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The contribution of CO_2 capture and storage to a sustainable energy system

Volume 4 in the CASCADE MINTS project

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Preface

The CASCADE MINTS project on 'CAse Study Comparisons And Development of Energy Models for INtegrated Technology Systems' is partially funded by the EU under the Scientific Support to Policies priority of the Sixth RTD Framework Programme. The project is registered at ECN under nr. 77596. More information on the project can be found on www.e3mlab.ntua.gr/cascade.html.

The following partners are involved in Part 2 of the Cascade Mints project:

- Energy research Centre of the Netherlands (ECN) (The Netherlands); coordination/MARKAL model.
- ICSS/NTUA - E3MLAB (Greece); PRIMES and PROMETHEUS models.
- The International Institute for Applied Systems Analysis (IIASA) (Austria); MESSAGE model
- IPTS (Institute for Prospective Technological Studies), Joint Research Centre, EC (Spain); POLES model.
- Paul Scherrer Institute (PSI) (Switzerland); GMM model.
- The Centre for European Economic Research GmbH (ZEW) (Germany); PACE model.
- The Institute for Energy Economics and the Rational Use of Energy (IER) (Germany); TIMES-EE and NEWAGE-W models.
- ERASME-Équipe de Recherche en Analyse des Systèmes et Modélisation Économiques, University of Paris (France); NEMESIS model.
- International Energy Agency (France); ETP model.
- U.S. DOE/EIA Energy Information Administration of the U.S. Department of Energy (USA); NEMS model.
- Research Institute of Innovative Technology for the Earth (Japan); DNE21+ model.
- National Institute for Environmental Studies (Japan); AIM model.
- Natural Resources Canada (Canada); MAPLE model.

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Abstract

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Summary

1. Introduction

1.1 The CASCADE MINTS project

The current report presents results of Part 2 of the CASCADE MINTS project (CMP2). The CASCADE MINTS project is split into two distinct parts:

- Part 1 focuses on modelling, scenario evaluation and detailed analysis of the prospects of the hydrogen economy. It involves extensive development and use of detailed energy models that have received assistance from previous framework Programmes of DG Research. The ultimate aim of this part of the project is to enable perspective analysis of the conditions under which a transition to an energy system dominated by hydrogen is possible.
- Part 2 does not involve significant model development. Its main aim instead is to use a wide range of existing operational energy and energy/economy models in order to build analytical consensus (to the extent that this is possible) concerning the impacts of policies aimed at sustainable energy systems. This part builds on the experience obtained in the ACROPOLIS project (Das et al, 2003), funded by DG Research within the 5th Framework Programme and involves common exercises carried out using a wide variety of models. This part involves modelling teams from both inside and outside the EU. The emphasis is placed on evaluating the effects of policies influencing technological developments.

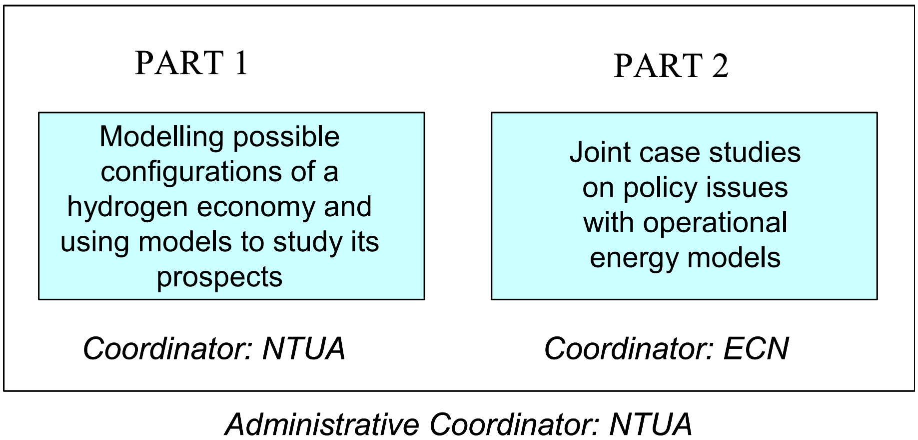


Figure 1.1 *Overview of the CASCADE MINTS project*

Part 2 of the project consists of six work packages. Five of these involve modelling work, and one work package is devoted to reporting and dissemination. In each of the work packages a set of common case studies is analysed with the participating modelling teams. The current report presents results of the third work package on nuclear energy/electricity. All work packages are briefly summarised below.

Baseline (WP 2.1)
The report on the first work package, on harmonisation of initial assumptions and evaluating a common baseline projection, has been published separately (Uyterlinde et al, 2004).

Renewable energy (WP 2.2)
The second work package has analysed the role of renewables in solving global and European energy and environmental issues. The main conclusion is that renewable energy can make a substantial contribution to reducing greenhouse gas emissions and improving diversification of the European energy production portfolio, although other technologies will also be needed in

order to achieve post-Kyoto targets. The report has been published separately (Uyterlinde et al, 2005).

Nuclear energy (WP 2.3)
Nuclear power currently accounts for approximately one-third of the electricity generating capacity in the EU and is therefore a main topic in the current debate concerning security of energy supplies in the EU and the reduction of GHG emissions. Replacement of existing nuclear power plants puts even more stress on both policy issues. Important issues which will shape the future trends in the nuclear sector, are the problems of managing nuclear waste, the economic viability of the new generation of nuclear power plants, the safety of reactors in eastern Europe, in particular Candidate Countries and the policies to combat climate change and improve the security of supply. The main research question that will be addressed is under what conditions and by means of which policy instruments will investments in new nuclear power plants become environmentally and economically feasible? What will be the potential impact of nuclear energy in terms of GHG emission reduction and improving of supply security in 2020 and 2050? The report has been published separately (Uyterlinde et al, 2006).

CO_2 capture/storage (WP 2.4)
CO_2 capture and storage will always come with an additional cost to any power generation plant. This is true both for the conversion to electricity and the conversion to hydrogen, if hydrogen is used as an energy carrier. CO_2 capture and sequestration will therefore only be applied if future specific or general policies provide the necessary financial incentive. Under what conditions and by means of which policy instruments will CO_2 capture and storage in e.g. old gas and oil fields or aquifers become environmentally and economically feasible? Considering different possible policy strategies to intervene and to stimulate CO_2 capture and storage becoming a mature technology, what is the potential impact of CO_2 capture and storage in terms of GHG emission reduction in 2020 and 2050?

Trade offs and synergies (WP 2.5)
The final work package forms the link between Part 1 and Part 2 of the project. It integrates WP 2.2 (renewable energy), WP 2.3 (nuclear energy), WP 2.4 (CO_2 capture/storage) and WP 1.2 (hydrogen).

1.2 Case study approach

As stated above, the current report presents results of Work-package 2.4. It concentrates on the role of CO_2 capture and storage technologies in the power sector. Three policy approaches are compared in order to address the question how to achieve significant CO_2 emission reductions through the application of CCS technologies. The policy case consists of three different parts:

1) In the first part CCS standards are introduced for new fossil fuel fired power plants. This can be seen as an extension of current policies that were introduced to curb SO_2 and nitrogen emissions. The main question this exercise should answer is how big a role CCS technologies could have in reducing CO_2 emissions?
2) The second part studies how the same emission reductions achieved in part one could be achieved more cost efficiently, without a rigid policy.
3) In the third part the effect of policies meant to reduce the investment costs of CCS technologies is studied. These policies can be direct investment subsidies and/or R&D investments.

