INTERNATIONAL ENERGY AGENCY

Energy Technology Analysis

PROSPECTS
FOR
CO$_2$ CAPTURE
AND
STORAGE

OECD

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ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty Member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;

- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;

- to operate a permanent information system on the international oil market;

- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;

- to assist in the integration of environmental and energy policies.

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Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- to achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;

- to contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and

- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

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FOREWORD

Fossil fuels will be used extensively and CO_2 emissions will rise over the next half century, if no new policies are put in place. It is clear that such a development is not sustainable. A number of options exist that can reduce the CO_2 emissions from the energy system. These include improved energy efficiency and a switch to renewable and nuclear energy. However, policies based on these options will, at best, only partly solve the problem. Carbon dioxide capture and storage (CCS) technologies constitute another promising option that can drastically reduce these emissions. To accomplish this, governments need to take action now to ensure that CCS technologies are developed and deployed on a large scale over the next few decades.

This publication describes the challenges that must be overcome for a CCS strategy to reach market introduction and achieve its full potential within the next 30-50 years. The quantitative and qualitative analyses in this book reveal that large-scale uptake of capture and storage technologies is probably 10 years off, and that without a major increase in RD&D investment, the technology will not be in place to realize its full potential in the coming decades. Effective emission reduction incentives will be needed to achieve market deployment from 2015 onward. Additional policies will have to be implemented to remove barriers and reduce uncertainties. If the right action is taken, CCS could become an essential 'transition technology' to a sustainable energy system for the next 50 to 100 years.

This volume shows how CCS technologies can help to reduce emissions significantly over the coming two to five decades. The analysis includes three important elements. First, it provides a comprehensive overview of the prospects, costs and RD&D challenges of CO_2 capture, transportation and storage technologies. Second, using a newly developed energy technology model, it presents global scenario analyses that investigate how CCS technologies can contribute to reducing CO_2 emissions and what conditions would be necessary to justify stepping up RD&D and international efforts to advance CCS. Finally, the third element highlights the priority policy actions that should be taken to ensure the timely deployment of CCS technologies.

The results suggest that an aggressive policy of developing and deploying CCS technologies could indeed achieve substantial reductions in worldwide CO_2 emissions. Although the main role of CCS would be in the electricity sector, interesting possibilities also exist in manufacturing and in the production of transportation fuels. With sufficient technology investment, and after successfully solving various environmental and legal issues, CCS can provide a way to curb greenhouse gas emissions substantially at acceptable costs in most areas in the world.

This publication is the first in a new IEA series entitled Energy Technology Analysis. The goal of this series is to use quantitative model analysis for the assessment of the prospects of emerging energy technologies and their potential impact on energy supply security, economic development and the environment. I am confident that this analysis provides new insights for IEA member governments and other decision makers on how to use innovative technologies as part of an efficient long-term emissions mitigation strategy.

Claude Mandil
Executive Director

ACKNOWLEDGEMENTS

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OVERVIEW

The IEA World Energy Outlook (WEO) Reference Scenario projects that, based on policies in place, by 2030 CO_2 emissions will have increased by 63% from today's level, which is almost 90% higher than 1990 levels. Even in the WEO 2004's World Alternative Policy Scenario – which analyses the impact of additional mitigation policies up to 2030 – global CO_2 emissions would increase 40% on today's level, putting them 62% higher than in 1990. Hence, to avoid substantial increases over the next few decades, stronger actions than those currently being considered by governments must be taken, including the development and deployment of technology options that have the potential to cut emissions significantly. One such option is to capture the CO_2 produced from fuel use at major point sources and prevent it from reaching the atmosphere by storing it.

This study shows that CO_2 capture and storage (CCS) is a promising emission reduction option with potentially important environmental, economic and energy supply security benefits. But more research and investment into CO_2 capture and storage is required. This study highlights the fact that large-scale uptake of capture and storage technologies is probably 10 years off and that, without a major increase in RD&D investment, the technology will not be in place to realise its full potential as an emissions mitigation tool from 2030 onwards.

This study compares CCS and other emission mitigation options and assesses its prospects. It describes the challenges that must be overcome for a CCS strategy to reach market introduction by 2015 and achieve its full potential over the next 30-50 years. It identifies the major issues and uncertainties that should be considered when deploying CCS as part of an emission mitigation strategy.

This analysis is in three parts. The first provides a comprehensive overview of the prospects, costs and R&D challenges of CO_2 capture, transportation and storage technologies. The second quantitatively tests the hypothesis that CCS is a viable and competitive strategy for cutting emissions and that it is worthwhile accelerating RD&D and international efforts to advance CCS to the levels required. The third highlights the priority actions that would need to be taken for the timely deployment of CCS as an emissions mitigation tool.

What is CO_2 capture & storage?

CO_2 capture and storage (CCS) involves three distinct processes, shown in the figure below: first, *capturing* CO_2 from the gas streams emitted during electricity production, industrial processes or fuel processing; second, *transporting* the captured CO_2 by pipeline or in tankers; and third *storing* CO_2 underground in deep saline aquifers, depleted oil and gas reservoirs or unmineable coal seams. All three processes have been in use for decades, albeit not with the purpose of storing CO_2. Further development is needed, especially on the capture and storage of CO_2. While pipeline transport is an established technology, the siting of CCS projects can reduce the need for an extensive transportation system. The challenge, cost and environmental impact of such a CO_2 pipeline system should not be underestimated.

What are the current and planned CCS projects?

An overview of CCS projects is provided in the table below. In most CO_2 capture demonstration projects, existing technologies are applied. Various small-scale pilot plants based on new capture technologies are in operation around the world. Only one power plant demonstration project on a megatonne-scale has so far been announced: the FutureGen project in the US. This is a coal-fired

CO$_2$ Capture, Transport and Storage Concept

CAPTURE for example

Power plants

Gas processing

Illustration: BUG, Statoil
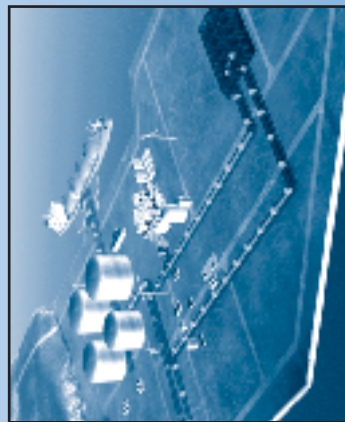
TRANSPORT

Pipelines

Ships

Photo: Sealand, Statoil
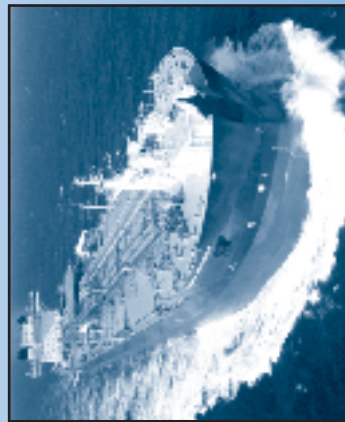
STORAGE for example
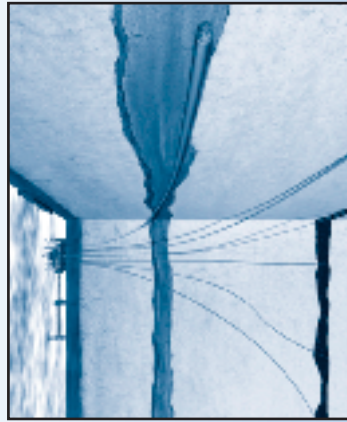
Storage in saline aquifers

Illustration: D. Fierstein, Statoil
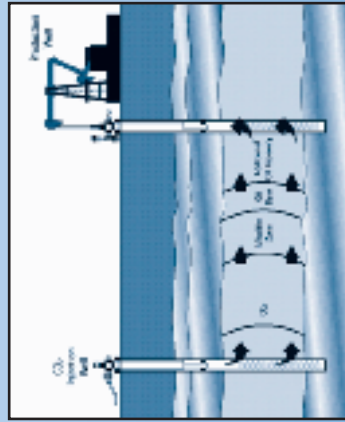
Enhanced oil recovery

Illustration: IEA GHG R&D Programme

advanced power plant for cogeneration of electricity and hydrogen. Its construction is planned to start in 2007. Other demonstration projects are planned in Canada, Europe, and Australia.

There are one hundred ongoing and proposed geologic storage projects. Two of these projects deserve special mentioning because of their scale. Storage in deep saline aquifers has been demonstrated in one commercial-scale project, at the Sleipner site in Norway (sub-sea storage). About 1 Mt of CO_2 per year has been stored since 1996. This project is important as it proves that storage in aquifers can work in practice. No leakage has so far been detected. Using CO_2 to enhance oil recovery and CO_2 storage underground have been demonstrated at the Weyburn project in Canada. About 2 Mt of CO_2 per year has been stored since 2001. In both projects the behaviour of the CO_2 underground has corresponded to what models had predicted, and important progress was achieved in the monitoring of CO_2 underground. Pilot projects suggest that CO_2-enhanced coal-bed methane (ECBM) and enhanced gas recovery (EGR) may be viable but the experience so far is not sufficient to consider these two as proven options. Encouraged by these promising results, many more storage demonstration projects have been started or are planned.

Overview of worldwide CCS projects

	No. of projects
CO_2 capture demonstration projects	11
CO_2 capture R&D projects	35
Geologic storage projects	26
Geologic storage R&D projects	74
Ocean storage R&D projects	9

Where could CO₂ capture technology be applied?

In principle, CO_2 can be captured from all installations used to combust fossil fuels and biomass, provided that the scale of the emissions source is large enough. In practice, only three areas are suitable: electricity generation (including district heating and industrial combined heat and power generation), industrial processes, and fuels processing. Emissions from other sources – such as the transport, agriculture, service and residential sectors – are too dispersed to make capture viable. Alternative measures, such as enhancing energy efficiency, renewables, CHP and increased use of hydrogen produced at centralised facilities fitted with CO_2 capture technology, may be better options for these sectors.

Since power production is responsible for over 29% of global CO_2 emissions, capturing from electricity plants offers the best initial potential for capturing the CO_2 generated from fossil-fuel use. To a lesser extent, CO_2 can also be captured during the production of iron, steel, cement, chemicals and pulp, and from oil refining, natural gas processing and the production of synthetic fuels (such as hydrogen and liquid transportation fuels from natural gas, coal or biomass).

Which CO₂ capture technologies are most promising?

CO_2 can be captured either before or after combustion using a range of existing and emerging technologies. In conventional processes, CO_2 is captured from the flue gases produced during combustion (post-combustion capture). It is also possible to convert the hydrocarbon fuel into CO_2 and hydrogen, remove the CO_2 from the fuel gas and combust the hydrogen (pre-combustion capture).

In pre-combustion, physical absorption of CO_2 is the most promising capture option. In post-combustion capture, options include processes based on chemical absorption or oxyfueling (combustion using oxygen separated from air, which generates nearly pure CO_2 flue gas). Chemical and physical absorption are proven technologies. Longer-term, gas separation membranes and other new technologies may be used for both pre- and post-combustion capture.

In electricity generation, CO_2 capture is most effective when used in combination with large-scale, high-efficiency power plants. Indeed, the success of a CCS strategy could depend on the use of such plants. For coal-fired plants, Integrated Gasification Combined Cycle (IGCC) fitted with physical absorption technology to capture CO_2 at the pre-combustion stage is considered to be promising. Coal-fired Ultra Supercritical Steam Cycles (USCSC) fitted with post-combustion capture technologies or various types of oxyfueling technology (including chemical looping, where the oxygen is supplied through a chemical reaction), may emerge as alternatives. For natural gas-fired plants, oxyfueling (including chemical looping), pre-combustion gas shifting and physical absorption in combination with hydrogen turbines, or post-combustion chemical absorption are promising options. At a later stage, fuel cells may be integrated into high-efficiency coal- and gas-fired power plants fitted with CCS. Capturing CO_2 from plants which co-generate electricity and synthetic fuels could have additional cost savings compared to stand-alone power production with CO_2 capture.

Advances in capture technology are needed to reduce the cost of CO_2 capture from power generation. Given the range of ongoing R&D efforts, it is not yet possible to pick a 'winning' capture technology. It is likely that several will be used in future. All require further improvements to cut costs and improve capture efficiency before they can be applied on a commercial scale, a process which is likely to take years. RD&D must be accelerated if CCS is to play a substantial role in the coming decades and have a significant impact on emissions.

How much CO₂ storage capacity is available?

Deep saline aquifers, depleted oil and gas reservoirs and unmineable coal seams offer the best option for underground CO_2 storage. This includes sub-sea reservoirs. Oceanic storage (*i.e.*, CO_2 storage in the water column) is problematic given the unknown environmental impacts. Surface mineralization is still at a conceptual stage.

In underground reservoirs, CO_2 is stored as a bubble under an impermeable caprock at a depth of more than 800 meters, in the top part of a water-filled reservoir rock. Deep saline aquifers offer potentially decades or hundreds of years' worth of storage capacity with between 1,000-10,000 Gt of capacity available, possibly even more. This is the single most important underground storage potential. Around 920 Gt of CO_2 could be stored in depleted oil and gas fields. The storage capacity of unmineable coal seams, where CO_2 is absorbed on the coal surface, is an order of magnitude smaller. While the absolute value of the potentials are uncertain as of yet, it is clear that they are large. CO_2 storage may be combined with enhanced oil recovery (EOR), enhanced coalbed methane recovery (ECBM), and enhanced gas recovery (EGR). Such combinations could create revenues that may offset part or even all of the capture and transportation cost.

Many storage sites are far from large emission sources. Coupled with the fact that long-range intercontinental transportation of CO_2 would incur significant additional cost, this means that the economic storage potential is country and region specific and smaller than the total geologic storage potential. However, in most world regions storage capacities do not pose a constraint for widespread CCS use for decades to come.

What is the risk and effect of CO_2 leakage back into the atmosphere?

All three storage options – deep saline aquifers, depleted oil and gas reserves and unmineable coal seams – need more proof on a large scale. The technology to store CO_2 underground should be considered proven technology. The problem is whether the CO_2 will leak from underground storage sites back into the atmosphere. The leakage discussion can be split into two parts: the question to what extent leakage can reduce the emissions reduction effectiveness of CCS, and public concerns that CO_2 leakage can be dangerous.

Small leakages of CO_2 may occur over a long period of time, which could reduce the effectiveness of CCS as an emission mitigation option. This so-called permanence problem is currently dealt with through field tests and through modelling studies. Depleted oil and gas fields have contained hydrocarbons for millions of years. This makes them a relatively safe place to store CO_2. The problem for such reservoirs is mainly if the extraction activity has created leakage pathways, and if abandoned boreholes can be plugged properly so the CO_2 cannot escape. The only existing large-scale aquifer storage demonstration project has shown no leakage since it started eight years ago. Many projects for natural gas storage and acid gas storage have worked well. Progress in modelling allows increasingly accurate forecasts of the long-term fate of the CO_2, which cannot be tested in practice. Several natural phenomena, such as CO_2 dissolution in the aquifer water, will reduce the long-term risk of leakage. The understanding of these phenomena is improving gradually.

CO_2 is not toxic, but CO_2 can be dangerous in high concentrations as it can cause suffocation due to lack of oxygen. Accidents where significant amounts of CO_2 are released from underground reservoirs, with potential risk for local residents, are highly unlikely. The storage under more than 800 metres of sediment excludes sudden eruptions of massive amounts of CO_2. However, there are cases where natural CO_2 emissions from underground have created locally dangerous situations. Proper CO_2 monitoring systems and remediation measures can prevent such problems.

While the RD&D results are encouraging, more pilot projects are needed to better understand and validate the permanence of underground storage in various geological formations and develop criteria to rank appropriate sites. Too strict criteria for leakage could unnecessarily reduce the potential for aquifer storage.

What is the cost of capturing, transporting and storing CO_2?

The future cost of capturing, transporting and storing CO_2 depends on which capture technologies are used, how they are applied, how far costs fall as a result of RD&D (innovation) and market uptake (learning-by-doing), and fuel prices. Since applying capture requires more energy use and leads to production of more CO_2, the cost per tonne of CO_2 emission mitigation is higher than the per tonne cost of capturing and storing CO_2. The gap between the two narrows as capture energy efficiency increases.

At this stage, the total cost of CCS could range from 50 to 100 USD per tonne of CO_2. This could drop significantly in future. In most cases, using CCS would cost 25-50 USD per tonne of CO_2 by 2030, compared to the same process without. Certain early opportunities exist with substantially lower cost, but their potential is limited.

The cost for CCS can be split into cost of capture, transportation and storage. Current estimates for large-scale **capture** systems (including CO_2 pressurization, excluding transportation and storage) are 25-50 USD per tonne of CO_2 but are expected to improve as the technology is developed and

deployed. If future efficiency gains are taken into account, costs could fall to 10-25 USD/t CO_2 for coal-fired plants and to 25-30 USD/t CO_2 for gas-fired plants over the next 25 years.

With CO_2 **transportation**, pipeline costs depend strongly on the volumes being transported and, to a lesser extent, on the distances involved. Large-scale pipeline transportation costs range from 1-5 USD/t CO_2 per 100 km. If CO_2 is shipped over long distances rather than transported in pipelines, the cost falls to around 15-25 USD/t CO_2 for a distance of 5,000 km.

The cost of CO_2 **storage** depends on the site, its location and method of injection chosen. In general, at around 1-2 USD per tonne of CO_2, storage costs are marginal compared to capture and transportation costs. Revenues from using CO_2 to enhance oil production (EOR) could be substantial (up to 55 USD/t CO_2), and enable the cost of CCS to be offset. However, such potential is highly site specific and would not apply to most CCS projects. Longer-term costs for monitoring and verification of storage sites are of secondary importance.

Using CCS with new coal- and gas-fired power plants would increase electricity production costs by 2-3 US cents/kWh. By 2030, CCS cost could fall to 1-2 US cents per kWh (including capture, transportation and storage).

How does the cost-effectiveness of CCS compare to other emission reduction options? The model analysis

CO_2 emission reduction options in the energy sector include lower carbon fossil fuels, renewables, nuclear, energy efficiency and CCS. Outside the energy sector there are options such as afforestation and land-use change, and reduction of non-CO_2 greenhouse gases. Each option is characterized by a (marginal) cost curve that allows for a certain emission reduction potential at a given CO_2 price. Therefore different options co-exist in a cost-effective policy mix. The more ambitious the emission reduction targets, the more options will be needed, and the more effective and costly the options that will be needed. CCS can reduce emissions by 85 to 95% compared to the same processes without CCS but it is a relatively costly emission reduction strategy. Therefore the widespread use of CCS only makes sense in a scenario with significant emission reduction.

The Energy Technology Perspectives (ETP) model is an economic partial equilibrium model. The world energy system for the period 2000-2050 is optimized, based on least cost. The model is based on a detailed representation of the energy system in terms of energy flows and energy technologies. Cost-effective emission reduction options are chosen from a technology database that contains options such as CCS, nuclear, renewables and energy efficiency. The model is a suitable tool with which to identify the best set of options and to map uncertainties.

CO_2 capture and storage (CCS) could potentially allow for the continued use of fossil fuels while at the same time achieving significant reductions in CO_2 emissions. Indeed, the results of IEA analysis show that CCS could even play a key role in a scenario where global CO_2 emissions are roughly stabilized at 2000 level by 2050. This would require significant policy action, however, equivalent to a CO_2 penalty level of 50 USD per tonne of CO_2. This scenario would halve emissions by 2050 compared to a scenario where no additional policy action was taken. CCS technologies contribute about half of the reductions achieved by 2050.

By 2050, 80% of the captured CO_2 would come from electricity production, particularly coal-fired generation. At a penalty level of 50$/t CO_2, power plants with CO_2 capture would represent 22% of total global installed generation capacity by 2050 and produce 39% of all electricity. Within the electricity sector, coal-fired IGCCs fitted with CCS that co-generate hydrogen and other

transportation fuels would play an important role. Capture from coal-fired processes would represent 65% of the total CO_2 captured by 2050, the remainder coming from gas, oil- and biomass-fired processes, and from cement kilns.

Up to 2025, CCS would mainly be applied in industrialized countries. By 2050, almost half of total capture activity could be rolled out in developing countries, mostly China and India. Technology transfer from industrialized countries (particularly of efficient power-generation plants) could help to realize the full potential of CCS in developing countries. If CO_2 policies were limited to industrialized countries, the role of CCS would be significantly reduced. This finding emphasizes the importance of international co-operation.

What would be the environmental benefits of CCS?

The potential benefits of CCS can be further illustrated by considering a scenario without CCS but with the same emission penalty level (50 USD/t CO_2). In this case, emission levels in 2050 would increase by over a quarter compared to the scenario in which CCS was included. In fact, without CCS, the CO_2 penalty imposed would need to be doubled before the same reductions could be achieved.

Additional scenarios were analysed that combine various key uncertainties such as the policy ambition level, the extent of international co-operation to mitigate emissions and the prospects for technological change. These scenarios suggest CCS potentials are between 3 Gt and 7.6 Gt CO_2 in 2030, and between 5.5 Gt and 19.2 Gt CO_2 in 2050. This compares to 38 Gt CO_2 emissions by 2030 under the WEO Reference Scenario. The fact that all scenarios show a potential on a Gt-scale suggests that CCS technologies constitute a robust option for emissions reduction.

Such results are sensitive to assumptions about future technology development, not only for CCS, but also for other mitigation options such as renewables and nuclear. More optimistic assumptions for the future cost reduction of renewables and the potential for expanding nuclear would considerably reduce the future role of CCS.

One important finding of this analysis is that renewables, nuclear and CCS technologies can co-exist as part of a cost-effective portfolio of options for reducing CO_2 emissions from energy production. However, the relative role of each would vary from region to region. It would also depend on policy efforts and cost developments for all technologies, the extent to which promising technology options actually work, institutional and legal barriers, and public acceptance (relevant for all three technology options). Investing in CCS RD&D could be a good 'insurance policy' for the future. Such a hedging approach would reduce the risk of failure.

What would be the fuel market consequences of CCS?

CCS would result in a significant increase in the use of coal compared to a scenario where CCS is not considered, but the same CO_2 policies are applied. As coal is considered a more secure fuel than oil and gas, the fact that coal remains a viable energy option increases supply security. CCS would have a limited impact on the use of oil and natural gas. CCS would result in a lower use of renewables and nuclear and increase clean fossil energy availability. However, this model result does not account for the uncertain growth potential of cost-effective renewables. Coal on the other hand is an established fuel. As CCS makes coal a more sustainable option, it increases the security of supply, even in regions where the actual investments in coal are of a limited scale.

For regions with ample coal reserves, such as North America, China and India, CCS could result in lower imports and increased reliance on domestic energy sources. For a number of countries such

as Australia, coal exports would be higher if global coal consumption were higher. This could have economic advantages that need to be analysed in more detail.

Is CCS relevant for all countries and all regions?

The relevance of CCS differs by region. Model analysis suggests that CCS can become an important option in North America, Australia and parts of Europe. While the CCS potentials in China and India are important as well, the realization of these potentials will depend on the extent of global efforts to reduce CO_2 emissions. If CO_2 policies are limited to industrialized countries, the role of CCS is significantly reduced on a global scale. This finding emphasizes the importance of technology transfer and international co-operation on both technology and policy.

Given that long-range transportation of CO_2 seems an unlikely option given its high cost, for countries without sufficient storage potential close to their emission sources, it may be more cost effective to consider alternative emission reduction strategies. While having CCS in a CO_2 policy portfolio is certainly attractive, the issue of its application will require a careful case-by-case project evaluation. This evaluation must account for the energy system characteristics on the continental, the country and the local scale.

What will it take to bring CO$_2$ capture & storage to market?

There is a 'window of opportunity' for CCS to compete as a technology option, starting from around 2020 and peaking in the second half of the 21st century. Beyond that, CO_2-free alternatives would make CCS redundant. In other words, CCS should be considered an essential 'transition technology' to a sustainable energy system for the next 50 to 100 years.

The single most important hurdle which CCS must overcome is public acceptance of storing CO_2 underground. Unless it can be proven that CO_2 can be permanently and safely stored over the long term, the option will be untenable, whatever its additional benefits.

The potential for 2030 is two to three orders of magnitude greater than the projected Mt-scale demonstration projects for 2015. This indicates the need for significantly increasing both investment in RD&D and the scope of projects, if a CCS strategy is to succeed. Taken together, all the planned CCS projects in the coming decade will barely reach the 10 Mt per year scale. If the full emission mitigation potential of CCS is to be realized, RD&D activities need to be scaled up and accelerated significantly.

Achieving this will require increasing the number of commercial scale storage pilot projects over the next 10 years and ensuring that the general public is consulted throughout. RD&D should initially focus on storage projects which enhance fossil-fuel production and those which advance knowledge on sub-sea underground storage, and aquifer storage in locations with low population density, in order to minimize planning hurdles. Processes which consult, review, comment and address stakeholder concerns should be built into all pilot projects. Procedures for independently verifying and monitoring storage and related activities should also be established. Finally, a regulatory and legal framework for CO_2 storage projects must be developed to address issues around liability, licensing, leakage, landowner, royalty and citizens rights.

Governments must address the present shortage of sizeable RD&D projects in order to advance technological understanding, increase efficiency and drive down costs. This will require increasing RD&D, investment into CCS demonstration projects, and power-plant efficiency improvements. By 2015 at least 10 major power plants fitted with capture technology need to be operating. These

plants would cost between 500 million and 1 billion USD each, half of which would be additional cost for CCS. The current CCS budget is over 100 million USD per year. The needed RD&D would represent a fivefold increase. While the amount required is challenging, it is not insurmountable given the scale of past energy RD&D budgets. It would represent a 30% increase of the current total RD&D budget for fossil fuels and power & storage technologies. Leveraging the funds in private/public partnerships is essential.

Creation of an enabling environment to ensure technology development must be accompanied by the simultaneous development of legal and regulatory frameworks. In the interests of time, and given the diversity of institutional arrangements and policy processes between countries, working at the national level using existing frameworks may be the best short-term option.

Finally, countries should create a level-playing field for CCS alongside other climate change mitigation technologies. This includes ensuring that various climate change mitigation instruments, including market-oriented trading schemes, are adapted to include CCS. The future role of CCS depends critically on sufficiently ambitious CO_2 policies in non-OECD countries. Therefore, outreach programmes to developing countries and transition economies and international commitment to reduce CO_2 emissions are a prerequisite. The maturation of a global emissions-trading scheme, a meaningful price for CO_2 and a predictable return on investment are important factors that could stimulate the timely deployment of CCS.

Chapter 1.
INTRODUCTION

Governments around the world are increasingly interested in CO_2 capture and storage (CCS) as a way of mitigating rising greenhouse gas emissions. Various international bodies established under auspices of the International Energy Agency explore the viability of CCS. These include the IEA Greenhouse Gas R&D Programme[1] which has been assessing CO_2 capture and storage technology for over 10 years (Freund and Davison, 2002), and the Working Party on Fossil Fuels, one of the IEA standing committees, which has focused on measures to introduce CO_2 capture (McKee, 2002). Such interest is supported by an increasing body of scientific knowledge on CCS collected over the past 30 years (Marchetti, 1977).[2]

With energy demand projected to rise by over 60% up to 2030, limiting CO_2 emissions from energy use is becoming ever more pressing. CCS is a strategy which can 'buy time' until CO_2-free energy solutions prevail. While the projected quantities of CO_2 which would need to be captured and stored to achieve significant global reductions are huge, technologies exist to do so. The extent to which CCS could be applied, however, remains in doubt, as does the benefit and impact such a strategy would have on the world economy, energy markets and electricity prices. Similarly, the rate at which CCS could be adopted and the way this could be done remain unclear, as does the attractiveness of CCS compared with other mitigation options, such as renewable energy or nuclear power.

The IEA Governing Board recently emphasized the importance of CO_2 capture and storage and requested the IEA Secretariat to prepare advice on a long-term policy framework to facilitate the commercial application of capture and storage of CO_2 from fossil fuels.

In line with this objective, this study sheds light on the economic potential for CO_2 capture and storage over the next 30-50 years using the Energy Technology Perspectives (ETP) model, a quantitative optimization model developed by the IEA. It assesses the prospects for CCS technologies based on the energy resources regions, regional and sectoral shifts in global energy demand, and modifications in energy technology portfolios. It compares CCS with other emission mitigation options and identifies key issues and uncertainties that should be considered in relation to CCS and its use as a CO_2 emission mitigation tool.

The study identifies the main uncertainties surrounding CCS, using sensitivity analyses and scenario analysis techniques. The results are cross-compared to determine the role for CCS under different scenarios in key world regions, and analysis is also undertaken to asses the impact of CCS on fuel markets using different CO_2 abatement incentives.

The ETP model findings are complemented by a detailed description of the current and promising technologies needed for CCS, where these can be applied, and their associated cost and energy requirements. An assessment is also made of the major policy mechanisms necessary to bring CCS

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1. The IEA Greenhouse Gas R&D Programme is one of 40 IEA Implementing Agreements. The Programme's main focus is on CO_2 capture and storage, making it the world's leading international research co-operation effort in this field. Some other Implementing Agreements – such as the Clean Coal Centre (CCC), the Energy Technology Systems Analysis Programme (ETSAP), and the Hydrogen Implementing Agreement – also work in this area, but it is not their main task.

2. Marchetti's paper focused on power plants with CO_2 capture and oceanic storage, using the downward flow from the Mediterranean sea into the Atlantic in the Strait of Gibraltar. Oceanic storage is still regarded as controversial.

technologies through R&D and deployment to commercialization, as well as issues around public acceptance, leakage monitoring, legal and regulatory frameworks, and timing.

The discussion of CO_2 capture technologies and the issues surrounding the permanence of CO_2 storage addressed in this book are not exhaustive. The special report on CCS by the Intergovernmental Panel on Climate Change (IPCC), scheduled for release in 2005, will discuss these topics in far greater detail. Nor does this publication aim to provide a technology roadmap. Instead, the reader is referred to the various roadmaps published in recent years (e.g. Henderson 2003, CO_2CRC 2004, McKee 2004a).

The IEA anticipates that the qualitative and quantitative insights provided by this study will help governments and industries that are considering adopting strategies to mitigate CO_2 emissions to better understand the status, cost and potential of CCS technologies and the steps required to bring them to full-scale implementation.

The Purpose of the Study

This book has three purposes. Firstly, it provides a comprehensive overview of the prospects, costs and R&D challenges of CO_2 capture, transportation and storage (CCS) technologies. Secondly, it tests the hypothesis that CCS is indeed a viable and competitive option for mitigating CO_2 emissions and that it is worthwhile accelerating R&D and international efforts to advance the technologies. Thirdly, it highlights the actions that would be needed if CCS were to be deployed as part of a CO_2 mitigation strategy. The following questions are addressed in this book:

- What are the characteristics of the energy system and its CO_2 emissions, and how can the role of CCS in this system be analysed?

- What is the current status of CCS technologies and what R&D gaps need to be filled?

- How do the environmental and cost benefits of CCS compare with other greenhouse gas emission mitigation strategies?

- What potential does CCS have as a mitigation strategy, and what are the risks and uncertainties of such a strategy?

- What impact would a CCS strategy have on fuel markets and overall energy supply security?

- Is it worth accelerating R&D into CCS technologies and, if so, what are the benefits of doing so and the international efforts required?

The Structure of the Study

The book is divided into eight chapters, four of which present the findings of the Energy Technology Perspectives (ETP) model, and two of which provide an overview of the status of CCS technologies and the major challenges which would need to be overcome if CCS were to be used as part of a CO_2 mitigation strategy.

Chapter 2 sets the scene by identifying the factors which have shaped past emission trends and those likely to be important for the evolution of the future energy system if no further climate or energy policies are enacted beyond those in place today. This is followed by a discussion of how CO_2 emissions could be reduced in the future through the development and deployment of various new energy technologies, one of which is CO_2 capture and storage (CCS).

Chapter 3 provides a qualitative assessment of the technical and economic characteristics of CO_2 capture, transportation and storage technologies, data which the ETP model uses to quantify the potential for CCS. The assessment is based on a comprehensive review of governmental publications, industry studies, peer-reviewed scientific literature and 'grey' literature such as workshop presentations.

Chapters 4, 5, 6 and 7 set out the four groups of results from the ETP model analysis.

Chapter 4 begins with an overview of the ETP model, setting out the method used to quantitatively assess the way in which CCS could reduce global CO_2 emissions. It then gives the results from the ETP BASE Scenario, followed by a detailed analysis of one scenario in which a penalty of 50 USD/t CO_2 is imposed globally, a reference case known as the GLO50 Scenario. Finally, it considers the benefits of deploying CCS, based on a set of model runs with and without CCS.

Chapter 5 discusses the results of sensitivity analysis undertaken on the ETP model's GLO50 Scenario in order to map the various uncertainties associated with individual parameters for CCS technologies, or parameters that affect the use of CCS technologies. Understanding this is a key part of determining if and how a CCS strategy should be applied, the impact that factors such as economic growth, technology development, environmental policy and regional deployment could have on CCS use, and the interrelation between the parameters.

Chapter 6 presents and compares the results of four ETP scenarios to assess the interactions of specific parameters identified during the sensitivity analysis outlined in Chapter 5 and hence the robustness of the results. In the first instance, the scenario results for CCS are considered on a global level. This is followed by a discussion of the regional scenario results. The regional results are then compared against actual and planned RD&D activities. This analysis provides insights for the CCS policy challenges discussed in Chapter 8.

Chapter 7 discusses the consequences of deploying CCS on fuel markets based on ETP model analysis. Apart from environmental concerns, supply security and economic consequences play an important role in the design of energy policies. While the analysis in the previous chapters showed that a CCS strategy can result in a significant reduction of CO_2 emissions and also lower the cost of environmental policies, it is less clear what impacts CCS would have on supply security and fuel prices.

Chapter 8 outlines the additional uncertainties associated with deploying CCS which are outside the scope of the ETP model but which could critically impact the timing and effectiveness of a CCS strategy. These factors, which are strongly interrelated, include bridging the RD&D gap to realize the potential for CCS, the need for public awareness and acceptance, the importance of putting in place appropriate legal and regulatory frameworks, particularly for CO_2 storage, and the need for a policy framework which encourages public-private sector co-operation and provides appropriate investment incentives.

Chapter 2.
THE WORLD ENERGY SYSTEM, CO$_2$ EMISSIONS AND MITIGATION OPTIONS

This chapter briefly reviews historical and future baseline developments of global CO_2 emissions. It sets out the factors which have shaped past emission trends and those likely to be important for the evolution of the future energy system if no further climate or energy policies are enacted beyond those in place today. This is followed by a discussion of how CO_2 emissions could be reduced in the future through the development and deployment of various new energy technologies, one of which is CO_2 capture and storage (CCS).

Global CO$_2$ Emissions: Past Trends and Future Outlook

Global CO_2 emissions increased by over 70% between 1971 and 2002. Since 1990 CO_2 emissions have risen by some 16% (Figure 2.1). The Reference Scenario of the IEA World Energy Outlook (WEO) projects that global emissions will be up 63% on today's level by 2030, around 90% higher than 1990 levels (IEA, 2004a). This corresponds to an average growth rate of 1.7% per year, roughly the same rate as over the last three decades (IEA, 2004b).

Historically, CO_2 emissions have come overwhelmingly from industrialized countries. However, two-thirds of the increase up to 2030 is expected to come from developing countries. By 2030, developing nations are set to account for almost 49% of global CO_2 emissions (up from 35% today), with OECD countries accounting for 42% and transition economies for 9% (IEA, 2004a).

Figure 2.1

Energy-related CO$_2$ emissions, globally and by region (1973-2030)
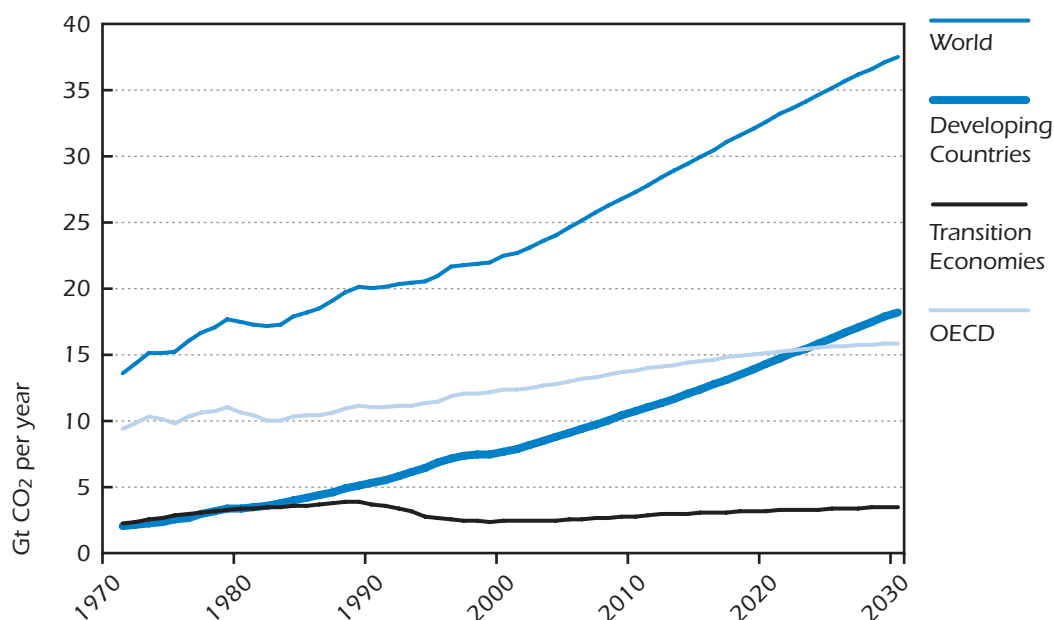
Note: Excludes CO_2 emissions from international marine bunkers.

Source: IEA, 2004a.

Over the past three decades, the burning of coal accounted for 40% of the *increase* in global CO_2 emissions, with oil responsible for 31% and gas 29%. The WEO Reference Scenario projects that of the *increase* in emissions between 2002 and 2030, oil will account for 37%, coal 33% and gas 30% (Figure 2.2). As a result, the share of coal in total emissions will drop from 39% in 2002 to 36% in 2030. The share of gas will rise from 21% to 24%, while the share of oil in total emissions remains roughly unchanged over the outlook period.

Figure 2.2

Energy-related CO_2 emissions by fuel (1973-2030)
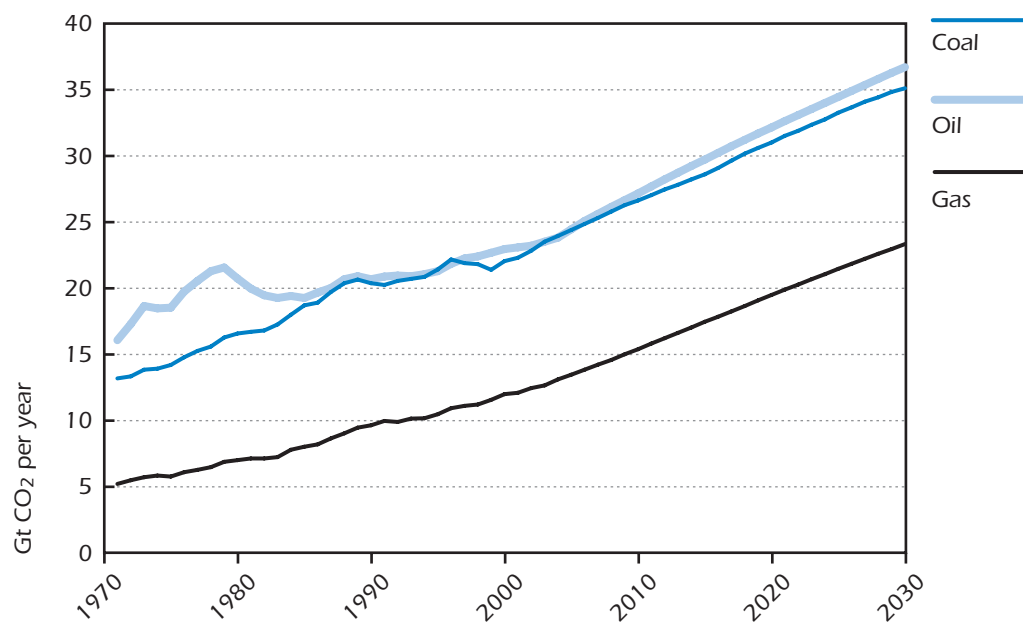
Note: Excludes CO_2 emissions from international marine bunkers.

Source: IEA, 2004a.

The Intergovernmental Panel on Climate Change (IPCC) published a Special Report on Emission Scenarios (SRES) in 2000 setting out a range of global emission paths up to 2100 (Nakićenović *et al.*, 2000). Figure 2.3 shows CO_2 emissions from energy use under three of these scenarios, all of which form part of the so-called SRES 'A1' storyline. These scenarios describe a future with very rapid economic growth in which the global population peaks in mid-century and declines thereafter, and in which new, more efficient technologies are rapidly introduced.

The A1 scenario group is divided into three sub-sets which describe alternative directions for technological change in the energy system: fossil-intensive (A1F1), non-fossil energy sources (A1T); and a balance across all energy sources (A1B).

While the level of CO_2 emissions in the three scenarios are fairly evenly matched up to 2020, they all show higher emission levels than the WEO 2004 Reference Scenario. Emissions increase through 2050 in all scenarios with 2050 levels ranging from 45 Gt to 85 Gt CO_2. Major differences occur after 2050. The cumulative emissions in these three scenarios are such that the CO_2 concentrations would range from 600 to 950 ppm by 2100, compared to the current concentration of roughly 375 ppm. This would result in an average global temperature increase of 3, 3.5 or 5 degrees Celsius for A1T, A1B and A1F1, respectively (with a margin of error of ±25%).

Even the A1T scenario, in which renewable energy technologies significantly reduce emissions after 2050, would result in significant global warming. This highlights the importance of reducing CO$_2$ emissions early to avoid atmospheric concentrations reaching levels that would have a serious impact on the climate beyond mid-century.

Figure 2.3

CO$_2$ emissions in the IPCC SRES A1 scenarios, compared to the WEO Reference Scenario
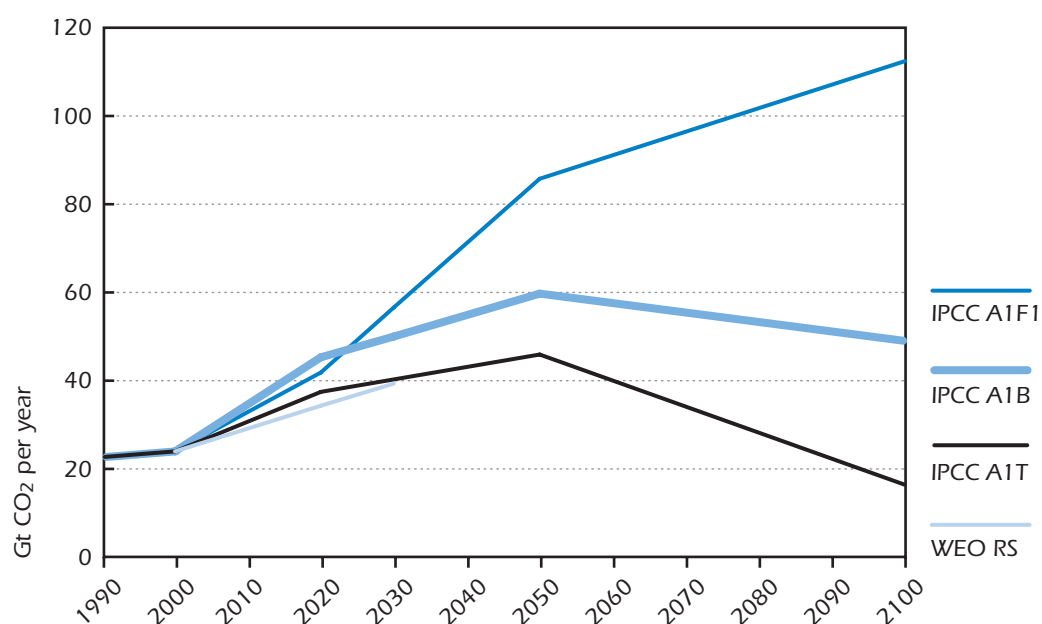
Source: IEA, 2004a; Nakićenović et al., 2000.

Factors Affecting and Strategies to Reduce CO$_2$ Emissions

Both the WEO Reference Scenario and the IPCC scenarios paint a challenging picture for energy policy makers: unless much stronger action is taken, CO$_2$ emissions from the global energy system will continue growing, with potentially serious implications for global warming. This implies that deep cuts in CO$_2$ emissions will only come about by transforming the way in which energy is supplied and used. While governments may emphasize different elements in their emission reduction strategies, this transformation must involve the more efficient production of fuels and electricity, the use of cleaner fuels and improved efficiency in converting energy into services for end-use consumers.

Understanding the factors which have shaped CO$_2$ emissions in the past, and those likely to do so in the future, is a first step in defining an emission reduction strategy. Growth in CO$_2$ emissions is clearly linked to the use of fossil fuels to meet the ever-increasing demand for energy services. In turn, demand for energy services is driven by economic growth, although historical data show that there has been a decoupling of the two: OECD countries and many non-OECD countries have

generally been successful in reducing the need for energy to fuel their economies. Today it takes only 70% of primary energy (in TPES terms) to produce one unit of the world's GDP than it did three decades ago. This decoupling of TPES from GDP can primarily be explained by three factors:

● Reduced demand for energy services relative to GDP;

● Improved energy efficiency in end-use sectors;

● Improved supply-side efficiency, particularly in electricity generation.

When considering the factors which link growth in GDP and energy-related CO_2 emissions, the list can be expanded to include the following:[1]

● The carbon content of the fuel used in different end-use sectors;

● The carbon content of the fuel used in electricity and district heat generation.

Average growth rates of world GDP and CO_2 emissions from 1973 to 2002 and throughout the projection period of the WEO are illustrated in Figure 2.4. Over the last three decades, GDP grew by 3.1% per annum, while CO_2 emissions increased at an average annual rate of 1.5 %, indicating an average annual decoupling rate of 1.6%. World economic growth throughout the Outlook period is assumed to be close to that seen from 1973-2002, but with a slightly stronger increase in CO_2 emissions of 1.7% per annum.

Figure 2.4

Growth in GDP and CO₂ emissions: decomposition of factors affecting the link
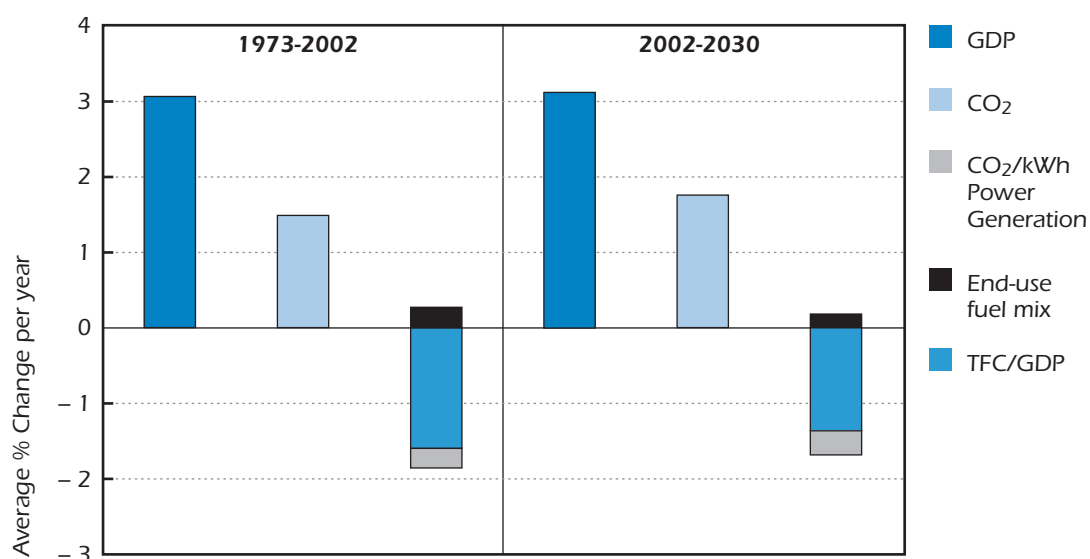
Source: IEA, 2004a.

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1. *In theory, the carbon content of fuels used to produce other secondary energy carriers (hydrogen and synthetic fuels) should also be taken into account. However, this factor has played a minor role in the past due to very modest production levels of these fuels to date.*

Figure 2.4 also illustrates the way in which CO$_2$ emissions have been decoupled from economic growth. The third bar in the figure illustrates the impact that changes in total final energy consumption (TFC) per GDP (factors 1 and 2 above), end-use fuel mix (*i.e.*, final energy mix, factor 4) and CO$_2$ intensity in power generation (factors 3 and 5) have each had on total CO$_2$ emissions developments. By far the most important component is the reduction in TFC per GDP. This decline is primarily due to improved end-use energy efficiency, although structural changes reducing the need for energy services relative to total GDP (*e.g.*, increased GDP from the service sector relative to that from steel production) also affected the development. A similar trend is expected up to 2030.

The world end-use fuel mix (including upstream emissions in electricity production) has become marginally more CO$_2$ intensive in recent decades, mostly due to the higher share taken up by electricity. Worldwide, electricity has a higher CO$_2$ intensity than fossil fuels due to generation losses and the high share of coal in the generation mix in most world regions (Figure 2.5). With a steady increase in the share of electricity in global final energy consumption expected up to 2030, the end-use fuel mix will continue to be a driving force for growth in global CO$_2$ emissions. On the other hand, the CO$_2$ intensity reduction of power generation itself has contributed to a lowering of emissions relative to GDP. This trend is expected to continue over the next 2-3 decades, although to a lesser extent.

Figure 2.5

CO$_2$ intensity in global electricity generation and fossil fuels
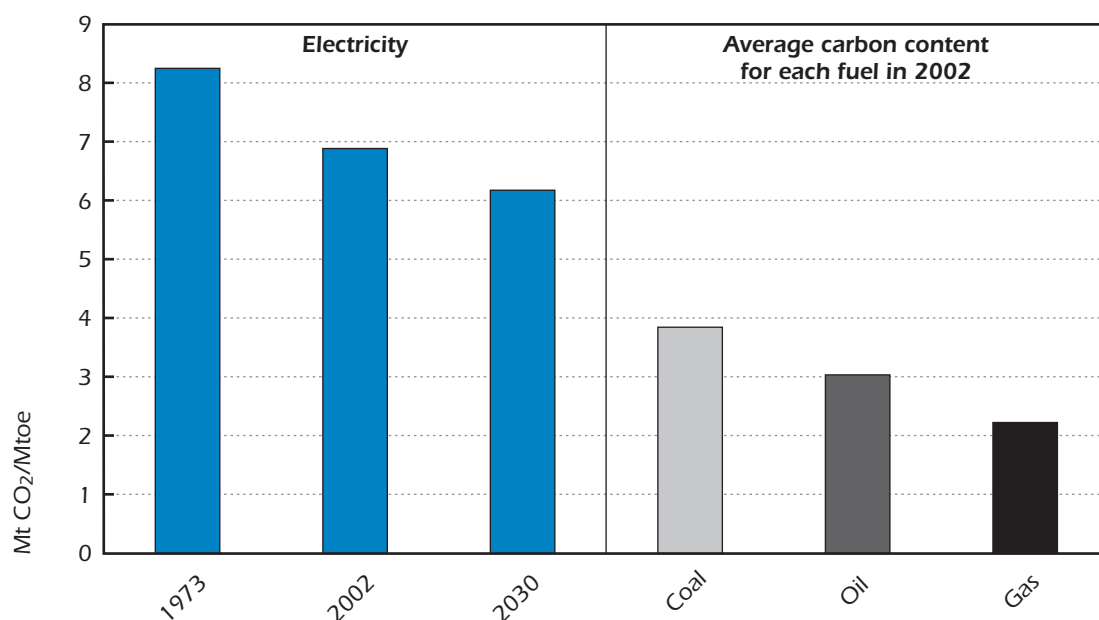
Source: IEA, 2004a.

In Figure 2.6, the fourth bar of each time period illustrates the impact of different factors affecting emissions from power generation; changes in the share of renewables; changes in the share of nuclear; changes in the mix of fossil fuels used for power generation; and changes in the efficiency of fossil-fuel based generation. The average annual percent change in these components adds up to the average annual percent change in CO$_2$ emissions per unit of electricity produced. The figure shows that the expansion of nuclear energy is the main reason for an historic decline in CO$_2$ intensity

in power generation. On the other hand, the share of renewable energy in power generation actually fell between 1973-2002, while more efficient fossil-fuelled power plants helped cut emissions over this period. The impact of changes in the fossil-fuel mix was modest.

In the WEO Reference Scenario, the reduction in carbon intensity in power generation over the Outlook period is less significant than that seen during the previous three decades. The main reason for this is that the share of nuclear energy in global electricity generation declines over the Outlook period. Although a substantial improvement in fossil-fuel-based generation efficiency and a lower carbon-fuel mix help to reduce emissions per unit of electricity produced, the total result is less of a decline in CO_2 intensity than that seen between 1973 and 2002.

Figure 2.6

Growth in electricity demand and CO₂ emissions from power generation: decomposition of factors affecting the link
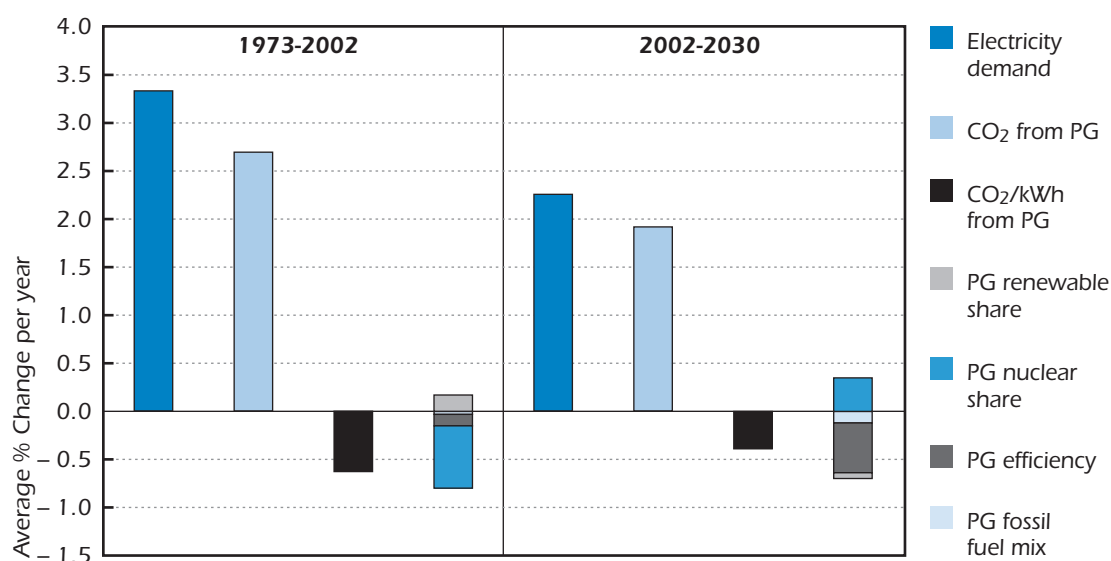
Note: PG = power generation.
Source: IEA, 2004a.

The increasing and then declining role of nuclear energy in the global electricity mix is also illustrated in Figure 2.7. The historical decline in the share of hydropower is expected to continue throughout the Outlook period. The increased share of other renewables, mostly wind, more than compensates for this decline so that the total share for renewables is slightly higher in 2030 than in 2002 (also indicated in Figure 2.6).

Coal has generally maintained its role in global electricity generation and is expected to do so over the Outlook period. Thus, the impact of changes in the *fossil fuel* generation mix shown in Figure 2.6 can be explained by natural gas taking a market share from oil. Gas has a somewhat lower carbon content than oil, which in turn has a lower carbon content per unit of energy than coal (see Figure 2.5).

Based on the decomposition analysis discussed above, Table 2.1 indicates the relative importance various factors have had on changes in past CO_2 emission level and on expected future emissions, based on the WEO 2004 Reference Scenario.

Figure 2.7

Share of fuels in global electricity generation
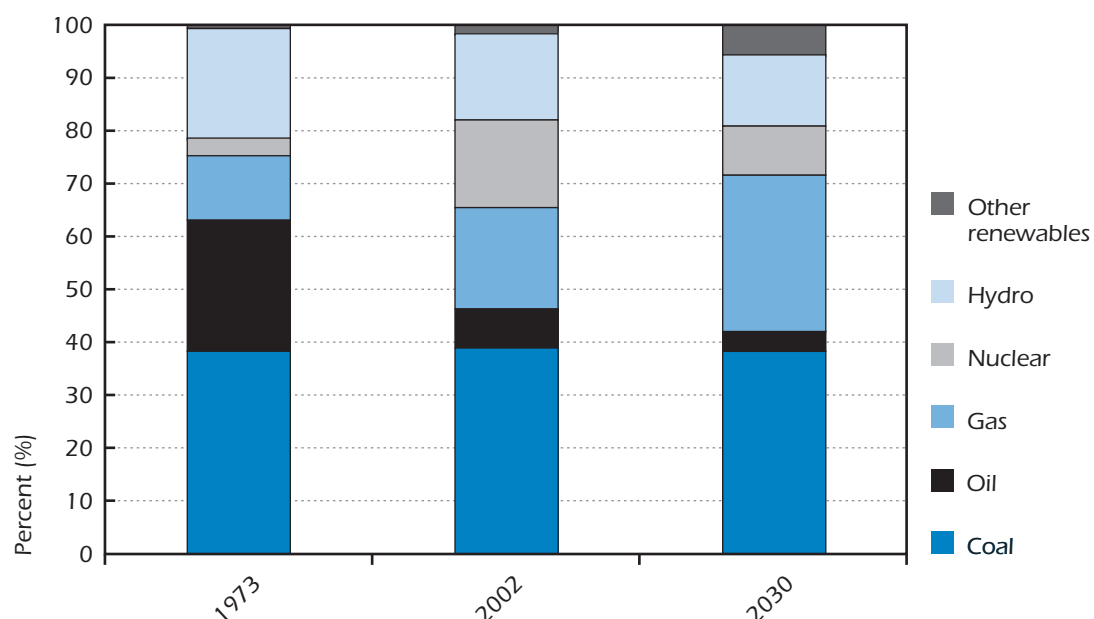
Source: IEA, 2004a.

The different factors listed in Table 2.1 are important to understanding how emissions have changed in the past, how they may change in the future and thence how they may be reduced through policy intervention. Examples of energy and environmental policies targeted at these components include:[2]

Table 2.1

Impact on global CO₂ emission reductions from different factors

Factor	1973-2002	2002-2030
Energy services per GDP	+	+
End-use efficiency	+++	+++
Generation efficiency	+	++
End-use fuel mix	–	–
Generation fuel mix:		
- Fossil fuels	0	+
- Nuclear	++	–
- Renewables	–	+

Note: +, ++ and +++ denotes small, medium and large positive impacts on emission *reductions*, and - denotes small negative impacts; 0 denotes a neutral effect.

● In transport, policies which encourage a shift away from private vehicle use to less energy-intensive public transport options;

● In end-use sectors, policies to improve energy efficiency such as standards and labelling for electric appliances, and voluntary agreements with industry;

_____

2. In addition to energy policy initiatives, the risk of global warming could also be mitigated by reducing emissions of non-CO₂ greenhouse gases, by minimizing tropical deforestation, and by sequestering carbon in trees and soil.

- In fossil-fuelled power generation, incentives to increase efficiency by developing advanced technologies, such as Coal Integrated Gasification Combined Cycle plants (IGCC) and ultra supercritical steam cycles (USCSC);

- Policies which encourage the use of biomass for heating and industrial use, and the use of natural gas as a 'cleaner' substitute for coal;

- In power generation, policies which influence fuel mix, for example to enable the development and deployment of renewable technologies, to allow for or negate the use of nuclear power and in some cases, to promote the use of natural gas instead of coal.

The World Energy Outlook 2004 includes a *World Alternative Policy Scenario* that analyses the impact policies that are being considered by OECD countries and other countries can have on developments through 2030. The policies analysed include polices in all the categories mentioned above. As a result of these policies, global primary energy use would be 10% lower in 2030 than in the Reference Scenario and the energy-related CO_2 emissions would be 16% lower. Almost 60% of the cumulative reduction in emissions will occur in non-OECD countries, reflecting primarily higher potential for efficiency improvements in transition and developing economies.

The difference between the rates of CO_2 emission growth in the WEO Reference and Alternative Policy scenarios is summarized in Figure 2.8. Almost 60% of the worldwide difference is the result of end-use efficiency measures encouraging the uptake of efficient vehicles, stricter standards for buildings, and appliances, and more efficient industrial processes. In transition economies and developing countries, the role more efficient played by energy efficiency measures is particularly large and reflects the potential for efficiency improvements. The other big contributor to lower

Figure 2.8

Reduction in energy-related CO₂ emissions in the WEO Alternative Policy Scenario, by contributory factor
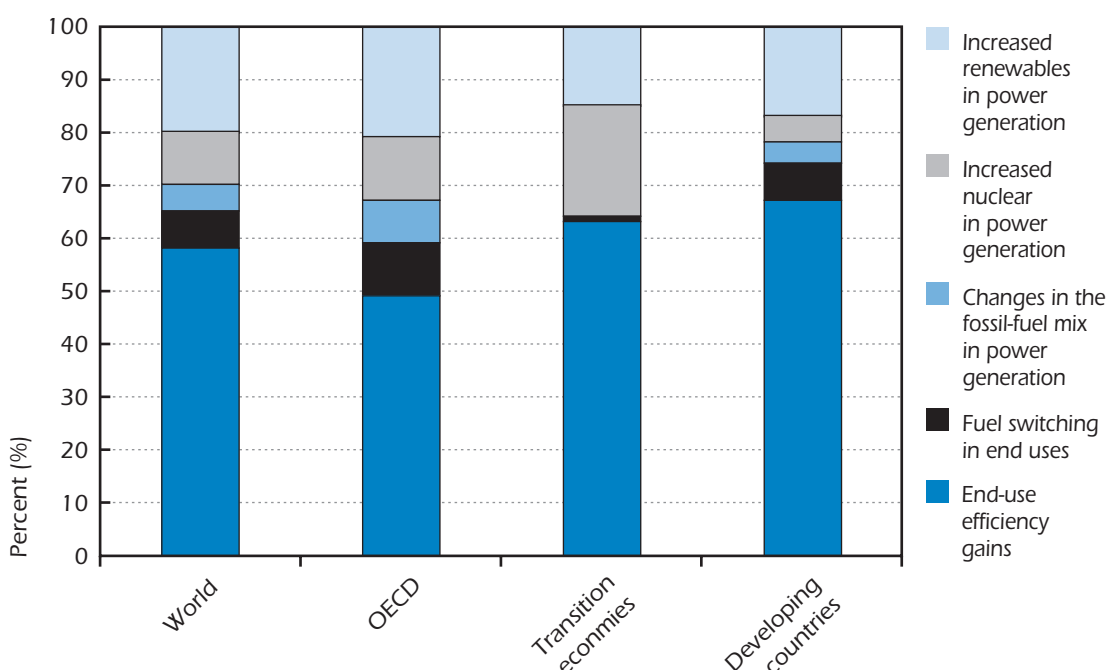
Note: PG = power generation.

Source: IEA, 2004a.

emissions is the increased share of renewable energy in power generation which accounts for a 20% reduction in global CO$_2$ emissions. An increased role for nuclear accounts for an additional 10%. Fuel switching in end-uses and switching from coal to natural gas in power generation can explain the rest.

Both historical developments and the WEO 2004 projections indicate that end-use energy efficiency is the most import factor affecting the decoupling of CO$_2$ emissions from economic growth. However, a recent IEA study of energy use and CO$_2$ emissions in IEA countries showed that the rate of energy efficiency improvements has slowed significantly since the late 1980s (IEA, 2004b). This is a general trend across all sectors and in almost all countries. While the economy-wide energy savings rate for the group of OECD countries included in the study averaged 2% per year between 1973-1990, it had fallen to just 0.7% per year by the end of the 1990s. This has implications for CO$_2$ emissions: a slowdown in the rate of energy saving is the primary reason for the weaker decoupling of CO$_2$ emissions from GDP growth observed in most OECD countries since 1990.

The IEA study's findings indicate that the oil price shocks in the 1970s and resulting energy policies did considerably more to limit growth in energy demand and CO$_2$ emissions in OECD countries than the energy efficiency and climate change policies implemented in the 1990s. As demonstrated in the WEO Alternative Policy Scenario, there is still considerable potential for improving energy efficiency, although recent trends indicate that OECD governments must make a stronger effort than in the past to exploit what potential remains.

Even with the policies analysed in the WEO Alternative Policy Scenarios, global emissions of CO$_2$ would increase by 37% on today's level, compared to 63% in the Reference Scenario, putting them almost 60% higher than 1990 levels. This implies that, in order to avoid substantial increases in emissions over the next few decades, options which cut emissions from fuel and electricity supply must be pursued in addition to improved energy efficiency in end-use sectors.

One such option is CO$_2$ capture and storage (CCS) which could reduce emissions while still allowing for continued fossil fuel use. Applying CCS in the electricity sector would reduce the carbon intensity of generation; it can be used in the production of synthetic fuels to provide low (or zero) carbon fuels for end-use sectors; it can also be applied to manufacturing processes to reduce the carbon intensity of this sector.

CCS competes and interacts with the other strategies discussed above. Low-cost options to reduce non-CO$_2$ greenhouse gases reduce the need for CO$_2$ emission reductions. If electricity consumption declines because of electricity savings, the potential for reducing emissions from electricity production also declines. Other emission abatement costs are influenced by this interaction. For example, the cost of biomass feedstock for transportation fuels depends on biomass demand for power generation.

The characteristics and potential of CO$_2$ emission mitigation options also differ by region, differences which must be taken into account when emission mitigation potentials are assessed. In industrialized countries, advanced technologies and capital intensive processes may be favoured. In developing countries, labour-intensive processes may stand a better chance. The potential for energy efficiency improvements is generally higher in developing countries than in developed countries.

All of this is further complicated by technological change. RD&D result in new technologies becoming available, while investments can result in further cost reductions due to learning-by-doing. The technologies that will be available 30 years from now could be radically different from those in place today. Proper consideration of technological change is essential for assessing the potential of and comparing long-term emission mitigation strategies.

As has been shown above, changes in CO$_2$ emissions are a function of many factors, with technological change playing a key role. While developments in the short and medium term can be projected with a reasonable degree of certainty, uncertainty increases for longer-term projections of half a century or more. Technological change is one of the uncertain drivers in this timeframe. A rigid analytical modelling framework can help assess emission reduction strategies and future trends in energy use in a structured, reproducible and logical way. For this reason, part of this study is based on modelling analysis.

The tool used for the analysis is the IEA's newly-developed Energy Technology Perspectives (ETP) model. This global 15-region model allows for an analysis of fuel and technology choices throughout the energy system, from the extraction of energy sources, *via* fuel conversion and electricity generation to technologies in all end-use sectors. The model's detailed representation of technology options includes several hundred technologies in each of the regions covered by the model. The ETP model belongs to the MARKAL family of bottom-up modelling tools. ETP-MARKAL is a linear programming model that minimizes total energy system costs over a 50-year period, given certain levels of energy service demands and constraints, such as the availability of natural resources.

This modelling analysis helps assess the cost implications of different CO$_2$ mitigation strategies. While technological change holds the key to meeting the world's future energy needs simultaneously capping emissions, the change will not come about voluntarily or without cost. Governments must be willing to encourage the development and deployment of clean and efficient technologies even if the up-front costs are not negligible.

The model analysis in this study uses CO$_2$ penalty levels as a representation of policy efforts that governments may take to reduce CO$_2$ emissions from energy production and use. This does not imply that CO$_2$ taxes should be the preferred policy measure; penalties are merely a way of representing the stimuli needed to bring the technologies that can cut emissions to market. This approach ensures that the technology mix in each scenario is selected on the basis of equivalent emission mitigation costs.

The uptake of technology options in the different ETP scenarios presented in this book depends on the cost and performance assumptions made for each technology. Chapter 3 discusses in detail the assumptions made for CSS technologies included in this study. Assumptions for other key technologies are presented in Annex 1.

Chapter 3.
CCS CHARACTERISTICS: TECHNOLOGIES, POTENTIAL, PERMANENCE AND COST

H I G H L I G H T S

CCS can build on existing technologies. It involves the separation of CO_2 produced during fossil fuel use, its transport, and its storage, *e.g.*, in geological media. All three activities have been implemented on a commercial scale in certain applications. Compared to many other CO_2 abatement options in the power sector, CCS requires less restructuring of energy supply systems and even a few projects could have a noticeable impact on country-level emissions.

CO_2 Capture Sources

The following three areas offer the best potential for large-scale, centralized capture of CO_2:

■ Electricity generation. With fossil-fuelled power production responsible for 29% of total current CO_2 emissions, capturing CO_2 from coal, natural gas, oil and biomass-fired power plants is the most promising area in which to apply CCS technology.

■ Industrial processes. CO_2 can be captured from the production processes of iron, cement, chemicals and pulp, activities which generate a combined 23% of world CO_2 emissions. In some cases, the cost of applying CCS in industry is lower than for power generation; in other cases it is similar.

■ Fuels production. CO_2 can be captured from oil refineries, natural gas processing installations and synfuel production. This includes hydrocarbon synfuels and hydrogen. The co-production of electricity and synfuels with CO_2 capture would result in cost savings per tonne of CO_2 captured, compared to stand-alone electricity production.

CO_2 Capture Technology

■ Currently available technologies can be used to either de-carbonise fossil fuels to produce hydrogen (pre-combustion capture), or to capture CO_2 from flue gases (post-combustion capture). For established technologies, gaps include improved specialised chemical and physical solvents to decrease energy requirement of capture process. For novel processes, investigations are focused on better and cheaper membranes to increase CO_2 concentration, more efficient air separation technologies (some options involve combustion in pure oxygen), cheaper and more efficient fuel cells (to convert chemical energy stored in hydrogen or methane into electricity), hydrogen turbines, chemical looping and others.

■ In order to be applied by the power sector, capture technologies need, in addition to basic R&D requirements, to be demonstrated on a much bigger scale than has so far been required by the chemical industry. They should be optimized together with highly efficient power plant technologies.

- CO_2 capture is energy intensive and results in increased coal and gas use for electricity production. The increase ranges from 39% for current designs to 6% for advanced future designs. Energy efficient power production is a prerequisite for CCS use in the power sector.

- Retrofitting high efficiency gas-fired power plants may be a feasible option in the future, if gas prices are sufficiently low. Pulverised coal-fired plants could also be retrofitted, with oxyfuelling seeming the best option.

- Reducing the cost of CO_2 capture is a major factor influencing the long-term viability of CCS. Several technologies already under development could reduce the cost of CO_2 capture but this requires concerted RD&D. The cost reduction potential through innovation seems significant, so efforts should initially aim for RD&D, rather than investment programmes.

- Emerging technologies such as membrane separation, oxyfuelling in combination with new oxygen production technologies, chemical looping and fuel cells hold promise of cutting energy use and cost in half. Currently, it is not possible to identify the 'winning technology'.

- Combining biomass-fuelled IGCCs with CCS could become attractive, even on a much smaller plant scale than coal-fuelled IGCCs due to the doubled CO_2 benefits compared to coal with CCS. Such a combination would have negative net emissions, since biomass carbon is based on CO_2 that plants have captured from the atmosphere. Biomass could be used in dedicated plants or, more likely, it could be co-combusted in fossil-fuelled plants.

CO_2 Transportation Technology

- While pipeline transport is an established technology, the proper siting of CCS projects can reduce the need for an extensive transportation system. Given potential pipeline siting constraints and transportation distances of hundreds of kilometers, a CO_2 transportation 'backbone' may be needed to which multiple power plants and a number of storage sites can be connected. Such a system would allow transportation over longer distances at acceptable cost. Transporting CO_2 by ship is also considered as an option.

CO_2 Storage Technology

- Underground CO_2 storage in deep saline aquifers, in depleted oil and gas reservoirs and in un-mineable coal seams seems the only realistic option in the short and medium term, due to reasons such as environmental risk and acceptance problems for oceanic storage, as well as cost and immature technology status for above-ground carbonate storage.

- Widespread use of CCS implies storage in deep saline aquifers. Deep saline aquifers potentially offer decades or hundreds of years' worth of storage with between 1,000 and 10,000 Gt of storage capacity available, possibly even more. Aquifers are more evenly distributed than oil and gas reservoirs.

- Depleted oil and gas reservoirs offer considerable potential as CO_2 storage facilities which could hold decades of global CO_2 emissions with a reasonable degree of certainty.

- Injecting CO_2 to enhance the recovery of fossil fuels could become a key early CO_2 storage opportunity, particularly since it can generate revenues that offset all or part of CO_2 capture and transportation costs.

- Several projects in a range of countries have proven the viability of storing CO_2 underground. Such projects include injecting CO_2 to enhance oil recovery and acid gas injection. However, this potential is not evenly distributed around the world.

Permanence of Storage and Monitoring

- There are two types of risk associated with leakages of CO_2: local, i.e., site specific, affecting health, safety and environment, and global, resulting from a return of stored CO_2 to the atmosphere. Considering only the latter, i.e., taking the storage effectiveness point of view, leakages of up to 0.1%/year seem acceptable. Maximum allowable leakage rates will set an upper bound on CO_2 losses in permit and accounting procedures, but this does not mean that the research community expects such leakages which, in reality, should be many times smaller.

- More pilot projects are needed to assess the permanence of aquifer storage, develop criteria against which the most suitable sites can be selected, and establish adequate monitoring procedures.

The Cost of CCS

- The cost of CCS ranges from a 40 USD benefit to a 100 USD/t CO_2 cost, if all capture and storage options are considered. At this stage, for a vast majority of options, the total cost of CCS could be within 50 to 100 USD per tonne of CO_2 emission reduction. By 2030, these costs should go down to 25-50 USD per tonne of CO_2 compared to the same process without CCS. Certain early opportunities exist with low-capture cost, but their potential is limited.

- The bulk of costs is on the capture side. If future efficiency gains are taken into account, the cost of capture could decline from the current level of almost 50 USD/t CO_2 to around 10-25 USD/t CO_2 for coal-fired plants and to around 25-30 USD/t CO_2 for gas-fired plants.

- CO_2 transportation costs (per t of CO_2) depend strongly on the volumes being transported and, to a lesser extent, on the distances involved; They range from 1 to 10 USD/t of CO_2, provided the pipeline transports more than 1 Mt of CO_2 per year and the distance is less than 500 km.

- CO_2 injection costs range from 2 USD/t CO_2 (for Mt size aquifer storage) to 50 USD for certain ECBM projects.

- Part of the cost of CCS could be offset by revenues from enhanced fossil-fuel production. These benefits could reach 55 USD/t CO_2. Revenues from enhanced oil recovery (EOR) in particular could be substantial, but this is highly site-specific and will not be the case for most CCS projects.

- Emerging technologies could result in a CCS electricity cost increase of only 1-2 US cents per kWh (including capture, transportation and storage). This cost range applies to both coal and gas-fired plants.

This chapter provides an assessment of the technical and economic characteristics of CO$_2$ capture, transportation and storage technologies, data used in later chapters of this book to quantitatively assess CCS potentials using the IEA's Energy Technology Perspectives (ETP) model. The analysis is essential reading for policy makers wishing to understand the range of CCS technologies on offer, their relative costs, merits and technology gaps and the areas in which further RD&D is required.

The viability of a CCS strategy depends on several key factors – the cost of CO$_2$ capture, transportation and storage, the potential for CO$_2$ storage and the permanence of storage – all of which are discussed in this chapter. The discussion will show that although capture costs dominate the overall CCS cost, there is potential for improvement. Developments are being made on a number of new CO$_2$ capture technologies that can reduce energy consumption and capture cost. R&D is a key to these cost reductions since the potential for learning-by-doing seems limited. However, at this stage it is not yet possible to select winning technologies.

The chapter begins with a detailed overview of CO$_2$ emission sources showing which sectors offer the best potential for applying CO$_2$ capture and storage (CCS). An assessment is then made of CO$_2$ capture technologies, both existing and speculative, in power generation, manufacturing and fuel processing. It includes a discussion on why CO$_2$ capture only makes sense for high efficiency power plants, the role of decentralized generation and cogeneration and technology learning effects.

CO$_2$ transportation and the benefits of producing chemicals and fuels from CO$_2$ are then examined. This is followed by assessment of CO$_2$ storage options, from aquifers to depleted oil and gas-fields, including issues surrounding storage permanence and monitoring. Special attention is given to the use of CO$_2$ to enhance fossil fuel production, which could generate revenues to offset all or part of CO$_2$ capture costs. Finally, the overall cost-effectiveness of CCS is assessed and the impact its deployment could have on electricity prices.

General Characteristics of CO$_2$ Capture and Storage

CO$_2$ capture and storage involves the separation of CO$_2$ produced during fossil fuel use, its transport, and its storage, *e.g.*, in geological media. All three activities have been implemented on a commercial scale in certain applications. For example, CO$_2$ capture is widely used in the chemical industry. Likewise, pipeline transport of CO$_2$ is an established technology, and CO$_2$ storage is used for enhanced oil recovery. These technologies must be further developed and demonstrated if they are to become a feasible option on the scale required. Before the characteristics of current and future technologies are discussed, a number of important features of a CCS strategy will be considered. These strategy features are the starting point for a discussion as to whether CCS is feasible.

CO$_2$ is the most important anthropogenic greenhouse gas. Over the past 200 years its concentration in the atmosphere has increased from 0.0275% to 0.0370%. This is largely a result of the combustion of fossil fuels. One way to reduce CO$_2$ emissions is to capture CO$_2$ before it is emitted into the atmosphere and store it elsewhere. In order to mitigate the risk of global climate change, huge quantities of CO$_2$ need to be captured and sequestered. In 2000, 23.4 gigatonnes[1] of CO$_2$ were emitted worldwide.[2] At a density of 500 kg/m^3, total annual global emissions could be contained in a cube measuring 3.5 km in length, width and height. Although this is a large volume, it is not impossible to store quantities of this order of magnitude.

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1. A gigatonne is a billion tonnes, equal to 10^9 tonnes

2. Energy related emissions including international bunkering. Excludes cement production and tropical deforestation.

If gaseous CO_2 is pressurized, it either becomes liquid or reaches a dense state called 'supercritical', a state between gas and liquid. The supercritical state occurs at temperatures greater than 31.1°C and pressures greater than 7.38 MPa[3]. The density of liquid and supercritical CO_2 varies with the pressure and temperature, from 200 to more than 1000 kg/m³ (Bachu, 2000). These physical properties influence the options for capturing, transporting and storing CO_2.

A CCS strategy can build on established technologies. CO_2 capture has been widely applied in industrial processes for decades. CO_2 needs to be removed from gas streams in a number of processes such as the production of hydrogen, ammonia and Direct Reduced Iron (DRI). The total quantity captured is in the range of 100 to 200 Mt CO_2 per year. CO_2 capture is also applied in the processing of natural gas. Some of this captured CO_2 is transported and used in the production of urea fertilizer and carbonated beverages, but most of it is vented. Around 40 Mt of CO_2 per year is also extracted from natural underground reservoirs and transported over hundreds of kilometers, to be used for enhanced oil recovery (EOR).

Existing, proven CO_2 processing technologies have not been developed for the purpose of CO_2 emission mitigation. While experience with these processes shows that the principle works on a large scale, a CCS strategy will require much new technology backed by a substantial reduction in the overall cost of CCS. The technology status and outlook for CCS will be discussed in more detail later in this chapter.

Underground storage of CO_2 in deep saline aquifers has been demonstrated in one commercial scale project, the Norwegian Sleipner facility. Other projects have only just started. While further effort is needed to demonstrate safety and to better understand the permanence of underground storage in various geological formations, deep saline aquifers represent a potentially huge and widely available medium for CO_2 storage.

CCS fits into the existing technology trajectory of fossil-fuel based energy supply and can be developed by existing energy technology suppliers. No major adjustments are needed in the energy infrastructure. This would avoid risky transition and unpopular economic restructuring efforts. Key players such as the fossil fuel industry and power producers have expressed their interest in a CCS strategy. Such support makes the strategy more attractive from a policy maker's perspective.

CCS allows the use of coal resources while reducing CO_2 emissions dramatically, compared to fossil-fuelled power plants without CO_2 capture. The use of coal instead of oil or gas may have important supply security benefits. These CCS advantages are lacking for many of the competing strategies.

In principle, CO_2 capture can be applied to all fossil fuel and biomass combustion processes. But only large point sources, each emitting quantities in the order of a million tonnes of CO_2 per year, can achieve the economies of scale that are needed to make CCS a cost-effective strategy. These point sources are electricity production (the main sector where CCS can be applied), manufacturing, and fuel processing. All three are considered in this book. A 500 MW coal-fired power plant with 40% electric efficiency emits about 2.5-3.5 Mt CO_2 per year, and a similarly sized gas-fired power plant emits about 1-1.5 Mt CO_2 per year. Given these quantities, a limited number of projects in certain sectors can have a significant impact on country level emissions.

