitious efficiency measures and continuing expansion of renewables in the NATP scenario leads to a clear fall in CO_2 emissions that more than compensates for the phasing out of nuclear power. The assumed smaller contribution of the efficiency and renewables strategy in the BRIDGE scenario leads to a fairly stable level of emissions between
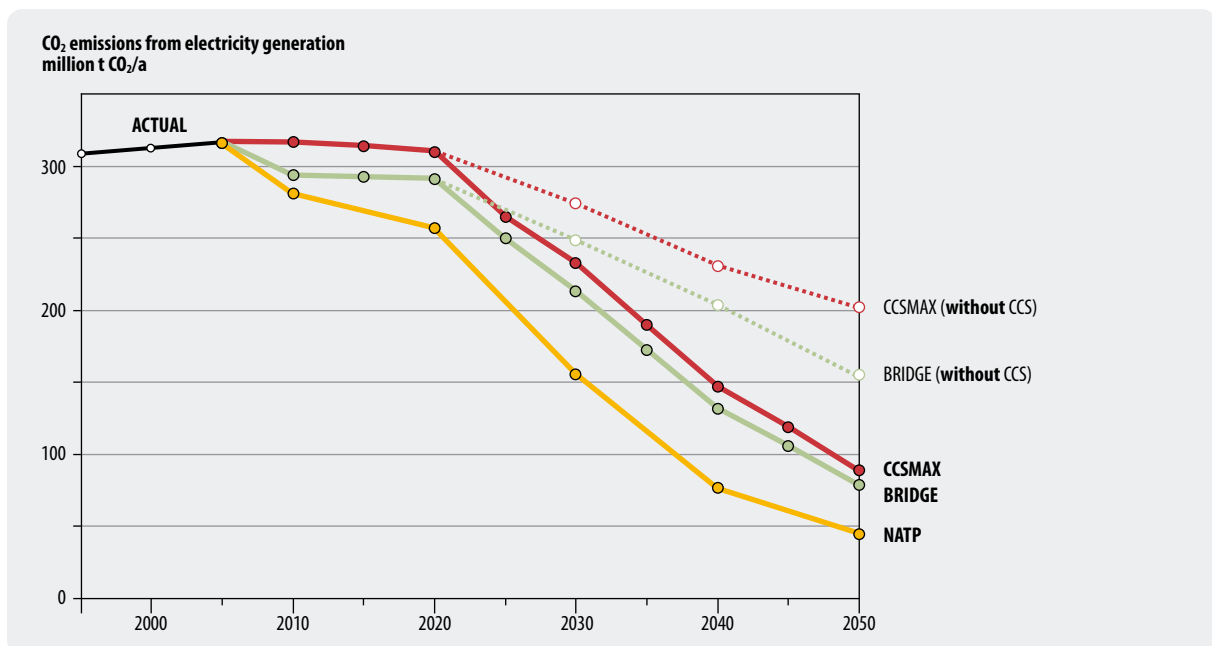
Fig. 14-13: CO_2 emissions from electricity generation in the scenarios (broken line = without introdution of CCS technologies; CHP electricity generation with credit for heat supply)

2010 and 2020 when the impact of phasing out nuclear power is greatest. In the CCSMAX scenario today's level of emissions is maintained until 2020. In comparison to the efficiency and renewables strategy in the NATP scenario, the CCS deployment scenarios achieve comparable gradients of CO_2 reduction after 2020, but are unable to make good the deficit that has accumulated before 2020. The NATP scenario achieves the lowest emissions figure for the electricity sector, with just 45 million t CO_2/a. By contrast, the CCSMAX scenario has 90 million t CO_2/a and the BRIDGE scenario 80 million t CO_2/a. In the BRIDGE scenario the CO_2 emissions avoided through application of CCS in electricity generation are 76 million t/a; in the CCSMAX scenario the figure is 113 million t/a.

Theoretically the NATP scenario could also be combined with a CCS strategy after 2020 to achieve similarly low emission values in 2050. But to do that the expansion of renewables would first have to be accelerated hard until 2020 and then drastically reduced again to free capacity for increased construction of CCS power stations. Under the conditions of these scenarios there would be no reason to do that because by that point – especially through their dynamic expansion – renewables (apart from photovoltaic) would have become almost completely competitive on the electricity market. So it is then unlikely that in this scenario CCS technologies would be able to gain any worthwhile foothold in electricity supply. If the expansion dynamic of renewables continued as in NATP it would at least in theory be possible to install about another 15 GW of CCS capacity by 2050. But this would have to occur primarily in cogeneration plants and in power stations with low load factors, so that only 40 TWh/a of CCS electricity could be generated. That would be an absolutely unattractive market niche.

If renewables are expanded more slowly from the outset – as proposed in the BRIDGE scenario – and at the same time progress on efficiency is slow, CCS technologies would have greater chances of establishing themselves in the German electricity market after 2020. In this scenario the market volume for CCS technologies is around 47 GW. For 2050 this results in a relatively balanced mix of electricity from renewables (245 TWh/a), CCS electricity (146 TWh/a) and conventionally generated electricity from fossil fuels (150 TWh/a). In this case CCS technologies could compensate for less than ideal development of renewables and efficiency technologies and thus ensure a tolerably low level of emissions from electricity generation (80 million t/a in 2050). Table 14-4 shows the situation in 2050 after introducing CCS for electricity generation.

14.2.4 Scenarios for Developing CCS Technologies in the Hydrogen Sector

Even with great success, emission-reducing measures in the electricity sector alone will not be sufficient to reduce total emissions far enough to meet the 80 % cli-

Table 14-4: Effects of applying CCS in electricity generation in the CCSMAX and BRIDGE scenarios in 2050

	Avoided CO_2	Captured CO_2	Extra primary energy required
	million t/a	million t/a	PJ/a
CCSMAX	**112.8**	**156.9**	**382**
from coal	16.7	21.9	44
from lignite	65.9	96.4	225
from natural gas	30.3	38.6	112
BRIDGE	**75.5**	**103.6**	**241**
from coal	27.8	36.5	74
from lignite	33.4	48.8	114
from natural gas	14.4	18.3	53

mate protection target. Similarly comprehensive measures are also required in the heat and vehicle fuels sectors. If we wish to apply CCS technologies here too, one obvious option is generating hydrogen from fossil primary energy while retaining the CO_2. Questions of resources and cost mean that only coal gasification comes into consideration.

The quantities of hydrogen to be produced in the scenarios were selected so as to ensure that the overall climate protection goal for 2050 was achieved for the German energy system (i. e. NATP emissions level, 240 million t CO_2/a). The following assumptions were made:

- The overall efficiency of coal gasification with CO_2 capture is 65 %, the plant load factor is 7,800 h/a. The CO_2 capture rate is 88 %, so CCS hydrogen is thus still burdened with CO_2 emissions of 0.017 million tCO_2/PJ_{H2} (in relation to the coal used that means 0.011 million tCO_2/PJ_{th}).

- CCS hydrogen only substitutes oil products (heating oil, petrol and diesel). So 0.055 million t CO_2 can be avoided for every PJ of hydrogen used (if natural gas is replaced the substitution effect sinks accordingly and amounts to just 0.039 million t CO_2/PJ_{H2}).

- In all the scenarios a baseline of 300 PJ/a is reached in 2030; this requires 16.5 GW_{th} gasification output and 460 PJ/a of coal, with which 310 PJ/a of crude oil can be substituted.

The quantity of H_2 required in 2050 in the CCS scenarios varies depending on the assumed reduction in final energy demand through increases in user efficiency and the assumed expansion of renewables. Table 14-5 summarises the main data.

	Hydrogen	Coal required	Gasification output	CO₂ reduction*)	CO₂ captured	Extra primary energy required*)
	PJ/a	PJ/a	GW$_{th}$	million t/a	million t/a	PJ/a
2030						
Both	300	462	16,5	17	37	152
2040						
CCSMAX	1,000	1,538	55	55	125	502
BRIDGE	700	1,077	38	38	87	351
2050						
CCSMAX	3,440	5,290	188	189	429	1,725
BRIDGE	1,800	2,770	99	99	224	904
*) Substitution for mineral oil						

Table 14-5:
Application of CCS in hydrogen production in the CCSMAX and BRIDGE scenarios in 2030, 2040 and 2050

In order to achieve the set goal of reducing CO_2 emissions to 242 million t CO_2/a in the BRIDGE scenario, about 60 % of the oil demand in 2050 would have to be replaced with 1,800 PJ/a hydrogen; in the CCSMAX scenario it would have to be 95 % (3,440 PJ/a hydrogen). The contribution made by hydrogen in this scenario would also influence the use of fossil feedstock in the chemicals industry, which would then have to partially switch to natural gas or synthesis gas produced by coal gasification. But these interactions cannot be investigated in any greater detail here. A move to substitution of natural gas is not sensible because of the small substitution effect, or would cause relatively high CO_2 avoidance costs. The additional quantities of coal required amount to 27 % (BRIDGE) to 42 % (CCSMAX) of total primary energy demand in 2050.

The expansion of gasification capacity would have to occur exceptionally quickly, with 1,650 MW$_{th}$/a having to be constructed between 2020 and 2030. In the period 2040 to 2050 this construction rate would have to rise to 6,100 MW$_{th}$/a in the BRIDGE scenario and to the very considerable figure of 15,000 MW$_{th}$/a in the CCSMAX scenario. So one minimum precondition for implementing this strategy would be for commercial coal gasification plant to be set up on a large scale from 2020 without major teething or acceptance problems and for hydrogen production and CO_2 capture and storage to operate at high load factor.

A second significant criterion is that a hydrogen infrastructure would need to follow this growth. Although the share of hydrogen in final energy demand in 2040 is relatively small in CCSMAX (14 %) and BRIDGE (10 %), by 2050 in the CCSMAX scenario hydrogen would already be the predominant final energy type (with 47 %). From today's perspective that appears to be a great obstacle (UBA 2006). But a share of 29 % (= 1,900 PJ/, including 100 PJ/a renewable hydrogen), as required in

the BRIDGE scenario to meet the climate protection target, appears achievable by 2050 in terms of infrastructure.

14.3 Conclusions of the Scenario Analysis for Germany

In our overall analysis we found very different structures for primary energy supply in Germany in 2050. The CCSMAX scenario represents an energy future strongly shaped by coal, indeed to speak of a 'renaissance of coal' would not be exaggerated. Here coal represents 47 % of primary energy, plus another 10 % lignite. Together with natural gas (whose quantities in this scenario are about the same as today) the share of fossil primary energy is 87 % – which is higher than today's 83 % (Fig. 14-14).

In the BRIDGE scenario, too, fossil fuels still predominate with a total of 77 %. Here coal with 35 % is no longer the predominant energy source, but it still represents the main fossil fuel. However, efficiency successes are already notable here (17 % less primary energy than in CCSMAX) as well as a noticeable contribution from renewables. In the NATP scenario effective implementation of major efficiency measures allows the absolute contribution of fossil fuels to be reduced considerably, to represent only 58 % of energy needs by 2050.

Fig. 14-15 compares the changes in primary energy structure in the CCSMAX and NATP scenarios. Put simply, NATP's avoidance of energy demand and greater contribution from renewables is replaced in the CCSMAX scenario by fossil primary energy whose CO_2 emissions are considerably reduced through the use of CCS technology. But in order to meet the 2050

Fig. 14-14:
Primary energy structures
in 2000 and 2005 and in the
scenarios for 2050, showing
the amounts of coal required
for production of CCS
hydrogen

CO$_2$ reduction scenarios for Germany

Legend: Renewables, Natural gas, Mineral oil, Other coal, Coal for CCS-H$_2$, Lignite, Nuclear

Primary energy, PJ/a

2000: 14,387
2005: 14,269

2050

CCSMAX: 12,484
BRIDGE: 10,419
NATP: 8,122

CO$_2$ storage in mio. t/a: CCSMAX 586 BRIDGE 328 NATP 0
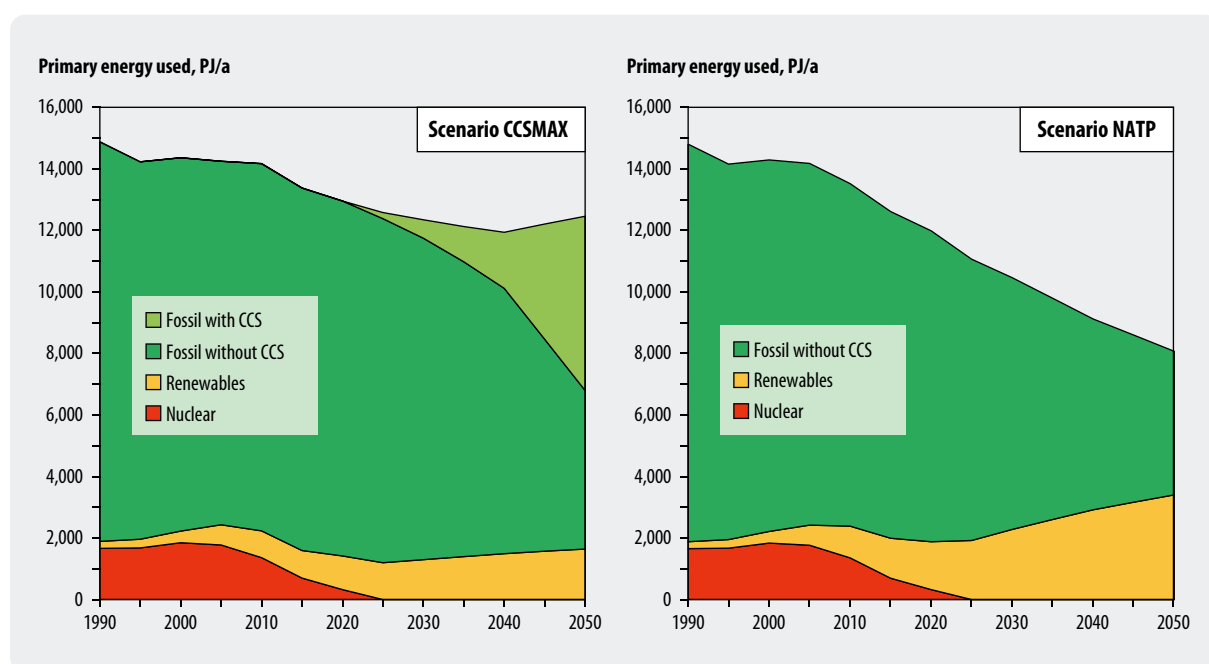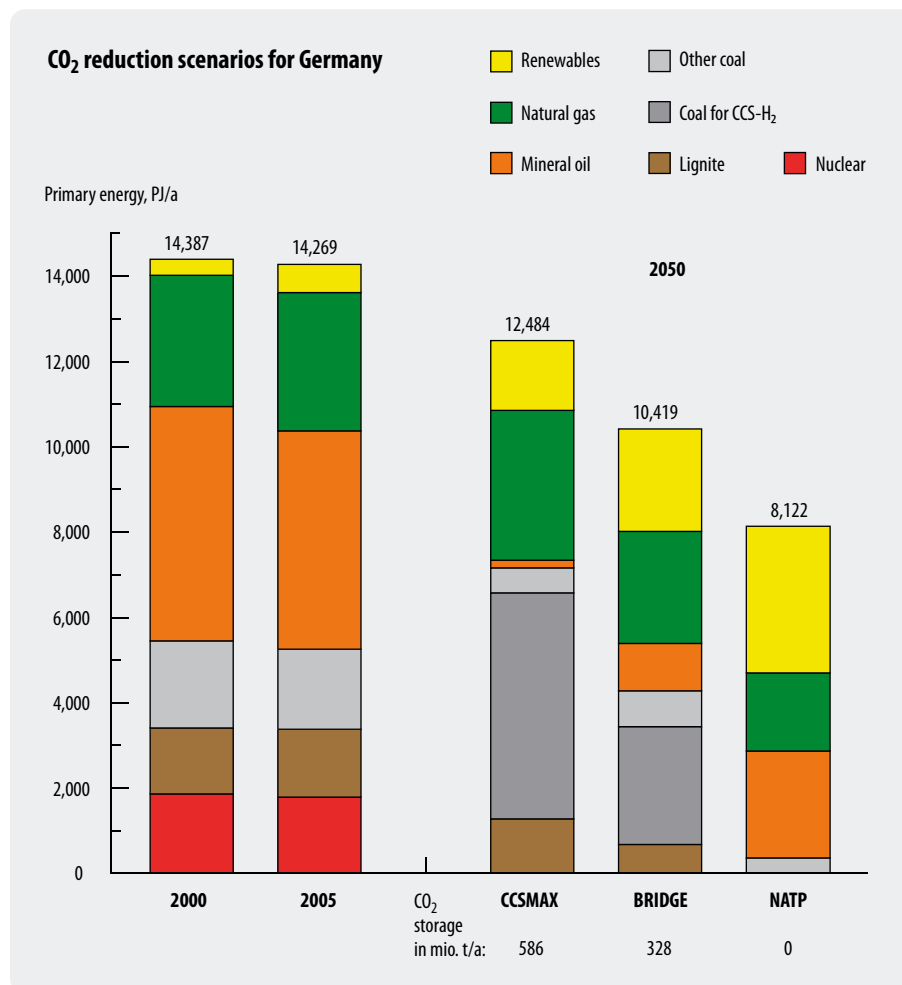
Fig. 14-15: Primary energy sources in the CCSMAX and NATP scenarios
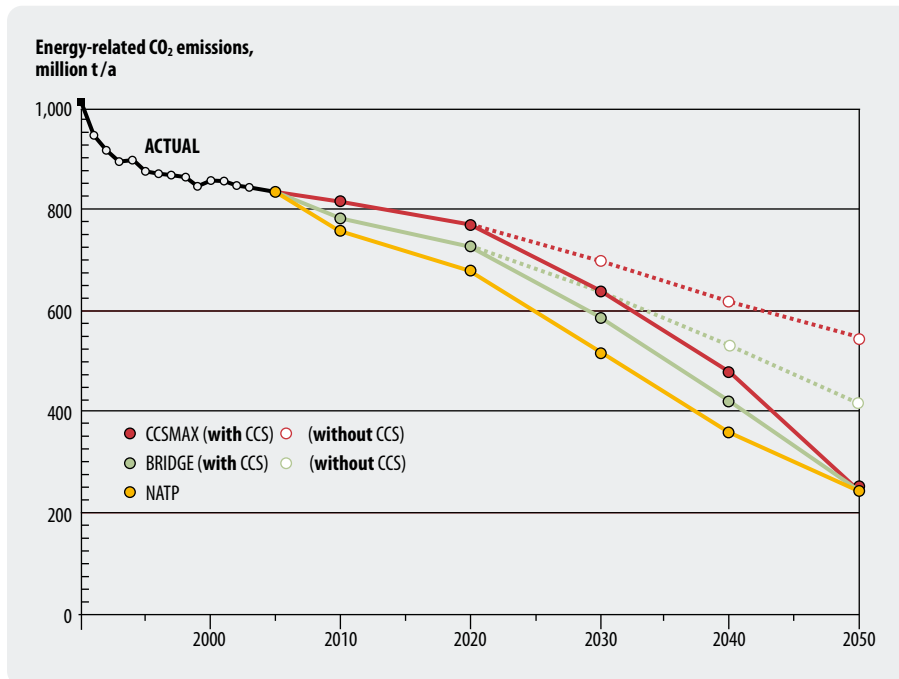
Scenario CCSMAX — Primary energy used, PJ/a
Legend: Fossil with CCS, Fossil without CCS, Renewables, Nuclear

Scenario NATP — Primary energy used, PJ/a
Legend: Fossil without CCS, Renewables, Nuclear

Energy-related CO$_2$ emissions, million t /a

Legend:
- CCSMAX (**with** CCS) ○ (**without** CCS)
- BRIDGE (**with** CCS) ○ (**without** CCS)
- NATP

ACTUAL

climate protection target extremely fast growth rates in that technology would be required after 2020 – a good deal faster even than the current rates of expansion in renewables.