Setup of the cases

	European models	Global models

Case1: CCS standards	Starting from 2015 all new fossil fuel based power plants have to be equipped with carbon capture and storage. Standards are not applied to small CHP-plants or small peak load plants (< 10 MW, or a utilisation rate lower than 20%[1]), if unit size is used in the model.	For industrialized countries and regions as with European models. For developing regions standards are applied 10 years later, in 2025.
Case2: CO_2 constraint	The emissions path corresponding to the results of case 1 is given as a constraint. Total emissions should be used instead of emissions from the power sector only, since otherwise CO2 leakage between sectors might again increase the mitigation costs. Technology standards are no longer used and no further policies are introduced.	As with the European models. The global CO2 path from case 1 should be used as a constraint in case 2.
Case3: Subsidies	Subsidies An investment subsidy of 35 % is given starting from 2015. The subsidy is reduced linearly, 1 %-unit per year. In 2030 the subsidy is 20 %. The CO_2 constraint used is the same as in case 2.	Subsidies An investment subsidy of 35 % is given starting from 2015. The subsidy is reduced linearly, 1 %-unit per year. The subsidy is reduced to 0 % by 2050. The CO_2 constraint used is the same as in case 2.

Other issues and assumptions

- Leakage rates from CO_2 storage are assumed to be zero.
- 2020 can also be used as the starting year for the policies, if 2015 is not possible.
- Macro economic models should show the macro economic effects of chosen policies. To do this, the results from bottom up models can be used.
- If the emission path from case 1 has too little reductions compared to the baseline to be used as a constraint, the partners facing this problem are encouraged to adopt a CO_2 reduction path from another modeling team (as a reduction in percentage compared to the baseline).
- In case 3, only CCS is subsidized and if CCS + power plant are modelled as a single technology, the subsidy should only be applied to the CCS part of the cost. Since CCS also uses electricity, the output of the plant is reduced. Therefore it could be argued that there is also an additional investment cost connected to the power plant itself, if the original output of the plant is to be kept unchanged (i.e. if a certain output is required, the plant has to be built bigger (higher fuel input) if it has CCS). We leave this outside the policy and subsidize only the direct investment in the CCS technology itself.

[1] However, the plants that qualify for peak plant status because of the below 20 % utilization rate have to have a constraint that guarantees that they stay below this 20 % also after the policy is introduced (if utilization rate is not a constant or already constrained below 20 % for these plants). Otherwise these plants might get an unfair advantage and therefore soon become middle load plants instead.

1.3 Report overview

This report is structured as follows.

2. Introduction to capture and storage of CO_2

It is very likely that the climate is currently changing as a consequence of the accumulation of greenhouse gases in the atmosphere, caused to a large extent by the anthropogenic use of fossil fuels for energy production. The consequences of climate change include temperature increase, sea level rise and change of weather pattern, which could lead to major economic losses and possibly to an increase in climate-related disasters (IPCC, 2001). In 1992, the United Nations Framework Convention on Climate Change (UNFCCC) concluded that measures should be taken to 'prevent dangerous anthropogenic interference with the climate system' (UNFCCC, 1992). Especially the emission to the atmosphere of CO_2, the most abundant greenhouse gas, and responsible for about two-thirds of the radiative forcing up to 2000, would have to be reduced structurally, which would essentially mean a substantial change in the way energy is generated (IPCC, 2001). Several technologies exist that can reduce the emission of CO_2. Energy efficiency, renewable energy, and nuclear energy are among the options in the energy sector that can significantly reduce CO_2 emissions. Recently, also CO_2 capture and storage (CCS) is mentioned as one of the options in the portfolio to mitigate climate change. This chapter gives an overview of the technology, the costs, potential, and a brief analysis of societal issues to CCS.

2.1 CO2 capture and storage technology

CCS involves the capture of CO_2 from a large point source, and the transport and subsequent storage in a geological reservoir, the ocean, or in mineral carbonates. This report only discusses geological formations, as that is the most mature storage option and appears to be most feasible.

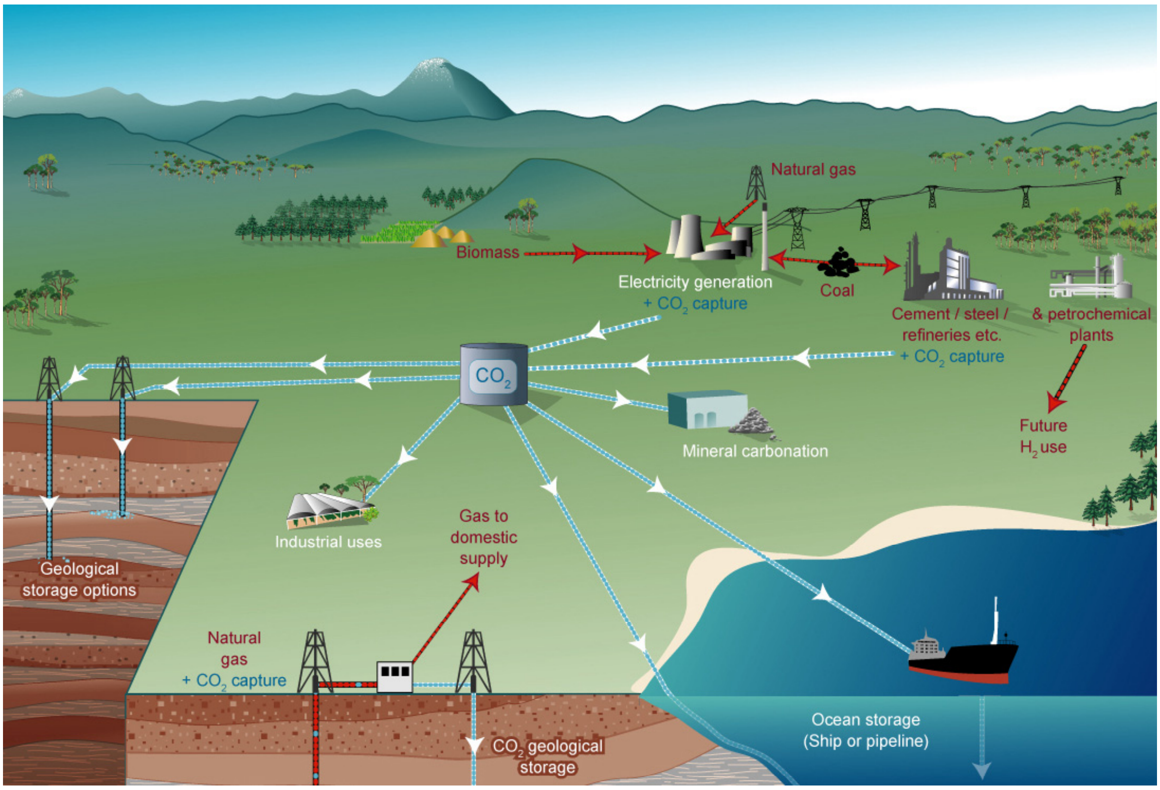


Figure 2.1 *Overview of CO_2 capture, transport, and storage options*
Source: IPCC, 2005.

Capture can be done at large point sources of CO_2 (IEA, 2004) such as electricity plants, refineries, hydrogen production units, or cement and steel factories. Toth and Rogner (2005) report that, although 60% of the global CO_2 emissions from fossil fuels are large point sources, capture is currently only opportune in a small number of these sources (around 10% of global fossil fuel CO_2 emissions) in 2020, and around 30% in 2050. The main reason is that it is more technically and economically feasible to apply capture to new installations than retrofitting existing installations. There are several sources of CO_2 (such as fertilizer factories or hydrogen plants; about 3% of all CO_2 produced in large point sources) that produce nearly pure CO_2, which makes the capture step more cost- and energy-efficient (Van Bergen et al., 2003). In most cases, the capture and compression step represents the bulk of the total energy use and cost of a CCS operation.