CCS in combination with hydrogen production from fossil fuels would result in a fuel that could achieve a substantial emission reduction from the transportation sector, a sector where few alternative cost-effective options exist. Such a CO_2-free transportation system based on coal or gas with CO_2 capture

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3. 7.38 MPa equals 73.8 Bar, almost 74 times atmospheric pressure.

would have advantages from a supply security perspective, as it is built on proven large-scale fossil-fuel supply systems, and would simultaneously reduce dependency on oil.

However, not all intrinsic CCS strategy characteristics are positive. As an add-on technology, CCS would incur additional costs and reduce energy efficiency, compared to the same processes without CO_2 capture. In principle, other CO_2-free energy options could result in lower-cost energy supply. If this is the case, it would make sense to use these supply options instead of CCS.

From an environmental policy perspective, it is worth bearing in mind that CCS may not always be the complete answer to the problem of CO_2. Past experience suggests that shifting flows from one medium to another can create new unforeseen environmental problems.[4]

So far, there is very little experience with long-term CO_2 storage and no proof that storage can be safely guaranteed over a period of centuries. Moreover while the potential for underground storage is substantial, it is not infinite. In addition, potential storage sites are not evenly distributed around the world. Certain world regions have substantial underground storage potential while others have none. Therefore, the relevance of CCS will differ by region.

It depends on the reader's time perspective as to whether CCS should be considered a potential 'solution' or a 'transitional strategy'. From a climate change perspective, reducing CO_2 emissions by over 75% in key parts of the energy system in the coming decades is certainly appealing. Such targets may seem overly ambitious. In fact they are not, if one believes that climate change poses a serious risk.[5] Emissions in developing countries will keep rising as their economies grow. This will put a higher burden on developed countries both to reduce their own emissions and to help developing countries to reduce theirs.

CO₂ Capture Opportunities in the World Energy System

The bulk of anthropogenic global CO_2 emissions are caused by fossil-fuel energy use. Analysing the world energy balance can help identify key source categories where CO_2 capture and storage could be applied. CCS is well suited to large stationary point sources, such as power plants, and less appropriate for smaller or dispersed point sources. Therefore, not only the total quantity emitted by a given source category, but also the emission by source, should be considered when assessing the potential for CO_2 capture.

Table 3.1 provides an overview of global energy use in 2000. It shows that total primary energy use, excluding marine bunkers, amounted to 417 EJ in 2000.[6] Of this amount, 125 EJ (30%) was used in upstream processes (including transformation processes, the energy sector and distribution

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4. For example the shift from waste disposal to waste incineration resulted in many countries in a significant increase of dioxin emissions. This problem has been solved by improved filters. This is an example how proper technology development can prevent this shift in environmental problems.

5. Recent measurements indicate that rapid climate change in Europe and eastern North America has occurred several times in the past. During these periods, the average temperature dropped by five degrees Celsius over a decade and remained at this level. These changes were related to variations in the Gulf Stream which transports heat from the tropics to the northern Atlantic. Past changes in the Gulf Stream were related to changes in salinity. Salinity of the seawater in the North Atlantic has changed dramatically in the past four decades (Dickson et al., 2002). It is thought that such changes are related to the melting of the Greenland glaciers. At some point, this may affect the Gulf Stream.

6. 1 EJ (exajoule) = 1000 PJ (petajoule) = 10^{18} joules.

losses). In the transformation sector, electricity and heat production accounted for almost 83 EJ net energy use (fuel input minus electricity and heat output), or over 100 EJ fossil fuel use, a quarter of total world primary energy use. These energy quantities and their related CO_2 emissions show that **the electricity sector is a prime candidate for CO_2 capture**.

Some 291 EJ (69%) of final energy is used in end-use sectors. Six end-use sectors are defined in the table: agriculture, residential, services, transport, industry and non-energy use. Industry accounts for 93 EJ final energy use (32%). Industry-related transformations, energy-sector activities and non-energy use such as coke ovens, blast furnaces, naphtha steam-cracking and aromatics production, accounted for in the IEA statistics as transformation and energy sector, are in fact industry operations. This industry-related energy use in the other categories amounts to 16 EJ.

The table also shows that final energy use by manufacturing industry amounted to 109 EJ in 2000, in the form of electricity and heat. Part of the electricity and most of the heat were derived from industrial combined heat and power (CHP) plants with high efficiency,[7] but the bulk (more than three-quarters) of the electricity was purchased from the grid. Given current efficiencies in electricity production, industrial demand represented 120-130 EJ primary energy in 2000, about 30% of total primary energy use. **This brief analysis shows the importance of the manufacturing sector for total global energy use and related environmental impacts, making it a second important category where CO_2 capture could be applied.**

A third major CO_2 emission category is the transport sector (75 EJ). The bulk of transport sector energy demand is for road vehicles. The problem with CO_2 capture in this sector is the dispersed nature of the emissions. CO_2 capture technologies for vehicles would be prohibitively expensive. However, switching from petrol to another fuel, such as hydrogen or externally-produced electricity from fossil fuels with CO_2 capture, could help overcome this problem. It would result in CO_2 from point sources that could be captured.

The table also shows that the residential, service and agriculture sectors accounted for 40% of final energy use in 2000. If upstream emissions are included in this figure, the percentage is increased because of the high share of electricity in the sectors' final energy mix. The dispersed nature of the emissions from fuel combustion in these sectors constitutes a problem similar to that in the transport sector. The optimal solution for these final consumption sectors is not yet clear and is likely to be diverse. Enhancing energy efficiency, increasing electrification and introducing alternative fuels such as hydrogen are competing options for CO_2-free energy in these market segments.

The relevance of emission categories for CCS will change in the coming decades. IEA projections suggest a doubling in electricity demand between 2000 and 2030 (IEA, 2002a). This growth is much higher than for primary energy use as a whole, which is projected to grow by 66% during the same time period. This will increase the relevance of a CCS strategy for the electricity sector.

Growth in electricity demand is particularly pronounced in developing countries, a factor which has significant consequences for the regional urgency of emission reduction. Growth in industrial energy demand is much lower than in other parts of the energy system. As a consequence, the importance of the industry sector for CCS will decrease.

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7. *The IEA fuel questionnaires ask only for an aggregate auto-producer CHP for all end-use sectors. This aggregate is reported under the heading 'transformation sector' in the IEA energy statistics. The heat output from CHP plants for own use is translated into a fuel equivalent to produce the same amount of heat in a boiler. This fuel equivalent is excluded from CHP in the transformation sector, and included in the industrial final end-use. Therefore, a number of other sources must be used in order to analyse industrial CHP.*

Table 3.1
Aggregate world energy balance by source category (2000)

	Coal (EJ/yr)	Biomass/waste (EJ/yr)	Natural gas (EJ/yr)	Oil (EJ/yr)	Nuclear (EJ/yr)	Other renewable (EJ/yr)	Electricity (EJ/yr)	Heat (EJ/yr)	Total (EJ/yr)
Production	*94.61*	*45.39*	*87.84*	*152.96*	*28.28*	*11.54*	*0.00*	*0.02*	*420.65*
From Other Sources	0.06	0.01	0.00	0.03	0.00	0.00	0.00	0.00	0.10
Imports	17.16	0.04	22.32	116.20	0.00	0.00	1.79	0.00	157.51
Exports	-16.93	-0.04	-22.45	-116.77	0.00	0.00	-1.79	0.00	-157.97
International Marine Bunkers	0.00	0.00	0.00	-5.89	0.00	0.00	0.00	0.00	-5.89
Stock Changes	2.70	0.05	0.52	-0.94	0.00	0.00	0.00	0.00	2.33
Primary Supply	*97.61*	*45.45*	*88.23*	*145.59*	*28.28*	*11.54*	*0.00*	*0.02*	*416.73*
Transfers	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.52
Statistical Differences	-0.69	0.00	-0.42	0.16	0.00	0.00	0.00	0.00	-0.94
Transformation Sector	*-72.61*	*-4.17*	*-31.02*	*-12.91*	*-28.28*	*-11.27*	*55.25*	*11.77*	*-93.26*
Electricity/heat/CHP[8]	-65.35	-2.40	-29.92	-12.45	-28.28	-11.27	55.27	11.75	-82.67
Coke Ovens	-1.61	0.00	0.00	-0.05	0.00	0.00	0.00	0.00	-1.66
Gas Works	-0.11	0.00	-0.08	-0.09	0.00	0.00	0.00	0.00	-0.28
Blast Furnaces	-4.87	0.00	0.00	-0.05	0.00	0.00	0.00	0.00	-4.93
Petroleum Refineries	0.00	-0.05	0.00	-1.21	0.00	0.00	0.00	0.00	-1.27
Liquefaction Plants	-0.63	0.00	-0.99	0.95	0.00	0.00	0.00	0.00	-0.67
Charcoal Production	0.00	-1.67	0.00	0.00	0.00	0.00	0.00	0.00	-1.67
Non-specified /others	-0.06	-0.05	-0.02	0.00	0.00	0.00	0.00	0.00	-0.11
Energy Sector	*-2.08*	*-0.01*	*-8.16*	*-8.70*	*0.00*	*0.00*	*-5.06*	*-1.06*	*-25.06*
Oil and Gas Extraction	0.00	0.00	-5.69	-0.60	0.00	0.00	-0.49	-0.18	-6.96
Coke Ovens	-0.72	0.00	-0.02	0.00	0.00	0.00	-0.01	-0.01	-0.77
Blast Furnaces	-0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.10
BCB Plants	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01
Petroleum Refineries	-0.01	0.00	-1.55	-7.82	0.00	0.00	-0.64	-0.59	-10.62
LNG Plants	0.00	0.00	-0.64	0.00	0.00	0.00	0.00	0.00	-0.65
Own Use Elec/heat	-0.56	0.00	-0.04	-0.10	0.00	0.00	-3.17	-0.09	-3.97
Non-specified /others	-0.68	0.00	-0.19	-0.06	0.00	0.00	-0.55	-0.09	-1.57

Distribution Losses	*-0.13*	*0.00*	*-0.87*	*-0.20*	*0.00*	*-0.01*	*-4.80*	*-0.81*	*-6.81*
Final Consumption	*22.10*	*41.27*	*47.76*	*124.46*	*0.00*	*0.27*	*45.40*	*9.93*	*291.19*
Industry Sector	**6.53**	**6.73**	**22.04**	**24.86**	**0.00**	**0.02**	**19.10**	**3.98**	**93.27**
Iron and Steel	5.54	0.20	2.16	0.73	0.00	0.00	2.24	0.40	11.28
Chemical	1.99	0.20	8.95	14.30	0.00	0.00	3.04	1.29	29.77
Non-Ferrous Metals	0.47	0.00	0.84	0.42	0.00	0.00	1.96	0.26	3.95
Non-Metallic Minerals	3.76	0.15	1.67	1.50	0.00	0.00	1.01	0.12	8.21
Transport Equipment	0.14	0.00	0.40	0.19	0.00	0.00	0.59	0.04	1.36
Machinery	0.37	0.00	0.99	0.42	0.00	0.00	1.67	0.45	3.90
Mining and Quarrying	0.16	0.00	0.19	0.46	0.00	0.00	0.64	0.02	1.47
Food and Tobacco	0.66	0.86	1.35	0.81	0.00	0.00	1.09	0.35	5.12
Paper, Pulp and Print	0.56	2.10	1.23	0.65	0.00	0.01	1.61	0.12	6.27
Wood/ Wood Products	0.06	0.45	0.12	0.15	0.00	0.00	0.32	0.28	1.38
Construction	0.16	0.00	0.11	0.61	0.00	0.00	0.17	0.07	1.13
Textile and Leather	0.34	0.01	0.39	0.56	0.00	0.00	0.69	0.15	2.14
Non-specified	2.31	2.76	3.63	4.06	0.00	0.01	4.09	0.44	17.29
Transport Sector	**0.25**	**0.35**	**2.25**	**71.23**	**0.00**	**0.00**	**0.80**	**0.00**	**74.87**
International Air	0.00	0.00	0.00	4.97	0.00	0.00	0.00	0.00	4.97
Domestic Air	0.00	0.00	0.00	4.38	0.00	0.00	0.00	0.00	4.38
Road	0.00	0.35	0.12	58.91	0.00	0.00	0.00	0.00	59.38
Rail	0.24	0.00	0.00	1.37	0.00	0.00	0.59	0.00	2.20
Pipeline Transport	0.00	0.00	2.12	0.00	0.00	0.00	0.11	0.00	2.23
Internal Navigation	0.00	0.00	0.00	1.43	0.00	0.00	0.00	0.00	1.43
Non-specified	0.00	0.00	0.01	0.17	0.00	0.00	0.09	0.00	0.27
Agriculture	**0.51**	**0.25**	**0.27**	**4.27**	**0.00**	**0.00**	**1.27**	**0.23**	**6.80**
Commerce/Services	**0.50**	**0.22**	**6.04**	**4.68**	**0.00**	**0.01**	**10.54**	**0.97**	**22.96**
Residential	**3.53**	**32.71**	**15.66**	**9.95**	**0.00**	**0.21**	**12.84**	**4.40**	**79.30**
Non-specified	**0.38**	**1.00**	**1.51**	**2.02**	**0.00**	**0.01**	**0.84**	**0.35**	**6.12**
Non-Energy Use	**0.41**	**0.00**	**0.00**	**7.46**	**0.00**	**0.00**	**0.00**	**0.00**	**7.86**

BCB = Brown Coal Briquettes; LNG = Liquefied Natural Gas. Nuclear electricity expressed in primary nuclear energy equivalents assuming 33% efficiency. Other renewables = hydro, wind and solar electricity. 100% efficiency, geothermal 10% efficiency.

Source: Based on IEA energy statistics.

8. This includes CHP in all sectors, but it excludes industrial steam production in CHP plants for own use (which is accounted for as industrial fuel use).

Table 3.2
Global CO₂ emissions by source category (2000)

	Coal (Gt CO_2/yr)	Biomass/waste (Gt CO_2/yr)	Natural gas (Gt CO_2/yr)	Oil (Gt CO_2/yr)	Inorganic (Gt CO_2/yr)	Total renewable (Gt CO_2/yr)
Total	**9.08**	**5.22**	**4.89**	**10.21**	**0.77**	**30.13**
of which:						
Transformation Sector	*6.22*	*0.49*	*1.74*	*0.94*		*9.36*
Electricity and heat plants	6.14	0.28	1.68	0.91		9.00
Gas Works	0.01	0.00	0.00	0.01		0.02
Petroleum Refineries	0.00	0.01	0.00	0.09		0.09
Liquefaction Plants	0.06	0.00	0.06	-0.07		0.05
Charcoal Production	0.00	0.19	0.00	0.00		0.19
Non-specified /others	0.01	0.01	0.00	0.00		0.01
Energy Sector	*0.11*	*0.00*	*0.46*	*0.62*		*1.20*
Oil and Gas Extraction	0.00	0.00	0.32	0.04		0.36
Petroleum Refineries	0.00	0.00	0.09	0.57		0.66
LNG Plants	0.00	0.00	0.04	0.00		0.04
Own-use electricity and heat	0.05	0.00	0.00	0.01		0.06
Non-specified/others	0.06	0.00	0.01	0.00		0.08
Final Consumption +bunkers +coke ovens/blast furnaces	*2.75*	*4.73*	*2.69*	*8.65*	*0.77*	*19.57*
Industry Sector	**2.26**	**0.77**	**1.24**	**1.92**	**0.77**	**6.97**
Iron and Steel incl. CO&BF[9]	1.21	0.02	0.12	0.05	0.07	1.48
Chemical incl. non-energy	0.21	0.02	0.50	1.16	0.00	1.89
Non-Ferrous Metals	0.04	0.00	0.05	0.03	0.12	

9. CO&BF = Coke Ovens and Blast Furnaces

Non-Metallic Minerals	0.35	0.02	0.09	0.11	0.70	1.27
Transport Equipment	0.01	0.00	0.02	0.01		0.05
Machinery	0.03	0.00	0.06	0.03		0.12
Mining and Quarrying	0.02	0.00	0.01	0.03		0.06
Food and Tobacco	0.06	0.10	0.08	0.06		0.30
Paper, Pulp and Print	0.05	0.24	0.07	0.05		0.41
Wood/ Wood Products	0.01	0.05	0.01	0.01		0.07
Construction	0.02	0.00	0.01	0.04		0.07
Textile and Leather	0.03	0.00	0.02	0.04		0.10
Non-specified	0.22	0.32	0.20	0.30		1.03
Transport Sector	**0.02**	**0.04**	**0.13**	**5.20**		**5.39**
International Marine Bunkers	0.00	0.00	0.00	0.43		0.43
Agriculture	**0.05**	**0.03**	**0.02**	**0.31**		**0.40**
Commerce/Services	**0.05**	**0.03**	**0.34**	**0.34**		**0.75**
Residential	**0.33**	**3.75**	**0.88**	**0.73**		**5.68**
Non-specified	**0.04**	**0.11**	**0.08**	**0.15**		**0.38**

Note: Includes energy and inorganic CO_2 emissions; excludes deforestation. No correction for carbon storage in synthetic organic chemicals.

Table 3.2 shows CO_2 emissions by source category. The emissions were calculated based on the year 2000 energy balance shown in Table 3.1. The energy use is multiplied by the carbon content per unit of energy.[10]

Emissions from limestone dissociation (mainly in cement, iron and glass production) have been added. The table shows that total global emissions amounted to almost 30 Gt CO_2 in 2000, of which 5.2 Gt CO_2 were from biomass combustion. While these emissions are usually not taken into account in CO_2 emission calculations,[11] there is no physical difference between CO_2 from fossil fuel combustion and CO_2 from biomass combustion. CO_2 capture could be applied to both cases.

Oil is the most important fuel from a CO_2 emissions perspective, closely followed by coal. Biomass and natural-gas related emissions are on par. From a sector perspective, electricity and heat plants constitute the single most important emissions source, followed by the industry sector.

CO_2 Capture in the Electricity Sector

This section discusses the following three main groups of technologies which can be used to capture CO_2 from power plants. Such options can be combined and integrated with various process designs:

- CO_2 capture from flue gas;
- Fuel reforming into hydrogen and CO_2, followed by capture from the concentrated and pressurized gas;
- The use of oxygen for combustion, which results in a concentrated CO_2 flue gas.

CO_2 capture options for power plants

The following assessment of CO_2 capture options for power plants is split into CO_2 capture for new plants and CO_2 capture for existing plants. The assessment of capture technology for new plants is further divided into existing capture technologies, emerging capture technologies, and an overview of technology efficiencies and cost.

Existing capture technologies for new power plants: post-combustion chemical and physical absorption

CO_2 capture is already widely applied in industrial manufacturing processes, refining and gas processing. These capture technologies can also be applied to power plants. In the 1980s, CO_2 capture from gas-fired boiler flue gases was applied commercially in order to produce CO_2 for enhanced oil recovery (EOR) projects (Chapel et al., 1999). These processes were commercially viable at a price of 19-38 USD/t CO_2. However, the plants were closed when the oil price collapsed.

Existing CO_2 capture systems are either based on chemical absorption, in combination with heat induced CO_2 recovery (using solvents such as MonoEthanolAmine MEA), or physical absorption

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10. *This is a crude approach, especially for transformation processes. For example, the carbon content of coal equals 94 kg CO_2/GJ, while the emission coefficient of blast furnace gas is 242 kg CO_2/GJ. A significant share of blast furnace gas is sold by the iron and steel industry to electricity producers. This CO_2 is emitted by power plants using blast furnace gas. This is not reflected in Table 3.2. In future, CO_2 may be removed from the blast furnace gas before it is delivered to the power plants, so one could argue that this is a more realistic allocation for an analysis of emission reduction potentials. According to IEA statistics, emissions from fossil fuel use amounted to 23.4 Gt in 2000. This includes a correction for carbon storage in synthetic organic chemicals of almost 1 Gt CO_2.*

11. *This is correct if the carbon in plants and soil recovers to its original level. Usually this will be the case for plantations. In fact such plantations may store CO_2 from the atmosphere, as they increase the soil carbon content.*

Evaluating the cost of CCS:
different methods yield different results

CO_2 capture and pressurization (necessary for transport and injection) increases energy use which results in additional emissions that must be taken into account when evaluating the impact and cost-efficiency of CCS (Freund, 2003). The CO_2 capture cost and CO_2 avoidance cost require two different evaluation methods. For power plants, capture cost can be translated into avoidance cost based on the equation:

$Cost(avoided) = Cost(captured) \times CE/[eff_{new}/eff_{old} – (1-CE)]$

where:

eff_{new} and eff_{old} is the efficiency of the power plants with and without CO_2 capture, respectively, and CE is the fraction of CO_2 that is captured. Cost expressed per t of CO_2 avoided is higher than costs expressed per t of CO_2 captured. For example, in case of eff_{new} is 31% and eff_{old} is 43%, and CE is 0.85, the correction factor is 1.48. The correction factor declines to 1.20-1.25 for energy efficient emerging CCS technologies.

Only CCS cost expressed per t of CO_2 avoided allow for comparison with other CO_2 abatement measures in terms of cost of environmental effects that have been achieved. Full economic analysis of technology options requires, however, introduction of another parameter that relates cost to the technology output. For power generation sector this would mean using cost of CO_2-free electricity. Using such cost parameter entails making additional assumptions concerning power plant capital cost, discount rates, plant's lifespan and others.

Comparison of cost expressed per unit of output (e.g., per kWh of CO_2-free electricity produced) can yield different results than a comparison of cost per tonne of CO_2 captured or CO_2 avoided. A typical example is that the per tonne cost for CO_2 (captured or avoided) will be lower for a coal-fired power plant than for a gas-fired power plant, while the electricity supply cost may be lower for the gas-fired plant with CO_2 capture. All three CCS cost parameters (USD/kWh of CO_2-free electricity, USD/t of CO_2 avoided, USD/t of CO_2 captured) are being used throughout the book. Modelling analysis, however, is based solely on the "output" cost parameter in USD/kWh of CO_2-free electricity.

CCS for a coal-fired power plant will reduce emissions significantly, compared to the same power plant without CO_2 capture. However, comparing an identical plant with and without CO_2 capture may not adequately reflect the real emission impact in the case of a green-field investment decision. A coal-fired power plant with CCS does not reduce emissions compared to a hydropower or nuclear plant. Therefore, the choice of a reference process is crucial for estimating CO_2 avoidance costs.

In a marginal costing approach, the reference plant is the plant with the highest supply costs in the base case without CO_2 policies, i.e., the plant that determines the product price in an ideal market. The emissions of this plant may be high or low, depending on the energy resource endowment and economic structure of a region. For many OECD countries, a gas-fired combined cycle power plant would be the marginal producer to which a coal-fired power plant with CO_2 capture should be compared. This reduces the CO_2 benefits by a half or even two-thirds.

Upstream emissions of CO_2 also need to be taken into account when considering coal or gas life cycles. The characteristics of the specific supply chain must be accounted for since global averages make no sense. Depending on the supply chain, upstream CO_2 emissions can amount to between 0% and 20% of power plant emissions. Upstream emissions may decline in the future because of technological progress and reduced leakages, although this trend may be balanced by increasing transportation distances and a shift from pipeline use to shipped LNG, driven by resource exhaustion. The net effect will likely be a slight decline in emissions. In the model analysis outlined later in this book, upstream emissions are accounted for and based on region-specific energy supply structures.

(using solvents such as dimethylether of polyethylene glycol, so-called Selexol), in combination with pressure-induced CO_2 recovery. A range of solvents is being studied as outlined in Table 3.3.

The chemical absorption process is inherently energy inefficient due to the energy needed to break the strong bonding of the solvent and CO_2. As a result, new chemical absorbents, such as so-called sterically-hindered amines, are being investigated. The bonding strength between the solvent and CO_2 is lower than for MEA. As a consequence, less energy is needed to release the CO_2 from the solvent. Steam consumption for the latest chemical absorption systems is on average about 1.5 tonnes of low pressure steam per tonne of CO_2 recovered (3.2 GJ/t) for a boiler system with 90% recovery (it is slightly higher for higher recovery rates; Mimura et al. 2002). The recovery energy declines from 3.4 to 2.9 GJ/t for CO_2 concentrations increasing from 3% to 14%. The extremes represent the conditions for natural gas turbines and coal-fired steam cycles.

Physical absorption is based on the weak binding of CO_2 and the solvent. Binding takes place at high pressure with the CO_2 released when the pressure is reduced. The only energy needed for CO_2 capture is the electricity for gas pressurization. The amount of energy per tonne of CO_2 is proportional to the inverse of the CO_2 concentration in the gas: twice as much energy is needed if the CO_2 concentration in the gas stream is halved. **Chemical absorption is the preferred method at low CO_2 concentrations (lower than 10%, such as flue gases from gas-fired power plants) because its energy use is not particularly sensitive to low concentrations and low partial pressures of CO_2. Physical absorption is the preferred method at higher CO_2 concentrations (higher than 15%) and at higher partial pressures.**

The flue gases from a gas-fired combined cycle power plant contain between 3% and 4% of CO_2 and those from a conventional coal-fired power plant between 13% and 14% of CO_2. These relatively low concentrations are a result of using air for the combustion process. From a combustion perspective, only oxygen is needed. However, air contains about 80% nitrogen and 20% oxygen. The nitrogen dilutes the CO_2 in the flue gas. **Capture is easier at higher CO_2 concentrations. Higher CO_2 concentrations can be achieved in two ways. The first is by using pure oxygen instead of air. The second is by converting the fuel gas into CO_2 and H_2, and pre-combustion CO_2 removal, before the air is added for combustion.**

Emerging capture technologies for new power plants: pre-combustion capture and combustion using pure oxygen

Gasification technology, shift reactors, air separation, hydrogen separation and hydrogen turbines play a crucial role in the pre-combustion removal of CO_2 (Dijkstra and Jansen, 2003). Existing General Electric F-class turbines can accept gas containing 45% H_2. However, further development of gas turbines is required before pure hydrogen can be used to generate electricity. For example,

Table 3.3

Commercial CO_2 scrubbing solvents used in industry

	Solvent name	Solvent type	Process conditions
Physical solvents	Rectisol Purisol Selexol Fluor solvent	Methanol n-2-methyl-2-pyrolidone Dimethyl ethers of polyethyleneglycol Propylene carbonate	-10/-70°C, >2 MPa -20/+40°C, >2 MPa -40°C, 2-3 MPa Below ambient temperatures, 3.1-6.9 MPa
Chemical solvents	MEA Amine guard Econamine ADIP MDEA Flexsorb, KS-1,KS-2,KS-3 Benfield and versions	2,5 n monoethanolamine and inhibitors 5n monoethanolamine and inhibitors 6n diglycolamine 2-4n diisopropanolamine 2n methyldiethanolamine 2n methyldiethanolamine Hindered amine Potassium carbonate & catalysts. Lurgi & Catacarb processes with arsenic trioxide	40°C, ambient-intermediate pressures 40°C, ambient-intermediate pressures 80-120°C, 6.3 MPa 35-40°C, >0.1 MPa 70-120°C, 2.2-7 MPa
Physical/ chemical solvents	Sulfinol-D, Sulfinol-M Amisol	Mixture of DIPA or MDEA, water and tertahydrothiopene (DIPAM) or diethylamine Mixture of methanol and MEA, DEA, diisopropylamine (DIPAM) or diethylamine	>0.5 MPa 5/40°C, >1 MPa

Source: Gupta et al., 2003.

combustion control for hydrogen-fuelled gas turbines requires better control of process parameters than for natural gas turbines. NO_x emissions also need to be reduced further to acceptable levels, without excessive water/steam injection (Roekke, 2003).

The efficiency of pre-combustion CO_2 separation in natural gas reforming, including the use of membranes, is expected to be slightly higher than for current post-combustion absorption systems (Norwegian Petroleum Directorate, 2002). Compared to post-combustion absorption membrane systems, the **efficiency gains of pre-combustion separation systems for natural gas are marginal. The uncertainty of technical data is higher than the projected efficiency gains. For coal, the pre-combustion removal of CO_2 is generally considered to be advantageous compared to post-combustion removal.**[12]

Oxyfueling is another promising strategy for CO_2 capture. By using oxygen instead of air, a relatively pure CO_2 stream is created during combustion. Oxyfueling can be applied to steam cycles and gas turbines but it requires an air separation unit. In the case of a gas turbine, a process redesign is needed in order to maintain an acceptable temperature in the gas turbine. One option is to recycle

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12. *Note that some studies suggest that post-combustion capture would be preferable, e.g., Canadian Clean Power Coalition, 2004. Such studies are usually based on the current state of technology, and they do not account for long-term cost reduction potentials. Advances in different power plant technologies pose a source of uncertainty that can affect the choice of the optimal CCS technology. Also the quality of the coal (hard coal or lignite) can influence the results to some extent. See also the technology roadmap in Chapter 8.*

CO$_2$ to cool the turbine (for example the so-called MATIANT cycle). A second option is to use a mixture of steam and exhaust as a gas turbine working medium (so-called Graz cycle; Gupta et al., 2003). The MATIANT cycle would require the development of new turbines since retrofitting existing turbines would not be feasible from a technical perspective.

The role of membranes in CO$_2$ capture

Gas separation membranes are likely to play a key role in CO$_2$ capture systems in the future. Their energy efficiency can be higher than for absorption separation systems, as a limited pressure drop across the membrane is sufficient to achieve separation. Their modular design also allows their use in combination with small-scale modular fuel cells, a power plant concept for the future. While membranes are widely applied for gas separation, they are not yet applied on a power plant scale.

The disadvantage of membrane separation systems for CO$_2$ capture is that their separation efficiency is relatively poor. Only a fraction of the CO$_2$ is recovered and the purity of the CO$_2$ is relatively low. For example, a study on membranes for fuel gas CO$_2$ separation from IGCC plant suggests that only multi-stage membrane systems can meet the necessary purity criteria. For IGCCs, ceramic membranes are preferable over polymer membranes, as they can operate at higher temperatures, thus reducing the need for cooling of fuel gases. Polymer membranes, however, are more developed than ceramic membranes and can achieve much higher CO$_2$ recoveries, around 57% compared to 7%.

At present, using polymer membrane separation systems would increase investment costs from 1,263 USD per kW to 5,700 USD/kW (Kaldis et al., 2003). Clearly, further cost reductions are needed as are improvements in separation efficiency for ceramic membranes. It is possible to combine membrane separation systems with absorption systems in order to achieve a higher efficiency of CO$_2$ separation. This type of combined separation system has been considered in the analysis.

In addition to gas separation membranes, gas absorption membranes offer high capture potential. These membranes work as contacting devices between gas and liquid flow. Their function is to increase the contact area, thus reducing the size of the scrubbing equipment (McKee, 2002). These absorption membranes increase energy efficiency and reduce capture cost, but to a lesser extent than the speculative, future gas separation membranes.

Some suggest that the efficiency of gas and even coal oxyfuel systems will be lower than for post-combustion absorption due to the high oxygen requirements and the energy use for oxygen production (Canadian Clean Power Coalition, 2004). This does not account for possible substantial improvements in oxygen production (see box). **While there is some debate as to whether oxyfueling has advantages for natural gas combined cycles and coal-fired steam cycles, oxygen blown gasifiers with pre-combustion CO$_2$ removal in combination with hydrogen turbines will be essential for coal-fired IGCCs.**

Chemical looping is another oxygen supply concept worth mentioning here. The concept is based on the use of a metal/metal oxide system to provide a reversible chemical reaction for oxygen supply. In one reactor the metal reacts with air to produce a metal oxide; in another reactor, the metal oxide reacts with the fuel to produce syngas and metal (so-called flameless combustion).

Metal and metal oxide are transported from one reactor to the other. Such a system avoids energy intensive air separation for pure oxygen supply. **Studies suggest that the electricity production cost for a coal-fired circulating fluidized bed with chemical looping and CO_2 capture would be lower than for IGCC (Nsakala *et al.*, 2003). Studies suggest up to 54% efficiency for a gas-fired power plant with chemical looping and CO_2 capture, including CO_2 pressurization (Brandvoll and Bolland, 2002).**

The concept of chemical looping for oxygen supply has been around for more than 25 years, but has only been applied in the laboratory, not on a commercial scale. In the past, similar process designs based on particle transfer have experienced plugging and abrasion problems. Metal oxide materials are needed that withstand chemical cycling and are resistant to physical and chemical degradation caused by impurities from fuel combustion (Gupta et al., 2003). The system also needs to be proven on a pilot plant scale. CO_2 capture based on chemical looping – for coal and for gas-fired electricity production – should be considered a speculative technology.

For a coal fired IGCC the electricity used for oxygen production amounts to 10% of the IGCC electricity production. This may be halved in the future (see the box above). The energy needed for CO_2 pressurization represents some 8% of the electricity output. Gasification efficiency is somewhere between 75% and 90% and depends on the gas cleaning technology. Low temperature gas cleaning is a proven technology but it results in energy losses compared to future high temperature gas cleaning, which is not yet proven on a commercial scale. The energy requirements for the shift reactor amount to 4% of the syngas LHV (Mathieu, 2003). This assessment does not account for gas turbine efficiency variations due to differences in the gas composition.

The importance of new air separation technologies

The efficiency of power plants and CO_2 capture systems using oxygen depends critically on the energy required for oxygen production. At present, large-scale oxygen production is based on cryogenic air separation with plants reaching capacities of up to 3000 t of oxygen per day. Energy consumption required for this has declined to around 0.3 kWh/Nm³ low pressure oxygen (210 kWh/t oxygen or 0.77 GJel/t oxygen). A further reduction to 0.28 kWh/Nm³ is projected for 2010 (a 6.7% energy efficiency improvement).

More complex processes at higher pressures may reduce power consumption further and result in capital cost savings (Castle, 2002). Vacuum Pressure Swing adsorption is an alternative for medium size plants up to 250-350 t of oxygen per day. A typical 250 MW IGCC needs 2,000 t of oxygen per day. Ion transport membrane systems, based on inorganic oxide ceramic materials, could be used to provide oxygen for IGCCs. What is not clear is whether this technology, which is still under development, will be economical when scaled up for use in power plants (Smith and Klosek, 2001). If membrane systems do succeed, the energy requirement for air separation may be reduced to 147 kWh/t oxygen (Stein and Foster, 2001). This would represent a 51% energy efficiency improvement, compared to the current cryogenic oxygen separation technology.

For an oxygen-blown IGCC this would imply an electric efficiency increase of 1-2 percentage points (2-5% in relative terms). At the same time, the costs of oxygen production are reduced by 35% and the investment costs for IGCC reduced by 75 USD/kW. These figures suggest that new air separation systems would enhance the prospects of oxyfuelling- based CO_2 capture strategies significantly.

An IGCC with CO_2 capture can be considered as a gas-based combined cycle where some processes have been added. The additions are coal gasification, oxygen production, shift reactor and CO_2 separation. Assuming a 60% efficiency for a gas-fired combined cycle without CCS (the total efficiency for the gas turbine and the steam cycle), a coal-fired IGCC with CCS can achieve between 36 and 43% efficiency. This back-of-envelope calculation shows where the main losses occur. Efficiency gains can be achieved in several ways. For example, efficiency in electricity generation can be increased by adding fuel cells; increasing gasification efficiency is achievable by using high-temperature gas cleaning; reducing the energy required for air separation unit can be done by using membrane separation processes.

IGCC designs are based on the use of oxygen and steam for coal gasification at high pressure, conditions that make the plant well suited for fuel gas CO_2 removal. However, this is balanced by the comparatively high cost of IGCCs and the relatively immature state of this technology. Estimates of future IGCC investment costs vary considerably. The variations can be attributed to a range of issues. For example, when high availability is required, a spare gasifier is needed, which increases investment costs by between 150 and 200 USD/kW.

At present, only so-called F class gas turbines are available. In future, H class gas turbines may become available. These would increase electric efficiency by 1.3 to 3.4 percentage points. Since higher gas turbine efficiencies imply smaller gasifiers, this would in turn reduce investment costs per kW by 10-20%. Three types of gasifiers exist: one-stage slurry fed such as the Texaco gasifier, two-stage slurry fed gasifiers such as the E-Gas gasifier, and dry fed systems such as the Shell gasifier. The efficiency of the dry fed systems is significantly higher, but so is the cost (IEA GHG, 2003). Furthermore, the type of coal used influences cost. For example, building a lignite-fired IGCC costs 400 USD/kW more than using a hard coal-fired IGCC (Breton and Amick, 2002). Some IGCC costing studies account for contingency cost, others do not. This makes a difference of 100 to 200 USD/kW. Furthermore, additional CO_2 capture costs differ depending on IGCC design, ranging from 350 USD/kW for Texaco quench-type gasifiers to 550 USD/kW for Shell and E-gas designs.

New capture technologies

In the quest for more energy efficient and less costly capture technologies, new technology concepts are being investigated. One concept is based on adsorption of CO_2 to solids. Temperature swing adsorption, pressure swing adsorption and electric swing adsorption are examples of this. However, adsorption is not yet considered attractive for large-scale separation of CO_2 from flue gas because the capacity and CO_2 selectivity of available adsorbents are low (Gupta et al., 2003).

Another strategy which has been proposed is based on the $CaO/CaCO_3$ system in which lime (CaO) is added to the combustion process in a fluidized bed. The CaO reacts with the CO_2 produced from fuel combustion. The $CaCO_3$ formed is recycled to another reactor, where it is calcined (dissociation at temperatures above 850 °C). The challenge is to identify process conditions where the CaO remains active. So far, such conditions have not been found (Salvador et al., 2003).

Given the low likelihood of these capture systems and their limited benefits compared to other more likely capture systems such as chemical and physical absorption, they have not been considered in this book's analysis.

While some experts question the attractiveness of IGCC compared to coal-fired steam cycles in a CO_2-unconstrained world, the attractiveness of IGCC increases compared to conventional steam cycles, when CO_2 capture is required. This is true for both hard coal and lignite-based electricity production systems (Ewers et al., 2003). However, it remains to be seen if this advantage is sufficient to tilt the balance in favour of IGCC.

In the long run, power plants including fuel cells may allow even higher efficiencies than today's gas turbines and steam cycles. Engineering studies suggest that certain designs would be well suited to CO_2 capture, as fuel cells need hydrogen as a fuel. For the time being, such systems are speculative, because these fuel cells have not yet been proven on a commercial MW-scale. Such power plant systems, including solid oxide fuel cells (SOFCs), have been considered in the analysis (Dijkstra and Jansen, 2003).

Overview of capture technology efficiencies and cost for new power plants

Table 3.4 provides an overview of the characteristics of power plants with CO_2 capture. All cases have been assessed based on a product CO_2 flow at 100 bar meaning that CO_2 compression is included in the efficiency losses. The efficiency loss due to CO_2 capture ranges from 12 percentage points for existing coal-fired power plants to 4 percentage points for future designs with fuel cells.

With regard to electricity costs, the gas-based systems with CO_2 capture seem cheapest. However, this result depends on local fuel prices and discount rates. Moreover, differences between coal and gas-fired systems are relatively small. **The figures suggest a prospective electricity cost price increase of 1-2 US cents per kWh.** This is an important increase, compared to production costs (+25-50%, see Table 3.4). However, electricity consumer prices are considerably higher than producer costs. The average electricity price was 10.6 US cents/kWh for households in OECD Member countries in 2000. The increase amounts to 10-20% of the consumer price.

CO_2 capture is energy intensive and results in increased coal and gas use for electricity production. The increase ranges from 39% for current designs to 6% for advanced designs (Table 3.4). This is a substantial increase with impacts on global coal and gas markets especially if CCS is widely applied. However, substitution effects resulting in fuel demand reductions can potentially be more substantial than fuel demand increases because of CCS use, resulting in a net fuel demand decrease on a global scale. Also CO_2 policies will result in a shift to higher efficiency power plants.

Biomass-fired power plants with CO_2 capture constitute a special option. Because renewable biomass is a CO_2-neutral energy carrier, combining biomass-fired power plants with CO_2 capture results in a net removal of CO_2 from the atmosphere (Möllersten et al., 2003; Möllersten et al., 2004). However, the problem with biomass is generally that the scale of operations is much smaller than for fossil-fuelled power plants. A typical biomass IGCC would have a capacity of 25 to 50 MW, compared to a coal-fired IGCC with a capacity of 500 to 1000 MW. As a consequence, investment costs per kilowatt are twice as high for biomass. Also, biomass is considerably more expensive than coal in most world regions. In a CO_2-constrained world, the removal of CO_2 from the atmosphere may offset these disadvantages. Moreover, certain industrial biomass conversion processes, such as black liquor gasifiers in pulp production, generate CO_2 in quantities of a similar order of magnitude as power plants (see section on industrial processes). Finally, a certain amount of biomass can be co-combusted in coal-fired plants.

Existing capture technologies are all characterized by relatively high costs per tonne of CO_2 and low energy efficiencies, compared to what society today is willing to pay for CO_2 emission mitigation. Energy efficiency losses due to CO_2 capture and pressurization play a key role. R&D is aiming for new technologies with higher efficiencies. Such developments are deemed critical for successful large-scale introduction of CCS (Klara, 2003). However, as the complexity of the designs increases so do capital costs. Systems integration problems also tend to increase. A number of new conceptual designs seem attractive, but

Table 3.4

Characteristics of power plants with and without CO$_2$ capture

Fuel, technology	Starting year	INV (USD/kW)	FIX (USD/kW.yr)	Eff (%)	Eff. loss (%)	Add. fuel (%)	Capt. eff. (%)	Capt. costs (USD/t CO$_2$)	El. costs (Mils/kWh)	Add. el. costs (Mils/kWh)
No CO$_2$ capture										
Coal, steam cycle	2010	1,075	23	43					29.1	
Coal, steam cycle	2020	1,025	31	44					29.2	
Coal, USC steam cycle	2020	1,260	30	50					31.5	
Coal, IGCC	2010	1,455	57	46					37.4	
Coal, IGCC[12]	2020	1,260	35	46					33.0	
Gas, CC	2005	400	14	56					26.1	
Gas, CC	2015	400	14	59					25.2	
Black liquor, IGCC	2020	1,300	50	28					23.5	
Biomass, IGCC	2020	2,400	50	40					74.6	
With CO$_2$ capture										
Coal, steam cycle, CA	2010	1,850	80	31	-12	39	85	24	51.0	21.9
Coal, steam cycle, membranes +CA	2020	1,720	75	36	-8	22	85	21	46.3	17.1
Coal, USC steam cycle, membranes +CA	2030	1,675	45	42	-8	19	95	17	49.0	17.5
Coal, IGCC, Selexol	2010	2,100	90	38	-8	21	85	20	52.3	14.9
Coal, IGCC, Selexol	2020	1,635	50	40	-6	15	85	11	41.0	8.0
Gas, CC, CA	2010	800	29	47	-9	19	85	29	36.8	10.7
Gas, CC, Selexol/OxF	2020	800	33	51	-8	16	85	25	34.8	9.6
Black liquor, IGCC	2020	1,620	50	25	-3	12	85	4	27.9	4.4
Biomass, IGCC	2025	3,000	100	33	-7	21	85	23	96.1	21.5

Speculative technologies										
No CO$_2$ capture										
Coal, IGCC & SOFC	2030	1,800	75	60					41.3	
Gas, CC & SOFC	2025	800	40	70					30.6	
With CO$_2$ capture										
Coal, CFB,										
Chemical looping	2020	1,400	45	39	13	-5	85	14	38.2	14.7
Gas, CC,										
Chemical looping	2025	900	25	56	7	-4	85	33	34.5	9.3
Coal, IGCC & SOFC	2035	2,100	100	56	7	-4	100	13	49.0	7.7
Gas, CC & SOFC	2030	1,200	60	66	6	-4	100	28	39.2	8.6

Note: The above comparison is based on a 10% discount rate and a 30-year process lifespan. The investment cost excludes interest during construction and other owners' costs, which could add 5-40% to the overnight construction cost. This approach has been applied to all technologies that are compared in this study. Coal price = 1.5 USD/GJ; gas price = 3 USD/GJ. CO$_2$ product in a supercritical state at 100 bar. CO$_2$ transportation and storage is not included. Capture costs are compared to the same power plant without capture. Capture costs are expressed per tonne of CO$_2$ captured – see box on evaluating the cost of CCS in this chapter for conversion factors to cost per tonne of CO$_2$ avoided. CA = Chemical Absorption. CC = Combined Cycle; CFB = Circulating Fluidized Bed; IGCC = Integrated Gasification Combined Cycle; OxF = oxyfuelling; SOFC = Solid Oxide Fuel Cell; USC = Ultra Supercritical.

Source: IEA GHG, 2000; David and Herzog, 2001; Dijkstra and Jansen, 2003; Freund and Davison, 2002; SFA, 2002; Herzog, 2003; Brandvoll and Bolland, 2002; Nsakala et al., 2003; Bolland and Undrum, 2003.

12. The IGCC data for 2010 refers to a European highly integrated plant based on a Shell gasifier, while the 2020 data refers to a less integrated US design based on an E-gas gasifier. The efficiency remains at the same level because new gas turbines will become available in the 2010-2020 period (the so-called 'H-class') and result in an increase in efficiency. The gasifier substitution reduces capture efficiency losses and reduces investment cost penalties.

their successful development is far from certain. The development of conceptual designs to full-scale power plants is generally a slow process that will take decades. CCS could be applied in the short term, but the cost and efficiency penalties would be higher than the ones listed in Table 3.4.

The optimal CO_2 capture system for gas-fired power plants is not yet clear. New solvents are being developed that reduce the energy needs for chemical absorption technology. Oxygen-fuelled systems with CO_2 recycle are also being examined. Finally, steam reforming of natural gas with fuel gas CO_2 capture, in combination with new hydrogen gas turbines, is being investigated. **Overall, it seems likely that novel approaches, such as re-thinking the power generation process, are needed if substantial reductions in the cost of capture are to be achieved.**

Retrofitting CO₂ capture technology onto existing power plants

All the designs that have been discussed so far represent greenfield investments. Some studies suggest it might be possible to retrofit power plants with CO_2 capture at a later stage.

In a case study of a new gas-fired power plant at Karstø in Norway, two capture systems were compared. The first was an integrated system, where steam was extracted from the power plant, and the second with its own steam supply. The integrated system resulted in an efficiency loss of 11 percentage points (from 58% to 47%). The stand-alone system resulted in an efficiency loss of 14.3 percentage points (from 58% to 43.7%). The wider applicability of this option would depend on local gas prices. However, power plant investment costs would be virtually the same at 675 Euros/kW. Given these figures, **retrofitting high efficiency power plants may be a feasible option in the future, if gas prices are sufficiently low** (Elvestad, 2003).

For IGCCs, it might be possible to reserve space for future expansion with CO_2 capture equipment (SFA Pacific, 2002). The initial design would accommodate space for a shift reactor, Selexol units, a larger Air Separation Unit, expanded coal handling facilities and larger vessels. Also CO_2-capture would involve changes in the gas turbine, as the gas composition would change. A case study suggests that an initial design that considers later retrofit would reduce capture investment cost from 438 USD/kW to 305 USD/kW. However, initial investment cost would be 59 USD/kW higher (Rutkowski and Schoff, 2003) meaning the net investment cost reduction for IGCC and CCS (in comparison with CCS for not capture ready IGCC) would be around 17%.

Pulverised coal-fired plants could also be retrofitted, with oxyfuelling seeming the best option (Singh et al., 2003). Total primary energy use for an Air Separation Unit (ASU), low temperature flash (LTF) for purification of CO_2 from 95% to 98%, and CO_2 separation and pressurization to 150 bar amount to 3.1 GJ natural gas per tonne of CO_2, assuming that the electricity needed is produced in a gas-fired combined cycle. The electricity use for CO_2 capture (air separation, CO_2 purification and CO_2 pressurization) amounts to 35% of the electricity produced in a plant without CO_2 capture.

Assuming 40% electric efficiency for the original power plant, additionally 0.72 GJ gas is needed per GJ of electricity produced. The percentage of CO_2 avoided is 74%. Capital cost amounts to 120 USD/t CO_2 captured (for a 400 MWel coal-fired power plant where 2.7 Mt CO_2 per year is captured). Half of the capital cost is accounted for by the ASU (Figure 3.1). Assuming an annuity of 15% of the investment cost, CO_2 capture cost amounts to 27 USD/t CO_2 captured, or 33 USD/t CO_2 avoided.

Lower costs can be achieved for greenfield oxyfuelling plants. One reason is that the process can be designed so the CO_2 recycle flow can be reduced significantly. Another is that better process integration can reduce electricity losses by 6 percentage points (Jordal et al., 2004).

Figure 3.1

Investment capital cost shares for oxyfuel retrofit of coal-fired power plants

*Key point: The air separation unit accounts
for half of the investment costs associated with oxyfuelling*
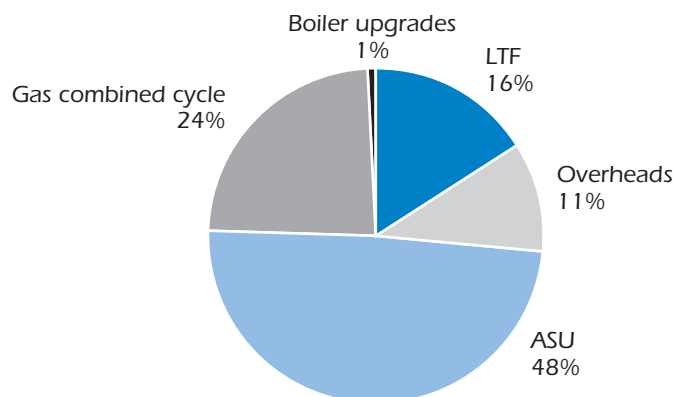
ASU = Air Separation Unit; LTF = low temperature flash for purification of CO_2.

Source: Singh et al*., 2003.*

The observations regarding retrofitting are important for a power sector strategy because there seems little incentive for CO_2 capture in the short term, while there is a need for significant new electricity production capacity. Also, coal-fired power plants have a very long lifespan, and existing plants may need to be retrofitted if emissions reduction becomes a priority. The relevance of this strategy depends on the age profile of the capital equipment stock.

Efficiency first: clean coal technologies

The net electric efficiency of individual operational coal-fired power plants ranges from 25% to 48%, and the regional average gross electric efficiency from 27% to 40% (Table 3.5). This wide range can be attributed to varying steam conditions, coal quality, cooling water temperature and the installation of emission mitigation equipment. A low efficiency power plant can make economic sense when fuel prices are low (as they are in many parts of the world), or when high-efficiency technology would imply imports of costly equipment (the case in many developing countries). CO_2 capture from plants with low electric efficiency makes no sense.

The higher the electric efficiency, the lower the emission mitigation cost will be, and the lower the cost increase per kWh of electricity (see box below). Therefore, **investing in high efficiency power plants is a first step in a CCS strategy.** All strategies for increased power plant efficiency are aimed at higher temperature conditions (Figure 3.6). However, higher temperature may also mean more corrosion and higher steam pressure. These factors constitute materials design problems.

Coal-fired steam cycles can be classified according to their steam conditions: namely, subcritical, supercritical and ultra-supercritical[13]. Supercritical coal-fired power plants can be considered an established

---

13. *The critical point for water is reached at 401°C and 221 Bar. At higher pressures and higher temperature, there is no longer a discernible phase transition from liquid to gas.*

Key point: Most standing coal capacity in Europe and North America
is over 25 years' old

Figure 3.2

European coal-fired power plant building activity (1920-2000)
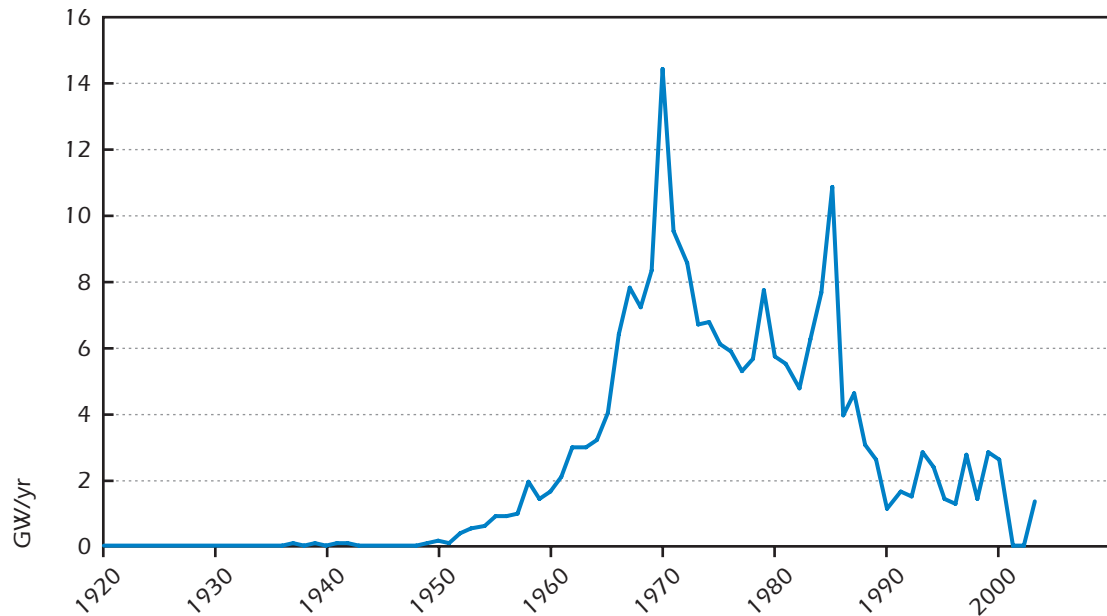
Source: UDI, 2003.

Figure 3.3

North American coal-fired power plant building activity (1920-2000)
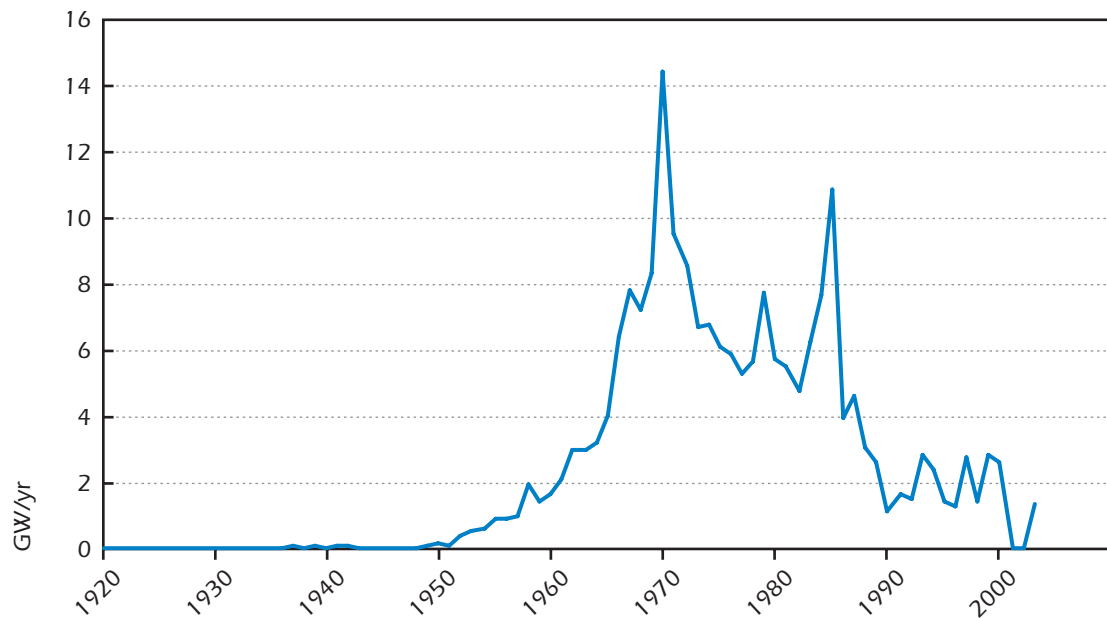
Source: UDI, 2003.

Key point: Most standing coal capacity in Japan
and China is less than 20 years old

Figure 3.4

Japanese coal-fired power plant building activity (1920-2000)
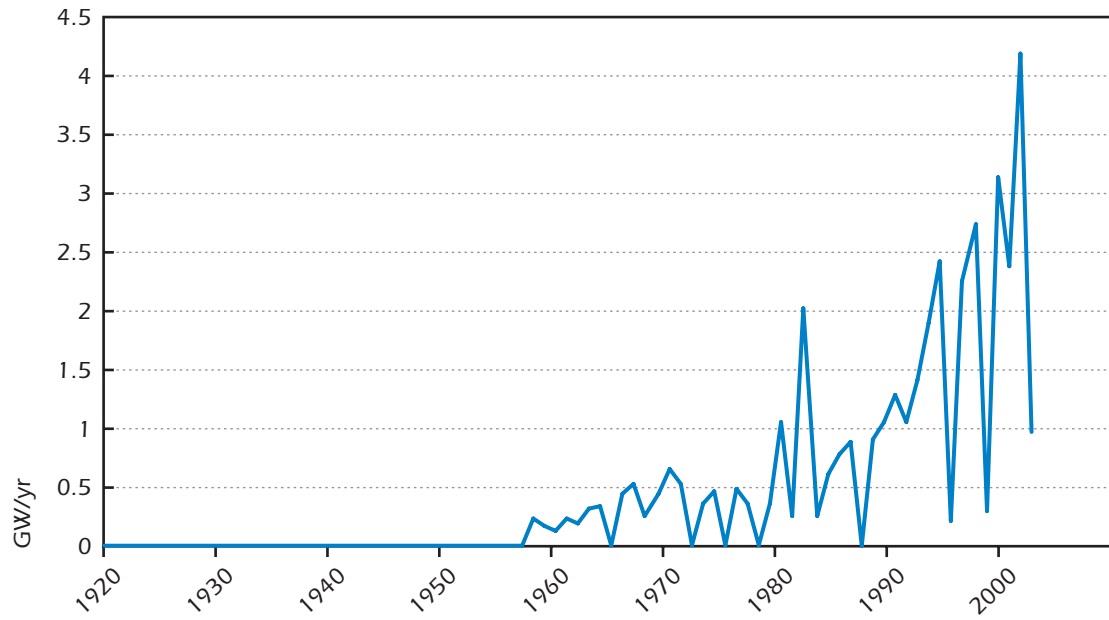
Source: UDI, 2003.

Figure 3.5

Chinese coal-fired power plant building activity (1920-2000)
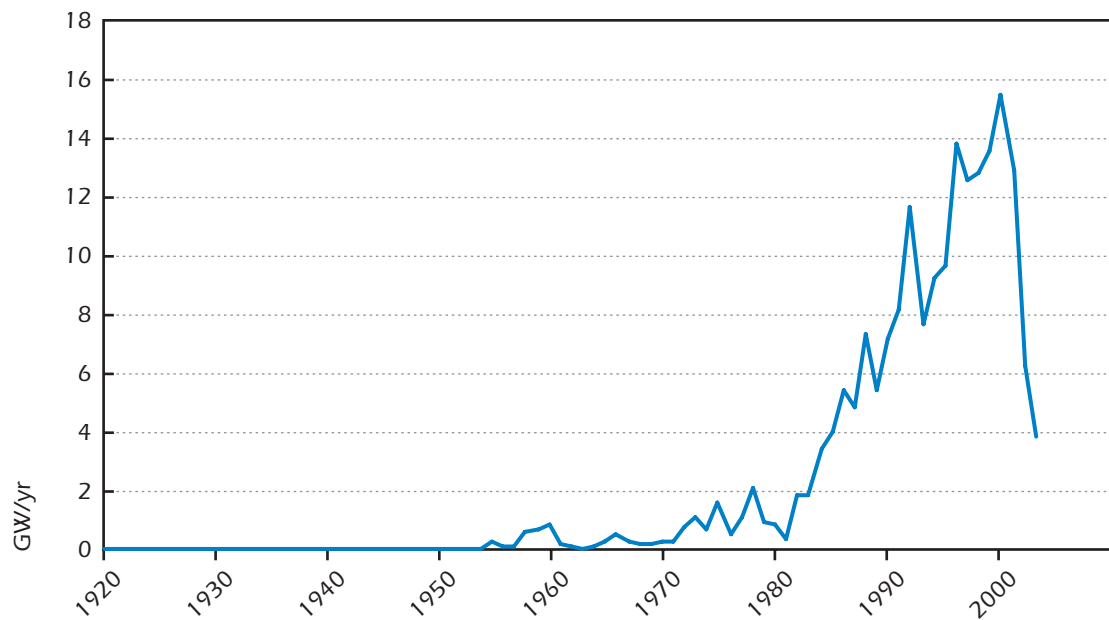
Source: UDI, 2003.

Retrofitting ageing, existing power plant stock

The discusison on retrofit can be split into existing plants and new plants that will be built in the coming decades without CCS. The existing power plant stock age differs around the world, depending on the historical electricity demand and supply mix. It is unlikely that recently-constructed power plants will be closed down within the next couple of decades. This is typically the category where retrofit may be considered. For this reason, the age profile of coal-fired power plants has been analysed in more detail here. Figures 3.2 to 3.5 show the age profile for four regions: Europe, USA and Canada, Japan and China.

North American stock shows a clear peak around 1970. Given a lifespan of 40-50 years, this suggests that many plants must be replaced around 2010-2020. This is the timeframe when CCS may become available. Therefore, retrofitting seems less relevant for North America. In the European case, only about a third of the stock is under 15 years in age. In 2020, these plants will have a lifespan of almost 35 years. Retrofit may be considered for these plants. In the case of Japan and China, the bulk of coal-fired power plant stock is under 15 years of age, meaning that retrofit may be considered. However, large-scale introduction of CCS in China is uncertain in the short and medium terms. This leaves Japan as a prime candidate for retrofit, along with certain parts of Europe.

The lifespan of coal-fired power plants is a source of uncertainty. One important factor that determines power plant lifespan is the outage rate. Unit forced outage rates for coal fired plants are generally low at an age of 10-20 years at about 5%, and increase exponentially to 20% at an age of 40 years. As a consequence, a trade-off exists between low efficiency and outage of ageing plants, versus investments in new plants (Armor, 1996). Generally speaking, the lifespan of US plants is 10-15 years longer than that of European plants, which may be attributed to lower coal prices and more liberalized markets resulting in a reluctance to invest in new more efficient plants.

In the USA, repowering projects for existing coal plants have significantly extended plant lifetimes and, in certain cases, resulted in substantial efficiency improvements. The changes are often so substantial that the projects are similar to the entire plant being replaced. In the statistics, however, such a facility may show up as a power plant with a very long lifespan.

Monitoring of power plant operations has improved, which results in a much better control of process conditions and longer power plant life. However steam temperature and pressure have increased in order to improve power plant efficiencies. Chemically-reducing conditions for NOₓ-control reasons and changing ash chemistry due to co-firing of other fuels, reduce a power plant's lifespan (Fleming and Foster, 2001). Electricity market liberalization has resulted in much more start-and-stop cycles than were considered in the original plant design. The net effect of these changes is a considerably reduced boiler life (Paterson and Wilson, 2002).

The lifespan of coal-fired power plants may change in the future, but it is hard to say whether it will increase or decrease, compared to plants that are closed down today. The lifespan of gas-fired power plants is much shorter than coal-fired power plants and capital costs are low compared to fuel costs. Therefore, retrofitting gas-fired power plants is unlikely

> *to be a strategy of prime importance. In general, technical lifespan is of secondary importance, as power plants can be replaced before the end of their lifespan.*
>
> *Retrofitting has not been considered in the model analysis presented in Chapters 4, 5, 6 and 7 because it is likely to be of limited relevance. Early replacements and reduced load factors for fossil fuelled plants without CCS have been considered.*

technology. New coal-fired power plants based on this technology can achieve efficiencies of between 44% and 45% (LHV). Even higher values of up to 47% and 48% are reported, but these can be attributed to exceptional conditions with low temperature seawater cooling.

Coal-fired power plants in the USA tend to have lower efficiencies than those in Europe or Japan due to higher flue gas temperatures at the outlet (the result of the sulphur content in the coal), higher cooling temperatures and the use of single versus double reheat. The difference can amount to 3 to 5 percentage points (Viswanathan, 2003).

The efficiency of steam cycles is determined by the steam conditions, especially the temperature. For an ideal Carnot cycle, the efficiency is given by the ratio of the cycle temperature difference, divided by the maximum temperature of the steam, expressed in Kelvin. So, if a steam cycle has a maximum temperature of 580°C and a cooling water temperature of 20°C, the Carnot efficiency is (580-20)/(580+273) =

Figure 3.6

Power plant efficiencies as a function of the cycle temperature (based on lower heating value, LHV)

Key point: Higher process temperatures are the key to higher electricity production efficiencies
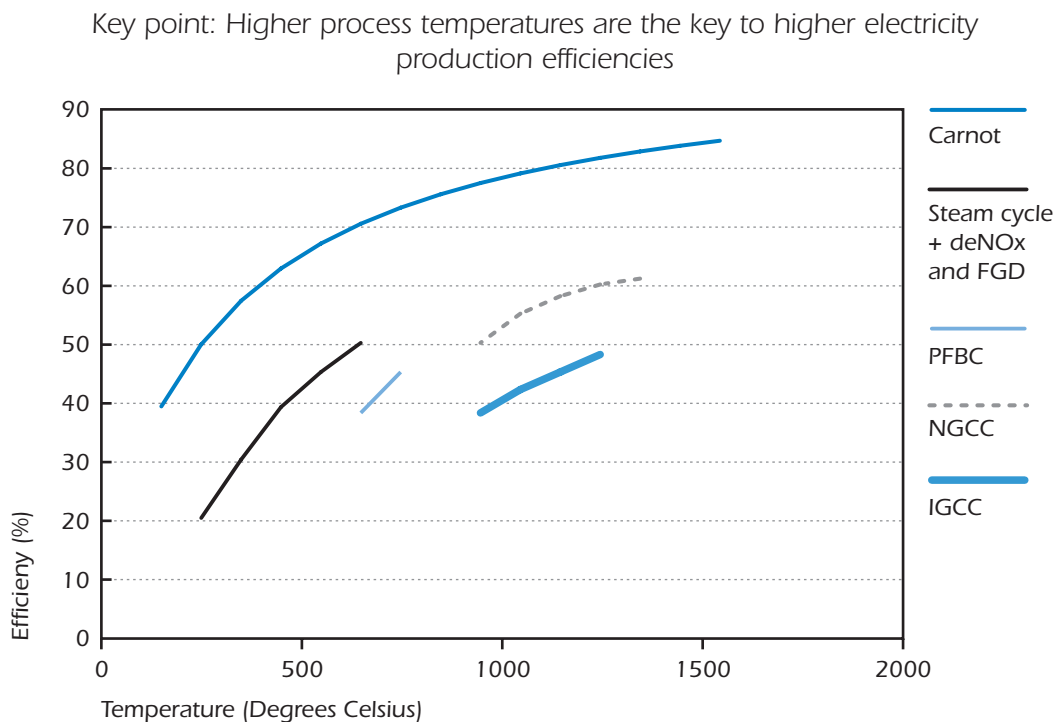
Note: The Carnot efficiency is the theoretical maximum, assuming a cooling water temperature of 15°C (Eurocoal, 2003). FGD = Flue Gas Desulphurization; PFBC = Pressurized Fluid Bed Combustion; NGCC = Natural Gas Combined Cycle.

Table 3.5

Average regional efficiencies for centralized, coal- and gas-fired power plants (2000)

	Hard coal-fired (%)	Natural gas-fired (%)
Africa	35	36
Australia/New Zealand	38	48
China	35	39
Central and South America	35	39
Eastern Europe	27	44
India	28	44
Japan	38	46
Middle East	40	35
Mexico	-	36
Other Asia	33	40
South Korea	36	50
USA/Canada	36	38
Western Europe	39	47

Note: Gross efficiency, excluding own electricity consumption. Based on Low Heating Value, LHV

Source: Based on IEA energy statistics.

66%. In practice, the efficiency is lower (up to 45% efficiency) because of significant losses for flue gas cleaning, pumping and other factors. If the steam temperature can be raised by 100°C to ultra-supercritical steam cycle (USCSC) conditions, the theoretical efficiency gain is 3 percentage points (48% to 50%).

In turn, the steam's maximum temperature is limited by materials that can withstand the steam conditions. Current steel alloys have reached their limits at a maximum steam cycle temperature of about 600°C. Research in the 1990s that focused on ferritic (up to 650°C) and austenitic steels (up to 700°C, so-called P91 and P92 alloys) for higher temperatures has not yielded satisfactory results (Fleming, 2002). In recent years, research has focused on nickel alloys. These alloys have the necessary properties to withstand temperatures of between 700-750°C.

The problem with nickel alloys is their price, which is 10 times that of ferritic and austenitic steels, and 100 times more than carbon-manganese (C-Mn) steels (Fleming, 2002). Moreover, the use of significant tonnages of nickel could increase the price of nickel. This has hindered the widespread use of these alloys so far. New power plant designs are being proposed in which nickel alloys are only used for critical parts of the power plant. Novel plant designs such as two pass, inverse twin tower and horizontal boiler concepts can reduce investment costs, and have been developed in the framework of the EU 700°C power plant project (AD700, not dated; Scott 2001). Their introduction would limit the use of nickel alloys and enable the construction of power plants with a maximum steam temperature of 700°C. **The net electric efficiency of such USCSC plants could exceed 50%. However, the reliability of these power plants needs to be proven in practice, a process that will take decades.**

Currently, it is not possible to say with a high degree of certainty what the characteristics of future USCSC power plants will be. It is, however, possible to define development targets that should be met by a cost-effective power plant design. Viswanathan (2003) concludes that USCSC total plant investment cost could be 12-15% higher than the cost of a subcritical steam cycle, and still be

Why CO_2 capture only makes sense for high efficiency power plants

It is often argued that CO_2 capture should be applied to low-efficiency power plants in developing countries as they emit the highest quantity of CO_2 per kWh. This reasoning is flawed. Firstly, new types of power plants such as IGCC allow the use of much more efficient low-cost CCS technology. Secondly, capture equipment costs are subject to economies of scale. Power plants in industrialized countries are often a factor of two to five times larger than in developing countries.

The loss of electric efficiency, in relative terms, is much higher for low efficiency power plants. This can be illustrated by comparing the physical absorption systems of two power plants: a 35% efficient coal-fired power plant (case A) and a modern 50% efficient power plant (case B). In case A, 0.96 kg CO_2 must be captured per kWh. In case B, 0.67 kg CO_2 must be captured per kWh.

Assuming that a chemical absorption system is added, steam requirements in case A amount to 0.0028 GJ/kWh, and to 0.0019 GJ/kWh in case B. Assuming a steam generation efficiency of 85%, this represents an increased fuel use of 45% and 32%, respectively. Also, electricity is needed for CO_2 pressurization (0.34 GJel/t CO_2). The electricity output declines by 13% and 8.4% respectively[14]. Therefore, the fuel use per kWh increases by 67% and 44% respectively[15]. This additional fuel use results in additional CO_2 which must also be captured.

Accounting for this increase implies additional fuel use per kWh of 77% and 44%, for case A and B respectively[16]. At a coal price of 1.5 USD/GJ, the additional fuel cost amounts to 1.2 US cents/kWh in case A and 0.6 US cents/kWh in case B. Per tonne of CO_2, additional fuel costs amount to 7 USD/t CO_2 in case A and 5.4 USD/t CO_2 in case B.[17] The capital cost is proportional to the amount of CO_2 to be captured, so the capital cost per tonne of CO_2 will be similar for both plants. In terms of cost per tonne of CO_2 and cost per kWh, case B is superior to case A. Clearly, efficiency is the first key step. In conclusion, this shows that retrofitting CCS onto low-efficiency coal-fired power plants in developing countries is not a viable strategy.

cost-effective. As the balance-of-plant cost is 13-16% lower (because of reduced coal handling and reduced flue gas handling), the boiler and steam turbine cost can be up to 40-50% higher.

Viswanathan concludes that the cost of an USC boiler would be 28% higher than that of a comparable subcritical boiler, but notes that unknowns in fabrication and erection costs with the new materials could change the results somewhat. Given loss of efficiencies for CO_2 capture, the efficiency of USCSC with CO_2 capture could reach 42%. This analysis suggests that IGCC development

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14. $0.131 = 0.96*1.45*0.34/0.0036*0.001$

15. $1.67 = 1.45/(1-0.131)$

16. $1.77 = 1+0.67*1.67/1.45$

17. $7 = 0.012/0.00096/1.77$

might not be crucial for a CCS strategy and that CCS could be applied successfully within the existing steam cycle technology paradigm.

CO$_2$ Capture in the Manufacturing Industry

Process industries

CO$_2$ capture could be applied in a number of production processes in the manufacturing industry. **Industrial sources of (potentially) relatively pure CO$_2$ are of limited importance on a global scale (<200 Mt CO$_2$ per year in total) and include the production of ammonia, ethylene oxide, existing hydrogen production and production of direct reduced iron (DRI).**

Given the limited CO$_2$ capture costs, these processes constitute prime candidates for the introduction of CCS. However, a number of important industrial processes – such as blast furnaces, cement kilns, steam crackers – are characterised by lower CO$_2$ concentrations[18] but large CO$_2$ quantities. Because of the low CO$_2$ concentrations, they would require either costly and energy-intensive CO$_2$ chemical absorption processes, or process re-design to increase CO$_2$ concentrations, such as those based on the use of oxygen in combination with post-combustion CO$_2$ removal or hydrogen production in combination with pre-combustion CO$_2$ removal.

Ammonia production

Nitrogen fertilizers are produced from ammonia which is produced from hydrogen. In turn, the hydrogen is produced from natural gas, heavy oil or coal. In older ammonia production plants, CO$_2$ is separated from the hydrogen before the ammonia production step. In newer plants, hydrogen rather than CO$_2$ is separated from the syngas. The residual gas containing CO$_2$, CO, unconverted methane etc. is used as a fuel in the reformer furnace, in which case there is no pure CO$_2$ stream. If there was a need to produce pure CO$_2$, it would imply a switch back to the old plant design.

A significant share of the CO$_2$ separated is used for the production of urea (CH$_4$N$_2$O), a popular type of nitrogen fertilizer. Given its chemical formula, 0.88 tonnes of CO$_2$ are needed for each tonne of urea produced. Global ammonia production amounted to 111 Mt in 2000 and urea production to 46 Mt (UN, 2003). Energy use for ammonia production amounts to 25-40 GJ/t, resulting in a CO$_2$ emission of roughly 1.5 tonnes per tonne of ammonia. If the CO$_2$ needs for urea production are accounted for, about 150 Mt CO$_2$ could be recovered for underground storage based on year 2000 production levels.[19] This quantity is relatively small, but it has the advantage that no new capture process would be needed, simply pressurization. As a consequence, this CO$_2$ is available at low cost.

Iron and steel production

Substantial amounts of CO$_2$ are captured in the iron and steel industry in the production of Direct Reduced Iron (DRI). The bulk of this CO$_2$ is released into the atmosphere. Global DRI production amounted to 38 Mt in 2001, resulting in CO$_2$ emissions of approximately 20-30 Mt CO$_2$. The production of DRI is mainly concentrated in countries with cheap stranded gas, including the Middle East.

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18. But in many cases still higher than for power plants.

19. A fraction of the captured CO$_2$ is also traded as food grade CO$_2$. However, the quantities are minor.

Iron production in blast furnaces requires approximately 500-550 kg of coke and coal per tonne of product. Total global iron production is about 540 Mt, providing a source of around 1,000 Mt of CO_2. Iron production is forecast to decline to around 350-400 Mt in 2030 as secondary steel production grows (Gielen and Moriguchi, 2003). The CO_2 emission from blast furnaces amounts to 1-1.5 t/t iron. This CO_2 can be removed by re-designing the blast furnace for oxygen use and subsequently removing CO_2 using physical absorbents. So far, this strategy has received only limited attention. Preliminary estimates suggest capture costs in the range of 10-20 USD/t CO_2, similar to the capture costs for IGCC (Gielen, 2003).

If CO_2 capture was applied to iron and steel production, its potential would be in the order of 0.5-1.5 Gt per year. The iron and steel industry is currently studying the best way of reducing emissions. A European project has started, known as ULCOS (Ultra Low CO_2 Steelmaking), which includes new engineering studies of CO_2 capture and sequestration strategies for iron production processes. This project is the European part of the globally-oriented CO_2 breakthrough project of the International Iron and Steel Institute. Introducing CO_2 capture in iron and steel production may be hampered by international competitiveness issues, depending on the policy approach chosen (Gielen and Moriguchi, 2003).

Cement

Worldwide, cement kilns emit about 1.3 Gt CO_2 per year, equal to 0.6-1.0 t CO_2 per tonne of Portland cement, depending on fuel and energy efficiency. Cement production is increasing, resulting in rising CO_2 emissions from this source category. Cement kiln CO_2 off-gas concentrations are higher than for conventional furnaces in other sectors because more than half of the CO_2 in the off-gas (0.5 t CO_2/t Portland cement) comes from a chemical reaction essential for cement production (so-called calcination): $CaCO_3 \rightarrow CaO + CO_2$

This inorganic portion means that the CO_2 concentration in the flue gases is about twice that in coal-fired power plants. Therefore, physical absorption systems (Selexol or other absorbents) could be used. Energy-related CO_2 emissions depend on the energy efficiency of the kiln (which may range from 3-8 GJ/t cement clinker) and on fuel type (more than half of the fuel may be waste wood, waste tyres etc., which is often not properly accounted for in energy statistics).

So far, no radically new designs have been proposed for cement kilns. The capture technology could be similar to that of an IGCC or a pulverised coal fired power plant with CO_2 capture from the flue gas. It might be possible to use oxygen instead of air in cement kilns. However, this would imply a process re-design in order to avoid excessive equipment wear. The effects on the process chemistry also need to be assessed. Preliminary data suggests about 0.9 GJel/t CO_2 for an oxyfuel process with CO_2 recycling and 90% recovery efficiency (Hendriks et al., 1999). However, these are very preliminary estimates and key data, such as the impact of a CO_2 atmosphere on the calcination process, are not known. As a preliminary estimate, the oxyfuel data for coal-fired power plants is used in the model. Currently, there is no major ongoing research in this area. Instead the cement industry is focusing on energy efficiency, use of waste fuels, and changing resources.

Investment costs have been set at 200 USD/t CO_2 annual capture capacity. This should be considered as a working assumption.

Petrochemicals

The production of ethylene oxide from ethylene inherently produces pure CO_2 as a by-product of a chemical reaction. Global ethylene oxide production amounts to a few Megatonnes per year, meaning

this is a CO$_2$ source category of secondary importance. Other petrochemical CO$_2$ emission sources are steam boilers, furnaces and CHP plants. Capture potential from CHP plants is similar to that of other power plants, so the discussion of options will not be repeated here. One of the large-scale processes is steam cracking of naphtha and other oil products to yield ethylene and other basic building blocks for the petrochemical industry. In this process, a mixture of residual gas from the cracking process and natural gas is used to heat the furnace of the steam cracker. Residual gas is a mixture of hydrogen and methane, so it is a gas with low CO$_2$ emissions per unit of energy. Chemical absorption is, therefore, the only feasible option.

Paper mills and ethanol plants

Both in chemical pulp production and in ethanol production from ligno-cellulose crops or sugar cane, only the sugar/cellulose and hemicellulose fraction of the plant is used. The remaining lignin fraction (called 'black liquor' in pulp processing) can be used for energy recovery. Strictly speaking, ethanol production is part of the fuels supply. However, as the CO$_2$ capture process is very similar to that for black liquor IGCCs with CO$_2$ recovery, it will be described in this section.

Energy recovery from black liquor is an established technology in the pulping industry. Such plants have a scale of 50-200 MW electric capacity. Currently, Tomlinson boilers are used for energy recovery and chemicals recovery from black liquor. IGCC technology, which can improve efficiency, is now being tested on a pilot plant scale as an alternative to these boilers. Black liquor IGCC technology is similar to coal-fired IGCC technology. Such plants could be equipped with CO$_2$ capture. The electric efficiency of a black liquor IGCC is 28%; with CO$_2$ capture it declines to 25%. The steam efficiency remains at 44% in both cases. Capital cost increases by 320 USD/kW electric when CO$_2$ capture is installed (Möllersten et al., 2003). The technology could also be applied to residues from ethanol production, provided future ethanol plants can reach sufficient economies of scale.

It is assumed that 40% of the biomass feedstock for ethanol production ends up as residue. The residue can be used for energy recovery, similar to black liquor in the paper and pulp industry. CO$_2$ capture from the gasified residue amounts to 413 kg/GJ electricity, or 104 kg/GJ ethanol produced. Including electricity and heat by-products (18 kg CO$_2$/GJ ethanol) and gasoline replacement (73 kg/GJ ethanol + 7 kg/GJ upstream), the emission reduction percentage compared to conventional transportation fuels amounts to 253%. This means that a 50/50 mixture of ethanol produced with CCS and gasoline would represent a CO$_2$-neutral fuel.