All the scenarios meet the defined climate protection target in 2050 (Fig. 14-16).[10] In CCSMAX the climate protection measures progress too slowly until 2020 and have to 'catch up' later in order to meet the target by 2050. Altogether CCS can be used to avoid between 175 million t CO$_2$/a (BRIDGE) and 300 million t CO$_2$/a (CCSMAX) in 2050, compared to the reference case. In 2030 and 2040 the contribution from the electricity sector still predominates, but by 2050 the contribution from hydrogen production is foremost (Table 14-6). In the CCS scenarios considerable amounts of CO$_2$ have to be captured and stored. In particular substituting mineral oil with hydrogen from coal (including CCS) requires capturing 2.26 million t CO$_2$ per *avoided* tonne of CO$_2$. This puts the amount of CO$_2$ to be captured and stored in 2050 at between 586 million t/a (CCS-MAX) and 328 million t/a (BRIDGE). Under these conditions the available storage volume in Germany would be exhausted within 25 to 80 years in the CCSMAX scenario (44 to 145 years in the BRIDGE scenario).

The **main points** are the following:

- As the main pillar of a climate protection strategy, CCS as modelled in the **CCSMAX scenario** runs

into structural limits if the climate protection target of reducing CO$_2$ emissions by 80 % by 2050 is to be met with efficiency and renewables merely following a 'business as usual' trajectory. The assumption that CCS technologies will not be commercially viable before 2020 necessitates accelerated construction of CCS plant and hydrogen infrastructure during the remainder of the period until 2050. The high demand for coal (in CCSMAX approx. 5,900 PJ/a or 3.1 times today's figure) leads to extensive purchases on the world market which would lead to corresponding price reactions. Cost advantages for the forms of energy produced using CCS (electricity and hydrogen) compared to renewables cannot be identified (electricity) or are small (hydrogen) so from the economic perspective there is no decisive incentive for such a one-sided prioritisation of CCS. Furthermore such a strong expansion of CCS would necessitate starting straight away with great investment in R&D and pilot plants for this technology option on a scale incompatible with the current energy policy of promoting efficiency strategies and expanding renewables. Also a very high degree of clarity would have to be achieved very quickly regarding the ecological compatibility and safety of CO$_2$ storage. To pursue both strategies 'at full steam' until 2020 (efficiency and expansion of renewables following NATP until 2020; CCS development as in CCSMAX), but then to largely drop one of the options would not be a sensible way to proceed. Also the potential storage capacity for CO$_2$ is insufficient for the required massive expansion of CCS.

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10 Here the climate protection target is defined solely in terms of the greenhouse gas CO$_2$. However, the large amounts of coal required for BRIDGE and especially for CCSMAX are associated with emissions of methane during coal mining, with considerable negative climatic impact (see chapter 10).

Table 14-6:
CO_2 emissions in the scenarios with and without CCS technologies, captured CO_2 quantities and resulting additional primary energy demand

Year/ scenario	Total without CCS	reduction			Total with CCS	H_2	Electricity	Total	CCS H_2	CCS-electricity	Total
		through electricity	through H_2	Total							
		CO_2 emissions (million t/a)				**captured (million t/a)**			**Additional primary energy demand (PJ/a)**		
2005	824 *)	–	–	–	–	–	–	–	–	–	–
2020											
CCSMAX	696	41	17	58	638	37	67	94	152	139	291
BRIDGE	638	35	17	52	586	37	48	85	152	110	262
NATP	517	0	0	0	517	0	0	0	0	0	0
2030											
CCSMAX	616	84	55	139	477	125	117	242	502	286	788
BRIDGE	530	72	38	110	420	87	100	187	351	228	579
NATP	357	0	0	0	357	0	0	0	0	0	0
2050											
CCSMAX	544	113	189	302	242	429	157	586	1,725	382	2,107
BRIDGE	417	76	99	175	242	224	104	328	904	241	1,145
NATP	242	0	0	0	242	0	0	0	0	0	0
*) Temperature-adjusted											

- A climate protection strategy following the **NATP scenario,** which manages without CCS, would not yet develop of its own accord. As well as maintaining the current dynamic rate of expansion of renewables in the electricity sector and extending their use to the heat sector on a significant scale, considerable additional support measures to encourage much greater efficiency in use and conversion of energy would be required if the 2050 climate protection target is to be met on time by this strategy. Expanding renewables and increasing efficiency are measures that take effect relatively quickly so – as long as the necessary support measures impact quickly – they allow the restructuring process to run more harmoniously than in the CCSMAX case described above. Major transformation of energy infrastructures would be required, but this could be realised in stages. A strategy concentrating especially on energy productivity also makes sense in broader economic terms because many of the efficiency measures to be taken represent the most economic option for climate protection regardless what measures are taken on the supply side. If external costs were included the overall economic situation would be even more favourable. To that extent this scenario represents an **'ideal strategy'** but one which demands that very effective energy policy decisions be taken quickly, especially a clear target oriented and expansion of energy efficiency policy (including combined heat and power). In the longer term this scenario necessitates considerable structural changes, increasing network and system integration on the electricity side, integrat-

ing energy import structures (e.g. electricity from solar thermal power plant in North Africa) and greatly expanding district heating systems.

- From today's perspective a development in line with the **BRIDGE scenario** would also definitely require additional stimuli for further increases in efficiency and further expansion of renewables that would have to exceed the current reference development. However, the necessary changes would probably be easier to implement than in the case of the NATP scenario. They are also easier to justify to other countries that have made less progress than Germany in the direction of an 'ideal' NATP strategy or have a greater interest in using coal. The pressure to introduce CCS technologies and a hydrogen infrastructure is less than in CCSMAX because until 2030 the required contributions from these options can remain relatively small. Nor – in the event that CCS technologies turn out to be a sensible energy policy option – does the level that needs to be reached by 2050 come up against any fundamental limits concerning required plant capacity, infrastructure changes or storage capacity.

In view of the real interests involved and the different assessments of technology options in the field of energy (especially in the global context), an energy policy following the BRIDGE strategy can be characterised as a **'pragmatic' strategy.** It demands a general intensification of energy policy efforts on a broad front (CCS, energy efficiency, renewables) if long-term climate protection goals are to be tackled

seriously. At the same time this strategy offers the possibility – in the interval until 2020 – of exploring the development and cost potentials of CCS technologies thoroughly and without enormous pressure of time and demonstrating their feasibility in initial pilot plants.

Analyses of the costs of renewables and CCS technologies for producing electricity and hydrogen show no obvious economic advantages for the CCS option. If the learning curves for renewable energy technologies continue and our assumptions about price developments for fossil fuels are correct, electricity generation from most renewable energy technologies around 2020 will tend to be cheaper than electricity generation with CCS. The latter will definitely require CO_2 prices between 30 and 50 €/t CO_2 if it is to be attractive to private investors compared with conventional electricity generation from fossil fuels. After 2020 the costs of renewable energy technologies fall still further, while the real cost of generating electricity from coal with CCS will probably remain roughly constant if technical developments are taken into account. If we include the external costs we find further advantages for energy efficiency and renewables.

There are many uncertainties concerning the relative profitability of CCS and renewables. The assessments presented above for renewables are based on a dynamic global market where very considerable cost-reduction effects can be exploited via mass production and learning curve effects.

One factor that could impede a comprehensive CCS strategy is that the broad introduction of generally expensive low-CO_2 or CO_2-free hydrogen has to come earlier than in a strategy based on the NATP scenario.

The aspects discussed above show that a consistent strategy following the NATP scenario make more economic sense in the medium to long term and should therefore be the goal of energy policy. At the same time it is advisable to subject the CCS option to continued thorough scrutiny and in particular a realistic practical demonstration, in order to have – after about a decade – more precise knowledge of the potential and limits of these technologies. If it then turns out that in the global restructuring of the energy supply the expansion of energy efficiency and renewables is 'only' running at the intensity laid out in the BRIDGE scenario, CCS would offer an additional climate protection option.

14.4 Applicability of Results to Other Countries

The analyses described above were conducted for Germany taking particular account of the situation there. This means they cannot be applied to other countries one-to-one. At the same time certain underlying tendencies do also apply elsewhere and in some cases similar starting conditions are also present (e.g. large

demand for short-term power station replacement). The scope of this study precludes us from going into the role of CCS in other countries in detail, but in the following we bring together findings from the scenario analyses for Germany that can be regarded as being more broadly applicable. The concluding chapter of this report (chapter 15) also examines the discussion of the role of CCS from a global perspective.

The following aspects are of a more general nature:

- The future role of CCS is affected by various factors. These include the structure and age of power station capacity and especially the domestic availability of fossil fuels. Countries with large coal reserves of their own (e.g. China, Australia) will be keen to use them as intensively as possible even if conditions (especially climate protection rules) change significantly.

- Large-scale CCS technologies will probably not come on stream until 2020, but the international trend for massive expansion of power station capacity continues apace (especially new coal-fired power stations). Just in China a new power station starts operation every week. This means it is necessary not only to consider new builds but also to direct increasing attention to the retrofitting option. Between 2006 and 2020 China will build about six to eight times more new power station capacity than the current installed total in Germany. Development efforts in this connection are required in particular to reduce the extra fuel required after CCS retrofitting (e.g. through more efficient scrubbing processes). But the question of how power stations can be prepared for later retrofitting (capture-ready status) when they are still at the planning stage (i.e. before they are even built) also needs to be answered.

- A climate protection strategy based largely on CCS appears conceivable neither for Germany nor for most other countries. Structural limits (e.g. storage capacity, infrastructure aspects) mitigate against it as does the necessity, according to climatologists, to take action well *before* 2020 not only to initiate climate protection measures but to implement them too.

- For Germany the analyses show that ambitious climate protection targets can be met without using CCS at all. For other countries with an even stronger focus on coal or faster growth rates for energy demand this might be more difficult or require deeper structural changes. But for these countries too, further expansion of renewables and improvements in energy efficiency will be the climate protection strategy of choice.

- The extent to which renewables and energy efficiency improvement meet with resistance that hinders their implementation and increases demand for supplementary climate protection measures will

be a decisive question. This may differ from country to country and increase the necessity for CCS as a bridge technology.

- The decisive factor for introducing CCS need not necessarily be the field of electricity generation. It is also conceivable that the greatest impetus will come from the production of hydrogen from fossil fuels. Rising oil prices in recent years (to more than \$90 per barrel) and the almost complete dependence of the transport sector on fossil fuels (especially petroleum products) have increased the incentives to turn to alternative options for supplying fuels. Alongside first- and second-generation biofuels these also include producing liquid fuel from coal. Processes for turning coal into synthetic fuels (coal-to-liquid) are being pursued in various countries, especially China, the United States and South Africa. But they suffer the great disadvantage that (considering the whole process from extraction to combustion) they have 90 % higher CO_2 emissions than conventional petrol or diesel. Even if the CO_2 produced during the conventional coal liquefaction process is captured and stored, the emissions over the process as a whole are higher than for the reference fuels. If coal is to replace conventional fuels while observing climate protection restrictions the only current option is producing hydrogen from coal and capturing the CO_2. This would require infrastructure investment as described above for the CO_2 logistics and for a completely new hydrogen infrastructure.

- Polygeneration projects of the kind currently planned or being implemented by RWE in Germany (and other actors elsewhere in the world) represent door-openers for such developments. These plants, based on gasification technology, possess great flexibility both in terms of the fuel they use and the product they produce. Possible products are electricity, synthesis gas, synthetic liquid fuels (via Fischer-Tropsch synthesis) and hydrogen.

- Finally it must be supposed that countries with potential for EOR or EGR (and consequently with a commercial interest in using CO_2) will be among the leaders. Companies from these countries may also be interested in expanding the capture of CO_2 during natural gas extraction (e.g. in LNG and H_2).

- Decisive impetus is also expected from countries with a strong gas industry (e.g. Norway, United Kingdom). They possess know-how that can be put to profitable use and depleted gas fields with storage potential.

- As well as the aspect of climate protection, implementation of CCS will also be determined by other, sometimes very pragmatic aspects. In particular tangible economic advantages will also make certain countries (or more precisely certain actors from these countries) into pioneers. This applies above all to countries such as Norway and the United Kingdom, which possess considerable storage potential underneath the seabed in hydrocarbon deposits and saline aquifers deep below the North Sea.

Chapter 15

CCS in the International Context

Is CCS a necessity if an ambitious climate protection goal is to be achieved, for example the European Union's 2°C target? And what requirements must then be met for international implementation? This chapter examines those two questions in the light of economic scenarios and thoughts about a possible institutional framework for CCS. The focus is on a global perspective for CCS.

15.1 The Significance of CCS as a Climate Protection Option

The importance of CCS in the context of climate protection lies primarily in the possibility of stabilising the level of CO_2 in the atmosphere at a lower level. If the increase in global average temperature is to be restricted to 2°C above the pre-industrial level it will very probably be necessary to stabilise the CO_2 concentration in the atmosphere at below 450 ppm (Meinshausen 2006). This is the climate protection goal of both the European Union and the German government.[1] There is good reason to believe that it will only be possible to achieve this low stabilisation level at low overall economic cost if CCS can be used as an additional option for reducing CO_2 (alongside renewables and enhanced energy efficiency).

In fact, the lower the stabilisation level of CO_2 concentration is to be, the greater the importance of CCS. Fig. 15–1 shows that the contribution of CCS is evaluated differently in different models. The reason for this is that the models make different assumptions about the growth in emissions and the technical and economic potential of renewables.

The discussion about the relevance of CCS for global climate protection has gained in importance in recent years as doubts have grown that today's strategies will suffice to achieve a global climate protection goal. In particular, international controversy has blown up about whether the European Commission's 2°C target (Tol, in press) is achievable or sensible. Here interest focuses on the costs and strategies of climate protection.
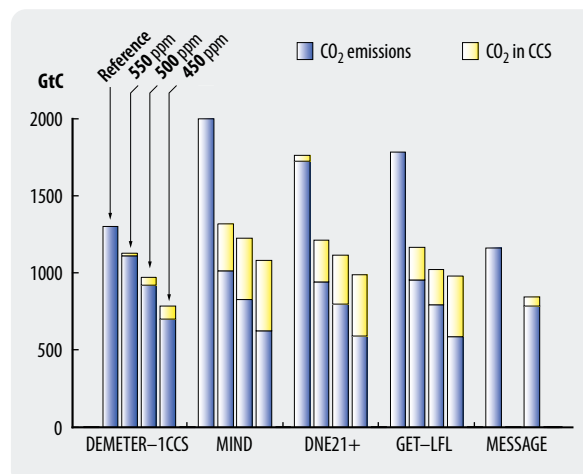
Fig. 15-1: Cumulative quantity of anthropogenic CO_2 emissions and CO_2 captured through CCS in relation to the stabilisation level of atmospheric CO_2 concentration (reference case = no stabilisation target) in various models (Edenhofer et al. 2006)

However, until recently assessments of climate protection costs have largely neglected the potential of technological progress for achieving reductions. Only recently have economists attempted to clarify the question of whether and to what extent technical progress can be fostered to reduce climate protection costs. The Innovation Modelling Comparison Project (IMCP) shows that technical progress really can reduce climate protection costs. The results of modelling presented in Fig 15–2 show that discounted economic costs increase clearly if a concentration target of 450 ppm or less is to be achieved, but in the overwhelming majority of the models they could be kept to figures below 1 % of global GDP.

In the case of climate protection, the economic costs quantify how many units of GDP would have to be sacrificed for the sake of climate protection.[2] Because these losses occur at different times they have to be normed to one particular point in time. This is done by discounting the GDP losses to a base year using a discount rate. Here the GDP growth in the case with climate protection is compared with growth without climate

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1   Cf. Sixth Community Environment Action Programme (2002), http://eur-lex.europa.eu/LexUriServ/site/en/oj/2002/l_242/l_24220020910en00010015.pdf.

2   This approach relates exclusively to the costs of *reducing* climate change (mitigation). The costs of *adapting* to climate change (adaptation) are not included.

Fig. 15-2: Discounted economic costs in percent of global GDP, taking technological progress into account, in various models that account endogenously for technological learning effects. ITC: Induced Technological Change (Edenhofer et al. 2006)

- Learning rates in using CCS,
- Learning rates for renewables,
- Leakage rates of geological formations,
- Discount rates,
- Costs of exploitation and extraction of fossil resources,
- Time of availability of CCS,
- Costs and speed of implementation of increased energy efficiency (supply and demand sides).

The term "uncertainty factors" should be understood as meaning that the listed factors have a decisive influence on the results of models of the use of CCS. At the same time the factors can be understood as risks that have to be discussed in connection with CCS.

The importance of CCS and the relevance of these uncertainty factors is reflected in a series of scientific studies where the outcomes of several different models of the application of CCS are compared (e.g. IPCC 2005, Edenhofer et al. 2006).[4]

In the public discussion about the implementation of CCS the debate about acceptable leakage rates takes a prominent place. If the part of the stored CO_2 quantified by the leakage rate escapes from the sink over a given period then the climate protection effect is reduced accordingly. The lower the rate the more effectively can CCS be implemented; therefore leakage is an important uncertainty factor in the economic analysis too. How these aspects could be dealt with institutionally and technically is discussed in section 15.3.

Alongside the question of the conditions under which CCS can make a contribution to climate protection, the possible impact of this technology on ecosystems and human health must also be discussed if we are to reach a comprehensive assessment. That approach of embedding climate protection in a more general understanding of sustainable development is ultimately also prescribed by the United Nations Framework Convention on Climate Change of 1997. In this context it must also be assumed that the perception of the risks associated with CCS could influence public acceptance of specific CCS projects at the local level (cf. e.g. Huijts 2003; overview in Flachsland 2005, 94 ff.). This question has already been discussed extensively earlier in this study.

protection. Discounted losses of one percent for the next hundred years mean that growth in the case with climate protection will be delayed by three months.[3]

In this context there is reason to hope that CCS can – especially at the global level – reduce the economic costs of climate protection, possibly by more than 30 % (IPCC 2005), if technical progress allows further refinement of the technologies.

The following main uncertainty factors affect the influence of CCS on the economic costs of climate protection, and are analysed in greater detail in section 15.2:

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3 The following example explains where this estimate comes from: If we assume that global GDP grows by 2 % per annum in the business-as-usual case (i.e. without climate protection) and by 1.97 % per annum if climate protection measures are introduced, the losses over the century as a whole (measured as a reduction in global GDP discounted at 5 % per annum) would add up to 1 %. Thus global GDP would reach the absolute value in 2101 that it would otherwise (in the business-as-usual case) have reached in 2100 (cf. Azar and Schneider 2002 for a similar argumentation).

4 The discussion about CCS and the associated uncertainty factors has also been conducted by pressure groups (especially environmental groups) and by the German government's Advisory Council on Global Change (WBGU) (cf. WBGU 2003, WBGU 2006).