The captured CO_2 is compressed and transported to a storage location, normally by pipeline, but in case of over-sea transport and large distances, transport by ship could become more attractive. The CO_2 is normally injected in a supercritical state. Once in the reservoir, the CO_2 is slowly immobilised through several trapping mechanisms, such as dissolution, residual gas saturation, and mineralisation.

Underground storage of CO_2 can be done in geological formations such as oil or gas fields, saline formations, or coal beds. The oil and gas fields could be depleted, but much is expected from enhanced hydrocarbon recovery by injecting CO_2 in a producing field, which would generate revenues. Enhanced Oil Recovery (EOR) is done on a large scale (about 40 $MtCO_2$ per year) in North America, although usually not with the purpose of reduction of CO_2 emissions. The sites are not selected for CO_2 containment, which would be a criterion if the site was designed for CO_2 storage. Plans for operations that would be done to avoid CO_2 emissions are made in several parts of the world. Enhanced Gas Recovery (EGR) is not yet done, but large-scale experiments are running. Storage in unminable coal beds can also lead to recovery of methane that is adsorbed in the pore space of the coal, as CO_2 has a higher affinity to coal than methane, and the methane is therefore suppressed by the CO_2 and can be recovered. This is called Enhanced Coal Bed Methane recovery (ECBM). The feasibility has been demonstrated in the United States, but many coal beds are not suitable for this type of storage due to unfavourable permeability.

CO_2 can also be injected into deep (>800m) saline water-bearing formations. They are often characterised by a thick layer of caprock and are usually not in use. Over longer timescales, the CO_2 injected would partly dissolve in the water and would partly undergo other physico-chemical conversion, leading to decreasing storage security. Injection in aquifers is done in the world's first CO_2 storage project: the Sleipner project off the coast of Norway, at a rate of about 1 $MtCO_2$ per year.

2.2 Costs and potential of CO2 capture and storage

The costs of CCS are related to the potential. Suitable storage reservoirs may be located at some distance from large point sources, which would increase transport costs. The capacity and location of reservoirs are uncertain, as many areas of the world have not been geologically characterised, and a generally accepted methodology for making estimates for storage capacity has not yet been agreed upon. Estimates of worldwide capacity range over two orders of magnitude; values of 1000 to 200,000 $GtCO_2$ have been reported, where especially the capacity of saline aquifers is uncertain (Manancourt and Gale, 2004). For the modelling exercises later in this report, the total storage capacity and the availability of suitable reservoirs near a point source of CO_2 is an important parameter to take into account. However, it should be noted that any aggregate number based on top-down estimates is inherently uncertain, because of the huge variety in local geological circumstances. Any site needs a detailed geological survey in order to make a reliable estimate of the suitability of the reservoir for storage of CO_2.

Of all geological formations, oil and gas fields are best characterised. Studies looking at the potential for storage of CO_2 in known oil and gas fields give numbers in the relatively narrow range of 500 to 1000 $GtCO_2$ total capacity. Some of these estimates are based on replacement ratios for the oil and gas formerly present in the reservoirs, but recovery of the oil and gas has been shown to cause geomechanical changes that could reduce the available pore space for CO_2, which could lead to uncertainties. Estimates for storage in coal beds land at capacities of up to 200 $GtCO_2$, depending on the assumptions on suitability of reservoirs. A small part of capacities for coal beds could also be suitable for ECBM. The world's capacity for saline aquifers is very uncertain, but is likely to be large, according to some at least on the order of 10,000 $GtCO_2$ (IEA, 2004; IPCC, 2005). Unlike gas and oil fields and to a lesser degree coal beds, saline aquifers are distributed more widely and are more likely to be close to large point sources of CO_2.

The proximity of CO_2 point sources to suitable storage reservoirs is relevant for the overall costs of large-scale deployment of CCS. Bradshaw and Dance (2004) have linked prospective geological characteristics to point sources and have created a map of the world that shows a good correlation between centres of emissions and potential storage reservoirs. The potential for 'no-regret options' for CCS, i.e. projects that generate net revenues, has been evaluated by selecting large, high-purity CO_2 sources (with low capture costs) at less than 50 km distance from enhanced hydrocarbon recovery reservoirs (EOR and ECBM). It was estimated that the worldwide potential for such early opportunities is 0.36 $GtCO_2$ (Van Bergen et al., 2003).

Costs of CCS vary greatly because of factors such as the CO_2 purity and partial pressure of the source, the amount of CO_2, the transport distance and means, the depth of storage, and whether revenues can be gained from enhanced hydrocarbon production. A lower concentration and partial pressure of CO_2 in the flue gases of a power plant causes a higher energy need for the capture process, resulting in lower conversion efficiencies.

Capture and compression is estimated to cost around an additional 1.5 €ct/kWh for a National Gas Combined Cycle (NGCC) plant, less than 2 €ct/kWh for Integrated Gasification Combined Cycle (coal-based IGCC) and around 3 €ct/kWh for a Pulverised Coal (PC) plant (Herzog, 2004). In terms of CO_2 avoidance costs from the electricity sector is estimated to cost between a net 5 and 50 €/tCO_2 for current technology, which may come down to 5 to 30 €/tCO_2 in the future. The low ends are for pure streams that only need compression. Including transportation and storage in the costs gives a broad range of -40 to 100 €/tCO_2. This range includes very optimistic estimates for EOR opportunities, and very conservative numbers for small-scale, remote, deep reservoirs (IEA, 2004). In general, it is expected that CCS will deploy on a large scale when the value of CO_2 emission reductions over the lifetime of the project is expected to amount 25 to 30 €/tCO_2 (IEA, 2004; Wise and Dooley, 2004; Herzog, 2004).

2.3 Regulatory issues and public perception

CO_2 capture and storage is a new technology and faces barriers to implementation. The model results given later in this report do not take into account many of the barriers highlighted in this section. It is important to realise that the actual deployment of CCS depends on how risks and environmental impacts, public perception, and the legal and regulatory framework are addressed.

The risks of CO_2 storage should be clear and acceptable. Although it is likely that certain trapping mechanisms are more effective over long timescales and the risks are reduced over the lifetime of the CO_2 reservoir, the possibility cannot be excluded that a reservoir may become leaky due to an unforeseen event, with consequential damage to humans or the environment. Risks can be grouped in three areas. These areas are the technical performance of the reservoir, the leakage contributing to climate change, and community safety (Bowden and Rigg, 2004). Although attempts are being made in several projects, there is not yet an agreed methodology for risk assessment.

The direct environmental impacts in a well-designed and contained reservoir are expected to be low. If leakage occurs, environment and humans may be affected. The environmental impacts of capture and compression of CO_2, apart from that capturing CO_2 means building a middle-sized chemical factory, are mainly found in the extra energy requirements and the associated upstream impacts of additional fossil fuel use.

Public acceptance of CCS is uncertain, but it is clear that the public is not well informed on CCS (Curry et al., 2004). A number of studies has been done, but they are limited in scope and significance. Many of them indicate that the public generally does not favour CCS over other mitigation options such as renewable energy or energy efficiency. In one case, based on willingness to pay, CCS seemed to enjoy less acceptance than nuclear energy (Palmgren, 2004). A survey in the Netherlands, which provided some information on CCS to the interviewees, showed that although the response was reluctant, there was not much resistance or fear (Huijts, 2003). The initial response of environmental non-governmental organisations to CCS was reserved, but several have expressed support for the option, although concerns are voiced that CCS diverts resources from more-desired renewable energy sources and energy efficiency, therefore slowing the deployment of those options.