Furnaces and CHP

Apart from dedicated processes, general boilers and furnaces can be equipped with CO$_2$ capture. CHP systems that represent an energy-efficient alternative to stand-alone boilers and furnaces can be equipped with CO$_2$ capture as well.

CO$_2$ concentrations in the flue gases of gas-fired boilers are about 7% compared to around 14% in a coal-fired boiler (Thambimuthu, 2003). Because of these low concentrations, chemical absorption is the only feasible capture strategy. However, as with power plants, oxyfueling may be applied to increase CO$_2$ concentrations. Pre-combustion reforming, followed by CO$_2$ capture and hydrogen combustion, could also be applied. Such strategies will be limited to large plants (10 MW+). For smaller plants, a link to a hydrogen supply system seems much more likely. CCS could be applied in the centralized hydrogen production process.

Part of the industrial process heat demand in the 400-800°C range can be provided by gas turbines. This option could be particularly attractive in the chemical industry (steam crackers) and in the refining sector (furnaces). Such processes could be equipped with CO_2 capture (Table 3.6). Hot exhaust gas from a gas turbine is directed to a furnace of an oil refinery at a temperature of 560°C. The gases are further heated to 700-800°C. After heating the oil, the cooled exhaust gases leave the plant at a temperature of about 150°C. The CO_2 is recovered from this stream using a chemical absorption technology. Electricity generated by the gas turbine is sold or used elsewhere.

The reference case outlined in Table 3.6 consists of a furnace with the same heating capacity and the power production is balanced by power from the grid (assumed to be a gas-fired combined cycle with 54% electric efficiency). Total fuel requirements for the CHP unit with CO_2 capture are about 2.57 times as high as for a boiler. However, the unit produces 0.78 GJ electricity/GJ heat as by-product, and the CO_2 is captured. Given that a chemical absorption technique is used, it seems that the gas turbine uses air. The CO_2 removal efficiency is 90%.

Hendriks et al. (2001) indicate a CO_2 avoidance cost of 16 USD/t CO_2 for such a system. These avoidance costs are considerably lower than the avoidance cost for power plants. These costs are expressed compared to the reference furnace without CHP. Comparing the CHP unit with and without CO_2 removal would provide a better, albeit higher, estimate of the actual cost.

Table 3.6

Characteristics of furnace/CHP unit with CO_2 capture

	Reference plant	CHP with CO_2 separation
Capacity furnace (MWth)	450	450
Load (hrs/yr)	8,200	8,200
Investment cost (million USD)	-	214
Fuel and O&M (million USD/yr)	35	101
Efficiency CHP	-	35% (electric) / 45% (heat)
CO_2 production (Mt/yr)	1.57	1.61
CO_2 recovered (Mt/yr)	-	1.4
Electricity costs (USD/kWel)	-	0.025
Costs (USD/t CO_2 avoided)	-	16

Note: Gross efficiency, excluding own electricity consumption. Based on Low Heating Value, LHV

Source: Hendriks et al., 2001

CO$_2$ Capture in Fuels Supply

The extraction of oil, gas and coal results in almost 400 Mt of CO_2 emissions (Table 3.2). The fuel transformation sector is an even more important emissions source. Petroleum refineries and LNG production account together for 700 Mt of CO_2 emissions per year (Table 3.2). In future, these emissions are bound to increase significantly. On the fuels supply side, LNG production will increase significantly, as larger quantities of natural gas must be transported over longer distances where pipelines do not constitute a viable alternative.

Currently, emissions from oil product use exceed the emissions from oil production and processing to a considerable extent. However, this may change in the future. Heavier crude oil types that require more upgrading are likely to gain market share as the quality of the remaining oil reserves declines. Synfuel production (e.g., through Fischer-Tropsch synthesis) is considerably more energy intensive than conventional refining. The use of hydrogen as a transportation fuel would result in the possibility of zero vehicle tailpipe emissions, and a significant potential to capture CO_2 from hydrogen production. Synfuels are projected to gain an increasing market share. Synfuels such as hydrogen, methanol, dimethylether, and synthetic gasoline and diesel can be produced from natural gas, coal or biomass. CO_2 capture could be applied to these production processes.

This section will discuss the following four categories of CO_2 capture from fuel supply:

- CO_2 capture in natural gas processing;
- Refinery CO_2 capture;
- Hydrogen production processes;
- Gasification and Fischer-Tropsch production of synfuels.

Natural gas processing

The CO_2 content of natural gas varies from virtually zero in Siberian gas, to 1.5% in certain North Sea gas fields and up to 70% in fields such as Natuna in Indonesia. The latter value is an extreme; an average CO_2 content is 1-2%. The quantity of CO_2 that is released when the gas is combusted is two orders of magnitude larger than the CO_2 from gas processing. This limits the worldwide potential for CO_2 capture in natural gas processing to less than 100 Mt CO_2 capture per year.

CCS for natural gas processing projects is receiving much attention as a low-cost CCS opportunity. CO_2 must be removed anyway before the gas can be sold, and storage sites are often nearby. The additional costs for compression, transportation and storage are limited. Moreover, CO_2 storage wells are similar to gas production wells, so the necessary equipment and expertise are available on site. Most existing and planned CCS projects are gas production projects. These include the Sleipner and Snohvit projects in Norway, the In Salah project in Algeria, the Gorgon project in Australia and the Natuna project in Indonesia.

Oil refineries

Oil refineries convert crude oil into oil products. They do so through a wide range of process operations. The most important of these are distillation, reforming, hydrogenation and cracking. Distillation processes require low temperature heat; hydrogenation requires hydrogen, and cracking produces significant amounts of heat and CO_2 from heavy oil residues. Refineries also consume considerable amounts of electricity. A subdivision of CO_2 emission sources of two types of refineries is shown in Figure 3.7.

Reformers, fluid catalytic crackers (FCCs) and possibly vacuum distillation units could be equipped with high-temperature CHP units with CO_2 capture. Together they represent 30-40% of the refinery energy consumption. On average, 5-10% of the crude throughput of refineries is used for the refining process. Modern refineries have higher emissions because they can use heavier crudes and produce more light products, especially gasoline and diesel.

Refinery heaters can be equipped with post-combustion CO_2 capture technology. A study for a UK refinery and petrochemical complex suggests that collecting 2 Mt of CO_2 per year would require 10 MW for blowers to push the flue gas through the network, and 10 MW for the pressure drop

Figure 3.7

CO_2 emissions from oil refining

Key point: Process heaters account for half
of the CO_2 emissions from oil refining

FCC refinery

Utilities
23%

Hydrogen
plant
20%

Process
heaters
44%

Power
13%

Hydrocracking refinery

Utilities
17%

Hydrogen
plant
14%

Process
heaters
55%

Power
14%
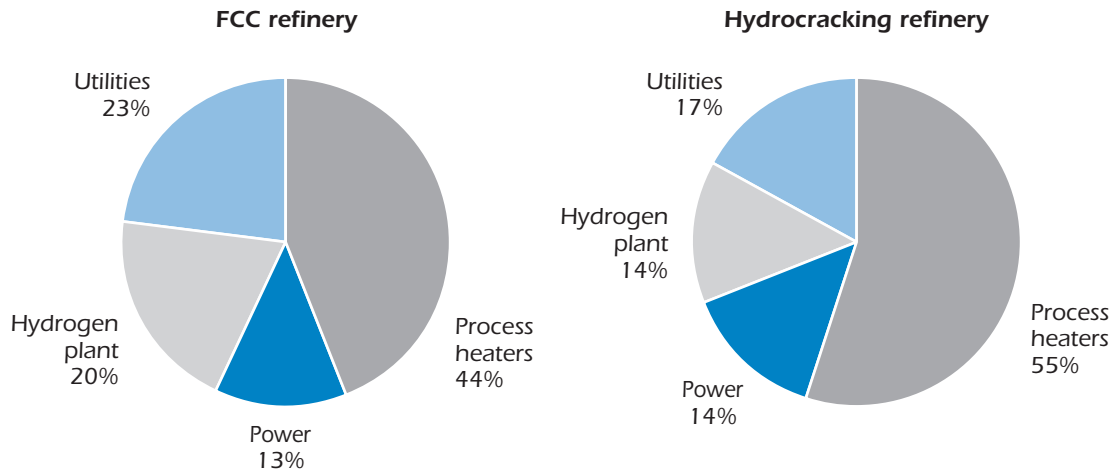
Sources: American Petroleum Institute, 2002; Clarke, 2003.

Figure 3.8

Investment cost structure for a refinery complex with CO_2 capture

Key point: CO_2 separation and compression is responsible
for less than half of the capture investment costs for oil refining

Gas gathering systems
8%

Utility and offsite systems
31%

NO_x and SO_2 removal
16%

CO_2 separation
35%

CO_2 drying and compression
10%
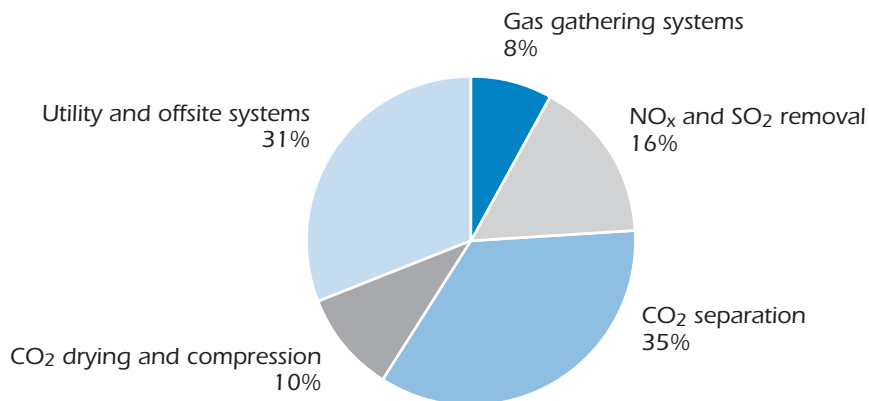
Source: Simmonds et al., 2003.

imposed by the packed column absorbers (Simmonds *et al.*, 2003). This equals 0.39 GJ/t CO_2. Pretreatment is needed to reduce NO_x and SO_2 concentrations. The system needs 396 MW of natural gas, which amounts to 6.2 GJ natural gas per tonne of CO_2 captured. This includes the energy needs for the blowers and the steam for the regeneration of the absorbents. This is a fairly high energy consumption, compared to CO_2 capture energy needs for power plants. There may be room for further improvements in the design. The investment costs amount to 238 USD/t CO_2 with the operational cost largely determined by natural gas costs. A breakdown of the investment costs is shown in Figure 3.8. Note that this is a conventional refinery. There may be potential to reduce capture cost through synergies, such as by using refinery waste heat for CO_2 capture.

Another study focused on oxyfuelling for a refinery power station boiler, using heavy oil and gas (Wilkinson et al., 2001). Electricity needs for the air separation unit and CO_2 separation amount to 1.5 GJ electricity per tonne of CO_2. Investment costs would amount to 50 USD/t CO_2.

The product mix of refineries is changing towards more light products with a higher H/C ratio, as demand growth is concentrated in transportation markets. The refineries can respond to the hydrogen deficiency by adding hydrogen (a process called hydrocracking) or by removing carbon (a process called coking). This trend is apparent if the regional refinery structures are compared. The higher the transportation fuel demand as a share of total fuel demand, the higher the coking and hydrocracking capacity (Table 3.7).

Table 3.7
Regional refinery structure (2000)

	Crude (Mbbl/d)	Crude (Index)	Coking (Index)	Catalytic hydrocracking (Index)	Gasoline and diesel in refinery product mix (%)	Comment
Australia	0.95	100	0	3	78	
Canada	1.91	100	2	14	72	
Eastern Europe	1.88	100	4	4	61	
FSU	8.40	100	3	1	48	Heavy crude
Japan	4.96	100	2	3	51	
Korea	2.56	100	1	5	34	
Middle East	5.99	100	1	10	41	Heavy crude
Mexico	1.53	100	3	1	47	Heavy crude
USA	16.54	100	13	9	71	
Western Europe	14.90	100	2	6	63	
Developing countries	21.64	100	4	3	44-55	
World	**81.25**	**100**	**5**	**5**		

Note: Index crude distillation = 100. FSU = Former Soviet Union.

Source: Oil & Gas Journal Energy Database, 2001.

Refinery coking capacity is much higher in the USA than in other world regions, while hydrocracking is concentrated in other OECD member countries and the Middle East. Global hydrogen use for refineries is already substantial, about 2 EJ in 2000 (0.5% of global primary energy use). Given a crude oil consumption of about 150 EJ (see Table 3.1), this equals on average 1 kg CO_2/GJ crude oil processed. This emission level is bound to rise significantly. For example, in the case of flexicoking, the process emission amounts to more than 20 kg CO_2/GJ of fuel processed.

According to IEA statistics, energy used in refining amounted to 11.9 EJ in 2000 (see Table 3.1). About half of this was for natural gas and refinery gas, and the other half for heavy oil products. Worldwide refinery CO_2 emissions amount to 0.75 Gt CO_2 per year (Table 3.2).

Gradually crude oil quality is changing towards more heavy product types. Unconventional oil production is also growing. Canadian oil sands and Venezuelan Orinoco tar sands constitute almost 2% of global oil production. These unconventional crude oil types require special refining operations to adjust the hydrogen/carbon (H/C) ratio. The reserves in place are of a similar order of magnitude to the quantities of conventional oil, with 580 billion barrels of recoverable reserves (IEA 2002a, p. 101). Total upgraded crude from both sources is projected to increase to 6.1 million barrels per day in 2030 (IEA 2002a, p. 102).

Canadian oil sands production amounted to 829 kbbl per day in 2002, 1% of the total global oil production. Crude bitumen extracted from oil sands is refined to a marketable hydrocarbon product[20] through a combination of carbon removal in high temperature coking vessels and by hydrogen addition in high temperature, high pressure hydrocracking vessels. The remaining fraction is either thermally cracked to gaseous products or converted into petcoke. The bulk of the petcoke is burned for energy recovery. The upgrading processes yield 0.84 cubic metres of syncrude per cubic metre of crude bitumen (Imperial Oil, 2000). The upgrading energy efficiency is 74% and the net emission amounts to 22-34 kg CO_2/GJ syncrude. A typical plant has a capacity of 250,000 bbl per day, amounting to an emission of 18 Mt CO_2 per year.

With the Orinoco tar sands, current plans are to apply deep conversion technology in order to produce high-value transportation fuels. Delayed coking is the primary conversion technology. Plans are to produce 622,000 barrels per day of syncrude by 2009. Four strategic associations have already started operating and aim for different levels of tar sand upgrading. Of this only the Sincor project, based on delayed coking, will be discussed in more detail. Here, some 212 kbbl per day virgin crude are upgraded to 186 kbbl of a 32°API quality synthetic crude (*i.e.* crude oil with a density of 0.865 t/m³). The product mix consists of 2% LPG, 13.9% naphtha, 17.5% kerosene,

Table 3.8

CO_2 emissions in various refining and synfuel production processes

	Efficiency[21] (%)	CO_2 available for storage (kg/GJ product)	CO_2 available for storage (Mt/yr/plant)
Syncrude oil/tar sands	74	34	18
Flexicoker	84	24	5.4
FT natural gas	57-70	7-25	0.25-2
FT coal	40	160	10-15
FT biomass	40	210	0.2
Methanol/DME from coal	65	110	5-10
Methanol/DME from natural gas	70	8	0.25-0.5

Note: FT = Fischer Tropsch synthesis.

Source: Steynberg and Nel, 2004; IEA data.

20. The syncrude gives good yields of kerosene and other middle distillates, so it is not exactly the same product as conventional natural crude oil.

21. Excludes electricity use for pumps, etc. With coal, the efficiency to liquid products is 41.1% with the power export amounting to 5% of the coal input.

28.7% diesel, 22.9% gasoil, 14.9% coke and sulphur. Hydrotreating is being considered as an alternative to delayed coking (Paez *et al.*, 2000).

Table 3.8 shows emissions of CO_2 per GJ of product and emissions per process unit. The high CO_2 emissions in oil sand and tar sand production and processing pose a problem. CO_2 capture and sequestration may be applied to the residue treatment, thus reducing CO_2 emissions to a considerable extent.

Hydrogen production

Hydrogen is a CO_2-free energy carrier. Like electricity, it can be produced from any other primary energy carrier, either by direct conversion or by production of electricity and subsequent water electrolysis. As a result, it is not subject to the same supply security problems as oil. When hydrogen is produced from carbon-containing energy carriers, CO_2 and hydrogen must be separated to produce pure hydrogen. An energy system based on hydrogen could be CO_2-free. Hydrogen production from fossil fuels with CO_2 capture could be the first step strategy toward a hydrogen economy, followed by hydrogen production from other CO_2-free primary energy sources in the longer term.

Hydrogen is widely considered to be the transportation fuel of the future. The competitiveness of hydrogen as a transportation fuel depends critically on the cost of hydrogen vehicles and the efficiency gains compared to conventional vehicle engines (IEA, 2003c). Major cost reductions are needed. Also, there is a chicken-or-egg problem: no vehicles without fuel supply, and no fuel supply without demand.

Apart from being a transportation fuel, hydrogen can be used for decentralized electricity production and for space heating, if a distribution system is in place. Hydrogen fuel cells may gain a market share. Given their high electric efficiency in combination with their small size, they would be suitable for residential and commercial heating systems. However, the discussion in the box below suggests that a future trend towards decentralized power production is by no means a certainty.

Least-cost hydrogen supply options with low CO_2 emissions are based on fossil fuels with CO_2 capture (Figure 3.9). All production routes that involve electrolysis are considerably more expensive: the two-step approach of electricity production followed by hydrogen production incurs higher capital costs, and reduces efficiency. This poses a major hurdle for any hydrogen economy built on renewables, except biomass and concentrated solar heat as they would not involve electrolysis. While technology learning can reduce the cost of hydrogen production from renewables, its cost will remain prohibitive in all but a few regions with abundant cheap renewable energy, such as Iceland.

One of the more exotic options for CO_2 capture is hydrogen production from biomass (Read and Lermit 2003; Azar et al. 2004). This strategy reduces atmospheric CO_2 concentrations and produces energy at the same time. The scale of biomass hydrogen production is typically one order of magnitude smaller than coal-based hydrogen production. Given that investment costs of chemical plants typically increase with scale by a factor of 0.7, the specific investment costs for biomass-based hydrogen production are twice those of coal-based hydrogen production per unit of energy.

Hydrogen and electricity can also be co-produced from fossil fuels. This reduces the product gas separation cost and can increase the plant load factor, while improving the economies of scale and reducing CO_2 capture cost. A demonstration project is planned in the USA, known as FutureGen. Synfuel cogeneration is considered in the ETP model (see box below).

Figure 3.9

Hydrogen production cost for a fully developed supply system

Key point: Producing hydrogen from fossil fuels with CCS
is less costly than doing so using nuclear or renewable energy
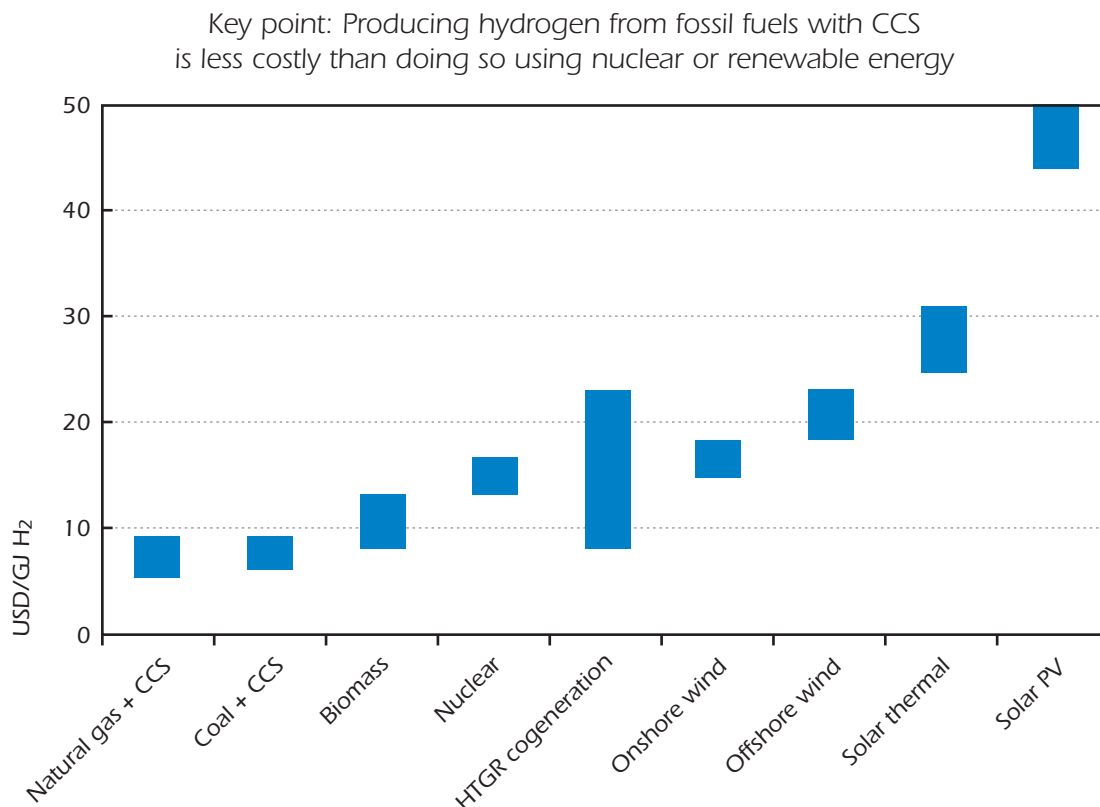
HTGR = High Temperature Gas-cooled (nuclear) Reactor.

The supply cost of hydrogen depends critically on the supply volume. Distribution and refuelling will add 7-9 USD to the production costs in Figure 3.9. These costs apply to large scale systems. In a transition period, decentralized production and/or liquid hydrogen distribution may be used. The costs of such supply systems are much higher. Moreover, decentralized production systems cannot be combined with CO_2 capture and sequestration.

Note that the costs in Figure 3.9 represent technology costs. In practice, investors may demand a much higher return on capital for new risky investments in a hydrogen infrastructure than for established oil and gas-based energy systems.

Gasification and Fischer-Tropsch production of liquid synfuels

Gasification of carbon-containing feedstocks, followed by hydrocarbon synfuel production, has received much attention in recent decades, given the potential for the production of synthetic transportation fuels to reduce dependency on oil. Coal, natural gas and biomass could be used as feedstocks. A number of synfuels have been proposed: methanol, DiMethyl Ether (DME), naphtha/gasoline and diesel. The energy efficiency of the production processes for these fuels ranges from 40% to 70%. As a result, they emit a large volume of CO_2 which could be captured and stored.

Cogeneration of electricity and synfuels with CO_2 capture

The production of synfuels is based on gasification, followed by purification and synthesis (except for H_2, where no synthesis step is needed). The gasification step is also applied in IGCC power plants. Therefore, co-generating electricity and synfuels is a logical step and can lead to economies of scale and higher capacity factors for the gasifier. The reactor output has to be separated into product and unreacted feedstock, which must be purified and recycled. This separation is a costly and energy-intensive step. Once-through processes have consequently received much attention.

In recent years there has been increasing attention for co-production processes of electricity and synfuels such as methanol, Fischer-Tropsch diesel and hydrogen from coal. The reasoning behind these concepts differs. In Europe, the main attention is focused on the comparatively low average load factor of IGCC power plants. Co-production would allow a high average load factor, which would reduce capital cost per unit of product (Lange et al., 2001). A study by Sasol points out that the co-production of liquids and electricity raises the energy conversion efficiency from 40 to 50%, compared to the same plant without electricity cogeneration (Steynberg and Nel, 2004).

US studies start from IGCC and focus on the supply security benefits and air pollutant benefits of co-production of synthetic fuels (Gray and Tomlinson, 2001). A coal-based power plant for co-production of electricity and hydrogen, in line with the US's FutureGen project, has been considered in the model. For gas, such a complex design would make little sense, given the comparatively low capital cost of gas-fired power plants and FT-synthesis from gas. Generally, the assessment of co-production is complicated by the fact that both products compete in volatile markets where future prices are hard to predict. Static analysis predicts that synfuel production costs may be reduced by 10% if a co-production strategy is applied (Yamashita and Barreto, 2003). This suggests there may be benefits to such cogeneration strategies, but they are not crucial.

Fischer-Tropsch (FT) production of synfuels is an established technology. Production of gasoline and diesel from coal was developed in Germany during the Second World War and further developed by Sasol in South Africa during the oil boycott in the 1980s and 1990s. Shell has a plant in Sarawak (Malaysia) that uses similar technology to convert so-called 'stranded' gas into longer chain hydrocarbons. The technology is based on fuel gasification to a mixture of CO and H_2, followed by catalytic chain building. The product mix consists of condensate and predominantly wax. The wax can be cracked to yield diesel and gasoline. The product mix depends on the process condition and catalyst choice (Zhou *et al.*, 2003). In the ETP model analysis, a 50/50 yield of diesel and gasoline was assumed.

Gas to liquids (GTL) is currently the most attractive FT option. Up to 1 million barrels per day are expected to come on stream before 2010, in locations with stranded gas such as Qatar and Nigeria (Chemical Market Reporter, 2004). All these plants produce primarily diesel. Investment costs are coming down rapidly, mainly because of economies of scale. For example, Sasol claims investment costs of 12 USD/GJ per year for new plants of 60 PJ product per year, with a further cost reduction potential to 9 USD/GJ per year (Marriott, 2000). In the IEA World Energy Outlook Reference

Scenario, gas-to-liquids is forecast to increase to 2.3 million barrels per day by 2030, some 2% of world oil supply (IEA 2002b).

Production of FT transportation fuels from coal with CO_2 removal has been described by the Coal Utilization Research Council (2002). Currently, a 40% liquid product yield (in energy terms) can be attained. The amount of CO_2 available for capture is much higher for coal-based processes than for gas-based ones (Table 3.8). The energy requirements for CO_2 capture are proportional to the quantity of CO_2 in the flue gas. Given a gas price of 0.5 USD/GJ, current FT supply costs are 25-30 USD/bbl (Marsh *et al.*, 2003). The capital cost for a coal-based process is about twice that of a gas-based process. Moreover, the energy efficiency is also lower. The production costs starting from coal are twice as high at the same feedstock price. However, cogeneration of fuels and electricity can reduce these costs (Steynberg and Nel, 2004). Oil price hikes can make coal or gas-based FT transportation fuel production a viable alternative.

Biomass feedstocks are technically feasible (Ree, 2000). Investment costs for FT biodiesel plant without capture are projected to decline from 60 USD/GJ in 2000 to 36 USD/GJ by 2020. This is twice the investment costs for coal because of the smaller scale plants. A plant would use 2 GJ biomass and 0.03 GJ electricity per GJ product. At a biomass feedstock price of 4 USD/GJ, the transportation fuel production cost in 2020 is 15 USD/GJ. This is about three times the current production cost of gasoline and diesel. CO_2 capture would add 0.05 GJ electricity use per GJ fuel produced (including CO_2 pressurization). Investment costs would increase by 30% (Marsh et al., 2003). About 120 kg of CO_2 is captured per GJ of fuel produced. The net emission reduction, compared to diesel and gasoline from crude oil, amounts to 264%. The emission reduction in excess of 100% is explained by the sum of the replacement of fossil fuels and storage of CO_2 from the process flue gas. The emission mitigation costs amount to 60 USD/t CO_2, but this depends critically on the assumed biomass feedstock cost.

DiMethyl Ether (DME) can be used as a fuel for power generation turbines, diesel engines or as an LPG replacement in households. However, its main use is as an aerosol propellant for hairspray. Current global DME production amounts to 0.15 Mt/yr. The only plant that produces DME for fuel use started operation in 2003 in Luzhou, China. This plant has a capacity of 10 kt/yr, and uses coal as a feedstock. A large number of pilot projects are being studied worldwide. Emissions from the production of DME from coal amount to 71-75 kg CO_2/GJ product. In comparison, emissions from DME production from natural gas amount to 6-16 kg CO_2/GJ (Sakhalin Energy, 2004).

Current DME production takes place in two-steps. Methanol is produced from syngas and the methanol is catalytically dehydrated to DME. New production processes are under development where DME is produced directly from syngas in a single step. Various process designs exist based on liquid phase conversion or gas phase conversion. Liquid phase conversion is preferred for syngas flows with a high CO content, while gas phase processes are preferred for syngas with a high hydrogen content (such as from natural gas steam reforming; Air Products, 2002).

Various designs have been proposed for methanol/DME co-production and for cogeneration of DME and electricity. Such designs circumvent the problem of recirculation of products because of incomplete conversion of feedstock into DME. For example, at 50 bar and 300°C, a CO conversion of more than 50% and a DME selectivity of more than 90% are obtained (Air Products, 2002; Ogawa *et al.*, 2003; Sinor, 2004). In the ETP model analysis, a once-through DME and electricity cogeneration plant with CO_2 capture is considered (Larson, 2002). This plant achieves 17% efficiency in coal-to-electricity conversion, and 33% efficiency in coal-to-DME conversion (5.88 GJ coal input/GJ electricity produced, and 1.94 GJ DME produced/GJ electricity produced).

Technology Learning Effects for CO₂ Capture

Technology learning is a term applied to the phenomenon of unit costs of technologies decreasing over time. For a large number of technologies it has been observed that unit production costs decline by a fixed percentage for each doubling of cumulative installed capacity. This observation is widely used to project future costs of energy technologies (IEA, 2000).

A cost decline can be attributed to various mechanisms. R&D may result in new processes to make the same product using fewer natural resources. Also, learning-by-doing plays an important role. Producers of equipment find more efficient ways to produce equipment as their experience increases. Standardization helps to reduce unit production cost. Finally, economies of scale play a key role. The larger the process or the equipment, the lower the unit production cost. Engineering literature usually suggests a 20% cost reduction for a doubling of the unit capacity.

Technology learning is very important for emerging technologies, where the cumulative capacities are small and capital cost dominates total process cost. This is the case, for example, for solar PV systems. The situation for CCS is fundamentally different. First, the energy efficiency loss for CCS and the related additional fuel use represent an important part of the CCS cost. Cost reductions based on energy efficiency improvements are usually not covered by technology learning curves, but they should in the case of CCS. There are examples of energy efficiency improvements for existing processes, e.g., for chemical absorption of CO_2. Second, the process equipment used for most CCS technologies has been widely applied; the main challenge is the integration of this equipment. However economies of scale may apply. Also, serial production of CO_2 compressors may result in significant equipment cost reductions. **The potential for learning-by-doing is probably more limited than the potential for learning-by-innovation, but it is not negligible.**

Moreover, CCS is not a single technology, as it covers a wide range of technologies. While the technology learning potential may be very important for certain CCS relevant technologies such as fuel cells or separation membranes, these technologies are currently far more expensive than chemical absorption systems. Applying the learning rate of such CCS emerging technologies to CCS as a whole, starting from the cost for chemical absorption systems, would result in a significant overestimation of the learning potential.[22]

Cost reductions for CCS can be split into:
- Creating benefits via CO_2 use for enhanced fossil fuel production;
- Reducing energy losses for CO_2 capture, based on new technology (this reduces fuel cost but it may also reduce capital cost, especially for power plants);
- Economies of scale;
- Standardization.

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22. *Riahi, Rubin and Schrattenholzer (2003) have assessed the impact of learning effects for CCS technologies. They assume a progress ratio of 87% (according to the authors this is a conservative estimate compared to other emerging technologies, based on learning for desulphurization technologies). The cumulative capacity is 1 GW for the starting year, with initial costs amounting to 45 USD/t CO_2 for capture from coal-fired plants and 30 USD/t CO_2 for capture from gas-fired plants (excluding transportation and sequestration). They assume that by the end of the 21st century, 90% of all power plants will be equipped with CO_2 capture. According to the learning curve theory, this would result in a cost reduction by a factor of four. However, the uncertainty surrounding this projection is significant. For example, the 1 GW initial cumulative capacity can be questioned. About 100 Mt ammonia is produced annually and 150–200 Mt CO_2 is captured in the process. The cumulative ammonia capacity is 300-400 Mt CO_2. A similar cumulative capacity of hydrogen production with CO_2 capture exists in other industries. Total cumulative capacity for ammonia and hydrogen equals 80-110 GW (coal-fired) power plants. If the learning analysis takes this higher initial capacity into account, the cost reduction potential is significantly reduced. Moreover, it is not clear why energy losses (operational costs) would decline proportionally with investment costs.*

In the ETP model analysis, cost reductions are estimated exogenously through specific technologies and vintage models for technologies with different investment costs for each vintage (Table 3.4). This is considered a sufficiently accurate method, as long-term cost can be projected based on equipment material cost, maximum feasible power plant size and the like. **The data in Table 3.4 implies a halving of CO_2 capture costs between 2010 and 2030, compared to the same power plants without CO_2 capture. The feasibility and future investment cost of speculative technologies are uncertain.**

CO_2 transportation

CO_2 can be transported via pipelines, by tank wagons and by ship. In practice, because of the huge volumes involved, only pipelines and ships are cost-effective options. Costs depend on the distance and volumes involved. Generally, transportation costs are considered to be small compared to the overall capture costs. Transportation cost estimates range from 1 to 10 USD/t CO_2, provided the pipeline transports more than 1 Mt of CO_2 per year and the distance is less than 500 kilometres (Figure 3.10). Per unit of weight the costs for CO_2 transportation are much lower than for natural gas or hydrogen transportation because CO_2 is in a liquid or supercritical state, with a 10 to 100 times higher density. Therefore, per unit of weight, CO_2 transportation is more akin to oil transportation in terms of cost than to natural gas or hydrogen.

An engineering study for the Norwegian Kårstø gas-fired power plant suggests that pipeline transportation represents about 40% of total CCS project investment costs (Elvestad, 2003). This

Figure 3.10

Cost of overland transportation of CO_2 by pipeline

Key point: CO_2 transportation costs depend strongly on the quantities and, to a lesser extent, on the distances involved
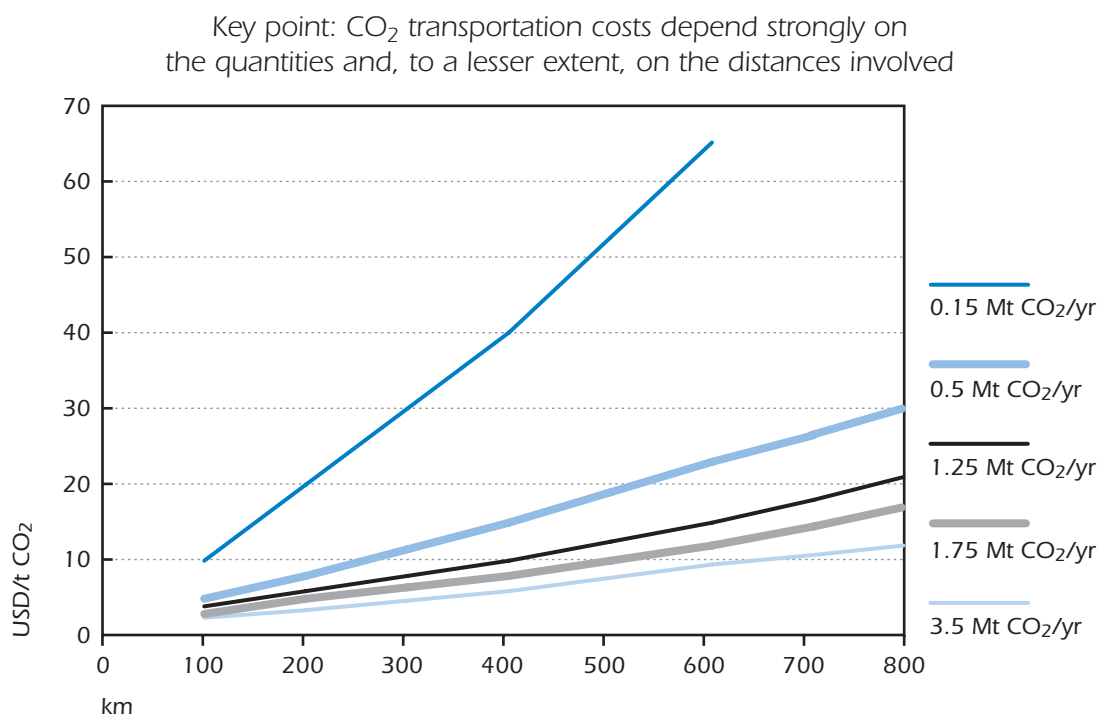
Source: IEA GHG, 2002a.

is an exceptional case with an over-sized pipeline that has to be laid above ground because of the geological conditions, but it shows the importance of local conditions for the transportation cost. Cost may be 2-4 times higher than in Figure 3.10 in instances where there are unfavourable conditions, in which case they cannot be neglected. CO_2 transportation in itself poses no special safety risks, provided the equipment is appropriately sited and regulations adhered to (Vendrig *et al.*, 2003).

Given potential pipeline siting constraints and transportation distances of hundreds of kilometers, a CO_2 transportation 'backbone' may be needed to which multiple power plants and a number of storage sites can be connected. Such a system would allow transportation over longer distances at acceptable cost.

Pipeline materials may be corroded by a combination of SO_2 and water (that yields sulphuric acid). Sulphur will be converted to H_2S in an anaerobic environment (*e.g.*, a CO_2 capture process in an IGCC installation) and oxyfuelling will result in SO_2. The CO_2 purity constraints may necessitate costly sulphur removal that will add to the cost. H_2S can be co-injected without problems, as it has been done on Canada for some years.

Shipping CO_2 is an established technology on a kilotonne scale. Shipping may become an important issue because the prime locations for underground CO_2 storage are unlikely to coincide with CO_2 source locations. For example, the bulk of the conventional oil reserves are located in the Middle East (see next section) and the main gas reserves in the Middle East and Russia. By contrast, the main emission sources are in major population centres of OECD countries. Future emission growth will be concentrated in developing regions such as eastern China. Therefore, the mismatch of sources and sink locations constitute a limitation for underground CO_2 storage in depleted oil and gas fields, unless cost-effective inter-regional transportation systems are developed. With regard to enhanced coal-bed methane recovery (ECBM), coal reserves are more evenly spread across the globe with some reserves close to main population centres.

Liquid CO_2 has a density of 1-1.15 tonnes/m³ compared to 0.454 tonnes/m³ for liquefied natural gas (LNG). Storage tanks for CO_2 are made of a less expensive material because transportation takes place at temperatures of -50 °C, compared to -162 °C for LNG. Current intercontinental shipping and storage costs for CO_2 would be in the range of 25-50 USD/t CO_2, based on natural gas shipping costs.[23] Further cost reductions may be achieved. Given these cost levels, it may make sense to ship CO_2 for EOR, if the CO_2 is provided for free and no CO_2 sources exist closer to the EOR site. This means that transportation of CO_2 to the Middle East should be considered as a long-term option if far-reaching CO_2 policies are implemented. Interregional transportation for storage in depleted oil and gas reservoirs has no obvious advantages over storage in local aquifers.[24]

The quantities of CO_2 involved are large, compared to total world commodity transportation. Global oil production and shipment amounts to 3.5 Gt per year, global coal production and shipment to 3.8 Gt per year, global cement production to 1.6 Gt per year, and global cereals production and shipment to 2.1 Gt per year. **In the long run, total CO_2 shipment could be of the same order of magnitude as shipments of all existing commodities put together. Therefore, the challenge of putting in place an appropriate transportation system for CO_2 should not be underestimated.**

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23. *The largest LPG tanker built to date has a capacity of 22,000 m³ and cost 50 million USD (IEA GHG, 2002). The transportation cost for a 500 km distance would be around 10 USD/t CO_2. This would be on par with offshore pipelines, but more than twice the cost for onshore pipelines. However from a distance of 1500 km, shipping seems cheaper. Recent analysis indicates cost of 25 USD/t CO_2 for a distance of 6,000 km, if a ship were built now (IEA GHG, 2004b). There would, in addition, be expenditure for a CO_2 holding tank at the port, as well as operating expenses. For longer distances, cost per kilometre would decrease. In the ETP analysis it is assumed that costs decline to 15 USD/t CO_2 for transportation over 5,000 km.*

24. *This is from a technical point of view. There may be benefits from a social acceptance point of view.*

CO$_2$ storage

This section will focus on the following storage options:

- CO$_2$ enhanced oil recovery (EOR);
- CO$_2$ enhanced gas recovery (EGR);
- CO$_2$ enhanced coal-bed methane recovery (ECBM);
- Storage in depleted oil and gas fields;
- Storage in deep saline aquifers;
- Other storage options.

Most studies suggest that injection well costs are of secondary importance compared to the costs of capturing and transporting CO$_2$. This is only correct if the cost for CO$_2$ compression is allocated to CO$_2$ capture. This is the approach chosen for this study, where the energy efficiency of the capture process accounts for pressurization to 100 bar. The injection pressure and transportation distance determine the need for CO$_2$ pressurization. The injection pressure is a function of the injection depth and the pressure profile in the ground. The minimum storage depth is about 800 metres (at this depth CO$_2$ will be in its supercritical state[25]), but many gas reservoirs are located 2-4 kilometres below ground. For storage at a depth of 800 metres, pressurization to 100 bar may suffice. However, storage in deep depleted gas fields will require surface pressures of 200-300 bar.

Table 3.9

CO$_2$ pressurization energy requirements for injection as a function of type of reservoir and depth

	100 bar pressure at 800m of depth (GJel/t CO$_2$)	200 bar pressure at 1600m of depth (GJel/t CO$_2$)
Aquifer/depleted oil and gas fields	0.22	0.38
EOR	0.34	0.50
EGR	0.25	0.40
ECBM	0.25	0.40

The pressurization energy requirement depends on the efficiency of the compressor (between 75% and 85%). Recycling CO$_2$ can also require significant energy. In practice, in the case of Enhanced Oil Recovery (EOR), recycling amounts to 16-40% of the CO$_2$ quantity injected (20-67% of the CO$_2$ retained). In the Enhanced Gas Recovery (EGR) case, it amounts to 14% of the CO$_2$ retained. The recycled volume for ECBM may be higher if the coal-bed gas contains significant amounts of CO$_2$, or if the CO$_2$ by-passes the coal through fractures in the rock. As a working assumption, CO$_2$ recycling for CBM is assumed to amount to 20% of the CO$_2$ retained.

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25. In the supercritical state there is no discernible transition from a gaseous to a liquid state, as pressure increases. The density of CO$_2$ at 100 °C and 200 bar is about 0.5 t/m³, at 500 bar 0.8 t/m³). The CO$_2$ density plateau depends on the local subsurface pressure and temperature gradient, and may range from 0.61-0.72 t/m³ (Rigg, 2001).

Table 3.9 provides an overview of pressurizing requirements. In most studies this electricity use is accounted for under CO$_2$ capture (as in Table 3.4), because pressurization takes place before the CO$_2$ enters the pipeline.

CO$_2$ injection well costs are small compared to capture and transportation costs. Figure 3.11 shows the cost of onshore oil wells.[26] These costs increase exponentially with depth. A similar cost curve applies to CO$_2$ injection wells. While injection may take place in an aquifer at 800 metres depth, a depleted gas field may require a 4000 metre-deep well. The cost of the injection well will differ by a factor of between 5-10.

Figure 3.11

Onshore oil well cost as a function of well depth

Key point: Well costs increase exponentially with well depth
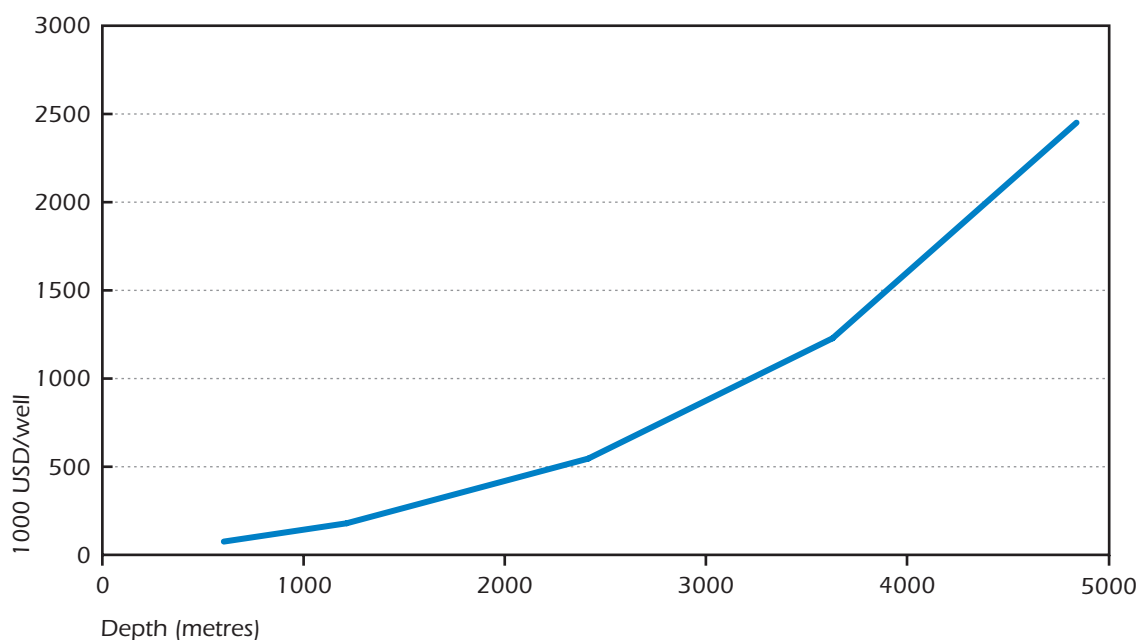
Source: Caldwell, 2001

In recent years, much attention has been paid to technologies which enhance the production of oil, gas and coal-bed methane. These CO$_2$ storage options could create additional benefits by enhancing fossil fuel production. The main characteristics of these benefits are listed in Table 3.10. **They amount to 1-55 USD/t of CO$_2$ (excluding the costs for the wells and CO$_2$ recycling).**

EOR creates the highest benefit, followed by ECBM and EGR. Given CO$_2$ capture costs of 10-35 USD/t (Table 3.10), there is potential to offset part or even total capture costs. In most cases, the costs for CO$_2$ capture will exceed the benefits of enhanced fossil fuel production. Also, the potential for enhanced fossil fuel production is limited by the location of suitable geological formations and the location of CO$_2$ sources.

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26. Offshore wells may be a factor of five times more expensive.

Storage in depleted oil and gas reservoirs (including those using EOR and EGR) is perceived to have a lower leakage risk than aquifers, as the geology of aquifers is often poorly known. It must be validated, however, that past exploration operations have not damaged depleted reservoirs and that the seals of shut-in wells remain intact.

Depleted oil and gas fields

Depleted oil and gas reservoirs can be filled with CO_2. The operation is quite simple, as only an injection well is needed. Moreover, part of the existing infrastructure may be re-used, which can reduce investment cost. A reservoir may need several injection wells, depending on the field geology and the rate of injection. The future potential will increase in time as more fields are depleted. Most of the conventional oil and gas production resources are located in the Middle East and the former Soviet Union (FSU). Using this potential would imply shipping CO_2 to these regions. Therefore, the economic potential is smaller than suggested by the figures in Table 3.10.

Table 3.10

Characteristics of CO_2-enhanced fossil fuel production

	EOR	EGR	ECBM
Technology status	Proven	Speculative	Speculative
Cost	5-20 USD/t CO_2	5-20 USD/t CO_2	10-75 USD/t CO_2
Benefits[27]	0.25-0.5 t oil/t CO_2	0.03-0.05 t methane/t CO_2	0.08-0.2 t methane/t CO_2
	15 USD/bbl oil	0.5-3 USD/GJ gas	0.5-3 USD/GJ gas
	25-55 USD/ t CO_2	1-8 USD/t CO_2	2-30 USD/t CO_2
Limitations	- Oil gravity at least 25° API	- Depleted gas field	- Coal cannot be mined
	- Primary and secondary recovery methods have been applied	- Local CO_2 availability	- Sufficient permeability
	- Limited gas cap		- Maximum depth 2 km
	- Oil reservoir at least 600 metres deep		- Local CO_2 availability
	- Local CO_2 availability	-	
Global potential (cumulative)[28]	*All depleted oil fields*	*All depleted gas fields*	*ECBM with net benefits*
2010-2020	35 Gt CO_2	80 Gt CO_2	20 Gt CO_2
2030-2050	100 - 120 Gt CO_2	700 - 800 Gt CO_2	20 Gt CO_2

It is not clear to which extent EOR and EGR can be applied since this will depend on the geology of a particular field. Also the distinction between EOR and storage in depleted oil fields and EGR and storage in depleted gas fields is not clear-cut. If revenues can be generated from EOR and EGR, such activities would be preferable to simply storing CO_2 in depleted oil and gas reservoirs.

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27. Excludes cost for CO_2 injection wells and recovery wells, CO_2 recycling and gas preparation. Fuels valued at wellhead price.

28. Note that these potentials only consider storage availability. In practice storage will be limited in the first decades by capture project expansion, not by storage capacities. Long-term potentials based on IEA GHG data (Freund and Davison, 2003).

The CENS project

There is considerable interest in the idea of setting up a 'backbone' CO$_2$ supply system for the multiple oil fields in the North Sea that will mature in coming decades. This initiative is known as the CENS project (CO$_2$ for EOR in the North Sea). The North Sea offers a unique opportunity because of the proximity of large anthropogenic CO$_2$ sources and oil fields. Preliminary estimates suggest that up to 30 Mt CO$_2$ per year could be used for EOR over a period of 15-25 years (Hustad, 2003).

Studies suggest that a combination of IGCC power production with CO$_2$ capture and offshore EOR in the UK would be a cost-effective strategy, even without credits for CO$_2$ emission reduction (Marsh, 2003). The project would have to start soon, however, as the first fields reach their EOR stage in 2006. EOR could be postponed for five years (Kaarstad, 2003), but not much longer, as the oil platforms would be dismantled or other EOR methods would be applied. Using EOR at a far later stage would require huge investments and make such a project uneconomic.

Table 3.11

CO$_2$ EOR projects worldwide

Country	Total projects	Ongoing projects
USA	85	67
Canada	8	2
Hungary	3	0
Turkey	2	1
Trinidad	5	5
Brazil	1	1
China	1	0

Source: Berge, 2003.

It is important to note that the storage potential in depleted gas fields is much larger than in depleted oil fields. They tend to be bigger reservoirs, and there are more of them. Total capacity is about 1,000 Gt of CO$_2$, almost 50 years of current global CO$_2$ emissions.

While the storage capacity can be estimated based on the historical quantities of oil and gas produced, the actual storage potential may be reduced as the pressure cannot be brought back to the original pressure, and parts of the reservoir may be water-flooded. Therefore, these are rough estimates only.

CO$_2$ enhanced oil recovery

US CO$_2$ EOR oil production amounted to 206 thousand barrels per day in 2003 (Moritis, 2004). This equals 31% of total US enhanced oil recovery, or about 0.25% of global oil production. 32 Mt CO$_2$ per year is used from natural resources and 11 Mt from industrial processes. A few CO$_2$ EOR projects exist

outside the USA (Table 3.11). CO_2 EOR has been applied for three decades and should be considered an established technology. However, this technology has been developed from the viewpoint of oil recovery, not from the viewpoint of CO_2 storage. Therefore, some adjustments may be needed for CO_2 storage.

EOR can enhance oil production substantially. The additional recovery amounts to 8-15% of the total quantity of original oil in place, which increases total recovery by 50% for an average field. Depending on the geology of the oil field and the oil type, enhancement can range from 25-100%. However, CO_2 EOR cannot be applied to all fields. An estimate for Norway is that EOR can increase ultimate oil production by 300 million m^3 (Mathiassen 2003), which represents about 10% of production to date and the remaining reserves (IEA 2002a). Given this increase, CO_2 EOR can increase the long-term conventional oil supply substantially. Moreover, the EOR revenues can offset part of the CCS cost.

EOR is limited to oil fields at a depth of more than 600 metres. The oil should also have a gravity of at least 23° API, equivalent to a density of at most 910 kg/m^3, which makes this method unsuitable for heavy oil or oil sands. At least 20-30% of the original oil should be still in place. EOR is limited to oil fields where primary production (natural oil flood driven by the reservoir pressure) and secondary production methods (water flooding and pumping) have been applied.[29] Many oil fields have not yet reached that stage. The occurrence of a large gas cap also limits the effectiveness of CO_2 flooding.

Up to temperatures of around 120 °C, CO_2 mixes with oil (a so-called miscible flood). At higher temperatures, CO_2 replaces the oil (a so-called immiscible flood oil). A miscible flood is more advantageous than an immiscible flood, because it results in higher oil recovery factors. Because of the physical constraints for CO_2 EOR, a detailed field-by-field assessment is required in order to assess its benefits properly. The CO_2 storage in case of miscible EOR ranges from 2.4 to 3 tonnes of CO_2 per tonne of oil produced. Estimates for storage potentials vary widely from a few Gigatonnes (Gt) to several hundred Gigatonnes of CO_2, depending on how many of the cost and geological constraints are considered. The cumulative storage capacity (the total quantity that can be stored over the whole period up to that year) increases with time as EOR can be applied to more depleted oil fields. In a recent study, 420 'early opportunities' for CO_2 EOR projects were identified, where capture sources and depleted oil fields are within 100 km distance and EOR could start in the coming years. Assuming around 1 Mt CO_2 storage per year per project, this suggests almost 0.5 Gt/yr of storage potential (Bergen *et al.*, 2004).

Worldwide, the potential for CO_2 EOR is limited. One reason is that oil fields are not evenly distributed around the world. The regions with ample oil reserves (Middle East, FSU) are not the regions with important point sources of CO_2; point sources may be far away from the oil fields (Figure 3.12). CO_2 EOR is also not suitable for all oil fields. Moreover, it competes with other EOR technologies (see Table 3.12). It depends on the reservoir and local supply conditions as to whether CO_2 flooding really is the best option from an oil recovery perspective, especially for heavy oil (*i.e.* oil of a density of more than 0.9 t/m^3) and for oil fields with a significant gas cap. The share of CO_2 EOR in total EOR has been expanding rapidly during the last two decades. **If CO_2 were available at low cost, CO_2 EOR could be applied to the majority of the world's oil fields.**

CO_2 EOR investment costs have dropped from more than 1 million USD per site in the 1980s to less than half of that today. Project costs vary depending on field size, pattern spacing, location and existing facilities, but in general, total operating expenses (exclusive of CO_2 cost) range from 2-3 USD per barrel (bbl). Costs can be split into capital costs (about 0.8 USD/bbl), operating costs (2.7 USD/bbl), royalties taxes and insurance (3.6 USD/bbl) and CO_2 costs (3.25 USD/bbl) (Kinder Morgan, 2002). Typically, to flood a field with CO_2, the field should have more than 5 million barrels

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29. There are examples of CO_2 EOR being applied as secondary oil production technology.

Table 3.12

Screening criteria for enhanced oil recovery methods

EOR method	°API I	Viscosity (cp)	Composition	Oil saturation (% PV)	Formation type	Net thickness (m)	Permeability (md)	Depth (m)	T (°C)	Cost (USD/bbl)
N₂ (&flue gas)	>35/48	<0.4/0.2	High % C1-C7	>40/75	Sandstone/Carbonate	Thin unless dipping	-	>2,000	-	
Hydrocarbon	>23/41	<3/0.5	High % C2-C7	>30/80	Sandstone/Carbonate	Thin unless dipping	-	>1,350	-	
CO₂	>22/36	<10/1.5	High % C5-C12	>20/55	Sandstone/Carbonate	-	-	>600	120[30]	7-30[31]
Micellar/	>20/35	<35/13	Light, intermediate	>35/53	Sandstone	-	>10/450	<3,000/1,100	<95/25	8-12
Polymer flooding, polymer, Alkaline/polymer Alkaline flooding	>15/ <40	<150/>10	-	>70/80	Sandstone	-	>10/800	<3,000	<95/60	5-10
Combustion	>10/16	<5,000/1,200	-	>50/72	High porosity sand/sandstone	>3	0>50	<4,000/1,200	>40/55	3-6
Steam	>8/13.5	<200,000/4,700	-	>40/66	High porosity sand/sandstone	>6	>200	<1,500/500	-	3-6

Note: The second figure indicates current average conditions. PV = Pore Volume.
Source: Green and Willhite, 1998, p.9.

30. For miscible CO₂ floods.
31. Lower end assumes CO₂ is available for free, higher end includes CO₂ cost.

Figure 3.12

Known conventional petroleum reserves of the world by region

Key point: The greatest potential for CO$_2$-EOR is in the Middle East and the FSU

Note: Excludes oil- and tar sands. Bln BOE = billion barrels of oil equivalent.

Source: IEA 2002a, p. 97
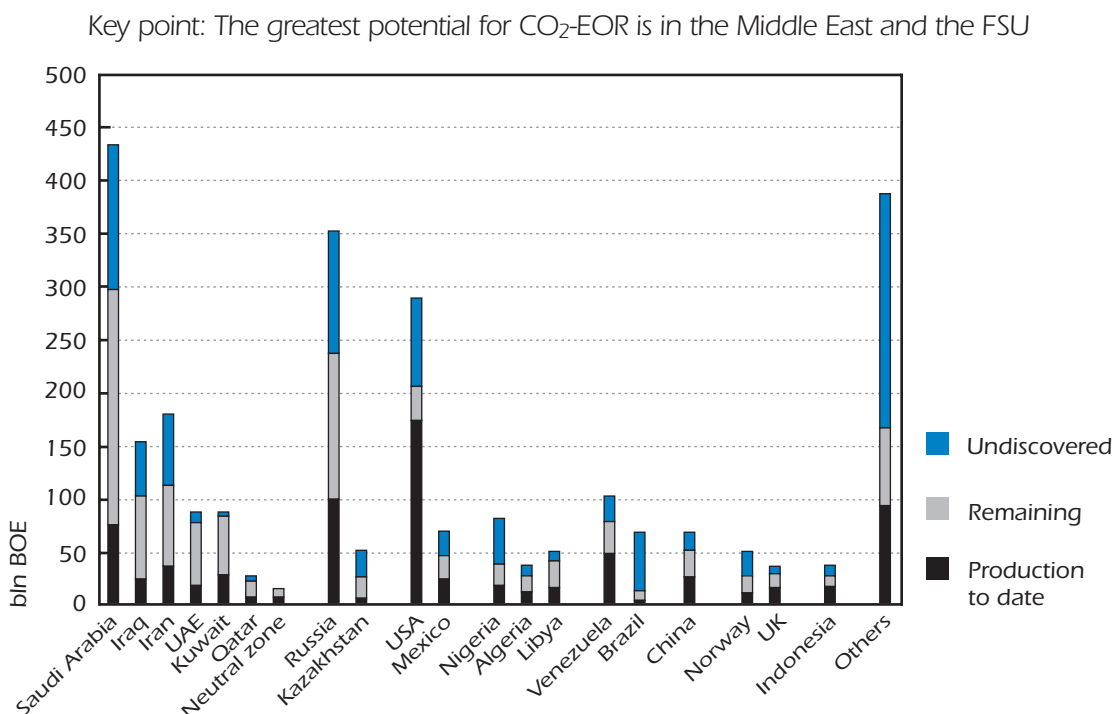
of original oil in place and more than 10 producing wells (Kinder Morgan, 2002). With EOR, total production costs (excluding CO$_2$ costs) are approximately 7 USD/bbl oil (about 50 USD/t oil). At a wellhead oil price of 15 USD/bbl and assuming an injection rate of 2.5 t CO$_2$ per tonne oil, the revenues amount to 25 USD/t CO$_2$, if the CO$_2$ is available for free. Note that this assumes a high oil recovery per tonne of CO$_2$. Oil revenues would be lower for most other fields.

Injection wells constitute the bulk of the capital costs for storage. In the case of depleted oil and gas wells it is recommended to drill new CO$_2$ injection wells, because there is a threat of a blow-out when old and possibly damaged production wells are used (Over *et al*., 1999).

The EOR impacts on oil supply can be substantial. Taking the case of Norway again, it is estimated that CO$_2$ EOR can result in an additional oil production of 260 to 300 million m^3. This equals 3.3 to 3.8 percentage points of the original oil in place. Given an original recovery factor of 44 percentage points, this represents an increase of 7.4% to 8.5% (Mathiassen, 2003). This estimate is based on a detailed field-by-field analysis, taking the feasibility of EOR for various fields into account. The recovery factor is set at 4% to 8%, roughly half the US experience, based on oil company feasibility studies for four North Sea fields. This suggests that the oil recovery potential may be higher than projected.

CO$_2$ enhanced gas recovery

Using CO$_2$ for enhanced gas recovery (EGR) is a speculative method for repressurizing depleted gas fields that can be applied to certain fields when 80-90% of the gas has been produced. Although

target reservoirs for CO_2 sequestration are depleted in methane with pressures as low as 20-50 bars, they are not devoid of methane. Additional methane can be recovered by injecting CO_2 using EGR (Oldenburg and Benson, 2001). The injected CO_2 will flow in the reservoir due to pressure and gravitational effects. Regardless of phase (gaseous, liquid or supercritical) CO_2 is notably denser than CH_4 at all relevant pressures and temperatures and will tend to flow downwards, displacing the native CH_4 gas and repressurizing the reservoir (Oldenburg and Benson, 2001). If CO_2 is injected at the bottom of a gas reservoir, it will 'chase' the gas toward the top where it can be produced. Not every gas field is suitable for CO_2 injection, however.

CO_2 EGR has not yet been applied anywhere in the world. Opinions are divided on whether this technology is feasible for most gas fields. It will depend on factors such as the time needed for the CO_2 to reach gas production wells. Modelling studies suggest that after 10 years the gas produced would still contain only 10% CO_2 by mass (Oldenburg and Benson, 2001). Given an initial pressure of 120 bar, another 5-15% of the initial gas in place could be recovered using EGR. The actual percentage depends on the geology of the gas field, and on the operator's selection of the percentage of CO_2 in the gas produced at which the EGR operation is closed down (Clemens and Wit, 2001).

About 1.8 GJ of gas could be recovered per tonne of CO_2 stored, if a whole reservoir was filled with CO_2 up to its original pressure.[32] Modelling studies for the Netherlands suggest that a coal-fired IGCC in combination with CO_2 removal and injection in a depleted gas field would be an economic option (Clemens and Wit, 2001). The potential for CO_2 use for EGR might be larger than for EOR (see Table 3.10). Per tonne of CO_2, the EGR revenues are substantially lower than for EOR.

CO$_2$ enhanced coal-bed methane recovery

CO_2 enhanced coal-bed methane (ECBM) is a speculative method for methane (coal gas) recovery from coal seams. While conventional coal-bed methane recovery may achieve 40-50% recovery (close to the wells), the recovery increases to 90-100% in the case of ECBM. ECBM is limited to coal seams that will not be mined.[33]

ECBM can only be applied to coal seams of sufficient permeability. Because of the increasing pressure, the CO_2 adsorption increases from 2 mole per mole methane at 700 metres, up to 5 mole per mole at 1,500 metres (Bergen *et al.*, 2000). The coal reserve should not be deeper than 2,000 metres because the increasing temperature limits the methane content of the coal and the increasing pressure at greater depth reduces the coal seam permeability. The methane content of deep coal seams can vary from 5-25 m^3/t coal and the thickness of the coal seams varies, so the ECBM potential per well and the CO_2 storage costs will vary by a factor of five or more. It is worth noting that the most attractive option from a methane recovery perspective (shallow coal reserves with thick coal layers) is the least attractive one from a CO_2 storage perspective and from a future coal mining perspective.

The following criteria must be met when screening coal reservoirs for ECBM (Stevens, 1998). Only a small fraction of all coal seams meet such criteria:

- A homogeneous reservoir, laterally continuous and vertically isolated from surrounding strata;
- Minimally faulted and folded;
- At least 1-5 millidarcies (mD) permeability. Most coal seams are much less permeable;

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32. 1.8 = 16/44x50x0.1

33. This constitutes a major source of uncertainty, because it depends on future mining technology and energy demand trends.

- High methane content;

- Stratigraphically concentrated coal seams are preferred over multiple thin seams;

- A possibility to use or export methane (pipeline) and CO_2 availability (local power plant, industry or pipeline).

The worldwide potential for CO_2 sequestration in deep unminable coal seams has been estimated at 148 Gt CO_2. An analysis of representative CO_2 ECBM projects indicates that 5-15 Gt of CO_2 could conceivably be sequestered at a net profit, while about 60 Gt of sequestration capacity may be available at cost of less than 50 USD/t CO_2, not including the cost of capture and transportation (IEA GHG Programme, 1998; Gale, 2004). Assuming that 2 moles of CO_2 replace one mole of methane, 10 Gt of CO_2 would equal 90 EJ of natural gas, which equals the current consumption of one year.

Note that these potentials depend critically on the assumptions regarding coal permeability, the costs for enhancing coal seam permeability and the costs for injection wells. One of the major problems concerning widespread use of CO_2 for ECBM is the variable, and often low, permeability of the coal. Furthermore, coal tends to swell in contact with CO_2 which reduces permeability. The only successful operation to date, the Allison unit in the San Juan Basin in the USA, is not representative because of very specific conditions. Low permeability can, in some cases, be overcome by fracturing the formation.

Figure 3.13

Cost breakdown of a proposed ECBM project in the Netherlands

Key point: Well costs represent two-thirds of total ECBM investment costs
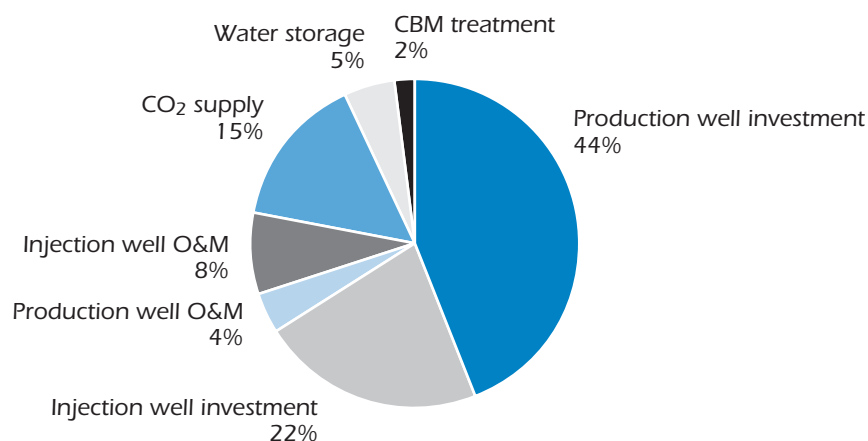
Note: Annuity for investments is 13%. Deviated injector wells because of siting constraints. CO_2 supply costs exclude capture, but include pressurization and transportation.

Source: Bergen et al.*, 2003.*

The cost of wells rises exponentially with the depth of the coal seam (compare Figure 3.11). Also deviated drilling is 70% more expensive than vertical drilling (Bergen *et al.*, 2003). Well costs are important with ECBM because a high well density is needed. As Figure 3.13 shows, well costs can represent three- quarters of total project costs. As a result, costs will vary on a project-by-project basis. Moreover, drilling a large number of wells could face opposition from land owners. Another

general problem for coal-bed methane projects is the necessary coal dewatering, which results in lowering of the groundwater levels (for shallow reservoirs) or production of brackish/salty water (for deep reservoirs).

So far, CO_2-ECBM pilot projects have been undertaken in the USA and Canada and a third pilot project in Poland is well underway. Results so far do not show conclusively that CO_2 enhances coal-bed methane production. The energy penalties and costs of ECBM are still unclear (C3 views, 2003). A case study for the Netherlands suggests transport and storage costs in the range of 55-75 USD/t of CO_2 – excluding the cost of CO_2 capture – at a natural gas price of 3.5 USD/GJ (Bergen et al., 2003).

In conclusion, CO_2-ECBM technology is at an early stage of technical development and its prospects remain uncertain. New demonstration projects currently underway should provide valuable information on the technology and allow a decision to be made within a few years on whether this can be regarded as a safe and environmentally-acceptable mitigation option. In most cases, revenues will be limited compared to the additional costs incurred. Obviously, high cost storage makes little sense if low-cost storage in depleted oil and gas fields and aquifers is an option.

Storage in deep saline aquifers

An aquifer is a layer of sedimentary rocks saturated with water and from which water can be produced through pumping, or into which fluids can be injected. Sandstone and carbonate rocks are usually aquifers. However, while most pore and fracture space in rocks are filled with water, only sedimentary rocks, such as sandstones and carbonates, have sufficient porosity to be considered for CO_2 storage. Crystalline and metamorphic rocks, such as granite, do not have the porosity necessary for CO_2 storage. In addition, fracturing usually present in the latter creates potential leakage paths.

An aquitard is a layer of rock from which water cannot be produced, but that has enough porosity and allows the flow of water on a geological timescale. Shales usually constitute aquitards. An aquiclude is a layer of rock that has almost no porosity and does not allow the flow of water. Salt and anhydrite beds are aquicludes. Water in aquifers deep below the ground in sedimentary basins is confined by overlying and underlying aquitards and/or aquicludes, usually has a high content of dissolved solids (brackish water and brine) and may have been there for millions of years. This water is unsuitable for human consumption. Because of the confined character of these aquifers and the lack of alternative applications, they have been proposed as locations for CO_2 storage.

Open and confined aquifers exist. The former type has no natural barriers to water flow, and there may be a natural circulation at a very low speed. Closed aquifers have no such circulation. Therefore, they might be better suited for CO_2 storage. Geological CO_2 sequestration in divergent basins (such as the foreland basins east of the Rocky Mountains and the Andes, the Michigan basin and the North Sea) is much safer than in convergent basins (California, Japan and New Zealand) because of the tectonic stability and general lack of significant hazardous events. Old continental core areas (*e.g.*, the Canadian and Brazilian shields) and mountain forming areas do not possess the rock characteristics necessary for CO_2 sequestration (Bachu, 2000). Sedimentary basins can be further subdivided in a number of criteria (Bachu, 2003). Based on such analysis, not every basin is suited for CO_2 storage.

Storage in aquifers is currently being studied in the Statoil CO_2 storage project in the North Sea. CO_2 is separated from natural gas produced from the Sleipner field, and stored in the Utsira aquifer below the gas field. The project has been storing 1 Mt CO_2 per year since late 1996. So far, results suggest that there is no leakage and CO_2 storage is technically feasible. However, there is still considerable

uncertainty regarding storage potential. The main uncertainty is to what extent the aquifer pore volume can be filled with CO_2. Calculations from the beginning of the 1990s suggest that 2% of the aquifer volume can be filled with CO_2 (Meer 1992), but more recent estimates suggest between 13% and 68% (Holt et al., 1995). The higher the average storage efficiency, the fewer the number of wells that will be required, the lower the storage costs and the higher the storage potential.

CO_2 injected in deep saline aquifers is trapped and stored by several mechanisms: 1) in its free phase as a plume at the top of the aquifer and in stratigraphic and structural traps (similar to oil and gas accumulations); 2) as bubbles that are trapped in the pore space after passing of a plume;[34] 3) dissolved in aquifer water; and 4) as a precipitated carbonate mineral as a result of geochemical reactions between the CO_2 and aquifer water and rocks. Numerical studies have shown that, during the period of injection, up to 29% of the CO_2 would dissolve in the brine (Bachu, 2000). As CO_2 has a lower density than the brine, the remainder would float on top of the brine and accumulate below the cap rock. During later periods, part of this CO_2 may dissolve in the brine or react with the aquifer rock matrix. Dissolution would continue after injection has ceased so that, over a period of a thousand years or more, the entire plume of CO_2 would probably dissolve.

Geochemical reaction to permanently sequester CO_2 would take several thousand years to have a significant effect. Where there is no stratigraphic or structural trap, the CO_2 would flow and spread over a large area below the aquifer cap rock. Modelling studies suggest a spread of tens or hundreds of square kilometers, depending on aquifer properties such as thickness, porosity and permeability (Saripalli and McGrail, 2002). This also depends, however, on the topography of the cap rock and the volume injected.

Table 3.13

Recent estimates of CO_2 storage potentials in deep saline aquifers

	(Gt CO_2)
Alberta (Canada)	4,000
USA	5-500
Western Europe	800
Worldwide	100-10,000

Note: Includes offshore aquifers.

Source: IEA GHG 2001; Bruant et al., 2002; Christensen, 2003; Bachu and Adams, 2003.

Generally, modelling studies have shown that, depending on aquifer characteristics and injection rate, a plume of CO_2 may spread between five and twelve kilometres from the injection well over a period of 1,000 years. Other studies suggest the plume would dissolve entirely. Such a large area would complicate the monitoring and verification of leakage, but the area needed would vary by case. The lower the initial CO_2 saturation of the brine, the smaller the area needed, as more CO_2 would dissolve in the brine.[35] This relationship could be used as part of aquifer selection criteria.

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34. *This process, also called imbibition trapping or residual gas trapping has received a lot of attention recently, with claims that it could trap 5-25% of the CO_2 injected. However, these estimates are based on model observations, calibrated with models for natural gas production reservoirs. A fundamental difference is that CO_2 dissolves in water, while natural gas does not dissolve. Therefore diffusion may reduce this pore phase trapping on the longer term, and it might therefore not contribute to the long-term permanence of CO_2 storage*

35. *It may be possible to mix CO_2 with brine before injection and inject the CO_2 in its dissolved state rather than as gas. While this option is speculative, it would reduce the leakage risk..*

The temperature profiles in underground sediments differ by location, because of variations in geothermal gradients and in surface temperatures. As a consequence, the state of CO_2 underground will vary, as will the density at a given pressure (Bachu, 2000). This affects both the storage potential per unit of surface and the relevance of leakage mechanisms. Aquifer CO_2 storage estimates are shown in Table 3.13. Estimates vary widely. For example, estimates from the USA of several hundred Gt CO_2 are almost a decade old and are probably too low.

More detailed assessments for the US mid-western Mt. Simon aquifer alone indicate 115 to 655 Gt CO_2 of storage potential (Gupta *et al.*, 2002) although storage potential of several thousand Gigatonnes is more likely. In conclusion, significant storage potentials exist, but they are not spread evenly across and within all regions. Ongoing studies are attempting to match potential capture sites with storage sites. Over a timescale of decades, it may be that power plants and industrial plants are relocated to sites where suitable transportation and storage infrastructure exists.

This conclusion is valid on a global scale, but on a regional scale limitations may exist. A simple back-of-the-envelope calculation clarifies the issues involved. A 500 MW coal-fired power plant would have to store about 3 Mt CO_2 per year. The CO_2 may be stored in an aquifer at a density of 0.5 t/m^3. Assuming an effective CO_2 layer density of 1 metre,[36] six square kilometres of aquifer are used for storage per year. During a power plant lifespan of 40 years, an area of 240 square kilometres would be needed, which equals an area of 15 by 15 kilometres. Some 16 Gt CO_2 of storage per year – a huge amount – implies an area for underground storage of 200 by 200 kilometres per year, the size of a country such as the Netherlands. This rough estimate indicates that CO_2 storage would require geo-engineering on a global scale.

Figure 3.14

The cost structure of Norway's Snohvit aquifer storage project

Key point: Pipeline and CO$_2$ compressor costs account for three-quarters of Snohvit's investment costs

Offshore CO$_2$ well
8%

Well completion
5%

CO$_2$ compressor train
37%

Pipeline 8", 160 km
38%

Sub sea well frame
6%

Control umbilical (sub sea)
6%
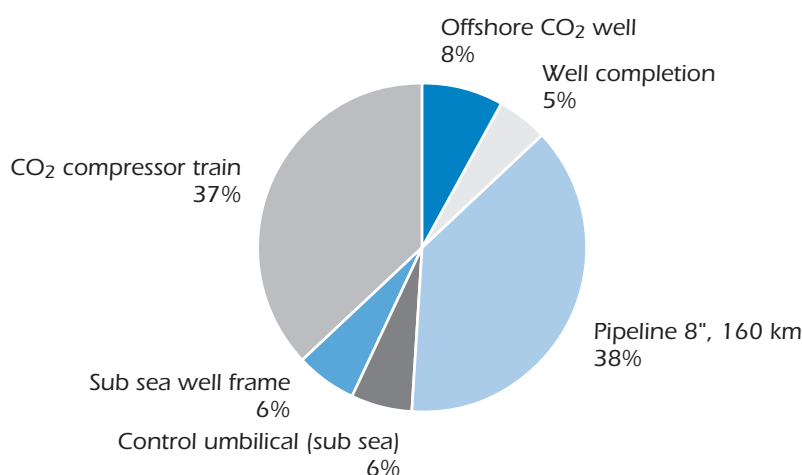
Source: Audus, 2003.

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36. If the sediment porosity is 30%, that means the top 3 metres of the aquifer are filled with CO$_2$.

The cost of the Sleipner project for CO_2 compression and injection amounted to 80 million USD, equal to an investment cost of 80 USD/t of CO_2. The investment costs for the Snohvit project (compression, transportation and injection) will amount to 191 million USD, equal to an investment cost of 275 USD/t CO_2 (Audus, 2003). Clearly these cost levels are higher than the values used for regular CCS assessment studies. The higher costs may be explained by extreme situations (North Sea offshore and Arctic, respectively), and by the fact that these are 'first of a kind' facilities. Yet, compressors and pipelines constitute the bulk of the cost (Figure 3.14), and these should be considered well established pieces of equipment, for which the learning potentials are limited. Therefore, **careful case-by-case cost evaluation is needed, and economies of scale will be essential, in determining the most cost-effective and environmentally sound options for CO_2 storage.**

Other storage options

A number of other storage options have been proposed. Only limestone ponds, surface mineralization and oceanic storage will be discussed here.

The concept of limestone ponds combines capture and storage. Limestone is dissolved in water in a pond. Flue gas is bubbled through this pond. The CO_2 in the flue gas bubbles reacts with the limestone. The carbonate solution is dissolved in sea water. There have been preliminary cost estimates of 21 USD/t CO_2 for the total of capture and storage (Sarv and Downs, 2002). This process has not been proven on a pilot scale. Most experts claim that it is impossible to produce bubbles that are sufficiently small (CO_2 transportation into the solution is the limiting factor), and the size of the ponds would be prohibitive. Given its speculative character, this option has not been considered in more detail.

The concept of surface mineralization is based on the reaction of ground magnesium and calcium silicate rock with CO_2 into carbonates. The volumes of material involved are significant. A 500 MW coal-fired power plant would produce about 30 kt of magnesium carbonates a day (about 1,000 truck loads; Goldberg *et al.*, 2001). The process has been tested on a laboratory scale. Certain types of peridotites and sepentinite would be the preferred rocks, containing 40-50 weight % MgO and CaO. These rocks occur worldwide. Binding one tonne of CO_2 would require 0.9 t of MgO, and generate 2.8 t of waste (Lackner *et al.*, 1997). These rocks, which are not sedimentary, occur worldwide in specific areas (*i.e.*, not in sedimentary basins where energy is usually being produced). For example, olivine and serpentine is found in North America on the east and west coast, while oil, gas and coal are produced mostly between the Appalachian and Rocky Mountains.

Advocates of this process argue that it is exothermic and, therefore, that the energy requirements would be negligible. Moreover, the olivine and serpentine starting materials are abundant. The most important hurdle from an engineering perspective is the reaction kinetics. So far, no process design has been proposed that results in realistic reaction times (Herzog, 2002). It should also be noted that large-scale application of this process would create large amounts of solid waste that require further processing. Finally, the process is not cheap. The goal is to reach storage costs of 30 USD/t CO_2 (excluding CO_2 capture and transportation), (Lackner, 1997). Transportation of olivine and serpentine to CO_2 sources, or of CO_2 to quarries where the former could be mined would make the process prohibitively expensive. As a result, this process would only be attractive if other storage options are unavailable (*e.g.*, because of environmental concerns). Mineralization has been considered in the ETP model.

Oceanic storage of CO_2 is the most controversial option. There are two types of storage: dissolution in seawater and storage of CO_2 hydrates or liquid CO_2 at depths of more than 4,000 metres. Most technologies for deepwater storage are established technologies. Little is known about the impact

increasing CO_2 concentrations would have on the oceanic ecosystem. Pilot projects in Hawaii and Norway were cancelled because of protests from environmentalists. While oceanic storage is not critical for Western countries it may emerge as a key alternative for Japan because of the country's limited underground storage potential. However, this is a country where the sustainable use of oceanic resources is a sensitive issue. Wide acceptance of environmentally-friendly oceanic storage systems would be a key requirement for the large-scale application of this option.