15.2 CCS in a Portfolio of Climate Protection Strategies: Analysis of Uncertainty Factors

Here we explore the role of CCS for climate protection using the tools of social cost-benefit analysis. The **MIND model** employs CCS as a technological option – alongside the use of renewables and measures to improve energy efficiency – with the goal of maximising social welfare and setting a limit to emissions or temperature rise.[5]

Here we discuss outcomes from the models in order to assess the global risks described above. In various scenarios we identify the critical variables for the introduction of CCS in the electricity sector by evaluating the effects of parameter modifications on the model results (total amount of CO_2 sequestered or costs incurred). In the graphics showing the results of the simulations (Figs. 15–3 ff.) each tile represents the result of the particular combination of parameters. The gradient represents the sensitivity: in areas of high sensitivity (steep gradient) small changes in the parameters cause large changes in the amount of sequestrated CO_2 or the costs.[6]

Altogether, the application of CCS demonstrates a broad range of outcomes. Depending on the assumptions used in the models, between 0 and 700 Gt carbon are sent for storage between 2000 and 2100. Using Monte Carlo simulations it was possible to show that under plausible assumptions the median and mean would amount to about 100 GtC by 2050 (Bauer 2005). That order of magnitude also corresponds with other estimates for the technical potential of CCS.[7]

15.2.1 The Cost Reduction Potentials of CCS and Renewables and the Discount Rate

The results of the simulation are conspicuously dependent on learning rates and leakage rates. **Learning rates** designate the cost reduction per unit that results when the cumulative capacity is expanded. Here the learning rates for CCS and for alternative technologies play the decisive role. CCS plant can come into play as an option above all where it becomes profitable more quickly than
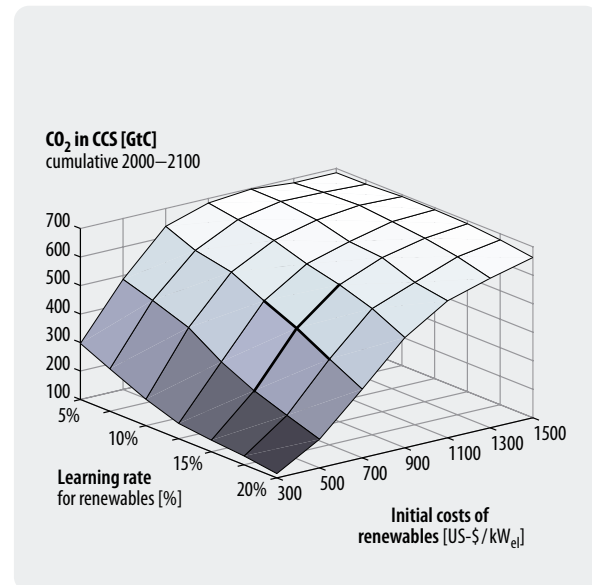
Fig. 15-3: Optimum cumulative amount of sequestered carbon between 2000 and 2100 in relation to learning rate and the initial investment costs of renewables

renewables. This assumes that the current learning rates and market developments for renewables will not continue over the next 20 years, in particular that there are no so-called technology leaps where as yet unforeseeable developments become usable for renewables. The more slowly the cost-cutting potential of renewables is realised and the more robust the technical possibilities and cost-cutting potential of CCS technologies become, the greater the cumulative amount of captured and stored CO_2 will be and the longer the timeframe for using CCS as a climate protection option. The less energy is saved and the higher the global primary energy consumption, the greater will be the importance of developing climate-friendly energy sources.

The MIND model investigates a direct connection between the development of the two learning rates in relation to implementation of the CCS option. Fig. 15–3 shows the amount of stored carbon in gigatonnes calculated by MIND in relation to the learning rate for renewable electricity generation options and the initial costs for new generation capacity for renewables.[8] A low learning rate and/or high initial costs characterise a development trajectory for renewables that takes effect relatively late compared with CCS. Therefore in this case the amount of sequestrated CO_2 increases significantly. An area of particularly high sensitivity is found for comparatively low initial costs for renewables with simultaneously high learning rates.

Alongside learning rates and initial investment costs, the level of **floor costs** also determines the rate of techno-

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5   The MIND model is an integrated assessment model that couples a model of the global economy based on the concept of endogenous growth (and focused on the energy sector) with a climate model. It calculates timelines of investment and consumption decisions which combine a prescribed limitation of the rise in global mean temperature with maximising the social good on the basis of per capita consumption over the whole period (Bauer 2005, Edenhofer et al. 2005).

6   The figures for the sequestrated amount are given in the graphics in gigatonnes of carbon (GtC). The corresponding amount of CO_2 is greater by a factor of $44/12 \approx 3.67$.

7   On the basis of technological solutions whose fundamental applicability has already been demonstrated, the IPCC concludes that it is almost certain that up to 200 Gt CO_2 could be sequestered (at least 99 % probability) and probable that up to 2,000 Gt CO_2 could be sequestered (66–90 % probability) (IPCC 2005). For a detailed discussion of storage potential see chapter 7.

8   In this model costs are given as specific investment costs (€/kWel), but this value allows no direct conclusions to be made about the level of electricity generating costs (Ct/kWh).
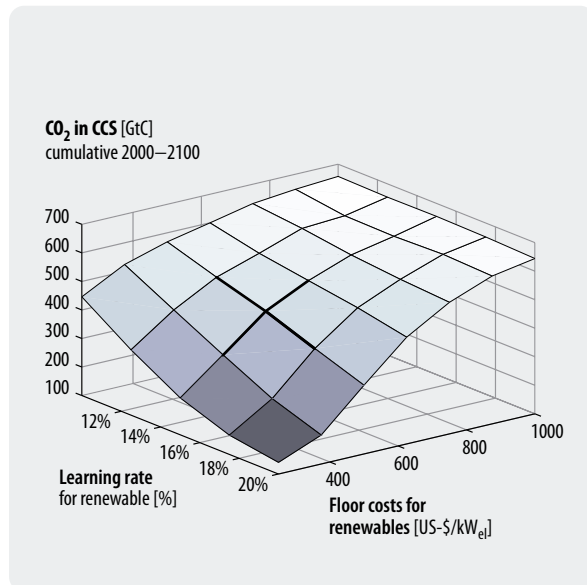
Fig. 15-4: Optimum cumulative amount of sequestered carbon between 2000 and 2100 in relation to learning rate and floor costs
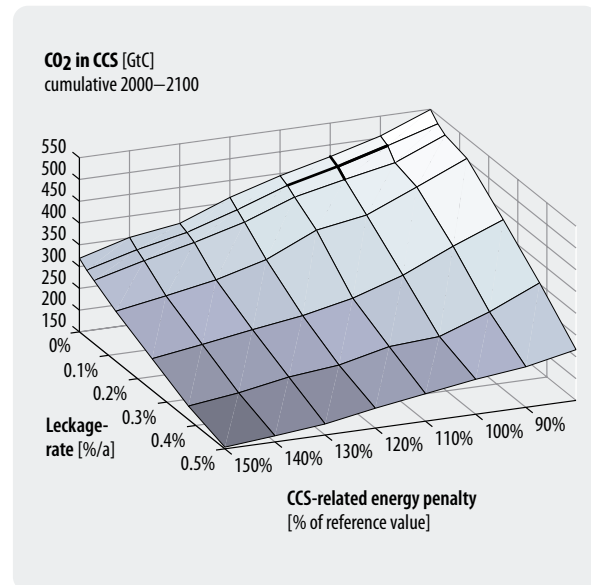
Fig. 15-5: Optimum cumulative amount of sequestered carbon between 2000 and 2100 in relation to leakage rate and the energy penalty on the optimum amount of sequestrated CO_2

logical progress.[9] The higher the floor costs for renewables, the more slowly the capacity of the renewables can be expanded, assuming a given volume of investment, and consequentially the greater the amount of sequestrated CO_2 for a given climate protection goal (see Fig. 15-4). With very high floor costs the potential for technological progress also falls. The contribution from CCS then ceases to be sensitive to the learning rate.

CCS can be applied economically efficiently only on condition that the forecast leakage rates of well under 1 % per annum are actually adhered to.[10] According to current estimates this condition is fulfillable. The IPCC's hypothesis is that for the global proven potential of 2,000 Gt CO_2 more than 99 % of the sequestrated CO_2 would "probably" remain in the sink after a storage period of 1,000 years (IPCC 2005).[11] Where CO_2 is stored in closed geological formations it should take several thousand years for significant amounts of CO_2 to come to the surface through diffusion processes, but measurable leaks could occur sooner too, for example through unexpected faults.[12] The sensitivity study presented here makes no claims as to the probability of leakage rates, but merely shows how the assumed leakage rates influence the overall result.

Fig. 15-5 documents how the overall amount of injected CO_2 depends on the leakage rate and the energy penalty.[13] It describes the effect whereby, because of the energy required for the CCS technology itself, the technical efficiency of the power station falls when additional components for capturing (and sequestrating) CO_2 are added. The smaller the amount of CO_2 escaping from the geological formations and the more favourable the energy penalty, the more cost-effective and efficient is the application of CCS. The figure also shows that the leakage rate definitely has a noticeable influence on the use of CCS, especially in connection with a low energy penalty.

For the cost-cutting potential the result is the following. If we assume an average learning rate of 15 % for renewables and an annual leakage rate of 0.05 % of the stored CO_2, it turns out that limiting atmospheric CO_2 to below 450 ppm would involve a relative loss of only 0.6 % of global GDP compared with the business-as-usual option, and the capture and sequestration of approx. 456 GtC.

With increasing use the relative costs of CCS sink. In comparison to versions with lower learning rates considerably more CO_2 is stored. Increasing efficiency of the investments in CCS (caused by learning curve effects and a decreasing energy penalty) allows the cumulative amount of CCS to increase until the technical progress is exhausted and no significant further reductions in the economic costs of climate protection can be achieved.

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9 Floor costs are those costs that cannot be reduced through learning processes, for example specific material consumption.

10 With an annual leakage rate of 1 % only about 60 % of the stored quantity would remain in the sink after 50 years, while after 100 years about two thirds of the original stored quantity would have escaped.

11 According to the IPCC "probably" means a probability in the range 66–90 %.

12 As well as geological strata other sinks, such as the oceans, are also under discussion. But in the general discussion geological formations play the dominating role.

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13 The energy penalty is the additional energy required for the CCS technology. One hundred percent represents a default value, values < 100 represent a lower energy penalty, in other words a smaller loss of efficiency.

The **discount rate** also plays an important role in models for calculating climate protection strategies because it is decisive in determining the emission reduction goals. The higher the discount rate, the more is consumed in the present and the less invested, which means that more of the costs of climate protection are displaced into the future – and with them the emission reductions.

The level of the discount rate has considerable influence on the selection of avoidance options. With a high discount rate CCS plays a bigger role and at the same time greater use of renewables is delayed. The reason is that in this case the investment that must be made in renewables today – and thus the costs of restructuring the energy system – is postponed, because a high discount rate makes it more profitable in the future. The extended use of fossil fuels implied by this constellation can only be reconciled with climate protection targets if the use of CCS is expanded.

The introduction and promotion of renewables (and an increase in energy efficiency, which is not explicitly addressed in this study) remain unavoidable, especially if we assume that geological storage potential is limited and relevant leakage rates will occur. Investment in CCS could ease the transition to an emissions-free energy supply if the current speed of market development and cost reduction for renewables were to slow considerably and at the same time CCS technologies were to realise their cost-cutting potential very quickly. If both options are roughly equally successful economically, the relative demand will depend largely on the level of successful efficiency increases.

15.2.2 The Costs of Exploration and Extraction of Fossil Fuels

The role of the availability of fossil resources has to date played little part in calculations of the opportunity costs of climate protection in general and CCS in particular. The more fossil resources (coal, oil, natural gas) are available when an effective climate protection policy is introduced, the greater the opportunity costs of climate protection. This is because climate protection devalues the reserves of fossil resources and the whole stock of capital that is tied up in the fossil resource sector. With climate protection a large part of the reserves that were economically usable in the business-as-usual scenario would no longer be viable.

The faster technical progress in the exploration and extraction sector opens up new fossil resources, the stronger this effect becomes. If technical progress in the exploration and extraction sector is very dynamic CCS will find relatively broad application in order to allow the fossil resources to be used even under the conditions of relatively ambitious climate protection. The following scenario analyses investigate the effects of uncertainties about the current status of progress in exploration and extraction and the associated costs – the detail of which is currently controversial.
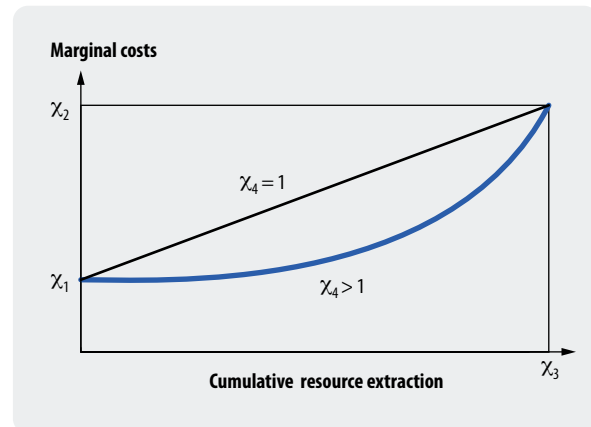
Fig. 15-6: Rogner curve, showing in a simplified form the marginal costs of resource extraction in relation to cumulative resource extraction (based on Nordhaus and Boyer 2000)

But first we have to clarify what we mean by resources: "resources" are the physical totality of existing raw materials, while "reserves" are the deposits that can be exploited with today's technology at today's prices (Rogner 1997). If the technical possibilities and associated costs change, resources become reserves. Rising prices lead to increasing efforts to open up new resources and turn them into exploitable reserves.

The Rogner curve abandons the distinction between resources and reserves. It describes the extraction costs in relation to the quantity extracted to date. The trajectory of the cost increase depends on three aspects. Firstly, the extraction costs themselves, secondly the possibilities of substitution between the different fossil fuels and thirdly technical progress (Rogner 1997, Leggett 2005).

The Rogner curve can be understood as follows: opening up new resources counteracts the exhaustion of the existing ones, and the more units of a resource have already been extracted the more exhaustion leads to increasing extraction costs. In the ideal case the cost increase is constant (see Fig. 15-6, Rogner 1997). Uncertainties about the shape of the curve are described by parameters: χ_3 represents the resource base; χ_4 describes whether the cost increase takes effect early (small value) or only begins later (high value).[14]

Fig. 15-7 shows that the costs of climate protection increase, if more fossil resources become available, for example through intensified exploration efforts. Fig. 15-7 shows the costs of climate protection in relation to the available resource base χ_3 and the parameter

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14 For example if $\chi_4=1$ is selected the Rogner curve is a linear function, i.e. a straight line, while $\chi_4=2$ produces a quadratic Rogner curve. In the quadratic case the costs remain lower than in the linear case until quantity χ_3 has been extracted. Beyond that point the quadratic function describes higher costs. This effect is amplified further by selecting larger values for χ_4 (e.g. $\chi_4= 3$, cubic).
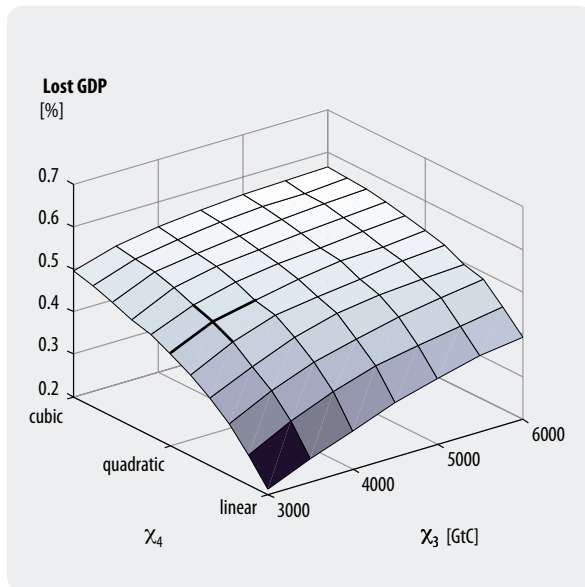
Fig. 15-7: Cost of climate protection as percentage loss of global GDP in relation to the resource base (χ_3) and the parameter characterising the development of extraction costs (χ_4)

Fig. 15-8: Marginal costs of resource extraction in relation to cumulative resource extraction for the scenarios described in the text

for χ_4. Even if the costs of extraction only increase relatively late, the economic costs of CCS also increase for the whole period. The reason is that if extraction costs rise late (in the business-as-usual case) relatively large quantities of cheap fossil fuels would be available and would be used – which would then no longer be possible in the climate protection case. This would result in higher opportunity costs for climate protection. Assuming strong technical progress in the extraction sector the gap between the business-as-usual and climate protection cases in terms of the emissions to be reduced is relatively large due to the extensive use of fossil resources. Consequently CCS is used particularly intensively in order to achieve the climate target at all (Fig. 15-9).

The resource base for fossil fuels is currently estimated at 3,500 to 6,500 GtC (WEC 2000). If all of that were to be converted into CO_2 it would be impossible to limit climate change. The limiting factor for use of fossil energy would be the climate system rather than the fossil resources. Because the extraction costs for coal will rise more slowly than those for oil, a partial substitution of oil by coal is to be expected. For this reason too, the importance of CCS will probably increase.

In economic terms, the debate about peak oil scenarios is primarily about the costs of replacing oil by coal and gas rather than the question of when extraction peaks. Because the uncertainties are enormous here, four additional scenarios were calculated using different assumptions about the shape of the Rogner curve

(see Figs. 15-8 and 15-9).[15] The three peak oil scenarios (Peak Oil (a) and (b), Tar Sands) assume that coal and gas can replace oil only at enormous cost. In the fourth scenario, which also enjoys a claim to plausibility and is used by Nordhaus as the basis of his forecasts (Nordhaus and Boyer 2000), the long-term costs of substitution are relatively low. The process of analysing the different Rogner curves described here – especially using bottom-up models – can be regarded as an important research task because it is on this that the economic benefit of CCS in the climate protection context will decisively depend.

If the costs of fossil extraction now fall through learning curve effects, the share of available reserves in the resource base expands. The lower the costs of exploration and extraction, the more CO_2 will be sequestrated over the course of the next century (Fig. 15-9). However, these learning curve effects and falling costs do not mean falling prices for fossil fuels, but rather a flattening out of the general price rise (in Fig. 15-8 this can be pictured as a transition to a curve with a less steep gradient).

The results of the simulations show that technical progress in exploration and extraction of fossil resources makes climate protection more expensive (cf. Fig. 15-7). Paradoxically, rising prices for fossil fuels do not lead the energy markets to invest exclusively in renewables. Instead, rising prices offer an incentive to invest in the exploration and extraction of high-emis-

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15 Nordhaus and Boyer (2000): χ_3 = 6,000 GtC, χ_4 = 4. Edenhofer et al. (2006): χ_3 = 3,000 GtC, χ_4 = 2. Peak Oil (a) :χ_3 = 500 GtC, χ_4 = 2. Peak Oil (b): χ_3 = 1,000 GtC, χ_4 = 2. Tar Sands: χ_3 = 500 GtC, χ_4 = 3. In all scenarios: χ_1 = 113 US\$/tC and χ_2 = 700 US\$/tC.
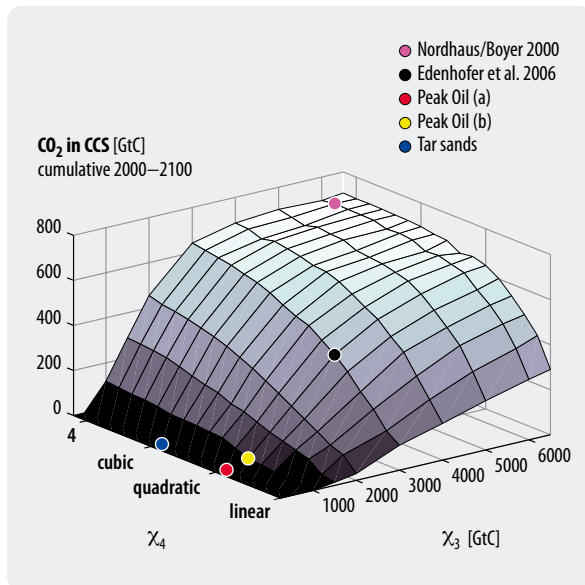
Fig. 15–9: Optimum cumulative quantity of sequestered carbon between 2000 and 2100 in relation to the resource base (χ_3) and the parameter characterising the development of extraction costs (χ_4). Coloured dots indicate the scenarios discussed in the text. Peak Oil (a) and (b) and Tar Sands are peak oil scenarios with relatively small differences in their parameters. As the name suggests, the Tar Sands scenario assumes that tar sands will be mined (see below).