As a new option, with risks possibly extending over long timescales, CCS demands a legal framework that also arranges long-term liability for the storage reservoir. Legal aspects for storing CO_2 should be separated into offshore and onshore storage. Offshore, sub-seabed storage of CO_2 is under jurisdiction of international legal treaties such as the OSPAR (Oslo-Paris) and London Conventions. International environmental conventions have normally been agreed with the purpose to prevent dumping of wastes and other materials in the ocean and its sub-seabed. At this point, it is uncertain under which conditions sub-seabed geological storage offshore is allowed under the relevant conventions. Onshore storage mainly falls within the scope of national legislation. National legislation is usually not CCS-specific, but regulations exist fragmentarily in countries with existing EOR or other underground activities (IEA, 2005).

Several other issues are also raised. Accepting CCS as a mitigation option reduces costs and increases flexibility of achieving stabilised greenhouse gas concentrations, and preventing climate change. However, contrary to energy efficiency and alternative energy sources, it does not reduce the use of fossil fuels, which is often seen as a disadvantage.

In terms of maintaining energy security in a carbon-constrained world, CCS could be regarded advantageous. Especially for countries with a booming demand for cheap (often coal-based) energy, CCS could still allow for a low-carbon energy supply. In addition, the combination of IGCC and hydrogen production with CO_2 capture and storage, is currently the cheapest way of producing low-carbon hydrogen, which in the longer term could play a role in the transport sector. The combination of biomass and CCS even generates negative CO_2 emissions, as sustainably grown biomass is already carbon-neutral. This option is still expensive, but there is potential for deployment when the value of CO_2 reduction is high.

In terms of the regulatory context, CCS will need a price on carbon or another CO_2 reducing policy in order to be deployed. In the Kyoto mechanisms, the European Emissions Trading Scheme, and the IPCC inventory guidelines, CCS is currently not included. To account for the reductions in CO_2, methodologies should be developed.

3. World models

3.1 GMM

3.1.1 Introduction

The aim of this case study was to analyze potential impacts of policies imposing stringent CO_2 capture and storage (CCS) standards in the power generation sector as compared to the role of CCS technologies could play in the achievement of a global CO_2 emission reduction target. In addition, impacts of policy actions that provide a financial incentive to the CCS systems in the carbon-constrained world are examined. The specification of three policy-scenarios analyzed in this report is provided in Table 3.1.

Table 3.1 *Scenarios description*

Scenario name	Description	Technology assumptions
Case 1 *CCS standards*	In the NAME, OOECD and EEFSU regions, all new fossil-fuel fired power plants are equipped with CCS from 2020. ASIA and LAFM apply the CCS standards from 2030. CCS is not applied to peak-load gas turbines.	See Table 3.2
Case 2 *CO_2 constraint*	The global emissions path equal to the one resulting from the adoption of CCS standards is applied as a CO_2 constraint. Fossil based power plants without CCS are allowed.	See Table 3.2
Case 3 *CCS subsidies*	The same CO_2 constraint as in Case 2.	Capital cost of CCS systems subsidized (reduced) by 35% starting from 2020, while the subsidy is reduced to 0 in 2050

CCS is considered only for the electricity sector in the GMM model. For the purpose of the CCS case study, the representation of CCS in GMM has been extended such that each type of fossil fired power plant is defined either as a reference plant without CCS or as a capture plant with CCS. Only the small-scale peak-load gas turbines and fuel cells have been excluded from the portfolio of CCS options.

Cost and performance characteristics of technologies with CO_2 removal, as summarized in Table 3.2, are adopted from David and Herzog (2000) and IEA (2002). Additional CO_2 storage cost (10 \$/tCO_2 or 36.7 \$/tC for every tonne captured) is charged for these technologies. This cost comprises expenditures for CO_2 transport, injection and disposal. No limit is provided for CO_2 that can be stored in any kind of reservoir. The level of carbon sequestration, however, is controlled by annual growth rates of technologies being operated with CO_2 emissions removal.

Technological learning (ETL) is endogenised for three CCS technologies in GMM: coal based advanced plants and IGCC, as well as the natural gas based NGCC. A higher value of learning rate (LR) for coal-fired technologies with CO_2 capture as compared to the reference plants is based on an assumption that the CO_2 capture device applied to the reference power plant might contribute to 'learning' potential of a reference plant. Technologies equipped with CO_2 capture, therefore, could undergo a stronger cost reduction.

Table 3.2 *Specification of fossil fired power plants in GMM*

	Technology	Start year	Life time	Load factor (max.)		Electric efficiency		Investment cost	Fixed O&M cost	Variable O&M cost	Learning rate
				start	2050	start	2050	$/kW	$/kW/yr	$/GJ	%
	Fossil-fuel based power plants										
COAL	Coal conventional electric	2000	30	0.65	0.75	0.370	0.380	1050	38	0.72	
	Coal conv. with $DeSO_x/DeNO_x$	2000	30	0.65	0.75	0.360	0.370	1150	48	1.22	
	Coal conv. with $DeSO_x/DeNO_x$ + CCS	**2020**	**30**	**0.65**	**0.75**	**0.296**	**0.304**	**2090**	**80**	**1.53**	
	Coal cogeneration	2000	20	0.65	0.75	0.370	0.380	1155	49	1.5	
	Coal cogeneration + CCS	**2020**	**20**	**0.65**	**0.75**	**0.296**	**0.304**	**2300**	**82**	**1.88**	
	Coal advanced (Supercritical, PFBC)	2000	30	0.65	0.8	0.429	0.500	1584	47.5	0.75	6
	Coal advanced + CCS	**2020**	**30**	**0.65**	**0.8**	**0.365**	**0.425**	**2060**	**90**	**1.13**	**7**
	IGCC	2000	30	0.85	0.85	0.425	0.500	1401	40	0.88	6
	IGCC + CCS	**2020**	**30**	**0.85**	**0.85**	**0.361**	**0.425**	**1910**	**52**	**1.23**	**7**
GAS	NGCC	2000	20	0.65	0.75	0.510	0.588	560	36.6	0.63	10
	NGCC + CCS	**2020**	**20**	**0.65**	**0.75**	**0.459**	**0.529**	**1015**	**60**	**0.88**	**10**
	Gas turbine	2000	20	0.2	0.2	0.360	0.360	350	58.5	0.51	
	Gas steam conventional	2000	20	0.65	0.65	0.333	0.410	987.7	50.6	0.56	
	Gas steam conventional + CCS	**2020**	**20**	**0.65**	**0.65**	**0.300**	**0.369**	**1790.21**	**82.95**	**0.78**	
	Cogenaration gas turbine	2000	20	0.4	0.46	0.370	0.370	750	51.6	0.63	
	Cogenaration gas turbine + CCS	**2020**	**20**	**0.4**	**0.46**	**0.333**	**0.333**	**1359.38**	**84.59**	**0.88**	
	Gas fuel cell (GFC)	2000	20	0.65	0.65	0.599	0.649	2463	43.5	0.63	18
OTHER	H_2FC (CHP) in industry	2010	20	0.85	0.9	0.4	0.6	3500	20	7.5	18
	H_2FC (CHP) in res&com	2010	20	0.85	0.9	0.4	0.5	3500	20	5.8	18
	Oil electric	2000	20	0.65	0.8	0.303	0.400	991	63.6	0.57	
	Oil electric + CCS	**2020**	**20**	**0.65**	**0.8**	**0.273**	**0.360**	**1796.19**	**104.26**	**0.80**	

Note: The CO_2 capture efficiency of 85% is assumed for plants with CCS.