With regard to oceanic storage, model calculations suggest that 80% to 90% of the CO_2 would remain in the ocean after a period of 500 years, if the CO_2 was injected at a depth of over 3,000 metres. For a depth of 1,000 metres, 30-80% would remain (Caldeira, 2002). The difference between the lower and the higher end of the range is the CO_2 that is released into the atmosphere and reabsorbed. The lower end of the range should be used for proper comparison of the efficiency with other options. These figures suggest that permanence is less of an issue if the CO_2 is injected at sufficient depth. In this case it is probably not the permanence but the direct environmental impacts on the sea ecosystem through a change in water acidity that are the main obstacle. If the carbon acidity is not neutralized with limestone or some other buffer, the addition of thousands of gigatonnes of carbon to the ocean will produce significant perturbations to ocean chemistry on a large scale. It is unclear at this time how best to monitor the health of broad reaches of the ocean interior, when so little is understood about these ecosystems. Again, more research is required to better understand deep-sea biota and its response to added CO_2 (Caldeira, 2002). In addition, international legal issues would pose a significant barrier to large-scale implementation of ocean storage.

CO2 Storage: Permanence and Monitoring

The idea of storing CO_2 in geologic formations immediately raises questions about storage permanence, the environmental risks involved and necessary monitoring. Certain potential storage sites may not leak at all, while others may do so at an unforeseen rate. At the moment, insufficient information is available to quantify leakage from CO_2 storage sites. It is possible, however, to quantify upper limits for leakage and to draw conclusions from these theoretical limits and the experimental information available so far.

A strict requirement for a zero leakage rate would impose excessively stringent conditions on storage selection procedures and result in a waste of a valuable resource, i.e., potential CO_2 storage sites. Certain leakage rates can be accepted and permitted. It has to be emphasized, however, that selection procedures should effectively eliminate sites with a risk of sudden releases of bulk CO_2 due to geological imperfections and tectonic moves.

There are two types of risk associated with leakages of CO_2: local, site specific, affecting health, safety and environment, and global, resulting from a return of stored CO_2 to the atmosphere. The majority of constraints imposed on storage permanence and also quality of monitoring will probably result from the first type (Keith, Pacala 2004). A local risk resulting from leaking CO_2 is a very site-specific issue, however, and will not be covered in the following discussion on maximum leakage rates.

Taking the global risk under consideration, the minimum storage permanence time depends on future emissions. The total quantity of fossil fuels in place (about 5.67 PtC remaining) puts an upper bound on required storage time. Oil reserves are probably most limited, followed by gas and coal. Coal reserves are very large and could last for hundreds of years. If CO_2 concentrations should not rise above 450 ppm this would imply a retention time of 7,000 years (Zweigel and Lindeberg, 2003).

On the other side of the scale, non-fossil power generation may become dominant in the second half of the 21st century. If fossil fuels are eliminated by 2100, then CO_2 storage for 100 years would suffice, according to this author. However, if large quantities of CO_2 are stored during this century, such a short retention time (or such a high leakage rate) will be hardly compatible with stabilizing CO_2 concentrations at any level, as stabilization of CO_2 concentrations will require near-elimination of net CO_2 emissions. Any storage time shorter than 100 years is questionable in all scenarios. In geological terms, these are very short periods. Oil and gas have been buried for millions of years, indicating that such favourable storage conditions are not uncommon.

A retention time between 100 and 2,000 years means the maximum acceptable leakage rate can be somewhere between 0.01% and 1% per year. However the more optimistic scenario is due to an assumption of heterogeneity among reservoirs. The emissions from leaky reservoirs are re-injected into more average reservoirs with much lower seepage rates, thereby reducing the average seepage rate over time (Torvanger *et al.*, 2004). Other studies have found that **leakage rates of up to 0.1% per year allow for an effective storage policy** (Hepple and Benson, 2003; Pacala, 2003). There are two important issues that need to be mentioned here:

- Maximum allowable leakage rates will set the upper bound on CO_2 losses in permitting and accounting procedures although this does not mean that the research community expects such leakages which, in reality, should be many times smaller, if any;
- Because of public perception issues, a maximum leakage rate considered in a site selection process will likely have to be one order of magnitude smaller than that resulting from the calculations.

One of the main elements of the site selection procedure is an assessment of faults and fractures that can compromise the cap rock strata (Friedmann and Nummedal, 2003). Usually, depleted oil and gas reservoirs are well characterized, so these imperfections can be identified without high cost. For aquifers, such data is not readily available and, when available, is not at the same level of detail and resolution. A costly suitability study may be needed.

Model studies suggest that a fracture 8 km from the injection well would result in preliminary leakage of CO_2 after 250 years and 10-20% leakage over the succeeding 2,000 years, equal to less than 0.01% per year (Lindeberg, 1997). Anthropogenic damage of the cap rock due to abandoned oil and gas exploration and production wells may cause additional leakage (Celia and Bachu, 2003). In some regions with a well-developed oil and gas industry, more than five wells occur per square kilometre. Most of the abandoned wells have been sealed. However, CO_2 reacts with the cement, often used for the seal, and can result in leakage. Also small gaps may exist between the well plug and the well casing. Leaking CO_2 may dissolve in other aquifers above the storage aquifer, thus preventing an emission to the atmosphere. So far, it is not clear whether this leakage mechanism poses a serious problem or not.

On the other hand several natural processes could enhance the permanence of storage (see previous discussion on storage in deep saline aquifers). The dissolution of CO_2 in the aquifer water is a key process. The solubility of CO_2 in 1 mole/l (M) brine reaches a maximum at 41-48 kg/m^3 below 600 metres depth. Increasing the salinity to 4 M decreases the maximum solubility to around 24-29 kg/m^3. Geochemical reactions can increase this solubility by 20%. This dissolution is kinetically limited and only takes place on a timescale of hundreds of years. Therefore, storage in water containing reservoirs (both aquifers and depleted oil and gas fields) should be interpreted as storage of a CO_2 'bubble' on top of a water layer (Rigg, 2001).

The dissolved CO_2 results in a type of 'sparkling mineral water', which occurs naturally in many places. For example, in many geothermal energy projects natural CO_2 from deep saline aquifers is

released into the atmosphere. In the high emission scenario, dissolution would reduce the minimum retention time for the CO_2 'bubble' from 7,000 to 2,000 years (Zweigel and Lindeberg, 2003). Chemical reactions with the rock would further reduce the retention time. In certain cases, physical adsorption can fix the CO_2, *e.g.*, in coal and so-called residual trapping mechanism,. Also, leaking CO_2 would change from a supercritical state into a subcritical state. This phase change would result in strong cooling, followed by formation of solid water ice and CO_2 hydrate. Modelling studies suggest that this process could inhibit leakage for hundreds of years (Pruess, 2003). 'Fixing' CO_2 through different mechanisms increases security of storage and, in certain cases, may result in a softening of monitoring requirements with time.

In recent decades there has been significant progress in the monitoring of underground oil and gas reservoirs with an improvement in 3-D and 4-D seismic methods. These methods can also be applied for monitoring of CO_2 in deep aquifers. However, many key aspects of fault geometry are below the resolution of existing seismic tools (Friedmann and Nummedal, 2003). A wide range of additional monitoring techniques may be applied, but these often require costly drilling (Vendrig et al., 2003). The Sleipner CO_2 injection has been monitored in the Saline Aquifer CO_2 Storage (SACS) programme. The cost of that programme amounted to 4.5 million USD, but this should be considered as a R&D programme with high costs; the cost for routine monitoring will be considerably lower.

On-land, 3D seismic may cost between 6,000 and 10,000 USD/km^2. If 25 km^2 is to be monitored, the seismic cost would amount to 150,000-250,000 USD. Assuming 10 Mt storage, this would amount to 0.15-0.25 USD/t CO_2. If seismic monitoring is undertaken at five or ten-year intervals, the cost may be of secondary importance. Other analyses estimate slightly higher total undiscounted storage (pre-operational, operational and closure) monitoring cost of 0.19-0.31 USD/t CO_2, and discounted monitoring cost of 0.05 to 0.10 USD/t CO_2 (Benson, 2004).

Simpler monitoring methods could be applied, such as surface measurements of CO_2 concentrations. It is possible to measure a flux resulting from a 0.01% leakage per year and differentiate it from background emission (Benson, 2004). This would allow for verification of storage permanence. It is also sufficient for early recognition of certain leaky storage sites, and planning a remediation action. Various new methods are being developed, e.g., in the framework of the CO_2 Capture Project. A list of technology gaps includes instruments capable of measuring CO_2-levels close to the background and to distinguish between CO_2 from natural processes and that from storage. Improved mathematical models may also contribute to a better understanding of long-term storage permanence.

Calls for better monitoring methods should not be taken as an endorsement of a 'some is good, more is better' view of monitoring (Keith, 2004). One of goals of storage demonstration projects is to define appropriate levels of monitoring for each particular type of storage site.

Out of many natural and industrial analogues, underground natural gas storage operations can provide very useful information. Underground storage of natural gas is widely applied, *e.g.*, in the Netherlands and the USA. In the USA, 119 Mt of natural gas was stored underground in 2002. Underground gas storage has been practiced for more than 90 years without problems, which suggests that underground CO_2 storage may be feasible as well.

Well mechanical flaws and abandoned wells have been the most common cause of leaks in underground gas storage facilities. Generally, such problems are fixed by repairing or reconditioning of the wells. For gas projects in the USA, overpressures of up to 17 kPa/m of depth have been used (Lippmann and Benson, 2002). At a depth of 800m, this would amount to an overpressure of 13,600 kPa, or 136 bar. Such high additional pressures are not proposed for CO_2 storage, which suggests cap rock fracture may be less of a problem. While such comparisons provide some guidance, differences

exist. The storage of natural gas is different from CO_2 storage because natural gas does not chemically react with the reservoir rock, and it is stored and removed periodically (Vendrig *et al.*, 2003).

Another commercial-scale analogue to CO_2 storage in geological media exists in North America where, since 1990, acid gas (a mixture of hydrogen sulfide H_2S and CO_2) has been injected into deep aquifers and depleted oil and gas reservoirs at more than 60 locations (40 of which have been in the Alberta basin in western Canada). Acid gas is produced through desulphurization of produced sour gas (natural gas that contains H_2S). H_2S is captured using a chemical absorption process. In this process significant amounts of CO_2 are also captured. The purpose of acid-gas injection operations is to dispose of the H_2S. Significant amounts of CO_2 are injected at the same time because it is costly to separate the two gases. At end-2002, 39 acid gas injection projects were in progress in North America. The cumulative injection of CO_2 in all sites exceeds 1 Mt. In the 13 years since acid gas injection started in western Canada, no safety incidents have been reported to the regulatory agencies (Bachu *et al.*, 2003). Plans are currently underway to apply this technology in Kazakhstan, the Middle East (Iran) and North Africa.

Production of Chemicals and Fuels from CO_2

At first sight, the production of transportation fuels from CO_2 does not seem a viable strategy because the energy of a fuel is released by its conversion into CO_2. The process only makes sense from an energy perspective where in one location a surplus exists of CO_2-free energy (either of nuclear or of renewable origin), while in another location a demand exists for fuels. CO_2 is shipped from one region to the other, while hydrocarbon fuels that are produced from this CO_2 are shipped in the other direction. The rationale would be that transportation of CO_2-free energy carriers (electricity, hydrogen) is costly. Also, for certain end-use sectors, notably the transportation sector, the introduction of CO_2-free energy is problematic.

If CO_2-free energy can be converted into a hydrocarbon energy carrier that can be transported and used at low cost, it would allow for the introduction of CO_2-free energy in markets without a local CO_2-free supply. In the transportation sector, hydrocarbons are the preferred fuel because of their high energy-to-weight and energy-to-volume ratio. Methanol and DiMethylEther (DME) are prominent candidates, because these fuels can be used in current combustion engines and in a reformer/fuel cell combination that may be the long-term propulsion system of choice.

Transportation and on-board storage of methanol and DME is considerably cheaper than hydrogen or electricity storage, and these fuels can be used in existing combustion engines. However, a renewable carbon source is required for CO_2-free methanol and DME. Biomass is the only renewable carbon source. CO_2 that is recycled from flue gases can be another carbon source that results in a significant overall emission reduction.

This strategy is being looked at in Japan. The synthesis of methanol via CO_2 hydrogenation is considered one of the most promising processes for the fixation and utilization of CO_2 (Takeuchi et al., 1999). The production of the hydrogen for the hydrogenation process requires significant amounts of energy. Hydrogen production accounts for 93% of the total energy required and CO_2 separation and liquefaction account for 6%. Total energy requirement is 28 GJ of electricity per tonne of methanol. In the case of a CO_2-free electricity source, the methanol constitutes a CO_2-free energy carrier. If this methanol is used to produce transportation fuels, it results in 3.14 tonnes of CO_2 emission reduction per GJ of oil transportation fuel that is substituted. In the case of an average

emission for electricity production of 0.1 CO_2/GJ, the net balance is an emission of 1.4 t CO_2/t methanol, and there is no emission reduction per GJ of oil transportation fuel that is substituted.

Obviously, the use of CO_2 feedstock would be a costly strategy for GHG emission reduction, because CO_2-free electricity is a costly energy source. However, trade among regions with special characteristics (*e.g.*, Australia with ample solar/wind resources and Japan with limited renewables potential and lacking indigenous oil resources) could make such a combination a viable alternative.

Overview of CCS Costs

CCS cost figures have been discussed throughout this chapter and the impact of methodological choices on the cost per tonne of CO_2 was discussed. It is clear that cost figures should not be applied indiscriminately. However, it is useful to give an overview of the cost range, and the main factors that determine these costs.

In most cases, the bulk of costs are for CO_2 capture and pressurization. There are a few exceptional cases where CO_2 is already separated from gas flows for other reasons. If this is the case, the only costs are for compression. In most cases, CO_2 must be separated from a gas stream. It depends on the CO_2 concentration and process design to determine which capture technology is best. Generally speaking, the capture costs per tonne of CO_2 are lower for coal-fired processes than for gas-fired processes, as CO_2 concentrations are higher. Improving technology can reduce capture costs substantially, to 5-30 USD/t CO_2 (Table 3.2). Costs could decline to 10-25 USD/t CO_2 for coal-fired power plants and to around 25-30 USD/t CO_2 for gas-fired plants; they could be even lower for biomass fired processes. The gap between capture and abatement cost narrows as the energy efficiency penalty for CO_2 capture decreases.

CO_2 transportation costs depend on volume, distance, population density (land prices), soil type and other factors. With optimistic assumptions, these costs may only amount to 2-10 USD per tonne. Low volumes, difficult terrain and other factors may increase transportation costs to 20 USD/t CO_2. The examples for Snohvit and Karstø discussed earlier show that transportation costs can be substantial. Work to assess future transportation costs deserves more attention.

Table 3.14

Overview of likely CCS costs

Activity	Cost (USD/t CO₂)	Uncertainties
CO₂ capture (including compression)	5 to 50 (current) 5 to 30 (future)	Low end for pure streams that only need compression; high end for chemical absorption from gas-fired combined cycles
CO₂ transportation	2 to 20	Depends on scale and distance
CO₂ injection	2 to 50	Low end for Mt size aquifer storage; high end for certain ECBM projects
CO₂ revenues	-55 to 0	No benefits for aquifers; highest benefits for certain EOR projects
Total	-40 to 100	

Note: Costs are expressed per tonne of CO_2 avoided – see box on evaluating the cost of CCS in this chapter for conversion factors to cost per tonne of CO_2 captured.

Costs for injecting CO_2 into depleted oil and gas reservoirs or aquifers are generally low. However, as the discussion of the Dutch ECBM project showed (Bergen *et al.*, 2003), this is not always the case. Cost depends both on the storage technology and on local conditions (*e.g.*, if deviated drilling is needed).

Part of the cost of CCS could be offset by revenues from enhanced fossil-fuel production. These benefits could reach 55 USD/t CO_2. Revenues from EOR in particular could be substantial, but this is highly site specific and will not be the case for most CCS projects.

Total CCS costs can range from a 40 USD/t benefit in the most optimistic case to a 100 USD/t cost in cases of small-scale projects capturing CO_2 from gas-fired power plants using existing technology (Table 3.14). This wide range shows that a case-by-case evaluation is needed for a proper cost assessment. At this stage, for a vast majority of options, the total cost of CCS could be within 50 to 100 USD/t CO_2. By 2030, these costs should go down to 25-50 USD per tonne of CO_2.

Chapter 4.
BASIC RESULTS FROM THE MODEL ANALYSIS

H I G H L I G H T S

■ The Energy Technology Perspectives (ETP) model has been used to assess the potential role of CCS. ETP is a technology rich model that makes it possible to calculate the least-cost energy system for the period 2000-2050. The model results show that CCS compares well with other technology options to reduce CO_2 emissions.

■ In a scenario without new CO_2 policies (which is based on the World Energy Outlook 2004 Reference Scenario up to 2030), emissions increase one-and-a-half-fold from current levels to over 60 Gt CO_2 by 2050. This increase is driven by strong economic growth and high coal growth rates.

■ A scenario with a 50 USD/t CO_2 emission penalty (GLO50) results in a stabilization of global emissions in the range of 23-28 Gt CO_2/yr, which more than halves BASE emissions in 2050. CO_2 capture and storage increases to 18.4 Gt in 2050. This result should be considered as an upper limit for the CCS potential.

■ Using CCS achieves a 25% deeper cut in global emissions compared to the same GLO50 scenario without CCS.

■ In the GLO50 scenario in 2020, 28% of total capture is from coal-fired processes. However, the share of coal increases to 65% by 2050, the remaining 35% being CO_2 capture from natural gas, oil and biomass-fired processes, and to a lesser extent capture from cement kilns. The high coal share indicates the important synergy of CCS and coal.

■ CO_2 capture in the electricity sector represents around 80% of total CO_2 capture potential in 2050. The remainder is evenly split between manufacturing and fuels production.

■ At a penalty level of USD 50/t CO_2, 39% of all electricity production would be from plants equipped with CO_2 capture in 2050, including those that co-combust biomass.

■ Without CO_2 policies, the average global efficiency of coal-fired power plants increases from 32.1% to 42.7% in 2050, an increase of 10.6 percentage points, or 33%. The efficiency of gas-fired plants increases from 36.0% to 57.4%, an increase of 21.4 percentage points or 59%. These efficiency gains are driven by technological progress and rising fuel prices, and they make CCS a viable option. However, due to the additional energy needs for CCS, global average plant efficiency is in fact 3-6% lower (a 1 to 3 percentage point reduction) in the GLO50 scenario with CCS.

■ Some 80% of all CO_2 capture in the electricity sector is from IGCC type power plants. Up to 15 EJ of biomass is co-combusted in coal-fired IGCCs. According to the model, IGCC plants that co-generate electricity and synfuels pose an interesting option.

■ If CO_2 penalties are introduced, ageing fossil-fuelled power plants with low efficiency and without CO_2 capture would either be closed down before the end of their technical lifespan or operate as peaking units. This indicates that the potential rate at which CCS can be introduced exceeds the rate at which capital stock is typically replaced. Regular

capital stock turnover projections for the electricity sector, based on historical turnover rates, do not apply if an ambitious CO$_2$ policy is put in place.

■ In 2030, 80% of all CO$_2$ capture takes place in OECD countries. By 2050, this share has declined to 60%, if CO$_2$ policies are introduced worldwide. This result is a function of the regional growth distribution of electricity demand, and global CO$_2$ policy scenarios.

■ In 2030, half of the captured CO$_2$ is used to enhance fossil-fuel production or stored in depleted oil and gas reservoirs, and half stored in aquifers. By 2050, aquifer storage dominates.

■ The additional emission reduction in GLO50, compared to the same CCS scenario without CCS, is equal to 40-45% of the quantity of CO$_2$ captured. The fact that the emission reduction is so much lower can be attributed to the additional energy use for CO$_2$ capture and pressurization and the related emissions, and the increased coal share in the energy mix.

■ The marginal emission reduction cost in the period 2030-2050 is halved, and the average emission reduction cost declines by about a third (from about 45 to 30 USD/t CO$_2$,) if CCS is considered, compared to a scenario without CCS. This suggests that applying CCS would result in a significant decrease in the policy incentives needed and it would also substantially reduce the cost of CO$_2$ policies.

This chapter starts with a brief description of the ETP model, followed by a discussion of the model analysis structure.

The ETP BASE scenario is presented, as this is the reference to which the other model scenarios are compared. This is followed by a detailed discussion of CCS in the GLO50 Scenario. In this scenario, where the CO$_2$ penalty is set at 50 USD/t CO$_2$, global emissions are roughly stabilized at 23-28 Gt CO$_2$ per year. The analysis shows that CCS can compete with other energy technology options, and that CCS technologies should form a key part of a CO$_2$ emissions abatement scheme. CCS use in three key sectors is discussed in more detail: power generation, manufacturing and fuel processing.

The chapter ends with an analysis of CCS benefits in terms of emission reduction and cost of CO$_2$ policies, based on a comparison of model runs with and without CCS.

The Energy Technology Perspectives (ETP) Model

CCS is a technology option for emissions reduction. The competition between CCS and other emission reduction options is a complex issue. Its proper quantitative analysis requires a model that can deal with technological change. A number of such models exist. The model used in this study is called the Energy Technology Perspectives (ETP) model. It belongs to the MARKAL family of bottom-up systems engineering economic models (Fishbone and Abilock, 1981; Loulou *et al.*, 2004). MARKAL has been developed over the past 30 years by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA Implementing Agreements (ETSAP, 2003).

Any model is a highly stylized representation of the world energy supply and demand, based on a dataset that approximates the real world. Each model has its own unique characteristics that may affect the results and conclusions. A different model may produce different figures. Therefore the

goal is to 'model for insights', not to 'model for figures', and each result should be interpreted with the uncertainty of the results in mind. In this study special attention has therefore been given to uncertainty analysis.

The ETP model is a micro-economic representation of part of the world economy (a so-called partial equilibrium model), divided into 15 regions. Only that part of the economy which is relevant to energy is modelled. This so-called energy system is modelled as a set of interdependent technical product flows and processes. Various technologies, characterized by their physical and economic properties, can be used to generate certain product flows. A brief overview of the model technology database is given in Annex 1.

The model process technology choice and process activity levels determine the physical and monetary flows within the energy system. ETP is a linear programming model that minimizes the systems cost, given a certain demand for energy services and certain constraints, such as availability of natural resources. Obviously, this is an abstract representation of the real world, where decisions are often not based on the same rigid cost minimization approach. Therefore, the primary goal of the ETP model is to identify optimal options and strategies and to assess the future role of energy technologies. It is not a tool for generating accurate energy projections.

ETP model analysis: caveats

The following ETP analysis discusses the potential for future use of CCS. It is not a prediction of what will happen, but rather an analysis based on the assumption of rational decision-making, a perfect market and perfect foresight. Risk and uncertainty are not accounted for. The system is optimized based on cost considerations only. By definition, any CO_2 emission reduction option that would reduce systems cost would be part of the BASE scenario. In reality, such a potential may exist, for example, through certain energy-efficiency measures on the demand side. Issues such as the uncertain permanence of CO_2 storage, legal and regulatory barriers, and public acceptance of CCS, have not been considered in the model.

Apart from methodological caveats, there are also caveats of scope. Emission reduction options for greenhouse gases other than CO_2 have not been accounted for. Land use, land use change and forestry options (LULUCF) for CO_2 emissions reductions are not considered either. If both of these emissions reductions were accounted for, the potential or need for CCS would decrease.

Finally, the analysis does not take into account the intra-regional distribution of emission sources and potential storage sites. Consideration of such issues may reduce the potential for CCS. Given these limitations, model results for CCS use should be considered as optimistic potentials, actual CCS use will be lower.

Overview of the Model Analysis Structure

Figure 4.1 provides an overview of ETP model runs and their use for the analysis in Chapters 4 to 7. A total of 35 model runs show a wide range of CCS potential and provide insights into the main uncertainties that surround these modelling outcomes. The goal is to identify the factors which

Figure 4.1

The role of ETP model runs in the analysis
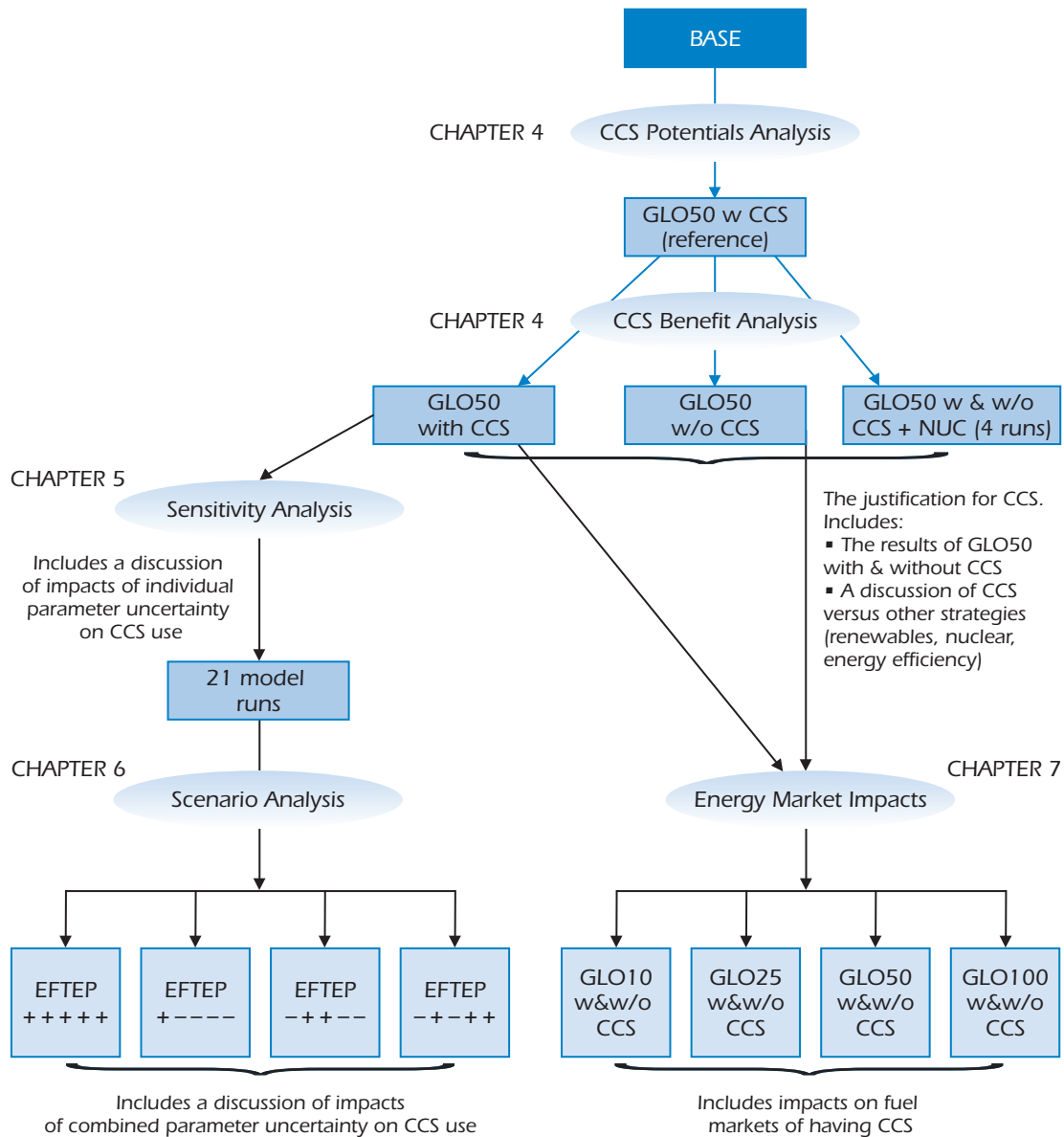
are essential for the future application of CCS. The results map the potential range of CCS use, help identify key CCS technologies, and assess the impact on different world regions. CCS impacts are analysed from the perspective of the three shared goals of the IEA: energy security, acceptable environmental impacts and affordable energy.

The discussion is split into five main parts: CCS potential, CCS benefits, sensitivity analysis, scenario analysis and fuel market impacts. The analysis starts by looking at the ETP's BASE scenario without CO$_2$ policies. This scenario is discussed in order to allow comparison with other model analysis studies. This is followed by the presentation of a scenario with a global penalty that gradually

increases to USD 50/t CO$_2$, named the GLO50 scenario. A penalty is an abstract way of representing regulatory and financial policy instruments. The 50 USD/t CO$_2$ penalty level was chosen for more detailed discussion because it roughly represents emission stabilization in the period 2000-2050, or a halving of emissions by 2050, compared to the BASE scenario. Furthermore, it is clear from previous analysis that CCS is a costly option compared to other greenhouse gas emission reduction options.

The GLO50 discussion focuses on CCS use by sector and on storage. This is followed by an analysis of CCS benefits. Benefits are considered in terms of environmental benefits (the additional emissions reduction due to CCS) and financial benefits (reduced cost to achieve certain emission reduction targets). For this purpose, a GLO50 case without CCS is compared to the one with CCS, and four model runs with and without nuclear and CCS are also compared.

In 21 sensitivity model runs, a range of potentially important parameters was varied for the GLO50 scenario in order to assess which of these are crucial for the future role of CCS. Next, four scenarios were defined along the lines of these key parameters. These scenarios are characterized by the acronym EFTEP: Economy (E), Fuel demand and price (F), Technological progress (T), Environment (E) and regional Policy scope (P). A plus (+) means that the parameter values of the scenario dimension result in high CCS potential, while a minus (-) indicates low CCS potential. These scenarios show how the interactions of positive and negative factors affect the potential for CCS use. The results can be used to identify which scenario dimensions are more important than others.

The fuel market consequences of CCS are analysed through a structured set of model runs with penalties of 10, 25, 50 and 100 USD/t CO$_2$, with and without CCS. Fuel use and prices are mapped for each of these scenarios. The differences provide insights into supply security consequences.

The BASE Scenario

The BASE scenario is the scenario against which all other scenarios in this book are evaluated. The scenario is based on the development in the World Energy Outlook 2004 Reference Scenario up to 2030 (IEA, 2004a). It includes, as the Reference Scenario, energy and climate policies enacted before mid-2004, as well as further policies beyond that. Refer to Chapter 2 for more discussion of the Reference Scenario.

For the period 2030 to 2050, the BASE scenario is a result of extrapolated demand projections and technology and fuel choices driven by the model algorithm and the technology assumptions. No additional polices are implemented beyond those included in the Reference Scenario. Given the fact that CCS will incur additional costs, there is thus no role for CCS in this scenario.

Primary energy demand in the BASE scenario more than doubles in 50 years (Figure 4.2). The growth is mainly accounted for by coal, and to a lesser extent by natural gas and oil. In the absence of CO$_2$ policies, this scenario therefore implies a continued reliance on fossil fuels. The high growth-rate for coal can be explained by slower growth in coal prices compared to oil and gas prices, and introduction of new coal conversion technologies. CO$_2$ emissions in this scenario increase substantially because of the high growth-rate for coal. The important role of coal in this scenario implies considerable potential for CCS if proper regulations or financial incentives are put in place.

In the BASE scenario electricity production almost triples in the period 2000-2050. The bulk of electricity production growth is accounted for by fossil fuels. Production of electricity from coal more

than doubles, while electricity production from natural gas quadruples. Nuclear electricity production increases, but at a low rate. Production of electricity from renewables quadruples over 50 years. The share of renewables in the electricity mix increases from 19% in 2000 to 28% by 2050. The growth in renewables is accounted for by hydro, biomass/waste, geothermal and wind.

Figure 4.2

Primary energy demand projections in the BASE scenario

Key point: If no CO$_2$ policies were introduced, coal would account
for the bulk of the increase in primary energy supply
in the BASE Scenario over the next 50 years
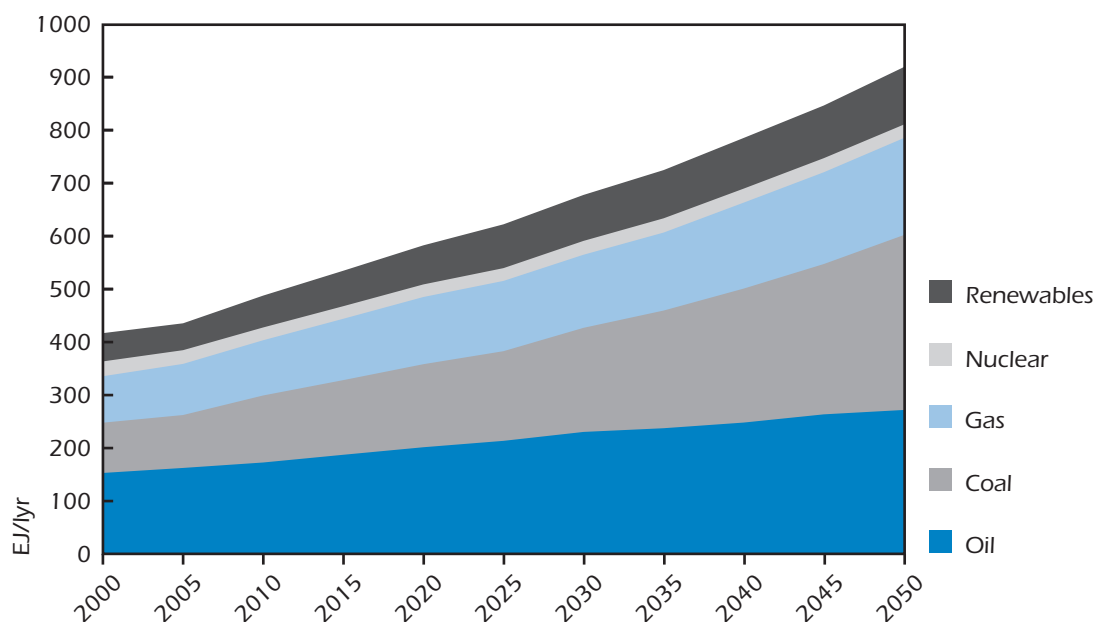
The GLO50 Scenario

This section discusses the CO$_2$ policy scenario entitled GLO50. The name GLO50 refers to the fact that this scenario includes a global CO$_2$ penalty at the level of 50 USD/t CO$_2$. The goal is to show the competitiveness of CCS in the three main application fields: electricity production, manufacturing industry and fuels supply. The discussion will allow the reader to understand better the ETP sensitivity analysis results outlined in the next chapter. Four specific scenarios are then discussed in Chapter 6, based on the analysis of the GLO50 results and the sensitivity analysis. These scenarios outline the future potential for CCS. It is worth noting at this stage that the GLO50 scenario should not be considered a 'best guess' scenario since a wide range of uncertainties can affect the results. **Given the high BASE emissions, optimistic assumptions for CCS and conservative assumptions for competing options in this scenario, the CCS results in GLO50 should be considered as an upper limit for the CCS potential.**

In a bottom-up model such as ETP, various types of policies can be simulated. For the analysis in this section, CO$_2$ policies are simulated by imposing CO$_2$ emission penalties. These CO$_2$ emission

penalties are invariably the costs incurred to deploy the relevant technologies (*e.g.*, because of regulations), but they can also be interpreted as the level of a tax on CO_2 emissions or the price of a tradable emissions permit on the market. According to standard economic reasoning, firms confronted with such 'prices' for GHG emissions will deploy all technologies that cost less than these 'prices'. Penalties are expressed in USD per tonne of CO_2 equivalent. They apply to all GHG emissions from the energy system.

Figure 4.3 shows the CO_2 penalties and the date at which they are introduced into the GLO50 scenario for each region. It is assumed that policies in developing countries are introduced at a later stage than in industrialized countries. The model input data specify that the penalty in industrialized countries starts in 2005, reaches the level of 50 USD/t CO_2 by 2015, and stabilizes thereafter. In developing countries, the policy is introduced in 2020 with the penalty reaching its maximum level by 2030.

While 50 USD/t CO_2 may seem a high burden for developing countries, it is not impossible that such penalty levels are applied in the long term, given the environmental concerns and the economic development potential. In the model scenarios, by 2050 per capita GDP in all regions except Africa is close to or higher than the per capita GDP in OECD Europe in 2000 (see Annex 3).

Figure 4.3

GHG penalties in the GLO50 scenario

Key point: In the model analysis, CO_2 penalties are introduced
by industrialized countries from 2005, reaching the level of 50 USD/t CO_2
by 2015 and stabilizing thereafter. In developing countries,
the policy is adopted 15 years later
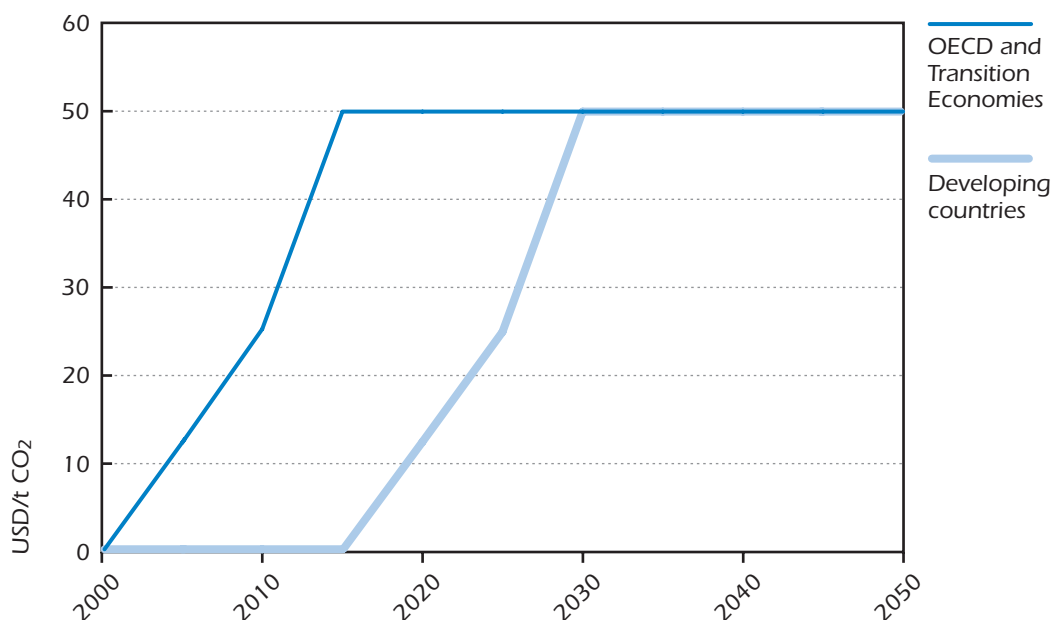
Figure 4.4 shows the CO$_2$ emissions in the BASE scenario and the GLO50 reference scenario. Note that **in the BASE scenario, the growth of CO$_2$ emissions between 2000 and 2050 is 1.8% per year, the same as for the period 1971-2000. The GLO50 scenario represents roughly a stabilization of global emissions at a level of 23-28 Gt CO$_2$/yr, which halves BASE scenario emissions in 2050.** This is a significant emissions reduction. A more detailed discussion in Chapter 5 will show that this scenario could be consistent with a stabilization of the atmospheric concentration of CO$_2$ at 550 parts per million (ppm).

Figure 4.4

Global CO$_2$ emissions, BASE and GLO50 scenarios

Key point: Emissions can be stabilized at a penalty of 50 USD/t CO$_2$
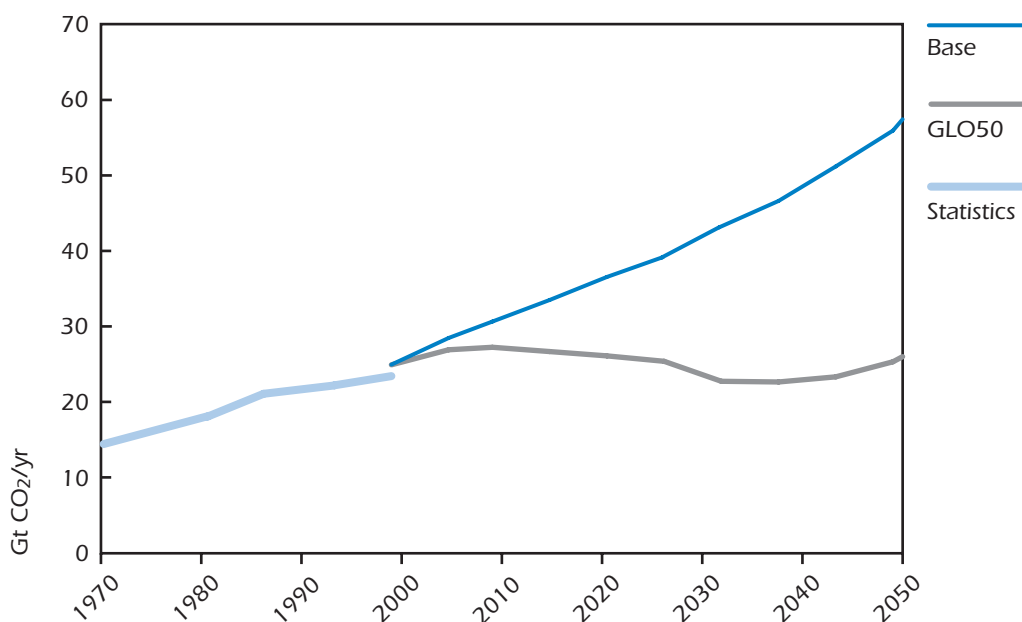
Note: Historical statistical data exclude CO$_2$ emissions from limestone calcination in cement production and other industrial process emissions, which explains the gap in 2000.

Source: IEA, 2002b.

Figure 4.5 shows the primary energy mix in the GLO50 scenario. Total primary energy use is about 850 EJ in 2050. This is some 8% lower than in the BASE scenario. This decline is the net result of fuel switching (which increases energy efficiency), demand-side energy efficiency measures, and increased energy use for CO$_2$ emission mitigation measures such as CCS.

In the GLO50 scenario, coal use is stable up to 2030, but shows strong growth beyond this date. Both coal and oil use in 2050 are significantly lower than in the BASE scenario. Gas use is virtually the same as in the BASE scenario. The use of renewables increases by 80%. Biomass use doubles and the use of wind more than doubles by 2050, compared to BASE. Nuclear shows no growth, but this is largely explained by the constraints applied to this energy source, in line with the *World Energy Outlook* (IEA, 2004a).

The results for CCS in the GLO50 scenario represent the upper limit of the potential role of CCS. This scenario includes speculative CCS technologies, but conservative estimates for competing emissions reduction options such as renewables and nuclear. The impact of different assumptions on CCS use is discussed in more detail in Chapter 5.

Figure 4.5

Primary energy mix in the GLO50 scenario

Key point: Compared to the BASE scenario, a penalty of 50 USD/t CO_2 results in significantly higher renewable energy use and a reduction in the use of coal
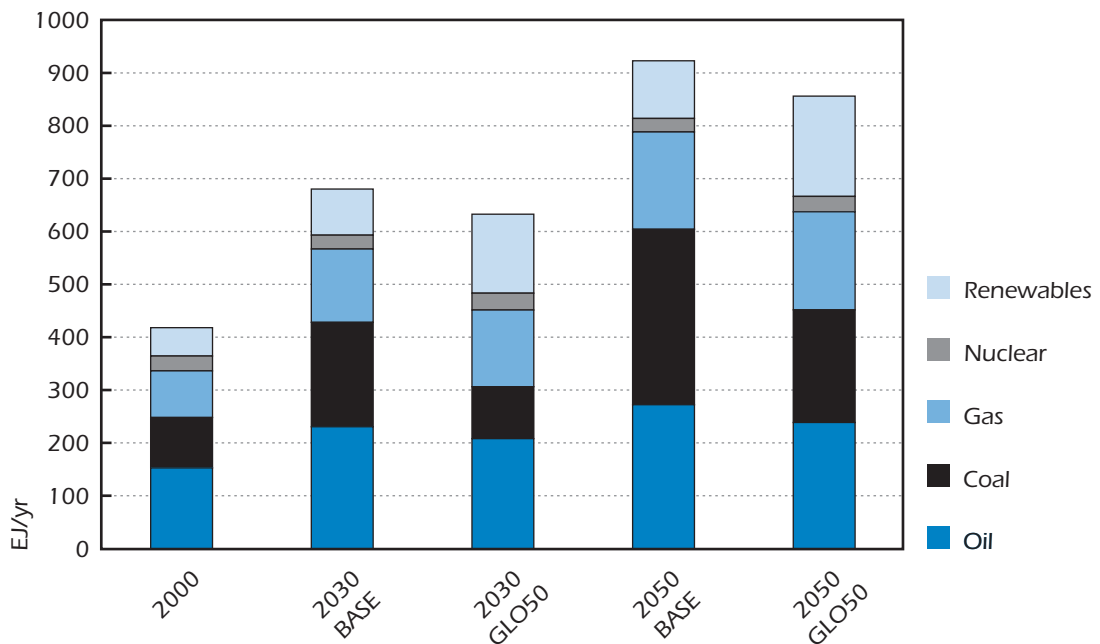
Figure 4.6 shows CO_2 capture in the GLO50 scenario by process area. Capture technology begins to be applied around 2015, increases to over 8 Gt by 2030 and to more than 18 Gt by 2050. These quantities should be considered as potentials, not as projections. The amount that is captured and stored can be compared to the 34 Gt of CO_2 emission reductions in this scenario by 2050, compared to the BASE scenario (Figure 4.4). The figures suggest that CCS represents a significant share of total emissions reduction. Note that the growth in CCS capacity between 2020 and 2030 is very rapid and may be unrealistic in terms of yearly expansion of the industry. No growth constraints have been applied to account for capacity expansion limitations such as regulatory procedures and slow growth of public acceptance.

Capture from power plants increases at a faster rate than capture in the manufacturing industry. The share of capture from power plants increases from 53% in 2020 to 80% of total CO_2 capture in 2050. This includes capture from industrial CHP installations and from plants which co-generate electricity and synfuels.

Figure 4.6

Global CO$_2$ capture by process area, GLO50 scenario

Key point: Capture from power plants represents
four-fifths of the cost-effective capture potential
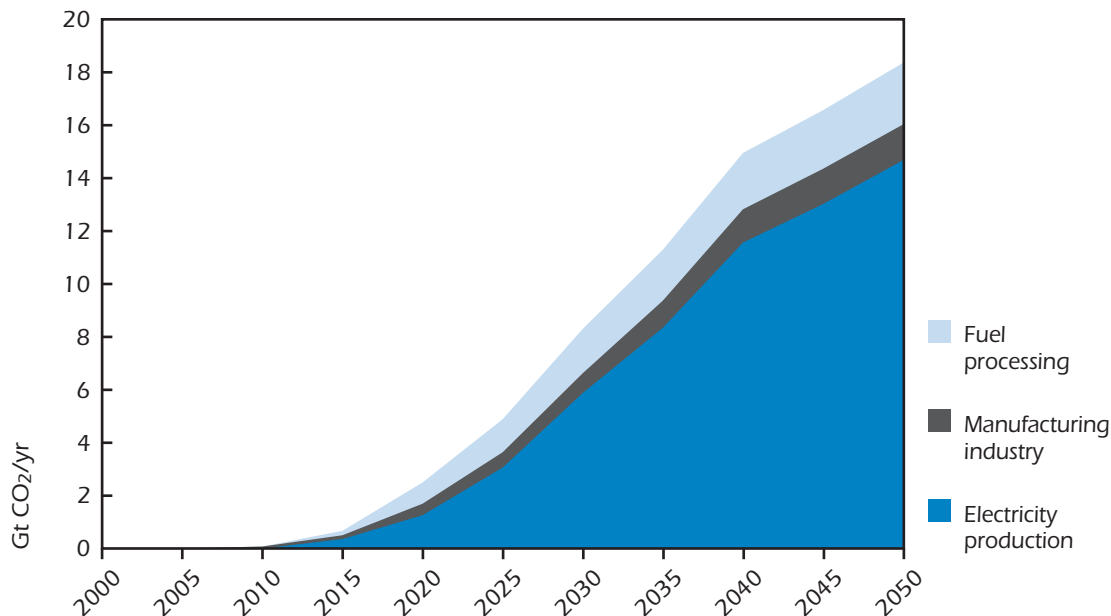
Note: The category electricity production includes capture from plants which co-generate electricity and synfuels as well as industrial CHP plants.

Out of the total quantity captured that is shown in Figure 4.6, 28% is from coal-fired processes in 2020. However, the share of coal increases to 65% by 2050. The remaining 35% is capture from natural gas, oil and biomass-fuelled processes, and to a lesser extent capture from cement kilns. This distribution indicates the importance of CCS for the future of coal in a CO$_2$-constrained scenario.

Figure 4.7 shows a subdivision of CO$_2$ capture by technology. The results suggest that **IGCC technology will play a key role in CCS.** This is closely related to the dominance of coal in the fuel mix. In this analysis, IGCC includes plants which co-generate electricity and synfuels. Chemical looping plays a secondary role compared to IGCC, while steam cycles with flue gas CO$_2$ capture are not selected. This result depends on the technology data assumptions. The impact of less optimistic assumptions for IGCC is discussed in Chapters 5 and 6.

Up to 2025, capture is concentrated in industrialized countries. Beyond 2025, capture in developing countries grows at a high rate. By 2050, 46% of total capture activity is undertaken in developing countries. This pattern can be explained by the assumption that there is a delayed introduction of CO$_2$ policies in developing countries and by the fact that growth in emissions over the next 50 years is concentrated in such countries. The high share of capture in developing countries in this scenario suggests that if CCS is not applied in developing countries, the total quantity captured worldwide will be much lower. This indicates that international co-operation regarding CO$_2$ emission mitigation is needed for the widespread uptake of CCS technology.

Figure 4.7

Total CO_2 capture split by technology, GLO50 scenario

Key point: IGCC with physical CO_2 absorption is the dominant
technology deployed to capture CO_2 from power generation processes
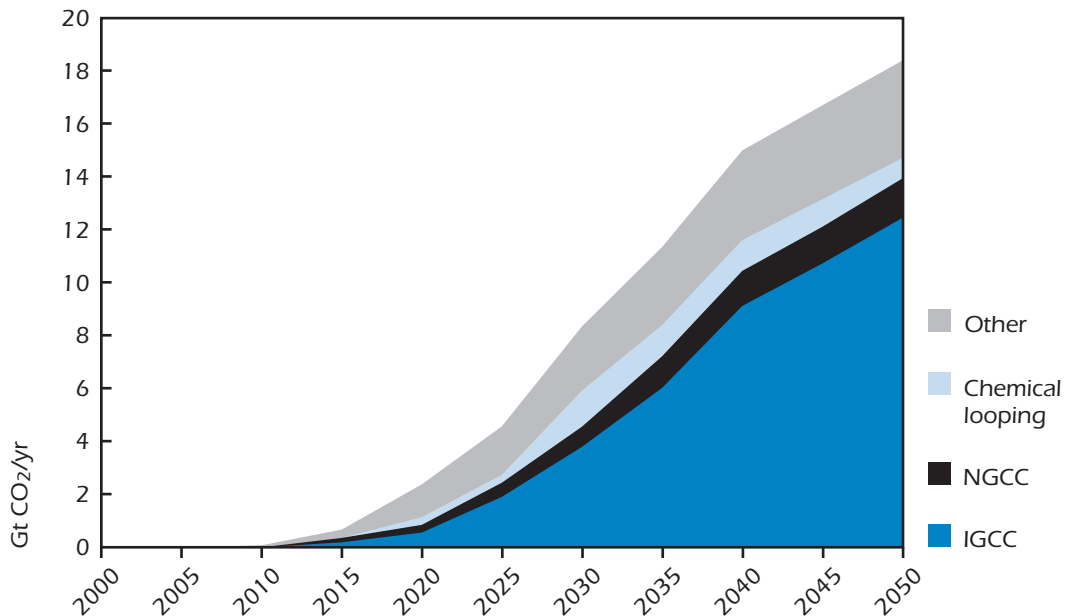
CCS and the WEO 2004 Alternative Policy Scenario

The World Energy Outlook 2004 Alternative Policy Scenario (APS) analyses the impact of faster deployment of many different types of end-uses and supply technologies. They range from hybrid vehicles to power generation fuel cells, from water solar heaters to distributed generation. The impact of the introduction of CCS and other breakthrough technologies is not included in the Alternative Policy Scenario. However, WEO 2004 presents an example where CCS is included as an add-on to the APS development.

In the Alternative Policy Scenario, about 136 GW of new coal-fired power-generation capacity and 38 GW of new centralized gas-fired capacity are expected to be built in OECD countries between 2015 and 2030. New capacity additions in the transition economies and the developing countries are larger. The WEO-CCS example assumes that all new capacity in OECD countries built after 2015 is equipped with CO_2 capture technology and that this capacity is matched by a similar amount in non-OECD countries. By 2030, the reduction in CO_2 emissions would be between 1.5 and 2 gigatonnes, depending on the utilization rate of the power plants and the energy consumed in capturing and pressurizing the CO_2. Taking the average of 1.75 Gt, the total emission reduction in the APS would increase from 16% to 21% compared with the Reference Scenario.[1] CCS would in this case cover 5% of total world generation capacity in 2030, compared to 36% for renewables-based generation.

1. This analysis does not take into account the cost-effectiveness of CCS compared with other options for reducing emissions, such as energy efficiency and renewables.

The potential for CCS in this example is significantly lower than in the GLO50 scenario. In the GLO50 scenario more than 900 GW of power generation capacity is equipped with CCS technology by 2030, of which 580 GW is coal-fired resulting in 8.3 Gt CO_2 being captured. There are several reasons for the difference between the WEO Alternative Policy Scenario example and the GLO50 scenario: the most important is that in the APS a large share of new OECD generating capacity is based on decentralized gas-fired generation and there is thus very modest growth in new centralized coal generation after 2015. Since only centralized plants are considered to be equipped with CCS technology in this example, this significantly reduces the potential. In the WEO Reference Scenario the growth in centralized gas and coal-based power generation is much higher. If, instead, CCS had been considered as an add-on to this scenario, it would have shown a potential for 4.7 Gt CO_2 capture by 2030.

Moreover, in the WEO analysis CCS is only considered for new centralized power plants and is, therefore, excluded from industry, fuel-processing plants and electricity and synfuel cogeneration plants. In 2030, 29% of the total amount of CO_2 that is captured in the GLO50 scenario is outside power generation. This share declines to 20% by 2050. Within the electricity sector, in the GLO50 scenario plants that co-generate electricity and synfuels account for 2 Gt capture in 2030, rising to 10 Gt CO_2 capture in 2050. This option doubles the capture potential in the electricity sector, and it was not considered in the WEO analysis.

CO₂ capture in the electricity sector

In the GLO50 scenario with CCS, electricity production capacity almost triples from 3.5 TW in 2000 to 10.3 TW by 2050. This includes industrial CHP plants and plants that co-produce electricity and synfuels. **Power plants with CO₂ capture represent 22% of total installed capacity by 2050. This is almost half the total installed capacity of fossil-fueled power plants.**

The electricity production mix in the GLO50 scenario is shown in Figure 4.8. Total production amounts to 153 EJ in 2050, compared to 148 EJ in the BASE scenario. Electricity production almost triples in the period 2000-2050. The small increase in GLO50 compared to BASE in 2050 can be explained by a higher share of electricity in the final energy demand. Additional electricity use for CCS is not accounted for explicitly; it will show up as a reduction in the power plant efficiency and, therefore, as increased fuel use in the electricity sector.

The production share of fossil-fueled power plants with CCS increases to 39% by 2050. This includes coal-fired power plants where biomass is co-combusted. If the share is corrected for biomass co-combustion, fossil fuels with CO₂ capture represent 37% of total electricity production. **The share of CCS in electricity production is much higher than the share of electricity production capacity. This can be explained by the high load factor for these facilities with CO₂ capture, and a declining load factor for plants without capture.** The reason for this change in load factors is that plants without CO₂ capture are operated as middle-load and peaking plants, while plants with CCS are operated as base-load plants. This, in turn, can be explained by the comparatively high marginal cost of power production from fossil fuels without CO₂ capture, if a CO₂ penalty is introduced. The share of fossil fuels in electricity production declines from 64% in 2000 to 54% in 2050. This is compensated by an increased share of renewables in the electricity mix, which increase from 19% in 2000 to 40% by 2050. The main increase of renewables comes from wind, biomass and hydro.

Figure 4.8

The electricity production mix, GLO50 scenario

Key point: Electricity production from power plants equipped
with CCS increases to over a third of total production by 2050
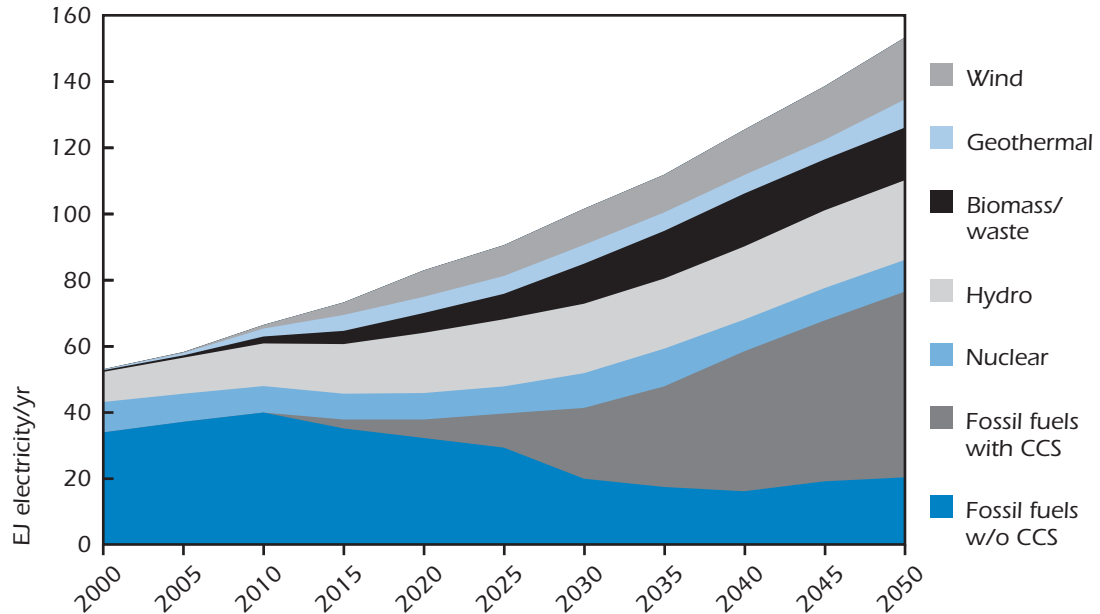
The future of decentralized power generation

Decentralized power generation has received considerable attention. During the past decade, most attention was focused on micro turbines and Stirling engines and renewables. In recent years, attention has switched to fuel cells. CHP is the largest existing decentralized market. Large-scale CHP systems (based on gas turbines and boilers) represent 96% of the CHP market worldwide (WADE, 2003). Decentralized power supply systems based on renewable energy have been introduced in developing countries where a transmission and distribution system is lacking. Sparsely populated regions of industrialized countries, high grid connection costs and the availability of renewable resources can also result in a switch to decentralized generation (Swisher, 2002). However these conditions apply to niche markets with different characteristics from densely populated urban areas, where security of supply and higher energy efficiency would be the main advantages of CHP use.

While CHP systems have reached maturity on a 1 MW+ scale, they are not yet widely applied on a smaller scale although there is potential in the residential and commercial sectors. Their main appeal would be savings in transmission costs and losses. However, the 40-50% electric efficiency of a gas-fired fuel cell is much lower than the 60% electric efficiency of new centralized gas-fired power plants. In CHP mode there are heat benefits of fuel cell systems but such systems require applications with a continuous heat demand, not only seasonal space heating or cooling.

Fuel cells for CHP have long-term potential (Pehnt, 2004). It can be argued that decentralized systems increase supply security, but this will depend on the reliability of the technology applied. Current decentralized systems (usually diesel engines) are often operated as back-up systems, so they do indeed increase reliability. However, it is debatable whether a decentralized system without a grid connection would increase security of supply. Another disadvantage is that CCS would not be feasible for small-scale fuel cell systems. If zero emissions in power generation are the aim, a hydrogen supply system would be needed, similar to existing natural gas pipeline systems.

In its Reference Scenario, the IEA World Energy Outlook projects 98 GW of fuel cell capacity by 2030. This represents about 1.3% of global electricity capacity (IEA, 2004a). In the Alternative Policy Scenario, global electricity generation from fuel cells using hydrogen from reformed natural gas is 530 TWh, twice as high as in the Reference Scenario in 2030. This projection suggests that hydrogen demand will be limited. Moreover, in regions where hydrogen can be supplied by pipeline, electricity transmission must be a viable alternative. Distributed generation based on hydrogen fuel cells is, therefore, considered a topic of secondary importance for CO₂ emission reduction. A rapid expansion of distributed renewable electricity generation, especially in developing countries, could limit the need for new centralized capacity and, therefore, reduce the need for CCS.

However, fuel consumption for electricity production remains stable up to 2025. This can be explained by a significant efficiency gain for fossil-fueled power plants during the period 2000-2025. Moreover, in the IEA accounting the primary energy equivalents of wind, geothermal and hydro electricity are equal to the amount of electricity produced. This is equivalent to a conversion efficiency of 100%. Therefore, switching from fossil fuels to renewables in the period 2000-2050 adds to power sector energy efficiency gains. The combined effect of increased production and efficiency gains is a stabilization of fuel use up to 2025.

From 2025 to 2050, fuel use doubles to reach 330 EJ. The reason for this is that electricity and transportation fuel cogeneration plants are introduced. These plants use more fuel per kWh of electricity produced, which results in increased fuel use. Moreover, these cogeneration plants use coal as a fuel. The increased share of coal in the electricity mix also results in a drop in average efficiency.

Figure 4.9 shows efficiency trends for coal and gas-fired power plants. CHP plants are excluded from this analysis. For plants that co-generate electricity and transportation fuels, a correction has been applied, based on fuel use for stand-alone synthetic transportation fuel production. The efficiencies in 2000 are gross efficiencies; net efficiencies are 1-2 percentage points lower.[2] All new power plants in the ETP model are characterized on a net basis, meaning that in 2050 all efficiency figures are on a net basis.

The model suggests important efficiency gains for coal and gas-fired power plants in the BASE scenario. **For coal, global average efficiency increases from 32.1% in 2000 to 43.2% by 2050. For gas, average efficiency increases from 36.1% in 2000 to 53.8% by 2050. These efficiency**

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2. Net efficiencies cannot be tracked from the IEA statistics because own electricity use by power plants is only reported as an aggregate for all fuels.

gains are the result of the replacement of old low-efficiency power plants, technological improvements, and increasing fuel prices that result in a switch to higher-efficiency power plants purely for economic reasons.

For gas, and to a lesser extent for coal, gains in the GLO50 scenario are smaller than in the BASE scenario because of additional power-plant electricity use for CO_2 capture and pressurization. The efficiency loss is to some extent compensated for by choosing more efficient power plant technologies. The efficiency level shown in Figure 4.9 is an average for power plants with and without CO_2 capture. This average efficiency is in fact 3-6% lower (a 1 to 3 percentage point reduction) in a scenario with CCS.

Figure 4.9

Efficiency trends for coal and gas-fired power plants

Key point: Future power plant efficiency increases by a third for coal and by two-thirds for gas
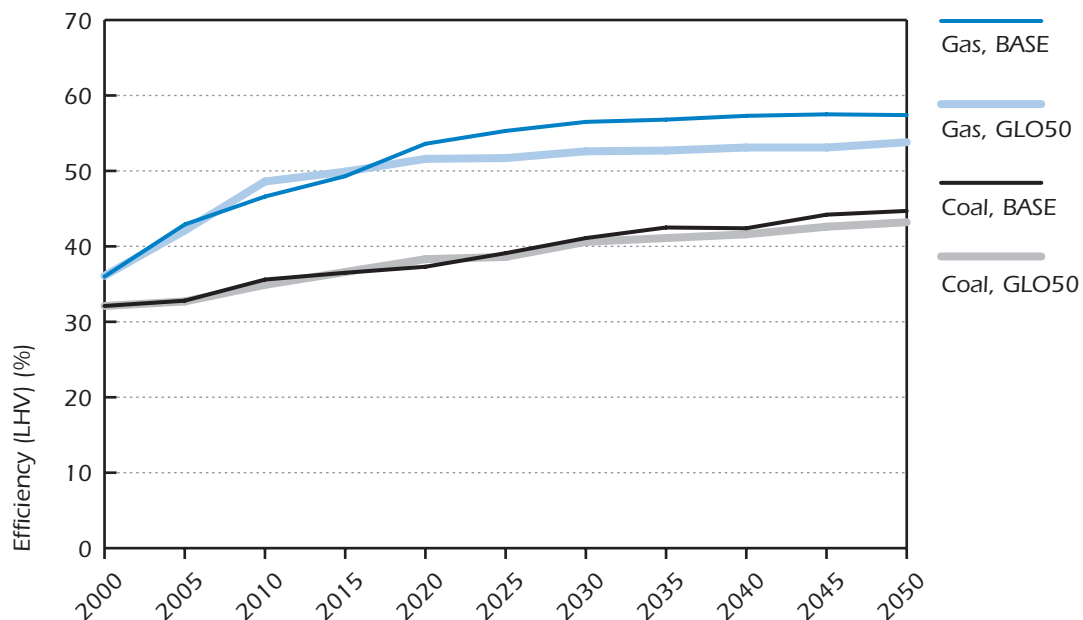
Note: Coal includes hard coal and lignite. Corrected for the co-production of synfuels. Efficiencies in 2000 are gross efficiencies, net efficiencies are 1-2 percentage points lower. Efficiencies in later decades are net efficiencies.

Figure 4.10 shows electricity production from power plants fitted with CO_2 capture. Total production amounts to 27 EJ in 2030 and 64 EJ by 2050. **Coal-fired power plants represent 60% of total electricity production capacity fitted with CCS in 2030. This percentage increases to 69% by 2050 (25% of total power production). Gas-fired power plants represent 28% of all power plants with CCS in 2030, declining to 23% by 2050 (8.4% of total power production).** The remainder is dedicated biomass-fired power plants fitted with CO_2 capture. Significant amounts of biomass are also co-combusted in coal-fired power plants, meaning that the share of coal with CO_2 capture is in fact somewhat lower and the share of biomass somewhat higher.

From 2025 onwards, **IGCC plants producing both electricity and synfuels show strong growth. Three-quarters of the synfuel produced is hydrogen, while the remainder is DME.** Hydrogen is used in equal parts by the transportation sector and by industry as a substitute for natural gas.

Note that hydrogen and DME are the only two synfuels for which co-production with electricity is considered. In principle, other synfuels such as methanol, low-sulphur diesel and naphtha could also be produced (Espinoza *et al.*, 1999; Steynberg and Nel, 2004). These fuels could be used in the existing transportation infrastructure. However, combustion of hydrocarbon synfuels results in CO_2 emissions. Overall, the CO_2 benefits will therefore be smaller if a carbon-containing synfuel is produced than if hydrogen is produced. So far, South Africa is the only country that produces synfuels from coal on a large scale, although China has announced its intention to produce 60 Mt of synfuels from coal by 2030, based on Sasol technology. Such plants would produce fuels and electricity in an 8:1 ratio in energy terms and achieve 46% overall energy efficiency (Steynberg and Nel, 2004).

The plants considered in this analysis would produce synfuels and electricity in a 2:1 ratio (for DME production) or in a 2:3 ratio (for hydrogen), and achieve an overall energy efficiency of 50-53%. Results could be affected by different technology assumptions. In a sensitivity analysis the impact of synfuel cogeneration technology has been analysed in more detail (see Chapter 5).

Figure 4.10

Electricity production from power plants fitted with CCS, by technology and fuel, GLO50 scenario

Key point: IGCC plants used for electricity and synfuel cogeneration dominate total power plant capacity fitted with CCS
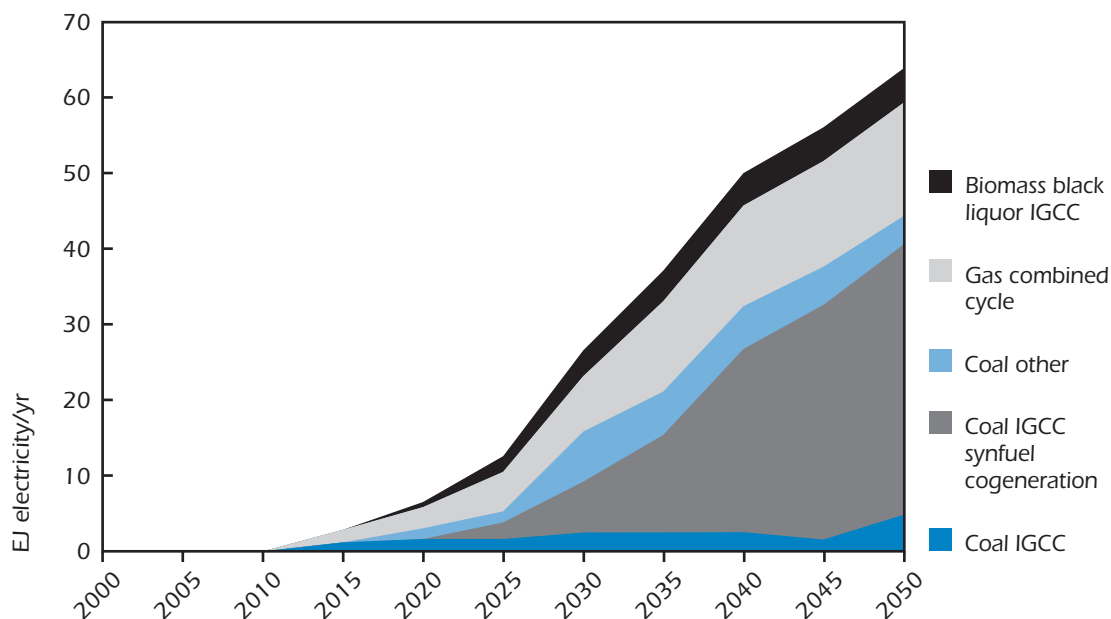
CO₂ capture in the manufacturing industry

Figure 4.11 shows CO_2 capture in the manufacturing industry. **Capture from manufacturing is an order of magnitude smaller than capture from electricity production plants. It can be split into three parts: ammonia production, cement kilns, and iron and steel production (blast furnaces and DRI production). These three sources are of similar importance.** While capture from ammonia and DRI plants is based on established technology, capture from cement kilns and blast furnaces is a new concept that may require major process adjustments. The future role of these sources is

therefore less certain than capture from ammonia plants. In the GLO50 scenario, CCS from ammonia plants starts in 2010. This represents an early application of the technology with low capture cost.

While the CCS potential in the manufacturing industry is initially significant, in later decades it is restricted by the limited growth of BASE scenario emissions. The growth rate of emissions in the electricity sector is much higher. One reason for this is the assumed global trend towards dematerialization of economic growth.

Note that in this study CHP plants fitted with CO_2 capture are allocated to the electricity sector. The bulk of these plants would actually provide heat to industrial firms, and may be owned by such firms. Also, the results suggest some hydrogen delivery to industry for stationary use. This hydrogen is produced from fossil fuels with CO_2 capture. CO_2 captured from the production of this hydrogen is allocated to the fuel-processing industry or the electricity sector. Given such linkages, one could argue that the use of CO_2 capture in industry is in fact higher than that indicated in Figure 4.11.

Figure 4.11

CO_2 capture in the manufacturing industry, GLO50 scenario

Key point: Capture from industry offers early opportunities,
but has limited long-term potential
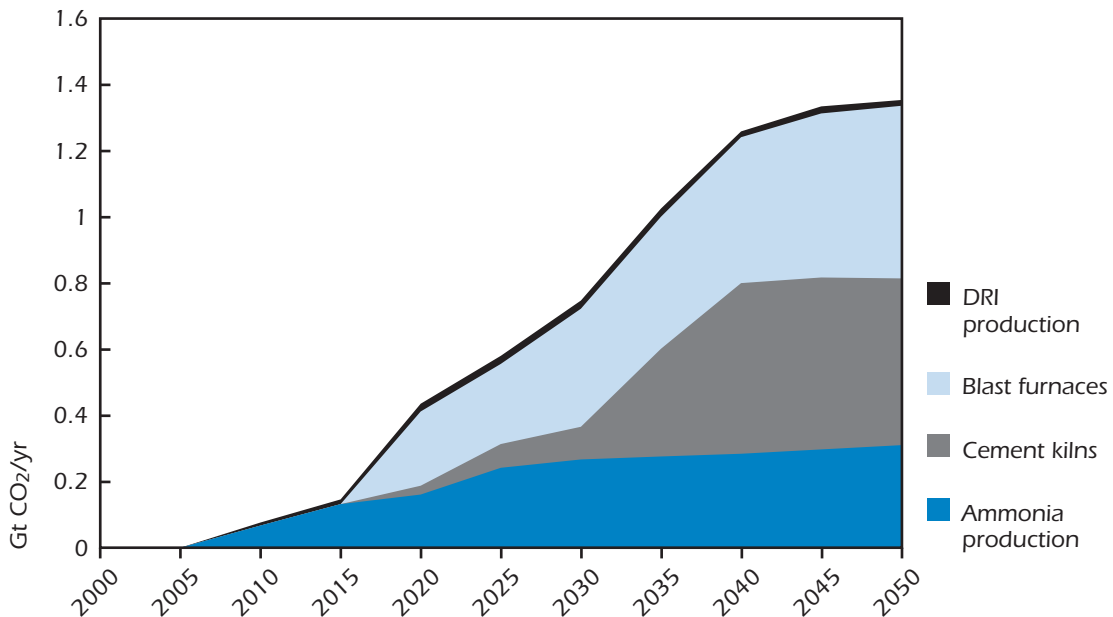
CO_2 capture in the fuels supply

Figure 4.12 shows CO_2 capture potential from fuel production processes. The total quantity captured is an order of magnitude smaller than that captured from the electricity sector. Roughly 40% is captured from hydrogen production processes that use natural gas, and another 40% is captured in the Fischer-Tropsch synthesis of transportation fuels that use biomass and coal. The remainder is captured from refineries, particularly coking units for heavy residues and tar-sand processing plants.

As mentioned earlier, CO_2 capture in cogeneration of electricity and synfuels is allocated to the electricity sector. **Capture from the cogeneration of electricity and synfuels is of much more importance than capture from dedicated synfuel production units. The capture from cogeneration plants amounts to 10 Gt CO_2 by 2050, two-thirds of which represents capture from electricity and hydrogen cogeneration plants. The capture from these cogeneration plants represents 54% of total CO_2 capture by 2050.**

Figure 4.12

CO₂ capture in the fuels supply sector, GLO50 scenario

Key point: There is considerable potential for capturing CO_2
from hydrogen production, fuel refining and FT synthesis processes
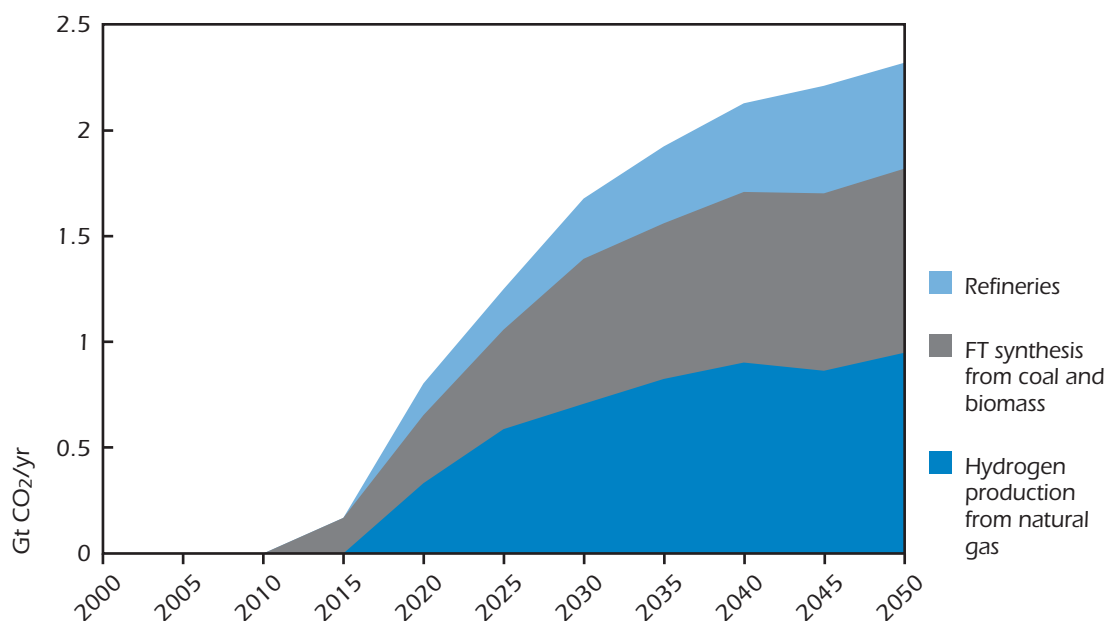
FT = Fischer-Tropsch

CO₂ storage

Figure 4.13 shows the results for CO_2 storage under the GLO50 scenario. **Storage is roughly evenly divided between aquifers and depleted oil and gas fields, including enhanced oil and gas recovery operations (EOR and EGR).** This is a result of the global distribution of potential storage sites and emission sources. Total cumulative storage over the period 2000-2050 amounts to 387 Gt, a small share of the total global storage potential, or roughly half the amount that can be stored worldwide in depleted oil and gas reservoirs.

In a least-cost optimization model such as ETP, one might expect that CO_2 use for enhanced fossil fuel production is chosen first. However, only 3% of the current world oil production is based on EOR. The remaining 97% is based on primary and secondary production technologies. The growth of EOR in general limits the growth of CO_2 EOR. In fact, CO_2 EOR has been applied on a limited scale for the past 25 years, and opportunities are likely to increase gradually over the next 15 years as production in certain basins such as the North Sea and the Gulf of Mexico matures. A similar

explanation can be given for the EGR model results. Also, CO_2-EOR competes in practice with other EOR options. Many oil and gas fields are in remote regions, far from sources where CO_2 could be captured. In such cases, the effort to bring CO_2 to the site must be compared to the cost of alternative EOR technologies. The model results regarding CO_2 use for EOR are subject to significant uncertainties. A proper assessment of the potential would require detailed field-by-field data, which is beyond the scope of the ETP model analysis.

Wherever there is an opportunity to generate revenues using CO_2, while achieving long-term storage, such opportunities should be used. The results suggest that such opportunities are not critical for the feasibility of CCS, however. This enhances the robustness of the results, as such fossil fuel revenues constitute a source of uncertainty. The timing for the introduction of EOR and EGR assumed in this analysis should be considered merely indicative, with an accuracy of ±10 years. With EGR, it is important to bear in mind that this is a speculative technology, and that benefits will in most cases be small, compared to benefits for EOR. Therefore, storage in depleted gas fields and EGR are considered as one single category in Figure 4.13.

Figure 4.13

CO_2 storage in the GLO50 scenario

Key point: Half of CO_2 is stored in aquifers
and the rest in oil and gas reservoirs
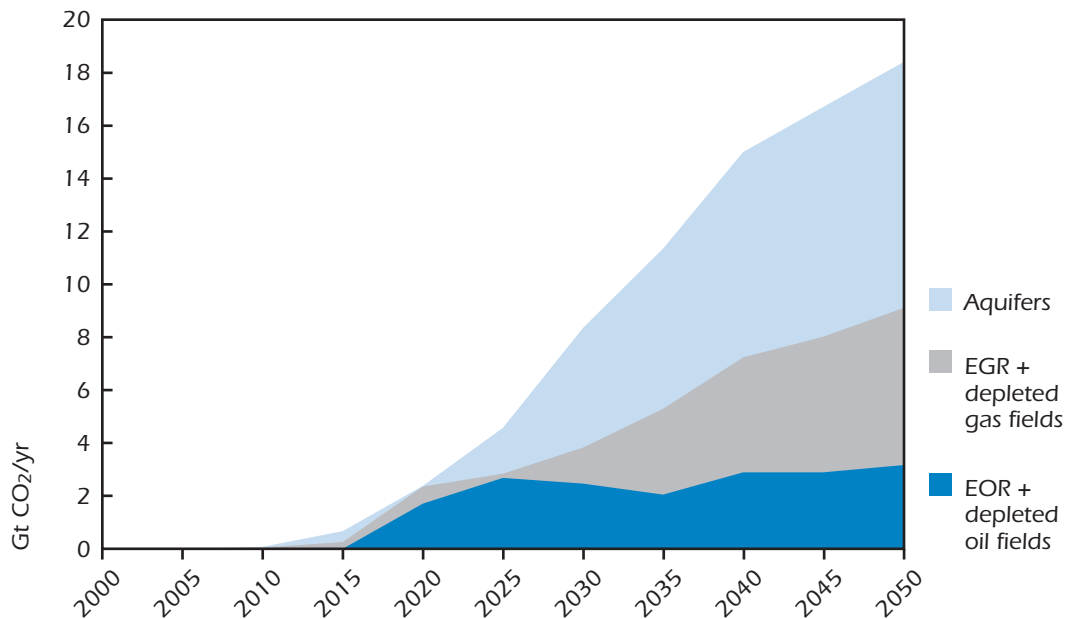
EOR = enhanced oil recovery, EGR = enhanced gas recovery.