Fig. 15-10: Optimum cumulative quantity of sequestered carbon between 2000 and 2100 in relation to the time when the technology becomes available

sion fossil resources that had previously been largely ignored ("unconventional resources").[16] This effect can be observed at present: the high oil price has stimulated the extraction of tar sands and oil shales in Alberta, where they can be mined economically on a large scale at a price of approx. $80 per barrel (Economist 2006). So high oil and gas prices greatly increase the economic value of the fossil resources to the extent to which new deposits are discovered. The ensuing technical progress causes fossil fuels to continue to be competitive until their costs catch up with those of renewables.

Without climate protection policy, i.e. without internalising the social costs of a destabilised climate (and in particular with a resource-led increase in the focus on coal) the necessary restructuring of energy systems would come much too late to be able to meet relevant climate protection goals.

However, in recent years a partial rethinking on the part of the energy business has been observed. As well as stimulating increased efforts to exploit unconventional resources, higher oil and gas prices have also given a clear boost to technologies for using renewables (Leggett 2005). The rising costs of climate protection caused

by technical progress in exploration and extraction of fossil resources can be moderated if CCS is introduced on a relatively large scale. Time is working for CCS: the longer it takes to agree a treaty regime for international climate protection, and the longer fossil fuels are used on a massive scale and can in some way benefit from learning effects, the more probable it becomes that CCS will be introduced on a large scale.

If a structural restriction on the extractability of conventional fossil fuels – and thus a lasting price rise – occurs within the coming years or decades different substitution effects will occur. But these types of substitution over time and their overall outcome have not yet been sufficiently investigated. Overall the analysis shows clearly that the development over time of the use of different fuels is still subject to uncertainties. In the following section the effects of CCS becoming available at different times are examined.

15.2.3 Timeframes of CCS Availability

In the discussion about the benefits of CCS the time when it becomes available plays a central role. Some critics claim that if the CCS option does not become available on a large scale within the coming decade then it will not be an economic proposition. This argument deserves closer examination.

The simulations show that CCS can still be worth using even if its introduction is delayed by decades – although the cumulative quantity of CCS for the twenty-first century decreases considerable if it turns out that the technology will only become available after 2050 (Fig. 15-10). The discounted consumption losses caused by the costs of climate protection rise accordingly (Fig.

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16 There are, however, limiting factors for the use of unconventional resources. For example social acceptance, which in the case of tar sands in Canada and oil shales in the United States could be a decisive factor, because of the severe environmental impact. Other limits are set by the scale that can be achieved over time. Large-scale provision of fuels gained from unconventional sources takes years and cannot be increased in any order (Economist 2006).

Discounted consumption losses [%]

Fig. 15-11: Discounted consumption losses in percent caused by cost of climate protection, in relation to the time when the technology becomes available

CO₂ emissions [GtC/a]

Fig. 15-12: CO₂ emissions paths with different availability dates of CCS

15-11), because the cost reduction potential of CCS for climate protection is greatest in the next four decades. However, if the CCS option becomes available later this does not decisively alter either the cumulative amount of reduced emissions or the timeline of reductions (Fig. 15-12).

Fig. 15-11: Discounted consumption losses in percent The results can be explained as follows. If there is a delay in the introduction of CCS it is more worthwhile from today's perspective to force the promotion of renewables from the outset, because after 2050 the costs of extraction of fossil fuels will increase steeply, which makes large-scale use of CCS after 2050 less attractive. With the assumption that learning curves for renewables remain constant, the rising costs of fossil fuels cause the opportunity costs of climate protection to rise most strongly in the first four decades when the CCS option is not available.

Overall the contribution of CCS to the implementation of an ambitious climate policy consists in reducing the costs regardless of when it is introduced on a large scale. These cost reductions turn out differently depending on whether CCS is implemented sooner or later.

15.3 Requirements for an Institutional Framework for CCS

The introduction of a climate protection option is associated with far-reaching consequences of an institutional nature. The specific costs and risks for CCS must be noted, but also the possibility of integrating CCS as an additional climate protection option in a portfolio of existing policy instruments.

In the following, various aspects are identified that will have to be taken into consideration when drawing up a regulatory framework for CCS. The starting point here is the question of what consequences can be drawn from the results of the modelling in the previous section for the debate about whether the "cap and trade" system or a technology protocol should be the governing approach in climate protection agreements. Then we move on to examine crucial legal aspects of a regulatory framework for CCS, supplemented by an overview of examples of existing arrangements in the United States, Japan, the EU and Germany. Lastly, the international challenges are outlined for an institutional framework that would accommodate the economic analysis from section 15.2 and aim to integrate it appropriately in the international climate regime.

The work of developing a suitable institutional framework involves challenges on several levels:

- Time: The long timeframe for CCS demands particular attention; the consequences of leakages must be dealt with over much more than a few decades.

- Space: Local risks (for example for ecosystems near a sink) and global impacts (i.e. the possible risk to climate protection goals through leakages from sinks).

- Content: New concepts are required if CCS is to be integrated in the global climate protection regime. Local risks have to be covered by existing legal frameworks as well.

The implementation of an institutional framework depends on the approval of democratic sovereign bodies, so the public perception of CCS must not be neglected. Currently CCS is regarded with scepticism by the pub-

lic, especially in direct comparison with other climate protection options, but there is also a great information deficit (IPCC 2005), so it would seem advisable to improve the supply of information to the public and intensify public discussion of the CCS option.

15.3.1 The Basis for an Institutional Framework: "Cap and Trade" versus Technology Protocol

The modelling results point to a central dilemma of current climate protection policy. Renewables are the central option for creating a sustainable low-emission energy supply, while CCS is seen as an option for reducing the costs of the transition (see also Bauer 2005). In both cases, the cost-cutting potential is only realised if sufficient investment occurs. But this investment will not be made unless the prices for emission certificates rise and the certificate prices cannot rise unless further emissions agreements are achieved. Such agreements are being held up because the treaty states regard climate protection as being expensive, but costs cannot be reduced unless there is investment.

If the oil price also rises – even if only temporarily – this will divert investment to the resource extraction sector where it can increase the size of available reserves which in turn further increases the economic cost of climate protection.

These are the arguments that are behind the debate between the technology protocol idea and a "cap and trade" system. On the one side the proponents of technology protocols do not expect that multilateral agreements will come soon enough to allow low-emission energy technologies to be developed sufficiently quickly. But the development of these technologies is necessary if the costs of climate protection are to be kept within acceptable limits. On the other side the supporters of "cap and trade" approaches argue that unless emissions reductions are specified there is no incentive to introduce CCS and renewables on a large scale. So in the long term a technology protocol alone cannot guarantee effective climate protection.

A combination of technology protocol and "cap and trade" certainly could offer an opportunity to bring movement into the international climate negotiations. And through its cost-cutting potential CCS could contribute to the success of this approach. At the same time, targeted support for CCS technologies makes sense then because the greatest economic benefit will be gained if CCS is introduced in the coming decades. Therefore political support for pilot projects is of great importance – not only for CCS but also for renewables and efficiency increases. Section 15.3.6 takes a closer look at the importance of pilot projects.

15.3.2 Critical Legal Aspects

Consequences of the precautionary and polluter pays principles in environmental law

Environmental law is based on fundamental principles that can serve as a normative guide for regulating CCS. They are applied at the German, European and international levels – sometimes with differing formulations and emphases (Kloepfer 2004).[17] Among these, the precautionary principle, the polluter pays principle and the principle of public responsibility are the most relevant for CCS.

The precautionary principle requires legislators to take preventive action even against possible future dangers. In view of the long-term nature of CO_2 storage and the ensuing consequences any institutional framework will have to define suitable arrangements for dealing with future risks. Specifically, the legal framework for CCS must therefore be in a position to ensure responsibility and liability for future risks – especially leakage of CO_2 – over very long periods of time. By the time a problem is discovered in the storage formation the company responsible for sequestration there may no longer even exist. Incentives to shift legal and financial responsibility to future generations must be avoided, but suitable global frameworks for that do not yet exist (IPCC 2005).

In this connection the polluter pays principle is also relevant: the cost of environmental harm is always borne by the polluter. But if the polluter cannot be identified or if application of the principle would lead to serious economic disruption, the principle of public responsibility dictates that the public has to bear the costs. For possible harm resulting from sequestration, that means arrangements have to be avoided that shift responsibility for risks from CCS from the responsible companies to the state. But the state will bear an ultimate responsibility, especially in the event that the company no longer exists when harm occurs (see also WBGU 2006).

Defining an acceptable leakage rate

As well as the unavoidable slow leakage from CO_2 sinks, accidents while capturing, transporting and storing CO_2 can also cause the sudden release of larger quantities of CO_2. Because of the risk of grave local damage to ecosystems and human health, safety thresholds must not be exceeded. However, arrangements for this can be based on existing regulations for plant failure (IPCC 2005). Low leakage rates have a great effect in the long term and are acceptable only up to a particular maximum level because they counteract the global climate protection effect and possible emission reduction obligations. The associated problems and proposals for solutions are discussed in more detail in section 15.3.5.

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17 For European Union law see Art. 174, para. 2, item 2 of the EC Treaty, introduced by the Single European Act of 1986. This provision was explicitly included in German law by Art. 34 of the Unification Treaty of 1990.

Selection and approval of sinks

The selected sinks must simultaneously satisfy the criteria of safety against accidents, low long-term leakage and good cost efficiency. Companies will attempt to externalise the costs of selecting safe sinks while also passing the risk of leakage to third parties, such as the state. Following the polluter pays principle, the crucial point will be to create incentives for companies to find safe sinks and accept liability for possible leakage. Here the liability rules should at the same time promote technical progress in the direction of enhancing safety (see for example Perrings 1989). On the other hand, the principle of public responsibility requires suitable arrangements to be found for the eventuality that the operating company ceases to exist.

Supervision and monitoring of sinks

Sinks have to be supervised in order to monitor the amount of CO_2 stored and the rate of leakage and to impose penalties if necessary. Apart from the issue of whether it is even technically possible to measure leakage rates in ranges under 0.1 percent per year, for example, it is also necessary to define the period of time over which sinks are to be supervised.

There are proposals to give this task to private-sector companies for a period of about 30 years (Wilson 2004). Given that reliable CO_2 storage must in principle be guaranteed over millennia, the precautionary and polluter pays principles throw up the question of how long-term supervision of storage can be guaranteed, and by whom. The argument against the idea of giving sole responsibility to the public sector would be that this might distort competition to the disadvantage of other climate protection options (Dietrich and Bode 2005).

Attributing responsibility and liability

The issues of responsibility and liability that arise in connection with CCS can be divided into three areas:[18]

- Operational responsibility and liability in connection with the processes involved,

- In-situ liability for harm to human health or to local ecosystems caused by an accident,

- Responsibility for leakages in terms of the consequences for climate protection, also in order to generate incentives even at the planning and sequestration stages for ensuring the best possible storage conditions.

Ways of dealing with the first two areas can be derived from existing arrangements (for example safety in manufacturing, transporting and storing chemical prod-

ucts), although it is difficult to achieve agreement with respect to balancing the polluter pays and public responsibility principles and thus the distribution of risks between operating companies and the state. But responsibility for consequences for the climate cannot easily be dealt with within the scope of existing arrangements. The potentially long interval between sequestration and the harm it could cause makes it more difficult to apply existing liability rules. Additionally, the violation of individual legal interests as a result of the negative effect on climate caused by the leakage is difficult to prove (Dietrich and Bode 2005).

A further challenge for regulations dealing with responsibility is the issue of sinks that extend across national borders. Sequestered CO_2 can cross borders intentionally or – via leakage between geological formations – unintentionally (IPCC 2005). This is another reason why CCS must be subject to an international regulatory system. The controversial proposal to inject CO_2 into international waters complicates the problem even further. International conventions, in particular the London Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter of 1972, must be taken into account here as considerable legal obstacles (IPCC 2005).

15.3.3 Statutory Regulations in Selected States and the EU

Here we briefly summarise the existing legal situation in the European Union and Germany, in Japan and the United States to the extent that is relevant for CCS (cf. description in Flachsland 2005, 165 ff. and references there).[19] For the legal position it is relevant that sequestration of CO_2 – apart from the first CCS pilot projects – has to date always been conducted as part of an industrial process rather than for reasons of climate protection. For example in the oil industry CO_2 can be injected into a deposit to improve the recovery rate (enhanced oil recovery). For this reason – and because the quantities and storage periods involved with CCS are many times greater and longer than for operations to date – the current legal situation cannot be applied to future CCS projects.[20] So the legal position is still rather unclear and requires further investigation.

European Union and Germany

CCS would probably be regulated at the level of European law, because the EU holds partial responsibility for the community's environmental policy (according to Art. 174 of the EC Treaty), and also because of the possibility of transfrontier storage. Directive 96/61/EC

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18 For a more detailed discussion see de Figueiredo et al. (2006).

19 As well as the legal situation, the treatment of CCS in the scope of EU emissions trading must also be considered. For more detail, please refer to the literature (Dietrich and Bode 2005).

20 The amounts of CO_2 sequestrated in current CCS pilot projects (e.g. Weyburn, Sleipner, Ketzin) are many times smaller than would be the case with large-scale CCS projects pursuing ambitious climate protection goals.

lists industrial facilities – principally large-scale point sources of emissions – that require official permits. Although the facilities required for CCS are not to be found in this list – and there would be certain problems involved in including them – it at least becomes clear that facilities of this kind do in principle require official approval under EU law.

With respect to possible contamination or pollution of drinking water, the European Water Framework Directive specifies that freshwater reservoirs must not be contaminated in any way. Here too the question arises how risks associated with CCS can be integrated in this framework.

In current EU law captured CO_2 is defined as waste (as of December 2007). Currently underground storage of substances that are subject to physical, chemical or biological change after disposal is explicitly forbidden in the EU.21 However, the European Commission has announced that it intends to exclude CO_2 captured forCCS purposes from waste law. In January 2008 it published a proposal for a "directive of the european parliament and of the council on the geological storage of carbon dioxide". Its main scope is the regulation of CO_2 storage and the removal of barriers in existing legislation to CO_2 storage.

In addition to EU environmental law, national legislation must also be considered. In Germany this includes the Federal Mining Act (Bundesberggesetz) on underground storage of natural gases, the Closed Substance Cycle and Waste Management Act (Kreislaufwirtschafts- und Abfallgesetz), the Federal Water Act (Wasserhaushaltsgesetz) and the Federal Immission Control Act (Bundesimmissionsschutzgesetz).

All the listed laws include points where official permits would be required for CCS, so integrating CCS in existing regulatory frameworks would bring with it a number of difficulties. Consequently, CCS would probably be regulated in a specially designed framework of its own.

Japan

Japan plays a special role among the states leading the development of CCS, because the geographical and geological situation there means that storage would probably take place largely in the oceans rather than in geological formations.[22]

One special problem that arises here is the possibility of harming the "biological pump" of the oceans, where phytoplankton in surface waters bind atmospheric CO_2 and subsequently transport it to greater depths. If injected CO_2 returns to the surface it will reduce the pH value there, which would in turn reduce the performance of the pump. Furthermore, the ecological consequences of increased CO_2 concentrations in marine systems are largely unknown (see also section 11.3).

United States

In the United States geological formations have been used to sequester waste since the 1930s. After problems arose, especially with contamination of drinking water, the federal authority, the Environmental Protection Agency (EPA) in the 1980s instituted the UIC programme (Underground Injection Control). Thirty-four states have expanded the scope of this federal regulatory programme by adding regulations of their own.

The central element of UIC is its classification of boreholes used for sequestration into different categories. The first category covers the storage of household and hazardous waste in sealed geological formations that are separated from drinking water reservoirs by impermeable strata. They must satisfy the strictest safety standards and they cause the highest regulatory costs. The second category comprises the extraction and sequestration of substances during energy production (enhanced oil recovery). Comparable standards apply here too, although authorisation is handled less strictly. The other regulatory categories are unlikely to be relevant for regular CCS operations.

The regulations for pipeline construction basically stipulate that a right of way (ROW) is required. In deciding whether to grant a ROW, the Federal Energy Regulatory Commission (FERC) considers possible ecological impact and the existing public interest in the respective pipeline.

15.3.4 CCS in the Kyoto Protocol

Multilateral agreements represent the main thrust of global regulation efforts. The most relevant for CCS are the United Nations Framework Convention on Climate Change and its expression in the Kyoto Protocol, where flexible market mechanisms (certificate trading, joint implementation and clean development mechanism) play a key role for achieving the agreed emissions reductions cost-efficiently. CCS could be included in the flexible mechanisms as an emission-reducing measure.

CCS is not yet mentioned explicitly in the United Nations Framework Convention on Climate Change (UNFCCC). But the revised version of the "IPCC 2006 Guidelines on National Greenhouse Gas Emission Inventories" (corrected April 2007) for the first time provides guidelines for defining and measuring emissions sequestered through CCS (and their possible re-

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21 In the case of CO_2 that could mean chemical reactions with other substances or phase changes caused by expected underground migration processes.

22 However, the London Convention (mentioned in section 15.3.2) presents legal obstacles to implementation. Furthermore, the lack of public acceptance could hamper or completely prevent the realisation of marine CO_2 storage (see also the analysis of actors in chapter 3).

emission).[23] CCS is categorised as a set of technologies that allows emissions savings that are to be included in the national greenhouse gas inventories (Eggleston 2006).

The possibility of stored CO_2 migrating across state frontiers is a challenge, especially when a flow of CO_2 occurs from an Annex B country to a non-Annex B country (IPCC 2005). In the aforementioned regulatory frameworks leakage from sinks is assigned to the emissions inventory of the state on whose territory sequestration was carried out (Eggleston 2006). Finally, technical uncertainties involved in the monitoring of sinks and the measurement of leakage rates still result in uncertainties in the calculation of emission reductions (IPCC 2005). The guidelines for this provide for a combination of measurement and modelling approaches to be specified on a case-by-case basis (Eggleston 2006).

In view of the uncertainties about leakage rates, the WGBU calls for sequestered CO_2 not to be counted in full as avoided emissions. Alongside regulatory agreements such as a fixed deduction from the emissions volume the WGBU proposes market-based liability mechanisms, in particular the instrument of Carbon Sequestration Bonds, which are described in the next section (WBGU 2006).

If CCS is included as an avoidance measure in the Kyoto Protocol, CCS projects could also be handled via flexible instruments such as the Clean Development Mechanism (CDM) and in principle also Joint Implementation (JI). The UNFCCC treaty states conference in November 2006 decided to instigate an SBSTA process with the aim of reaching a decision at the 2008 treaty states conference (CoP 14).[24] Beforehand there was also discussion in the responsible bodies about the economic incentive effect of the flexible instruments in connection with CCS and the question of how long-term liability could be shared by the participating states (Wuppertal Institut 2006).[25]

15.3.5 Carbon Sequestration Bonds: A Proposal for Regulating Responsibility for CO_2 Storage

The central question in regulating CCS is to systematically include critical uncertainty parameters in the institutional framework and to create incentives that would encourage the CCS and renewables options to develop in a complementary way (see section 15.2.1). In this context the specific case with CCS is that it is *not* a backstop option that can be applied as a permanent

long-term solution to the climate problem, because the storage capacities and fossil resources are limited. Instead, this option is a set of technologies that could fulfil an important bridging function for the transition to an energy system characterised by renewables and energy efficiency. The later or more slowly the cost-cutting potential of renewables can be mobilised, the more important this function would potentially be.

The long-term stability of sinks (i.e. the leakage rate) represents an uncertainty factor that demands risk management of its own over and above the emissions trading of the Kyoto Protocol. The instrument of **Carbon Sequestration Bonds** (CSBs) is the only proposal to date for this (the following description follows Edenhofer et al. 2004, see also WBGU 2006). It presupposes a modified system of CO_2 emissions trading and is to that extent compatible with the market approach of the existing Kyoto Protocol. The CSB instrument attempts to solve the key problems of how the use of sinks with low leakage rates can be encouraged and how residual leakage and its climate impact can be dealt with.