3.1.2 Results

3.1.2.1 Primary energy consumption

The introduction of *CCS standards* for the electricity production leads to the changes in the primary energy fuel use. The changes are most pronounced for the coal consumption, which is reduced by nearly 30% relative to the Baseline in 2050. This reduction is associated with the reduced use of coal in the power sector. The consumption of other fossil fuels, natural gas and oil, is affected by a lower extend. The use of natural gas is reduced only by 4% in 2050, despite a substantial drop in the gas demand for the power generation from power plants without CCS, especially NGCC. The reduction in the natural gas use for power production from NGCC is balanced by an increased gas use for GFC, hydrogen production, as well as an increased gas demand on the end-use markets. The contribution of carbon-free fuel supplies, i.e. nuclear and renewables, increases by about 40% in 2050 in comparison to the Baseline scenario.

The carbon constraint imposed over the reference case in the scenarios *CO_2 constraint* and *CCS subsidies* results in larger reductions in coal and oil uses as compared to the *CCS standards* case. The coal consumption in 2050 is halved relative to the Baseline, and the oil use is lower by more than 6%. The global use of natural gas remains basically unchanged under the CO_2 cap. As is shown in Figure 3.1, nuclear and renewable energy sources increase their shares by 50% over the Baseline in 2050. The overall global primary energy demand is also reduced in the end of the computation period by 5% as compared to the Baseline.

The higher share of coal consumption in the *CCS standards* case as compared to the CO_2 constrained scenarios is due to the structural changes in the power sector, wherein the gas based generation is almost eliminated under the *CCS standards* and substituted with the coal plants with CCS. In addition, the efficiency loss linked to CCS contributes to the higher use of coal under the *CCS standards* policy.

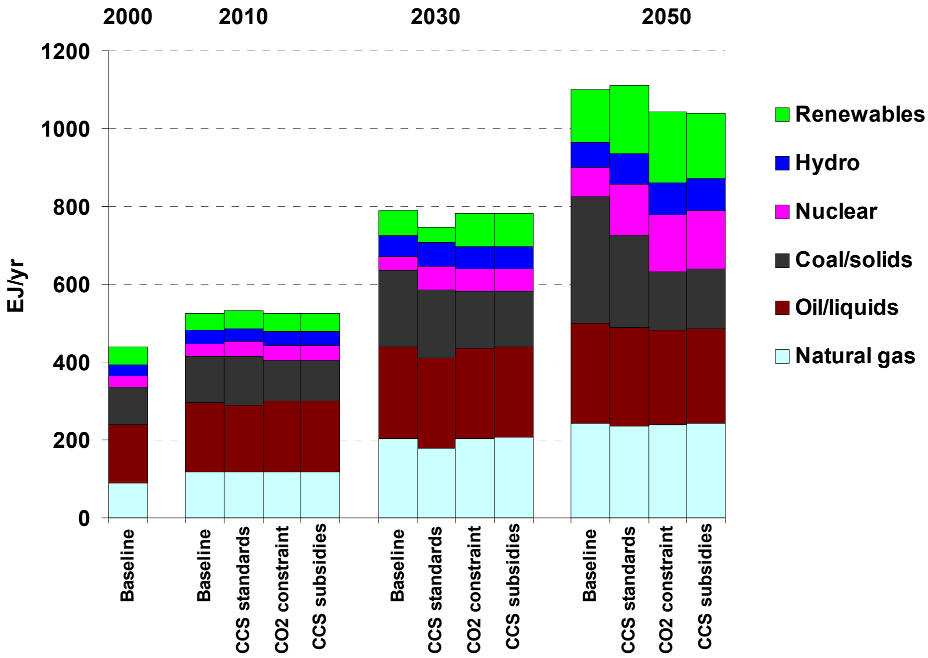


Figure 3.1 *Global primary energy use for the Baseline and policy scenarios*

3.1.2.2 Electricity generation

As is illustrated in Figure 3.2, if the *CCS standards* are implemented in the power sector, the electricity production based on fossil fired power plants is reduced substantially as a result of policy-induced phase out of technologies without CCS. On the global level, about 50% of the power production from the CO_2 non-scrubbed power plants reported for the Baseline scenario in the end of the time horizon is substituted with technologies equipped with CCS.

To compensate for the fallback of fossil-based power production, the contribution of nuclear power plants increases by more than 80% over the Baseline in 2050. Similarly, power plants based on renewable energy sources and fuel cells increase the market share by about 85%. The technologies with CCS contribute by 40% to the global power generation in 2050, while the nuclear and renewable electricity production corresponds to almost 60% of the total generation mix.

The *CO_2 constraint* scenario allows for a larger flexibility in achieving the carbon reduction target. The reduction in the fossil-based power generation, therefore, occurs at much lower extend as compared to the *CCS standards* case. The overall reduction by 54% over the Baseline case in 2050 is reported, and is associated mainly with the decreased production from coal-fired technologies. Power plants with CCS contribute to the CO_2 reduction and their share in the global electricity mix increases from 4% in 2030 to 14% in 2050.

The second largest increase in the carbon-mitigation options under the *CO_2 constraint* is reported for the nuclear energy, which growths from a 10% market share in the Baseline in 2050 to 22% under the carbon constraint. This increase in nuclear power production is by 23% higher than in the *CCS standards* case. On the other hand, the increase in the market share of renewable electricity sources over the Baseline for the *CO_2 constraint* is halved in comparison to the *CCS standards* scenario.

In the scenario *CCS subsidies*, the reduction in fossil-based systems without CCS and the increase in nuclear power relative to the Baseline remain at the same level as in the *CO_2 constraint* case. Subsidies provided for the portfolio of CCS technologies result in an increased global contribution from these systems by 15% as compared to the no-subsidy case. A larger penetration of CCS is balanced by a proportionally lower contribution from renewables and fuel cells.