CCS Compared to other Emission Reduction Options

This section discusses the environmental and financial benefits of a CCS options, compared to other CO_2 emission reduction options in the energy sector. The analysis is split into two parts. First, the GLO50 scenario with and without CCS are compared. This builds on the analysis in the previous section. Next, four model runs, with and without CCS and nuclear, are compared. This analysis

provides insights regarding the financial benefits of having CCS, compared to other emission mitigation options.

In order to assess the benefits of CCS, the GLO50 scenario and the same scenario without CCS technologies (GLO50noCCS) are compared in this section. Comparing results at the same policy incentive level with and without CCS illustrate the benefits of CCS and its impacts on the energy system.

Firstly, CO_2 mitigation benefits are discussed. Figure 4.14 shows CO_2 emissions in a GLO50 case with and without CCS. The difference amounts to 4.6 Gt in 2030 and 7.9 Gt by 2050. **Without CCS, CO_2 emission reduction declines by about 20%, with emissions 28% higher compared to the same GLO50 scenario with CCS.**

Figure 4.14

CO_2 emissions with and without CCS

Key point: Without CCS, total emission reduction potential declines by one-fifth
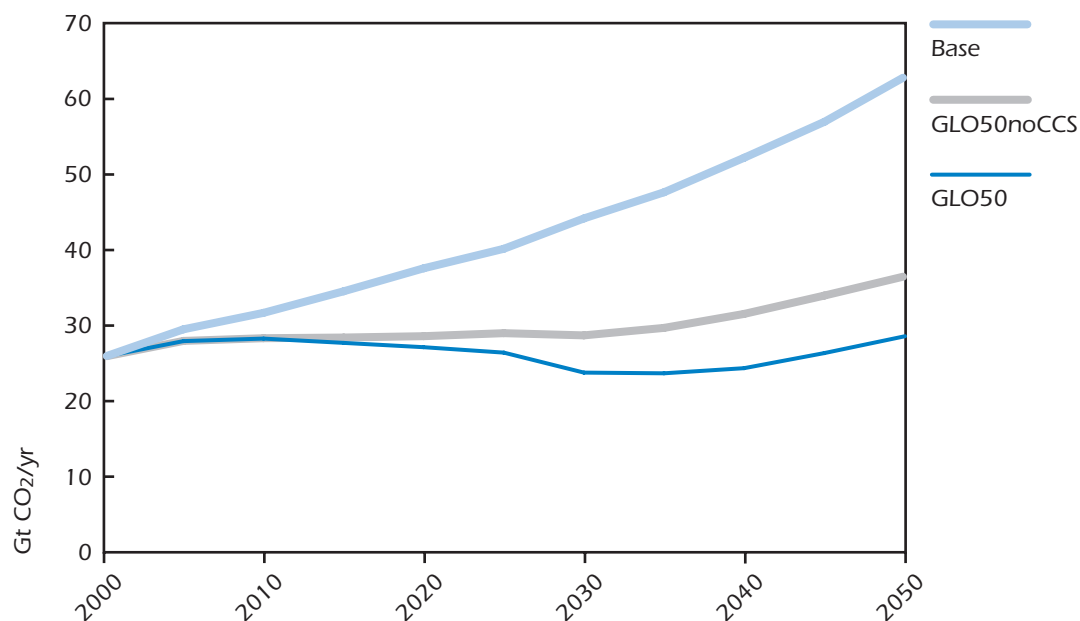
Secondly, the economic benefits of CCS are discussed. In Figure 4.15, the cumulative emission reduction for the period 2000-2050 is shown as a function of the CO_2 penalty. **With ambitious policy targets, allowing for CCS cuts by half the penalty needed to reach a certain cumulative emission reduction.** When CCS is not considered, other emission reduction options can be applied to reach the same targets, but the cost will increase. For example, the undiscounted cumulative systems cost to reach the GLO50 scenario cumulative emission reduction without CCS increases by 11 trillion USD, or 63%. This result does, however, depend critically on the technology learning assumptions for renewables and the ambitious policy target, and should be considered a high end estimate.

Figure 4.15 also shows the cumulative CO_2 capture in the period 2000-2050. The quantity captured equals some 43-58% of the total cumulative emission abatement. The area between the curves with and without CCS is smaller and indicates that **the actual emission reduction of CCS is only**

40-45% of the quantity captured. This is due to the additional energy used for CO_2 capture and pressurization and related emissions, and certain leakage effects (more coal use and less use of other fuels with low associated CO_2 emissions).

The cumulative capture increases with the penalty level. This shows that there is indeed no single cost figure for CCS, as discussed in Chapter 3. Instead, a cost range exists. The shape of the curve indicates that the additional cumulative capture decreases for each USD increase of the penalty. Most of the CCS potential is below 50 USD/t CO_2. For CCS, the additional capture in the case of higher penalties is limited. The impact of the penalty level on CCS use is studied in more detail in Chapter 6.

Figure 4.15

Cumulative emission abatement for 2000-2050 as a function of the penalty level

Key point: Up to 2050, the cumulative reduction in CO_2 emissions is one-fifth lower if CCS is not considered than it would be if CCS was applied. This shows the environmental benefits of CCS
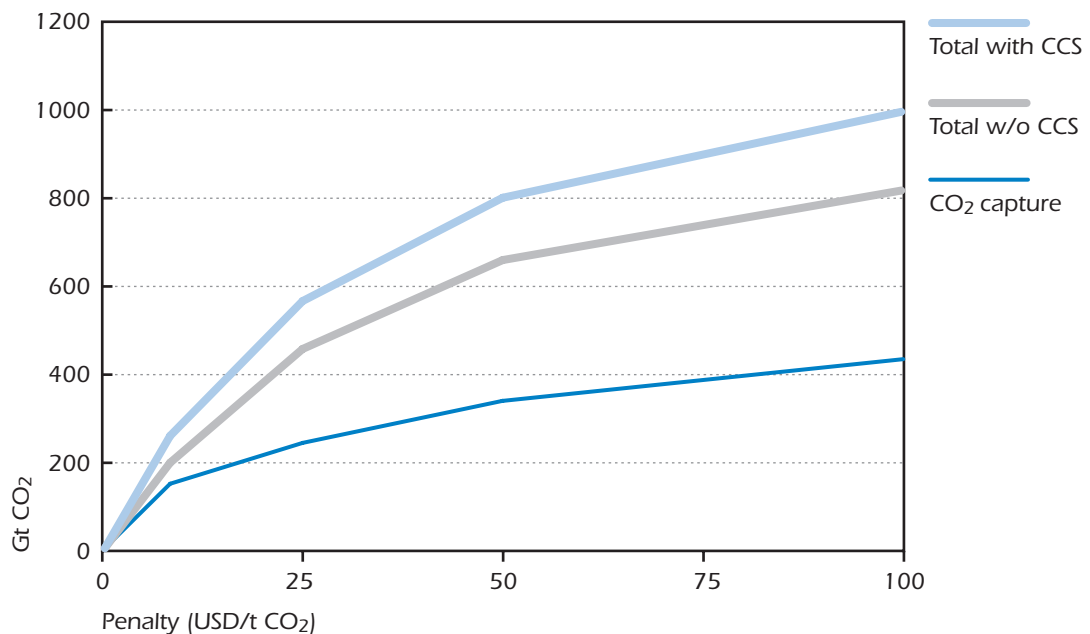
The comparison of the GLO50 model results with and without CCS also provides insights into the impact of CCS use on fuel markets. Chapter 7 studies this analysis in more detail. Without CCS, coal use declines over the next 50 years. With CCS available, coal use doubles. This increase is compensated by a reduced growth of renewables and by reduced energy efficiency gains, compared to a scenario without CCS. The results suggest that the fuel market consequences of CCS could be substantial on a global scale.

Next, the global annual emissions are fixed as in the GLO50 scenario, and the set of options available to reduce the emissions is varied. Four combinations with and without nuclear and/or CCS are analysed: no CCS and nuclear (no NUC+CCS), CCS, NUC and CCS+NUC. In this approach, the CCS case is almost equivalent to the GLO50 case. Small differences can occur because the emission constraint that is imposed in the model in the CCS run is applied to the world as a whole, while

the penalty in the period 2005-2030 in the GLO50 scenario differs for industrialized countries and developing countries. In the CCS run, the model chooses cheaper emission reduction options in developing countries in the period 2005-2030 instead of applying costly options in industrialized countries that are selected in the GLO50 scenario. From 2030 onwards, however, GLO50 and the CCS case are virtually identical.

The NUC case allows for unlimited nuclear growth in OECD countries, and 10% annual growth potential in developing countries, while nuclear growth potentials in all runs without NUC are halved in developing countries, and a maximum nuclear use is defined for OECD countries, in line with the WEO Reference Scenario (IEA, 2004). The actual nuclear investment depends on cost-effectiveness, compared to other zero emission strategies.

The resulting marginal emission reduction costs are shown in Figure 4.16. These show that indeed the CCS case is almost equivalent to the GLO50 scenario, with the marginal cost from 2030 onwards at 50 USD/t CO_2. The average emission reduction cost is shown in Figure 4.17. As could have been expected, the lowest cost occurs for the scenario where both options are considered (CCS+NUC), while the highest cost occurs for the scenario with no CCS+NUC.

Figure 4.16 shows that **the marginal emission reduction cost in the period 2030-2050 is halved if CCS is considered.** The benefits of having nuclear only are more limited. This can be explained by the fact that nuclear is an emission reduction option for the electricity sector only, while CCS can be applied more widely. Especially at ambitious emission reduction targets (as is the case here), emissions must also be reduced outside the electricity sector.

Figure 4.16

Marginal emission reduction cost with various sets of options available

Key point: If CCS is considered, the marginal emission
reduction cost is halved
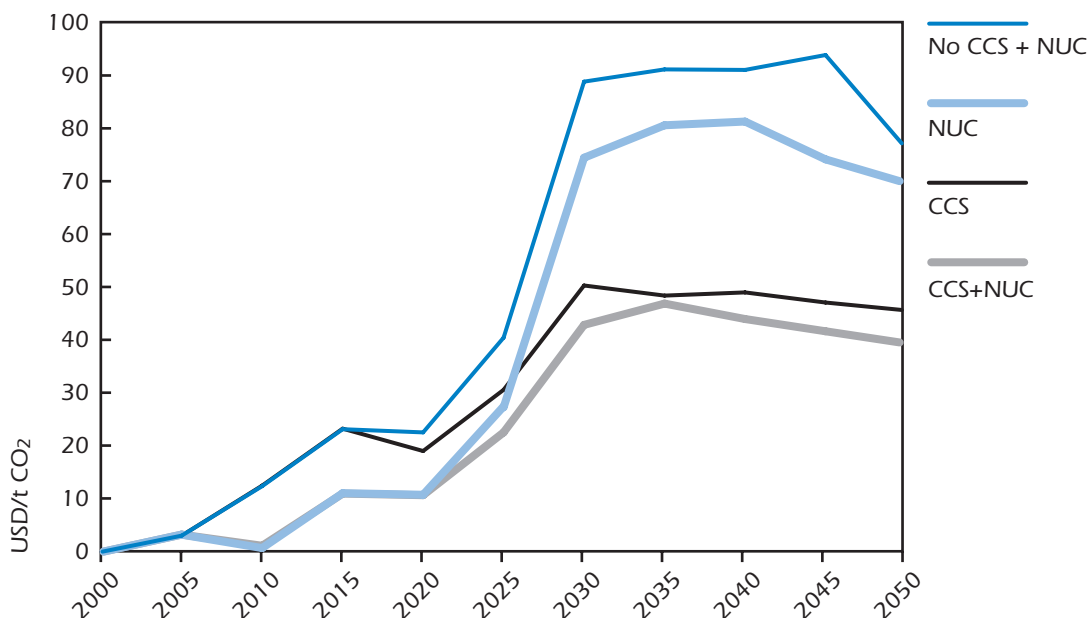
NUC = nuclear

The average emission reduction cost declines by a third if CCS is considered (Figure 4.17). But the CCS benefits depend on the availability of nuclear energy. If nuclear is available, the benefits of having CCS on top of that amount to between 5-10 USD/t CO_2 in the period 2030-2050.

Figure 4.17

Average cost of emission reduction with various sets of options available

Key point: If CCS is considered, the average emission reduction cost declines by a third
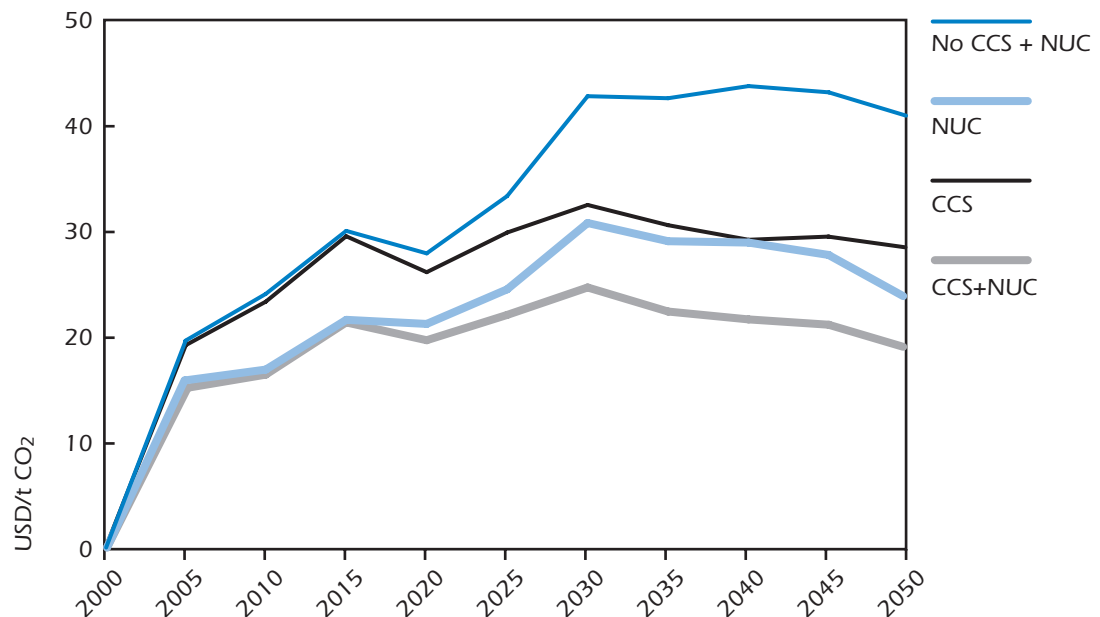
NUC = nuclear

Chapter 5.
CCS SENSITIVITY ANALYSIS

H I G H L I G H T S

- The use of CCS is not limited by storage constraints or by capture possibilities, but is affected by the cost of competing technologies (such as renewables) and emission mitigation measures (such as land use change and reduction of non-CO_2 greenhouse gases), as well as by policy decisions regarding acceptable levels of climate change risk. Sensitivity analyses suggest that, overall, CCS is a robust option from a cost-effectiveness perspective.

- For penalties ranging from 10 to 100 USD/t CO_2, the CCS potential in 2050 ranges from 8 to 25 Gt CO_2 per year.

- At penalties above 15-20 USD/t CO_2, the fraction of CCS in total emission reduction is virtually constant. Under a scenario of optimistic CCS technology assumptions, its share represents over 50% of total emission reduction in 2050.

- In case of a penalty of 50 USD/t CO_2, a 10-15 year delay in putting CCS policies in place results in a 20% decline of the cumulative amount of CO_2 captured over the whole period 2000-2050. This indicates the importance of timely action. However the quantities captured in later decades are virtually the same.

- Variations in the price of oil or gas do not significantly affect the CCS potential.

- Policies that account for a possible decline of conventional oil supply in the long term may favour more CCS use in combination with synfuel production.

- The prospects for competing CO_2-free electricity options, progress in CO_2 capture technology, and the inclusion of developing countries in a global emission reduction effort are key factors for the future prospects of CCS.

- A CO_2 penalty limited to OECD countries results in a 53% decline of the CCS potential in 2050. If commodity trade barriers are completely removed, such a scenario could result in industry relocation to countries without CO_2 policies. This would result in a substantial further decline of the CCS potential.

- The potential of CCS is to some extent influenced by GDP growth, especially by the global distribution of this growth.

- In the case of more optimistic learning assumptions for renewables than in the GLO50 reference scenario, the CCS potential declines by up to a quarter. CCS could be considered as a transition strategy until the full potential of renewables is developed.

- If nuclear competes on a cost basis alone, the role of CCS could decline significantly, particularly in Japan and the USA. However, such a scenario is unlikely, given that any significant expansion of nuclear power in these regions would depend on a change in public acceptance and on resolving issues associated with radioactive waste disposal.

- Ultra-supercritical steam cycles (USCSC) and IGCCs with CO$_2$ capture could both play an important role as efficient and cost-effective generation options for coal. This finding suggests that CCS is a robust option, independent of the market acceptance of IGCC.

- Without certain promising but speculative CCS technologies such as IGCC with synfuel cogeneration and chemical looping, total capture declines by a third.

This chapter presents the sensitivity analysis on the GLO50 Scenario that was discussed in Chapter 4. The goal of sensitivity analysis is to quantify the uncertainty that surrounds the ETP results. Understanding it is a key part of determining if and how CCS should be applied.

The sensitivity analysis indicates that a number of key parameters can significantly impact the potential of CCS. The variations on these parameters may interact, reinforcing each other or cancelling each other out. Such interactions are assessed in more detail in the scenario analysis that is presented in Chapter 6.

It is worth noting that the ETP sensitivity analysis presented here, together with the scenario analysis in Chapter 6, solely concern uncertainties which are within the scope of the ETP model. Certain other uncertainties, such as the legal and public acceptance issues associated with CCS, are outside the scope of the model but are discussed in more detail in Chapter 8.

As a starting point, Table 5.1 provides an overview of the parameters used to analyse the uncertainty in the ETP model results. The table shows the parameter value in the GLO50 scenario and in the uncertainty analysis. Each of these parameters will be considered in turn. The chapter concludes with an overview of the impact of these parameter variations on CCS use.

Table 5.1

Overview of ETP sensitivity analysis

Variable	GLO50 scenario	Sensitivity level/range
CO$_2$ penalties	50 USD/t CO$_2$	10, 25, 100 USD/t CO$_2$
CO$_2$ policy scope and timing	Worldwide	OECD countries only
	Policies start 2005	Policies are delayed by 10-15 years
GDP growth and energy demand	World average 2000-2050 2.8%/yr	World average 2.2%; 3.2% (see annex 3 for regional details)
	-	10% additional electricity savings
Nuclear power	Growth path fixed in OECD countries and growth limited to 5% per year in developing countries	Only cost considerations limit growth in OECD countries and growth limited to 10% per year in developing countries
Renewables	Low learning rates and missing targets result in limited investment cost reductions	High learning rates and ambitious policy targets result in more cost reductions
Market structure	Government guarantees and soft loans, resulting in low discount rates	Completely liberalized highly competitive power industry, resulting in high discount rates

Variable	GLO50 scenario	Sensitivity level/range
Technology progress	IGCC 'FutureGen' and other synfuel cogeneration, SOFC+CCS and chemical looping reactors are available	IGCC 'FutureGen' and other synfuel cogeneration, SOFC+CCS and chemical looping reactors are not considered
	CO_2-EOR is the only viable EOR option	A wide range of competing EOR options are available
	Aquifer storage	No aquifer storage
Fuel prices	Average oil price: 2020-2040 30 USD/bbl	OPEC supply curve twice as steep, resulting in higher oil prices
	Gas price: 3-5 USD/GJ	Gas price: 2-4 USD/GJ
Analysis time horizon	2050	2070

CO₂ Policy Targets

The analysis for the GLO50 scenario in the previous chapter focused in a global CO_2 penalty of 50 USD/t CO_2. This scenario was chosen for detailed discussion because it resulted roughly in an emissions and CO_2 concentration stabilization. Future CO_2 policies are unclear as they will depend on new insights regarding the urgency of climate policies and on the outcome of a difficult international negotiation process. If and when developing countries curb their emissions is unclear as yet. Consequently, both the penalty level and the penalty scope have been varied. This section discusses the impact of the penalty level, while the next section discusses the impact of the penalty scope.

Three alternative CO_2 policy targets to GLO50 are examined in this section. The penalty levels stabilize at a level of 10, 25 and 100 USD/t CO_2, compared to 50 USD/t CO_2 in the GLO50 scenario. The impact these levels have on CO_2 capture is shown in Figure 5.1. The results suggest that, even at lower penalty levels, CCS would be a viable alternative on a large scale. This result is important because many studies suggest that the damage caused by a tonne of CO_2 emissions (in terms of environmental impacts, impacts on humans and property) should be valued at less than 50 USD/t CO_2. Moreover, a significant potential exists for reduction of non-CO_2 greenhouse gases and carbon storage through land use change, at cost levels well below 50 USD/t CO_2.

Even at a penalty of 10 USD/t CO_2, the amount of CO_2 captured reaches 8.4 Gt by 2050. This is likely to represent an overestimation. The model does not account for variations in reservoir geology and in site-specific CO_2 supply and demand within regions that are of particular importance for EOR; it may be that CO_2 sources and potential EOR sites are too far apart to allow CO_2 use for EOR. Moreover, EOR benefits will depend on the oil yield per tonne of CO_2, which is highly site specific. At higher penalty levels, aquifer storage dominates, which is less sensitive to such site specific factors.

CO_2 emissions under various penalty levels are shown in Figure 5.2. The GLO50 scenario is in line with a stabilization of global CO_2 concentrations at a level of around 550 ppm during the 21st century. Under the GLO10 and GLO25 scenarios, emissions would continue to rise to higher levels that are not in line with long-term stabilization at 550 ppm. The GLO100 scenario is the only scenario where global emissions decline below 2000 levels. This scenario would be in line with a 'green' 450 ppm scenario. Note that the 550 ppm and 450 ppm curves start in 2000 at a higher

Figure 5.1

CO₂ capture at various policy incentive levels

Key point: Higher penalties result in increased CCS use
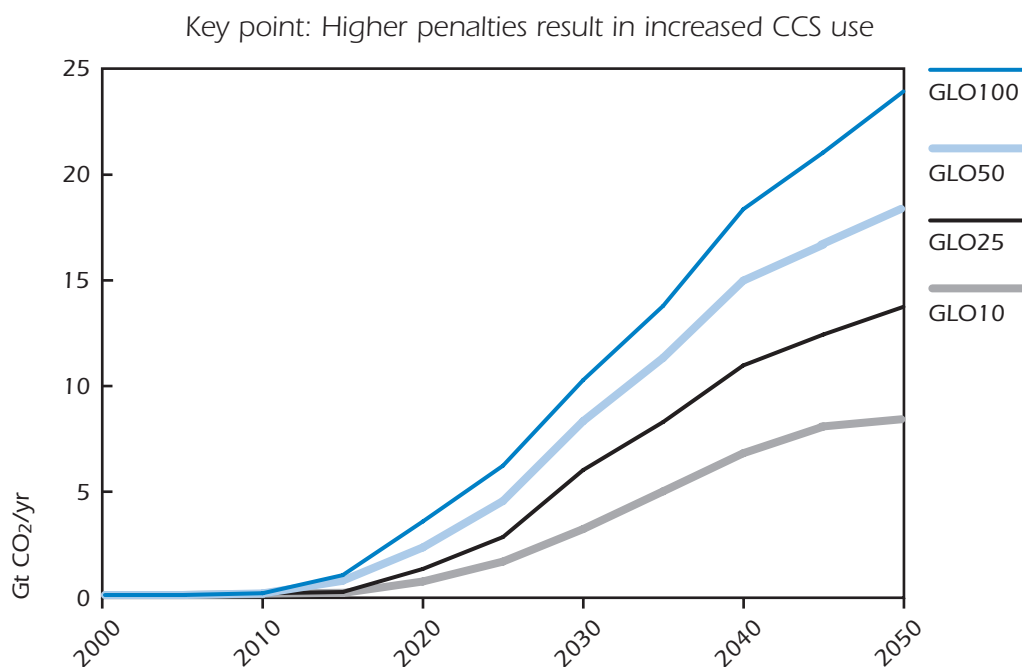
emission level than the model runs. The difference is accounted for by CO_2 emissions from deforestation, which is not accounted for in the model. The comparison of model emission projections and long-term CO_2 concentration stabilization scenarios shows that **it is not possible to define a unique target emissions path for the coming decades on scientific grounds.** Policy makers should aim for emission reductions that balance cost and the risk of important climate change impacts, based on the uncertain information that is available.

Note that in Figure 5.1 the use of CCS keeps rising if the penalty is increased from 50 to 100 USD/t CO_2. This suggests that the technical potential is even higher, and **the use of CCS is not limited by storage constraints or by capture possibilities, but by the cost of competing emission mitigation measures and by policy decisions regarding acceptable levels of climate change risk.**

The captured quantities of CO_2 shown in Figure 5.1 are high. At the higher penalty levels in 2050 they equal current global CO_2 emissions. However, these are scenarios with rapid base case emissions growth, ambitious CO_2 policies, and limited other options to mitigate emissions. **The following analyses will show that CCS use would be much lower under slightly different assumptions, but it would still be on a Gt-scale.**

Figure 5.3 shows the share of CCS in total CO_2 emission reduction. This takes account of additional emissions caused by energy use for CO_2 capture and storage. The share of CCS in total emission mitigation increases gradually with time, and stabilizes in the period 2040-2050, where it represents over half of total CO_2 emission reduction. The penalty level does not have a strong impact on the total share of CCS in the emission mitigation.

The results suggest that CCS constitutes a key emission mitigation option at all penalty levels above 15-20 USD/t CO₂. There is no set threshold value, however, above which CCS should be

Figure 5.2

Energy-related and inorganic CO$_2$ emissions at various policy incentive levels, compared to long-term stabilization scenarios at 550 ppm and 450 ppm

Key point: A penalty of 50 USD/t CO$_2$ is in line with a long-term target
to stabilize CO$_2$ concentrations at 550 ppm
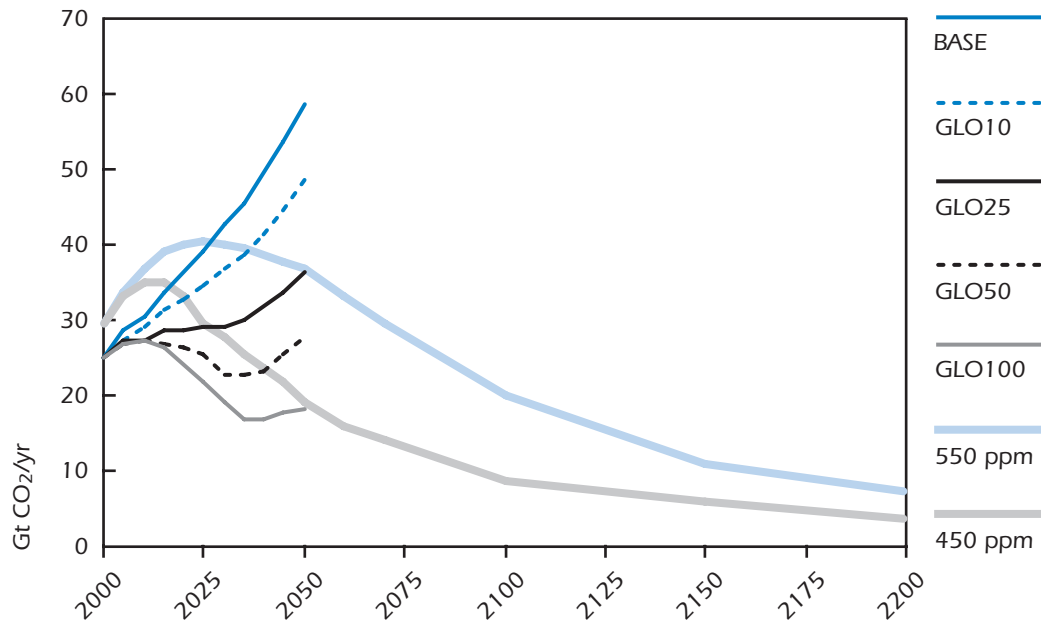
Source: IPCC, 2001.

considered by policy makers. This is a result on the global aggregation level; such penalty thresholds may exist on a regional or sectoral level.

CO$_2$ policy scope and timing

In order to asses the impact of the policy scope (i.e., the regional distribution of CO$_2$ emission reduction efforts) the GLO50 scenario is compared to a scenario where only OECD countries introduce a CO$_2$ policy. Two cases have been analysed. In the first case (OECDHT), the current commodity trade barriers (tariff and non-tariff barriers) stay in place. In the second case (OECD50), these trade barriers are completely removed, and the sum of production cost and transportation cost from production site to the markets determines the industry location choice. The second case is particularly relevant as global trade negotiations are aiming for more liberalized markets. This is also the assumption that has been applied in the GLO50 scenario.

Carbon leakage is defined as an increase of emissions in regions without CO$_2$ policies as a result of CO$_2$ policies in other regions that have introduced CO$_2$ policies (Kuik and Gerlagh, 2003). One reason for leakage is the relocation of industries to regions without CO$_2$ policies as a consequence of production cost advantages. Another reason is a redistribution of primary energy use, where scarce CO$_2$-free (biomass) or low-CO$_2$ (natural gas) energy carriers are increasingly used in regions with CO$_2$ policies, while the other regions rely increasingly on coal. As a consequence of such changes, the potential for CCS declines in the regions with CO$_2$ policies.

Figure 5.3

Share of CCS in total CO$_2$ emissions mitigation

*Key point: The share of CCS in total CO$_2$ emissions mitigation
does not depend on the penalty level*
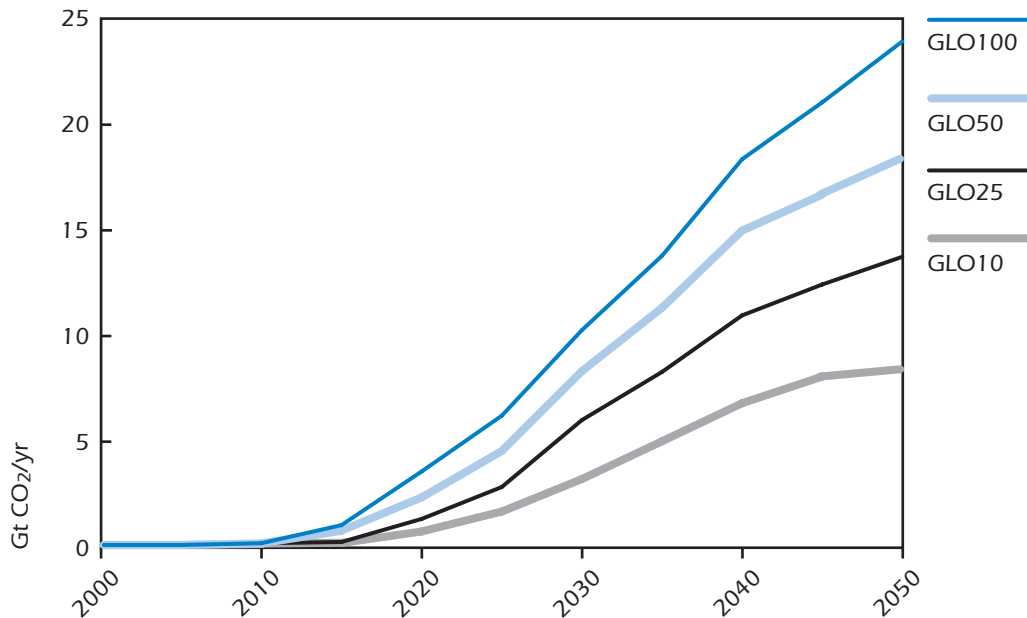
CO$_2$ capture in both model runs is compared in Figure 5.4 (the two lower curves). In the GLO50 scenario, total CO$_2$ capture worldwide increases to 18.4 Gt in 2050. Almost half of this is captured in OECD member countries (8.6 Gt CO$_2$). In the OECDHT case, capture in OECD countries is equal to the capture in these countries in the GLO50 scenario. **The fact that developing countries and a number of transition economies do not introduce CO$_2$ penalties does result in a decline of CCS use by 53% in 2050.** In the OECD50 model run, the total worldwide CO$_2$ capture potential declines to 3.1 Gt CO$_2$ in 2050. This represents an 83% decline. The difference with the OECDHT case is that capture in OECD countries also declines by 65% to 3.1 Gt CO$_2$. This decrease can be attributed to so-called 'leakage effects'.

The future importance of trade barriers is not clear, as it depends in part on any new World Trade Organisation (WTO) trade agreements coming into force. The results suggest that the interaction of trade liberalization and CO$_2$ policies is an issue that deserves more attention. One way to prevent major leakage, with or without trade barriers, is to reach agreement on global CO$_2$ emission mitigation policies.

Another factor which has not been taken into account is that limiting CCS to OECD countries results in less learning-by-doing and, therefore, reduces the potential for CCS cost reductions from technology learning. However, as discussed in Chapter 3, innovation offers the highest learning potential for CCS technology, meaning that the impact of policy scope on CCS cost reductions is likely to be limited.

In order to assess the policy timing issue, two model runs in particular were analysed. In the first model run, the GLO50 penalty path was followed as discussed previously, but the introduction of the penalty was delayed by 15 years. **Cumulative capture in the delayed policy case scenario for the whole period 2000-2050 is about 50-75 Gt CO$_2$ lower than in the GLO50 scenario, equivalent to a decline of about 20%. This shows the importance of timely action.** With this delay, capture

Figure 5.4

CO$_2$ capture for a 50 USD/t case with global policy targets and OECD policy targets

Key point: Restricting CO$_2$ penalties to industrialized countries results in a limited uptake of CCS

World, GLO50

OECD GLO50 and OECD HT Scenarios

OECD, GLO50
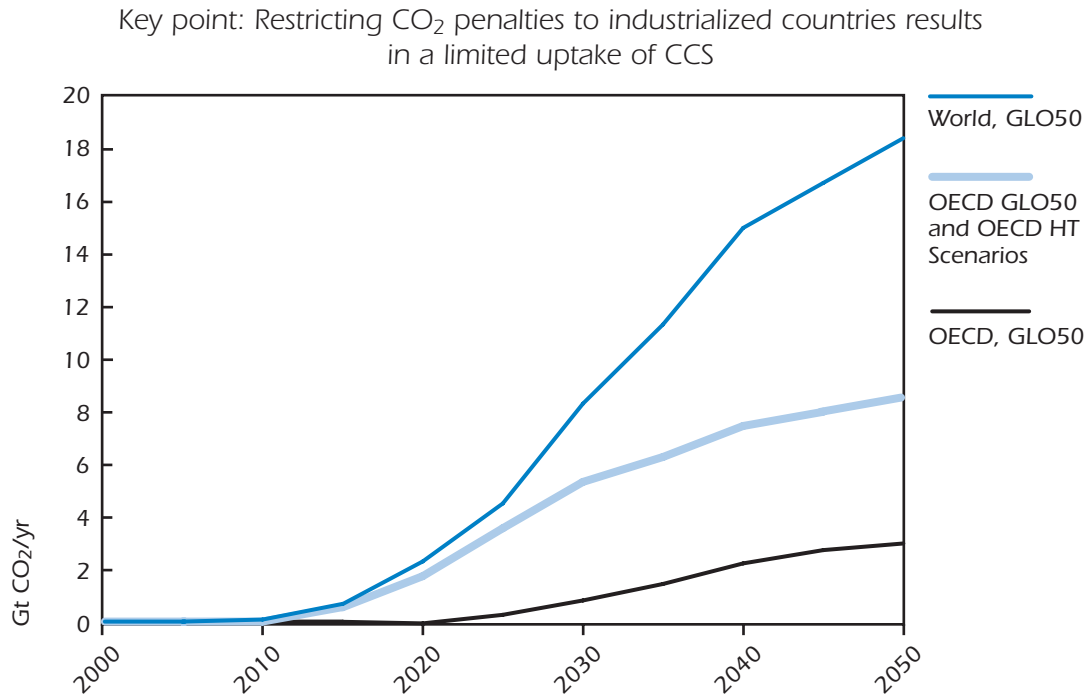
Note: OECD HT high trade cost (reflecting sustained trade barriers).

is 1-2 Gt lower than in the GLO50 scenario, and more in line with the GLO25 scenario up to 2040. After 2040, capture is significantly higher than in the GLO25 scenario, but still below the capture in the GLO50 scenario. The fact that there is a significant capture by 2050, even in the case of policy delays, points to the robustness of the CCS option.

In the second model run, the GLO25 penalty path is followed, but with a delay of 10 years. Delay in the GLO25 case has virtually no impact on the quantities captured. In conclusion, **a 10-15 year policy delay has no dramatic impact on whether or not CCS or competing emission mitigation options are chosen in the future. The quantities captured in later decades are virtually the same, although cumulative capture over the whole period 2000-2050 is reduced.** Assuming that one third of the cumulative emission stays in the atmosphere, such a delay would result in atmospheric CO$_2$ concentrations that are about 15 ppm higher in 2050, compared to the GLO50 scenario.

GDP Growth and Energy Demand

Since energy use and CO$_2$ emissions are closely related to economic activity, GDP growth is clearly an important driver for CO$_2$ emissions. The higher the CO$_2$ emissions, the higher the penalty that is needed to meet a certain emission target. At a given penalty level, there are also more opportunities for CCS as the emissions from point sources will be higher. Moreover, higher GDP rates imply more

investment in new capital stock, which results in more opportunities to introduce CCS. CCS does not necessarily increase linearly with GDP, however, as resource availability, for instance, is independent of GDP.

Figure 5.5 shows global GDP and CCS use in the GLO50 scenario with both lower and higher GDP growth levels. GDP in 2050 is 25% lower or higher than in the GLO50 scenario. The CCS use is 16% lower and 14% higher, respectively. So CCS use increases and decreases with an increase or decrease of GDP, but the elasticity of CCS use for GDP is less than 1. This can be explained by the assumed regional GDP growth distribution. The global average GDP growth difference is mainly accounted for by developing countries (see Annex 3). CCS use per unit of GDP in developing countries is lower than in OECD countries. Therefore, a higher GDP growth results in lower CCS use per unit of GDP. The policy conclusion that can be drawn from this analysis is that **the relevance of CCS for global emission mitigation is affected by the regional distribution of GDP growth.**

Figure 5.5

The impact of GDP growth on the global use of CCS

Key point: CCS use increases with GDP
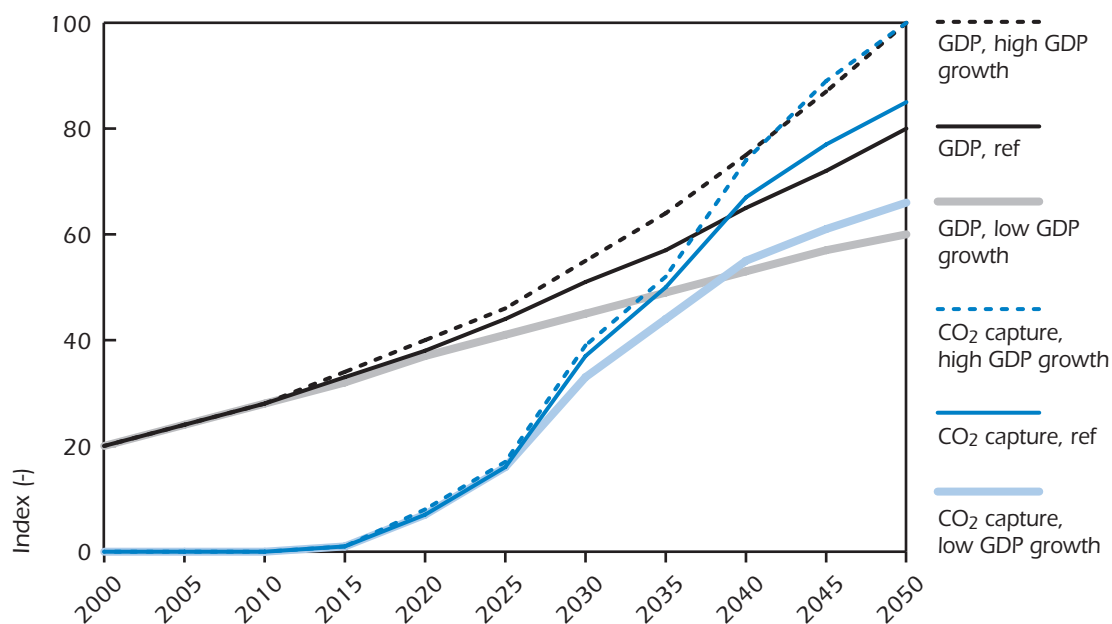
Note: Index high GDP growth case 2050=100.

A related topic is the impact of future energy demand on CCS use. This is not only a function of GDP, but it depends also on the energy intensity of GDP and the market uptake of end-use energy efficiency measures. A model run was undertaken in which efficiency in electricity use was increased over time compared to the GLO50 scenario. This was done by reducing electricity demand by 10% for all regions, and by assuming higher electricity transmission efficiency.

A reduction in electricity demand results in lower electricity production and therefore reduced CCS potential. The use of CCS may scale with electricity sector investments, rather than electricity production capacity. Therefore a 10% decline in electricity demand may have a much more significant impact on electricity sector investments, and therefore on CCS potentials.

The results show a decline of 25-35% in the use of CCS in the period 2015-2025. In later years, CO_2 capture is reduced by 10-15%, compared to GLO50. This pattern can be explained by the fact that in the short term investments are reduced significantly, whereas in the long term all power plants must be replaced, so CCS potentials are proportional to electricity use. **This result suggests that demand-side efficiency measures can have a significant impact on CCS potentials in the medium term (2020-2030), but that long-term potentials (2050) are less sensitive.**

This result for electricity demand could be extended to other types of final energy use. However, efficiency measures for other types of final energy use are often more costly than for electricity. A recent study for Germany with a similar model shows that ambitious emission reduction targets would result in a significant CCS uptake. Without CCS, costly building-insulation measures would be needed to meet the same targets (Markewitz *et al.*, 2004). This result may be country specific, and more analysis is needed on the competition of CCS and energy efficiency measures.

Renewables

The future CCS potential is not only a function of the cost of CCS technologies, but also a function of the cost of competing emission reduction options. One competing emission reduction option is the increased use of renewables. Key questions for renewable energy relate to their potential and future cost. The cost of renewable energy is largely determined by capital cost, as the primary energy is usually available for free. Future capital costs, in turn, are a function of current capital cost and the cost reduction that can be achieved through technology learning. This concept was introduced in Chapter 3, where it was discussed for CO_2 capture technologies.

The relevance of technology 'learning by doing' is much higher for certain renewable energy technologies than for CO_2 capture technologies. Technology learning will be a main mechanism to reduce the cost of renewable energy. This cost reduction, in turn, will affect the competition of renewables and fossil fuels with CCS, especially in electricity production. Therefore this section focuses on the sensitivity of CCS for renewables technology learning. This is done through a set of model runs where investment costs for renewables are reduced through increasingly optimistic technology learning assumptions. In one scenario this learning is based on active government policies that are under consideration (GLO50REN), in two other scenarios more learning is achieved through even higher market uptake of renewables than in the GLO50REN scenario (GLO500515 and GLO500718, respectively).

Although cheap renewables options exist today, their potential in terms of energy supply is limited. Future potential and cost must, therefore, be considered in tandem. A detailed Geographical Information System (GIS) has been developed for this purpose (see Annex 1).

In the GLO50 scenario, investment cost reductions are based on the cumulative capacities that follow from the deployment path in the World Energy Outlook (WEO) Reference Scenario (IEA 2004a), in combination with a technology learning rate. Investment costs decline by a fixed fraction for each doubling of the installed cumulative capacity (IEA, 2000). In the sensitivity analysis (GLO50REN), current and prospective policy deployment initiatives are added to the model as renewables quota (lower bounds). These deployment targets are defined per renewable energy type. It is possible to quantify what such targets will look like up to the year 2020. It is assumed that after 2020, there will be no new policy initiatives and, therefore, no deployment targets are added

Table 5.2

Renewable electricity deployment targets in the sensitivity analysis GLO5OREN (PJ electricity/yr)

(PJ/yr)	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU
Production 2000															
Small hydro	3.0	1.7	60.7	164.8	52.0	43.4	9.2	3.0	3.5	0.6	1.3	3.7	0.2	34.7	173.4
Biomass	0.0	6.0	26.5	7.1	46.6	2.3	9.2	4.8	46.6	0.0	1.6	5.5	1.4	258.2	176.5
Geothermal	1.6	10.5	0.0	0.0	6.8	4.8	0.2	0.0	12.1	0.0	21.2	51.4	0.0	52.6	17.5
Wind	0.3	0.6	0.9	0.2	0.8	0.0	0.0	5.7	0.4	0.0	0.0	0.1	0.1	20.3	80.3
Solar	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	1.9	0.4
Tidal	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1
Targets 2010 (PJ)															
Small hydro	4.8	2.7	74.0	221.4	84.8	70.6	14.9	4.9	4.7	0.8	1.6	6.6	0.3	42.3	211.4
Biomass	0.1	8.8	39.2	18.3	120.8	14.2	19.8	7.9	75.9	0.0	2.6	14.2	2.3	382.2	287.5
Geothermal	5.0	13.2	5.7	0.6	14.7	7.8	0.5	0.0	16.2	0.0	45.9	83.7	0.0	70.0	25.9
Wind	9.5	2.0	23.7	1.0	28.4	4.7	4.7	14.7	1.2	0.0	0.1	0.2	0.2	125.9	324.9
Solar	0.2	0.4	1.1	0.2	0.8	0.1	0.0	1.2	0.1	0.2	0.6	0.5	0.7	11.8	3.2
Tidal	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0
Targets 2020 (PJ)															
Small hydro	7.9	4.4	90.2	297.6	138.1	115.1	38.7	7.9	6.3	1.2	2.0	11.8	0.4	51.5	257.7
Biomass	0.4	14.3	58.1	74.2	375.1	88.1	42.8	12.9	123.6	0.0	4.2	36.7	3.8	622.5	468.3
Geothermal	15.6	16.2	5.7	14.2	38.2	12.6	2.2	0.0	21.8	0.0	99.0	112.5	0.0	140.0	46.4
Wind	38.3	6.1	23.7	5.9	391.3	65.2	18.9	38.2	4.9	0.1	0.5	0.6	0.4	509.5	3,026.2
Solar	1.3	2.7	8.0	1.2	5.0	0.2	0.0	11.0	0.8	1.8	4.0	1.9	2.2	109.8	16.7
Tidal	0.1	0.1	0.1	0.9	0.1	0.0	0.0	0.0	0.1	0.0	0.0	1.9	0.0	9.5	47.3

to the model after 2020. However, investment costs decline further due to technology learning. Actual investments after 2020 are determined by the model, based on cost-effectiveness.

Deployment targets up to 2020 are shown in Table 5.2. They are based on a wide range of national and regional policy plans and policy instruments that have been converted into a single unit (PJ electricity output per year). Deployment targets have been defined for solar photovoltaics (PV) and thermal solar separately. Those for wind are defined separately for onshore and offshore. These splits are not shown in Table 5.2.

The technology learning rates used in this analysis are listed in Table 5.3. A combination of learning rates and cumulative capacities yield investment cost reductions. The model is based on the assumption of global learning, whereby new capacity anywhere in the world contributes to technology cost reductions in all other world regions. As the installed capacity increases, the investment costs per kW decline. The most important cost reduction occurs for PV, where investment costs in the GLO50REN case decline by 77% between 2000 and 2050. Technology learning has also been assumed for operation and maintenance costs, but the learning rates are generally lower.

Table 5.3

Learning rates and investment costs used in the ETP model

	Learning rate (%)	2000	GLO50 (USD/kW)		GLO50REN (USD/kW)	
			2020	2050	2020	2050
Wind onshore	7	1,000	849	773	684	623
Solar PV	18	5,500	3,196	2,283	1,778	1,270
Solar thermal	5	2,400	2,086	1,912	1,792	1,643
Geothermal	5	1,440	1,378	1,291	1,330	1,245
Small hydro	5	2,500	2,428	2,323	2,392	2,289
Biomass IGCC	10	2,500	2,468	2,373	2,468	2,373
Tidal	5	3,200	2,968	2,780	2,503	2,344

The decrease in future investment cost due to learning-by-doing depends on both investments and learning rates. Learning rates are a source of uncertainty. Factors that commonly complicate their accurate estimation are: new technologies with little or no price/cost history (*e.g.*, PV, fuel cells); technologies with highly site-specific installation costs (e.g., hydropower, biomass, geothermal); and technologies where market dynamics obscure the relation of capacity and investment cost (*e.g.*, PV, combined cycle gas turbines). The learning rates used in this study are in line with the range found in the literature (Cody and Tiedje, 1997; Neij, 1997; Harmon, 2000; IEA, 2000; Junginger *et al.*, 2005).

The GLO50REN analysis shows about 10% lower CO_2 capture than the GLO50 scenario. However, the impact differs by region. In particular, the USA and Europe are affected by lower investment costs for renewables. CO_2 capture in the USA is about 20% lower, while CO_2 capture in Europe is 40% lower.

Table 5.4 shows the electricity production mix. Wind is significantly higher in 2030 and 2050, while solar is higher in 2050. Electricity production based on fossil fuels with CCS is 21% lower in 2050. The decline for biomass is caused by the reduced opportunities for co-combustion in coal-fired power plants with CCS.

Table 5.4

Electricity production by fuel and technology category for various learning assumptions for renewables, 2050

(EJ/yr)	2030				2050			
	GLO50	GLO50 REN	GLO50 0515	GLO50 0718	GLO50	GLO50 REN	GLO50 0515	GLO50 0718
FF w/o CCS	19.9	15.7	26.5	24.7	20.3	16.4	25.5	21.4
FF with CCS	21.4	16.1	16.9	15.4	56.1	44.2	38.3	32.0
Nuclear	10.5	10.0	9.7	9.6	9.6	9.5	9.4	9.3
Hydro	21.0	20.6	20.9	21.0	24.1	23.5	23.5	21.7
Bio/waste	12.1	14.0	7.9	7.7	15.9	15.8	9.6	9.9
Geothermal	5.7	5.7	7.7	6.9	8.5	7.4	7.5	6.4
Wind	10.9	19.4	12.4	16.5	18.7	31.6	26.7	33.6
Tidal	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.7	0.8	2.3	0.0	6.2	12.8	21.5
Total	101.4	102.3	102.8	104.1	153.3	154.5	153.2	155.7

In a second set of sensitivity analyses, the learning rates and the cumulative capacities were more widely varied for wind and PV.[1] A certain minimum quantity of renewables was forced in via a lower bound. The investment costs were calculated from a combination of the resulting cumulative capacities and the learning rates. The model is free to invest more, but this does not result in additional cost reductions per unit of capacity.[2] Four levels of policy targets have been considered for PV, and three for wind. These are reflected by minimum capacity constraints. Two technology learning rates have been considered: 5 and 7% for wind, and 15 and 18% for PV, respectively.

Table 5.5

Cost reductions for PV as a function of the target level

Target	Cumulative capacity 2050 (GW)	2000 (USD/kW)	15% LR 2050 (USD/kW)	18% LR 2050 (USD/kW)
0	0.3	5,500	5,500	5,500
1	38.3	5,500	1,817	1,422
2	116.7	5,500	1,400	1,034
3	281.5	5,500	1,138	804
4	654.1	5,500	934	631

LR = learning rate (the investment cost reduction per doubling of the cumulative capacity).

1. PV was selected for this sensitivity analysis instead of solar thermal (concentrating solar technologies) because the cost reduction potential is more significant.

2. In fact, the model runs are valid 'least-cost' solutions only in the case where if the model chooses to invest more than the specified minimum.

Table 5.6

Cost reductions for wind as a function of the target level

Target	Cumulative capacity 2050 (GW)	2000 (USD/kW)	5% LR 2050 (USD/kW)	7% LR 2050 (USD/kW)
0	11.6	1,000	1,000	1,000
1	167.2	1,000	821	756
2	671.6	1,000	741	654
3	3,131.7	1,000	661	557

LR = learning rate (the investment cost reduction per doubling of the cumulative capacity).

The cumulative capacities and resulting investment cost reductions at various learning rates are shown in Tables 5.5 and 5.6. Higher investments and higher learning rates result in lower investment costs per unit of capacity. Comparison of investment costs per unit of capacity in 2050 in Tables 5.3, 5.5 and 5.6 shows that GLO50REN is situated between levels 1 and 2 for PV, and between levels 2 and 3 for wind.

Any amount of renewables can be forced into the model through model constraints. Within the optimization framework, the solution is a better systems configuration if the systems costs are lower than in a run without such constraints (but with higher investment cost per unit of capacity). The model results show indeed that if a CO_2 penalty is introduced, most combinations of PV and wind targets result in a reduction of the systems cost. This reduction can be attributed to the more optimistic assumption regarding investment cost reductions due to learning, which was not considered in the GLO50 model run. Not only does this reduction in investment cost per kW reduce the costs of the total investments that were already taking place in the GLO50 scenario, but it allows the introduction of more renewables at lower investment cost levels as well.

With high learning investments (level 4 for PV and level 3 for wind), the share of renewables increases to 60% by 2050. The impact on CCS and renewables use in electricity production is outlined in Table 5.4. This very high share of renewables is surprising as it is often stated that intermittency problems would limit the share of renewables. However, intermittency is accounted for in the ETP model (see Annex 1). Nevertheless, since in reality the model regions nowadays often contain multiple separate electricity grids, the problem of intermittency may be underestimated. Analysis on a more detailed level of individual grids is needed to assess this problem in more detail.

With the learning and policy assumptions for renewables in the scenario analysis, fossil fuels with and without CO_2 capture and storage would represent 21 to 25% of total electricity production by 2050, compared to 37% in the GLO50 scenario.[3] Total CCS use declines to 15.0 Gt in the GLO500515 case (-18%) and to 13.8 Gt CO_2 in the GLO500718 case (-25%).

The results suggest that, compared to GLO50, the future use of CCS would decline by up to a quarter if significant learning effects for renewables occur. However, in all cases CCS can play an important role, and can allow a gradual transition to renewables in the long term. CCS and renewables should therefore not be considered as competing but as complementary options.

This analysis is based on an extrapolation of past learning effects. Whilst this is a widely applied approach, it results in optimistic projections of future cost. A better understanding of the mechanisms

3. This excludes biomass co-combustion in fossil-fuelled power plants with CCS, which would add 2-3 percentage points.

that drive future cost reductions is needed in order to reduce the uncertainty. This would enhance the quality of the policy advice and allow for a better comparison between CCS and renewables. An added advantage of a renewable energy development is that it may still be attractive even if the urgency of CO_2 emission reductions turns out to be low. This advantage has not been taken into account in this assessment. It could warrant a preferential treatment of renewables, even if the costs are higher. But given the scale of the emission reduction challenge, such a consideration will not influence the conclusion that both CCS and renewables should be further developed.

Nuclear Power

In the ETP sensitivity analysis, nuclear energy investments are allowed unconditionally in OECD countries, while the maximum growth rate in developing countries is increased from 5% per year to 10%. The electricity production mix in the scenario with nuclear is shown in Figure 5.6. The share of fossil-fuelled power plants with CCS declines from 39% to 19% in 2050. **If cost optimization was the only constraint, nuclear would be an attractive option for reducing CO_2 emissions.** This is based on investment costs that decline from 2,200 USD/kW in 2000 to 2,000 USD/kW in 2040 (see annex 1). The results show a significant increase of the nuclear capacity in the world electricity mix, up to about a third of total electricity production.

Figure 5.6

Electricity production, GLO50nuclear

Key point: If cost were the only consideration in the selection of emission reduction options, nuclear investments would cut the share of fossil fuels with CCS in the electricity mix in half
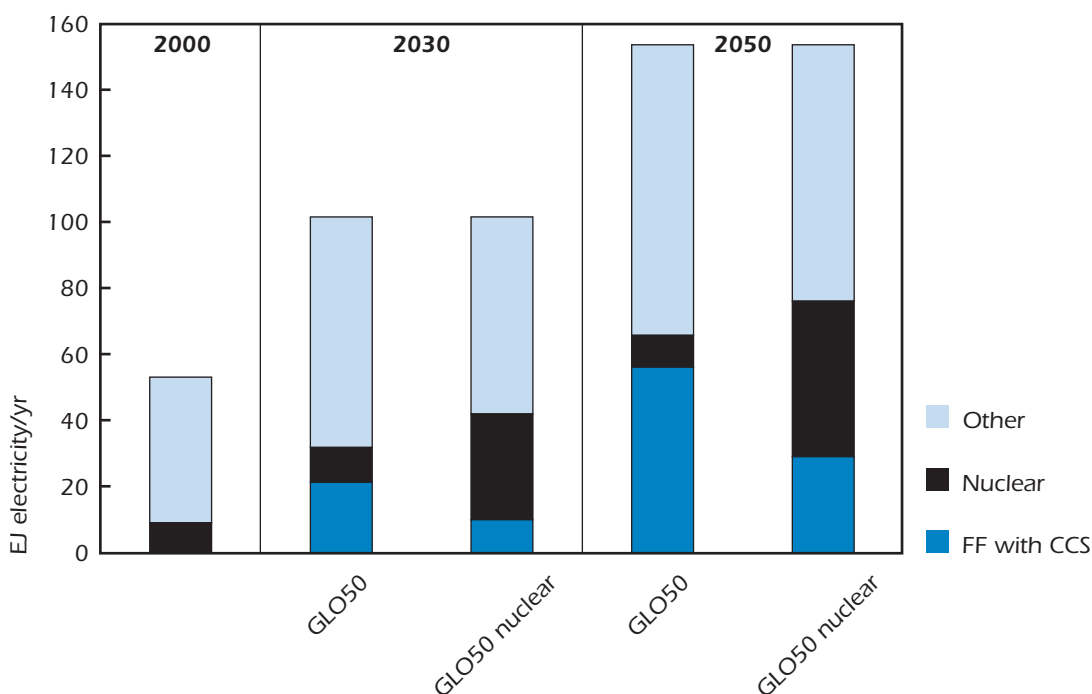
Note: Index high GDP growth case 2050=100.

As illustrated in Figure 5.7, CCS declines by 3.9 Gt (47%) in 2030 and by 7.8 Gt (42%) in 2050 if nuclear is considered as an option that competes on a cost basis. The main changes occur in Japan, the USA and Europe where CCS use declines by 75%, 56% and 53%, respectively under the GLO50nuclear scenario. Clearly, this illustrates that **the future role of nuclear energy is of key importance for the future role of CCS, especially for industrialized countries.**

However, the other three non-cost issues (public acceptance, waste treatment and proliferation) must be solved before a worldwide nuclear renaissance is likely.

Figure 5.7

CO_2 capture by region, GLO50 and GLO50nuclear

Key point: CCS use in Japan and in the USA declines significantly if nuclear competes on a cost basis, and other nuclear issues are not considered
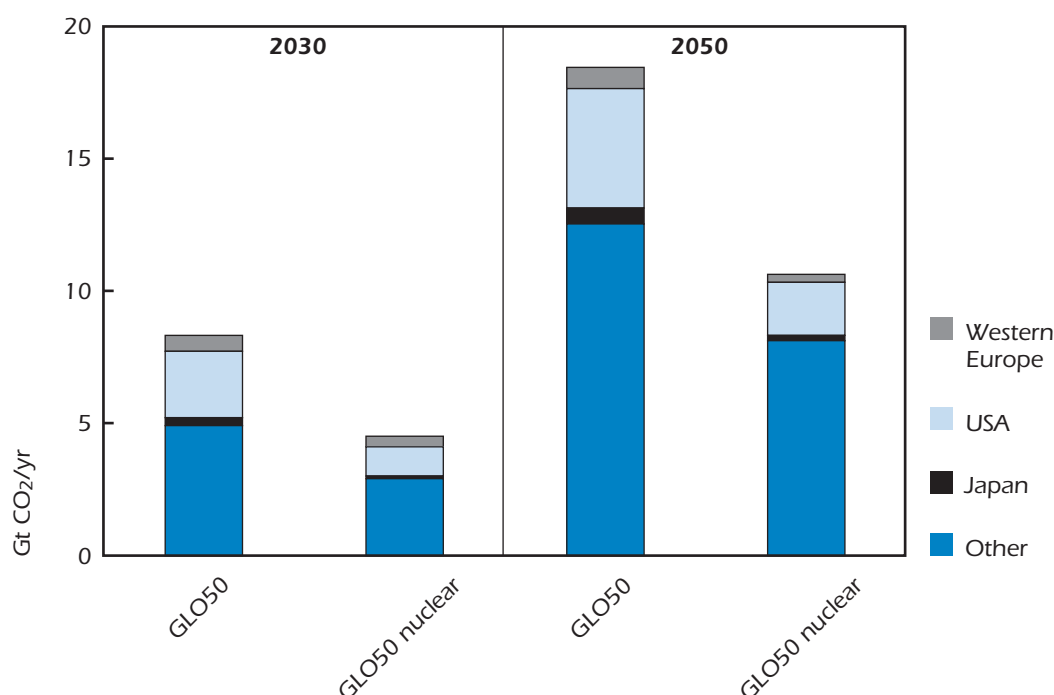
CCS Technology Progress

The future role of CCS depends not only on the general energy system characteristics, but also on the characteristics of CCS technologies. The substantial contribution CCS can make to reducing emissions, as outlined in this chapter, is based on technology that is not yet proven on a commercial scale. If only proven technologies are considered, the role of CCS would be less prominent. The goal of this sensitivity analysis is to quantify this decline.

Therefore, in a sensitivity analysis the most speculative technology options have been removed. Given the CCS technology mix in the GLO50 scenario, IGCC for cogeneration of electricity and synfuels was considered a prime candidate for such sensitivity analyses. In a sensitivity analysis, this option was therefore excluded. Then in a second, more restrictive sensitivity analysis, all speculative CCS technologies were removed. In addition to IGCC cogeneration plants, this involved chemical looping reactors for gas and coal, and power plants including solid oxide fuel cells for gas and for coal.

Figure 5.8 shows the results for CO$_2$ capture when IGCC with synfuel cogeneration is excluded. Total CO$_2$ capture is 31% lower in 2050. Moreover, the technology mix changes significantly. CO$_2$ capture from IGCC is halved, compared to the GLO50 scenario, while CO$_2$ capture from chemical looping reactors increases.

Figure 5.8

CO$_2$ capture without IGCC transportation fuel cogeneration

Key point: CO$_2$ capture in the electricity sector declines by a third if IGCCs with synfuel cogeneration are excluded from the generation mix
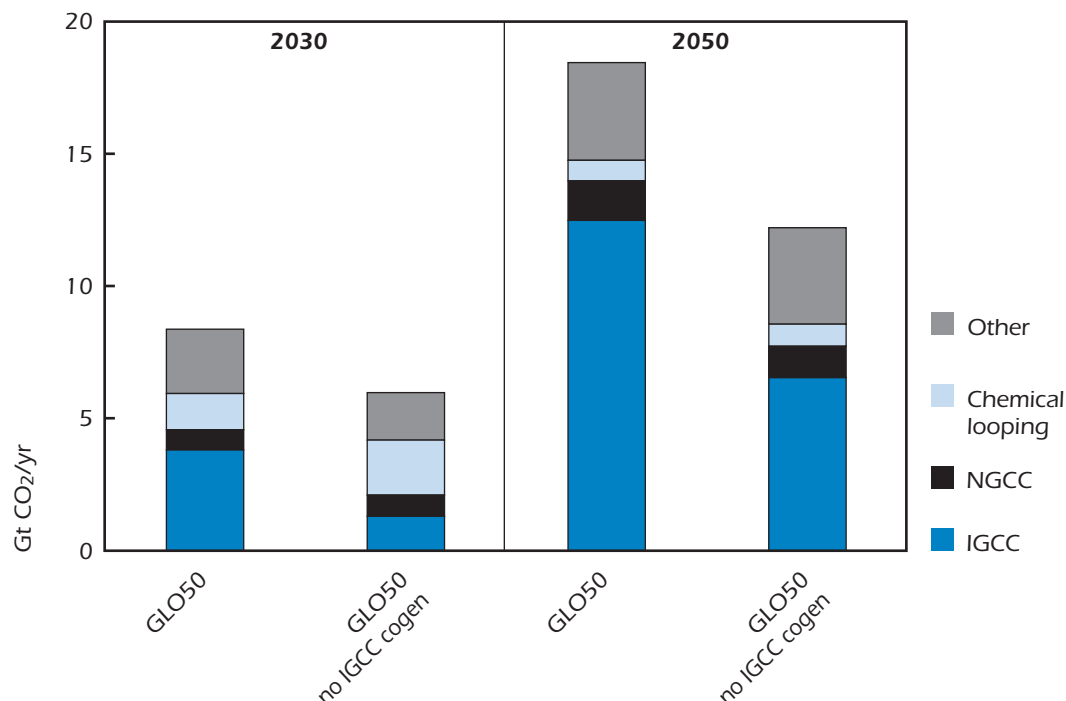
In the sensitivity analysis where all speculative technologies are excluded, the decline compared to the GLO50 scenario amounts to 32% in 2050. So the additional decline compared to the sensitivity analysis that excluded the cogeneration IGCCs only is small. This suggests that **the availability of these synfuel cogeneration units is a key uncertainty for total CCS use, but the availability of chemical looping and fuel cells is less important.** However, the technology mix changes. In this model run, coal-fired ultra-supercritical steam cycles (USCSC) with CO$_2$ capture emerge as an important technology.

CCS technology includes not only the capture technology, but storage technologies as well. In order to asses the impact of storage assumptions, the parameters for EOR and for aquifer storage have been varied. With regard to EOR an important uncertainty is if CO$_2$ EOR is really the best EOR option for a certain field. Rigid analysis would require a field-by-field assessment of the oil recovery potential of each EOR option. Instead in this analysis the oil recovery potential was kept the same for all EOR options, and only the availability of EOR alternatives was varied. With regard to the aquifer storage potential, a key uncertainty is whether such storage is really permanent. The results so far have been encouraging, but some studies assume, for example, that only confined aquifers are suited for storage, which would reduce the storage potential significantly (see Chapter 3). In a sensitivity analysis, it is assumed that aquifers are not available for storage.

When it comes to CO_2 storage, the availability of competing EOR options could reduce the potential use of CO_2 and may, therefore, affect the overall use of CCS. **However, the analysis suggests that this is not the case. A penalty of 50 USD/t CO_2 results in CO_2 being available "for free" for EOR use. Therefore CO_2 EOR is cheaper than competing EOR options. CCS use is hardly affected by the availability of competing EOR options.** CCS use declines by 4% in 2030 and by 1% in 2050.

Without aquifer storage, total storage is lower. The decline is limited to 10% in 2030 and 14% in 2050. However important regional differences occur. For example, in Korea and Japan there is no CO_2 capture and storage if aquifers are not available as storage sites. In other regions, there is heavy reliance on depleted gas fields. The matching of these depleted fields and CO_2 sources is not taken into account in this analysis. This may overestimate the cost-effective storage potentials in a scenario without aquifer storage. The actual importance of aquifers may therefore be higher than the model analysis suggests.

Market Structure

In order to assess the role that liberalized electricity markets play in the uptake of CCS, a model run with liberalized and highly competitive electricity markets was undertaken. The impact of the market structure has been simulated by varying the discount rates for electricity-sector investment decisions. Discount rates are used to mimic investor behaviour in a MARKAL-type model. The difference in discount rates compared to GLO50 amounts to 4.5% (Annex 2). Higher discount rates mean that capital-intensive emission reduction options become less attractive, while options with high variable cost become more attractive. For example, nuclear has high capital cost, while the capital cost of renewable options vary (high for PV, but comparatively low for biomass). The capital intensity of CCS options is high, but not necessarily higher than for other supply-side emission reduction options. As fuel cost and renewables supply curves differ by region, the impact of the discount rate on CCS use can differ by region. The impact by region is shown in Table 5.7.

In terms of gigatonnes of CO_2 stored, global CCS use is about 10% lower with high discount rates. This decrease is not evenly distributed around the world. While CCS use increases in most OECD countries, it decreases significantly in developing countries (Table 5.7). This means that, on a regional level, market structure can be of importance for the future role of CCS. However, the impact of the market structure depends on the characteristics of competing emission mitigation options.

Fuel Prices

Many modelling studies suggest that fuel prices are a key factor that will determine future emission levels of CO_2. The choice of CCS technologies is also influenced by fuel prices (Rubin *et al.*, 2004). While fuel prices tend to fluctuate in the short and medium terms, the analysis in this publication is more concerned with long-term trends. As a result, long-term oil and gas price trends have been varied, without paying attention to more extreme short and medium-term fluctuations.

Oil prices in the BASE and GLO50 scenarios are in line with the World Energy Outlook, reaching 29 USD/bbl (in USD of 2000) in 2030 (IEA 2004a). However, much higher or lower oil prices may occur. In the ETP sensitivity analysis, the impact of higher oil prices has been assessed. The supply curve for oil from the Middle East is twice as steep as in the GLO50 calculations. This results in a higher oil price. The extent to which this curve increases the price depends on the

Table 5.7

**Change in CCS use in a liberalized market
(GLO50 liberalized compared to GLO50)**

	2030 (%)	2050 (%)
AFR	28	7
AUS	2	5
CAN	-25	-3
CHI	-9	-18
CSA	-1	-28
EEU	-21	-20
FSU	-45	-62
IND	-73	-14
JPN	-17	-18
MEA	-33	-38
MEX	-13	-8
ODA	-10	-38
SKO	4	-16
USA	10	6
WEU	29	27

supply curve for other regions, and on substitution options. The sensitivity analysis results show a 20-25% increase in the price of oil up to 2050.

In this high oil price sensitivity analysis the increase of CO$_2$ capture amounts to 0.6 Gt in 2030 and 1.8 Gt in 2050. These are relatively minor differences (<10%). **Therefore, it can be concluded that the price of oil is of secondary importance for the use of CCS.**

In a second sensitivity analysis for gas, it was assumed that unlimited amounts of gas can be produced in the Middle East at a wellhead price of 0.5 USD/GJ. This assumption results in a reduction of OECD gas prices by 1-1.5 USD/GJ. As a consequence, gas use is higher. OECD gas use increases by 13% in 2030 and by 18% in 2050, compared to GLO50. Global gas use increases even faster. As a consequence of this increase in gas use, global CCS use declines by 1% in 2030 and by 7% in 2050. The limited impact can be explained by the high cost of LNG supply from the Middle East to coal-rich regions such as North America and China. Instead of introducing natural gas, these regions rely on coal with CCS, even at a reduced gas-supply cost level. Therefore, it can be concluded that **the price of gas is of secondary importance for the use of CCS.**

Analysis Time Horizon

The ETP model has a time horizon of 2050. Developments that occur after this date are not taken into account in the optimal investment path calculated by the model. Such short-sightedness can pose a problem if, for example, oil production peaks shortly after 2050. A transition to a very different energy system configuration might take decades, so sensible energy policies should take such depletion into account.

If the post-2050 period is taken into account, the investment path in the period 2000-2050 may look different. For example, for the electricity sector, post-2050 benefits from technology learning for renewables may result in an increased use of renewables in the period 2000-2050. In order to analyse such effects, the time horizon has been extended to 2070, while keeping all parameter values in the period 2050-2070 constant at their 2050 levels.

The results suggest that total CO_2 capture is not affected by such a broader time perspective. The impact on total CO_2 capture in all periods is less than 5%. On a process level, the differences are more important. There is about 1.5 Gt more CO_2 capture from power plants with synfuel cogeneration by 2050, and less capture from cement kilns and coal-fired chemical looping reactors. This result can be explained by the 'running out of oil' effect, which leads to a need for significant amounts of synfuels in the second half of the 21st century.

Overview of Sensitivity Analysis Results

The sensitivity analysis suggests that the following sets of parameters are of key importance for the future role of CCS technology, as they affect CCS use by more than 10% (see Table 5.8):

- The urgency of CO_2 capture and sequestration and, therefore, the emission mitigation targets;

- The willingness of non-IEA countries to participate in such a scheme;

- The timing of CO_2 policies;

- The feasibility of underground CO_2 storage, and the feasibility of speculative CO_2 capture technologies;

- The feasibility of nuclear energy as a competing emission mitigation option;

- Characteristics of competing renewables emission mitigation technologies;

- Future GDP growth;

- Future energy demand.

The following variables are of lesser importance, as they affect CCS use by less than 10%:

- Liberalized, highly competitive markets versus protected markets (shown as differences in discount rates);

- Oil and gas prices;

- Prospects beyond 2050.

It should be kept in mind that other uncertainties which have not been identified may affect the results significantly. Also, the input data range that has been applied affects the uncertainty range outcome.

Table 5.8

Overview of sensitivity analysis results

Variable	Sensitivity level/range	Delta CCS 2030 (Gt CO_2/yr)	Delta CCS 2050 (Gt CO_2/yr)
CO_2 policy scope and timing	OECD countries only	-3.0 (-35%) to -7.4 (-89%)	-9.8 (-53%) to -15.3 (-83%)
	Policies delayed by 15 years	-2.8 (-34%)	-1.9 (-10%)
CO_2 penalties	10, 25, 100 USD/t CO_2	-5.1 to + 1.9 (-61 to +23 %)	-10.0 to +5.6 (-54 to +30%)
Nuclear power	Unlimited growth in OECD countries and higher growth in developing countries	-3.9 (-47%)	-7.8 (-42%)
Technology progress	No IGCC for synfuel cogeneration	-2.1 (-25%)	-5.7 (-31%)
	No IGCC for synfuel cogeneration, Chemical looping, SOFC	-2.5 (-30%)	-5.9 (-32%)
	Competing EOR options are available	-0.3 (-4%)	-0.1 (-1%)
	No aquifer storage	-0.8 (-10%)	-2.5 (-14%)
Renewables	Important cost reductions/ policy programmes	-0.3 to -1.4 (-4% to -17%)	-1.8 to -4.2 (-10% to -25%)
GDP growth and energy demand	2.2%-3.2%	-0.8 to + 0.2 (-10 to +2%)	-3.0 to +2.5 (-16 to +14%)
	10%+ additional electricity savings	-1.1 (-13%)	-2.4 (-13%)
Market structure	Completely liberalized	-0.6 (-7%)	-1.7 (-9%)
Fuel prices	OPEC oil supply curve twice as steep	+0.6 (+7%)	+1.7 (+9%)
	Gas price reduction 0.5-1.5 USD/GJ	-0.1 (-1%)	-1.3 (-7%)
Analysis time horizon	2070	-0.4 (-5%)	+0.2 (+1%)

Note: Figures in brackets indicate the percentage change compared to GLO50.

Chapter 6.
REGIONAL ACTIVITIES AND CCS SCENARIO ANALYSIS

H I G H L I G H T S

CCS RD&D trends and needs

■ Global RD&D efforts to develop CCS technologies are growing rapidly. In an optimistic scenario there will be 10 Mt CO_2 capture capacity in power plant demonstration projects worldwide by 2015. A hundred- to a thousand-fold increase is needed up to 2030 to realize the global potential for CCS identified in this study and for the technology to have a significant impact on global emissions. The initiatives announced so far are therefore likely to be insufficient to realize the potential for CCS identified in the ETP scenario analysis.

■ Worldwide, at least 10 new storage projects should be developed on a Mt per year storage scale under varying geological conditions, in order to validate the permanence of storage and in order to develop regulatory protocols. Given that permanence of storage is a sine qua non for a CCS strategy and the cost of such projects are reasonable, they should be established in the short term. Aquifer storage in particular needs to be further developed because of its potential importance on a global scale.

■ One IGCC demonstration project with CCS has been announced to date, the USA's FutureGen project. Canada and the EU have announced plans for further demonstration projects for coal-fired power plants with CCS, and Australia has established an emission reduction project funding programme which may include such plants. It remains to be seen which of these projects are actually realized in the coming years. Even if all four projects are implemented, more will be needed to adequately cover the full range of capture technologies.

■ Worldwide, five coal-fired 250 MW IGCC pilot plants have been built to date. So far, electricity companies have expressed only limited interest in investing in this technology. Ongoing efforts in Europe to develop high efficiency steam cycles, in combination with CCS, may result in alternatives to IGCC with CCS.

■ To date, not a single demonstration project has been planned for 250 MW+ gas-fired power plants with CO_2 capture. There are plans to do so in Norway, but it is not clear if and when these will be realized. But the technology challenge for gas seems less than for coal and biomass, and the CCS potentials are lower on a global scale, so this constitutes a lower RD&D priority than coal.

ETP Scenario Analysis Results

■ CCS can play an important role as a future CO_2 emission reduction strategy. Scenario analysis suggests a global potential of 3-8 Gt CO_2 capture by 2030 and 5-19 Gt CO_2 capture by 2050, if ambitious CO_2 policies are introduced. This suggests that CCS is a robust strategy.

- The scenario analysis suggests that the interaction of key parameters has only limited impact on the CCS potentials. Policy incentives and regional policy scope are the main factors, followed by technology progress.

ETP Regional Results

- ETP model analysis suggests that CCS is a robust strategy for North America, Europe and Australia. The quantities that are captured and stored in all four scenarios are substantial. Even in countries and regions where CCS investments would be limited, the fact that coal remains a viable option has strategic advantages;

- While the CCS potential for CCS in China and India is significant, its realization will depend on technology transfer from industrialized countries and on global efforts to reduce CO$_2$ emissions. Without substantial emission mitigation efforts in these countries, CCS will not be introduced. CCS only makes sense in the case of high efficiencies in electricity production. Given the comparatively low electricity production efficiency in these countries, priority should be given to increased energy efficiency.

- In the Middle East, revenues from EOR alone would not be sufficient to merit widespread CCS use. Therefore, the countries in this region should either be part of a global emission reduction initiative or CO$_2$ could be supplied from other regions for free or at low cost.

The ETP model sensitivity analysis that is outlined in Chapter 5 showed that a number of key parameters can significantly affect the potential for CCS. These may interact to reinforce their respective impacts or, conversely, to cancel out one another's impact. Scenario analysis is a way of assessing such interactions. A scenario is defined as a logical combination of parameters that can influence the future role of CCS.

This chapter, the third of four sets of quantitative results from the ETP model, discusses and compares the results of four scenarios using ETP analysis. Certain results are valid in all scenarios. This suggests that the results are robust. When scenarios show different results, such information can be used to develop hedging strategies that leave room for a more flexible response. The results for CCS in the four ETP scenarios are first discussed on a global level. This is followed by a discussion of the regional scenario results. The regional results are then compared against actual and planned RD&D activities. This analysis provides insights for the CCS policy challenges that are discussed in Chapter 8.

Global CCS Scenario Analysis

Four scenarios are defined. These scenarios are characterized by the acronym EFTEP which stands for Economy, Fuel demand and price, Technological progress, Environment, and Policy co-operation.

These areas constitute five dimensions that are used to characterize the scenarios. Each dimension is tracked as a plus (+) or a minus (-), meaning that the set of parameter values is positive or negative for the future use of CCS.

The dimensions are not completely independent. For example, combining high CO_2 urgency and policies in industrialized countries only has not been considered, because it seems a less likely combination. GDP growth and the extent of electricity sector opening have been grouped together in the first variable for economic conditions. Higher GDP growth is more likely if markets are deregulated. Combining both is ranked as being positive overall in the EFTEP analysis. Future energy demand has been varied primarily through high or low demand-side efficiency gains for electricity (either in line with GLO50, or in each region 10% lower final demand in 2050, plus additional gains in transmission efficiency).

Technology progress has been modelled through renewables learning assumptions (in line with GLO50 or with more optimistic assumptions for renewables in line with GLO50REN, see Chapter 5), nuclear potentials (maximum potential in line with GLO50 or doubled) and feasibility of CCS technologies (speculative capture technologies considered or not, aquifer storage considered or not). Balanced sets of technology assumptions have been used, with either optimistic or pessimistic assumptions regarding technology progress for CCS and renewables alike. In the case of limited technology progress for CCS and renewables, nuclear is more widely accepted as a strategy of last resort.

The penalty level has been varied (25 or 50 USD/t CO_2) and the policy scope has been varied (worldwide or only industrialized countries).

The goal of this chapter's scenario analysis is not to assess the full range of conceivable outcomes, but to show a range of likely outcomes and the way in which key variables might interact. Comparing the scenarios provides insights into the future role of CCS in the global energy system.

The following four EFTEP scenarios have been defined, the characteristics of which are listed in more detail in Table 6.1:

- **Scenario 1: +++++.** High economic growth/liberalized power markets (+), limited efficiency gains (+), rapid technological progress (+), high CO_2 mitigation urgency (+), CO_2 penalty applied worldwide (+);

- **Scenario 2: +----.** High economic growth/liberalized power markets (+), high efficiency gains (-), limited technological progress (-), moderate CO_2 mitigation urgency (-), CO_2 penalty applied in IEA countries only (-);

- **Scenario 3: -++--.** Moderate economic growth/partially liberalized power markets (-), limited efficiency gains (+), rapid technological progress (+), moderate CO_2 urgency (-), CO_2 penalty applied in IEA countries only (-);

- **Scenario 4: -+-++.** Moderate economic growth/partially liberalized power markets (-), limited efficiency gains (+), limited technological progress (-), high CO_2 urgency (+), CO_2 penalty applied worldwide (+).