In the following we describe the two versions and their respective impact on safety of storage. They are not mutually exclusive, and indeed could be combined. In both cases politically supported CCS pilot projects could improve the effectiveness of the CSB system and thus of global regulation. By improving the reliability of information about CCS, pilot projects would resolve market distortions that could otherwise reduce the chances of success of the CSB instrument.

Version 1: CSB as an instrument supplementing emission rights

The maximum level of harm caused by leakage of stored CO_2 is easy to calculate in financial terms. It is the amount of CO_2 that escapes from the geological formation multiplied by the certificate price of the emissions at the time leakage occurs. If CO_2 escapes from a geological formation, the atmosphere is used as the "sink" for the CO_2, but no price has been paid for this use. So in the event of leakage the company would have to purchase a certificate for this use of the atmosphere.

Because the volume of certificates doesn't rise, their price increases. This signals to investors, consumers and businesses that utilisation rights for the atmosphere are scarcer than they originally assumed.

However, with this solution alone it will not be possible to prevent companies from acting speculatively when they store CO_2 in geological formations. The management of a company could speculate that the CO_2 will not escape until the company has ceased to exist, that the certificate price will fall in the long term or simply that a different management team will have to cope with the problem. If the timeframe of investors and managers is shorter than the suspected timeframe of CO_2 leakage and the willingness to take risks is high, storage in geological formations with less long-term stability can represent a business opportunity for investors to pass the

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risk on to future generations. So it is crucial to create an incentive in advance for companies to store CO_2 in the safest possible formations in their own interests.

The introduction of Carbon Sequestration Bonds opens up the possibility of rational risk management. Any business that wished to store CO_2 in geological formations would have to purchase a bond corresponding to the value of the stored quantity of CO_2. From the company's point of view, this bond is an asset that appears on the assets side on its balance sheet. The company guarantees for the term of the bond that the CO_2 will remain in the geological formation. If this actually happens the bond will be repaid to the company with interest (at the level of a long-term security). But the bond is also depreciated every three years by an as yet unspecified environmental agency, unless the company can demonstrate beyond doubt that the CO_2 has remained in the geological formation. If CO_2 escapes, the bond will be partially devalued and the company is forced to partially write off its claim against the environmental agency.

The sum that passes to the environmental agency can be used to subsidise renewables. This earmarking is designed to keep the transition to a climate-friendly energy system as short as possible. Subsidisation can also be understood as compensation for the competitive disadvantage suffered by renewables. But if stored CO_2 escapes from the geological formations in the intervening period, valuable time that would have been needed for a cost-effective restructuring of the energy system will have been wasted. As such, the bond represents a kind of insurance premium against risky and insecure CO_2 reduction activities.

Carbon Sequestration Bonds must be tradable on markets. Then a company can sell its bonds to obtain liquid funds. But companies will only be able to sell their bonds if they are able to offer buyers a better rate of interest than a security without risks. How high this risk premium is will depend on how great buyers perceive the risks to be that the bond will be devalued. So the company will only be able to achieve a high price for its bonds if it can convince buyers that the sink is safe.

The whole sector therefore has an incentive not to undermine confidence in the bonds. The threat of devaluation turns the safety standard of the geological formation into a tradable commodity, because companies then have an incentive to develop powerful monitoring techniques to demonstrate that the CO_2 has remained in the geological formation.[26] The better the proof the greater the value of the bonds. Because CSBs are tradable, investors can express their confidence in CCS by buying bonds. The greater public confidence is, the higher the price. Moreover, this would give the public the opportunity to participate via investment decisions in the general decision on whether or not to implement CCS.

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26 This proof would have to be verified by an independent body.

Version 2: CSBs as special emission rights

In the second version CSBs are issued to ensure that a maximum emissions limit is observed. Here the CSB is no longer a separate instrument, but is fully integrated in the certificate trading system. So preconditions would be the implementation of such a trading system and the definition of a corresponding upper limit for emissions.

As in the first version, companies involved in CCS are required to purchase a certain number of bonds, again before sequestration. A bond represents an asset that can be traded immediately on the markets. But the purchaser of the bond then himself bears the risk that this bond will lose value if later emissions are subsequently charged to it. Only then would the bond have mutated into an emissions right. But the bond should not contain an emission right until it has been possible to demonstrate clearly what proportion of the CO_2 can be stored permanently.

After a certain latency period an independent environmental agency will verify how high the proportion of permanently stored CO_2 actually is. If a company can prove that the CO_2 is stored safely it is free to sell the bonds. This ensures that the emissions limit is not exceeded, and furthermore ensures that it is profitable for companies to store CO_2 as securely as possible.

In comparison with the first version, the security of storage is given a higher priority. A higher than expected level of leakage would not only cause a monetary devaluation of the bonds, but also the loss of real emission rights.

15.3.6 The Role of Pilot Projects: Levelling the Playing Field

Successful control of leakage risks through CSB is subject to two processes of market distortion: a) liquidity restrictions, b) social herd effects and time inconsistencies. Pilot projects initiated by the state and publicly funded could avoid these processes (Held et al. 2006).

Liquidity restrictions

Both versions implicitly presuppose smoothly functioning financial markets. But in reality liquidity problems can arise: Banks could overprice credit, and potential purchasers of CSBs could offer prices that were too low if they falsely overestimated the risks of different forms of storage because the financial markets lacked information about the future leakage rates of the alternatives. In other words there is an asymmetrical information structure. Pilot projects could provide the financial markets with the required information. Then the financial markets would be in a position to promote the further refinement of CCS efficiently and without further state control mechanisms.

Social herd effects and time-inconsistency

When CSBs are transferred, expectations about risk are exchanged. Where there is great uncertainty about future leakage rates market participants might tend to copy the buying behaviour of other participants rather than making risk assessments of their own. At the beginning the risk might be underestimated (because leakage is more likely to be a problem in the distant future). If it turns out later that the confidence in CCS was too great, the prices for CSBs will sink. This forces other sectors to reduce their emissions more strongly or might even persuade the state to relax the upper limit for emissions. Conversely, in the long term overestimation of risk may discourage others from implementing potential emission reductions. The market horizon for CSB is consequently too short to allow a rational estimation of the risks. In this situation the state has to promote pilot projects to rectify the time-inconsistency by signalling to the market that it is pursuing a long-term interest in maintaining its emissions limit and having CCS with low leakage rates. At the international level this strengthens the confidence of other states that climate protection obligations will be observed.

The ultimate responsibility of the state arising from the principle of public responsibility that was underlined earlier as one of the crucial legal aspects (see section 15.3.2) also means that the state should emphasise its lasting responsibility for successful climate protection at an early stage by initiating lighthouse projects. In this sense ultimate responsibility would not be a matter only for the distant future.

Altogether Carbon Sequestration Bonds represent an innovative instrument to minimise the risk of leakage endangering climate protection goals while at the same time achieving a plausible distribution of responsibility between companies, investors and the state (WBGU 2006). With respect to the increasing involvement of re-insurers and "green funds" in climate protection, the introduction of a market instrument for regulating liability and safety could prove to be a sensible choice.

15.3.7 CCS in the Kyoto Architecture after 2012: A Possible Strategy for the EU

The challenge for a climate policy for the period after 2012 is to set the right price incentives for investment in emission-reducing technologies by means of effective international agreements (see sections 15.2.2 and 15.3.1). The European Union has set itself the climate protection goal of restricting the rise in global mean temperature by 2100 to a maximum of 2°C. This goal cannot be achieved by Europe acting alone, even though Europe's emissions goals are much more ambitious than the commitments made by other coun-

tries.[27] But the question is whether these goals signal credibly to the other main emitters that the EU is actually pursuing – and will implement – a policy that will both meet the agreed European reduction targets and also offer an international incentive for the other main emitters to aim for ambitious emissions targets themselves.

Convincing incentive systems are required to prevent countries from becoming successful "free riders" in climate protection. This will be all the more the case the quicker the involved parties learn that climate protection is associated with relatively modest costs and might even produce an additional dividend through growth potential (triggered for example by exports of innovative technology).

Currently one of the greatest challenges in international climate policy is persuading states that currently do not make such commitments – either because they are sceptical about the Kyoto regime (e.g. the United States) or because as newly industrialising or developing countries they are not covered by the firm obligations of Annex B (e.g. China) – to agree to adopt and observe emissions reductions. The introduction of CCS as an instrument could improve the chances of this. At the same time, from the EU's perspective the chances would improve of achieving its own ambitious climate protection goals. The idea that the CCS option would improve the willingness to adopt emission reductions can be backed up as follows for the cases of the United States and China.

The US Department of Energy (DoE) regards CCS as the central climate protection element for pursuing what the US-American administration regards as ambitious climate protection goals (e.g. stabilisation at today's level). And CCS is also an important issue in the Asia Pacific Partnership.

Over the coming decades China will undertake a great expansion of its power station capacity. The number of coal-fired power stations is expected to triple by 2030 (IEA 2002). So a potential market for CCS is already emerging today. The current Kyoto Protocol signatories could now grant countries like China and India generous emission rights that largely correspond with their business-as-usual emissions trend. At the same time an international fund could buy up these emission rights and take them out of circulation at least until the price of CO_2 rises to a point where CCS becomes profitable (von Weizsäcker 2004).

However it must be feared that the price of taking certificates out of circulation would be high. Europe would have to take on a disproportionate share of funding for climate protection. Europe can only reduce this funding burden if it succeeds at the same time in launching a credible technology policy that has the goal of bring-

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27 The EU aims to reduce CO_2 emissions by at least 20 % by 2020 (under certain conditions by 30 %) and by 60–80 % by 2050 (compared with 1990).

ing CCS technologies – and also renewable energy and efficiency technologies – quickly to the point where they are ready for large-scale commercial application. Europe could then hope to export CCS technologies. And the costs of buying up the certificates might possibly then be redeemed.[28]

The potential of the CCS option for globalising the market in emission certificates and thus enabling fast emission reductions should, however, not be overestimated. CCS can act as a bridge between today's energy system and a future energy system whose contours are only just becoming apparent. Most energy analyses show that renewables, alongside efficiency increases, will play a decisive role in the energy mix of the future. But they will be part of a portfolio of technologies where – especially from the global perspective – CCS could be able to make a decisive contribution to lowering costs and thus act as an incentive in international climate negotiations

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28 In terms of game theory, purchasing certificates and taking them out of circulation represents a side-payment.

Appendix

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A.1 Physical Properties of CO₂

Carbon dioxide (CO_2) is a colourless, odourless, tasteless gas, which is not flammable and – at the normal atmospheric concentration of approx. 0.04 vol.% – not toxic. With a specific gravity density of 1.85 kg/m³ (at 15 °C and 1 bar) it is about 1.5 times heavier than air and consequently accumulates in low areas when present at high concentrations. The highest permissible workplace concentration is 0.5 % or 5,000 ppm (parts per million). Because carbon dioxide displaces atmospheric oxygen, breathing air with concentrations greater than 7–8 % will lead to death by suffocation within 30 to 60 minutes.

As the phase diagram shows (Fig. A–1), CO_2 is a gas (g) under normal conditions (1.0 bar/15 °C) and freezes at a temperature of –78,5 °C (Table A-1). Frozen CO_2 is referred to as dry ice. Below 5.8 bar heating causes it to pass directly from the solid state (s) to the gaseous state (sublimation). The liquid phase (l) exists only above the triple point (TP) of 5.8 bar and –57 °C. The triple point is the point where all three phases coexist in equilibrium. So at ambient temperatures CO_2 can be compressed for example to 100 bar for transport purposes. In the liquid state the density increases (e.g. to 824 kg/m³ at 15 °C and 51 bar), meaning that in the liquid state the volume to be dealt with is much smaller than in the gaseous state. In the supercritical range (supercr.) above the critical point (CP) of 74 bar and 31 °C CO_2 occurs in a uniform phase with a constant density (464 kg/m³).

A.2 CO₂ Capture Methods (to Chapter 5)

Several fundamentally different methods are available for decarbonising combustible gases and flue gases. In the following we describe the methods and their characteristic features and assess their suitability for possible use in CO_2 sequestration systems.

Table A–1: Chemical and thermodynamic properties of carbon dioxide (CO_2)

Molecular weight		44.01	kg/kmol
Relative density of gas (air = 1)		1.53	–
Density of gas		1.85	kg/m³
Density of liquid*)	(–50°C/6.84 bar)	1,156	kg/m³
	(0°C / 34.86 bar)	928.8	kg/m³
	(15°C / 50.85 bar)	823.8	kg/m³
	(31.06°C /73.84 bar)	463.7	kg/m³
Density of solid		≈ 1,550	kg/m³
Boiling/freezing point (at 1 bar)		–78.5	°C
Triple point		5.81	bar
		–56.6	°C
Critical point		73.84	bar
		31.06	°C
*) Saturated			
Source: Dubbel (1990), Reiniger and Schubert (1999), Richter (2003)			

CO_2 capture methods can be placed in two basic categories:

- low-temperature methods and
- high-temperature methods.

With **low-temperature CO₂ capture methods** the gases generally have to be cooled and the water condensed out before the actual capture process begins. The low-temperature methods are:

- Chemical absorption in organic and inorganic solutions (alcohol-amine, alkali carbonate, etc.),
- Physical absorption in organic and inorganic solutions (methanol, propylene carbonate, water),
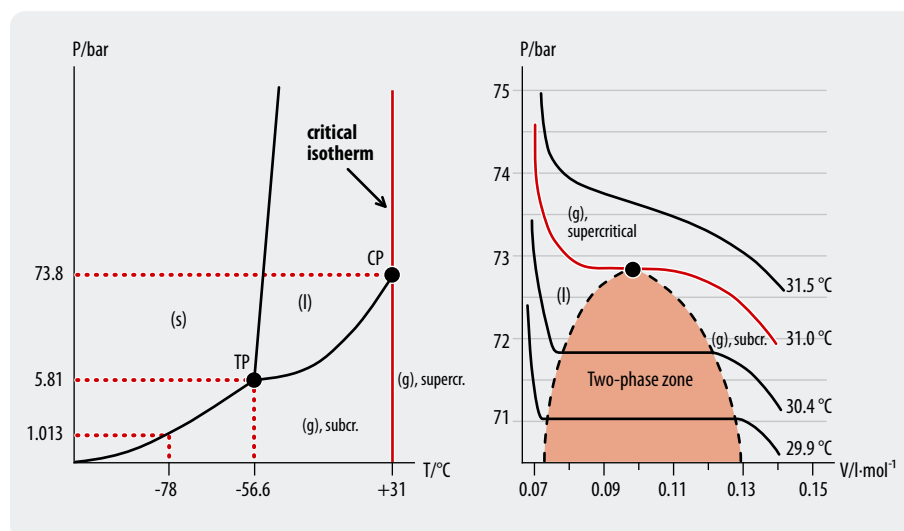
Fig. A–1:
Phase diagrams for carbon dioxide (p/T diagram on left, p/V diagram on right) (Reininger and Schubert 1999)

- Adsorption on solids (molecular sieves, activated carbon, etc.)
- Cryogenic distillation
- Membrane methods

Methods using **chemical and physical absorption** in solutions are current state of the art. Their suitability for CO_2 capture has been extensively demonstrated in gas scrubbing processes and enrichment. The most commonly used solutions are: ethanol amine (monoethanol, diethanol, triethanol amine), potassium carbonate, propylene carbonate, methanol (Rectisol), polyethylene glycol dimethyl ether (Selexol), and others. The most extensively tested process is capturing CO_2 from flue gases with monoethanolamine (MEA). For example, a CO_2 scrubber using a 20 % MEA solution has been operating since 1991 at a 300-MW CHP plant at Shady Point (Oklahoma). The daily production of 200 t of CO_2 is used in the food industry. Because amine is degraded by impurities such as dust, SO_2, NO and O_2, these must be removed from the flue gas before amine capture (Hendricks 1994).

Zeolite molecular sieves, activated carbon, aluminium oxide, silica gel, etc. can be used to capture CO_2 in **adsorption systems**. This technology is state of the art, but has not yet been used in the power station sector. The most commonly used process is pressure swing adsorption (PSA) with molecular sieves. One major drawback of molecular sieves is their affinity for water. Consequently any water must be condensed out before CO_2 capture.

CO_2 can be condensed out of gas mixtures through cooling at pressures as low as 4–5 bar (**cryogenic distillation**). Exxon has developed and industrially tested the controlled freezing zone process. The process is energy-intensive, especially when the CO_2 concentration is low. However, its advantage is that capture and compression for transport are accomplished in a single step. Today it is already used for conditioning biogas, but no experience has yet been gathered in the power station sector.

Membrane methods separate gases by making use of differences in their ability to pass through thin membranes. Efficient separation demands high selectivity, a large membrane surface and high permeability for the desired gas components. This method is currently under development and is not yet state of the art. Today membranes are used for gas separation on a small scale. They are especially efficient for separating gases with very different-sized molecules. Membrane separation of H_2 is today close to becoming competitive with other methods. By contrast, given the still very poor membrane selectivity, CO_2 capture from flue gases (largely N_2/CO_2 mixtures) is still a long way from commercial application, and no breakthrough can be expected in the next ten to fifteen years.

High-temperature methods for CO_2 capture are based on binding CO_2 to oxides or silicates, e.g. CaO. This method is still at the development stage. Its attraction is that CO_2 capture occurs at high temperatures, so (tar-laden) combustible gases from a gasification process can pass to a turbine without having to be cooled first. This allows efficiency to be increased in comparison with conventional CO_2 capture methods (e.g. scrubbing). It makes sense to implement these systems in IGCC power stations (coal-fired integrated gasification combined cycle) and gas-fired combined cycle power stations before combustion or directly in the combustion chamber. CO_2 bonding occurs at temperatures below the equilibrium temperature. The absorbent has to be regenerated after the absorption phase. The regeneration temperature is approx. 50–100 °C above the equilibrium temperature.

In the following section the aforementioned methods are briefly outlined and assessed. The theoretical specific energy requirement for the capture methods listed below relates to capture of CO_2 from flue gases (ZSW 1996). A distinction must be made between thermal and electrical energy. In practice the values are (sometimes) much higher so they should be treated with caution. The decisive factor is the achieved power station efficiency.

A.2.1 Chemical/Physical Absorption

Description of process: Chemical and physical absorption of CO_2 in solutions is an industrially tested capture method. In chemical absorption CO_2 is bonded chemically to organic or inorganic molecules. In physical absorption the amount of CO_2 the solvent will accept stands in an approximately linear relationship to the partial pressure of the CO_2. The levels of bonding energy involved are much weaker than with chemical absorption, which is advantageous when it comes to regeneration. After the CO_2 has been scrubbed from the raw gas the saturated solution must be regenerated and the CO_2 extracted. With chemical absorption the solutions are regenerated by heating, with physical absorption by a drop in pressure.

Theoretical specific energy requirement after ZSW (1996)

Chemical absorption:
1.08 MJ/kg CO_2 (MEA with 50 % capture rate)
1.95 MJ/kg CO_2 (MEA with 90 % capture rate)

Physical absorption: 0.1MJ/kg CO_2

Achievable capture rate:
Chemical absorption: 90 %
Physical absorption: 60–80 %

Applications and experience: The technology is state of the art. Whether physical or chemical scrubbing is used depends on the partial pressure of the CO_2. Below 10 bar chemical absorption is used, above 10 bar physical absorption.

Possible uses: CO_2 capture from flue gases (coal-fired thermal power stations, CC, coal-fired IGCC), e.g. at

Shady Point, Oklahoma (200 t CO_2/day for the food industry, ABB technology).