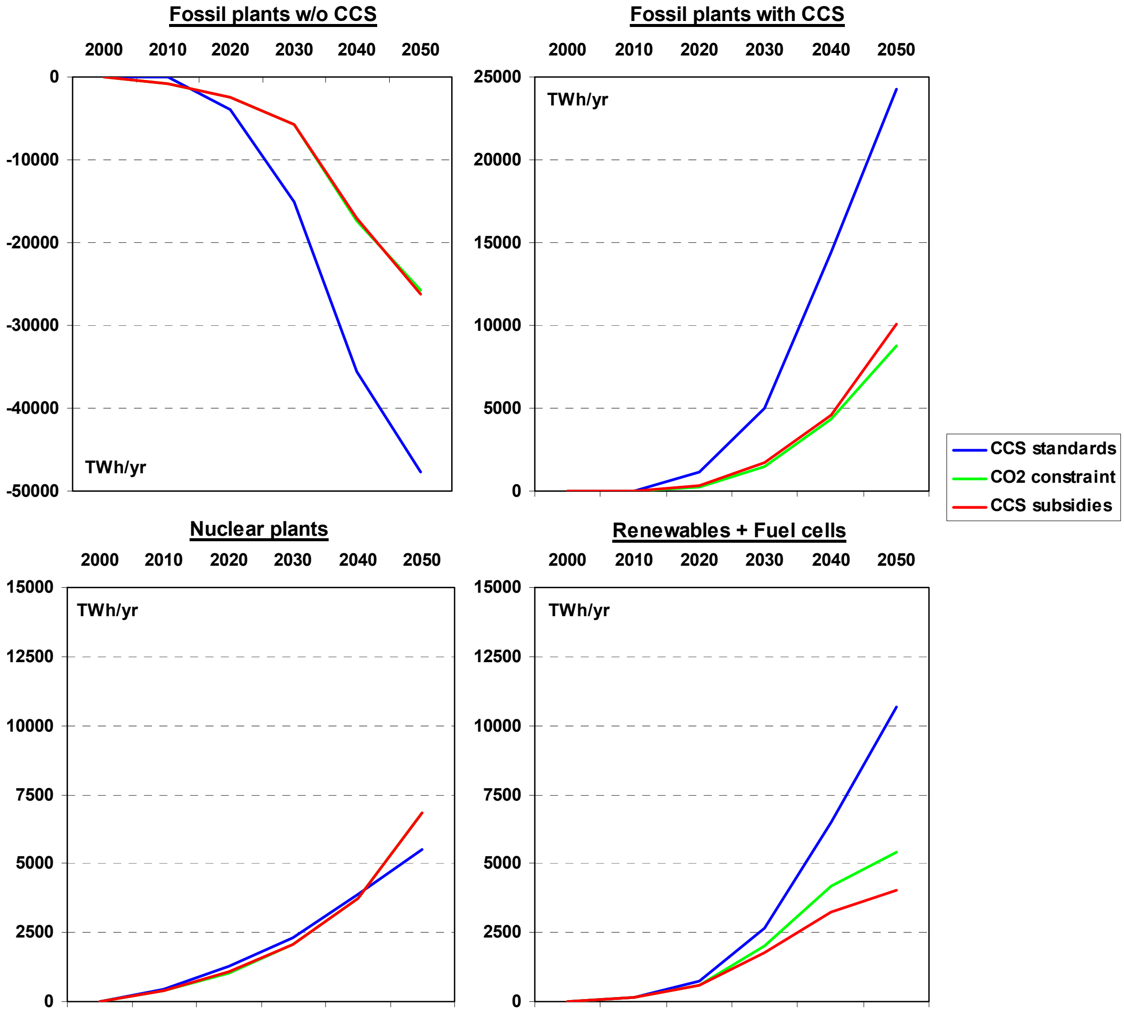


Figure 3.2 *Change in the global electricity generation by fuel over the Baseline for policy scenarios*

The most important change in the power generation profile for the *CCS standards* in 2050 relative to the Baseline is the forcing of non-CCS plants out from the global power system by the end of the time horizon. This behaviour is a consequence of the CCS standards in the each world region and the assumed lifetime of reference fossil power plants, as given in Table 3.2. By 2050, the most competitive power plants with CCS are IGCC and advanced coal based plants. The large penetration of these two technologies is related also to the cost reducing effect of ETL assumed for these systems. From other CCS systems represented in GMM, three additional technologies gain a market share in 2050: conventional coal power plant with CCS, NGCC with CCS, and conventional gas power plant with CCS. Attendant to the massive elimination of fossil-fired power plants and their gradual replacement by CCS systems is a higher contribution from both conventional and advanced nuclear plants, as well as carbon free renewables, i.e. hydropower, SPV, biomass and geothermal plants. The remarkable penetration of GFC is related also to the significantly higher availability of natural gas due to the policy-induced elimination of NGCC in the end of horizon.

Under the CO_2 constrained scenarios NGCC becomes the most competitive fossil-based technology. Among the coal-fired power plants, IGCC with CCS gains the largest market share in 2050 followed by highly efficient advanced coal plants. Penetration of IGCC plants with CCS halves, however, in the *CO_2 constraint* scenario as compared to the *CCS standards* case. Contribution of advanced coal with CCS and NGCC with CCS power plants is reduced significantly as well. Under the *CO_2 constraint*, a lower contribution from SPV and biomass systems is reported. On the other hand, competitiveness of nuclear power increases relative to the Baseline and *CCS standards* scenario.

The feedback from subsidies provided for the CCS systems in the *CCS subsidies* scenario is the most pronounced for the IGCC+CCS and NGCC+CCS technologies. Penetration of the advanced coal plants with CCS remains at the same level as in the *CO_2 constraint* case. For the *CCS subsidy* scenario, the contribution of NGCC and nuclear power plants remains the same as in the *CO_2 constraint*, but the penetration of other capital intensive systems, e.g., SPV and hydrogen fuel cells is lowered.

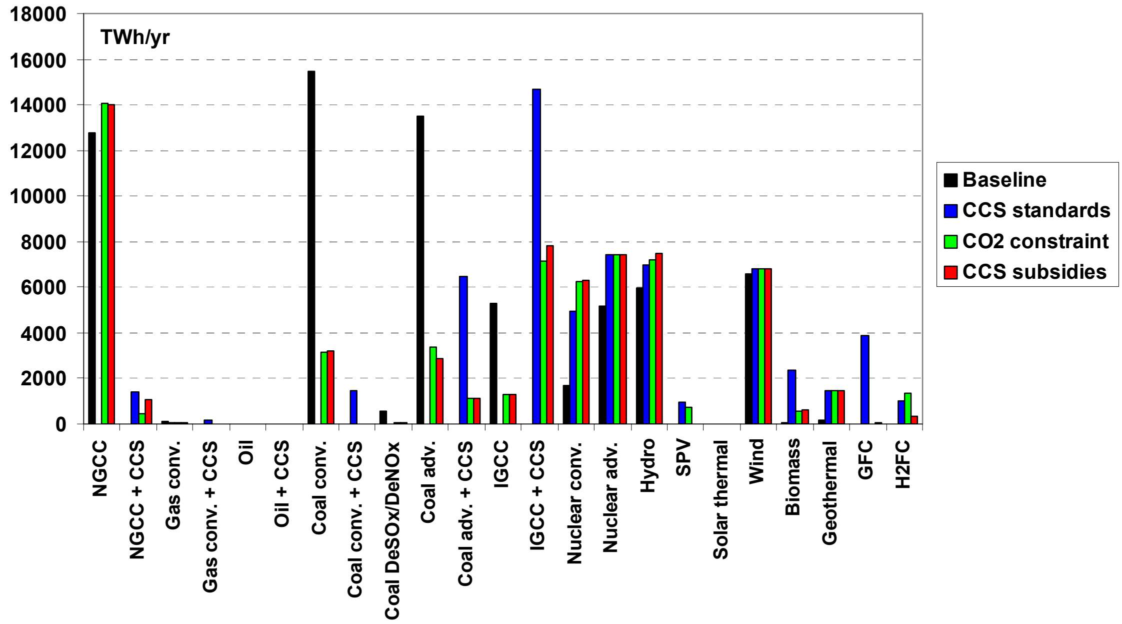


Figure 3.3 *Contribution of technologies to the global electricity generation mix in 2050*

3.1.2.3 Effects on CO_2 emissions

The adoption of *CCS standards* policy induces a strong decarbonisation effect for the global and regional energy systems. The emission reduction is a result of introduction of CCS systems within the electricity sector on a large scale, as well as is a consequence of accelerated penetration of carbon-free nuclear and renewable energy sources, as explained in the previous section. The overall reduction in global energy-related CO_2 emissions for the *CCS standards* scenario relative to the Baseline represents about 15% and 40% in 2030 and 2050, respectively. In the end of the time horizon, the global CO_2 emissions are stabilised at 9.5 GtC/yr.

The *CO_2 constraint* scenario imposes the same emission reduction trajectory as resulting from the *CCS standards* case. Nevertheless, due to an enhanced flexibility in reaching the reduction target, the distribution of CO_2 mitigation options is different under the *CO_2 constraint* as compared to the *CCS standards*. In the former case, the inter-fossil fuel switching, nuclear energy and end-use demand reductions play a dominant role in the CO_2 abatement. The latter case projects significantly larger contribution of CCS and renewables to the emission abatement process.

As is depicted in Figure 3.4, both carbon-constrained scenarios (i.e. *CO_2 constraint* and *CCS subsidies*) project a larger emission reduction for the periods 2010-2020. This early reduction occurs because of structural shifts and the adjustment of the energy system to the carbon cap under the perfect foresight assumptions.