Table 6.1

Characteristics of the ETP model's EFTEP scenarios

EFTEP	Scenario 1: +++++	Scenario 2: +----	Scenario 3: -++--	Scenario 4: -+-++
Economic conditions which favour CCS (E)	**High:** ● 3.2%/yr average worldwide GDP growth (see Annex 3 for regional details) ● Liberalized electricity sector with high discount rates	**High:** ● 3.2%/yr average worldwide GDP growth (see Annex 3 for regional details) ● Liberalized electricity sector with high discount rates	**Moderate:** ● 2.2%/yr average worldwide GDP growth (see Annex 3 for regional details) ● Partially liberalized electricity sector with low discount rates	**Moderate:** ● 2.2%/yr average worldwide GDP growth (see Annex 3 for regional details) Partially liberalized electricity sector with low discount rates
Fuel demand and prices that lead to efficiency gains (F)	**Limited** efficiency gains	**High** efficiency gains from low growth electricity demand	**Limited** efficiency gains	**Limited** efficiency gains
Technological progress on the supply side (T)	**Rapid:** ● Includes speculative CCS technologies ● Renewable energy targets result in strong technology learning	**Limited:** ● No FutureGen-type of cogeneration plants ● No SOFCs or chemical looping ● No CO₂ capture from blast furnaces and cement kilns ● Nuclear accepted as the last resort	**Rapid:** ● Includes speculative CCS technologies ● Renewable energy targets result in strong technology learning	**Limited:** ● No FutureGen-type of cogeneration plants ● No SOFCs or chemical looping ● No CO₂ capture from blast furnaces and cement kilns ● Nuclear accepted as the last resort ● No aquifer storage of CO₂
Environmental policy through CO₂ penalty (E)	**High** CO₂ mitigation urgency: 50 USD/t CO₂	**Moderate** CO₂ mitigation urgency: 25 USD/t CO₂	**Moderate** CO₂ mitigation urgency: 25 USD/t CO₂	**High** CO₂ mitigation urgency: 50 USD/t CO₂
Scope of CO₂ penalty (P)	**Worldwide** (see GLO50 scenario)	**OECD** countries only	**OECD** countries only	**Worldwide** (see GLO50 scenario)

Figure 6.1 shows the growth in CO_2 emissions between 2000 and 2050 in the four EFTEP scenarios. **The only scenario which results in a real reduction in emissions is the one in which economic growth is limited and there is global co-operation to reduce emissions (-+-++).**

Emissions can be stabilized at 30-35 Gt CO_2 per year, in line with a 550 ppm stabilization scenario, through either low economic growth or global co-operation. However, in the +++++ scenario, an initial decline in emissions is followed by a strong increase in the period 2030-2050, which suggests a further increase beyond 2050.

Figure 6.1

CO_2 emissions in the four EFTEP scenarios (2000-2050)

*Key point: CO_2 Emission trends range from a significant
increase to a limited decline on 2000 levels*
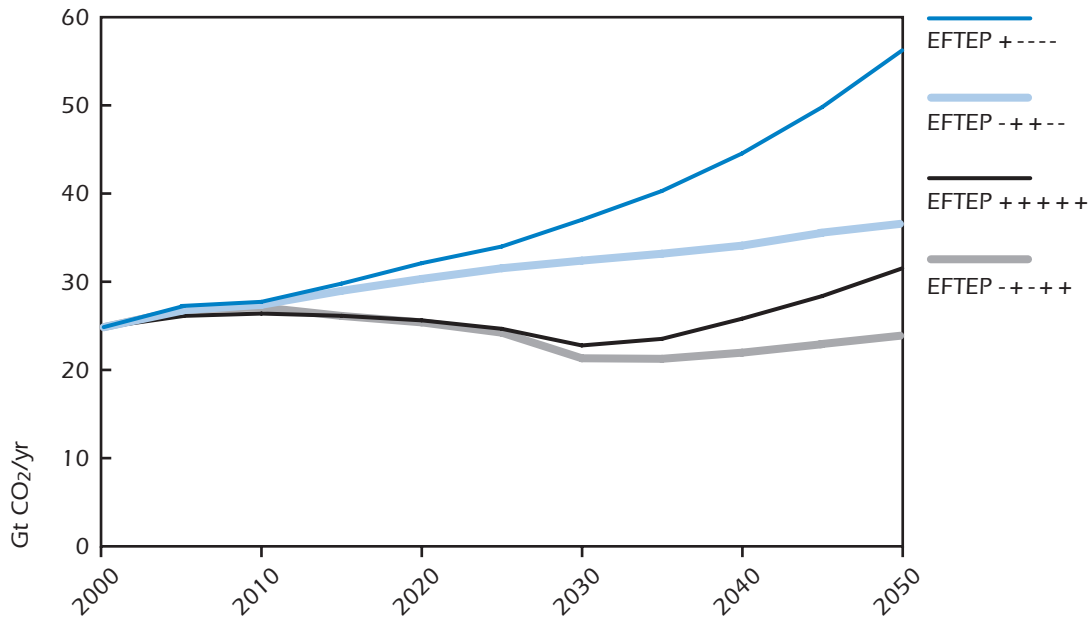
The highest emissions occur in the +---- scenario, where high economic growth is coupled with limited CO_2 emission reduction efforts in OECD member countries, limited CCS technology development and limited competing emission mitigation options. Under this scenario, emissions in 2050 are more than double the levels seen in 2000.

Figure 6.2 shows the rate of CO_2 capture between 2030 and 2050 in the four scenarios. Capture ranges from 3-7.6 Gt in 2030 and from 5.5-19.2 Gt CO_2 in 2050. Three out of four scenarios are at the lower end of this range. Although the range suggests that the potential is significant, at present only the order of magnitude can be given. The potentials in all scenarios are sufficient to warrant further development.

Comparing the scenarios -+-++ and +++++ shows that the main difference occurs post-2030 and is linked to the question of whether CCS is widely applied in developing countries. Comparing the scenarios -++-- and +---- indicates that high or low economic growth and high or low technology progress are of secondary importance for CO_2 capture in industrialized countries.

The results suggest that CO_2 capture and storage can play an important role in all scenarios, but its use in 2050 may vary by a factor of four, depending on global co-operation to reduce CO_2 emissions and on technology transfer. Also, CCS alone is not sufficient to stem the growth of CO_2 emissions. It must be combined with other emission mitigation strategies.

Figure 6.2

CO₂ capture in the four EFTEP scenarios (2000-2050)

Key point: The four scenarios show between 5-19 Gt of CO₂
captured by 2050
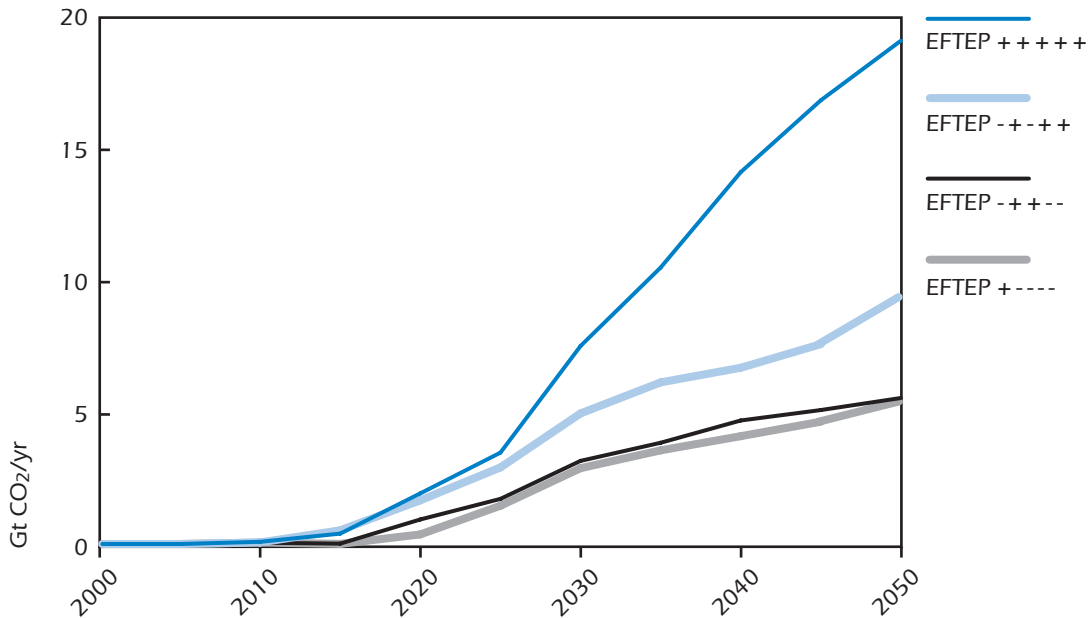
Figure 6.3

**CO₂ capture by technology type in the four EFTEP scenarios
(2030 and 2050)**

Key point: Half to three-quarters of all CO₂ capture is from IGCCs
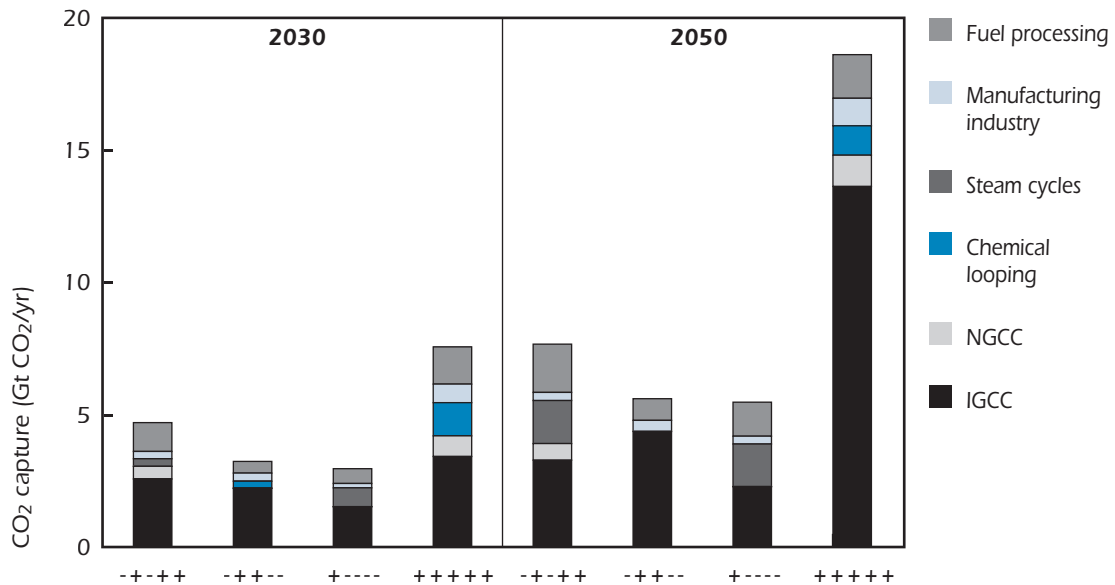
Figure 6.3 compares CO_2 capture by technology type in 2030 and 2050 in the four scenarios. In 2030, the use of IGCC is already dominant and responsible for 45-70% of all CO_2 captured. Coal-fired ultra-supercritical steam cycles, gas-fired power plants and capture from fuel processing make up the difference. In scenario +++++, chemical looping and capture in manufacturing also play an important role. The main difference in 2050 is the extent to which IGCC is applied: CO_2 capture from IGCCs ranges from 2.3-13.7 Gt CO_2 per year.

Figure 6.4 compares CO_2 capture by fuel type in 2030 and 2050 under the four EFTEP scenarios. In 2030, capture from coal-fired processes represents between 41-55% of total CO_2 captured. In 2050, it represents 46-72% of total CO_2 captured. The remaining fraction is split between capture from gas-fired and biomass-fired processes, and to a lesser extent capture from oil fired processes. The differences in terms of CCS fuel shares for 2030 are limited. In 2050, however, major differences occur. High CCS use implies a higher share of coal.

Figure 6.4

CO_2 capture by fuel type in the four EFTEP scenarios (2030 and 2050)

Key point: Half to three-quarters of all CO_2 captured is from coal-fired processes
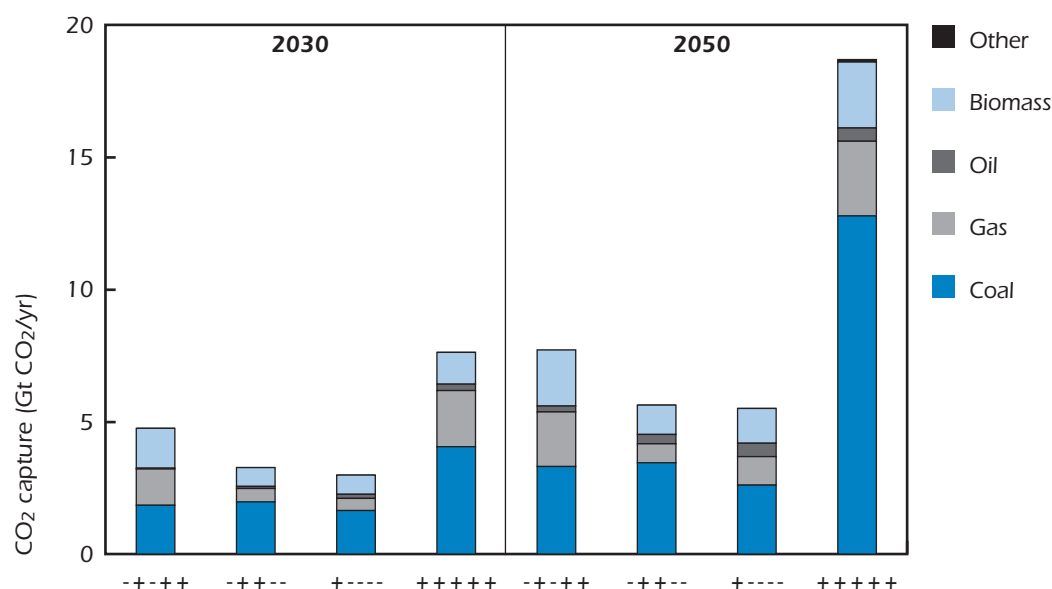
Figure 6.5 compares the primary fuel mix in 2030 and 2050 under the EFTEP scenarios. Total primary energy use in 2030 ranges from 587-674 EJ and from 677-956 in 2050. Increasing economic growth by 1% per year during the period 2000-2050 results in a significantly higher primary energy use in 2050. The main variation is in the use of coal, which ranges from 91 to 343 EJ in 2050. Higher coal use allows for more CO_2 capture.

The share of renewable energy in primary energy use ranges from 20-34% in 2030 and from 19-34% in 2050. This represents a significant increase from 2000 levels, when renewables, including traditional biomass, represented 13% of primary energy use. Biomass represents 65 to 72% of total renewable primary energy. As wind and solar electricity are accounted for on an electricity output

basis, their role is more important than their share in primary energy suggests (3.8 to 6.0% by 2050). The share of fossil fuels in the primary energy mix ranges from 60 to 77% in 2050. Their share amounted to 80% in 2000. So according to the model there is a trend away from fossil fuels, but it is not very strong. The 60% share is for the -+-++ scenario, which has almost 10 Gt CO_2 capture in 2050. So high rates of CCS use can coincide with a high share of renewables. In fact this is the only scenario where global emissions decline.

Figure 6.5

Primary fuel mix in the four EFTEP scenarios (2030 and 2050)

Key point: The four ETP scenarios show a wide range for future coal use
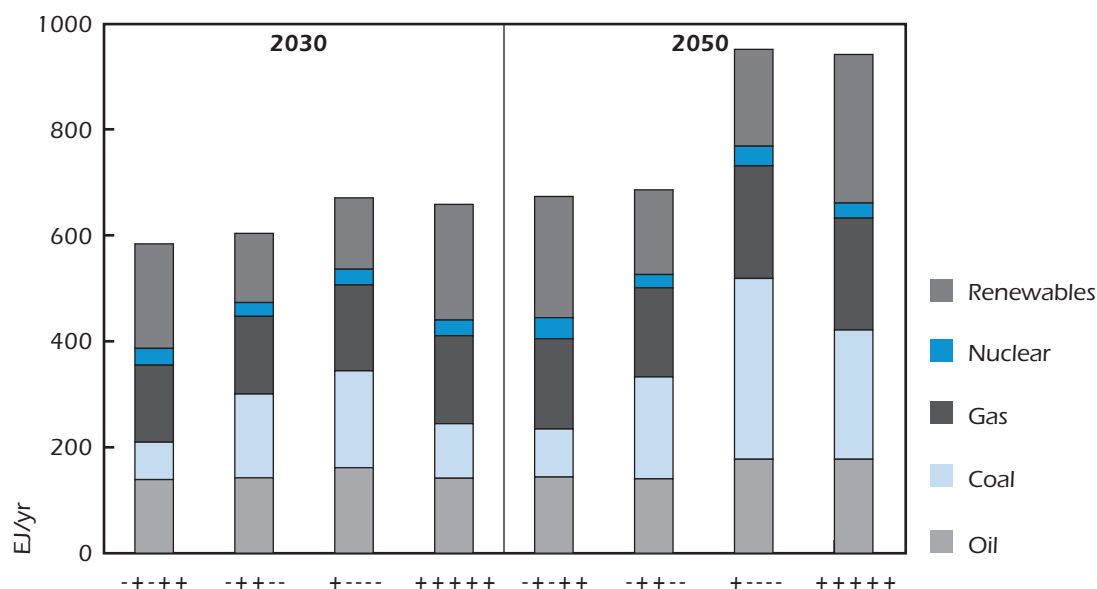
Figure 6.6 compares electricity output by fuel and power plant type in 2030 and 2050 under the four EFTEP scenarios. Power plants with CCS represent between 7-15% of global electricity production in 2030, which increases to between 8-29% in 2050. This excludes CHP plants with CCS which represent another 9% of electricity production in the +++++ scenario by 2050. This result suggests that CCS can play an important role in the electricity sector, but its future share in the electricity mix is uncertain and depends on factors beyond the control of CCS RD&D decision makers. But the fact that CCS is applied in all four scenarios suggests that it is a robust strategy.

In summary, the scenario analysis suggests that the urgency of CO_2 emission reduction (*i.e.*, the penalty level) and international co-operation to combat climate change (*i.e.*, the scope of the penalty) are the dominant factors that determine the future role of CCS. Next in order of importance comes CCS technology progress. CCS is to a large extent a coal strategy, except in the -+-++ scenario of low economic growth and low technology progress, where capture from coal processes represents less than half of total capture. IGCC is a key technology in all scenarios. Only in the +---- scenario, its share is less than half of total capture in 2050.

Figure 6.6

**Electricity production by fuel type
in the four EFTEP scenarios (2030 and 2050)**

Key point: The share of fossil fuels with CCS in the
electricity mix is limited in three out of the four ETP scenarios
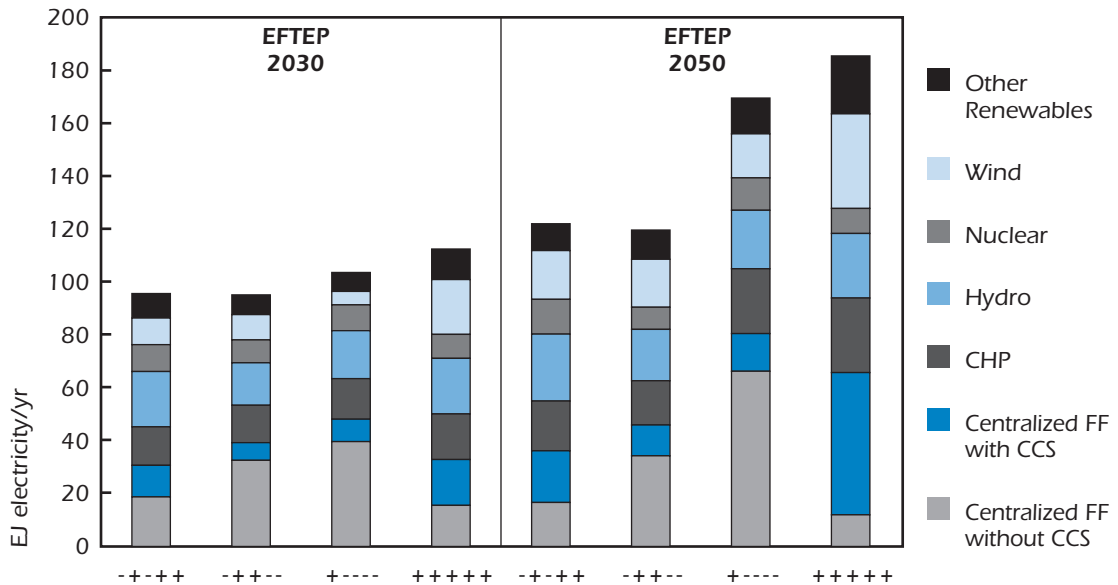
FF = Fossil Fuelled.

CCS Potentials and RD&D Activities in a Regional Perspective

This section and the remainder of this chapter provide an overview of CCS activities and policy plans in major world regions, supplemented by ETP scenario analysis results for these regions. The comparison of short- and medium-term policy plans and modelling results is designed to show whether government activities match the potential for CCS.

A comprehensive overview of individual research, development and demonstration activities in the field of CCS is available online (IEA GHG, 2004). It includes descriptions of approximately 90 projects, including 11 commercial CO_2 capture projects, 35 CO_2 capture R&D projects, 26 geologic storage demonstration projects, 74 geologic storage R&D projects and nine deep ocean storage R&D projects. It is beyond the scope of this study to discuss all these projects in detail. Only some key projects and concepts will be discussed and compared to the potential identified by the ETP model results.

In 2030, capture in industrialized countries (OECD and transition economies) dominates in all four scenarios. By 2050 capture in developing countries can reach a similar level to that seen in industrialized nations. However this is only the case in the scenario +++++. In three out of four scenarios, capture in industrialized countries dominates total capture in 2050.

The analysis in Chapter 4 suggested that the bulk of the CCS potential is in the electricity sector. Figure 6.7 shows the electricity produced by power plants with CO_2 capture by region under the GLO50 scenario. In 2030, North America represents 37% of the electricity production with CCS. By 2050, Chinese CO_2 capture in the electricity sector surpasses North American production. **By 2050, CO_2 capture is concentrated in North America (with 5.5 Gt) and China (4.5 Gt). Capture and storage in Europe amounts to 1.5 Gt.** The quantities of CO_2 captured in Europe (East + West) are smaller than in certain other regions, but they are still significant. The regional distribution of CCS can largely be explained by differences in fuel prices and fuel availability (better access to natural gas from pipelines in Europe). The following sections provide a break-down of the regional outlook.

Figure 6.7

Electricity production by power plants fitted with CCS technology, by region (2030-2050, GLO50 scenario)

Key point: North America and China show the strongest uptake of CCS technology in power generation by 2050
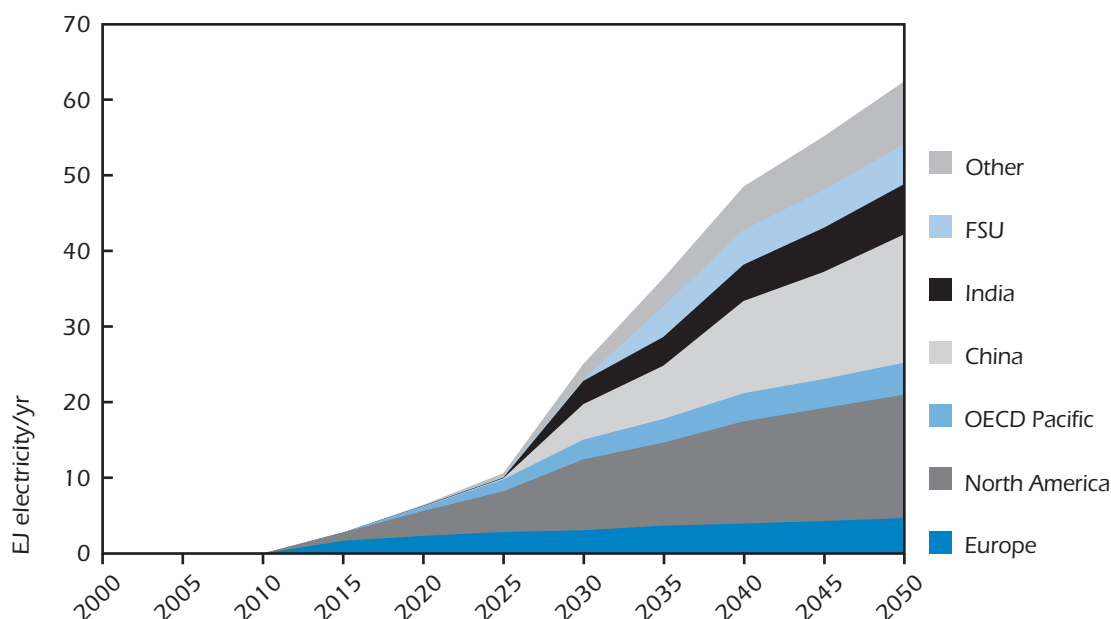
North America

Both the US and Canada have significant RD&D programmes investigating the potential application of CCS. The US programmes are driven by large indigenous coal reserves, and skepticism as to whether other options can provide sufficient emissions reduction. Moreover, hydrogen from FutureGen-type plants could be used as a CO_2-free coal derived transportation fuel. This would reduce CO_2 emissions and the need for oil imports. The Canadian programmes aim to find out whether it is worth applying CO_2 for EOR. Moreover, the extensive oil sand reserves can only be used to their full extent if CO_2 policies pose no development constraints. Unlike the US, Canada has ratified the Kyoto protocol. Canada therefore has an added incentive to cap emissions.

RD&D for CCS in the US totaled 40 million USD in 2004. More than 70 projects have received funding (McKee, 2004b). These include:

- 15 projects looking at pre- or post-combustion capture of CO_2;

- 17 projects investigating CO_2 sequestration, including the potential for terrestrial, geologic and some oceanic storage;

- 14 projects to measure, monitor and verify sequestered CO_2;

- 9 projects exploring breakthrough CO_2 capture and storage concepts;

- 16 basic research projects within the US National Energy Technology Laboratory.

A detailed overview of these projects is provided by Tomski (2003). The US Department of Energy (DOE) aims to reduce the cost increase for CO_2 capture to 10% of electricity production costs (Klara, 2003). For this purpose, a wide range of new CO_2 capture technologies for power plants are being investigated. Two IGCC demonstration power plants are in operation: Tampa and Wabash. A third one, the Sierra Pacific plant, is no longer operational. All three plants have a capacity of around 250 MW. None is designed for CCS.

The FutureGen power generation project, one of the US's major planned initiatives for CCS, will operate at net 275 MW capacity using IGCC technology to produce both electricity and hydrogen while sequestering 1 Mt of CO_2 per year. The project will cost 950 million USD with international partners expected to contribute 8% of this sum. The plant is projected to be ready in 2012 with testing planned by 2015 (DOE, 2004). Since the US has opted for IGCC as the future coal-fired power plant technology, relatively little attention has been paid to advanced steam cycles.

To date, electricity companies have been reluctant to invest in IGCCs. US companies have considerable experience in long-range CO_2 transportation and the use of CO_2 for EOR. However, these EOR projects have not been designed for CO_2 storage purposes. A wide range of CO_2 storage projects are underway, but they remain relatively small in scale. One injection project is testing a depleted oil field near Roswell, New Mexico, and a saline aquifer storage project is being developed near Houston, Texas (the so-called Frio project).

An EOR project in Wyoming known as Teapot Dome, named after a nearby rock formation, is currently in its preliminary engineering and testing stages. This would store CO_2 from a natural gas processing plant that is transported over a distance of more than 500 kilometres. Storage could begin by 2006 and last 7-10 years. The site is projected to store at least 1.6 Mt of CO_2 a year when fully operational. The storage potential of another site, the Mt. Simon aquifer, is also being studied in more detail. This reservoir potentially has a very large storage capacity.

Seven regional CO_2 sequestration partnerships, which began in August 2003, are aimed at developing frameworks for validation and deployment of CO_2 sequestration technologies for US regions. The two-year-long Phase I effort is valued at 18.1 million USD, and will be followed by a Phase II which will test CO_2 sequestration.

On an international level, the US recently initiated the CO_2 Sequestration and R&D Leadership Forum (CSLF). The purpose of the CSLF is to make CCS technologies broadly available internationally, including to developing countries and transition economies, and to identify and address wider issues relating to CO_2 capture and storage. This could include promoting the appropriate technical, political, and regulatory environments for the development of such technologies. Table 6.2 provides an overview of approved CSLF projects, some of which are subsequently discussed in more detail.

Table 6.2

CSLF international co-operation projects

Name	Partners	Topic
ARC Enhanced Coal-Bed Methane Recovery Project	Canada, United States United Kingdom	The objective of this project is to evaluate, from both economic and environmental criteria, a process of CO_2 injection into deep coal beds for simultaneous sequestration of the CO_2 and liberation (and subsequent capture) of coal-bed methane.
CANMET Energy Technology Centre enhanced oil (CETC) R&D Oxyfuel Combustion for CO_2 Capture	Canada United States	The objective of this project is to demonstrate oxyfuel combustion technology with capture of a high-purity CO_2 stream suitable for recovery and to provide information for the scale-up, design and operation of industrial and utility plants based on the oxyfuel concept.
CASTOR	European Union France Norway	The objective of this project is to attempt to validate, from process, economic, legal, and public acceptance perspectives, post-combustion capture and storage of CO_2 with a goal of achieving a major cost reduction in CO_2 capture cost.
CO_2 Capture Project, Phase II	Italy Norway United Kingdom United States	The objective of this project is to continue the development of new technologies to reduce the cost of CO_2 separation, capture, and geologic storage from combustion sources such as turbines, heaters and boilers.
CO_2 Separation from Pressurized Gas Stream	Japan United States	The objective of this project is to evaluate processes and economics for CO_2 separation from pressurized gas streams with gas separation membranes.
CO_2SINK	European Union Germany	The objective of this project is to test and evaluate CO_2 capture and storage in order to better understand the science and processes involved in underground storage of CO_2 and to provide experience for use in development of future regulatory frameworks for geological storage of CO_2.
CO_2STORE	European Union Norway	The objective of this project is to demonstrate, as a follow-on to the current Sleipner project, monitoring to track CO_2 migration to undertake additional studies to gain further knowledge of geochemistry and dissolution processes.
Frio Project	Australia United States	The objective of this project is to demonstrate CO_2 sequestration in an onshore underground saline formation in order to verify conceptual models and monitoring methods, demonstrate that no adverse health, safety or environmental effects will occur, and develop the experience necessary for larger-scale experiments.
ITC CO_2 Capture with Chemical Solvents	Canada United States	The objective of this project is to demonstrate CO_2 capture using chemical solvents, with a goal of developing improved cost-effective technologies for separation and capture of CO_2 from flue gas.
Weyburn II CO_2 Storage Project	Canada Japan United States	The objective of this project is to utilize CO_2 for enhanced oil recovery at a Canadian oil field, including monitoring of CO_2 migration within the oil field, with a goal of determining the overall performance and risks in using CO_2 for enhanced oil recovery.

In Canada, an association of seven Canadian utilities and coal producers, together with the US's Electric Power Research Institute (EPRI), has formed the Canadian Clean Coal Coalition to develop coal-fired power plants with low CO_2 emissions. The completed Phase I concluded that amine scrubbing (chemical absorption) is the technology of choice, with gasification and electricity and hydrogen co-production also offering most potential. Phase II will conduct detailed studies of IGCC plants prior to committing funds for demonstration projects (Canadian Clean Power Coalition, 2004).

The Clean Coal Coalition plans to carry out two demonstration projects. The first will look at capturing CO_2 from an existing coal-fired power plant and is expected to be operational in 2007. The second proposal provides for the development, construction and operation of a full-scale demonstration project by 2012, which will remove CO_2 and other emissions of concern from a greenfield power facility. Both demonstration projects will cost 766 million USD, partially funded by the Canadian government (NRCAN, 2004).

On the storage side, Canada's Weyburn project is looking at using CO_2 for EOR with special emphasis on CO_2 storage, monitoring and validation. The project started in 2001. The 32 million USD Phase I has been completed (Wilson *et al.*, 2004). Phase II, which started in July 2004, is expected to receive a similar amount of funding and to last four years. The Weyburn project uses CO_2 EOR to increase oil recovery from 34% to almost 50% of the original oil in place. About 5 kt of CO_2 per day is taken from a coal gasification plant in North Dakota (USA), and transported over 330 km. At the conclusion of the project, some 19 Mt of CO_2 will have been sequestered in the reservoir.

A number of other R&D projects related to CCS are underway in Canada, backed by financial support in the form of a 15 million USD incentive programme. These include projects to sequester CO_2 in oil sands tailing streams, to use CO_2 in ECBM pilot projects, to use CO_2 to enhance gas hydrate production, and an oxyfuel demonstration project. The intention of the US-supported programme is to stimulate the growth of a Canadian CO_2 capture and storage industry. Eligible expenditures are defined as up to 50% of the cost of capital equipment and all other direct expenses required for capturing, compressing, transporting and injecting CO_2 (NRCAN, 2004).

Canada could become an important oil supplier if the oil sand production is further developed. However, the production of crude from these sands would be an important source of CO_2. Due to the geology of Canada, the province of Alberta is where current oil, oil sands and gas activities are concentrated. The provincial authorities are actively supporting research in the development of CCS technology in order to allow future expansion of these production activities. A total of 11 million USD of royalty credits has been approved for four CO_2 EOR projects in Alberta.

The fact that important CCS RD&D activities are taking place in North America is in line with the projected potential importance of this strategy for this region. Figure 6.9 compares CO_2 capture from major point sources in 2030 and 2050 in North America under the four EFTEP scenarios. Total capture is significant, up to 5 Gt CO_2 per year in 2050. Since the amount captured is not very scenario dependent, CCS therefore seems to be a 'safe bet'. The results suggest 2-3 Gt CO_2 capture by 2030. Electricity production represents the bulk of the CO_2 capture potential, while the storage potential of the FutureGen project is 1 Mt per year by 2015. A 2,000-fold increase is needed in order to realize the storage potential shown in Figure 6.8. Expansion on this scale presents a major challenge. Although current policy efforts are important, they are not geared to deploying CCS on such a large scale within the next 25 years.

Figure 6.8

**CO₂ capture in North America
in the four EFTEP scenarios (2030 and 2050)**

Key point: CO_2 storage potential in North America is up to 5 Gt CO_2
and supported by high CCS use in all scenarios
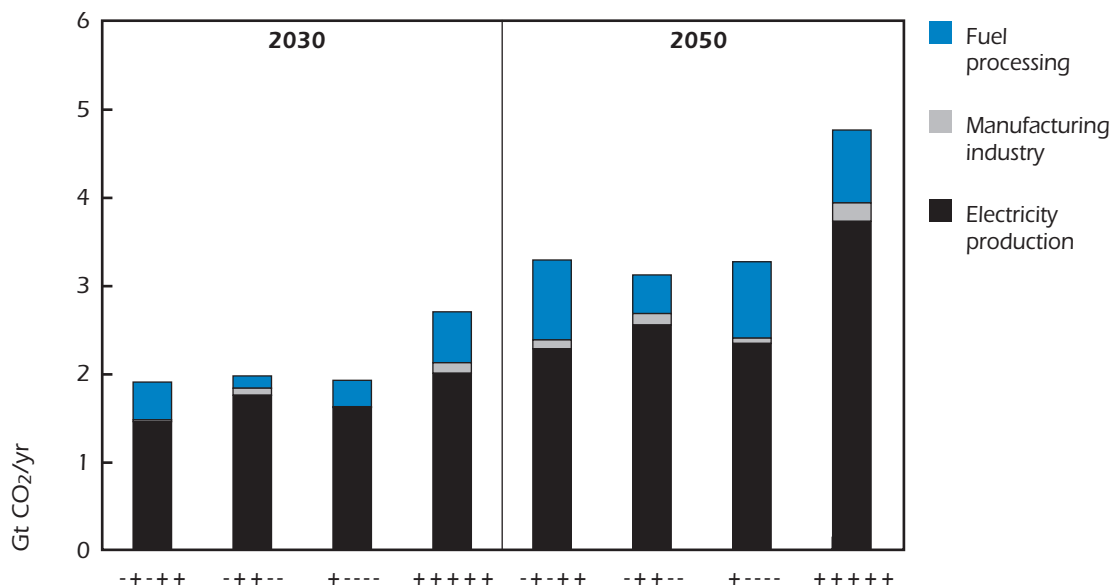
Europe

For the purposes of the discussion in this section, Europe includes Eastern and Western Europe. At present, Europe already has advanced CO_2 emission reduction policies in place. These include CO_2 market mechanisms, demand-side policies, and support programmes for renewables and other emission reduction technologies. CCS is gaining increasing attention, as policy makers start to realize that significant emission reductions require a wider portfolio of emission mitigation strategies. CO_2 may also be used for EOR in the maturing North Sea oil fields.

The prospects for CCS differ by country. Norway, for example, is very active in this area in the field of subsea aquifer storage through the Sleipner demonstration project and the planned Snohvit LNG project. There is also considerable interest in using CO_2 for EOR. CENS and Statoil's New Energy group are studying the supply of CO_2 for EOR to the Gullfaks field within the Statoil Tampen 2020 project (see Chapter 3) (Coleman, 2004). However, the project is not cost-effective without a CO_2 incentive. Norway has conducted a number of feasibility studies for gas-fired power plants with CO_2 capture, and Denmark has studied the feasibility of CO_2 capture for coal-fired power plants, but these studies have not yet resulted in any further demonstration plans.

In Europe as a whole, electricity companies have so far been reluctant to invest in IGCC technology. To date, two IGCC demonstration projects have been built in the region, at Buggenum in the Netherlands and at Puertellano in Spain, each with a capacity of around 250 MW. More interest is hoped for from the EU's CASTOR project, which began in 2004 and is under the leadership of

the Institute Française de Petrole (IFP). The project involves 30 companies and research institutions from eleven European Union countries and aims to reduce the cost of capturing and separating CO_2 from flue gases to 20-30 EUR/t. Much of the research on capture, representing 70% of the four-year Castor budget of 19.1 million USD, will focus on a pilot plant able to treat 1-2 t/hr of CO_2 from real flue gases (10 kt/yr or 1% of the US's FutureGen demonstration plant).

The EU is co-funding various storage projects. One is the first CO_2 storage in an onshore aquifer in Ketzin, close to Berlin, known as CO_2Sink. Previously, the site was used for natural gas storage. The goal is to improve understanding of the behaviour of CO_2 underground (GFZ Potsdam, 2004). The RECOPOL project in southern Poland is an EU-funded pilot/demo project for CO_2 ECBM. Within the CASTOR project, storage research will take place at four sites: in the abandoned Casablanca oil reservoir off Spain, the Snohvit aquifer storage project in the Norwegian Sea, a depleted offshore deep gas reservoir owned by Gaz de France in The Netherlands (also known as the CRUST project, mentioned below), and a depleted shallow gas reservoir owned by Rohoel-Aufsuchungs AG in Austria.

A large number of CCS projects are being co-funded by the EU. It is beyond the scope of this analysis to discuss all of these in detail. Further information can be found on the IEA GHG project database (IEA GHG, 2004).

The European Commission has announced the so-called Quick-start hydrogen programme. This is a 10-year programme with a budget of 3.4 billion USD (2.8 billion EUR), that covers hydrogen supply and hydrogen demand. From December 2004, demonstration projects can be proposed for hydrogen production from fossil fuels with CCS (HypoGen). A budget of 1.6 billion USD (1.3 billion EUR) is foreseen for HypoGen, roughly half the funding for which would come from the EU framework programmes. HypoGen focuses on hydrogen and electricity cogeneration and is similar to the US's FutureGen project. HypoGen aims to demonstrate the economic viability of hydrogen and electricity production from de-carbonated fossil fuels, to prove concepts and test the regulatory environment for safe and reliable geological storage of CO_2 (European Commission, 2004).

The EU Emissions Trading Scheme (ETS) which begins in 2005 will provide incentives for CO_2 emission reduction. CCS is mentioned in the relevant ETS Directive, but emission reductions must be proven. The permit price under the ETS is projected to be less than 10 USD/t CO_2, which will be insufficient as an incentive for CCS use, but which may help to demonstrate feasibility for certain EOR projects. However, penalties of up to 100 EUR/t CO_2 are envisaged for the period 2007-2012 for non-compliance. These penalties are much higher than CCS costs, and therefore CCS may be introduced, if other strategies do not result in sufficient emissions reduction.

In terms of individual countries, Germany has started a large RD&D programme known as Cooretec which aims to develop and demonstrate energy efficient fossil-fueled power plants, including CO_2 capture technologies (Cooretec, 2003). It includes a roadmap to further increase efficiencies by 20% by 2020. An oxycoal process for CO_2 separation will be developed. Cooretec funding amounted to 10 million EUR in 2004, and will amount to 30 million EUR per year in 2005 and 2006. The goal of the programme is to maintain Germany's leading role as a power plant supplier. Most work is focused on materials and systems design for high-efficiency steam cycles with attention to IGCC restricted to desk studies. While these efforts are not directly focused on CCS development, energy efficiency improvements constitute a crucial step that will enable CCS introduction.

Representatives of the regional government of North Rhine-Westphalia have indicated that the decision to construct a reference coal power plant might be taken before the end of 2004 (Geipel, 2004). This would be a hard coal-fired power steam cycle plant with 45.9% efficiency, which can be increased to 47.3% with additional investments of about 50 USD/kW. A large-scale test facility

for USCSC will be built in the German Scholwen power plant as part of the so-called AD700 project (AD700, not dated).

In the UK, the Department of Trade and Industry's Carbon Abatement Technologies (CAT) programme (DTI, 2004) is developing a strategy for a near-to-zero emission fossil-fuel combustion plant. The new CAT strategy is expected to be finalized by autumn 2004. It will address a number of strategic issues that need to be considered before a decision can be taken on the demonstration of CCS. In the UK, the fourth call for carbon abatement technologies runs for three years and covers ten projects for a total amount of 18 million USD over a period of three years. Topics include combustion gasification, efficiency, emissions, design studies, CO_2 capture and hydrogen (Morris, 2004).

The longer-term strategic importance of CCS is recognized in the UK government's Energy White Paper. CO_2 EOR receives special attention because the UK fields in the North Sea are rapidly depleting (DTI, 2003). This opportunity only exists in the short term, however, and CO_2 injection needs to start by 2006/8 if it is to have an impact on the largest fields before the existing infrastructure is dismantled.

The Netherlands plans a small pilot project for offshore storage in a depleted gas field, called CRUST (CO_2 Re-use through Underground Storage). The Netherlands has also launched the CATO programme (CO_2 capture, transport and storage) for further technology development (Tweede Kamer, 2003). The programme funding amounts to more than 30 million USD over a period of five years (2004-2008), half of which is government funding.

Italy has a national CCS R&D programme in which hydrogen production from fossil fuels is a key priority. Underground storage potentials have already been analysed with two pilot projects planned.

Figure 6.9

CO₂ capture in Eastern and Western Europe in the four EFTEP scenarios (2030 and 2050)

Key point: CO₂ storage potential in Eastern and Western Europe is up to 1.6 Gt CO₂, although the potential is halved under some scenarios
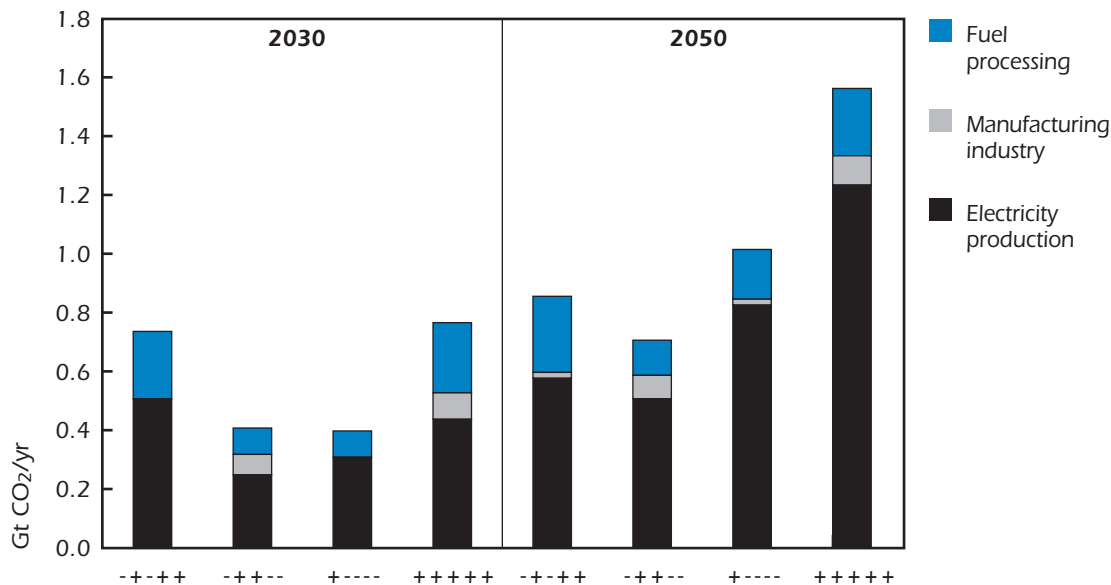
One is the Sibilla EOR project in the Adriatic Sea which will sequester 1.5 Mt of CO_2 over a period of 10 years, starting in 2007. The second is an ECBM project in the Sulcis area of Sardinia, where 1 Mt CO_2 sequestration is planned (Capra, 2004).

Figure 6.9 compares CO_2 capture from major point sources in 2030 and 2050 in Western and Eastern Europe under the four EFTEP scenarios. Total capture is significant, up to 1.6 Gt CO_2 per year in 2050. The capture potential is half to a third of the potential in North America. The amount captured is not very scenario dependent, and so, as in the case of North America, CCS seems a 'safe bet'. The extensive CCS RD&D activities taking place in this region are in line with the projected potential importance of this strategy for the region. The results suggest 0.4-0.8 Gt of CO_2 capture by 2030. Current policy efforts are not geared to CCS use on such a large scale within the next 25 years.

Asia-Pacific OECD Countries

The OECD Asia-Pacific region encompasses Australia, Japan, New Zealand and Korea. Since New Zealand has very low CO_2 emissions and Korea has no CCS plans to speak of, the following discussion is limited to Australia and Japan.

Australia relies on coal for the bulk of its electricity production. As the largest coal exporter in the world, Australia has important business interests to develop CCS technology. A technology roadmap has been published by the Co-operative Research Centre for greenhouse gas technologies in Australia (CO_2CRC, 2004). Since 1999, the Australian Petroleum Co-operative Research Centre (APCRC) has carried out research into deep geological storage of CO_2 through its GEODISC programme, which shows that Australia has very high potential for cost-effective geological storage of CO_2.

The Australian and State governments are working with industry to support CCS R&D. The Australian government is spending approximately 20 million USD per year on all clean coal technology research, of which a significant proportion is directed to CCS R&D. This includes design of energy efficient coal-fired power plants (hard coal and lignite), new capture technologies, CO_2 storage, and hydrogen technologies. The government has established a 350 million USD fund that should attract another 700 million USD in private investment to develop and demonstrate low emission technologies, including CCS (Jones, 2004).

Aquifer storage is planned for the Gorgon gas field situated 130 km off the north-west coast of Western Australia. CO_2 separated for LNG production will be re-injected into the gas field, with approximately 5 Mt CO_2 storage aimed at per year. Production from the Gorgon gas field is projected to begin in 2008-2010 (Gorgon, 2004).

Japan has studied CO_2 capture and storage for quite some time. However, onshore underground storage potentials are limited by the geology of the country and the lack of indigenous oil and gas reserves. As a consequence, studies have focused on oceanic storage, but this strategy is highly controversial in Japan and abroad. Therefore, attention is now switching to ECBM, with a 10 Gt cumulative storage capacity, and a pilot project is underway. A small aquifer storage pilot project has also started, where 10 kt of CO_2 will be injected over a period of one and a half years (RITE, 2003).

The Engineering Advancement Association of Japan (ENAA) undertook estimates for geological storage potential in the early 1990s. These estimates indicated the potential to store some 92 Gt CO_2 in geological reservoirs, the majority of which (52 Gt) are offshore aquifers. Seen in comparison

to 500 Mt CO_2 emissions per year from stationary sources, geological storage in Japan would seem to have significant potential. However, Japanese storage potentials are not evenly distributed, which will limit the practical storage potential.

In 2001, Japan launched a new research project, involving the Research Institute of Innovative Technology for the Earth (RITE) and ENAA, which will build upon the earlier research work. The 5-year project will involve a number of activities, including:

- A field-scale injection study to demonstrate the potential for CO_2 injection in Japan and obtain data on the actual behaviour of carbon dioxide underground.
- A geological survey around the Pacific offshore region of Japan. The study will compile existing seismic and exploration data in the region and generate a GIS database that will act as a support tool for future storage activities.
- Undertake a system analysis to assess possible combinations among locations of large-scale CO_2 sources and storage options. A cost evaluation model will be used to assess cost-effective storage options for Japan (Gale, 2002).

So far, Japanese policies are targeted at increasing energy efficiency and the use of nuclear power to reduce emissions. However, the future expansion of nuclear energy is controversial. As a result, R&D is looking at maximizing coal-fired plant efficiency with most attention focused on fluid bed combustion. A 25 MW IGCC demonstration project, known as EAGLE (Coal Energy Applications for Gas, Liquid & Electricity) is now underway. This plant integrates fuel cells and could be used for synfuel cogeneration (similar to FutureGen). So far, there are no plans for CO_2 capture from this installation (Wakamatsu, 2004).

Figure 6.10

CO₂ capture in the OECD Asia-Pacific region in the four EFTEP scenarios (2030 and 2050)

Key point: CO₂ storage potential in the OECD Asia-Pacific region is up to 2.1 Gt CO₂, although the potential is halved under some scenarios
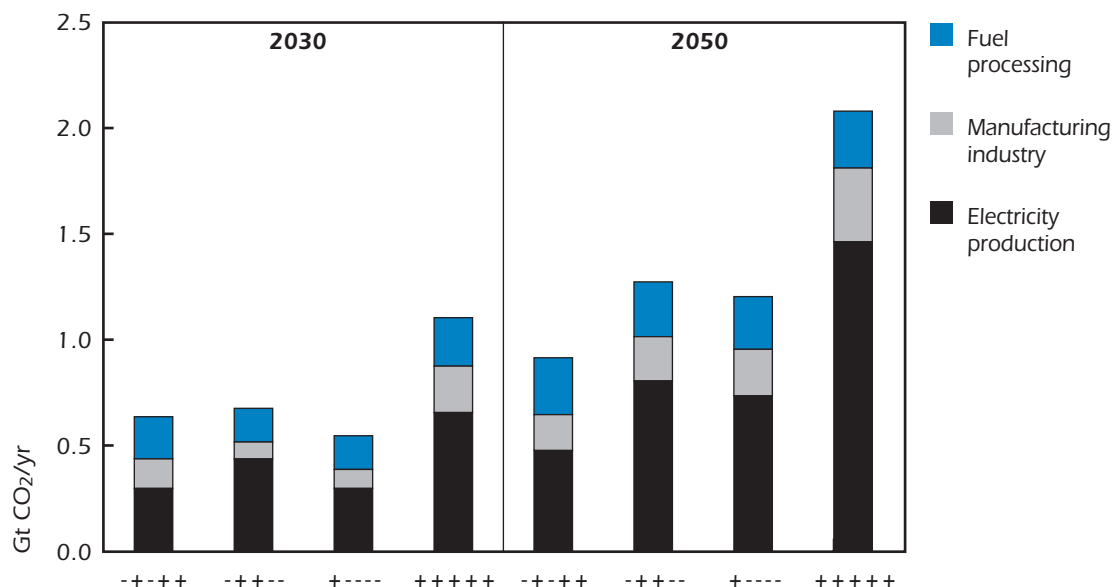
Figure 6.10 compares CO_2 capture from major point sources in 2030 and 2050 in Japan, Korea, Australia and New Zealand under the EFTEP scenarios. Total capture is significant, up to 2.1 Gt CO_2 per year by 2050. Capture is of a similar order to that in Europe, even though the OECD Asia-Pacific region has only a third of the population. The potential for CO_2 capture is significant, especially in Australia. The amount that is captured is not very scenario dependent, so once again CCS seems a 'safe bet', similar to the situation in North America and Europe.

The fact that important CCS RD&D activities are taking place in Australia is in line with the projected potential importance of this strategy for this region. The results suggest 0.5-0.1 Gt CO_2 capture by 2030. Current policy efforts are not geared to CCS use on such a large scale within the next 25 years. Electricity production represents the bulk of the CO_2 capture potential. Capture in manufacturing industry and fuels processing is also of importance.

China

China relies to a large extent on coal for its energy supply. A recent study predicts that the efficiency of coal-fired power plants will increase from 32.0% in 2000 to between 39.2% and 44.4% by 2020 (ERI, 2003). This means that new Chinese coal-fired power plants would achieve current OECD best-practice efficiency levels by 2020. However, opinions in China diverge on whether the country should adopt advanced steam cycles or IGCC technology for new plant. Approval has been given for a feasibility study for a 300-400 MW IGCC plant in Shangdong province. As discussed in Chapter 3, either choice does not impede the use of CCS, as long as the plants achieve high efficiencies.

China has considerable potential for the capture and utilization of coal bed methane (CBM). At present, the China United Coal-bed Methane Corporation (CUCBM) remains the sole professional state-owned company responsible for CBM exploration, development, production, pipeline construction and sale in China. In addition, CUCBM has obtained exclusive rights for the exploration, development and production of CBM, in co-operation with foreign companies.

Twenty CBM projects with international co-operation have been signed, covering an area of 32,000 km^2 and representing a reserve of 3,654 billion m^3 (more than 100 EJ gas; BHPBilliton, 2003). CUCBM is planning two CO_2 ECBM field tests in co-operation with a consortium of Canadian groups (Law and Gunter, 2003). It remains to be seen whether the coal permeability makes ECBM a viable option. As in other oil-producing countries, China is also interested in enhancing the output from oil reservoirs as their output diminishes over time. An enhanced oil recovery project is currently underway at the Liaohe Oil Field, looking at injecting boiler flue gases into a production well (Zhu *et al.*, 2001).

Figure 6.11 compares CO_2 capture from major point sources in 2030 and 2050 in China under the four EFTEP scenarios. The total capture potential is significant, up to 4 Gt CO_2 per year in 2050. At this level, capture is of a similar order to that in North America. However, the amount that is captured is very scenario dependent, and much lower than in other regional scenarios. The policy choice to mitigate CO_2 emissions is a key variable. But even in the -+-++ scenario with a CO_2 penalty but with less optimistic technology assumptions, the use of CCS in 2050 is small, although it is still at the same level as in Europe. The fact that no important CCS RD&D activities are taking place in China is in line with the uncertain future of CO_2 emission reduction in this region. China is participating in the CSLF. **The results suggest that more Chinese involvement in CCS might be warranted.**

Figure 6.11

CO₂ capture in China in the four EFTEP scenarios (2030 and 2050)

Key point: CO₂ storage potential in China is around 3.8 Gt CO₂, although much lower quantities or none are observed in three out of the four scenarios
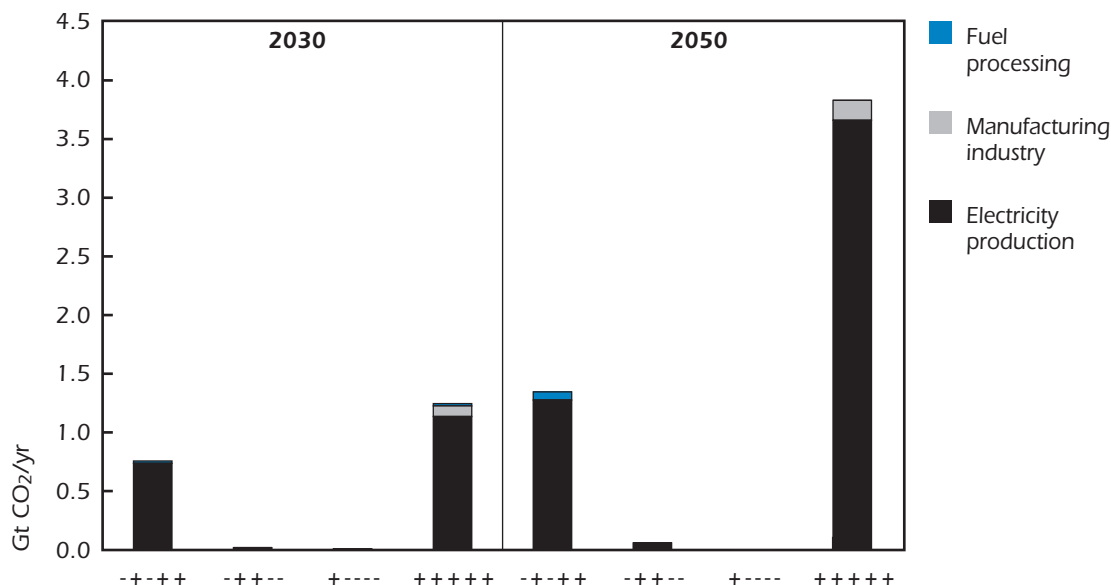
India

The Indian energy system will continue to rely on indigenous coal, which is largely high ash coal. In combination with subcritical steam cycle power plant technology, this results in low efficiencies in electricity production. This issue has been discussed in Chapter 3. As a consequence of this low efficiency, CO₂ capture would make little sense for India on the short and medium term. As a first step, a programme is needed to establish high-efficiency, large-scale power plants. At a later stage this could be followed by CO₂ capture and storage. To date, India has no programmes in the field of CCS. However the country is participating in the CSLF. There is some potential for ECBM, but the cost for CO₂ capture would outweigh the benefits of ECBM.

Figure 6.12 compares CO₂ capture from major point sources in 2030 and 2050 in India under the four EFTEP scenarios. The total capture potential is significant, up to 2.5 Gt CO₂ per year in 2050. At this level, capture is of a similar order as in Europe. However, the amount that is captured is very scenario-dependent, and it is negligible in two out of the four scenarios. The policy choice to mitigate CO₂ emissions is a key variable. But even in the -+-++ scenario with a CO₂ penalty but with less optimistic technology assumptions, the use of CCS in 2050 is small. The fact that no important CCS RD&D activities are taking place in India is in line with the uncertain future of this strategy for this region. **It would be better for India to focus first on switching to high-efficiency power plants, with the possibility for retrofitting CCS at a later stage.**

Figure 6.12

CO_2 capture in India in the four EFTEP scenarios (2030 and 2050)

Key point: CO_2 storage potential in India is up to 2.6 Gt CO_2, but much lower quantities or none are observed in three out of the four scenarios
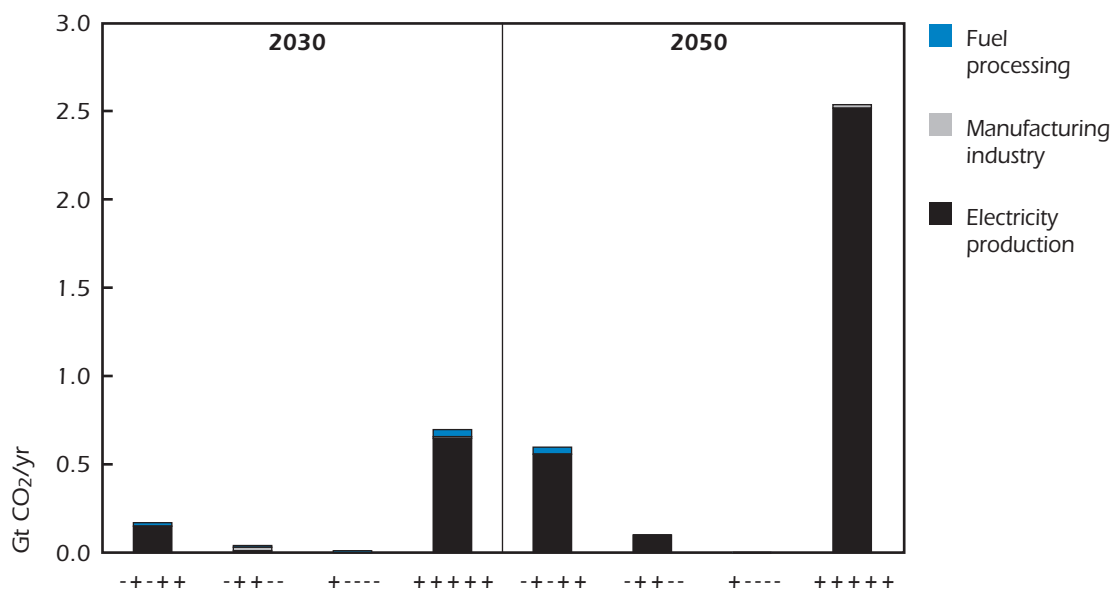
Middle East

The Middle East has the energy resources to become the main source for oil and gas in the coming decades. At the same time, many of its giant oil fields are ageing. For example, half the proved reserves have been produced from Ghawar, the world's largest oil field in Saudi Arabia (Abdul Baqi and Saleri, 2004). CO_2 EOR could be a way of increasing Middle Eastern oil production from fields that are in decline. There are two challenges for widespread CCS use in this region. The first of these is of a technical nature, while the second concerns CO_2 supply at acceptable cost.

About 80% of oil that is currently produced in the region is medium and heavy sour crude (ENI, 2004). Medium crude is crude between 26-35°API (0.898 to 0.845 t/m³). This oil is heavier than oil in fields where CO_2 EOR has been successfully applied so far. Various authors give maximum oil gravities for CO_2 miscible floods ranging from 0.8 to 0.95 t/m³, but typically 0.9 t/m³ is considered a maximum (see Chapter 3, Shaw and Bachu, 2002). The oil that remains underground following water injection is probably heavier than the oil that is produced at the moment. Therefore the technical potential of CO_2 EOR needs more attention.

Also, reservoir temperature should not exceed 120°C to ensure CO_2 and oil miscibility. This would exclude the Ghawar field, for example, which has a reservoir temperature of 137 to 150°C. If miscible flooding is not possible, immiscible CO_2 flooding may be applied. However this will cut the EOR oil recovery factor in half. A careful, field-by-field assessment is needed if CO_2 injection is to be judged suitable for recovering significant amounts of remaining Middle Eastern oil.

While the Middle East has a significant storage potential in depleted oil and gas fields, it is not a primary emissions source in a region where emissions amounted to 1 Gt CO_2 in 2000 (IEA, 2002b). The region's electricity production is largely based on indigenous oil and gas reserves, not on coal. CO_2 could be imported from other regions, however. This could even be a feasible option without CO_2 policies in the Middle East. For distances up to 5,000 kms (Western Europe-Middle East) transportation would be in the 15-25 USD/t CO_2 range (IEA GHG, 2002a; IEA GHG 2004b). **These transportation costs must be balanced against the EOR benefits.**

Figure 6.13 compares CO_2 capture from major point sources in 2030 and 2050 in the Middle East under the four EFTEP scenarios. **Total capture is significant at up to 0.35 Gt CO_2 per year in 2050. However, this potential is an order of magnitude smaller than in the regions discussed earlier, and the amount that is captured is very scenario dependent.** Apart from CO_2 shipping from other regions, a closer look may reveal certain low-cost CO_2 supply options, possibly with relocation of oil or gas-intensive industries with a low-cost CO_2-capture potential to the Middle East (ammonia, DRI etc.). The analysis in Chapter 4 suggests that such relocation would depend on future commodity transportation cost and trade barriers. The viability of such a strategy needs to be studied in more detail.

Figure 6.13

**CO₂ capture in the Middle East
in the four EFTEP scenarios (2030 and 2050)**

Key point: CO₂ storage potential in the Middle East is around 0.35 Gt CO₂, although no potential is observed in two of the four scenarios
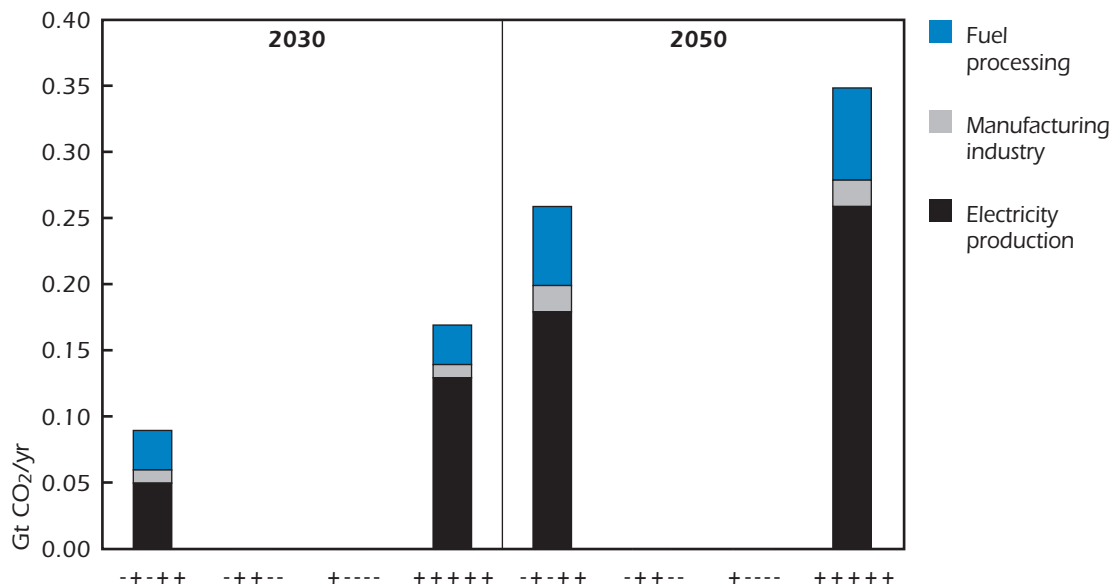
Chapter 7.

THE IMPACT OF CCS ON ENERGY MARKETS: MODEL RESULTS

H I G H L I G H T S

The analysis of the impact of CCS on energy markets has concentrated on the global level. Country specific results may differ, depending on the resource endowment and trade effects.

Impact of CCS on Coal Markets

- In the case of CO_2 penalties above 25 USD/t CO_2 with the CCS option available, coal use is stable up to 2030, but doubles from 2030 to 2050. The increase in the use of coal is accounted for by electricity and synfuel production. While coal use increases in absolute terms, it declines in relative terms compared to the BASE scenario projection for 2050. CCS plays a key role in keeping coal a viable option. Without CCS, coal use in 2050 declines by 64% in a scenario in which a USD 50/t CO_2 penalty is imposed, compared to the same penalty level with CCS.

- If CCS is not considered, coal prices decline by 10%, compared to the scenario with CCS. This decline can be attributed to lower coal demand. These fuel price impacts are small compared to the penalties for emissions caused by coal use without CCS.

Impact of CCS on Gas Markets

- Gas use doubles between 2000 and 2050. This growth is not significantly affected by CO_2 policies and/or the availability of CCS. For example, exclusion of the CCS option results in gas use variations of +/- 15%, depending on the period and the penalty level.

- If CCS is not considered, the impact on gas prices is mixed and region specific, but can be significant. Modelling results suggest a small price decline for Europe and a significant increase for the US. As in the case of coal, these fuel price impacts are small compared to the penalties for emissions caused by gas use without CCS.

Impact of CCS on Oil Markets

- Oil production declines by 10-20% at higher CO_2 penalty levels. If CCS is not considered, an additional 10% decline of oil production occurs at penalty levels above 50 USD/t CO_2. At lower penalty levels the impacts of having CCS are small. This assumes that technology alternatives exist for CO_2 enhanced oil recovery.

- If CCS is not considered, oil prices would increase by about 10%, compared to a scenario with CCS. As is the case for coal and gas, fuel price impacts are small compared to the penalties for emissions caused by fuel use.

Impact of CCS on Renewable Energy

■ Biomass is the most important renewable energy option for CO_2 policies. Its use can grow up to 150 EJ in 2050. Biomass use is barely affected by CCS.

■ In the BASE scenario, the use of other forms of renewable energy increases threefold from current levels during the period 2000-2050. If CO_2 policies are put in place, a five-to-sixfold increase in renewable energy use (excluding biomass) could occur. Additonally, other renewables use can increase by up to 40%, in cases where CCS is not considered. This additional renewable energy is mainly used in the electricity sector.

■ With more optimistic learning assumptions for renewables, the share of CCS in the electricity mix may decline from 37% to 20%. The share of renewables would increase accordingly. Both renewables and fossil-fuelled power plants with CCS will be needed for an electricity supply system with low emissions.

Impact of CCS on Electricity

■ Excluding CCS results in a 4 to 52% increase of electricity prices (feed-in prices). As a consequence of price increases, electricity demand declines by 7% in 2050, compared to the same scenario with CCS. Without CCS, renewables substitute part of the fossil fuels in the electricity mix.

This chapter, the fourth and final set of quantitative results from the ETP model, discusses the consequences of deploying CCS on primary energy (coal, gas, oil and renewables) and electricity markets, using ETP model analysis. Apart from the obvious environmental concerns, supply security and economic factors play an important role in the design of energy policies. While the analysis in the previous chapters has shown that a CCS strategy can significantly reduce CO_2 emissions and also lower the cost of environmental policies, it is less clear what impact CCS would have on fuel markets. This chapter discusses the impacts on fuel quantities and fuel prices.

The effects of CCS on fuel markets can be split into three categories: fuel substitution effects (*e.g.*, enhanced coal competitiveness compared to other fuels), effects on fossil fuel recovery and increased energy demand for CCS.

The additional oil and gas recovery potential due to CO_2 use is elaborated in Chapter 3. If CO_2 is used for EOR, it increases oil recovery by 10-40% compared to a situation without EOR. Injecting CO_2 into depleted gas fields can increase gas recovery by up to 5%. Enhanced coal-bed methane recovery also has significant gas supply potential. However EGR and ECBM are speculative options. This enhanced fossil-fuel recovery is a secondary CCS benefit. CO_2 capture can increase fuel demand because of the energy required for capture and pressurization (see Chapter 3). The fuel demand of fossil-fueled power plants increases by 6-39%.

This chapter will explore in more depth the net effect of these different mechanisms.

Coal

The emissions per unit of energy for coal are higher than for other fuels. CO_2 policies can therefore have a negative effect on the use of coal. However, CCS can reduce the emissions per unit of coal energy significantly, which in turn reduces the negative impacts of CO_2 policies on coal use. The

introduction of CCS results in an efficiency loss of 39% (a 12 percentage points decline of electric efficiency) for existing power generation technologies. This loss may decline to 4 percentage points in the long term due to the introduction of new CCS technologies in combination with new types of power plants (see Chapter 3). Coal demand increases due to this efficiency loss. Finally, CCS results in increased oil and gas recovery when CO_2 is used for EOR, EGR or ECBM. The resulting lower oil and gas prices reduce the demand for coal. Given its perceived low importance, this effect has not been analysed in more detail in this study.

Figure 7.1 shows the impact of various policy incentive levels on global coal use. During the period 2000-2050, coal use increases in all scenarios that include CCS. However, the introduction of policy incentives results in a decline in coal use compared to the BASE scenario. This result shows that even if CCS is considered, coal use will decline if CO_2 policies are introduced. By 2050, coal use in the GLO100 scenario has declined by 44% compared to the BASE scenario. Note that the most significant decline occurs at the lower policy-incentive levels. The additional decline of coal use from GLO50 to GLO100 is relatively small. Note also that coal use is virtually flat up to 2030 but is followed by a 'renaissance' due to the introduction of coal-based electricity and transportation fuel cogeneration plants with CO_2 capture. **The results suggest that CO_2 policies negatively affect coal use, even if CCS is considered.**

Fuel substitution effects that reduce coal use far outweigh additional coal use due to the lower efficiency of power plants with CCS. This efficiency decline due to CCS is also balanced by a trend towards higher efficiency power plants if CO_2 penalties are introduced. **However, the results suggest that coal use can grow, even in a highly CO_2 constrained world, if CCS is considered.**

Figure 7.2 shows the decline in the use of coal if a CO_2 penalty is applied but CCS is *not* available. The decline is expressed relative to the coal use in a scenario with the same penalty level where CCS

Figure 7.1

Coal use under various CO_2 penalty levels, if CCS is considered (2000-2050)

Key point: CO_2 penalties halve coal use. However, even at high penalty levels, coal use in 2050 is higher than in 2000
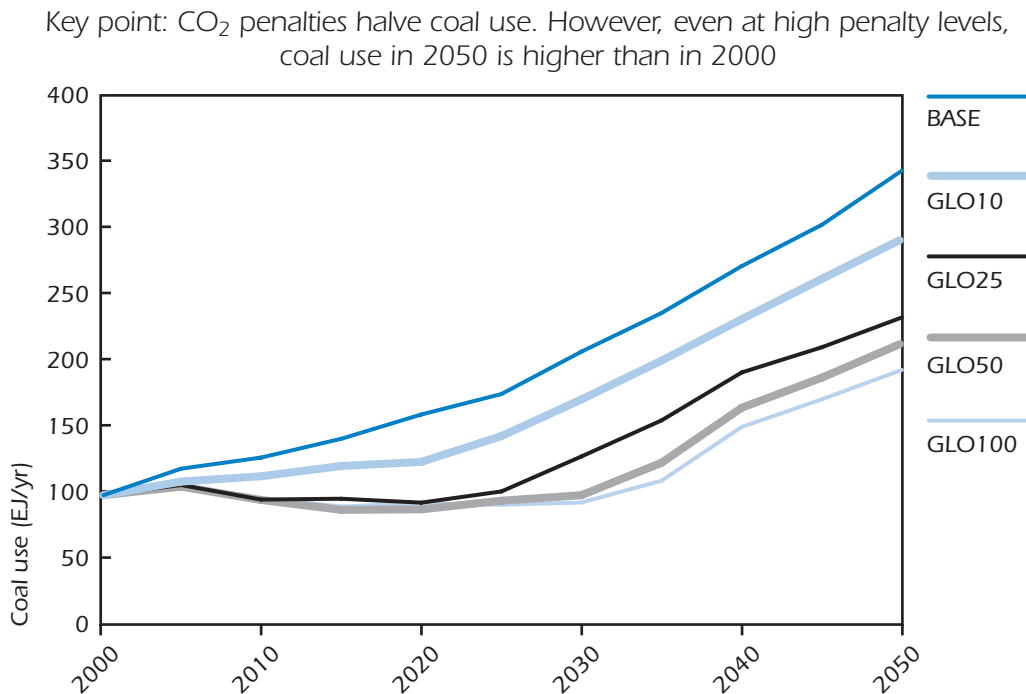
is considered (Figure 7.1). The decline that is shown in Figure 7.2 is a measure of the impact of CCS on the future use of coal. **While the benefits of CCS are limited up to 2020, they are substantial in the period 2020-2050, especially at higher penalty levels. The results show that without CCS, coal use would decline by more than 60% in the GLO50 scenario and by more than 70% in the GLO100 scenario. Therefore CS is of key importance for the future role of coal.**

Figure 7.2

Relative change in coal use without CCS vs. with CCS under various CO$_2$ penalty levels (2000-2050)

Key point: Not deploying CCS causes a decline in coal use.
The result suggests that the decline doubles between 25 and 50 USD/t CO$_2$,
while a further increase to 100 USD/t CO$_2$ has little impact.
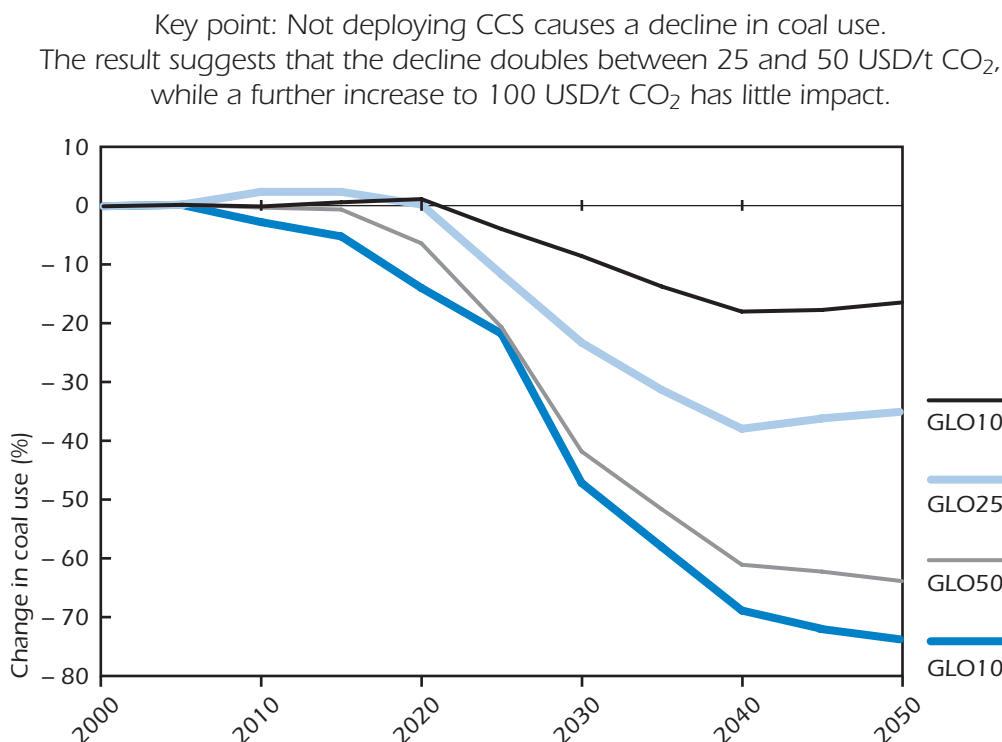
The OECD countries of Australia, the Czech Republic, Germany, Greece, Poland,Portugal, Turkey and the US have over 65% of coal in their electricity sector fuel-supply mix. These countries would benefit significantly from a CO$_2$ capture and sequestration strategy. Other countries may benefit indirectly, because the option to switch to coal with CCS as a supply substitute for natural gas and oil transportation fuels will limit the market power of oil and gas suppliers.

Table 7.1 shows changes in coal fuel price compared to the BASE scenario in Europe and the US in five CO$_2$ penalty scenarios, as calculated by the ETP model. The prices exclude the CO$_2$ tax. The impact of a CO$_2$ tax that corresponds with the penalty (if CCS is not applied) is indicated separately. **The analysis shows that coal prices tend to increase with CO$_2$ penalties**[1]. Coal prices are at their lowest in the GLO50noCCS scenario, because demand is reduced significantly. Note that a CO$_2$ tax that corresponds to the penalty level (the last column in Table 7.1) would dwarf the fuel price fluctuations (the centre four columns in Table 7.1). This suggests that the price impact of a

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1. Due to upstream emissions of CO$_2$ and methane in coal supply.

Table 7.1

Model coal price changes under various CO$_2$ penalty levels, compared to BASE (2040)

	Coal				Additional CO$_2$ tax
	WEU (USD/GJ)	(%)	USA (USD/GJ)	(%)	(USD/GJ)
GLO10	-0.05	-3	0.03	2	0.94
GLO25	0.02	1	0.06	4	2.35
GLO50	0.14	9	0.11	7	4.70
GLO100	0.36	24	0.22	15	9.40
GLO50noCCS	-0.03	-2	-0.13	-9	4.70

CO$_2$ taxes are not included in the coal price changes.

penalty can be estimated based on the carbon content of the fuel and the penalty level, so there is no need for more complex analysis.

Finally, the positive effects of CCS on coal gas recovery need to be mentioned. The analysis in Chapter 3 suggests that about one year of current gas consumption may be recovered through enhanced coal-bed methane recovery (ECBM). However, compared to conventional and other unconventional gas supply options, this is a limited potential. More research is needed on the potential of ECBM.

Gas

CO$_2$ emissions per unit of energy are much lower for gas than for oil and coal,[2] although they are higher than for renewables and nuclear energy. A CO$_2$ policy without CCS would therefore enhance the position of gas compared to other fossil fuels, but reduce the competitiveness of gas compared to non-fossil fuels. It is not clear what the net effect would be on natural gas comsumption and gas prices, or whether the effect would be the same in all world regions.

CCS technology also has some secondary effects on gas supply and demand. As with coal, the introduction of CCS will result in lower efficiency of gas use. However, the efficiency decline in relative terms tends to be smaller for gas-fired power plants than for coal-fired power plants, due to the higher efficiency of gas-fired power plants (see Chapter 3), so the impact on fuel use is smaller.

Figure 7.3 suggests that global gas use is not affected by CO$_2$ policy incentives. While differences exist in the 2010-2040 period, natural gas use doubles under all incentive levels over the whole period 2000-2050. The small impact of CO$_2$ penalties is remarkable. The result can be explained by the fact that the coal vs. gas competition is not significantly affected by the LNG gas prices. In certain regions coal is cheaper than LNG, while in other regions gas (either indigenous or from pipelines) is cheaper. The model results suggest almost a doubling of LNG trade, however, if the BASE scenario and the GLO100 scenario are compared.