Advantages and disadvantages, CO_2 avoidance costs, power station efficiency: The operating temperature for chemical absorption is around 50–60 °C (for physical absorption less) so the gas being treated must be cooled and cleaned (of SO_x, NO_x, dust, etc.). This leads to loss of energy in the form of sensible heat. The power station technology must be adapted for absorption with solvents (e.g. gas scrubbing, O_2 concentration). Specific investment costs, e.g. for a CC power station, rise by about 87–93 % and the overall efficiency of the arrangement is – at about 48–55 % – significantly lower than without CO_2 capture. The CO_2 avoidance costs lie in the range of \$32–49/t CO_2. For a coal-fired power station the overall efficiency of 33–37 % is significantly lower than with a conventional generating process without flue gas decarbonisation. The specific investment costs rise by about 80 %. Specific CO_2 avoidance costs in the range of \$47–49 per avoided tonne of CO_2 are cited in the literature. One advantage of this method is that power stations can be retrofitted.

Technical limits and required R&D: Most solvents (especially amines) are subject to degradation over time, leading to losses and consequent environmental impacts (amines are toxic!). Degradation of the solvent depends strongly on the concentrations of impurities in the flue gases (e.g. SO_x and NO_x). Many solvents are also corrosive and consequently cause material problems. Research is still required into the development of corrosion-resistant materials. The system as a whole (power station plus CO_2 capture) has yet to be demonstrated in the long term.

Timeframe for large-scale application: The technology is available and is already used in the oil industry and for extracting CO_2 from power station waste gases for use in the food industry. Long-term experience in large-scale commercial power stations is still lacking.

A.2.2 Adsorption on Solids

Description of process: Zeolite molecular sieves, activated carbon, aluminium oxide, etc. can be used to capture CO_2 in adsorption systems. The most commonly used process is pressure swing adsorption (PSA) with molecular sieves. Adsorption is accomplished through physical forces (van der Waals forces). The adsorption phase is followed by regeneration by means of pressure reduction. The adsorbent can also be regenerated thermally (temperature swing adsorption) or in a combined process of pressure and temperature swing adsorption (PTSA). Molecular sieves have the highest CO_2 adsorption capacity per kg in comparison with other materials.

Specific energy requirement after ZSW (1996): 2.9 MJ/kg CO_2 (molecular sieves, PSA, TSA)

Achievable capture rate: 90 %

Applications and experience: The method is state of the art. So far it has only been used for small gas flows. No experience has yet been gathered in the use of this method with large gas flows (e.g. power stations).

Advantages and disadvantages, CO_2 avoidance costs, power station efficiency: Adsorption is a relatively simple, well-tested method, but it has not yet been used for large gas flows. The large energy requirement reduces the attractiveness of this method for CO_2 capture in power stations. Additional investment costs are not especially high. Energy consumption is lowest with PSA (approx. 1/3 compared with TSA). One important drawback is the affinity of molecular sieves for water. For this reason the water must be condensed out before CO_2 capture. Calculations show that in almost all types of power station, implementing CO_2 capture with PSA would double electricity generating costs.

Technical limits and required R&D: The process is mature, but not relevant for CO_2 capture in power stations. However, new methods such as metal oxide gels could make the process more viable.

Timeframe for large-scale application: The technology is already available, but unattractive for power stations. New advances could be ready for implementation in about twenty years.

A.2.3 Cryogenic Distillation

Description of process: CO_2 can be condensed out of gas mixtures by cooling at pressures as low as 4–5 bar. The gas mixture being treated must be dried first.

Specific energy requirement after ZSW (1996): 4.35 MJ/kg CO_2

Achievable capture rate: 90 %

Applications and experience: The method is very energy-intensive, especially where the CO_2 concentration in the gas is low. In the past it was used to extract CO_2 from gases with CO_2 concentrations > 90 vol.%. Today cryogenic distillation is already used for conditioning biogas (CO_2 + CH_4), but no experience has yet been gathered in the generation sector. Future implementation of the process would be conceivable with IGCC (O_2) and oxyfuel processes. However, from the energy (and consequently ecological) perspective application is very questionable.

Advantages and disadvantages, CO_2 avoidance costs, power station efficiency: The gas being treated must be free of water (big disadvantage). The method is only feasible for gas flows with high CO_2 concentrations. However, the advantage of this process is that capture and compression for transport are accomplished in a single step, with a single-stage process producing solid or liquid CO_2. Large-scale industrial application is not on the horizon. Calculations for IGCC and oxyfuel power stations show that cryogenic CO_2 capture would reduce

power station efficiency by 14 and 18 percentage points respectively. Investment costs increase by approx. 80 %. Another possibly more attractive application could arise with fuel-cell power stations, where CO_2 occurs in a very concentrated form.

Technical limits and required R&D: There is still a great need for research to optimise the process with the goal of significantly reducing the energy requirement.

Timeframe for large-scale application: The technology is in principle already available. Oxyfuel power stations and SOFC are regarded as the best opportunities for implementation. But commercial viability is not expected for another fifteen to twenty years.

A.2.4 Membrane Method

Description of process: Membrane methods make use of the different rates at which gases pass through thin membranes. Efficient separation demands high selectivity, a large membrane surface and high permeability for the required gas components in comparison with the other gases in the mixture. Polymers, metals or ceramics can be used as the membrane material.

Specific energy requirement after ZSW (1996): 1.15 MJ/kg CO_2

Achievable capture rate: 60 %

Applications and experience: CO_2 capture using membranes could be implemented with CC (reforming or combustion in O_2) and coal-fired IGCC power stations before or after combustion. However, membrane technology is not yet state of the art.

Advantages and disadvantages, CO_2 avoidance costs, power station efficiency: When used for CO_2 capture with CC or IGCC oxyfuel power stations (in situ CO_2 capture before combustion) the efficiency of the CC power station is 48–50 %, or 8–10 percentage points less than that of a conventional power station. The efficiency of a coal-fired IGCC power station with membrane capture is 35–39 %, or 6–10 percentage points less than IGCC without CO_2 capture. The specific investment costs are 33–54 % higher than for IGCC without CO_2 capture. The CO_2 avoidance costs are in the range $18–40/t.

Technical limits and required R&D:
Development work is still required on the following components and processes:

- efficient membranes for separating CO_2
- reactor concepts for in situ CO_2 capture with high-temperature membranes
- high-temperature membranes for separating off O_2
- reactors for the separation process
- turbines for H_2-rich gases

Timeframe for large-scale application: The method is not state of the art but in the development stages. It will be available in ten to fifteen years at the earliest. Improvements are needed above all in selectivity, permeability and stability (at high temperatures). A combination of membrane and absorption solution would be an interesting prospect. This development is at the laboratory stage.

A.2.5 High-temperature Methods

Description of process: The high-temperature methods for capturing CO_2 are based on in-situ bonding of CO_2 (combustion, gasification, reforming) with oxides (quick lime, dolomite, etc.), silicates, etc. This method is still at the development stage. The attraction of the method is that CO_2 capture is accomplished at high temperatures so the combustion gases can pass to the turbine without cooling. This makes it possible to achieve higher levels of efficiency than with conventional CO_2 capture methods (e.g. absorption solutions). The CO_2 absorbent is located either directly in the conversion reactor (combustion, reforming, gasification, etc.) or downstream (e.g. in a shift reactor).

Specific energy requirement: 0.8 MJ/kg CO_2

Achievable capture rate: > 90 %

Applications and experience: High-temperature O_2 capture could be implemented in the pre-combustion phase in CC (steam reforming) and IGCC processes and in the combustion phase in coal-fired power stations. High-temperature absorbers for CO_2 are in the development stages. The promising options include natural carbonates (e.g. limestone and dolomite) and natural and synthetic silicates and zirconates. The most important property of the high-temperature absorber is its cyclic stability. For industrial application the absorbers must be able to withstand as many CO_2 absorption/ regeneration cycles as possible without significant loss of capacity. Toshiba has developed a lithium orthosilicate that is claimed to maintain its stability over more than five hundred cycles.

Advantages and disadvantages, CO_2 avoidance costs, power station efficiency: The attraction of CO_2 capture at high temperatures is that the combustion gases do not need to be cooled, and can be used directly. In this case even tars in the product gas can be utilised without problems. CO_2 absorption is exothermic and the heat of reaction can be integrated in the process. One disadvantage of the process is the regeneration of the saturated absorbent, for which temperature change is the principal option. Repeated absorption/regeneration destroys the structure of the absorber, which gradually loses its capacity to absorb CO_2. The presence of water accelerates this process.

These materials have not to date been used industrially for CO_2 capture.

Technical limits and required R&D: Development work is still required on the following materials and process design:

- cyclically stable materials that withstand as many absorption/desorption cycles as possible without significant changes in absorption capacity
- reactor and process concepts for in situ CO_2 capture
- efficient regeneration.

Timeframe for large-scale application: The method is not yet available. Possible industrial application in approximately fifteen to twenty years.

A.2.6 Conclusions

As things stand today, the most efficient processes for CO_2 capture in power stations causes efficiency losses of 6–14 percentage points. In order to maintain the same nominal output the power stations consume approx. 15–35 % more fuel, and investment costs rise by 30–120 %. Capturing CO_2 from flue gases by absorption in solutions is state of the art and can be implemented in all (existing and future) power station types. Of all the CO_2 capture options, flue gas decarbonisation in conventional coal-fired power stations using absorption solutions is the least favourable.

There is believed to be great potential in pre-combustion CO_2 capture methods when combined with new power station types such as:

- CC with steam reforming
- IGCC
- Power stations using the oxyfuel process (combustion in O_2/CO_2).

This would require R&D in the fields of membranes for CO_2 and O_2, hydrogen turbines, power station engineering and high-temperature absorbers. Large-scale industrial application can be expected in approx. fifteen to twenty years.

Cryogenic distillation can be implemented where CO_2 occurs in concentrations upwards of 90 %, for example in oxyfuel power stations, high-temperature fuel cells (SOFC), chemical looping, etc. This would require development work in power station design. Large-scale industrial application can be expected in approx. fifteen to twenty years.

An economically advantageous solution is offered by pre-combustion capture of CO_2 in IGCC power stations. Commercial availability can be expected in fifteen to twenty years.

It should be noted that efficient methods of CO_2 capture are tied to power station technologies that are not yet state of the art. In the long term membrane technologies will play an important role in reducing the energy requirements and investment costs of CO_2 capture. A combination of oxygen-permeable membranes and the oxyfuel process could in future lead to a major reduction in the energy required for CO_2 capture.

A.3 Worldwide Overview of CCS Projects (to Chapter 7)

Globally there are more than one hundred projects relating to CCS. A good overview and introduction is provided by the Intergovernmental Panel on Climate Change (IPCC):

www.ipcc.ch

and by two websites maintained by the International Energy Agency (IEA):

www.ieagreen.org.uk/ccs.html
www.co2captureandstorage.info.

The websites are organised by region and topic, making it easy to access the large amount of information. The world maps below show a selection of global activities in the fields of capture (Fig. A–2) and storage (Fig. A–3).

In international comparison North America has the most studies and projects relating to CCS (71), followed by Europe (36) and Asia (13) (as of October 2006). Japan plays an important role, running or participating in six of the Asian projects (see Table A–2, left-hand side).

If we look at the types of issue investigated (see Table A–2, right-hand side), CO_2 storage comes first with 44 studies addressing geological storage (30 of them in North America) and 8 (in the United States and Japan) examining marine storage options. In second place come 41 studies focusing on new technologies (especially in relation to the process of capture at the power

Table A–2: Global distribution of projects and main research areas (as of 10/06)

Number of projects by region		Number of projects by research area	
United States and Canada	71	Geological storage	44
Europe	37	New technologies	41
Asia (Japan)	13(6)	Uses for CO_2	12
Australia	6	Modelling and databases	13
New Zeeland	1	Marine storage options	8
Brazil	1	CCS costs	4
United Arab Emirates	1	CO_2 monitoring projects	6
Algeria	1	Hydration	2
Total	**131**	CO_2 transport	1
		Total	**131**

Global CO₂ capture projects

Global CO$_2$ capture projects

- Snohvit
- Sleipner
- CASTOR
- Boundary Dam
- Dakota Gasification Plant
- Bellingham Cogen
- Warrior Run
- IMC Global Inc.
- Shady Point
- Sumitomo Chemicals
- Mitsubishi Plant, Nagasaki
- In Salah
- Indo Gulf Fertilizer Co.
- Luzhou Natural Gas
- Gorgon

● Gasification synfuels plant
● Major Pilot Plants (Post-Combustion)
● CO$_2$ Separation at extraction of NG (CO$_2$ as a carrier gas)
● Food-grade CO$_2$ / carbonation of brine /
  Urea (Post-Combustion)

Fig. A–2: Global CO$_2$ capture projects (selection)

CO₂ storage projects operating worldwide

CO$_2$ storage projects operating worldwide

- 50 acid gas injection facilities in North America
- 4 CO$_2$ EOR projects in Canada
- Snohvit
- Sleipner
- K-12B
- CO$_2$Sink
- RECOPOL
- Alberta ECBM
- Penn West
- Weyburn
- Teapot Dome
- Rangely
- Mountaineer
- Burlington
- West Pearl Queen
- Frio
- Hokkaido
- Qinshui Basin
- Nagaoka
- In Salah
- 70 CO$_2$ EOR projects in the United States
- Gorgon
- Cerro Fortunoso

● ECBM* project
● EOR** project
● Gas production field
● Saline aquifer

 * Enhanced Coal Bed Methane
   (= deep coal seams)
** Enhanced Oil Recovery

Fig. A–3: Selection of global CO$_2$ storage projects (http://www.co2captureandstorage.info/docs/IEAGHGccsworldmap.pdf)

Fig. A–4: Overview of the global distribution of CCS projects (encircled in red) in relation to the major sources of CO_2 emissions (dots)

Selection of European field trials and demonstration projects (not exhaustive)

Sleipner Gas Field
Lead: Statoil
Type: CO_2 capture from gas
production and sequestration
in aquifer
Scale: 1,000,000 t/a CO_2
http://www.statoil.com

Hammerfest
Lead: Sargas
Type: Commercial NGCC power station,
CO_2 capture, solid absorbent
Scale: 100 MW
http://www.co2captureandstorage.info

Snohvit Aquifer
Lead: Statoil
Type: CO2 capture from LNG
production at Hammerfest,
160-km CO_2 pipeline,
storage in aquifer
http://www.co2castor.com

K12B Gas Field
Lead: Gaz de France
Type: CO_2 storage study,
CO_2 capture from gas production,
enhanced gas recovery (EGR)
http://www.co2castor.com

Esbjerg Powerstation
Lead: Elsam
Type: Post-combustion CO_2 capture
Scale: 1-2 t/h CO_2
http://www.co2castor.com

Ketzin
Lead: Grossforschungszentrum Potsdam
Type: Study of CO_2 in disused gas storage
facility, risks, long-term behaviour
Scale: 30,000 t/a CO_2
http://www.co2sink.org/

Kalundborg Aquifer
Lead: Energi E2, Statoil
Type: CO_2 storage aquifer
Scale: 900 million t CO_2
http://www.co2store.com

Schweinrich Aquifer
Lead: Vattenfall
Type: CO_2 storage aquifer
Scale: 400 million t CO_2
http://www.vattenfall.de

Tarragona, Casablanca Oil Field
Lead: Repsol
Type: CO_2 storage study
Scale: 500,000 t/a CO_2
CO2 capture at Tarragona refinery,
storage in offshore Casablanca
Oil Field
http://www.co2castor.com

Schwarze Pumpe
Lead: Vattenfall
Type: Oxyfuel pilot plant
Scale: 30 MWth
http://www.vattenfall.de/
www/vf/vf_de

In Salah Gas Field
Lead: BP, Sonatrach
Type: CO_2 capture from gas production
and sequestration
Scale: 900,000 t/a CO_2
http://www.co2captureandstorage.info

Lindach Gas Field
Lead: Rohoel AG
Type: CO2 storage study
Scale: 300,000 t/a CO_2
http://www.co2castor.com

Fig. A–5: Selection of European field trials and demonstration projects (not exhaustive)

station) followed by 13 projects preparing models and databases and 12 on possibilities for using CO_2. One project analyses CO_2 transport and two involve hydration of CO_2,[1] while four projects focus on the costs of CCS and six investigate CO_2 monitoring.

A.3.1 Projects within the EU

The European approach to CO_2 reduction in the field of electricity generation from fossil fuels does not differ fundamentally from the activities worldwide. Generally priority is given to increasing power station efficiency, which reduces specific CO_2 emissions and in general also makes economic sense. Beyond this there are also numerous possibilities for CO_2 capture, as discussed below. The measures differ in terms of technology, cost of capture (e.g. energy consumption and financial cost), development status and thus availability timeframe. The development perspectives in different countries also differ according to the respective political and economic framework. As well as increasing efficiency, reducing the cost of capture processes is also another leading goal.

Fig. A–5 shows the distribution of field trials in Europe by way of illustrating the technological development perspectives. Most field trials already in existence or in advanced stages of planning tend to follow economic frameworks. As can be seen from the map (Fig. A–5) there is a concentration of field trials among the numerous oil and gas fields of the North Sea. On the one hand, locations are found where the CO_2 contained in raw natural gas has to be separated off when the gas is conditioned following extraction. On the other hand, project locations are also associated with the exploitation of oil fields, where CO_2 is injected to boost falling recovery rates (enhanced oil recovery or EOR). It is not yet clear to what extent the use of compressed CO_2 for EOR or EGR (enhanced gas recovery) can be regarded as a storage option.

There are considerably fewer field trials for CO_2 capture from power station flue gases or for developing new power station concepts with subsequent CO_2 transport and sequestration, because in these fields economic frameworks are not yet in sight. For one thing, CO_2 capture at the power station requires a great deal of energy (reduced efficiency, increased fuel consumption), while for another there is still a great shortage of information concerning long-term behaviour (leakage, environmental impact).

Through its research programmes the European Union promotes the development and demonstration of technologies and measures for reducing and storing CO_2. Activities concerning the field of energy are summarised at: http://europa.eu.int/comm/research/energy/nn/nn_rt/nn_rt_co/article_1150_en.htm.

There are national and international programmes for promoting CCS projects. In April 2005 the European Commission published the first draft of its seventh Research Framework Programme proposing a total of nine current research areas with a funding volume of €2,951 million for the period 2007–13. In the seventh Research Framework Programme –as was already the case in its predecessor – CO_2 capture and storage ('near zero emission power generation') plays an important role in the field of energy research, and in absolute terms has actually increased considerably in importance (see also http://europa.eu.int/comm/index_de.htm).

Furthermore, as part of its initiative to create a European Research Area (ERA) the European Commission supports the EU-level coordination of corresponding national programmes, for example in the field of low-emissions power stations the ERA Net FENCO (Fossil Energy Coalition). In December 2005 the EU also started a new technology platform on 'CO_2-free' power stations for fossil fuels.

The text box below outlines selected CCS research projects (in particular EU-funded projects) with information about their aims, timeframes and participating German research partners.

As well as the aforementioned research projects, **Sleipner** (Norway) and **CRUST** (Netherlands) represent two major European CO_2 storage projects that are already operating commercially.

In the field of research into CO_2 sequestration the following **networks** exist at the EU level:

CO_2GeoNet – This network focuses on geological CO_2 storage. The members come from the spheres of science and industry.

CO_2NET – The European networking development programme for geological CO_2 storage, CO_2 capture and zero-emissions technology has given rise to the European Carbon Dioxide Thematic Network (CO_2NET), which networks the geological agencies of EU member states and other research institutes.

EuroGeoSurveys – Network supporting the EU by collecting the entirety of technical know-how of the geological agencies of EU member states and membership candidates.

Eurogif – Represents the European oil and gas service and supply industry. 'EUROGIF brings an industry perspective to the EU in terms of their formulation of both energy policy and Framework Programmes for sponsored research.'

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1 Process whereby water molecules become attached to dissolved ions through electrostatic forces between the charged ions and the water dipoles.