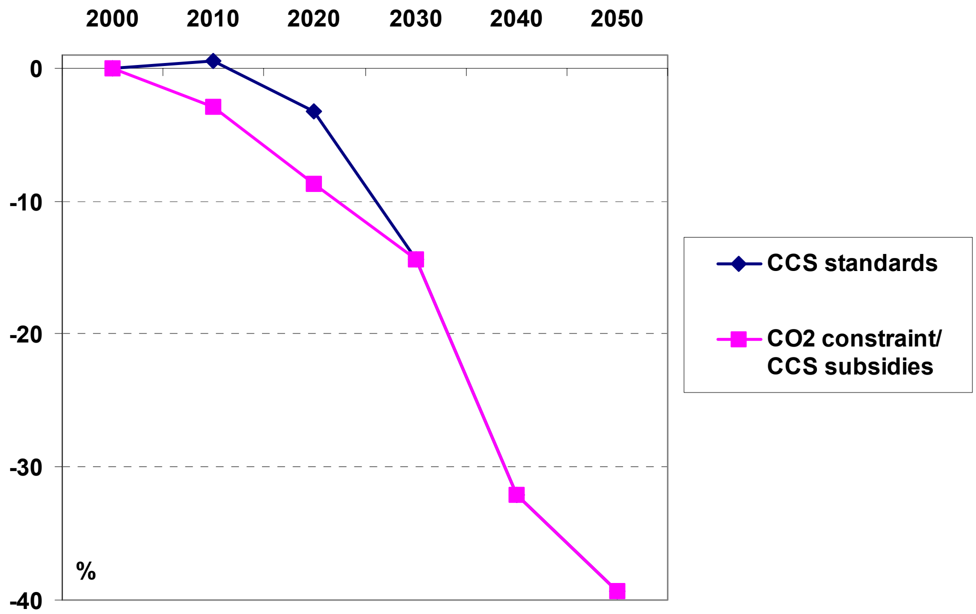


Figure 3.4 *Change in global energy-related CO_2 emissions relative to the Baseline*

3.1.2.4 Amounts and the distribution of CO_2 emissions captured and stored

The cumulative amount of CO_2 captured and stored on the global level between the periods 2020-2050 for the *CCS standards* scenario is nearly 260 Gt CO_2[2]. This amount is by 67% and 64% less in the scenarios applying the carbon constraint, i.e. *CO_2 constraint* and *CCS subsidies*, respectively, wherein the reduction is obtained mainly by fuel switch, nuclear energy and demand reductions. The cumulative impact of subsidies provided to CCS systems in terms of additional CO_2 captured corresponds to 6.3 Gt CO_2 for the years 2020-2050.

As is shown in Figure 3.5, CO_2 capture from coal-fired power plants prevails largely over the natural gas related emission capture. Globally represents the coal-related capture some 96% of the total amount captured in 2050 for the *CCS standards* case. It has to be noticed that the coal-related CCS is not a dominant source of CO_2 capture in all regions and in all policy-cases. For example, the NGCC+CCS power plant contributes more to the capture process under the *CO_2 constraint* scenario for regions OOCD, LAFM or NAME. This result is explained by the relatively low electricity generation cost of NGCC plant, as well as is linked to the optimistic assumptions on ETL for this technology.

2 For comparison, IEA (2004) estimates the cumulative potential for CO_2 storage in all depleted gas and oil fields to 800-920 $GtCO_2$ by the year 2050.

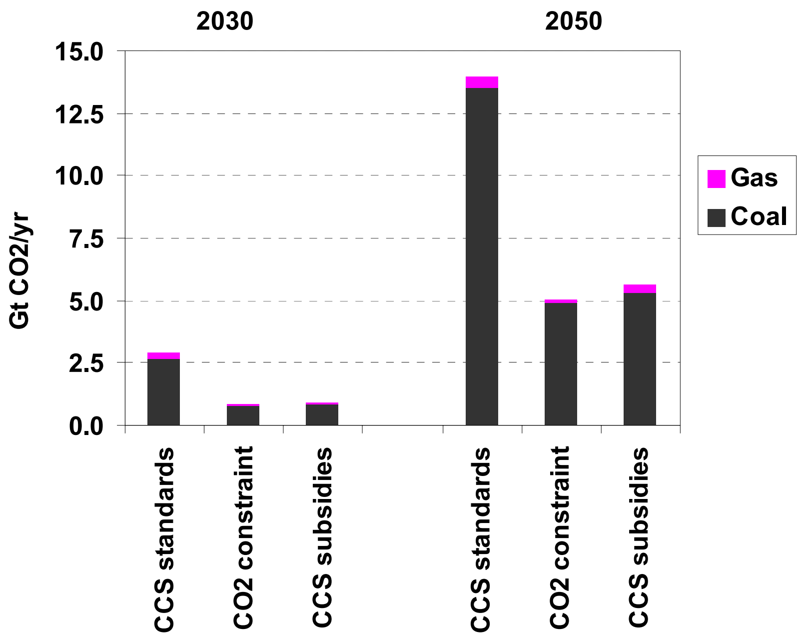


Figure 3.5 *Global CO_2 capture from power production by fuel*

The regional distribution of CO_2 capture is shown in Figure 3.6. In the *CCS standards* scenario, the industrialised regions contribute by about two thirds of the total amount of CO_2 captured in 2030. The fraction of CO_2 captured in the developing world increases, however, to 72% by the end of the time horizon. Under the carbon-constraint scenarios, dominant contributors to the overall CCS process are the 'coal-intensive' regions of ASIA and EEFSU. As a result of subsidies provided for CCS technologies, regions of ASIA, NAME and LAFM increase their share in the global CO_2 capture.

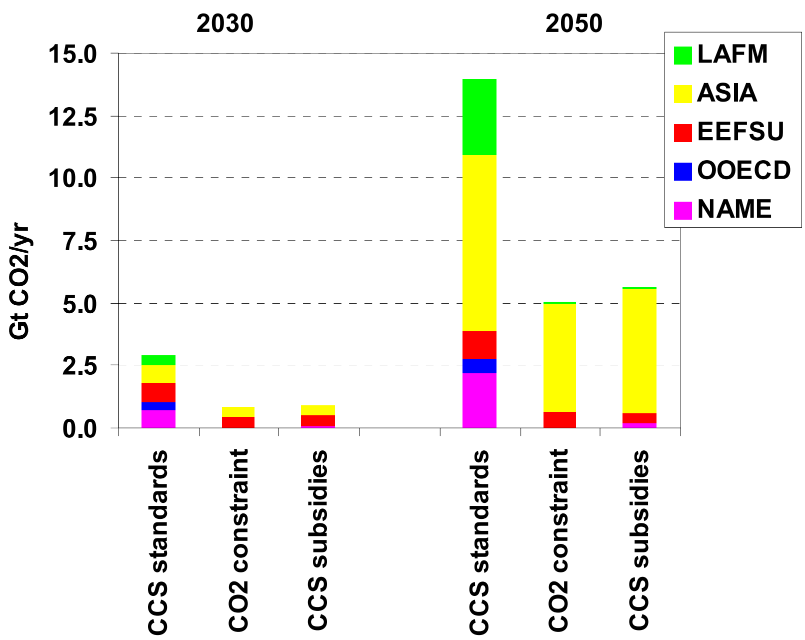


Figure 3.6 *CO_2 capture from power production by regions*

3.1.3 Consequences

System-cost effects of policies promoting CCS technologies in the electricity sector are depicted in Figure 3.7a, showing the increase in cumulative discounted energy system costs for policy scenarios relative to the Baseline scenario. Two elements of the total cost increase are distinguished: the cost associated to technology changes and system adjustments, and the cumulative cost for the CO_2 storage in all types of reservoirs (i.e. 10 \$/tC).