CCS availability has a limited impact on gas use. At penalty levels up to 50 USD/t CO$_2$, the absence of CCS results in an increase of up to 10%. At a penalty of 100 USD/t CO$_2$, gas use declines by up to

2. Emissions of CO$_2$ and methane in gas supply must be accounted for (upstream emissions are higher for gas than for coal).

15%. So the impact on gas use is much smaller than the impact on coal. This pattern can be explained by the increased substitution of coal by gas at low penalty levels. However, gas in itself is not a CO_2-free energy carrier, so at 100 USD/t CO_2 gas is replaced by CO_2-free fuels and energy efficiency measures. The analysis in Chapter 3 also showed that the choice between coal and gas in the power sector is barely affected if CCS is considered. If CCS is not considered, gas increases in competitiveness compared to coal, but loses competitiveness compared to renewables and nuclear. These factors can explain the relative rigidity of gas demand under various CO_2 policies with or without CCS.

Figure 7.3

Gas use under various CO₂ penalty levels, if CCS is considered (2000-2050)

Key point: Gas use is not very sensitive to a CO_2 penalty
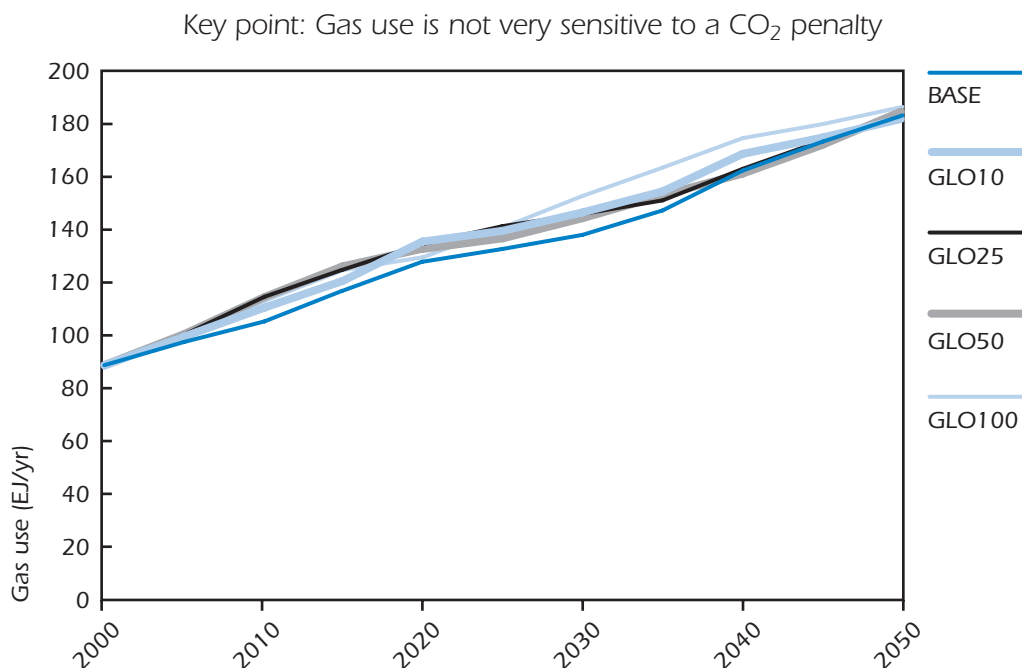
The impacts of CCS on gas imports is more pronounced. By 2040, gas imports in Europe, the US and Japan are 10-15% higher in a situation without CCS. Imports in China, India and Korea are even 40-100% higher. Clearly gas import dependency increases if CCS is not available. Also from this perspective, CCS increases supply security.

On the supply side, CO_2 EGR accounts for 11 EJ of gas supply by 2050, equal to some 5% of total gas supply. When CCS is not considered, the development of remotely located gas and other unconventional gas becomes more attractive from a price perspective. On a regional basis, CCS results in 10 EJ more indigenous gas supply in the US by 2050, compared to the same scenario without CCS. In a scenario without CCS, this is compensated for by 10 EJ of additional gas imports from South America. The impacts on other world regions are limited. In conclusion, CCS has a limited effect on global gas supply security.

Table 7.2 shows gas price changes compared to the BASE scenario in Europe and the US under five CO_2 penalty scenarios, as calculated by the ETP model. The prices exclude the CO_2 tax. The impact of a CO_2 tax that corresponds with the penalty (if CCS is not applied) is indicated separately. The results suggest that the impact CCS has on gas price differs by region and by scenario. Gas prices tend to decline at penalty levels up to 50 USD/t CO_2. However, at high CO_2 penalty levels (GLO100), gas prices are considerably higher than in the BASE scenario. Higher gas prices will reduce the tendency to switch from coal to gas in order to reduce CO_2 emissions.

The impact of CCS on gas prices is not the same in Europe and the US. In Europe, prices in the GLO50noCCS scenario are lower than in the GLO50 scenario. In the US, they are higher. Note that a CO_2 tax that corresponds to the penalty level would have a much more important impact than the fuel price fluctuations.

Table 7.2

Model natural gas price changes under various CO_2 penalty levels, compared to BASE (2040)

	Gas				Additional CO_2 tax
	WEU (USD/GJ)	(%)	USA (USD/GJ)	(%)	(USD/GJ)
GLO10	-0.27	-7	-0.60	-14	0.56
GLO25	-0.27	-7	-0.73	-17	1.40
GLO50	-0.05	-1	-0.66	-15	2.80
GLO100	0.60	15	0.42	10	5.60
GLO50noCCS	-0.31	-8	0.74	17	2.80

CO_2 taxes not included in gas price changes.

Oil

The production of crude and syncrude from oil sands and tar sands is shown in Figure 7.4. The ETP model predicts that oil production will increase by 56% between 2000-2050. **The results suggest that CO_2 policies can reduce oil production and demand by between 10-20% compared to the BASE scenario, a relatively small impact. The results also suggest that these savings only take place at penalty levels from 50 USD/t CO_2 upward.**

Figure 7.5 shows the changes in oil use when CCS is not applied. At lower penalty levels there is a small increase in oil consumption of a few percent. However, in the GLO100 scenario, oil use declines by 10% in later decades.

CCS has a limited impact on total oil production and the regional distribution of oil supply. The model results suggest that Canadian production of oil sand is considerably lower in the period 2020-2035 if CCS is not available. This can be attributed to the CO_2 intensity of oil sand production. Oil production in the Middle East increases by 5-10% in the period 2030-2050, if CCS is not available. The share of oil production based on CO_2 EOR increases to 17 EJ if CCS is considered. This represents 10% of total oil production. This result depends on the modelling assumptions, however, and needs to be studied in more detail. Given the uncertainty in the results and the relatively small impacts, the results do not allow for far-reaching conclusions about oil supply security benefits through CCS.

In conclusion, the results suggest that **CCS does not affect future oil use significantly.** All scenarios show a steady increase in oil supply. However, synfuels grow at a much faster rate than oil supply, increasing to around 100 EJ in the GLO50 scenario in 2050. This includes synthetic oil products from Fischer-Tropsch synthesis, DME, methanol, ethanol and hydrogen. **The steady growth of crude oil supply should be a topic for further analysis, given differing expert opinions as to when a peak in conventional oil supply will occur.** Most experts agree that such a peaking is

Figure 7.4

Crude and syncrude use under various CO$_2$ penalty levels, if CCS is considered (2000-2050)

Key point: Oil use is not particularly sensitive to a CO$_2$ penalty
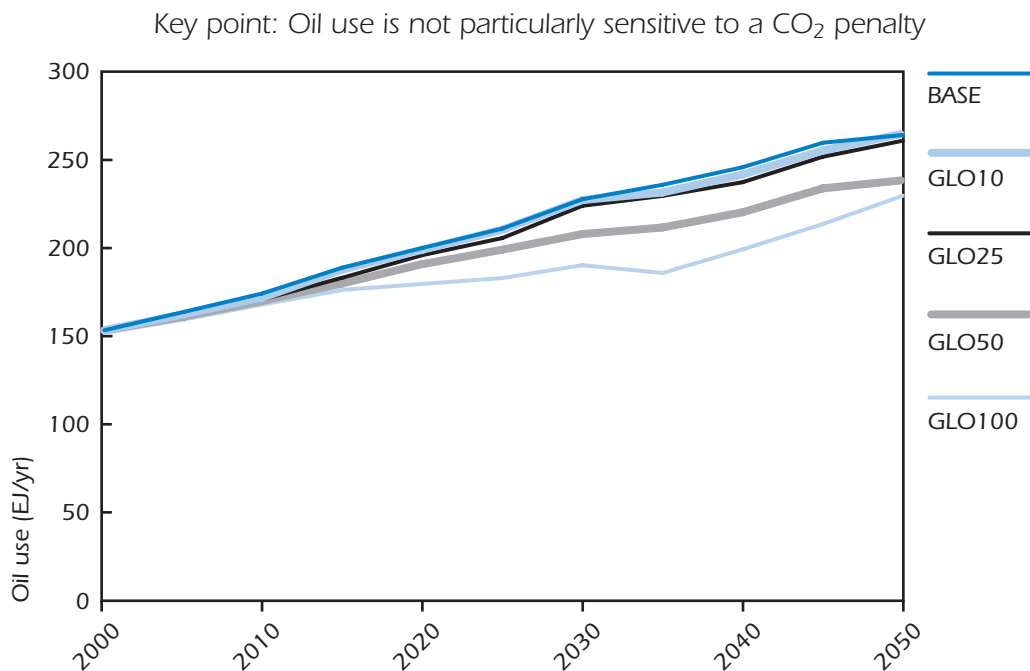
Figure 7.5

Relative change in crude and syncrude use without CCS vs. with CCS under various CO$_2$ penalty levels, 2030 and 2050

Key point: Not using CCS causes a decline in oil use at high penalty levels
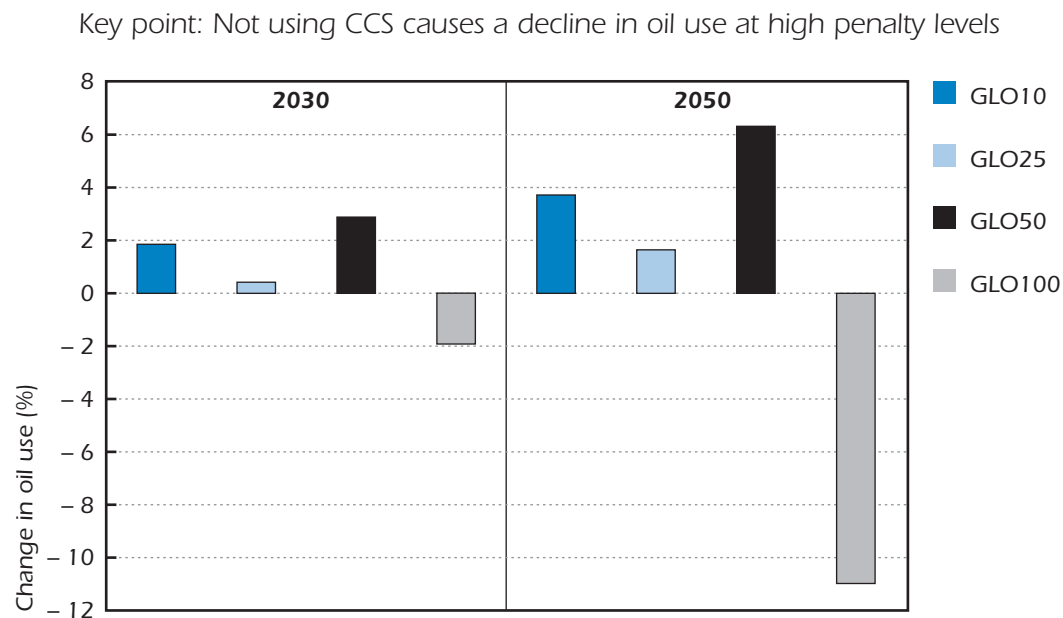
likely before 2050. However, given the importance of synfuels in the modelling results, such an early peaking would simply accelerate the introduction of synfuels in the model. In reality, rapid expansion of synfuel production may be a challenge.

Table 7.3 shows the changes in oil prices compared to the BASE scenario in Europe and the US under five penalty scenarios, as calculated by the ETP model. The prices exclude the CO_2 tax. The impact of a CO_2 tax that corresponds to the penalty if CCS is not applied is indicated separately. The results suggest that both in absolute terms, and compared to the potential impact of a CO_2 tax, CCS would have only a small impact on fuel prices. Impacts are similar for both regions, suggesting a small price increase. Although prices are not significantly affected by CO_2 policies if CCS is available, in the GLO50 scenario without CCS they are 12% higher than in the GLO50 scenario. This can be explained by the lack of cogeneration of electricity and transportation fuels from coal in this scenario, which increases oil demand. Note that a CO_2 tax corresponding to the penalty level (the last column in Table 7.3) would dwarf the fuel price fluctuations (the centre four columns).

Table 7.3

Model oil price changes under various CO_2 penalty levels, compared to BASE (2040)

	Oil				Additional CO_2 tax
	WEU (USD/GJ)	(%)	USA (USD/GJ)	(%)	(USD/GJ)
GLO10	0.37	7	0.37	7	0.73
GLO25	0.18	4	0.18	4	1.83
GLO50	0.15	3	0.15	3	3.65
GLO100	0.14	3	0.14	3	7.30
GLO50noCCS	0.64	13	0.64	13	3.65

CO_2 taxes not included in oil price changes.

Renewables

The discussion of renewables in this section is split into biomass and other renewables. The reason for this is because biomass represents the bulk of renewables in the GLO50 scenario (see Chapter 4).

Figure 7.6 shows the use of biomass under various CO_2 penalty levels. Even the BASE scenario shows an increase of about 50% between 2000-2050. **Biomass use increases with rising penalty levels, and reaches about 125 EJ in the GLO50 scenario and 145 EJ in the GLO100 scenario, in line with the maximum biomass availability. The total amount of biomass used at higher penalty levels is substantial and of a similar order to current global oil use. This makes biomass the single most important renewable energy option.**

Total biomass use for the residential, commercial and agricultural sectors remains roughly constant in the GLO50 scenario, compared to the BASE scenario. However, its use in industry increases significantly, particularly in the categories industrial boilers/process heat, industrial CHP units and black liquor boilers. Biomass use in the electricity sector also increases, while the share of biofuels used in the transportation fuel market also rises (Figure 7.7).

Figure 7.6

Biomass use under various CO₂ penalty levels, if CCS is considered (2000-2050)

Key point: If CO₂ penalties are introduced, biomass use can reach current oil use levels by 2050
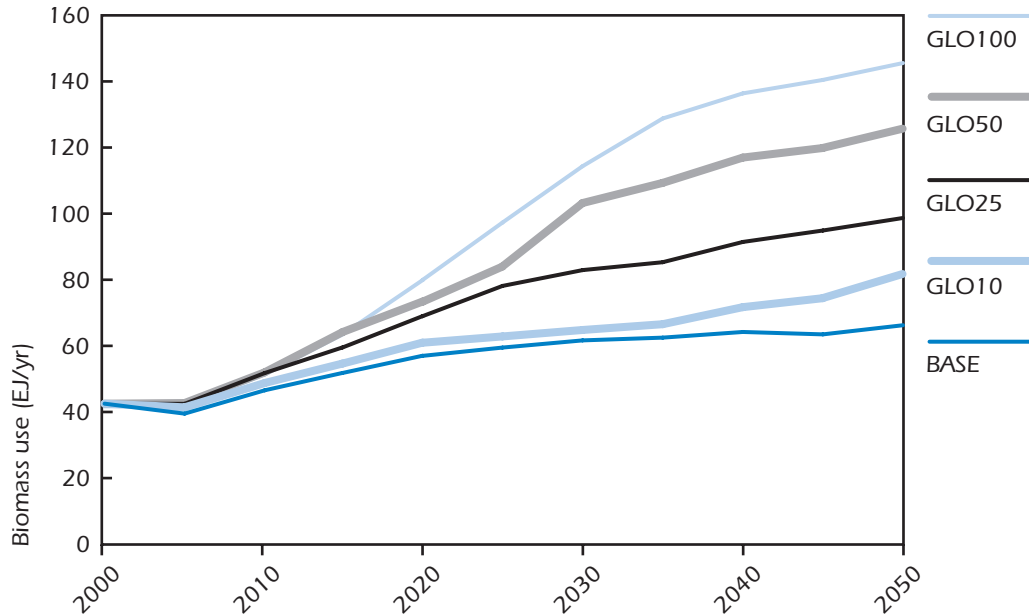
Note: Excludes black liquor.

Figure 7.7

Biomass use in the GLO50 scenario (with CCS)

Key point: The potential for biomass is concentrated in industry, electricity and synfuel production
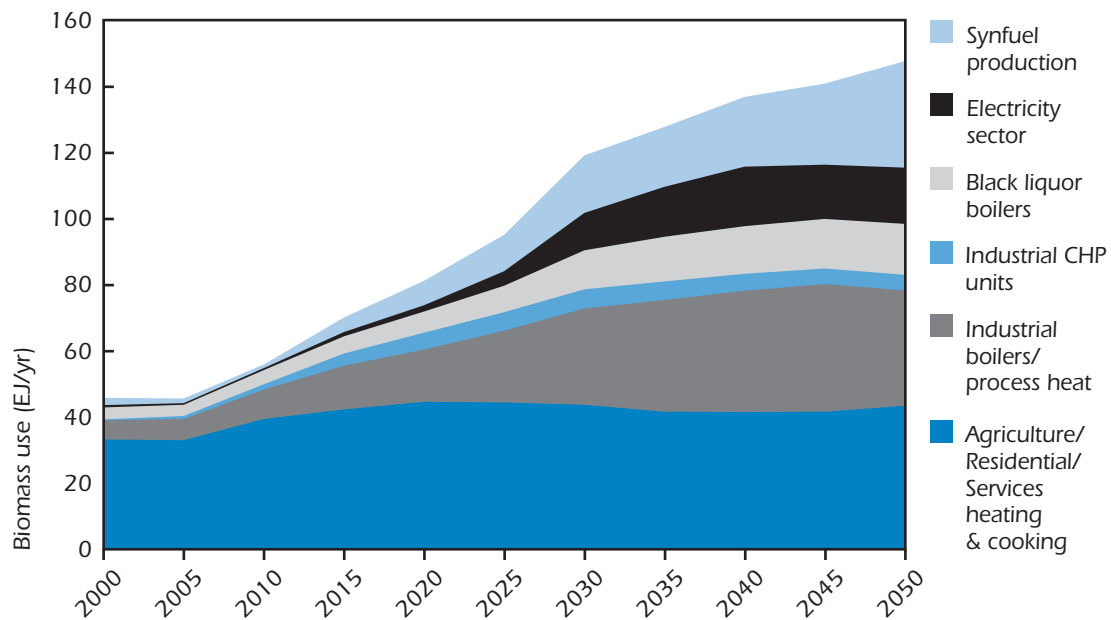
CCS has a minor effect on biomass use, as shown in the model runs with CCS (±5%). **This indicates that the future role of biomass does not depend on the deployment of CCS.**

When CO_2 penalties are applied, the increase in the use of other renewables is less substantial than for biomass in absolute terms (Figure 7.8). In relative terms, however, the increase is very substantial, with a fivefold increase in the GLO50 scenario and a sixfold increase in the GLO100 scenario between 2000 and 2050. Most of the other renewable energy is used in the electricity sector, as described in more detail in the next section.

Figure 7.8

The use of other renewables under various CO_2 penalty levels, if CCS is considered (2000-2050)

Key point: If CO_2 penalties are introduced, the use of other renewables increases by a factor of six on 2000 levels
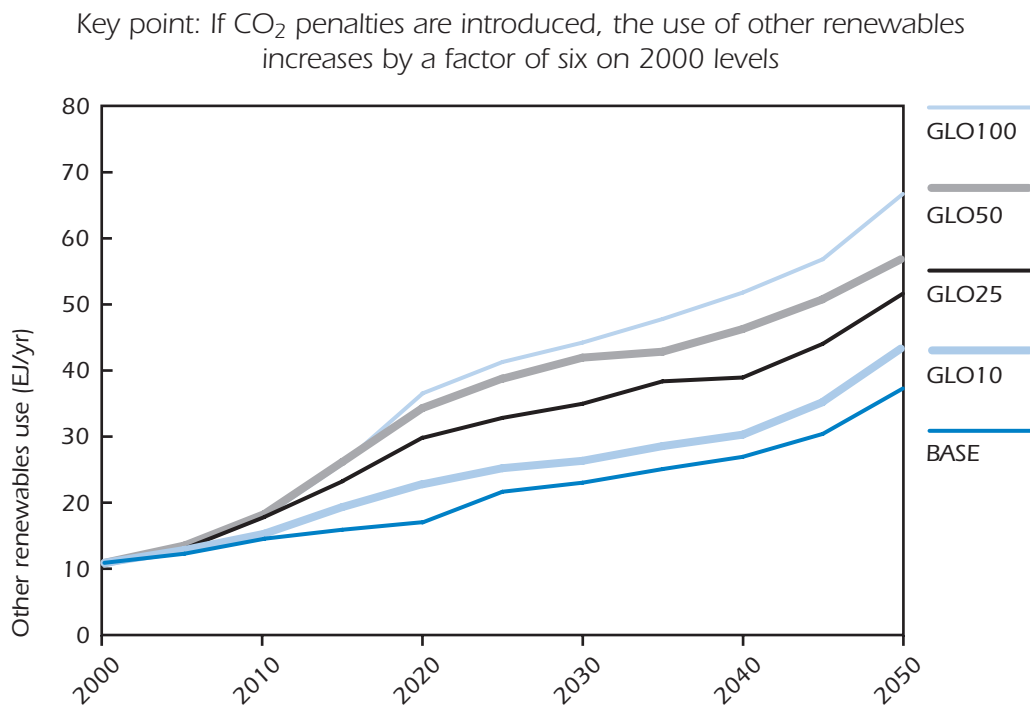
Figure 7.9 shows the change in the use of renewables when CCS is not considered. If CCS is excluded, the use of these renewables increases by up to 40%, compared to the same penalty levels with CCS. The main increase occurs after 2020. The results indicate that **CCS reduces the growth of other renewables. However, with or without CCS, renewables will still grow rapidly.**

The GLO50 scenario assumes that renewables policies are in line with the WEO 2004 Reference Scenario (IEA, 2004a). The sensitivity analysis in Chapter 6 showed that ambitious policy targets and technology learning effects can result in renewables increasing their share at the expense of fossil fuels with CCS, which can halve electricity production from fossil fuels with CCS. The results regarding the impact of CCS and CO_2 penalties on renewables are therefore highly dependent on the technology learning assumptions and policy targets.

Figure 7.9

Relative change in other renewables use without CCS vs. with CCS under various CO$_2$ penalty levels (2000-2050)

Key point: At high penalty levels, not using CCS can lead to a significant increase in the use of other renewables
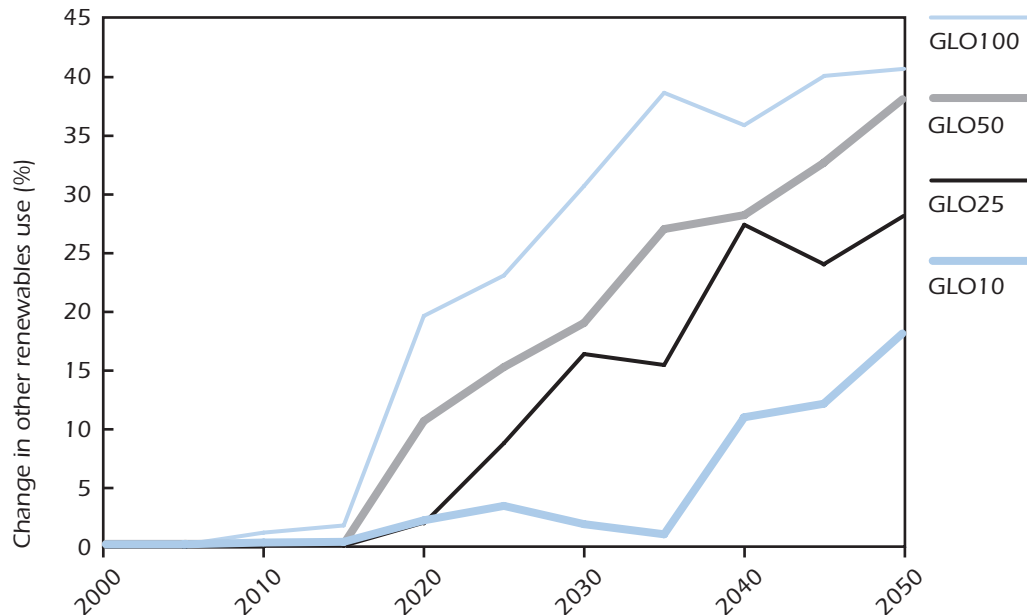
Electricity

The availability of CCS is of greatest importance in the electricity sector. Table 7.4 shows the electricity production mix with and without CCS. Total electricity production is 10 EJ lower if CCS is not considered. This is the result of increased energy efficiency and fuel substitution in the end-use sectors. Electricity production from fossil fuels declines by 10 EJ in 2030 and by 45 EJ in 2050, resulting in more or less stable electricity production from fossil fuels. The use of coal for electricity production virtually disappears. Production from nuclear, hydro, geothermal and wind are considerably higher than in the case with CCS.

Biomass use for electricity production declines if CCS is not considered (see Table 7.4). This can be explained by the significant co-combustion of biomass in coal-fired power plants in the GLO50 scenario. This opportunity is not attractive when CCS is excluded.

CO$_2$ policies and the availability of CCS affect electricity prices significantly. Table 7.5 shows the average annual electricity price increase by region. The electricity price in this analysis excludes transmission and distribution costs that would double the price for residential and commercial consumers. Therefore relative price changes would be halved if consumer prices were compared. Since these consumer prices differ by sector, a comparison of prices excluding transmission and distribution was chosen. The increase in the GLO50 scenario compared to the BASE scenario amounts

to between 5 and 73%. The additional increase when CCS is not considered amounts to between 4 and 52%. Therefore the impact of not having CCS can double the impact of a 50 USD CO_2 penalty. The price increases are so significant that demand may decline in the long term.

Table 7.4

Electricity production by fuel type, with and without CCS technology (2030 and 2050)

	2030			2050		
	BASE (EJ/yr)	GLO50 (EJ/yr)	GLO50noCCS (EJ/yr)	BASE (EJ/yr)	GLO50 (EJ/yr)	GLO50noCCS (EJ/yr)
FF without CCS	63.8	19.9	29.5	97.5	20.3	42.3
FF with CCS	0.0	21.4	0.0	0.0	56.1	0.0
Nuclear	8.7	10.5	11.9	8.4	9.6	15.4
Hydro	16.2	21.0	22.3	20.2	24.1	28.0
Bio/waste	5.9	12.1	11.0	8.6	15.9	12.3
Geothermal	4.4	5.7	10.9	6.5	8.5	14.3
Wind	1.0	10.9	12.4	6.5	18.7	28.8
Tidal	0.0	0.0	0.0	0.0	0.0	0.7
Solar	0.0	0.0	0.0	0.0	0.0	1.2
Total	100.1	101.4	98.0	147.6	153.3	142.9

Note: FF = fossil fuels.

Table 7.5

Model electricity price increase under various CO_2 penalty levels, with and without CCS technology (2040)

	GLO50 Compared to BASE (%)	GLO50noCCS Compared to GLO50 (%)
AFR	61	35
AUS	46	22
CAN	33	4
CHI	35	17
CSA	5	52
EEU	27	43
FSU	70	13
IND	39	34
JPN	43	29
MEA	71	15
MEX	22	46
ODA	73	18
SKO	41	32
USA	35	32
WEU	26	6

Chapter 8.
CHALLENGES AHEAD AND PRIORITIES FOR ACTION

H I G H L I G H T S

- A five-fold increase in funding for RD&D on CO_2 capture and storage will be needed to prepare CCS technologies for full-scale commercial introduction within 10–15 years.

- **Capture technologies:** RD&D efforts should focus on innovative capture technologies with high efficiency and low cost. Special attention should be given to the integration of CCS into new power plant designs. At least several more projects are needed to demonstrate CO_2 capture on a commercial scale. Finding sufficient funds for such projects will be a significant challenge. Some investors may wish to proceed immediately to commercialization.

- A new generation of highly efficient coal-fired power plants is being developed and introduced but it will take them decades to conquer the market. This means that only synchronous development of a new generation of plants and CCS technologies will lead to CCS market introduction within 10-15 years. This also means that work should continue on all capture options (CCS with steam cycles, including oxy-fuelling, and CCS for gasification cycles).

- **Storage:** Sufficient proof of storage permanence is essential for any credible CCS strategy and for public awareness and acceptance. As a first step, RD&D should focus on CO_2 projects which enhance fossil fuel production and on those which advance knowledge on sub-sea underground storage, and aquifer storage in locations with low population density. Stakeholder processes for reviewing, commenting and addressing concerns should be built into all pilot projects. Procedures for independently verifying and monitoring storage and related activities should also be established.

- To facilitate the acceptance of CCS by the general public, industry decision makers, and policy makers, it will be necessary to make available and broadly disseminate the results of RD&D projects.

- Given the controversial nature of oceanic storage, CO_2 storage efforts should primarily focus on underground options, both off-shore and on-shore.

- Further investment in CCS, including demonstration projects, is hindered in some countries by uncertainties over the lack of appropriate legal and regulatory frameworks. Countries should create an enabling legal and regulatory environment for national CO_2 storage projects. In the interests of time, and given the diversity of institutional set-ups and regulations between countries, working at the national level using existing frameworks may be the best short-term option.

- Contracting parties to international instruments should be proactive in clarifying the legal status of CO_2 storage in the marine environment, taking into consideration their objectives to stabilize CO_2 in the atmosphere.

■ In addition to the acceleration of RD&D funding, countries should create a level-playing field for CCS alongside other climate change mitigation technologies. This includes ensuring that various climate change mitigation instruments, including market-oriented trading schemes, are adapted to include CCS.

The ETP model analysis presented in the four preceding chapters quantified the economic and environmental benefits of a CCS strategy. Not even the most sophisticated models can predict the future in detail, however. Indeed, modelling can only ever be a 'what if' exercise illustrating the potential that exists. What can be concluded from the ETP analysis presented in this book is that CCS technologies can significantly contribute to the abatement of CO_2 emissions. This conclusion is valid even if, in the future, CO_2 is priced very differently from the 50 USD/t CO_2 assumed in the GLO50 scenario. This potential will be lost, however, if various supporting efforts to foster CCS are not undertaken in a timely manner.

This chapter outlines the various factors associated with deploying CCS which could critically impact the timing and effectiveness of a CCS strategy. These factors include bridging the RD&D gap, the need for public awareness and acceptance, the importance of putting in place appropriate legal and regulatory frameworks, particularly for CO_2 storage, and the need for a policy framework which encourages public-private sector co-operation and provides appropriate investment incentives.

Interrelated Challenges

There are major RD&D gaps to be bridged over the next few years if CCS technologies are to be developed in time for their potential to be realised. To develop CCS technologies, significant technology development and deployment efforts are necessary and must be accompanied by the *simultaneous* rather than the sequential development of legal, regulatory and policy frameworks and enabled by public awareness and acceptance.

At the same time, an appropriate environment must be put in place to encourage private sector involvement. On the capture side, the activities by oil companies and chemical companies are encouraging. The real challenge is the introduction of widespread CO_2 capture in power production where the bulk of the costs arise. Investment costs for CO_2 capture from a single power plant are in the order of hundreds of millions of dollars. Even for a power company which owns several power plants, such additional investment poses a major financing challenge. Linkage of power plants and storage sites will imply the development of extensive CO_2 pipeline 'backbones', to which capture plants and storage installations can be connected. On the storage side, the best sites and optimal storage approach need to be identified and storage permanence needs to be assured.

Most power companies do not have the resources to develop new power production technology by themselves. That is where engineering firms come in and where government-private partnerships may be needed. Power producers need a clear indication that CO_2 emission reductions will be rewarded sufficiently over a period of decades. It is a task for government to establish these credible long-term policy goals and mechanisms to ensure that deep emission cuts from a single plant can be shared by others with less promising emission reduction prospects. Governments also need to ascertain that CCS really is the most economic strategy to reduce emissions and deal with energy

security concerns. This will depend on the resource base of a country, site-specific factors, prospects for other emission reduction strategies, and public acceptance.

As shown in Chapter 3, different regions are in different phases of their capital stock renewal cycle. Technology development must match these cycles in order to succeed. In general, power producers are unable to postpone investments until better technology comes onto the market.

Finally, developing countries must be included if CCS is to be applied widely.

Timing Issues

Rapid advances in CO_2 capture technology hold great promise for increasing efficiency and reducing costs. However, power producers need reliable technology that is proven on a commercial scale. If appropriate investments are to be made from 2015-2020 onwards, CCS technology needs to have been demonstrated on a commercial scale by this date. Timing is key as the following assessment of the likely implementation timeframe illustrates.

Planning a CCS plant could take 3-5 years, building it could take another 2-3 years and testing it an additional 3-5 years. A certain period of time may then be needed to reach full capacity and overcome operational problems. At best, such a cycle takes up to eight years. If CCS plants are to be demonstrated by 2015-2020, this cycle must begin in the next few years. Market introduction and construction of a fourth and fifth plant would require an additional 4-5 years apiece. The best examples are provided by fluidized bed combustion or IGCC plants where first projects have taken up significant resources. In other words, there is very little time to start planning for the wave of full-scale CCS pilot and demonstration facilities. Therefore, the quantity and pace of work on CCS should be increased urgently, particularly given the trends and consequences of climate change.

The four initiatives to develop megatonne-scale power plants with CO_2 capture identified in Chapter 6 – FutureGen in the US, the Canadian Clean Power Coalition, the Australian initiative and the European HypoGen initiative – show that governments are willing to meet this challenge. However, the actual realization of these plans remains uncertain. Furthermore, four initiatives will be insufficient to establish widespread market acceptance of CCS from 2015-2020 onwards.

This tight schedule may require that less efficient technologies are combined with CCS by 2015, instead of waiting for more advanced and less costly technology. It may also require the construction of power plants in 2015 that are suited for retrofit a decade later. This could imply building an IGCC that would allow future low-cost CO_2 capture, while a supercritical steam cycle would be a cheaper option if CCS was not considered. The RD&D into CCS may not be completed by 2015 and a continued effort on the scale of billions of USD may be needed over a period of decades. Whether such a global effort is feasible depends on the ultimate willingness to embrace the CO_2 mitigation potential that CCS offers.

It is worth mentioning that the timescale of CCS deployment depends on political and economic factors and that there are examples of technologies going straight to large-scale use without first passing through the demonstration phase. Despite the additional risk of technical problems and higher costs than if demonstration plants were built and operated first, new power plants could be fitted with CO_2 capture technology now if incentives were high enough. CO_2 storage faces more of a time constraint because of the need to demonstrate safety and security before large-scale implementation.

RD&D Challenges

Chapter 3 provided an assessment of the various CCS technology gaps that need to be bridged. In particular, it highlighted the need to reduce the cost of CO$_2$ capture across various applications by a factor of two or more. It also highlighted the need for CCS to be demonstrated on a large scale and for CO$_2$ storage to be proven as feasible and environmentally safe. When such RD&D requirements are compared with the ongoing and planned RD&D initiatives outlined in Chapter 6, it is clear that there is quite a sizeable gap to be bridged.

With CO$_2$ capture, governments must address the present shortage of sizeable RD&D projects in order to advance technological understanding, increase efficiency and drive down costs. This will require increasing RD&D an early commercialization investment into CCS and power plant efficiency. By 2015 at least 10 major power plants fitted with capture technology need to be operating. These plants would cost between 500 million and 1 billion USD, of which half would be additional cost for CCS.

The CCS budget is over 100 million USD per year at present. The scale of planned RD&D initiatives is too small and insufficient to ensure that CCS is implemented on a large scale in the second quarter of this century. A five-fold increase of the funds for capture and storage projects is required in the short term if gigatonnes of CO$_2$ are to be captured over the next 20-30 years. This means that feasibility studies for several CO$_2$ capture and storage projects of a scale of hundreds of MW and Mt of CO$_2$ should begin now.

The current trend for RD&D budgets runs contrary to this requirement (Figure 8.1). Government energy RD&D budgets have been falling in recent decades, with total energy RD&D expenditure in 2002 just under 8 billion USD, equal to 49% of the 1980 value. The budget for fossil fuels has declined from its peak of 2.7 billion USD in 1981 to 0.7 billion USD in 2002, a decline of 73%.

While the amount required for CCS is challenging, it is not insurmountable given the scale of past energy RD&D budgets. It would represent a 30% increase of the current RD&D budget for fossil fuels and power & storage technologies. The additional public RD&D budget that is needed for CCS development is in the range of historical R&D budgets in these categories. The proposed budget increase seems a challenge, but could be feasible. Leveraging the funds in private/public partnerships is essential.

Demonstration of the safety and integrity of CO$_2$ storage is a critical factor for technology development. A large number of data gathered through demonstration projects is needed to establish suitable legal and regulatory frameworks, to attract financing and to gain public acceptance. Storage demonstration projects should fully utilize early opportunities created by enhanced oil recovery (EOR) projects and sources of cheap CO$_2$.

CO$_2$ capture and storage have different RD&D challenges. **The key issue in CO$_2$ capture is to lower capture costs** to economically practicable levels; the processes involved are known and do not represent high technology risks. On the other hand, significant RD&D work is needed to **prove the feasibility and integrity of CO$_2$ storage** in various reservoirs through long-term monitoring projects. Pipeline transportation of CO$_2$ is a proven technology and does not require significant research, and transportation by vessels is, so far, of less importance at this stage.

The cost of capturing CO$_2$ depends on the type of power plant used, the plant's overall efficiency and the energy requirements of the capture process. The preferred design is for high efficiency power

plants generating concentrated streams of CO_2. The discussion below is focused on capture technologies in coal-based power plants which would comprise a bulk of CO_2 capture facilities. As far as gas-fired power plants are concerned, R&D needs seem less challenging because their potential for efficiency improvements is limited as the efficiency of new plants is already high, and available post-combustion capture systems have a relatively low energy penalty. It is also unlikely that pre-combustion capture systems based on natural gas will show a markedly superior performance over post-combustion capture. Novel technologies for both coal and gas, using chemical looping and fuel cells for example, require significant basic research, meaning that their implementation would follow CCS deployment in power plants based on steam cycles and/or "regular" IGCC.

Figure 8.1

IEA government RD&D budgets

Key point: Budgets have been declining over the last
two decades and currently amount to 8 billion USD per year
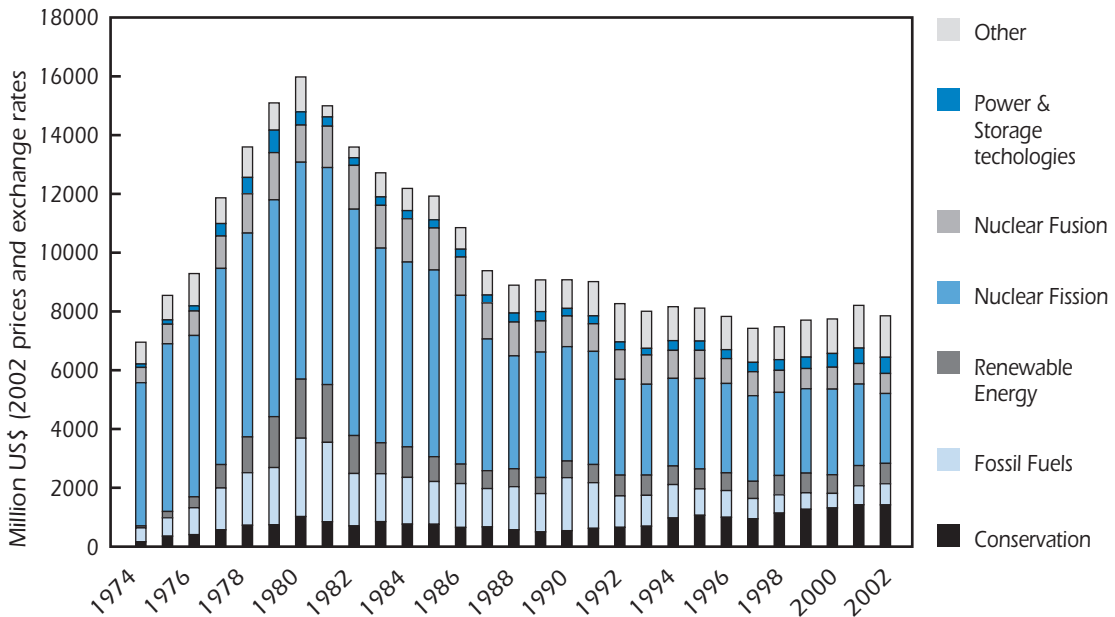
Increasing the efficiency of fossil-fuel power plants is a powerful CO_2 abatement measure on its own. Several roadmaps have been proposed which include two interconnected paths of technology developments. The first trajectory leads to increasing efficiency of power plants, and the second one to including CCS in power systems. Both trajectories eventually merge (Figure 8.2). The timing of the merger depends on RD&D developments as well as on a process of monetisation of CO_2 abatement, the introduction of legal and regulatory frameworks and on levels of public acceptance.

The two diagrams below (Figures 8.3 and 8.4) outline roadmaps for efficiency improvements and CCS development in OECD and non-OECD countries as proposed by the IEA Clean Coal Centre (Henderson, 2003). With both diagrams, the first path represents goals for pulverised coal steam cycles, the second path concerns IGCC plants, and the third the implementation of CO_2 capture (efficiencies given in Figures 8.3 and 8.4 differ slightly from the data provided in Chapter 3).

Figure 8.2

Trajectories for increased efficiency and CCS development
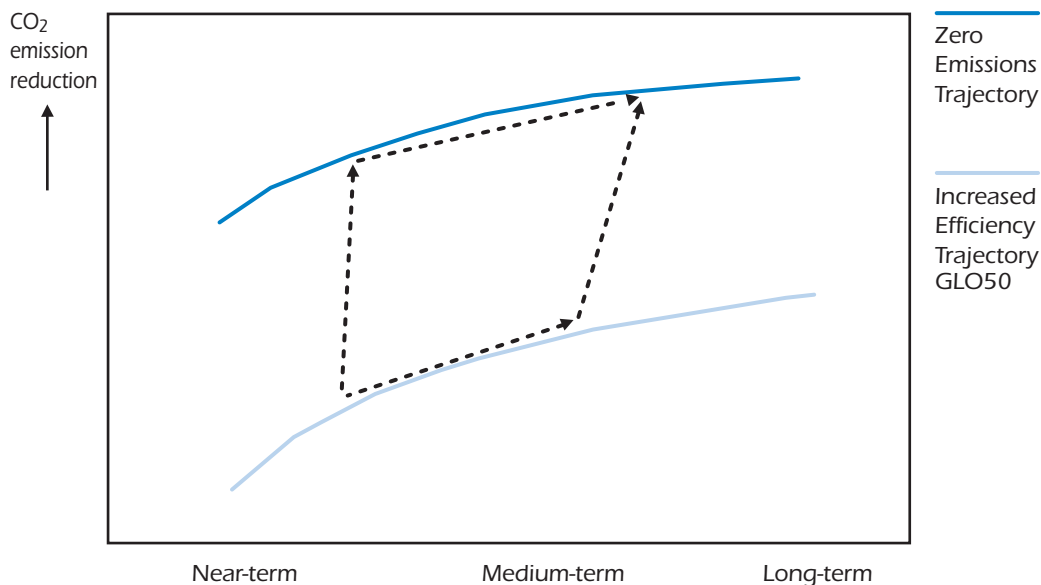
Source: Otter, 2004.

As Figures 8.3 and 8.4 illustrate, coal-fired power plants based on steam cycles and IGCC technology hold great promise for further efficiency gains. RD&D into steam cycles is focused on developing ferrous alloys and nickel-based super-alloys for higher steam conditions, further improvements in steam turbine and the introduction of oxy-coal combustion. RD&D on CO_2 capture from this type of plant is focused on developing new chemical and physical solvents for CO_2 scrubbing, membrane and adsorption separation techniques and, in general, minimizing the energy required for CO_2 capture.

Work on improving IGCC plants includes improving refractories, gas coolers and coal feeding systems to increase reliability and the availability of installations, improving coal conversion and co-gasification, dry gas clean-up, turbines for synthesis gas and hydrogen, and air separation for O_2 production. Improvements are also being made to fuel cells to scale up and demonstrate their use of hydrogen from synthesis gas. RD&D for CO_2 capture involves developing CO_2 separation technologies for fuel gas.

The technology developments and efficiency improvements outlined above cannot be taken for granted, however. Major efforts need to be undertaken and significant resources committed by governments and industry to realize these projects. The COORETEC programme, recently launched by the German government in co-operation with industry, is an example of an ambitious initiative focused on efficiency improvements with parallel projects on CCS (COORETEC, 2003).

So far, the significant work done on CO_2 storage suggests that CO_2 can be stored for thousands of years or longer if held in a suitable reservoir. Storage risks are known and have been shown to be low, providing the right facility is chosen. Furthermore, RD&D has developed appropriate monitoring techniques that can be applied at reasonable cost, as well as remediation techniques. Nonetheless, further RD&D is required, particularly into the following areas (Benson, 2004):

- investigation of storage effectiveness through monitoring CO_2 storage sites, studying analogues, basic research on physicochemical processes involved in trapping CO_2 and numerical simulation;
- estimating and proving storage capacity on a global, regional and national level;

- environmental risk assessment, identification of risks involved and the development of appropriate site selection procedures, monitoring techniques and remediation actions, and the development of a regulatory framework;
- demonstration projects to further prove the viability of long-term storage.

Figure 8.3

Roadmap for efficiency improvements and CCS development in coal-fired power plants in OECD countries

Increasing efficiency, lower emissions, lower costs

Now ————————————————————————————→ 2020

Clean coal technologies

SCSC 40-45 %	→	SCSC 47 % USCSC demo 50 %	→	USCSC 50-55 %	→	USCSC 50-55 %

IGCC demo 45 %	→	IGCC 47 %	→	IGCC 50 % IGCC-SOFC demo	→	IGCC 50 % + (IGCC-SOFC below)

Path to near-zero emissions

Efficiency improvements; better environmental control Retrofit SCSC with chemical absorption 30 %	→	SCSC + CA 35 % Retrofit IGCC + PA 35 %	→	SCSC Oxyfueling 40 % IGCC PA 40 %	→	IGCC membrane techs 45 % IGCC-SOFC 55-60 % IGCC for synfuel cogeneration

Source: Henderson, 2003.

Figure 8.5 shows the cumulative capacity of major ongoing and planned storage demonstration and monitoring projects. In order to ensure the projected exponential growth, a far larger number of such projects are needed to fully validate the CO_2 storage concept. The general public, including non-governmental organisations (NGOs), must be involved in CCS development at every stage. Storage is a key area where gaining public acceptance is of critical importance. This includes acceptance for a CCS strategy in general and also local acceptance of specific storage projects.

Public-private partnerships have a crucial role to play in financing RD&D activities. To encourage their involvement, governments must take into consideration the various objectives and priorities of different stakeholders. Oil and gas companies will need CO_2 removal for gas purification. CO_2 EOR is likely to be an economically attractive option for many reservoirs. The expertise oil and gas companies offer for gas injection techniques and reservoir management would be useful for all CCS geological storage projects, not only those involving gas and oil fields. Manufacturing companies working for the oil and gas industry are likely to be interested in CCS for similar reasons; coal companies would be interested in CCS to ensure a market for their product, while electricity utilities may be interested in CCS to help them prepare for the introduction of CO_2 abatement fiscal mechanisms. In general, corporate responsibility could be a powerful driving force for many companies.

Figure 8.4

Roadmap for efficiency improvements and CCS development in coal-fired power plants in non-OECD countries

Increasing efficiency, lower emissions, lower costs

Now ⟶ 2020

| Clean coal technologies |

| Subcrit. SC 40-45 % | → | SCSC 45 % | → | USCSC 50 % | → | USCSC 50 % + |

| IGCC 40-45 % | ⟶ | IGCC 50 % + |

| Path to near-zero emissions |

| Efficiency improvements; better environmental control | → | SCSC 45 % | → | SCSC CA 35 % IGCC 45-50 % | → | IGCC PA 40 % |
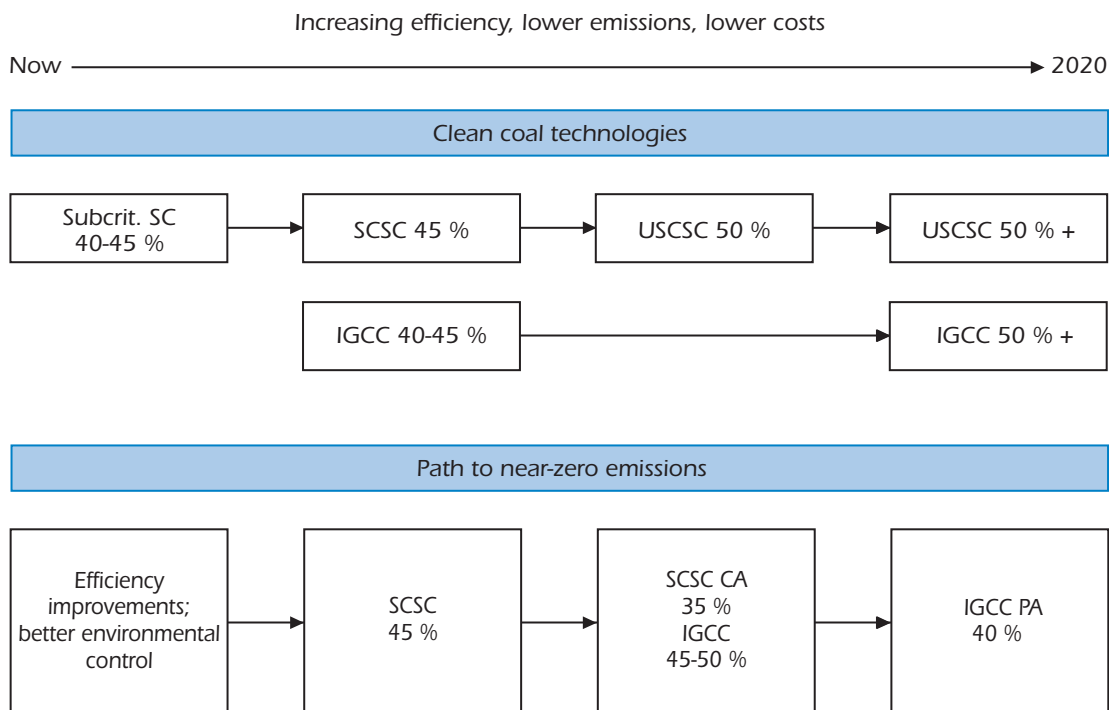
Source: Henderson, 2003.

Figure 8.5

Major CO₂ storage projects and the uncertain long-term developments (cumulative)
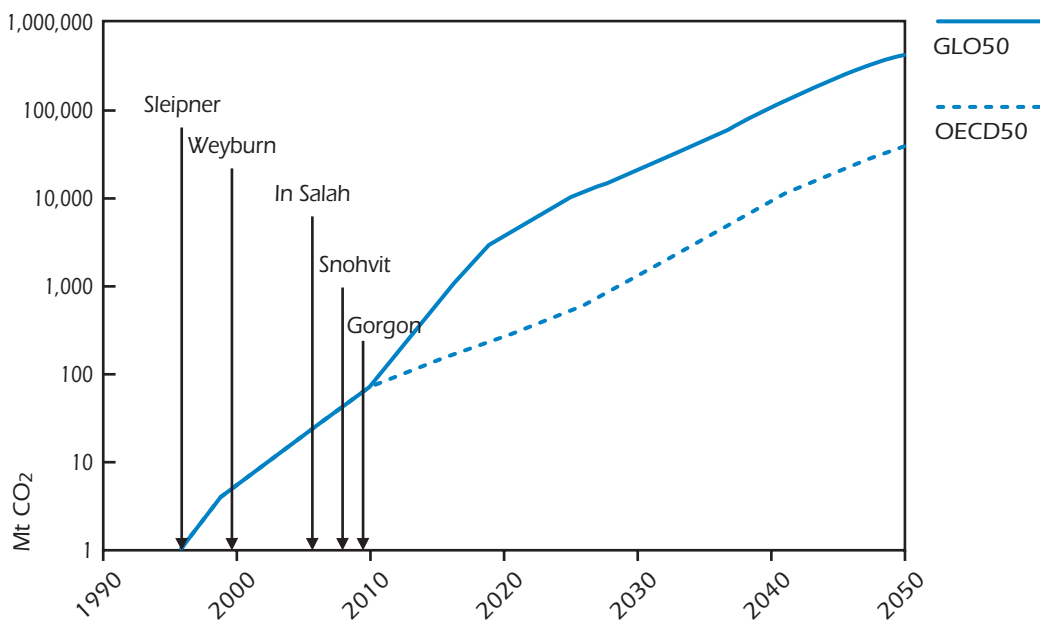
Public Awareness and Acceptance

The deployment of CCs technologies will require broad understanding and long-term commitment by numerous constituencies (McKee, 2003). These include, among others, central and local governments, the general public, environmental and non-environmental NGOs, industrial and commercial organisations, academic and scientific institutes, financial institutions, the media, and international organisations. The following discussion on awareness and acceptance is limited to the general public and environmental NGOs.

Until recently, CCS technologies were of interest to a relatively small group of experts. This means that, at present, public awareness of CCS is very limited. A recent review (Curry and Herzog, 2004) shows that few people know anything about CO_2 capture and storage or understand the relation between CCS and climate change. The survey also revealed a poor understanding of CO_2 sources, mechanisms driving climate change and mitigation measures.

Awareness of the potential of CCS is the first step towards gaining acceptance for its deployment. If CCS is to be widely accepted, a policy of 'openness' is required. All communication efforts should be based on high quality data. National consultation and regional negotiations are critical to the success of CCS projects since, by its very nature, the technology would require large industrial-sized projects affecting local and regional communities.

Two types of opposition can be discerned at this stage: opposition from stakeholders who prefer other mitigation measures to CCS (or object to the use of fossil fuels and CCS completely), and local opposition to specific projects, notably storage. Independent credible analysis, based on scientific data which addresses the real risks and also pros and cons of CCS and associated projects, is required for any ultimate acceptance.

To facilitate acceptance of CCS by the general public, industry decision-makers, and government policy makers, it will be necessary to develop well-structured education and outreach programmes (Esposito and Locke, 2003). The absence of organised, effective communication strategies, controversy and fear of leakage could pose an obstacle to scientific research and CCS deployment. Such problems have already arisen for two oceanic storage R&D projects (in Hawaii and Norway). With coal-bed methane recovery in the US, locals have suffered from a lowering of groundwater levels, a deterioration in surface water quality, and soil pollution, among other things. As a result, considerable opposition has built up towards coal gas extraction in general (Powder River Basin, 2004). Similar problems could arise for ECBM projects. The lesson that can be drawn from these experiences is that involving stakeholders at an early stage is essential to mitigating major development problems. Given the dispersed nature of potential CO_2 storage sites, development should focus on areas which are less ecologically sensitive than others, even if this incurs additional costs. Stakeholder processes for reviewing, commenting and addressing concerns should be built into all pilot projects, together with procedures for independently verifying and monitoring storage and related activities.

Environmental NGOs understand the need for a deep cut in GHG emissions and the majority of NGOs consider CCS to be a potential bridging technology on the way to a CO_2-free energy system based on renewables. NGOs generally support RD&D work on CCS technologies (Goerne, 2004). Their main concern centres on the fact that CCS is seen and presented as a solution which would allow for the continued use of fossil-fuel resources as long as they are available.

NGOs are also concerned about the following factors, among others (Craig 2003):

- CCS may divert resources away from alternative emission mitigation options such as increased renewable energy use and energy efficiency.
- CCS may give false hope to those who could regard it as the 'silver bullet' of CO_2 mitigation. This could set back other climate change policies in the short and medium term.
- CCS leads to additional energy use.
- Environmental issues associated with the impact of fossil-fuel extraction and transportation remain.
- The risk of CO_2 leaking from storage sites.
- CCS results in a 40-80% increase in the cost of electricity.
- The competitiveness of CCS in relation to renewables and energy efficiency measures still needs to be established.

These issues have been analysed in the previous chapters. NGOs strongly object to CO_2 storage in the oceans (in the water column) because of its potentially harmful impact on the marine environment and the fact that CO_2 could diffuse to the ocean surface and eventually reach the atmosphere. A lack of scientific data and uncertainty over the behaviour of CO_2 does not allow for any larger-scale pilot project. Thus, injection into the water column is not being widely pursued as a viable storage option for the time being. This does not present a significant problem, however, as other storage options based on geological storage represent sufficient capacity on a global scale. That said, serious academic research on ocean storage is being undertaken in some countries, notably Japan.

The Regulatory and Legal Framework

National and international legal and regulatory frameworks for CCS need to reflect scientific and technological progress as well as the various objectives of the stakeholders and the international community. The legal and regulatory frameworks currently applied to CCS were established before it emerged as a viable technology and environmental policy option, before climate change mitigation became a priority among the international community. These frameworks will need to be updated to take into account the scientific progress that has been achieved in CCS and in light of the new greenhouse gas mitigation objectives.

On-shore storage primarily falls within the scope of national legal frameworks. CO_2 storage demonstration projects, including EOR with CO_2 storage, are being carried out in several countries under a myriad of non-CCS-specific regulations, such as those governing oil and gas activities, mining, pipelines, transport, environmental impact assessment, property or liability.

Off-shore storage primarily falls under the international legal framework governing the marine environment. Under this framework, large-scale offshore projects will face legal uncertainties existing under the London Protocol and the OSPAR Convention.

Cross-border exchanges of CO_2 and storage of CO_2 in or under international waters may pose a number of specific liability issues in the context of the UN Framework Convention on Climate Change (Haefeli *et al.,* 2004). National and international legal and regulatory frameworks are discussed in more depth in the publication *Legal Aspects of Storing Carbon Dioxide* (IEA, 2004c). Major issues and priority actions are summarized below.

National regulatory frameworks for onshore CCS activities

Legal and regulatory situations vary considerably from one country to another depending on the fossil fuel resources available, what stage each country is at with CO_2 storage technologies, and specific public acceptance concerns. Countries with mature oil and gas reserves tend to have more experience with CO_2 storage through CO_2 EOR and acid gas injection than others.

Each of the various activities involved is governed by existing laws, such as those covering oil and gas activities, mining, pipelines, transport, environmental impact assessment, property or liability. Therefore, CCS activities potentially fall within the scope of many regulations. Carrying out a comprehensive due diligence of the applicable framework is an expensive exercise. In general, existing frameworks are better suited to the capture and transport stages of CCS than to injection and storage.

Regulatory gaps are associated with long-term storage, site characterization, monitoring and liability. Countries declare a lack of empirical understanding of associated risks to fully assess these gaps and thus improve their regulatory framework. The other main gap is the inclusion of CCS in climate change mitigation mechanisms.

United States

In the US, there are two levels of legal and regulatory framework in accordance with the allocation of powers between the Federal and State governments. At the Federal level, the Environmental Protection Agency currently considers that CO_2, like other greenhouse gas emissions, is not an air pollutant subject to regulation under the Federal Clean Air Act[1]. There are no Federal laws explicitly governing each stage of CCS, namely capture, transport, injection and post-injection.

There is, however, a large body of existing Federal law governing interstate pipeline activities, hazardous wastes and underground injection wells and their controls. These could be adapted to encompass CO_2 storage activities. Furthermore, there is a large body of existing Federal case law distinguishing between EOR, storage and waste disposal for the purposes of classifying injection activities. Whether or not the substance being injected has a commercial value is an important criterion for determining whether it is categorized as a waste when being stored. This might have a bearing on the determination of any future framework for CO_2 storage.

At the State level, there are a significant number of regulations governing CO_2 capture, transport and injection, developed for the oil and gas industries. Site ownership issues also fall under the jurisdiction of State law, which may vary considerably from one State to another. Given this institutional structure, regulating CCS in the US will not be a 'one stop shop'. Some powers might be vested with the Federal government, but most will be vested with the State.

Whichever mix is eventually chosen, there is already a substantial body of Federal and State law that could be adapted to encompass CCS activities and thinking on how to apply it to CCS. Whether reform will come from individual States or the Federal government will depend largely on how existing Federal laws are interpreted, including the Clean Air Act. Should it be decided that Federal laws do not apply, there will be more room for States to step in.

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1. At the time of writing, this issue is before the Federal courts, where environmental NGOs are suing the EPA on the grounds that CO_2 is an air pollutant.

United Kingdom

There is a large body of regulations applicable to onshore CCS activities in the UK,[2] although these were generally not designed with CCS activities in mind.

Regulations applicable or potentially applicable to onshore storage of CO_2 include the Petroleum Act, the Pollution Control Act, the Planning and Building Act, the Chemical Regulations, legislation covering dangerous goods, health and safety legislation, Regulations to the Petroleum Act, and the Major Accident Hazards Regulations. In addition, all CO_2 storage activities would have to comply with applicable EU regulations, including the Contaminated Land and Health and Safety Directive and the Water Framework Directive. There is no existing case law on CO_2 storage in the UK, but there are precedents on gas storage.

Overall, the existing framework is not likely to prohibit CO_2 storage. Adapting it to take into account capture and transport activities is not expected to raise particular problems. Injection and storage activities, on the other hand, could lead to issues which would need to be addressed.

According to a study carried out for the British government, there seems little doubt that CO_2 would be classified as waste if permanently stored ('disposed of') because CO_2 has no value and, therefore, there would be no intention to recover it at a later stage. For CO_2 EOR or ECBMR, the classification of CO_2 could depend on the value placed on the delivered CO_2. If CO_2 is considered waste, its storage would be governed by applicable EU regulations as transposed in UK law, such as the Waste Framework Directive and the Landfill Directive.

The most important legislative gaps concern the status of CCS within the market-based and regulatory framework to address CO_2 abatement, in particular the emission trading scheme, and the long-term monitoring and ownership issues associated with it. Emissions data from offshore injection would have to be provided to the UK Greenhouse Gas inventory.

Japan

There is no legal or regulatory framework explicitly applicable to CO_2 storage in Japan. As of July 2004, there was only one CCS field experiment being conducted in Japan. The research institute responsible for this is acting under the existing legal framework – mainly the Road Traffic Law, the High Pressure Gas Safety Law, the Mining Law, the Mining Safety Law, the Agricultural Land Law, the Water Control Pollution Law and the Waste Disposal Law. All responsibilities for the project lie with the research institute. This project is conducted under existing laws because it is experimental and small in size. Additional regulation would have to be drafted for larger projects.

Canada

Like the US, the Federal government and the Provinces of Canada have different jurisdictions over CCS activities. Resource ownership and development fall under the jurisdiction of the Provincial governments. The Federal Government has jurisdiction when trans-boundary or trade and environmental issues are involved.

There are currently two ongoing CO_2 EOR projects in Canada and almost fifty acid gas (H_2S) injection schemes for disposal and containment. Four additional demonstration projects may be coming up in Alberta in the coming years. Although there are no particular incentives in the market to encourage

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2. Given its oil and gas resources, the UK is more interested in offshore storage, which would be governed by international frameworks and regulations specifically applicable to offshore activities under the jurisdiction of the Crown.

private operators to engage in long-term storage, the Canadian government is strongly encouraging any CO_2 EOR initiative as well as any longer-term storage and monitoring initiatives. A federal CO_2 capture and storage incentive programme and an Alberta royalty credit programme have been initiated to further stimulate commercial demonstration projects in CO_2 –based resource recovery.

Federal and Provincial frameworks that may apply include legislation governing land administration, land-lease, explosives and dangerous goods, petroleum safety, pipelines, mineral resources development, occupational health and safety, planning, coal mining safety, the environment and off-shore activities. None of these frameworks was specifically designed to address CCS.

Like other countries, existing legal frameworks in Canada adequately cover or could be modified to cover the capture, transport and possibly injection stages of CO_2. There are serious gaps, however, regarding long-term storage issues such as monitoring and liability. In addition, there is no framework governing the valuation of CO_2 stored, emission reductions and emission permits.

The development of relevant frameworks in Canada is likely to follow scientific progress and knowledge acquired from the various CO_2 storage projects conducted in Canada.

Australia

The Federal Government and the States of Australia have different jurisdictions over CCS activities.

There is no legal and regulatory framework specific to CCS activities in Australia, except for one project-specific legislation for the Gorgon Project in Western Australia. Applicable legislation includes laws governing occupational health and safety, the environment, petroleum activities, mineral resources, dangerous goods, coal mining safety and health, offshore activities, land lease, land administration, explosives and dangerous goods, pipeline and planning. In addition, offshore geo-sequestration might be considered as dumping under the Dumping Act.

Australia recognizes the existence of legal and regulatory gaps for CCS. Accordingly, it has been agreed that the Federal and State governments will work together to develop a common and consistent national framework to cover all aspects of CCS regulation in the country.

The approach taken has been to prepare a draft set of non-binding regulatory principles which will be submitted to a ministerial council for endorsement. Each individual jurisdiction would then decide whether, when and how to implement them.

Because many of the issues involved with CCS are already covered by existing legislation, it is expected that implementing these principles would mostly be accomplished by amending existing legislation rather than drafting new laws.

Access and property rights as well as long-term liabilities are considered to be the issues on which most work still needs to be done. Community consultations to raise community awareness are considered paramount and have started in some areas.

The EU

There are several EU directives that are potentially applicable to CCS: namely, the Framework Directive on Waste Materials (75/442), the Directive on Dumping of Waste Materials (1999/31), the Environmental Impact Assessments Directive (85/337 as amended by Directive 97/11) and the

Framework Directive on Water (2000/60/EG)[3]. These Directives were not designed with CCS in mind and, at the time of writing, no CCS legislation is being drafted in Brussels.

The applicability of the Directives to CCS will, therefore, be determined separately by each EU member state, on the basis of their various implementation instruments. Also relevant in the European Union is the EU Emissions Trading Scheme (ETS) which allows CCS subject to the establishment of satisfactory monitoring and reporting guidelines.

International legal frameworks for offshore storage

The main international legal frameworks relevant for CO_2 storage are those governing marine environment protection and climate change. These embody two of the main environmental objectives of the international community – stabilizing the atmosphere and protecting the hydrosphere and its environment – which have so far been pursued independently from one another despite sometimes having overlapping scopes.

The marine protection framework, which was established before the emergence of CCS as a major CO_2 emissions reduction option, contains significant constraints on offshore CO_2 storage activities. By contrast, the climate change framework has yet to deliver effective CO_2 emission reductions obligations on contracting parties and incentives for CCS development.

How to combine the respective objectives of these frameworks in the face of technological change and growing knowledge of climate change is one of the main challenges to the development of an enabling international legal framework for CCS. The main international conventions and their status are listed below (Table 8.1).

Table 8.1

Main international conventions relevant to CCS

Convention	Subject	Signature	Entered into force
UNCLOS	"Constitution" of the seas	1982	Yes
London Convention	Marine protection	1972	Yes
London Protocol	Marine protection	1996	No
OSPAR Convention	Marine protection	1992	Yes
UNFCCC	Climate change	1992	Yes
Kyoto Protocol	Climate change	1997	No

Marine Protection

International marine environment protection was established in 1972 with the *London Convention* to regulate the dumping of wastes and other matter at sea. In 1982, this field was extended through the adoption of the *United Nations Convention on the Law of the Sea* (UNCLOS). As an overarching

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3. *The Framework Directive on Water aims to 'maintain and improve the aquatic environment in the Community.' The Directive defines a pollutant as 'the direct or indirect introduction, as a result of human activity, of substances or heat into the air, water or land which may be harmful to human health or the quality of aquatic ecosystems or terrestrial ecosystems directly depending on aquatic ecosystems which result in damage to material property, or which impair or interfere with amenities and other legitimate uses of the environment.' CO_2 is not on the Directive's lists of pollutants or dangerous substances, but potential points of contention include whether CO_2 injection and storage could affect ground and surface waters.*

agreement, UNCLOS does not contain detailed operative provisions on most maritime issues; rather, it provides a framework for all areas, including marine protection, and allows other, more targeted treaties to fill in the gaps.

UNCLOS and the legal zones of the sea

The conditions under which the various international maritime agreements apply to CO_2 storage depend on the location of storage sites within one or other of the specific legal zones of the sea defined by UNCLOS: the Territorial Sea, the Exclusive Economic Zone (EEZ), and the High Seas (Figure 8.6). A country's territorial sea constitutes the band of ocean stretching up to 12 miles from its shores. Within this area, nations' 'sovereignty over the Territorial Sea is exercised subject to ... rules of international law.'

A nation's EEZ extends from the end of the Territorial Sea out to 200 miles from a country's coast (i.e., 188 miles from the end of the Territorial Sea). Coastal states have sovereign rights to explore and exploit the natural resources of the seabed and subsoil of the continental shelf [land which is usually contained within the EEZ].' Beyond this area are the High Seas which are open to all countries. However, each country is entitled to complain if the activities of others cause undue harm to their interests.

Figure 8.6

UNCLOS legal zones of the sea
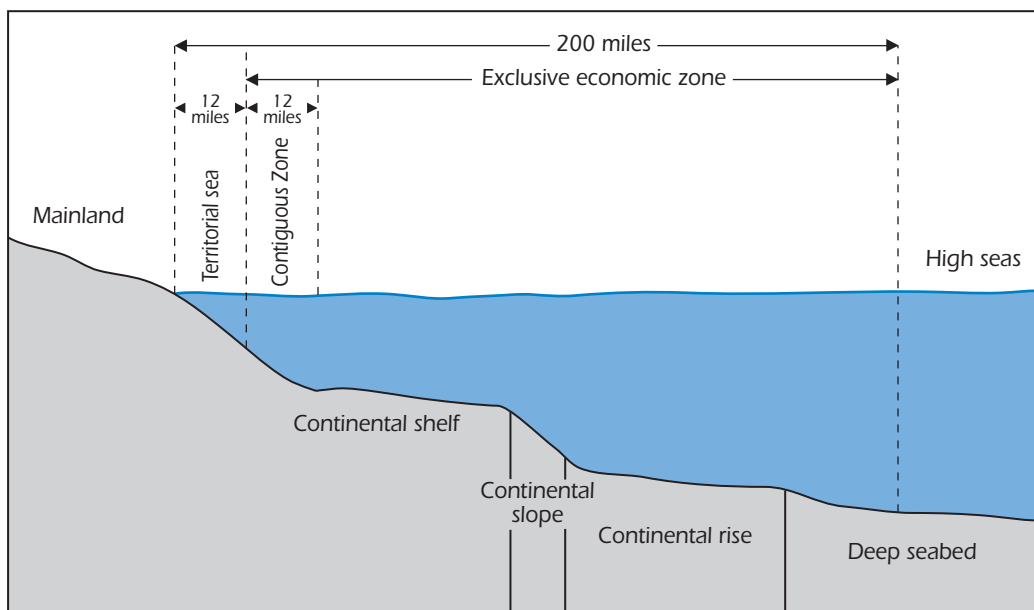
Source: IEA GHG R&D Programme, 1996

With regard to marine pollution, the standards are set by the Convention on the Prevention of Marine Pollution by Dumping of Wastes and other Matter, signed in London in 1972 and known as the London Convention. Underneath the **London Convention** fall several regional agreements covering specific areas of the ocean. The most widely known of these is OSPAR, the Convention for

the Protection of the Marine Environment of the North-East Atlantic. OSPAR's regulations on marine pollution are markedly stricter than those of the London Convention, and, unusually, its decisions are legally as opposed to politically binding on its Contracting Parties.

The relevance of the London Convention to CO_2 storage is limited as it only applies to storage conducted from vessels, platforms and other man-made structures in the water column. Consequently, it does not apply to storage in saline aquifers or any other geologic formations. In addition, the London Convention only prohibits CO_2 storage in the water column if CO_2 is considered as industrial waste, which is still an open debate requiring clarification. Some discussions on CO_2 storage were held within the London Convention in recent years, including whether CO_2 should be classed an industrial waste. No definitive conclusions were drawn, however. The Scientific Group established under the London Convention has a watching brief on the issue.

The London Convention also requires Contracting Parties to be guided by the precautionary approach to environmental protection when implementing their obligations under the Convention. According to this principle, appropriate preventive measures must be taken when there is reason to believe that substances or energy introduced into the marine environment are likely to cause harm even when there is no conclusive evidence to prove a causal relationship between input and effect.[4] It has been argued that this principle would prevent ocean storage of CO_2 even if CO_2 is not considered an industrial waste. However, it has also been claimed that it is not yet clear whether storage with impermeable caps would be considered as a risk to the marine environment. No definitive legal position has been adopted on this issue, whether by the Consultative Meeting of Contracting Parties, the International Court of Justice or other international entity with jurisdiction over the matter.

The **London Protocol** has not been ratified yet. However, its remit is far wider with regard to dumping at sea than the London Convention. The dumping that applies to both comprises:

- deliberate disposal at sea (including in the water, seabed and subsoil but not territorial waters of states) of wastes loaded on board a vessel and from offshore installations; and
- any storage of wastes in the seabed and the subsoil.

In addition, the London Protocol circumvents the waste definition issue by prohibiting all dumping except for wastes listed on a 'reverse list', of which CO_2 is not a part. However, dumping under the Protocol does not include pipeline discharges from land, operational discharges from vessels or offshore installations or placement for a purpose other than disposal, if such activities do not run contrary to the aims of the protocol.[5] Subject to these exceptions, the London Protocol would, therefore, prohibit without distinction the storage of CO_2 both in the water column and in the sub-seabed.

The **OSPAR Convention**, established in 1992 by 15 north European member states and the European Union,[6] is considered by far the most comprehensive and strict legal framework governing the marine environment. Although not drafted specifically with CO_2 storage in mind, some of its provisions are interpreted as creating significant constraints on any offshore CO_2 storage activities. The OSPAR commission is developing an agreed position on whether placing CO_2 in the sea and the aquifers below the sea is consistent with the OSPAR Convention. This highlights the legal uncertainty confronting potential offshore investors.

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4. *Resolution LDC.44(14), 1991.*
5. *Whether CO₂ storage may constitute such a placement is still open to question.*
6. *It is also used as a guideline for marine environment protection by non-OSPAR contracting parties.*

Atmosphere stabilization

The climate change framework was established in the early 1990s to restrain man-made emissions of greenhouse gases. It consists primarily of the UN Framework Convention on Climate Change (UNFCCC) signed in 1992 and effective since 1994, the Kyoto Protocol adopted in 1997 and regional and national implementing instruments.

The main objective of the climate change framework is to stabilize the concentration of greenhouse gases, including CO_2, in the atmosphere by reducing emissions. The UNFCCC does not create binding obligations upon countries to reduce CO_2 emissions but promotes, in general terms, the utilization of carbon sinks. The Kyoto Protocol creates binding obligations on a minimum number of developed countries to reduce their CO_2 emissions by 5.2% below 1990 levels through a system of emission quotas and emission trading. The entry into force of the Protocol is likely, given the recent Russian signature.[7]

Neither the UNFCCC nor the Protocol expressly include or exclude CCS as an encouraged or permitted emission reduction device giving rise to emission credits. Should the Kyoto Protocol enter into force, the status of CCS would have to be clarified in order for it to reap the benefits provided by the Protocol, in particular those of emissions trading. This includes establishing whether or not signatory countries could account for CCS in national inventories (Haefeli *et al.*, 2004).

Priority Actions

To overcome legal uncertainties for investors, the following priority actions are recommended.

Additional storage and monitoring projects need to be carried out to fully assess long-term storage risks and establish purposeful and consistent siting and monitoring requirements. Ongoing EOR projects have not focused on long-term storage aspects and there are too few storage projects with detailed monitoring components to be of large-scale use. Empirical data and close co-operation between the scientific community, industry and regulators will be essential to establish standards for regulatory and legal frameworks and address public acceptance issues for CCS.

In the short-term, governments should provide the appropriate national legal environment for increasing the number of storage demonstration projects. Longer term, national frameworks should be formulated on the basis of adequate empirical knowledge of the conditions and risks of long-term storage.

Contracting parties to international instruments should take a proactive stance in clarifying the legal status of CO_2 storage in marine environment protection instruments, taking into consideration not only their marine environment protection objectives, but also those regarding climate change mitigation. Similarly, clarification of issues relating to cross-border movements of CO_2 might be needed.

Long-term Policy Framework and Incentives

As outlined earlier in the chapter, public-private funding is needed for RD&D to get to the market deployment stage. In addition, the full-scale commercial deployment of CCS will require appropriate

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7. *The Kyoto Protocol will enter into force after at least 55 Parties to the Convention - incorporating Parties which accounted in total for at least 55% of the total CO_2 emissions for 1990 from the group of industrialized countries - have ratified it and completed all formalities.*

remuneration of investors for the additional capital and operating costs of CO$_2$ control installations. In order to support development and deployment of CCS, companies need a clear indication that CO$_2$ emission reduction will be rewarded sufficiently over a period of decades. It is the responsibility of governments to establish credible, long-term policy frameworks and incentives. This chapter only briefly mentions CO$_2$ mitigation policies and incentives under discussion. This issue will be the subject of a follow-up publication.

Investors are expecting long-term certainty about investment and fiscal incentives and/or a CO$_2$ pricing mechanism. This latter option could be in the form of a fixed CO$_2$ tax or use of a flexible mechanism based on a market response to abatement policies. When introduced, flexible mechanisms would initially set the CO$_2$ price at a level adequate to cover costs of the cheapest abatement options.[8]

CCS is unique in the sense that it is applied to large point sources where it results in deep emission cuts. A regulatory approach aiming for CO$_2$ emission reductions of a few percent from each power producer is not an appropriate tool with which to kick-start CCS. Flexible mechanisms will be needed where the credits can be traded, or where a carbon tax could be used.

Carbon taxes are viewed favourably in some countries, although debate on their effectiveness continues in others. Countries which have introduced carbon taxes include Finland, Sweden, Germany, the UK, the Netherlands and Norway. Norway's carbon tax has been instrumental in fostering the Sleipner project – covering the cost of CO$_2$ pressurization and storage. Carbon taxes are also being actively considered in many other parts of the world. In most cases, it is expected that only large CO$_2$ emitters would be targeted.

Under the terms of the Kyoto Protocol, three flexible mechanisms are defined:

- *The Clean Development Mechanism (CDM).* This was created to allow industrialized nations to meet part of their emission reduction targets by cutting emissions in developing countries, providing this contributes to the sustainable development of the host country. The CDM is expected to result in increased investment into developing countries, thereby fostering environmentally beneficial projects that might not otherwise have been feasible.
- *Joint Implementation (JI).* This constitutes the other project-based mechanism defined in the Kyoto Protocol to allow the joint implementation of greenhouse gas reduction activities within countries with agreed reduction targets (38 industrialized countries, including 11 in Central and Eastern Europe). This enables participating countries to work together to meet their respective targets.
- *Greenhouse Gas Emission Trading Schemes (ETS)*. These are briefly reviewed below.

All of the above will help to encourage greater international co-operation, leading to more rapid and effective development and application of CO$_2$ control strategies. It is still unclear, however, how policy makers will consider the eligibility of CCS for the CDM and JI mechanisms – and it is not clear how CCS activities should be accounted for in national inventories to demonstrate compliance with the Kyoto objectives. There is a prevailing opinion that no special agreement should be sought concerning the eligibility of CCS, rather that 'testing the water' projects should be packaged and submitted according to general requirements. Questions relating to ways of accounting for CCS activities and

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8. *CO$_2$ abatement cost curves for deploying renewables and energy efficiency measures indicate that there are still many cheaper options than CCS. Their potential, however, is limited. After a certain point, they would increase in cost with a CO$_2$ price gradually rising to levels adequate for implementing CCS. The process may take years and would take longer in developing countries than in developed economies. It is estimated that, within the EU, implementing options cheaper than CCS would be a viable strategy only for the next 10-15 years.*

establishing appropriate baselines for CDM or JI projects based on CCS technologies have been investigated by the IEA's Energy Efficiency and Environment Division (Haefeli *et al.*, 2004).

Greenhouse gas emissions trading schemes

A greenhouse gas emissions trading scheme is a market-based mechanism that allows emission reductions achieved by one party to be sold or passed on to a second party. It is generally assumed that the assigned emissions target for the country in question will ultimately be passed on to individual enterprises and commercial organisations in the form of emissions caps. Those with emissions below the cap will be able to sell excess credits to another party; levels in excess of the cap will require the purchase of additional credits from elsewhere. This concept is not new; similar schemes for SO_2 trading have been operating successfully in some parts of the world for a number of years. Extensive modelling studies carried out suggest that adopting a comprehensive carbon trading scheme will be instrumental in cutting national CO_2 emissions.

Greenhouse gas trading schemes have a role to play in encouraging further development and use of carbon control strategies. When a commercial or industrial enterprise adopts appropriate CO_2 control measures, this creates the potential for bringing emission levels down to below the agreed cap value. If such a potential is realised, excess credits can be traded or sold, generating an additional source of income.