CASTOR: CO_2 from capture to storage
CO_2 storage in aquifers / CO_2 storage in hydrocarbon reservoirs / membranes / modelling and mapping / monitoring and verification / physical absorption / safety and environmental questions
Period: February 2004 – January 2008
Participants: BGR

CO₂SINK: Storage of CO_2 from a biomass power station in aquifers (near Ketzin)
Modelling and mapping / monitoring and verification / safety and environmental questions
Period: April 2004–March 2009
Participants: GFZ, G.E.O.S, Stuttgart University, RWE Power AG

CO₂STORE: CO_2 storage project in aquifers
Monitoring and verification
Period: 02/03–02/06
Participants: BGR

GESTCO: Assessment of European storage potential for CO_2 from combustion of fossil fuels
Period: June 1999–December 2001
Participants: BGR

ICBM: Investigation of a series of technical challenges in sequestration of CO_2 by the ECBM method (Enhanced Coal Bed Methane Recovery)
Period: October 2003–October 2006
Participants: Deutsche Steinkohle AG

Dynamis: Towards Hydrogen and Electricity Production with Carbon Dioxide Capture and Storage
Goal of this project is to investigate possible ways of low-cost industrial hydrogen production with integrated CO_2 capture and storage. Funding from the EU and a consortium of industrial partners
Period: 36 months starting March 2006
Participants: BGR

CO₂-Geonet: European Network of Excellence on Geological Storage of CO_2
Building on the findings of previous EU research projects, the partners in this network together coordinate development of R&D work in order to consolidate Europe's leading position in this field.
Period: April 2004–March 2009
Participants: BGR

ENCAP CO₂: ENhanced CAPture of CO_2
Development of low-CO_2 power station concepts with CO_2 capture before or integrated in combustion (low-CO_2 IGCC, oxyfuel, membranes)
Period: March 2004–March 2009
Participants: RWE, Siemens

OxyCoal-AC: Programme to develop components (phase 1) and bring them together in a pilot plant (phase 2) for the oxyfuel process (combustion in oxygen), with development of high-temperature membrane methods
Funding from BMWA and BMWF
Period: September 2004–2007 (phase 1)
Participants: six departments at RWTH Aachen, RWE Power, E.ON, Siemens, Linde, WS-Wärmeprozesstechnik

RECOPOL: Trial CO_2 storage (near Katowice) in uneconomic deep coal seams
Period: November 2001–November 2004
Participants: RWTH Aachen

ISCC: Innovative in Situ CO_2 Capture technology for solid fuel gasification
The project has the aim of process-integrated capture of storable CO_2 during lignite gasification ($CO_2 > 90\,\%$)
Period January 2004–December 2006
Participants: Stuttgart University, IVD

GeoCapacity: Assessing European Capacity for Geological Storage of Carbon Dioxide
The goal of this project is to create a European information system on the distribution of CO_2 sources and storage possibilities. The project integrates and builds on the results of preceding GESTCO and CASTOR projects, and adds in particular data for the new EU member states in eastern Europe. The research project is funded by the European Union and a consortium of industrial partners.
Period: January 2006–January 2009
Participants: BGR

Research programmes of selected european states

The UK government's **CATS** initiative (Carbon Abatement Technology Strategy) is a research and demonstration programme for furthering the development of 'zero-emission technologies' and increasing efficiency in the field of coal-fired power stations. This is a ten-year programme also focusing on international cooperation in this field.

Also in the UK the **Carbon Capture and Storage Association (CCSA)** has been founded. This is an alliance of companies – largely from the energy supply and plant engineering sectors – that are interested in working to develop geological storage and representing their interests in this field.

Also worth mentioning is the Dutch CCS research programme **CATO** (CO_2 Capture, Transport and Storage in the Netherlands), led by the Utrecht Centre for Energy Research (UCE) and supported by Dutch industry, research institutes, universities and environmental organisations. The goal of this programme is to demonstrate under what conditions CCS can be integrated in a sustainable energy system, taking into consideration economic, technical, social and ecological aspects. The programme has total funding of €25.4 million for the period from 2004 to 2008.

In Norway offshore natural gas extraction is subject to a CO_2 tax. In 1996 this led Statoil to begin storing CO_2 coming out of the **Sleipner** gas field (where the extracted gas mixture contains 9 % CO_2) in a saline aquifer located

Fig. A–6:
Electricity generation using
hydrogen at Peterhead,
Scotland (BP Sustainability
Report 2005)

North sea fields

Gas processing

British gas grid

Reformer and CO_2 sequestration

Miller oil field

Hydrogen power station

British electricity grid

Enhanced oil recovery
with long-term CO_2 storage
in geological formation

Oil refinery

Oil products

Natural gas   Electricity CO_2
Hydrogen   Oil
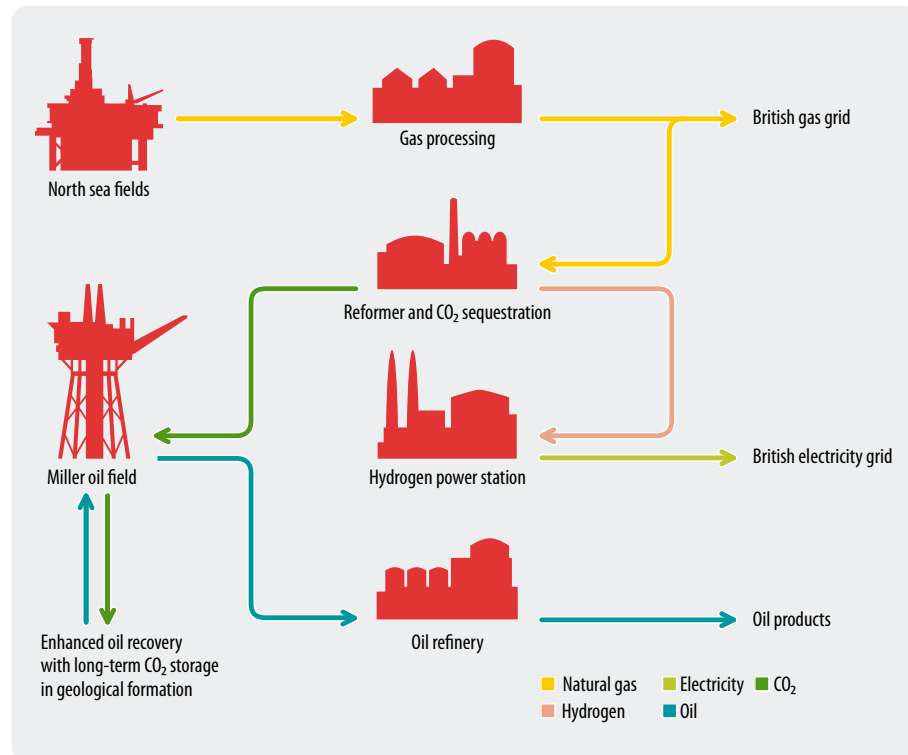
above the gas field (the Utsira Formation) (1 Mt/a). Furthermore Statoil and the Anglo-Dutch Shell company drew up plans to build a combined cycle power station at Tjeldbergodden in Norway by 2012 at the latest and transport the carbon dioxide emissions to the Draugen and Heidrun oil and gas fields where the captured CO_2 was to be used for EOR/EGR, with the outcome of storing 2–2.5 Mt CO_2 annually. This project has, however, since been abandoned for reasons of cost.

The **CRUST** project, which has been operating since March 2005, represents the first attempt to inject CO_2 into a gas field that is still producing. This pilot project has begun by storing 20,000 tonnes of CO_2 annually; it is planned to increase that figure later to 480,000 tonnes per year. In terms of its approach the project can be designated as enhanced gas recovery (EGR), but its prime concern is in fact to research the migration behaviour of CO_2 rather than actually to increase the gas recovery rate. The gas produced has a high CO_2 share of approx. 13 % (IEA 2005). The project is 90 % funded by the Dutch Economics Ministry, so it has to date required little funding from the private sector (the remaining 10 % are provided by Gaz de France).

CRUST involves capturing CO_2 from the produced gas and then returning it into the reservoir. The Netherlands, incidentally, has a pricing regime for CO_2-free electricity which in principle would also include electricity generated from fossil fuels, presuming the CO_2 involved is withdrawn from the atmosphere.

An integrated project reforming natural gas to hydrogen and CO_2 was planned by BP in conjunction with Cono-

coPhillips, Shell and Scottish and Southern Energy at **Peterhead** in Scotland (see Fig. A–6). The hydrogen was to be used to fuel a CC power station capable of generating electricity to supply more than 700,000 households. Per year 1.8 million tonnes of CO_2 were planned to be transported offshore and injected into the Miller oil field at a depth of more than three kilometres below the seabed, which would extend the productive life of the oil field by fifteen to twenty years and increase the yield (BP 2005). Actually this plant is now to be built in the United Arab Emirates in Abu Dhabi. According to BP, the UK government delayed its financial contribution (The Scotsman 2008).

Development perspectives in Europe

As well as the international and US-American information platforms and networks, the European Union offers information platforms and networks as part of its research programmes.

The establishment of the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ETP **ZEFFPP** 2005) created a body to coordinate the measures required for reducing CO_2 emissions from electricity generation. Fig. A–7 shows the organisational structure. The Strategic Research Agenda and Strategic Deployment Document produced by working parties define strategies for market introduction and for Europe to achieve the CO_2 reduction goals, divided into immediate measures, measures to be taken by 2030 and beyond then.

Technology Platform ZEFFPP
Organisational Structure

Advisory Council

Mirror Group
of Member States

Coordination Group

Secretariat

| Plants & CO_2 Capture | CO_2 Use & Storage | Infrastructures & Environment | Market Regulation & Policy | Communication & Public Acceptance |

Strategic Research Agenda (SRA)

Deployment Strategy (DS)
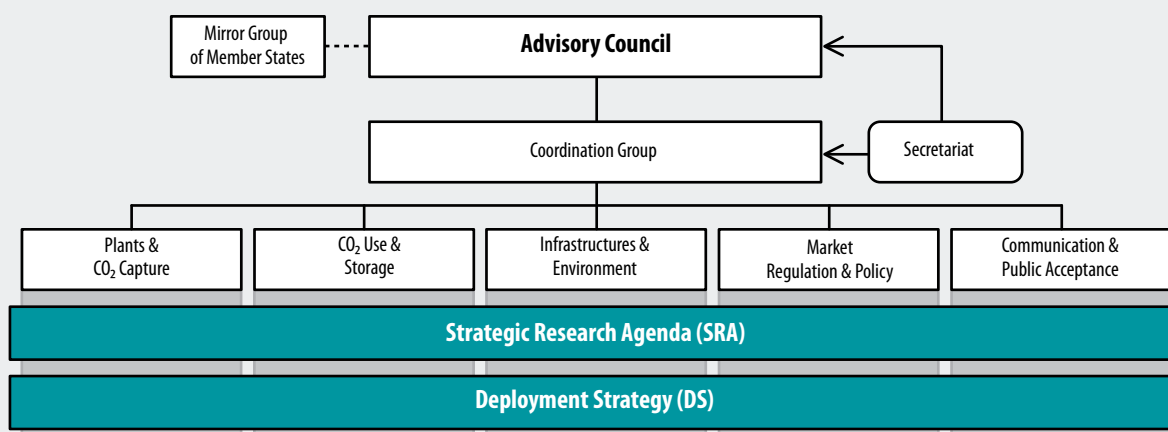
Technology Platform ZEFFPP
Members of Advisory Council

Generators

Kurt Haege	Vattenfall AB (Chair)	:Germany
Bernhard Fischer	E.ON Energie AG	:Germany
Santiago Sabugal Garcia	ENDESA Generation	:Spain
Johannes Lambertz	RWE Power AG	:Germany
Gennaro di Michele	ENEL	:Italy
Hakon Mosbech	ENRGI E2 A/S	:Denmark

Equipment Suppliers

Charles Soothill	ALSTOM (Vice-Chair)	:UK
Harry Lampenius	Foster Wheeler	:Finland
Iain Miller	Mitsui Babcock	:UK
Norbert Koenig	Siemens AG Power Generation	:Germany
Francois Jackow	Air Liquide	:France
Giuseppe Zampini	Ansaldo Energia SpA	:Italy

Oil/Gas

Gardiner Hill	BP (Vice-Chair)	:UK
Jean-Michel Gires	Total SA	:France
Philippe Lacour-Gayet	Schlumberger	:France
Graeme Sweeney	Shell Gas and power	:UK
Arve Thorvik	Statoll	:Norway

Research

Olivier Appert	IFP (Vice-Chair)	:France
Antonio Valero	CIRCE (Vice Chair)	:Spain
Niels Peter Christensen	GEUS	:Denmark
Josek Dubinski	CMI	:Poland
David Falvery	BGS	:UK

NGOs

Frederic Hauge	The Belona Foundation	:Norway
Kirsten Macey	Climate Action Network Europe	:Belgium
Stephan Singer	WWF International	:Belgium

Fig. A–7: Organisational structure and members of the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEFFPP) (http://ec.europa.eu/research/energy/pdf/zeffpp_power_plant_en.pdf)

Fig. A–8:
CSLF project categories
and research areas
(Hake 2005)
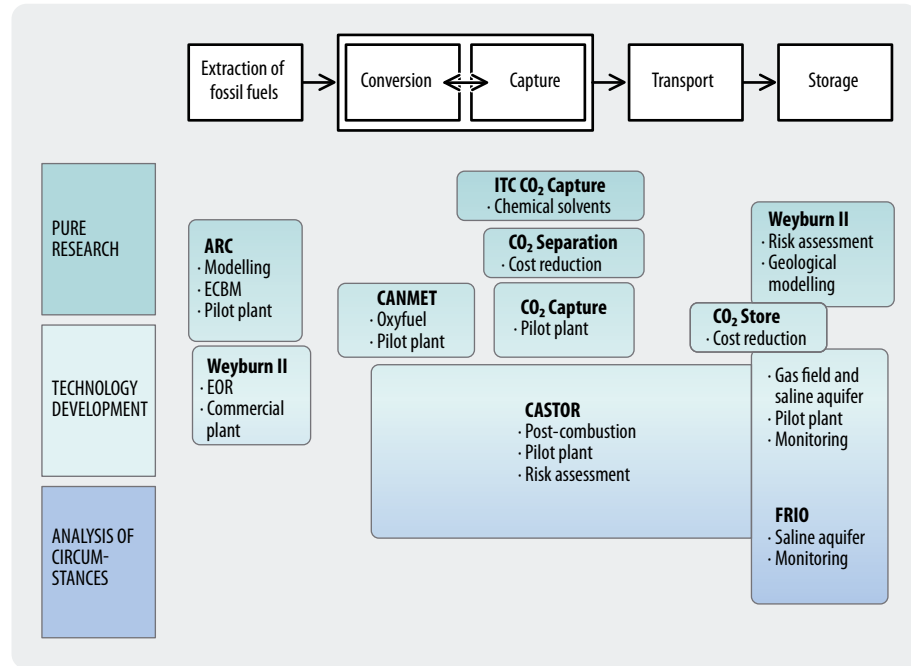
A.3.2 International Activities and Political Strategies

The Carbon Sequestration Leadership Forum (CSLF) is an internationally important climate protection alliance that was set up in 2003 on the initiative of the United States. The CSLF works for the development of cost-effective capture and storage technologies, low-cost CO_2 transport and long-term stability of storage, and promotes the exchange of information about CCS activities in the field of climate protection. As well as the EU, twenty other states are also members of this initiative (www.cslforum.org). Currently about seventeen projects supported by the CSLF are under way across the world. Fig. A–8 shows the research priorities.

One of these projects is the Enhanced Coalbed Methane Recovery Project of the Alberta Research Council (ARC) in Canada, which is running a trial to investigate whether CO_2 can be injected into a deep coal seam and how the methane released in the process can be used (ECBM). The results will be used as the basis for the development of China's Coalbed Methane Technology/ Carbon Dioxide Sequestration Project.

The International Energy Agency (IEA) is conducting the following work in the field of CCS: the Working Party on Fossil Fuels promotes the development of 'zero emissions technologies' and coordinates international cooperation and exchange in this field. The Clean Coal Centre stimulates the innovation and use of coal as a 'clean fuel' by identifying the potential of apparently suitable technologies, identifying open questions and jointly publishing the results of cooperative projects. The Greenhouse Gas R&D Programme analyses and assesses various technical options for their potential for climate protection, and publishes the results.

Certain countries have set up their own CCS programmes; these are briefly outlined below. The Australian **COAL 21** programme aims to reduce greenhouse gas emissions from electricity generation using coal through a joint initiative supported by the government, industry and research bodies.

The EU-China Partnership on Climate Change established in autumn 2005 includes an EU-China Action Plan on Clean Coal which seeks to promote joint development and implementation of 'near zero emission coal projects'. The first concrete agreement in this context was concluded in January 2006 between the UK and China: a three-year feasibility study will begin by examining the practicality of various concepts and investigating the options for geological storage of CO_2. This shows that research efforts and also first practical steps in the field of CCS are beginning to extend beyond the EU and the United States.

The United States has published an internationally significant policy strategy in the form of the *Carbon Sequestration Technology Roadmap and Program Plan* (DoE 2003/2005), which covers the following three fields of research:

A. **Core R&D** The goal of this programme is to advance sequestration research and develop new sequestration technologies through to the market launch phase. The core programme has five areas:

- CO_2 capture,
- CO_2 storage,
- Monitoring, mitigation and verification,
- Control of other greenhouse gases,
- New concepts.

CO$_2$ sequestration projects in North America

Weyburn, Canada
Lead: ENCANA
Type: Geologic, Depleting oil reservoir
Phase: Injection began in 2001
Scale: 20 MM tons CO$_2$ over 15 yrs
Highlights: Demonstrate use of time lapse (3D) seismic and other technologies to monitor CO$_2$.
http://www.netl.doe.gov/publications/factsheets/project/Proj282.pdf

Johnson County
Lead: Kansas Geologic Survey
Type: Geologic, coal seam
Phsase: Pre-injection
Scale: TBD
Highlights: Will explore the possibility of injecting untreated landfill gas (50/50 CO$_2$/CH$_4$)into a coal for both enhanced CBM recovery and landfill gas purification.
http://www.netl.doe.gov/publications/factsheets/project/proj324.pdf

Marshall County, WV
Lead: Consol Energy
Phase: Pre-injection, 2005 injection planned
Scale: 26,000 tons CO$_2$ over 1 year
Highlights: Plan to demonstrate horizontal CO$_2$ injection wells with up to 3,000 feet of horizontal length.
http://www.consolenergy.com/content.asp?c=GreenhaoseGasManagement_20030613113634

Yolo County, CA
Lead: Yolo County Planning and Public Works Dept.
Type: Non-CO$_2$, LFG
Phase: Construction of test cells completed
Scale: 12 acres
Highlights: Seek to demonstrate LFG generation over 5-10 years as opposed to typical 10-30 years for more economical recovery.
http://www.netl.doe.gov/publications/factsheets/project/Proj199.pdf

New Haven, WV
Lead: American Electric Power
Type: Geologic, Saline formation
Phsase: Pre-injection
Scale: TBD
Highlights: Injection well revealed low permeability in target zone; evaluating potential storage capacity in shallower formations.

Hazard, KY
Lead: University of Kentucky
Type: Terrestrial, tree planting
Phase: Third year of planting
Scale: 500 acres
Highlights: Demonstrated increase site indices and sequestration while increasing water infiltration and reducing sediment runoff with tree planting in uncompacted or ripped mineland.

San Juan Basin, NM
Lead: Burlington Resources, Advanced Resources International
Type: Geologic, coal seam
Phase: Post-injection
Scale: 280,000 tons CO$_2$ over 6 years
Highlights: Developed improved understanding of coal swelling and ability to predict CO$_2$ storage capacity.
http://www.netl.doe.gov/publications/factsheets/project/Proj228.pdf

West Pearl Queen, NM
Lead: Strata Production
Type: geologic, Depleting oil reservoir
Phase: Post-injection
Scale: 2,200 tons CO$_2$ over 42 days
Highlights: Tested tracer and seismic MM&V; examined alternative CO$_2$ trapping mechanisms.

Frio, TX
Lead: University of Texas Bureau of Economic Geology
Type: Geologic, Saline formation
Scale: 1,800 tons CO$_2$ over 3 weeks
Highlights: Developped a thorough Environmental Assessment under NEPA.
http://www.begutexas.edu/environqlty/co2seq/fieldexperiment.htm

Paradise, KY
Lead: Tennessee Valley Authority
Type: Terrestrial, tree planting
Phase: Post-planting, second growing season
Scale: 100 acres
Highlights: Achieved 80% survival rate for maple poplar, sweet gums, and sycamore using FGD sludge as amendment and irrigating with FGD setting pond water.
http://www.netl.doe.gov/publications/factsheets/project/proj34.pdf

Fig. A–9: CCS demonstration projects in the United States (DoE 2005, Department of Energy)

These research areas are complemented by demonstration projects focusing on different aspects, see Fig. A–9.

B. Infrastructure development The US Department of Energy (DoE) in 2003 initiated seven regional CO$_2$ sequestration partnerships with the goal of developing an infrastructure for future CCS pilot projects. This partnership has given rise to a national network of firms and experts aiming to advance the use of CCS, and to a Carbon Sequestration Atlas of the United States that identifies priority regions for CCS pilot projects.

C. Program management This is the R&D management programme. In a bid to deploy its budget and pursue its research goals as effectively as possible, the DoE has set up public-private partnerships, and engaged in national and international cooperation, analyses and project evaluation, and proactive public relations work.

As part of the broad-based Clean Energy Programme, which has funding of almost $2,000 million of which 80 % is provided by the state, the DoE has launched the **FutureGen** venture with the aim of producing the prototype for a new commercial coal-fired power station technology. It involves the biggest electricity generating and coal mining corporations in the United States, including RAG AmericanCoal and Eon. The technology is to be based on coal gasification, aiming for efficiency of 60 % and a CO$_2$ capture rate of 90 %. As well as electricity, hydrogen is also to be generated for other applications, for example for fuel cells for road transport. The aim is to generate electricity at a cost no more than 10 % higher than with current technologies.

RAG Coal International is also involved in another research project in the United States, the Zero Emission Coal to Hydrogen Alliance **(ZECA),** which also tackles the issue of generating electricity from coal without CO_2 emissions. The goal of this project is to safeguard coal's long-term future as a fuel. The starting point for the research is a process where the CO_2 emissions produced when coal is burned to generate electricity are not released but fixed in mineral form. Initial experience is to be gathered from an industrial-scale power station based on fuel cell technology, which is to begin operating in the second half of this decade. Further details on the ZECA project can be found at www. zeca.org.

One commercially run storage project in the United States and Canada is found at the **Weyburn** oil field (Canada), where CO_2 is used for enhanced oil recovery (EOR).[2] The CO_2 is supplied by a pipeline system from a gasification plant in North Dakota (USA). After injection it remains underground.

One place where CO_2 is also already being used industrially is the **Shady Point** CHP plant in the state of Oklahoma, where 200 tonnes of CO_2 daily are captured from a part of the flue gas and supplied to the food industry.

At **Carson**, California, there are plans to build a hydrogen power plant using oil coke. This would demonstrate that low-CO_2 energy can be generated from coal, of which the United States has abundant reserves. After starting operation the Carson project would generate 500 MW of low-CO_2 electricity, enough to supply about 325,000 households in southern California. The plant is also to be used to sequester and permanently store about 4 million tonnes of CO_2 annually. BP and the Edison Mission Group intend to make the final investment decisions in 2008 after preparation of detailed technical and commercial studies. If they go ahead the new power station could come on stream in 2011 (BP 2005).

The **Greater Gorgon Gas Development** in Australia is a project for gas extraction and subsequent LNG production operated by ChevronTexaco. For LNG production (planned annual volume 10 million tonnes) the CO_2 present in the extracted gas must be removed.[3] The rest of the extracted gas is transported on in gaseous form to the compressor. The CO_2 to be injected arises largely from LNG production and in other energy-intensive processes, while a smaller part is contributed by the CO_2 in the extracted gas. The storage formation is a saline aquifer underneath Barrow Island, where the LNG plant will also be located. The storage project will cost at least AUS$300 million (approx. €180 million). According to ChevronTexaco there is no obligation under Australian law to avoid CO_2 emissions. The stated motivation is concern about climate change and the company's responsible attitude to greenhouse gas management (Gorgon 2005).

In Japan and Australia, too – as in most of the road maps – immediate measures to increase efficiency in new power stations are at the top of the agenda. Since 1995 there has been a continuous increase in the steam parameters of new power stations (pressure and temperature) (Santos and Davison 2006). Whereas short- to medium-term attention in Europe and the United States is focused on pre- and post-combustion measures, Japan has made an early choice to prioritise the introduction of fuel cell technologies in combination with coal gasification. Japan and Australia also cooperate in the fields of oxyfuel combustion and integrated drying gasification combined cycle (IDGCC), which is mainly being pursued in Australia. In the joint Hypercoal Project coal is to be demineralised in Australia and used in Japan for low-emissions energy generation.

Also worthy of note are projects initiated by BP/Sonatrach and ChevronTexaco that have already reached the planning stage. In a joint venture between BP and Sonatrach in Algeria, the In Salah CO_2 Geological Storage Demonstration Project, the accompanying CO_2 is separated out as the gas is produced in order to stay within the export specifications (CO_2 content < 0.3 %). The removed CO_2 is not released into the atmosphere as usual but instead injected into a geological formation. All in all, 900,000 to 1,000,000 tonnes of CO_2 annually are to be stored underground in this way. BP says it is motivated by the company's promise to reduce its climate-relevant emissions. BP has an internal emissions trading system where the stored CO_2 can then be converted into certificates. It should be emphasised that most of the CO_2 emissions originate from energy-consuming processes, and the CO_2 from the extracted gas represents only a small proportion (IEA 2005).

Research into CO_2 sequestration also includes the following networks:

Monitoring Network – Founded on 8 November 2004 at a meeting at the University of California Santa Cruz organised by the IEA GHG and BP with the support of EPRI and the American Department of Energy (DoE/ NETL).

International Network for CO_2-Capture – The IEA GHG set up the CO_2 Capture Network to serve as a forum and to support research projects in the field of capture. All the members are industrial companies.

International Network on Biofixation of CO_2 and Greenhouse Gas Abatement with Microalgae – The purpose of the Microalgae Biofixation Network is to offer a platform for organisations interested or involved in R&D work aiming to reduce greenhouse gases using microalgae. Members come from the spheres of science and industry and from the American Department of Energy.

ZECA Zero Emission Coal Alliance – A consortium from the United States and Canada composed of eighteen members from government, research organisations and the coal industry. Its purpose is to advance the

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2   Process whereby water or CO_2 is injected into boreholes to increase the oil recovery rate.

3   The CO_2 would otherwise freeze and damage the equipment.

German projects in the geotechnologies R&D programme of the Federal Ministry of Education and Research Focusing on 'Exploration, Use and Protection of Underground Resources'

CO_2-TRAP: Development and evaluation of innovative strategies for permanent storage of CO_2 in geological formations
RWTH Aachen, Bayreuth University, Stuttgart University, RWE-DEA AG (Hamburg), RWE Power AG (Cologne), Saar Energie GmbH (Saarbrücken), Deutsche Steinkohle AG (Herne), Deutsche Montan Technologie (Essen)

Enhanced Gas Recovery (EGR): Storage of CO_2 in deep natural gas deposits with the possibility of enhanced gas recovery – a feasibility study
Clausthal Technical University, BGR (Hannover), Vattenfall Europe, EEG (Gommern), E.ON-Ruhrgas, Wintershall (Kassel)

COSMOS: CO_2 storage and development of monitoring and safety technologies
GeoForschungsZentrum Potsdam, Deutsches Brennstoff Institut – Gastechnologisches Institut GmbH (dbi-gti), Vattenfall Europe Mining AG (Cottbus), Karlsruhe University, RWE Power AG (Essen)

RECOBIO: Recycling of CO_2 through microbial biochemical conversion into methane (CH_4) deep underground
GEOS-Freiberg Ingenieurgesellschaft mbH, Dresdner Grundwasserforschungszentrum e.V. (DGFZ)

CDEAL: Fixing CO_2 through mineral reactions in acid pit water and flooded disused pits in an open-cast lignite mining area
Freiberg University of Mining and Technology

CO_2CRS: High-resolution underground imaging for CO_2 storage using the CRS method
Trappe Erdöl Erdgas Consultant (Isernhagen), Karlsruhe University, Free University of Berlin
Development of the SPIN instruments system for exploration and monitoring for underground CO_2 storage using nuclear magnetic resonance
Geohydraulik Data, TU Berlin, FH Gelsenkirchen

CHEMKIN: Real-time monitoring of the chemical and kinetic behaviour of carbon dioxide during geological sequestration
GeoForschungsZentrum (Potsdam), Umwelt- und Ingenieurtechnik GmbH (Dresden), Potsdam University, Clausthal Technical University, Optimare GmbH (Wilhelmshaven).
Numerical investigations of CO_2 sequestration in geological formations – problem-based benchmarks
Stuttgart University, Deutsche Montan Technologie (Essen)

CO_2-UGS-Risks: Integrated safety and risk analysis of CO_2 storage in Germany
Gesellschaft für Anlagen- und Reaktorsicherheit (GRS) mbH (Braunschweig)

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development of new and highly efficient technologies for electricity generation and/or hydrogen production from coal 'with zero atmospheric emissions'.

EnergyNet – A national Canadian network covering the spheres of science and industry and government ministries for developing future perspectives and new technologies to open up a broad supply of affordable and environmentally sound energy.

A.3.3 CCS Projects in Germany

In Germany too, projects in the field of CO_2 capture and storage are already being conducted or are under development. In addition German institutions are also involved in various EU-wide research projects (see chapter 17.3.1).

One particularly important project is the EU-funded **CO_2Sink** led by the Potsdam-based Geoforschungsinstitut, where CO_2 is injected into a geological formation under real conditions. Seventeen different partners are now involved in this project, including power companies. Storage is in a porous geological formation underneath an underground storage facility for natural gas at Ketzin near Berlin. One of the aims is to use different monitoring methods to track the behaviour of the stored gas and thus gain knowledge about long-term stability.

In its research and development programme **GEO-TECHNOLOGIEN** the Federal Ministry of Education and Research has since March 2005 been funding ten interdisciplinary research groups from scientific institutes and private industry with almost €7.5 million. The goal of this research programme, which is initially to run for three years, is to examine the technological, ecological and economic perspectives of underground storage of the greenhouse gas CO_2 (see the overview in the text box).

The Federal Ministry of Economics initiated the **COORETEC** research concept, which is designed to lead to the realisation of low-emissions fossil-fuelled power stations through an alliance of partners from the spheres of science and industry. The programme aims to show how the technologies required for highly efficient, largely emissions-free and economic coal- and gas-fired power stations could be developed by 2020. One offshoot of this programme is the **COORIVA** research project (CO_2 reduction through integrated gasification and capture), whose aim is to develop an IGCC concept making use of experience already gathered in industrial-scale projects and integrating CO_2 capture. In parallel investigations are already under way into the potential of gasification of lignite and coal, the creation of modelling tools and upscaleable studies.

Among the power companies, RWE has announced the construction of an IGCC plant with CO_2 capture by

2014, and in May 2006 Vattenfall began building a demonstration oxyfuel power station at Schwarze Pumpe, which is due to begin operations in 2008.

A.4 Central Issues for Planning a CO_2 Transport Infrastructure (to Chapter 8)

Central questions that could guide the process of designing and setting up a CO_2 transport infrastructure are listed below:

1. What are the similarities and differences in the handling of natural gas and CO_2?
   - physical and thermodynamic properties,
   - risk management,
   - corrosion,
   - pipeline transport (pressure, cross-section, volume and mass flows, compressor capacity).

2. Where is experience with handling and transporting CO_2 or with transporting gases with similar properties (e.g. LPG) located already?

3. Who is likely to be operating CO_2 pipelines?

4. What combinations of onshore/offshore transport systems are conceivable (e.g. onshore pipelines + main pipeline + intermediate storage + ship loading + …) and which of these make sense?

5. What infrastructure questions arise (loading/unloading systems, competition with existing shipping, etc.)?

6. What selection of route makes sense (in economic and ecological terms and in relation to questions of risk and acceptance)?

7. How many compressor stations (electrical/gas-powered) must be constructed, and where?

8. What questions are relevant for cost analysis?
   - € per kilometre of pipeline (as function of diameter, pressure, volume/mass flows, topography…).
   - € per tonne-kilometre of transported CO_2 (as function of phase, capacity, maturity of technology …).
   - Cost of additional equipment (liquefiers, compressors, collectors, measuring stations…).

9. What might the learning curves for CO_2 pipelines look like (individual pipelines, networks, etc.)?

10. What questions are relevant when analysing the timeframe?
    - When could which power stations and CO_2 sinks come into operation?
    - When will which sinks be full?

- How long would it take to set up a CO_2 pipeline infrastructure (time for planning, approval and construction)?
- When will which CO_2 intermediate storage facilities be required, and when will they be available (for offshore ship transport and onshore road and rail transport)?

11. What approval procedures and planning periods are generally required for building new pipelines or expanding existing ones?

12. What problems can arise if CO_2 pipelines are constructed parallel to existing natural gas pipelines (e.g. space requirement where route is narrow, acceptance if additional forest clearance necessary)?

13. What CO_2-specific requirements are the pipeline network and components such as compressors, measuring stations subject to in terms of safety, corrosion, etc.?

14. Where CO_2 is transported in the supercritical state: is it sufficient to compress once at the beginning (at the power station) or are additional compressor stations required? If so, after what distances or pressure losses?

15. Might disused town gas pipelines be suitable for CO_2 transport (following conversion)? If so, what is their geographical distribution (transport from where to where) and what transport capacities do they provide?

A.5 Data Used for Analysing Mass Flows of Fuel and CO_2 (to Chapter 10)

See Tables A–3 and A–4.

Table A–3: Analysis of additional fuel quantities required for CCS and quantities of CO_2 to be disposed of for different power station types (**electricity production**)

1) CO_2 quantities

Fuel	Process	Specific CO_2 emissions (fuel) [g_{CO_2}/MJ_{in}]	Specific CO_2 emissions (fuel) [g_{CO_2}/kWh_{in}]	Power station output (net) [MW_{el}]	Efficiency η_{el} without CCS [%]	Efficiency η_{el} with CCS [%]	Specific CO_2 emissions (electricity) without CCS [g_{CO_2}/kWh_{el}]	Specific CO_2 emissions (electricity) with CCS [g_{CO_2}/kWh_{el}]	Full load hours [h/a]	Annual electricity production [MWh_{el}/a]	Annual production of CO_2 without CCS [t_{CO_2}/a]	Annual production of CO_2 with CCS [t_{CO_2}/a]	Capture rate [%]	CO_2 to be disposed of [t_{CO_2}/a]
Lignite	Steam turbine	112	403	700	46%	34%	877	1,186	7,000	4,900,000	4,294,957	5,810,824	88%	5,113,525
Coal	Steam turbine	92	331	700	49%	40%	676	828	7,000	4,900,000	3,312,000	4,057,200	88%	3,570,336
	Steam turbine, Oxyfuel	92	331	700	49%	38%	676	872	7,000	4,900,000	3,312,000	4,270,737	99,5%	4,249,383
	IGCC	92	331	700	50%	42%	662	789	7,000	4,900,000	3,245,760	3,864,000	88%	3,400,320
Natural gas	CC	56	202	700	60%	51%	336	395	7,000	4,900,000	1,646,400	1,936,941	88%	1,704,508
Extra light fuel oil	CHP	74	266	2	38%	–	701	–	4,000	8,000	5,608	–	–	–

2) Fuel quantities

Fuel	Process	Fuel consumption without CCS [MWh/a]	Fuel consumption with CCS [MWh/a]	Difference with / without CCS [MWh/a]	Difference [%]	Calorific value of fuel [MJ/kg]	Calorific value of fuel [kWh/kg]	Fuel density	Fuel consumption without CCS	Fuel consumption with CCS	Additional fuel for CCS
Lignite	Steam turbine	10,652,174	14,411,765	3,759,591	35%	8.6	2.39	1kg/kg	4,459,050 t/a	6,032,832 t/a	1,573,782 t/a
Coal	Steam turbine	10,000,000	12,250,000	2,250,000	23%	29.4	8.17	1kg/kg	1,224,490 t/a	1,500,000 t/a	275,510 t/a
	Steam turbine, Oxyfuel	10,000,000	12,894,737	2,894,737	29%	30.4	8.44	1kg/kg	1,184,211 t/a	1,527,008 t/a	342,798 t/a
	IGCC	9,800,000	11,666,667	1,866,667	19%	29.4	8.17	1kg/kg	1,200,000 t/a	1,428,571 t/a	228,571 t/a
Natural gas	CC	8,166,667	9,607,843	1,441,176	18%	46.5	12.92	0.780 kg/m³	810,587,262 m³/a	953,632,073 m³/a	143,044,811 m³/a
Extra light fuel oil	CHP	21,053	–	–	–	42.7	11.86	0.845 kg/l	2,100,508 l/a	–	–

Shaded cells are modifiable starting parameters

Source for specific fuel data (emissions, calorific value, density): BayLfU (2004)

Table A–4: Analysis of additional fuel quantities required and quantities of CO_2 to be disposed of for different synthesis gas plants (**H_2 production**)

1) CO_2 quantities

Fuel	Process	Specific CO_2 emissions (fuel) $[g_{CO2}/MJ_{in}]$	Specific CO_2 emissions (fuel) $[g_{CO2}/kWh_{in}]$	Net output without CCS $[MW_{th}]$	Net output with CCS $[MW_{th}]$	Process efficiency η without CCS [%]	Process efficiency η with CCS [%]	Spezific CO_2 emissions (H_2) without CCS $[g_{CO2}/kWh_{th}]$	Spezific CO_2 emissions (H_2) with CCS $[g_{CO2}/kWh_{th}]$	Full load hours [h/a]	Annual H_2 production $[MWh_{th}/a]$	Annual production of CO_2 without CCS $[t_{CO2}/a]$	Annual production of CO_2 with CCS $[t_{CO2}/a]$	Capture rate [%]	CO_2 to be disposed of $[t_{CO2}/a]$
Coal	Gasification	92	331	560	522	59%	55%	561	602	8,000	4,480,000	2,514,875	2,697,775	88%	**2,374,042**
Natural gas	Steam reforming	56	202	350	329	74%	69%	274	292	8,000	2,800,000	766,957	816,903	71%	**580,001**

2) Fuel quantities

Fuel	Process	Fuel consumption without CCS [MWh/a]	Fuel consumption with CCS [MWh/a]	Difference without / with CCS [MWh/a]	Calorific value of fuel [%]	Calorific value of fuel [MJ/kg]	Calorific value of fuel [kWh/kg]	Fuel density	Fuel consumption without CCS	Fuel consumption with CCS	Additional fuel for CCS
Coal	Gasification	7,593,220	8,145,455	552.234	7%	29.4	8.17	1 kg/kg	929,782 t/a	997,403 t/a	**67,621 t/a**
Natural gas	Steam reforming	3,804,348	4,052,098	247.751	7%	46.5	12.92	0.780 kg/m³	377,602,762 m³/a	402,193,390 m³/a	**24,590,628 m³/a**

Shaded cells are modifiable starting parameters

Efficiency figures relate to the heating value of H_2 (3.00 kWh/Nm³)

Conversion factor for H_2 calorific value (3.55 kWh/Nm³ / 3.00 kWh/Nm3) = 1.18

Source for specific fuel data (emissions, calorific value, density): Bayl.flU (2004)

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