An EU Directive for emissions trading comes into effect in January 2005. During the first phase, (2005-2007), CO_2 will be tackled through a 'cap and trade' system, concentrating initially on emissions from large industrial and power generation activities. It is estimated that the scheme will affect roughly 45% of total EU emissions of CO_2 projected for 2010. Organisations that fail to meet their agreed targets will be required to pay a harmonized penalty charge, while those with excess credits will be able to trade these with third parties. Several EU member states already have their own schemes in place and discussions are in hand on how to harmonize these. So far, 12,000 installations in Europe have been 'capped' with opening trading prices estimated to be around 8-15 USD (7-13 EUR).

Although it is not specifically mentioned, CCS is likely to be eligible for trading under the Directive but would require the establishment of national storage monitoring and verification guidelines by each country. Renewables and other zero emissions energy technologies are supported by independent incentive schemes.

Countries should create a level-playing field for CCS alongside other climate change mitigation technologies. This includes ensuring various climate change mitigation instruments, including market-oriented trading schemes, are adapted to include CCS. The future role of CCS depends critically on sufficiently ambitious CO_2 policies in non-OECD countries. Therefore, outreach programmes to developing countries and transition economies and international commitment to reduce CO_2 emissions is a prerequisite. The maturation of a global emissions trading scheme, a meaningful price for CO_2 and a predictable return on investment are important factors that could stimulate the timely deployment of CCS.

Annex 1.
ETP MODEL CHARACTERISTICS

In order to quantitatively assess the merits of CO_2 capture and storage technologies in comparison to other technology and policy options, the IEA has used an in-house optimization tool known as the Energy Technology Perspectives (ETP) model. This enables the benefits of CCS and other technology options, such as nuclear and renewable energy, to be cross-compared in a structured, logical and transparent manner.

This annex provides an overview of the structure and scope of the ETP model and the assumptions that lie behind the analysis. The general structure of the model is outlined, followed by a discussion of key technology parameters. The annex will be of interest to those wishing to understand the way in which the quantitative analysis has been structured in order to reach the results provided in Chapters 4, 5, 6 and 7.

The Value Added of the ETP Model CCS Analysis

The ETP model belongs to the MARKAL family of bottom-up systems engineering-economic models (Fishbone and Abilock, 1981; Loulou *et al.*, 2004). MARKAL has been developed during the past 30 years by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA implementing agreements (ETSAP, 2003).

A model is a structured, logical and reproducible method to analyse a complex policy problem. While no-one can predict the future with certainty, the goal is to 'model for insights', not to 'model for figures'. Any model of this kind is a highly stylised representation of the world energy supply and demand, based on a dataset that approximates the real world. Each model has its own unique characteristics that affect the results and conclusions.

The ETP model is a complex model. Using it for the purpose of CCS analysis requires a significant effort. This raises the issue why such a complex model is needed for proper assessment. The reason is that this model accounts for a large number of key characteristics of the energy system that are of importance for long-term CCS decision making. If these characteristics were not accounted for the outcome of the analysis would be different, and in all likelihood the outcome would be less relevant for decision making. The model has the following features, some of which are elaborated on in more detail in this annex:

- The model represents the world split into 15 regions. This detailed representation of the world energy system accounts for the specific characteristics of the energy system on a regional level, such as availability of primary energy resources, acceptance of nuclear, and regional capital availability.

- The model optimizes the energy system for the next 50 years. Such a long-term perspective is needed in order to assess the role of CCS properly.

- The model provides insights concerning the impact of deploying CCS on global fossil fuel and electricity markets, an issue that has received limited attention so far.

- The model accounts for competing emission reduction strategies in certain sectors. For example renewables and energy efficiency options are considered as well as CCS.

- The model accounts for interactions on the systems level. For example, use of more fossil fuels with CCS may result in less use of renewable energy. If this is the case, the marginal benefits in terms of emissions reduction of using CCS are small. Therefore the assessment of CCS CO_2 benefits

with ETP can result in a fundamentally different answer than a back-of-envelope calculation where, for example, coal-fired power plants with and without CO$_2$ capture are compared.

- The model accounts for the difference between CO$_2$ capture and storage cost (model input) and CO$_2$ emission abatement cost (model output). CCS is evaluated based on emission abatement cost, which is a better measure for the cost and benefits of an emission mitigation strategy.

- The model contains a database of current technologies and emerging technologies. Therefore the assessment of CCS is not only based on the technological characteristics of the current energy system, but also on the characteristics of the future energy system. This is of key importance because the characteristics of the future energy system will be very different from the current energy system if CO$_2$ policies are introduced.

- The model representation is based on detailed technology data. These data have a solid basis in engineering studies and scientific literature. This solid basis enables the identification of technology RD&D opportunities. This is a value added compared to econometric top-down models with a very aggregate representation of particular technology, that does not allow validation of particular technology development prospects and that does not allow identification of RD&D opportunities.

- The model accounts for capital stock turnover. This is of importance for proper assessment of the transition to fossil fuels with CCS.

- The model represents electricity supply and demand in detail, accounting for the difference of base load and peak load plants and intermittency of renewables. The future annual electricity load curve is calculated by region, based on the demand for useful energy. The load of individual power plants can be varied over the year and during the lifespan of the plant, as is the case in practice. CHP is represented in detail, with a seasonal heat load curve. This detailed representation of the electricity system is of key importance for the assessment of CCS in the electricity sector.

- The model accounts for future demand for synfuels such as hydrogen and DME for the transportation market; based on a detailed representation of transportation demand, competing transportation technologies and fuel supply options. This allows for proper assessment of CCS potentials in fuels supply.

- The model accounts for carbon leakage through industry relocation and changes in global energy markets, if regional CO$_2$ policies differ.

The Model Representation of the Energy System

The ETP model is a micro-economic representation of part of the world economy, divided into 15 regions.[1] Only the energy part of the economy is modelled (*i.e.*, the energy system). The energy system is represented as a set of interlinked markets in economic equilibrium. The model covers the production of primary energy carriers, their conversion into final energy carriers such as gasoline, electricity and heat, and the conversion of final energy carriers into useful energy or so-called energy services, such as lighting and transportation. This so-called energy system (Figure A1.1) is modelled as a set of interdependent technical product flows and processes.[2] Various technologies can be used to generate certain product flows, *e.g.*, a number of coal and gas-fired power plant types for electricity production. The model includes a technology database with around 1,500 supply and demand side technologies.

1. The 15 regions considered in this study are: Africa, Australia/New Zealand, Canada, China, Central and South America (CSA), Eastern Europe, the Former Soviet Union (FSU), India, Japan, Mexico, Middle East, Other Developing Asia (ODA), South Korea, the US and Western Europe.
2. Models of this type, which start from descriptions of technical options, are often called 'bottom-up models' as opposed to 'top-down' models that start from a description of the economy as a whole.

ETP is a linear programming model that minimizes an objective function. This objective function represents total discounted energy systems cost over a number of periods that satisfies a certain energy demand under certain constraints (*e.g.*, the attainment of certain production levels, the availability of certain technologies, etc.). ETP is a partial equilibrium model: the model solution represents the equilibrium that would be achieved in an ideal market and (according to neoclassical welfare economics) would maximise welfare. The model version that is used for this analysis has a fixed demand for energy services. Other versions exist where the useful energy demand responds to price changes. However, for this analysis this additional complexity is not included.

The technology choice and process activity levels in the model determine the physical and monetary flows within the energy system. A model solution consists of a set of process activities, flows and resulting emissions (the so-called primal solution in linear programming), and prices (the so-called dual solution).

The strength of these types of model is that they are very well suited to assessing long-term investment decisions for complex systems, where future technology characteristics are very different from current technology. This is in contrast with so-called top-down models that have little technological detail. Moreover, the single objective function ensures that the resulting scenario is internally consistent, as decision making for all processes and all flows is based on the same criteria.

On the other hand, these types of models have no explicit representation of macro-economic relations. Therefore the impact of changes in the energy system on labour markets and financial markets is not taken into account. The analysis in this book is limited to the variations of the energy system.

Black boxes known as 'processes' or 'technologies' are the building blocks of a MARKAL model. They are characterized by:

- their *physical inputs and outputs* of energy;
- their *costs*;

Figure A1.1

The ETP model reference energy system
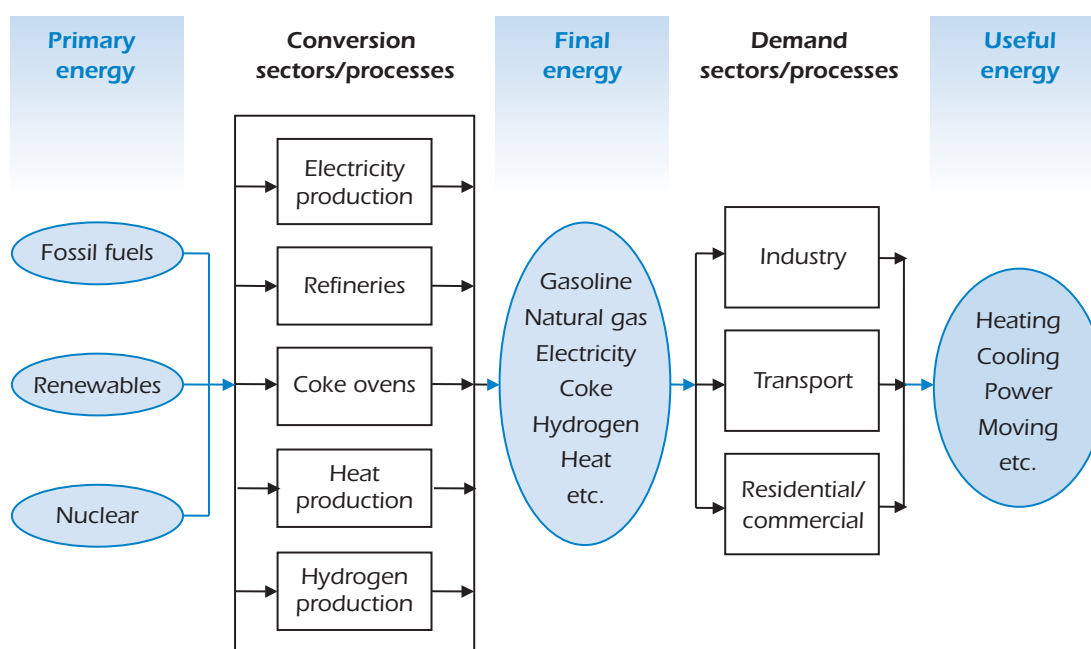
- other characteristics such as environmental impacts (in this study *GHG emissions*), over a number of time periods.

Implicitly these process descriptions yield a very detailed input-output structure linking hundreds of interdependent processes through flows of materials and energy. The model covers all major processes and energy chains 'from well to wheel' (Figure A1.1). Given adequate input of data for the individual technologies, the model structure is suitable for life cycle analysis of both energy and materials in a dynamic perspective. Upstream and downstream effects are taken into account.

Process descriptions follow a standard format, consisting of two data sheets. One sheet describes the physical inputs and outputs (of energy and materials), while the other characterizes the economic and remaining process data. The input data structure depends to some extent on the process that is characterized. Data for fuel mining and transportation, power plants, other transformation processes in the energy sector, materials manufacturing industry, and other end-use technologies are characterized in different units (*e.g.*, per kW for power plants and per tonne product for materials-producing industries). A schematic example of the model input structure for power plants is shown in Table A1.1.

The data input is divided into eleven time periods. These cover the period 2000-2050, meaning that each period represents five years. One column is reserved for time-independent variables (TID). The physical data refer to all the physical inputs and outputs that are considered relevant in this study; inputs and outputs of energy products and materials as well as emissions of all relevant GHG emissions. GHG include CO_2, N_2O, CH_4, with their usual weights, corresponding to their 100-year global warming potential. The physical process data do not represent the total mass and energy balance where input equals output (because of flows that are not accounted for, such as low temperature waste heat).

In order to keep track of costs under changing economic environments, the data sheet distinguishes between three cost categories:

- investment costs (which are proportional to the installed capacity),
- fixed annual costs (proportional to the installed capacity), and
- variable costs (proportional to production volume).

Regional cost multipliers and region specific discount rates are applied in order to reflect the different economic conditions (see Annex 2).

Flexibility in the input/output ratios

This input structure enables the representation of changing technology parameters in time. For instance, increasing process efficiency can be modelled by decreasing inputs per unit of output (such as for fuel in Table A1.1). Decreasing costs or changing restrictions can be modelled in a similar way. This is illustrated by the investment costs in Table A1.1 which decrease over time. This is one way to account for so-called 'learning-by-doing', accounting for decreasing costs as the installed capacity increases. The more complex option is where learning is a function of cumulative investments as calculated by the model (so-called endogenous technology learning). This approach has not been applied in this study.

Bounds

The user of the model can impose restrictions on the deployment of certain technologies. Such restrictions (called 'bounds' or constraints) may reflect consumer or political preferences, intentions or objectives expressed in policy papers, or long- and short-term physical constraints such as natural resource availability.

Table A1.1

MARKAL model data structure for a power plant - an example

	Period	Unit	TID	2000	2005	2010	...	2050
Sheet 1: Physical flows								
Inputs	Fuel	(GJ/GJel)		2.0	1.8	1.6	...	1.4
Output	Electricity	(GJel)		1	1	1	...	1
Sheet 2: Other data								
	Investments	(USD/kW)		1000	800	700	...	600
	Fixed annual costs	(USD/kW.yr)		5	5	5	...	5
	Variable costs	(USD/GJel)		2	2	2	...	2
	Delivery costs	(USD/GJ)		1	1	1	...	1
	Availability factor	(unit/unit cap)		0.9	0.9	0.9	...	0.9
	Peak contribution	(kW/kW)		1	1	1	...	1
	Life	(years)	25					
	Start	(year)	2000					
	CO_2 emitted	(kg/GJel)		15	14	13	...	10
	CO_2 captured	(kg/GJel)		150	135	120	...	105
	Residual capacity	(GW)		2	0	0	...	0
	Maximum capacity	(GW)		5	10	50	...	50
	Minimum capacity	(GW)		0	0	0	...	0

In this study the following types of bounds play a role:

- bounds on maximum penetration of certain technologies, reflecting social and strategic considerations for instance (*e.g.*, a maximum bound on *nuclear* and *hydropower*, a maximum import of *natural gas* from Russia). These bounds are mainly based on acceptance issues or on technical data concerning the availability of resources and the timespan necessary to start implementing the required technologies (*e.g.*, the necessary time for building pilot plants and plant construction);

- reflecting the standing capacity from earlier periods (*e.g.*, for the existing building stock);

- bounds on the availability of natural resources (*e.g.*, availability of oil, gas and renewable energy).

The ETP model matrix contains 700,000 rows and 750,000 columns, and 5 million non-zero coefficients. Given the size of the model, it is not possible to discuss all the input data in detail. Only the general structure of the model will be discussed, followed later on in this chapter by a discussion of key modules that affect the CCS technology choice.

Demand categories

Processes represent all activities that are necessary to provide certain products and services – for example space heating or vehicle-miles to be travelled. Many products and services can be generated through a number of alternative (sets of) processes that feature different costs and different GHG emissions.

The current model contains 106 'demand categories' across the main end-use sectors. A general overview is provided in Table A1.2. For each demand category, energy service demands are specified in terms of useful energy or so-called energy services (*e.g.*, vehicle kilometers).

Table A1.2

Demand categories in the ETP model

Sector	Number of demand categories
Agriculture	1
Services	17
Power plants own use	1
Industry	46
Non-energy use	7
Residential	19
Transportation	15
Total	**106**

As ETP is a global model, it covers trade in energy commodities and industrial commodities. Trade is limited by cost only. In this approach it would be possible to account for carbon leakage effects due to changes in global commodity trade.

The BASE scenario GDP growth (see Annex 3) and electricity demand are calibrated with the 2004 World Energy Outlook (IEA, 2004a), but it is virtually impossible to achieve a 100% match. ETP demand is defined in useful energy terms, and ETP final and primary energy demand is a result of technological development, efficiency trends and cost optimization. On the other hand WEO is an econometric model, where projected final energy demand is based on econometric data. The very different nature of both modelling approaches will result in different outcomes.

The model includes a detailed database of energy supply and energy demand technologies. On the demand side, this database contains energy efficiency options and energy substitution options. For example a hybrid car is modelled as an alternative for a conventional gasoline-fuelled internal combustion engine, while at the same time a hydrogen-fuelled fuel cell car is considered. The

Future technology characteristics: a key uncertainty

An analysis with a broad time horizon (2050 in this study) will be based on technology data from different sources. These data will have different levels of accuracy. Often the accuracy of the data is not clear. Generally speaking, assessment studies for new technologies will often suggest a significant improvement potential compared to existing technologies. However, the data are more uncertain. In fact, many new technologies do not make it to the market. In a least-cost planning model with perfect foresight, such as ETP, uncertainty is not accounted for.

Without proper guidance by the modeler, risky speculative technologies are selected instead of less attractive but proven technologies. Such technology optimism can create modelling results that suggest radical technological change. Considering only proven technologies can increase the credibility of the study. However, consideration of technological change may lead to radically different policy conclusions. Therefore, the model should contain a balanced dataset, and common sense is required regarding the conclusions that are drawn from any model run including speculative technologies. The technology dataset should be part of the uncertainty analysis.

technology choice depends on least-cost criteria that include regional fuel prices, discount rates and technology cost assumptions.

The ETP model structure and model data have been characterized in more detail in a number of publications, *e.g.*, (Gielen and Karbuz, 2003; Gielen *et al.*, 2004).

The Fossil Fuel Supply Module

In most sectors the fuel prices constitute a set of key parameters that determine the fuel choice. The price assumptions from the World Energy Outlook are listed in Table A1.3. These prices have been used to calibrate the model. The figures indicate a coal and gas price gap in 2030 ranging from 0.60 USD/GJ in regions with ample gas resources up to 3.27 USD/GJ in regions with LNG imports and indigenous coal reserves.

Table A1.3

Coal and gas price projections, 2000-2030

			2000	2010	2020	2030
Oil		(USD/GJ)	4.95	3.93	4.52	5.12
Gas	USA/CAN/MEX/CSA	(USD/GJ)	3.67	3.58	3.99	4.42
	WEUR/EEUR/AUS	(USD/GJ)	2.88	3.11	3.59	4.06
	FSU/MEAST/AFR/OASIA	(USD/GJ)	1.34	1.15	1.63	2.10
	JAP/SKO/CHI/IND	(USD/GJ)	4.48	3.66	4.13	4.52
Coal	AUS/CHI/USA	(USD/GJ)	1.00	1.05	1.10	1.15
	Others	(USD/GJ)	1.14	1.36	1.44	1.50

Source: IEA, 2004a.

Fuel prices in the ETP model are endogenous. This is a major difference with other bottom-up models, where fuel supply curves are defined exogenously. Using endogenized fuel prices enables the impact of CCS technology on fuel supply to be taken into account. Coal, gas and oil markets have been modelled. Understanding the model structure can help to understand the interaction of CCS technology and fossil fuel markets. The fossil fuel supply model structure will therefore be discussed in more detail.

Figure A1.2 shows the oil production and processing module. Only one type of crude oil has been modeled. The numbers in the figure refer to the number of technologies in a specific category. Primary, secondary and tertiary oil production are modelled as a sequence of processes. Crude oil competes with syncrude and oil products compete with synthetic fuels. CO_2 EOR competes with other methods for enhanced oil recovery.

There is consensus that oil reserves will not be exhausted over the next 50 years (IEA, 2001). In fact, total conventional oil production increases in the IEA WEO projections from 74 mbpd in 2002 to 108 mbpd in 2030, which represents an increase of 49% (IEA, 2004a). Non-conventional oil increases to 10.1 mbpd by 2030. This non-conventional oil production could increase further. The growth in oil demand will be largely met by producers in the Middle East.

Figure A1.2

Oil and gas production module
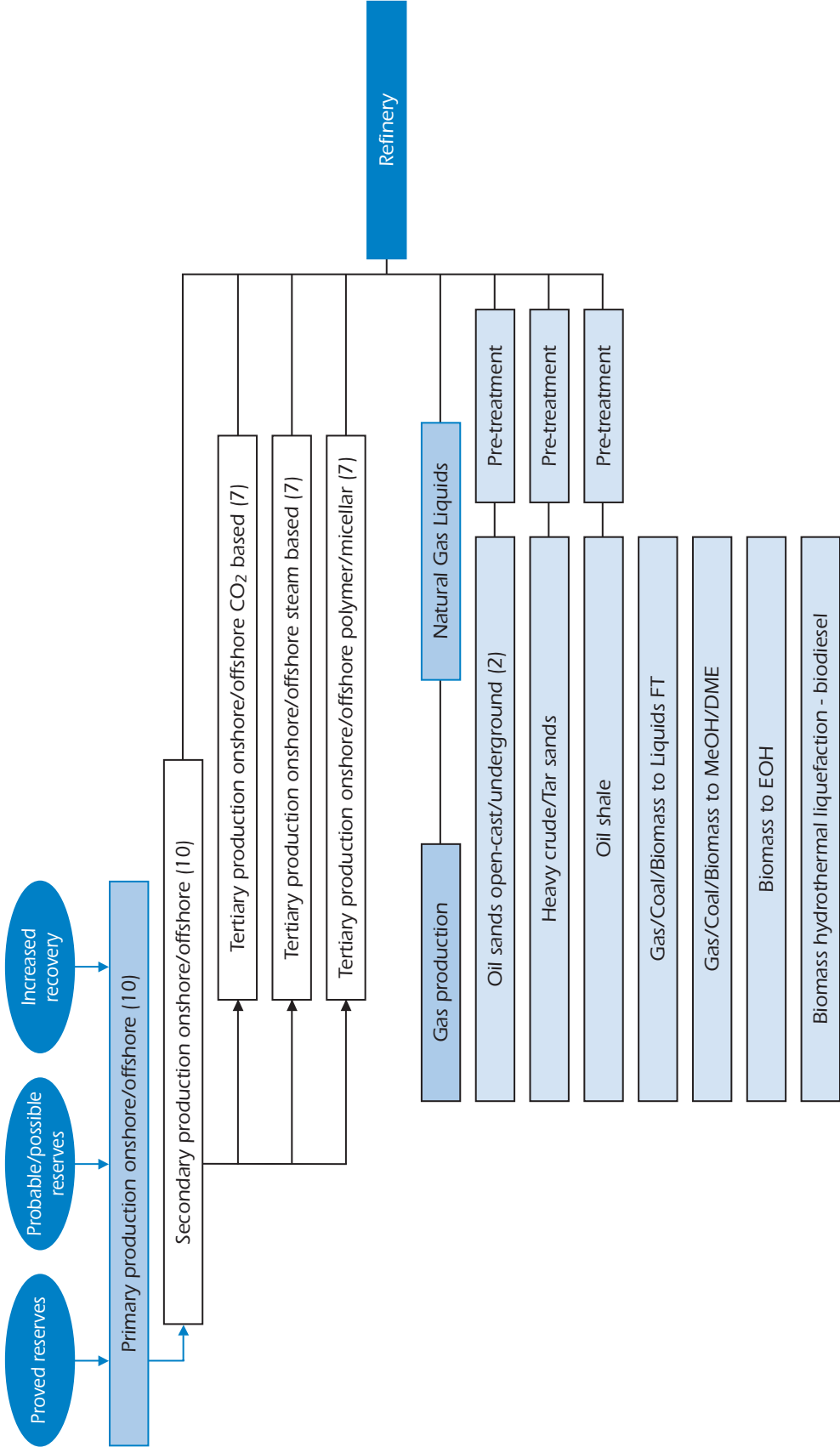
Note: Figures in brackets refer to the number of technologies in a specific category. FT = Fischer-Tropsch; MeOH = Methanol; EOH = Ethanol.

In the model, increasing dependence on producers in the Middle East results in price increases. This is reflected in the model through a supply curve for producers in the Middle East. The higher their production, the higher the price. This curve is split into 8 discrete steps. The ETP model supply curve is based on the *2002 WEO* (IEA, 2002a).

Figure A1.3 shows the ETP model structure for gas supply. A number of gas supply options have been considered. Associated gas has been considered as a single category together with conventional gas. A number of unconventional supply options have been considered. For example in the USA, unconventional gas production already constitutes a significant share of total gas production.

Gas transportation constitutes a key cost component, so transportation pipelines and LNG transportation have been modelled in detail. Stranded gas (at remote locations) and gas close to consumer markets have been modelled separately. Stranded gas can be converted into synfuels or it can be converted into LNG. In the longer term new types of high-pressure pipelines may allow transportation of gas from remote sites to consumer markets. Pipelines from the Middle East to Europe deserve special attention in this respect. For the time being, such pipelines have not been considered. While pipeline supply is a suitable option for Europe and possibly for East Asia, the US will increasingly rely on LNG imports. This results in higher regional gas prices.

The coal market is a competitive market, with many suppliers from around the world. Moreover, coal reserves are much more extensive than oil and gas reserves, so there is no strategic need for governments to intervene. Resource availability poses no constraints well beyond the model time horizon.

Figure A1.3

Structure for gas supply in the ETP model
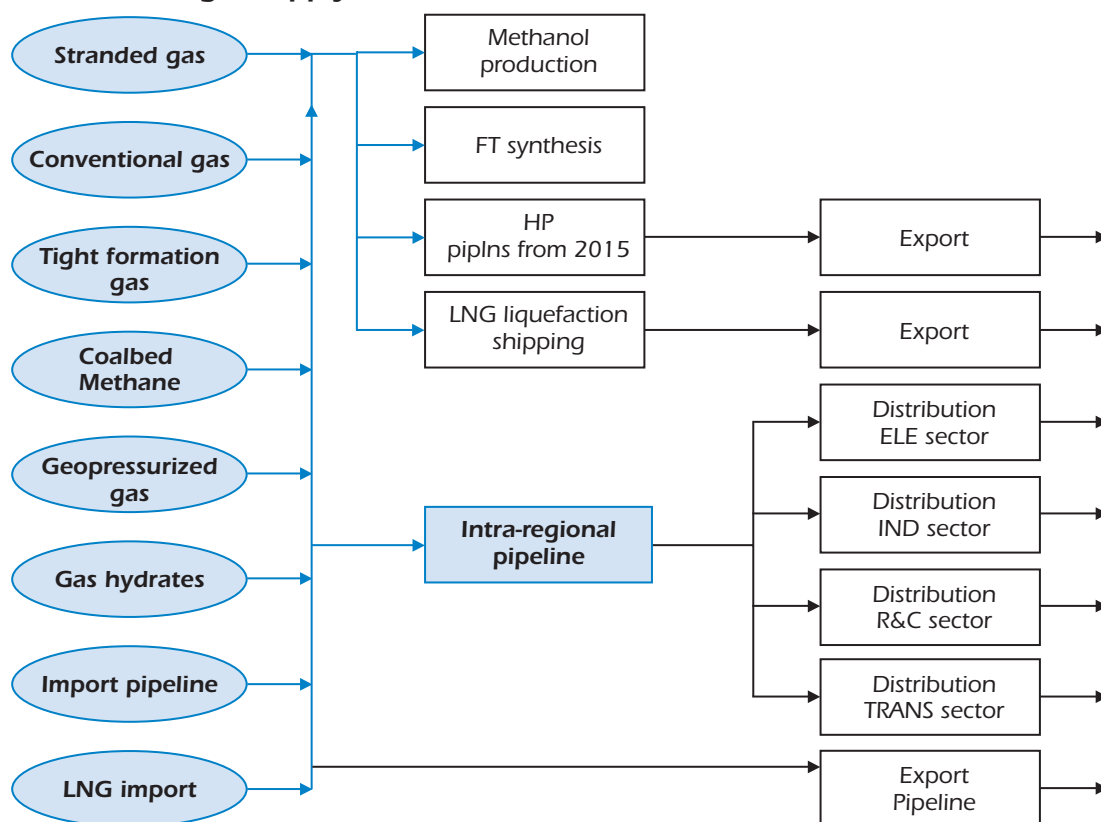
Figure A1.4

Structure for coal in the ETP model
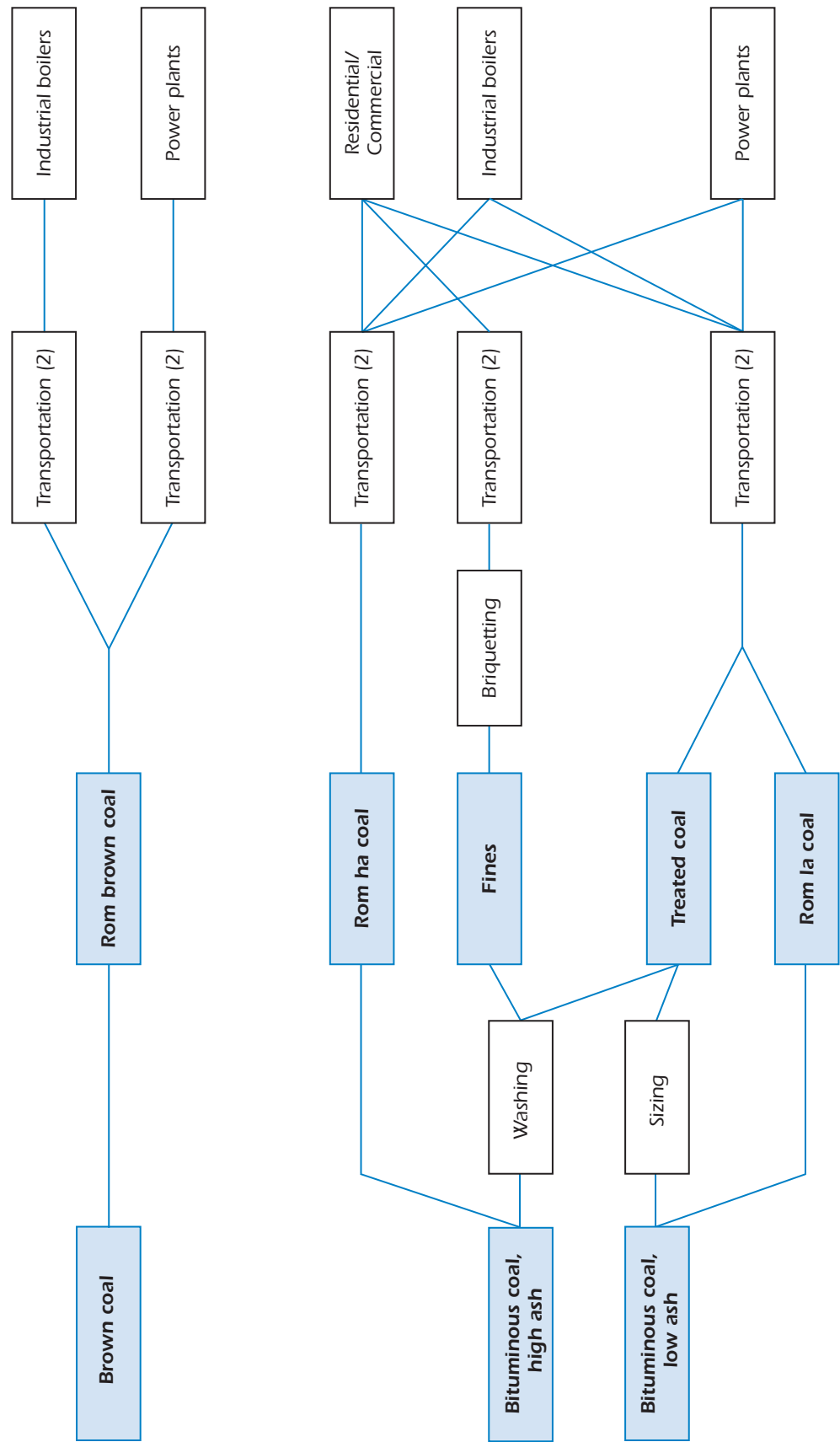
The coal model structure is shown in Figure A1.4. Brown coal and hard coal have been modelled separately. With regard to hard coal, raw coal and washed coal have been modelled separately for regions where the use of high-ash raw coal is significant. For all other regions only one coal type is defined. It is assumed that all this coal is either washed or it is low-ash coal that needs no washing. The current model version does not account for the varying sulphur content and mercury content of coal. For the residential and commercial sector, briquettes have been modelled separately. Transportation has been split into two categories (demand close to the mines and long-distance transportation).

The CCS Module

The ETP model structure for CCS in the electricity sector is shown in Figure A1.5. The structure can be split into three parts: capture, transportation and storage. The set of capture technologies is split into likely technologies (that are proven, or that require limited technology development) and speculative technologies (whose demonstration on a relevant scale has not yet started). The likely technologies include supercritical power plants with flue gas capture, IGCC with fuel gas capture (for coal and for lignite), and gas-fired power plants with either flue gas or fuel gas CO_2 capture.

The speculative technologies include chemical looping reactors for coal and gas, power plants including solid oxide fuel cells for both coal and gas, and ultra-supercritical steam cycles for coal. The various capture technologies were discussed in detail in Chapter 3. For gas, the quality of the dataset does not allow a split of chemical absorption systems, pre-combustion natural gas reforming and oxyfueling; therefore all three have been represented by a single placeholder. Also, a number of cogeneration units with CCS have been considered (cogeneration of heat and electricity and cogeneration of synfuels and electricity).

Several industrial, large-scale CHP technologies with CO_2 capture have also been considered in the model. These include biomass IGCC, black liquor IGCC, and gas-fired combined cycles for the chemical industry. The cogeneration units in other industries are smaller, making CO_2 capture a less likely option. For iron and steel, CO_2 capture from blast furnace gas has been considered; consideration of CCS for blast furnace gas-fired power plants would result in double counting.

Apart from CO_2 capture in the electricity sector, capture in the manufacturing industry and in fuel supply has been considered for the following processes:

In manufacturing:
- Blast furnaces;
- DRI plants;
- Portland cement kilns;
- Ammonia plants;

In fuels supply:
- Flexicoker;
- Fischer-Tropsch synfuel production from gas, coal and biomass;
- Hydrogen from gas, coal and biomass. Hydrogen use has been considered for all types of industrial burners, steam boilers and kilns, and for refinery purposes. Also, hydrogen is considered as a fuel for residential and commercial heating. Finally, hydrogen has been considered as a transportation fuel.

CO_2 transportation costs have been varied for aquifers (3 USD/t), depleted oil and gas fields (10 USD/t), enhanced fossil fuel recovery (5 USD/t), and inter-regional CO_2 shipping (15 USD/t).

These should be considered optimistic estimates for large-scale transportation systems that exclude cost for pressurization. Variations in transportation costs within each category have not been accounted for. A number of CO_2 storage options have been considered. Onshore and offshore potentials have been characterized separately, as the acceptance for each may differ. The potentials differ by region; some storage options are not available in certain regions.

Figure A1.5

Schematic CCS model structure for the electricity sector
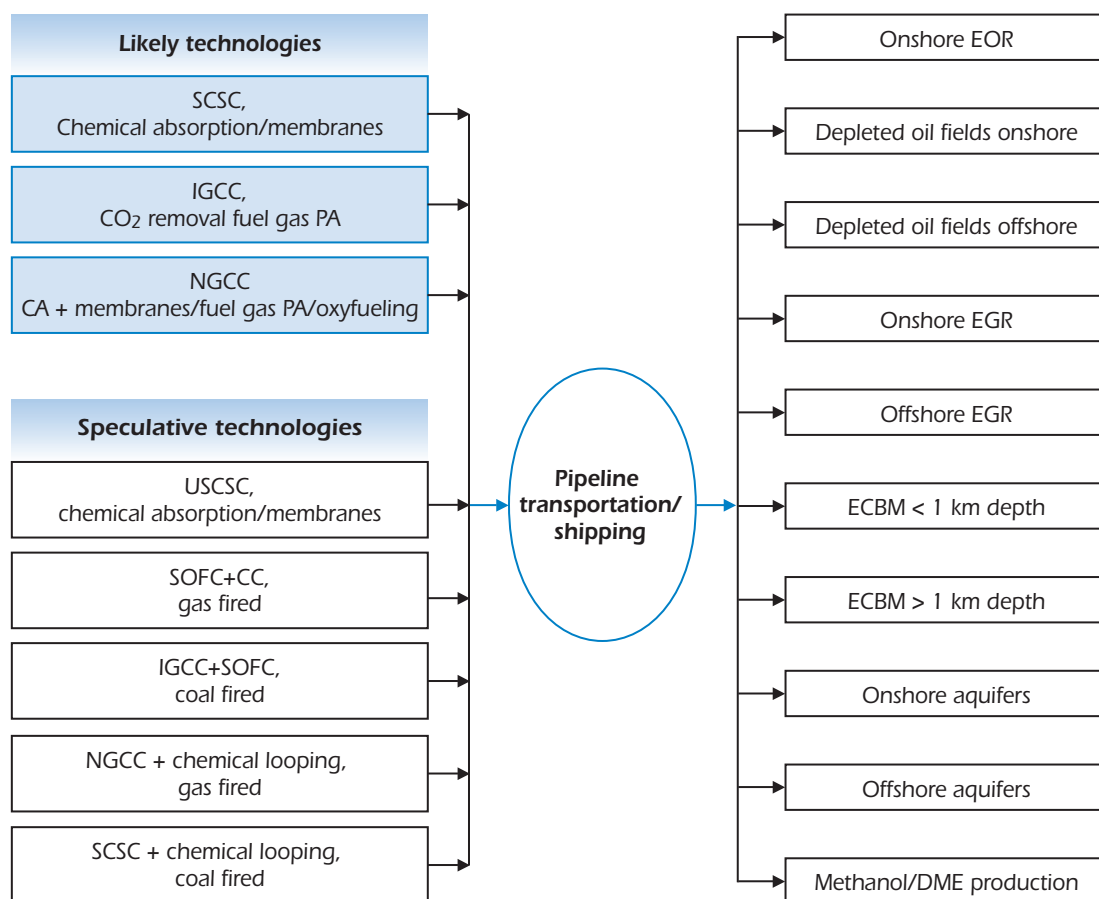
Note: Only centralized fossil-fuelled power plants are shown in this figure.

SCSC = SuperCritical Steam Cycle. USCSC = Ultra Supercritical Steam Cycle. NGCC = Natural Gas fired Combined Cycle. CA = Chemical Absorption. PA = Physical Absorption. SOFC = Solid Oxide Fuel Cell. IGCC = Integrated Gasification Combined Cycle.

The Renewables Module

For the accuracy of modelling, it is important to consider the regional techno-economic characteristics and potentials of the renewable energy supply. A detailed Geographical Information System (GIS) has been developed for this purpose. The GIS data are aggregated into supply curves that serve as input for the global ETP model analysis. A GIS-analysis is based on the principle of overlaying maps. It implies the use of location-specific data of high resolution for inherently consistent global analysis. This is important because, for many developing countries, accurate potential estimates are not available.

The GIS analysis produces estimates of regional supply curves of sufficient quality for the model, based on data sets publicly available, without the need of surveys of each individual region. It builds on meteorological and geological datasets. The assessment has focused on solar, wind and geothermal. The meteorological data sets (ECMWF, 2003, and Czisch, 2003) are based on a 1°x1° global grid (*i.e.*, 111x111 km at the equator).

Auxiliary data sets on land-cover, population distribution, topography, etc., have significantly higher resolution, usually 1, 5 or 15 minutes (1 minute = 1.8 km at the equator). An overview of key assumptions is shown in Table A1.4. The resulting global capacity potentials should be compared to a projected need for 7000 GW electric capacity by 2030 (IEA, 2002). **The renewables potentials do not pose a constraint for their expansion in the electricity sector. Cost and intermittency limit the growth.**

Table A1.4

Key assumptions in the GIS analysis of the potential for renewables

Wind onshore	• Certain land cover types have been excluded (no urban areas, forests or wetlands);
	• The distance to the centres of demand has been considered; either within 25 km (cost class A) or within 100 km (cost class B);
	• Dense population areas have been excluded because of noise and acceptance problems (more than 100 persons/km^2);
	• A maximum of 4% of remaining area is considered exploitable in order to account for competing land uses and other acceptance and environmental concerns;
	• The resulting area translated into potential using an average turbine density of 13 MW/km^2;
	• Resulting global potential capacity 8,252 GW;
	• This is divided into a number of wind speed classes.
Wind offshore	• Electricity grid access within 50 km (cost class A) or within 100 km (cost class B);
	• Water depth less than 25 m (cost class A) or less than 50 m (cost class B);
	• 33% of remaining area is considered exploitable;
	• The resulting area is translated into a wind potential using an average turbine density of 13 MW/km^2;
	• Resulting global potential capacity 5,597 GW;
	• This is divided into a number of wind speed classes.
PV	• Access to electricity grid;
	• 1% of remaining area exploitable (this accounts also for land cover limitations);
	• Resulting area translated into potential using 40 Wp/m^2 ;
	• Resulting global potential capacity 19,482 GW.
Solar thermal	• Land cover (no urban areas, forests or wetlands);
	• Access to electricity grid;
	• Not too densely populated (less than 100 persons/km^2);
	• 0.5% of remaining area exploitable;
	• Resulting area translated into potential using 40 Wp/m^2;
	• Resulting global potential capacity 5,121 GW.
Geothermal	• Cost split into drilling and above ground installations;
	• Three types of reservoirs: high and low quality hydrothermal and hot dry rock;
	• Total geothermal heat potential of 43 EJ/yr is distributed to the 15 ETP regions and subdivided into heat flow classes using GIS heat flow data;
	• Five heatflow classes have been defined with varying drilling cost;
	• Resulting global potential capacity 1,363 GW.

The supply curve for hydropower is split into large dams, run of river and small hydropower. Large dams are split into six classes. Three cost classes are competitive at current cost levels, and three cost classes are technological potentials that are not yet cost competitive. Repowering of existing hydropower installations has been considered as a separate option that can increase capacity by 15%. The potentials are based on a World Energy Council study (WEC, 2001). Data for small hydro are taken from the recent IEA renewable electricity book (IEA, 2003b). The total hydro potential is almost 60 EJ electricity per year (about 4500 GW).

Geothermal heat supply is split into three types: high and low quality hydrothermal reservoirs and hot dry rock. A GIS data set for geothermal heat flow (Pollack *et al.*, 1991) is used to allocate the global potential to the 15 ETP regions, and to subdivide the potential into five heat flow classes. Each heat flow class results in a different heat temperature and has therefore a different electricity production efficiency, and different drilling cost. The total worldwide potential amounts to 43 EJ geothermal energy (Bertani, 2003). In electricity terms, the potential amounts to 13.3 EJ. Surface costs are set at 1,000 USD/kW, and drilling costs for the least-cost class amount to 460 USD/kW and increase up to 1,700 USD/kW for the most expensive cost class (Stefansson, 1999).

Biomass supply has been split into a range of by-products and waste biomass as well as dedicated plantations. For example building waste, waste paper, forestry residues, production residues, commercial and non-commercial fuelwood have been considered. The total biomass potential increases from 70 EJ in 2020 to 150 EJ in 2050. This potential is uncertain. Estimates for 2050 range from 20 to 450 EJ, depending on future agricultural productivity and food consumption trends (Hoogwijk and Berndes, 2000).

In the ETP model, biomass co-combustion can take place in ordinary coal-fired and, following gasification and gas cleaning, in gas-fired power plants. Dedicated biomass gasifiers have also been considered in the electricity sector. In other sectors, there are options such as biomass combustion and black liquor gasification in the pulp and paper industry, and biocrude and bioalcohol production processes.

Figure A1.6 shows as an example the supply curve for onshore and offshore wind in Western Europe. Costs decline by about 25% in a period of 30 years due to technology learning. The potential for wind energy is substantial in terms of gigawatts, but the capacity factor for these plants is comparatively low, between 20-40%, while fossil-fuelled plants can achieve a capacity factor of up to 95%. Even so, with about 800 GW total electricity capacity potential, wind can play a very important role. The current incentives for wind energy in various European countries are also indicated in this figure. Even higher incentives occur. Clearly these incentives are sufficient to achieve a substantial growth in wind use. But the introduction of significant amounts of intermittent electricity sources such as wind raises questions about the security of electricity supply.

The intermittency of renewable electricity supply may cause problems because backup capacity is needed in order to meet the demand during periods when insufficient renewable electricity is available. In practice, this usually implies the installation of gas turbines or oil fuelled engines. An alternative approach would be an electricity supply from renewables that is tailored for peak demand with significant amounts of surplus electricity used for production of hydrogen in periods of excess supply. The latter approach is considered in the ETP model, but it is rather energy inefficient and costly.

In regions where natural gas is not available, more capital intensive coal-fired units, pumped hydro-storage units, or even nuclear may be operated as backup units. The investment cost of low-cost peaking units is in the range of 200-500 USD/kW but fossil fuel supply systems are needed for these installations. These costs must be added to the cost of renewable systems. Another way of dealing with peak load is demand management.

Figure A1.6

ETP wind electricity supply curve for Europe

Key point: There is no single 'true' figure for renewables.
The marginal supply cost depends on the quantity involved and on learning effects
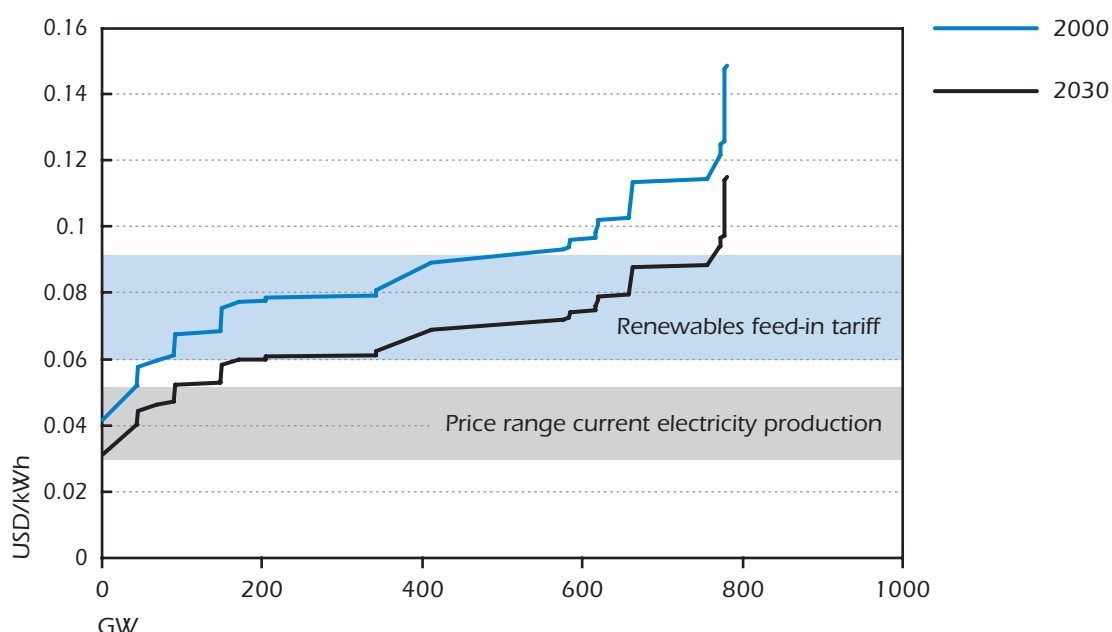
In a MARKAL model, intermittency is taken into account through a so-called peaking equation. The year is split into three seasons (winter, summer and intermediate) and day and night (a total of six time slices). In the multi-regional ETP model, the split of seasons and day/night is the same across all regions.[3] Winter and summer each represent three months while spring and autumn are represented by a single intermediate season. In the intermediate season, day and night represent 12 hours each. In winter, day lasts 9.6 hours and night lasts 14.4 hours. In summer these are reversed.

For each demand category, the demand can be distributed over the six time slices. The shape of the electricity demand curve is calculated by the model as the sum of all demand categories (see Figure A1.7). As the demand structure differs by region, the shape of the load curve differs by region. Reserve capacity accounts for fluctuating demand within one season. This reserve capacity is defined as a share of the demand in the time slice with maximum electricity load. It includes the capacity required to meet peak requirements in that time slice, forced outage, and scheduled outage. In the ETP model, this capacity is set at 30%. The peaking equation ensures that the installed electricity capacity equals demand in the time slice of maximum demand, plus the reserve capacity.

A peaking contribution is defined for each electricity supply technology. The peaking contribution ranges from zero to 100%, and can be time slice specific (*e.g.*, solar is only available during the day). For wind and for solar the peaking contribution has been set at 30% of the installed capacity, while it is 100% for fossil-fuelled plants. In the model this peaking contribution has a certain monetary value that is region and period specific. Usually it amounts to 10-15% of the electricity price.

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3. *This is obviously a simplification. In principle the MARKAL code could be extended to allow for more detailed modelling of the electricity load curve.*

Figure A1.7

ETP electricity load curves for Western Europe

Key point: Electricity demand varies over the year. Such variability may increase in the future.
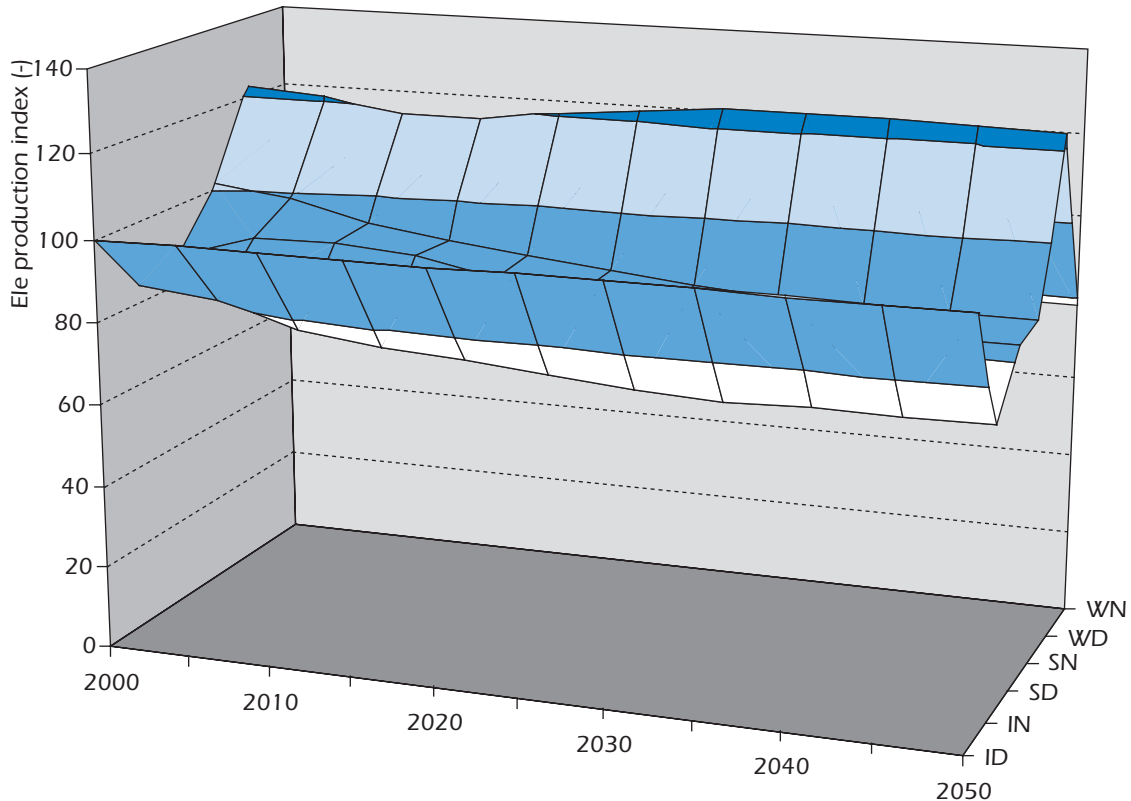
Note: The gap between peak and base load is a factor of two and it increases with time. Normalized to the daytime electricity demand in the intermediate season. Excludes reserve capacity.
ID = Intermediate Day; IN = Intermediate day
S = Summer; W = Winter.

A second issue is the interaction between technology learning and investment costs. In practice, investments can result in technology learning, which results in cost reductions. The investment costs decline by a fixed fraction for each doubling of the installed cumulative capacity (IEA, 2000). A 'virtuous cycle' can occur, where additional investments result in additional learning which results in additional investments etc. This phenomenon can explain the rapid switch from one systems configuration to another in reality or in models with endogenous technology learning.

Learning can be split into learning by R&D (innovation) and learning-by-doing. So far, it is not clear how cost-effective each can be, or which approach should be followed. In this analysis, a simple approach is applied that is in line with other bottom-up energy modelling studies. Emerging technologies are modelled explicitly as discrete technologies. This is a way of representing learning by innovation.

Learning-by-doing is important for technologies that start from a very low cumulative capacity, yet the potential for fundamentally different process designs is limited. Learning-by-doing has been

considered for all key renewables technologies[4] (see chapter 5). The learning rate assumptions are crucial to the cost reduction potential. It is difficult to estimate learning rates. True production cost data are scarce; often only price data are available that obscure cost reductions. Spill-over effects from investments in other countries can affect the learning rates that are measured in a specific country.

Factors that commonly complicate the accurate projection of learning rates are: new technologies with little or no price/cost history (*e.g.*, PV, fuel cells); technologies with highly site-specific installation costs (*e.g.*, hydropower, biomass, geothermal); and technologies where market dynamics obscure the relationship between capacity and investment costs (*e.g.*, PV, combined cycle gas turbines).

In general, lower learning rates are found for technologies based on established, inherently large-scale components such as steam turbines. This is the case for fossil-fuelled power plants with CCS technology. Higher learning rates occur for new designs with modular components suitable for mass-production manufacturing, such as PV modules, wind turbines and fuel cells (Neij, 1997).

Only CO_2 benefits are considered in this analysis. **Other pollutants represent about a quarter of total damage cost of electricity produced from fossil fuels. They are not taken into account in this analysis** (Table A1.5). This results in a slight underestimation of the benefits of renewable and nuclear electricity supply options, in comparison to CCS. The impacts and the valuation of these impacts are location specific and the emissions depend on the technology choice. Generally, abatement costs are much lower than damage costs. Another reason to exclude local air pollutants is that many renewable energy options have other impacts that are hard to measure, such as horizon pollution by wind turbines or biodiversity impacts of biomass plantations.

Table A1.5

Damage costs for fossil-fuelled power plants

(US cents/kWh)	PM_{10}	SO_2	NO_x	CO_2	Total
Coal (built since 2000)	0.1	0.4	1.0	3.9	5.4
Oil (built since 2000)	0.1	0.5	1.2	2.9	4.8
Gas (built since 2000)	0.0	0.0	0.4	1.8	2.2

Note: Figures refer to typical European power plants. CO_2 emissions are valued at 50 USD/t CO_2.

Source: Zwaan and Rabl, 2004.

The Nuclear Energy Module

Approximately 438 commercial nuclear generating units were in operation throughout the world in 2000, with a total production capacity of 351 GW. Nuclear power is a CO_2-free energy source. However, its use is controversial. The accidents at Three Mile Island and Chernobyl have virtually stopped new investment in most OECD countries.

The problem of long-term storage of nuclear waste and the potential use of nuclear waste for production of dirty bombs or even nuclear bombs have prevented rapid growth in developing

4. One could argue that for example in the case of solar electricity, fundamental technological change can be of similar importance. For example, thin film technology and polymer PV systems are fundamentally different from the established crystalline and amorphous PV cells. Given the scope of this analysis, such issues were not taken into account.

countries. On the other hand, growth in Asia continues, as countries such as Japan, China and India build new nuclear plants. Last year Finland announced the construction of a new nuclear reactor. Other European countries may follow. The development of new inherently safe reactor types such as the pebble bed modular reactor may reduce investment cost while eliminating both the risk of nuclear accidents and the problem that current reactors are only economic at a 1-2 GW scale (Kenny, 2004).

Nuclear energy faces a number of challenges (Rothwell and Zwaan, 2003). First, is the high cost of nuclear electricity, compared to fossil-fuelled power plants. Second, is the restricted proliferation of the technologies on which it relies. Third, is the (perceived) risk of serious accidents, and fourth is the waste issue.

The cost structure of nuclear power plants is different from those of fossil-fuelled power plants in a number of ways. Investment costs dominate the cost profile, while operating costs are comparatively small. For an amortized French nuclear reactor, the production cost are 14 Mils/kWh (Bataille and Birraux, 2003). A recent MIT study states that based on numbers from 'actual experience' instead of engineering projections, new nuclear electricity costs 6.7 US cents/kWh, at a real discount rate of 8.5%. Plausible but unproved reductions in capital and operating costs could lower that to 5.1 US cents/kWh (MIT, 2003). This is still 10-20% higher than for coal and gas-fired power plants with CO_2 capture (these electricity production cost are discussed in Chapter 3).

The time needed to build and commission nuclear power plants is substantial. The interest on the working capital during this period adds to the investment cost. Also, the costs of decommissioning, reprocessing and waste management are not negligible. In France, decommissioning costs are set at 15% of the cost of a nuclear reactor. Reprocessing of spent fuel and waste management represent a similar provision (Economist, 2004). Therefore 30% of the costs are in fact not direct investment costs. If there are significant delays in the plant construction, the gap between overnight investment cost and actual life-cycle investment cost will increase further. The costs of reprocessing are substantial; a once-through system without reprocessing results in a lower capital cost but higher waste volumes.

A number of new reactor designs are being studied that may reduce capital cost. For a series of ten European Pressurized water Reactors (EPRs) of 900 MW each, the investment costs are estimated at 2,000 USD/kW (Bataille and Birraux, 2003). It is not clear what is included in this cost estimate, but it is in line with the overnight construction cost given by MIT (2003). In this study, a 25% reduction in these costs is projected. Adding decommissioning and waste fuel processing costs yields 2,000 USD/kW as an optimistic estimate of future nuclear power plant cost.

A number of other designs are being proposed by different suppliers around the world. The lowest cost claim is for the Pebble Bed Modular Reactor, being developed by Eskom, at 1,400 USD/kW. This type of reactor is not yet proven on a commercial scale and this estimate probably excludes the cost adders. Cost reductions for nuclear reactors can be achieved via standardized designs, serial production, economies of scale, and reduced construction periods. Given the importance of capital cost, the discount rate at which nuclear power is evaluated is a key parameter. In a liberalized market, nuclear has a disadvantage.

In the reference model calculations, nuclear capacity has been fixed in line with WEO Reference Scenario assumptions. In a sensitivity analysis, the potential for nuclear was assessed, assuming competition with other emission mitigation strategies on a cost basis. The costs of new nuclear reactors were set at 2,200 USD per kW, declining to 2,000 USD per kW in the long term. This includes spent fuel processing and decommissioning costs.

Annex 2.
REGIONAL INVESTMENT COSTS AND DISCOUNT RATES

Regional Investment Costs

The ETP model covers 15 regions. The database is set up as one 'reference database' with cost data for the USA. Costs in other regions are calculated by multiplying US cost data with a region-specific factor. Region specific cost multipliers are listed in Table A2.1.[5] These multipliers are applied to all processes.

This detailed, but still rather crude, representation of the world energy system poses certain limitations:

- The currency exchange rates tend to fluctuate. Changing exchange rates affect the relative investment costs. In particular, exchange rates for developing countries can fluctuate by a factor of two.

- The project system boundaries may differ by region and by site. For example in developing countries it may be necessary to build roads, new power lines or other infrastructure for new power plants.

- The regions in the model are very large. Any cost factor is an average that may differ considerably for locations (and countries) within regions.

- Particularly in developing countries, some technologies require imported equipment, while others are based on locally produced equipment. Such a difference can impact investment cost significantly.

- In developing countries the availability of skilled labour may be a limiting factor. If workers have to be hired from abroad, this will affect labour cost. Operating and maintenance costs consist of 50% labour costs (that are region specific) and 50% materials and auxiliaries costs (that are assumed to be the same in all regions).

Table A2.1

Region specific cost multipliers

	INVCOST	FIXOM	VAROM
AFR	125	90	85
AUS	125	90	90
CAN	100	100	100
CHI	90	80	80
CSA	125	90	85
EEU	100	90	85
FSU	125	90	85
IND	90	80	80
JPN	140	100	100
MEA	125	90	85
MEX	100	90	90
ODA	125	80	80
SKO	100	90	90
USA	100	100	100
WEU	110	100	95

USA = 100.

5. These multipliers do not apply to energy and materials inputs that are modelled as physical flows. The regional price of these flows is calculated by the model.

Discount Rates: Liberalization, Risk and Time Preferences

The discount rates in the model differ by region and by sector. Model discount rates, shown in Table A2.2, should reflect the real world discount rates. These discount rates are usually significantly higher than the long-term social discount rate. Economists' opinions differ as to which discount rates should be applied for CO_2 policy analysis (Portney and Weyant, 1999).

ETP model discount rates are real discount rates, excluding inflation. The discount rate will differ among world regions, depending on capital availability and perceived risk.

Money supply can be divided into loans and own capital and equity. The long-term return on investment for equity is several percent higher than for loans, because the owner of the equity is exposed to an increased risk (that the company goes bankrupt, in which case loans are paid back first, and usually the equity owner gets nothing). In a situation where electricity supply is governed by government, the lending rate may apply.

In a liberalized market, the equity rate is more plausible. The ETP figures are based on the 30-year government bond rate (for the main country in the region, if applicable), corrected for inflation. For developing countries Moody's country ranking has been used as a measure for creditworthiness. Industry financing has been split into lending and equity (stocks etc.). One percentage point has been added in the case of borrowing by companies, compared to government bond rates, in order to reflect the average incremental risk associated with lending to companies. 5.5% has been added to the bond rate for industrial equity risk (NYU Stern, 2002).

Table A2.2

Region and sector specific discount rates in the ETP model

	Real bond yield 2000-2001 (%/yr)	Industry/Electricity Lending (%/yr)	Industry/Electricity Equity (%/yr)
AFR	8.2	9.2	13.7
AUS	2.6	3.6	8.1
CAN	3.7	4.7	9.3
CHI	5.2	6.2	10.7
CSA	7.2	8.2	12.7
EEU	5.7	6.7	11.3
FSU	8.7	9.7	14.3
IND	8.0	9.0	13.5
JPN	2.0	3.0	7.5
MEA	5.6	6.6	11.1
MEX	7.2	8.2	12.7
ODA	8.2	9.2	13.7
SKO	5.6	6.6	11.1
USA	4.2	5.2	9.7
WEU	3.7	4.7	9.3

Annex 3.
GDP PROJECTIONS

Gross domestic product (GDP) growth is a key driver for future emissions and, therefore, for the potential of CCS technologies. The GDP projections in the ETP model's GLO50 reference scenario are in line with the IEA World Energy Outlook 2004 (IEA, 2004a). The growth projections by period and by region are shown in Table A3.1.

Table A3.1

BASE/GLO50 GDP growth projections (% per year)

	2000-2005	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050	Average growth 2000-2050
AFR	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
AUS	1.1	1.5	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.4
CAN	2.3	2.7	2.3	2.1	2.0	1.9	1.7	1.7	1.7	1.8	2.0
CHI	7.1	5.8	5.2	4.6	4.1	3.8	3.5	3.0	2.5	2.0	4.1
CSA	2.0	3.5	3.3	3.1	2.9	2.7	2.5	2.5	2.5	2.5	2.7
EEU	3.4	3.4	3.4	3.4	3.5	3.5	2.4	2.4	2.4	2.4	3.0
FSU	3.1	3.1	3.1	3.1	3.1	3.1	2.5	2.5	2.5	2.5	2.9
IND	5.3	5.4	5.0	4.6	4.2	3.9	3.6	3.0	3.0	3.0	4.1
JPN	1.1	0.6	0.9	1.0	0.4	0.4	1.5	1.5	1.5	1.5	1.0
MEA	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
MEX	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
ODA	4.0	4.1	4.0	3.9	3.9	3.9	3.2	3.1	2.6	2.6	3.5
SKO	4.0	4.4	3.9	3.3	2.9	2.6	1.3	0.9	0.8	0.4	2.4
USA	2.5	2.8	2.4	2.1	1.8	1.6	1.3	1.3	1.3	1.3	1.8
WEU	1.7	2.4	2.1	1.9	1.7	1.6	1.4	1.4	1.4	1.4	1.7
Global	3.2	3.5	3.2	3.1	2.9	2.7	2.5	2.4	2.3	2.1	2.8

Table A3.2 shows what these growth figures mean in per capita GDP on a purchasing power parity (PPP) basis. The figures suggest a strong convergence of income levels. In 2050 the poorest world regions will reach the same per capita GDP as Europe had in 2000. Obviously this is an optimistic assumption that implies high economic growth in developing countries for the next half century. In sensitivity analysis, the impact of lower and higher growth rates was investigated. In particular, growth in developing countries has been varied (Tables A3.3 and A3.4).

Table A3.2

BASE/GLO50 per capita GDP

USD(2000)/capita	2000	2010	2020	2030	2040	2050
OECD North America	26.0	30.4	34.1	38.0	41.8	45.3
OECD Europe	18.8	23.2	28.3	33.2	40.0	47.7
OECD Pacific	22.1	26.5	32.4	39.3	47.3	55.9
FSU	5.6	7.5	10.1	13.5	16.5	20.1
Eastern Europe	4.6	6.4	9.1	12.8	16.4	21.0
China	3.8	6.1	9.8	15.6	22.7	32.9
Other Asia	3.3	4.7	6.7	9.6	13.6	19.4
India	2.2	3.5	5.5	8.7	12.3	17.6
Middle East	5.7	7.3	9.5	12.3	15.9	20.5
Latin America	6.3	8.4	11.3	15.2	19.5	25.0
Africa	1.9	2.7	3.9	5.6	7.9	11.3

Table A3.3

GDP growth projections for the sensitivity analysis with lower growth rates (% per year)

	2000-2005	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050	Average growth 2000-2050
AFR	3.6	3.6	3.1	3.1	3.1	2.6	2.6	2.6	2.6	2.6	3.0
AUS	1.1	1.5	1.2	1.2	1.2	0.9	1.0	1.0	1.0	1.0	1.1
CAN	2.3	2.7	2.1	1.9	1.7	1.4	1.2	1.2	1.2	1.3	1.7
CHI	7.1	5.8	4.2	3.6	3.1	2.3	2.0	1.5	1.0	0.5	3.1
CSA	2.0	3.5	2.8	2.6	2.4	1.7	1.5	1.5	1.5	1.5	2.1
EEU	3.4	3.4	2.9	2.9	3.0	2.5	1.4	1.4	1.4	1.4	2.4
FSU	3.1	3.1	2.6	2.6	2.6	2.1	1.5	1.5	1.5	1.5	2.2
IND	5.3	5.4	4.5	4.1	3.7	2.8	2.6	2.0	2.0	2.0	3.4
JPN	1.1	0.6	0.7	0.9	0.3	-0.1	1.0	1.0	1.0	1.0	0.7
MEA	2.6	2.6	2.1	2.1	2.1	1.6	1.6	1.6	1.6	1.6	1.9
MEX	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
ODA	4.0	4.1	3.5	3.4	3.4	2.9	2.1	2.1	1.6	1.6	2.9
SKO	4.0	4.4	3.9	3.3	2.9	2.6	1.3	0.9	0.8	0.4	2.4
USA	2.5	2.8	2.2	1.9	1.6	1.1	0.8	0.8	0.8	0.8	1.5
WEU	1.7	2.4	1.9	1.7	1.5	1.1	0.9	0.9	0.9	0.9	1.4
Global	3.2	3.5	2.8	2.6	2.4	1.8	1.6	1.5	1.3	1.2	2.2

Table A3.4

GDP growth projections for the sensitivity analysis with higher growth rates (% per year)

	2000-2005	2005-2010	2010-2015	2015-2020	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050	Average growth 2000-2050
AFR	3.6	3.6	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
AUS	1.1	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.5
CAN	2.3	2.7	2.5	2.3	2.2	2.4	2.2	2.2	2.3	2.3	2.3
CHI	7.1	5.8	5.7	5.1	4.6	4.8	4.5	4.0	3.5	3.0	4.8
CSA	2.0	3.5	3.5	3.3	3.1	3.2	3.0	3.0	3.0	3.0	3.1
EEU	3.4	3.4	3.9	3.9	4.0	4.5	3.4	3.4	3.4	3.4	3.7
FSU	3.1	3.1	3.6	3.6	3.6	4.1	3.5	3.5	3.5	3.5	3.5
IND	5.3	5.4	5.5	5.1	4.7	4.9	4.6	4.0	4.0	4.0	4.8
JPN	1.1	0.6	1.0	1.1	0.5	0.5	1.6	1.6	1.6	1.6	1.1
MEA	2.6	2.6	3.1	3.1	3.1	3.6	3.6	3.6	3.6	3.6	3.3
MEX	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
ODA	4.0	4.1	4.5	4.4	4.4	4.9	4.2	4.2	3.6	3.6	4.2
SKO	4.0	4.4	3.9	3.3	2.9	2.6	1.3	0.9	0.8	0.4	2.4
USA	2.5	2.8	2.6	2.3	2.0	2.1	1.8	1.8	1.8	1.8	2.1
WEU	1.7	2.4	2.2	2.0	1.8	1.8	1.6	1.6	1.6	1.6	1.8
Global	3.2	3.5	3.5	3.4	3.2	3.4	3.2	3.1	3.0	2.9	3.2

Annex 4.
WEBSITES WITH MORE INFORMATION ON CCS

The following websites provide a starting point for those wanting more information on CO_2 capture and storage technologies. The list is not exhaustive and some of the websites may have a limited lifespan.

Second Annual Conference on Carbon Sequestration, Alexandria, VA,:
www.carbonsq.com/proceedings.cfm

Third Annual Conference on Carbon Sequestration, Alexandria, VA:
www.carbonsq.com/

CO_2 capture project (activity of eight leading energy companies):
www.co2captureproject.org/index.htm

IEA GHG R&D Programme: www.ieagreen.org.uk/

IEA GHG Programme R&D project database:
http://script3.ftech.net/~ieagreen/co2sequestration.htm

NOVEM overview of CCS projects: www.cleanfuels.novem.nl/projects/international.asp

DOE carbon sequestration website: http://carbonsequestration.us/

Natural Resources Canada CO_2 capture and storage roadmap:
www.nrcan.gc.ca/es/etb/cetc/combustion/co2trm/htmldocs/technical_reports_e.html

Innovative technlogieen zur Stromerzeugung – auf dem weg zu CO_2-freien Kohle – und Gaskraftwerken. Conference proceedings, May 10-12 2004, Berlin.
www.kraftwerkskongress.de/deu/index.htm

IEA Clean Coal Centre: www.iea-coal.co.uk/site/index.htm

Carbon sequestration leadership forum: www.cslforum.org/

Annex 5.
DEFINITIONS, ABBREVIATIONS, ACRONYMS AND UNITS

This section provides definitions of the energy, economic and financial terms and the regional groupings used throughout this publication.

Fuel and Process Terms

Readers interested in obtaining more detailed information should consult the annual IEA publications *Energy Balances of OECD Countries, Energy Balances of Non-OECD Countries, Coal Information, Oil Information, Gas Information and Electricity Information.*

API Gravity

Specific gravity measured in degrees on the American Petroleum Institute scale. The higher the number, the lower the density. 25 degrees API equals 0.904 kg/m^3. 42 degrees API equals 0.815 kg/m^3.

Aquifer

An underground water reservoir. If the water contains large quantities of minerals it is a saline aquifer.

Associated Gas

Natural gas found in a crude oil reservoir, either separate from or in solution with the oil.

Biomass

Biomass includes solid biomass and animal products, gas and liquids derived from biomass, industrial waste and municipal waste.

Coal

Unless stated otherwise, coal includes all coal: both coal primary products (including hard coal and lignite) and derived fuels (including patent fuel, coke-oven coke, gas coke, coke-oven gas and blast-furnace gas). Peat is also included in this category.

Electricity Production

Electricity production shows the total amount of electricity generated by power plants. It includes own-use and transmission and distribution losses.

Enhanced Coal-bed Methane Recovery (ECBM)

ECBM is a technology for recovery of methane (natural gas) through CO_2 injection into uneconomic coal seams. The technology has been applied in a demonstration project in the US, and is being tested elsewhere.

Enhanced Gas Recovery (EGR)

EGR is a speculative technology where CO_2 is injected into a gas reservoir in order to increase the pressure in the reservoir, so more gas can be extracted.

Enhanced Oil Recovery (EOR)

EOR is also known as tertiary oil recovery. It follows primary recovery (oil produced by the natural pressure in the reservoir) and secondary recovery (using water injection). Various EOR technologies exist such as steam injection, hydrocarbon injection, underground combustion and CO_2 flooding.

Fischer-Tropsch (FT) synthesis

Catalytic production process for synthetic oil products. Natural gas, coal and biomass feedstocks can be used.

Fuel cell

A device which can be used to convert hydrogen into electricity. Various types exist that can be operated at temperatures ranging from 80°C to 1,000°C. Their efficiency ranges from 40-60%. For the time being their application is limited to niche markets and demonstration projects due to high cost and the immature status of the technology, but their use is growing fast.

Gas

Gas includes natural gas (both associated and non-associated with petroleum deposits but excluding natural gas liquids) and gas works gas.

Heat

In the IEA energy statistics, heat refers to heat produced for sale. Most heat included in this category comes from the combustion of fuels, although some small amounts are produced from electrically-powered heat pumps and boilers.

Hydro

Hydro refers to the energy content of the electricity produced in hydropower plants assuming 100% efficiency.

Integrated Gasification Combined Cycle (IGCC)

IGCC is a technology where a solid or liquid fuel (coal, heavy oil or biomass) is gasified, followed by electricity generation in a combined cycle. It is widely considered a promising electricity generation technology due to its potential for high electric efficiency and low emissions.

Liquefied Natural Gas (LNG)

LNG is natural gas which has been liquefied by reducing its temperature to minus 162 degrees Celsius at atmospheric pressure. In this way, the space requirements for storage and transport are reduced by a factor over 600.

Non-conventional Oil

Non-conventional oil includes oil shale, oil sands-based extra-heavy oil and bitumen and derivatives such as synthetic crude products, and liquids derived from natural gas (GTL).

Nuclear

Nuclear refers to the primary heat equivalent of the electricity produced by a nuclear plant with an average thermal efficiency of 33%.

Oil

Oil includes crude oil, natural gas liquids, refinery feedstocks and additives, other hydrocarbons and petroleum products (refinery gas, ethane, liquefied petroleum gas, aviation gasoline, motor gasoline, jet fuel, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, paraffin waxes, petroleum coke and other petroleum products).

Other Renewables

Other renewables include geothermal, solar, wind, tide, and wave energy for electricity generation. Direct use of geothermal and solar heat is also included in this category.

Other Transformation, Own Use and Losses

Other transformation, own use and losses covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes energy use and loss by gas works, petroleum refineries, coal and gas transformation and liquefaction. It also includes energy used in coal mines, in oil and gas extraction and in electricity and heat production. Transfers and statistical differences are also included in this category.

Renewables

Renewables refer to energy resources, where energy is derived from natural processes that are replenished constantly. They include geothermal, solar, wind, tide, wave, hydropower, biomass, and biofuels.

Purchasing Power Parity (PPP)

The rate of currency conversion that equalizes the purchasing power of different currencies, *i.e.*, makes allowance for the differences in price levels between different countries.

Scenario

An analysis dataset based on a consistent set of assumptions.

REGIONAL GROUPINGS

Africa

Comprises: Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, the Central African Republic, Chad, Congo, the Democratic Republic of Congo, Cote d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, the United Republic of Tanzania, Togo, Tunisia, Uganda, Zambia and Zimbabwe.

Central and South America

Comprises: Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, the Dominican Republic, Ecuador, El Salvador,

French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, St. Kitts-Nevis-Anguilla, Saint Lucia, St. Vincent-Grenadines and Suriname, Trinidad and Tobago, Uruguay and Venezuela.

China

Refers to the People's Republic of China.

Developing Countries

Comprises: China, India and other developing Asia, Central and South America, Africa and the Middle East.

Eastern Europe

Comprises: Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Macedonia, Poland, Romania, Slovakia, Slovenia, Yugoslavia.

Former Soviet Union (FSU)

Comprises: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Ukraine, Uzbekistan, Tajikistan, Turkmenistan.

Middle East

Comprises: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates and Yemen. It includes the neutral zone between Saudi Arabia and Iraq.

OECD Europe

Comprises: Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Organization of Petroleum Exporting Countries (OPEC)

Comprises: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates and Venezuela.

Other Developing Asia

Comprises: Afghanistan, Bangladesh, Bhutan, Brunei, Chinese Taipei, Fiji, French Polynesia, Indonesia, Kiribati, Democratic People's Republic of Korea, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, Pakistan, Papua New Guinea, the Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Thailand, Vietnam and Vanuatu.

Western Europe

Comprises: Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

ABBREVIATIONS AND ACRONYMS

AFR	Africa
API	American Petroleum Institute
ASU	Air Separation Unit
AUS	Australia and New Zealand
BKB	Brown Coal Briquettes
CA	Chemical absorption
CaCO3	Calcium carbonate
CAN	Canada
CaO	Calcium oxide
CAT	Carbon Abatement Technologies
CC	Combined cycle
CCC	Clean Coal Centre
CCS	CO_2 Capture and Storage
CDM	Clean Development Mechanism
CENS	CO_2 for EOR in the North Sea
CERT	Committee on Energy Research and Technology
CFB	Circulating Fluid Bed
CHI	China
CHP	Combined Heat and Power
CO2	Carbon dioxide
CRUST	CO_2 Re-use through Underground Storage
CSA	Central and South America
CSLF	Carbon Sequestration Leadership Forum
CUCBM	China United Coal-bed Methane Corporation
DME	Dimethyl Ether
DOE	Department of Energy
DRI	Direct Reduced Iron
ECBM	Enhanced Coal-bed Methane recovery

EEU	Eastern Europe
EGR	Enhanced Gas Recovery
EOH	Ethanol
EOR	Enhanced Oil Recovery
EPR	European Pressurized water Reactor
ESPOO	ECE convention on Trans-boundary Impact Assessment
ETP	Energy Technology Perspectives
ETS	EU Emissions Trading Scheme
ETSAP	Energy Technology Systems Analysis Programme
EU	European Union
EUR	Euro
FCC	Fluid Catalytic Cracker
FGD	Flue Gas Desulphurization
FSU	Former Soviet Union
FT	Fischer-Tropsch
GB	Governing Board
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Geographical Information System
GTL	Gas-to-Liquids
HTGR	High Temperature Gas-cooled Reactor
IEA	International Energy Agency
IET	International Emissions Trading
IGCC	Integrated Gasification Combined Cycle
IND	India
IPCC	Intergovernmental Panel on Climate Change
JI	Joint Implementation
JPN	Japan
LHV	Lower Heating Value
LNG	Liquefied Natural Gas

LPG	Liquefied Petroleum Gas
LTF	Low Temperature Flash
MEA	Middle East
MEA	MonoEthanol Amine
MeOH	Methanol
MEX	Mexico
$MgCl_2$	Magnesium Chloride
MgO	Magnesium Oxide
NGO	Non-Governmental Organisation
NO_x	Nitrogen oxides
ODA	Other Developing Asia
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of Petroleum Exporting Countries
OSPAR	Oslo Convention and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic
OxF	OxyFueling
PA	Physical Absorption
PFBC	Pressurized Fluidized Bed Combustion
PM10	Particulate Matter of less than 10 micron diameter
PPP	Purchasing Power Parity
PV	PhotoVoltaics
RD&D	Research, Development and Demonstration
SACS	Saline Aquifer CO_2 storage
SC	Supercritical
SCSC	Supercritical steam cycle
SKO	South Korea
SOFC	Solid Oxide Fuel Cells
SO_2	Sulphur dioxide
TPES	Total Primary Energy Supply
UNCLOS	United Nations Convention for the Law of the Sea

UNFCCC	United Nations Framework Convention on Climate Change
USA	United States of America
USC	Ultra Supercritical
USCSC	Ultra Supercritical steam cycle
USD	United States Dollars
WEO	World Energy Outlook
WEU	Western Europe

UNITS

MJ	megajoule = 10^6 joules
GJ	gigajoule = 10^9 joules
PJ	petajoule = 10^{15} joules
EJ	exajoule = 10^{18} joules
t	tonne = metric ton = 1000 kilogrammes
Mt	megatonne = 10^3 tonnes
Gt	gigatonne = 10^9 tonnes
kW	kilowatt = 10^3 watts
MW	megawatt = 10^6 watts
GW	gigawatt = 10^9 watts
TW	terawatt = 10^{12} watts
bbl	(blue) barrel
BOE	Barrels of Oil Equivalent. 1 BOE = 41.868 GJ
°C	degrees Celsius
kWh	kilowatt-hour
mD	millidarcies = 10^3 darcies
mils	0.001 US dollar
MPa	megapascal = 10^6 Pa
Nm^3	Normal cubic metre. Measured at 0 degrees Celsius and a pressure of 1.013 bar.
ppm	parts per million
Pa	pascal
Wp	watts peak

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