The increase in total system costs for the *CCS standards* scenario is basically twice as high as the cost increase for the *CO_2 constraint*. This result indicates that the implementation of stringent regulatory policy forcing CCS into the power sector might be costly when compared to the more flexible policy of a carbon constraint (or tax) applied over the whole energy system and over all sectors, while achieving the same emission reductions. The cost impact of subsidies for CCS technologies under the CO_2 constrained regime is rather limited and corresponds to the total reduction in the policy-invoked cost penalty by 3%.

Figure 3.7b shows the marginal cost of CO_2 reduction for both cases where the global CO_2 cap is adopted. Variations in the marginal cost of the CO_2 abatement reflect the severity of the constraint in the specific time period, as well as the ability of the energy system to adjust its structure in order to reach the given emission target. Marginal costs for the *CO_2 constraint* case vary between 37 \$/tC in 2020 to 290 \$/tC in 2040. The reduction in marginal costs observed in the year 2050 is attributed to the accelerated learning performance of technologies contributing to the abatement process (e.g., CCS, renewables and nuclear plants). The reduction in marginal cost due to subsidising the CCS systems accounts for 3% to 7% for periods 2030-2050.

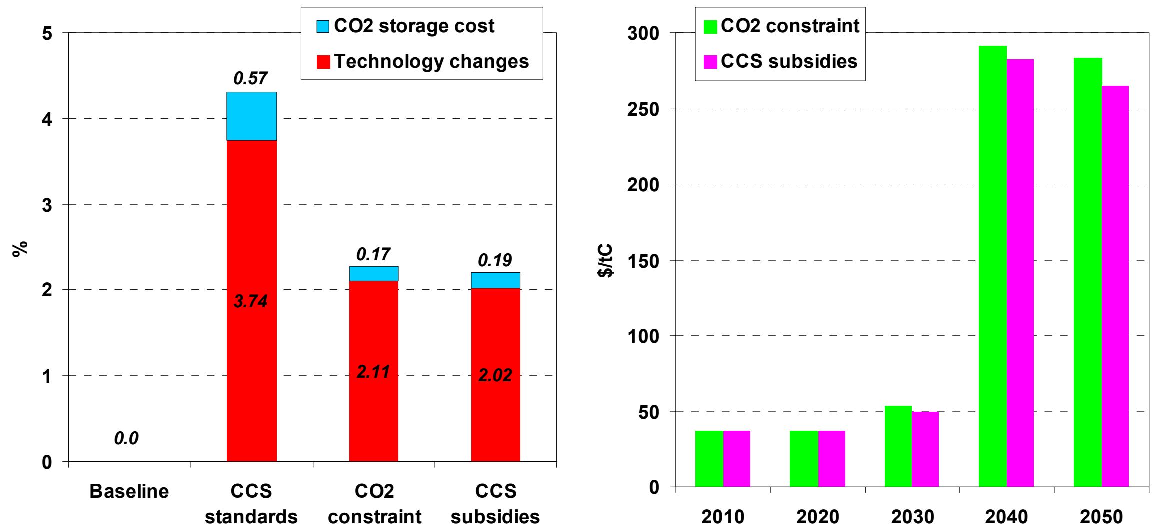


Figure 3.7 *a) Change in the total discounted system cost relative to the Baseline*
b) Marginal cost of CO_2 reduction for scenarios applying carbon constrain

Note: The marginal cost for 2010-2020 reported in Figure 3.7b is given by the baseline CO2 tax (10 €/tCO_2) applied in the OOECD region.

3.1.4 Conclusions and recommendations

- *CCS standards* for fossil-based power generation might be potentially a powerful policy instrument to reduce substantially CO_2 emissions from the electricity sector. A prerequisite for the implementation of this type of regulatory measure is that CCS technologies are available and affordable for a large-scale application. Therefore, a gradual adoption of such policy is necessary to reduce the associated cost penalty.
- The modeling results show that the introduction of *CCS standards* is two times more costly as imposing a *CO_2 constraint* that reaches the same emission cuts. This means, a more

flexible selection of CO_2 abatement options will improve the cost effectiveness of a given climate response policy.

- The level of subsidies adopted for CCS technologies improve the competitiveness of CCS only marginally. The penetration of CCS within the electricity sector is highly dependent on the assumptions made for competing CO_2 reducing technological options, i.e. nuclear and renewable energy sources.
- Other factors that influence the uptake of CCS under the *CO_2 constraint* are first the degree of learning rates for CCS systems, and their maximum annual growth rates. The relatively large contribution of power plants with CCS under the *CCS-standard* policies and the carbon constraint is influenced also by the projected Baseline scenario development, which is largely fossil (and especially coal) intensive.
- The cumulative amount of CO_2 globally captured under the *CCS standards* represents only around 30% of the total storage potential in depleted oil and gas fields. Nevertheless, the regional availability, distribution, leakage rates and related capture cost need to be further evaluated to gain additional insights into the future role of CCS in overall CO_2 abatement efforts.
- Competitiveness of different CCS systems is region specific. On the global level the majority of the CO_2 captured originates from the coal-related CCS. Outcomes of this modeling exercise suggest that particularly IGCC+CCS, advanced coal+CCS, and in some cases NGCC+CCS belong to the portfolio of technological options for curbing issues of CO_2 mitigation.

3.2 MESSAGE

3.2.1 Introduction

This study analyses the effects different policies have on the global energy system with particular emphasis on the penetration of carbon capture and sequestration (CCS) technologies in the power sector. Our baseline follows the assumptions of a MESSAGE-B2 scenario, given in the CASCADE-MINTS baseline report (Uyterlinde et al., 2004). Demands remain the same throughout the study and no price responses are included. All case studies model CCS technologies connected to power plants as endogenously learning. For a description on how learning is implemented see (Riahi et al., 2004).

We analyze the effects of three different policy instruments and their combinations: CCS standards for fossil fuel fired power plants, global greenhouse gas (GHG) emission constraint and investment subsidies for CCS technologies. Using these instruments, we establish five cases that will be analyzed:

1. Case 1: New fossil fuel plants have to be equipped with CCS technology starting from 2020 for industrialized countries and 2030 for developing countries.
2. Case 2: The global GHG emission path derived from Case 1 is used as a constraint without any further restrictions or policies.
3. Case 3: An emission path corresponding to that of Cases 1 and 2 is used as a constraint. In addition to this, an investment subsidy is given to CCS technologies used in the power sector. The initial level of the subsidy in 2020 is 30% globally and it declines linearly reaching zero in 2050 (see Figure 3.8).
4. Case 2L: A global emission constraint more restrictive than the one in Case 2 is introduced. This constraint would lead to GHG concentration of slightly above 500 parts per million by volume (ppmv) in 2100. No subsidies are given to any technologies.
5. Case 3L: The strict emission constraint introduced in Case 2L is used also here. Subsidies are given to CCS technologies and the setup for these subsidies is identical to Case 3 above.

In Cases 3 and 3L an investment subsidy is introduced to help the technologies penetrate to the markets. However, this subsidy is defined as a share of the investment and it is reduced linearly until it reaches zero percent in 2050. Simultaneously, investments in the technology lower the investment costs as a result of learning, but the reducing subsidy is dampening this effect. For Cases 3 and 3L, we have therefore defined the specific investment costs of CCS technologies as functions of time and cumulative capacity, as shown in Figure 3.8. In cases with zero subsidy, the specific investment cost is defined by cumulative capacity alone. The emission paths that are used as constraints in Cases 2, 3, 2L and 3L are shown in Figure 3.9.

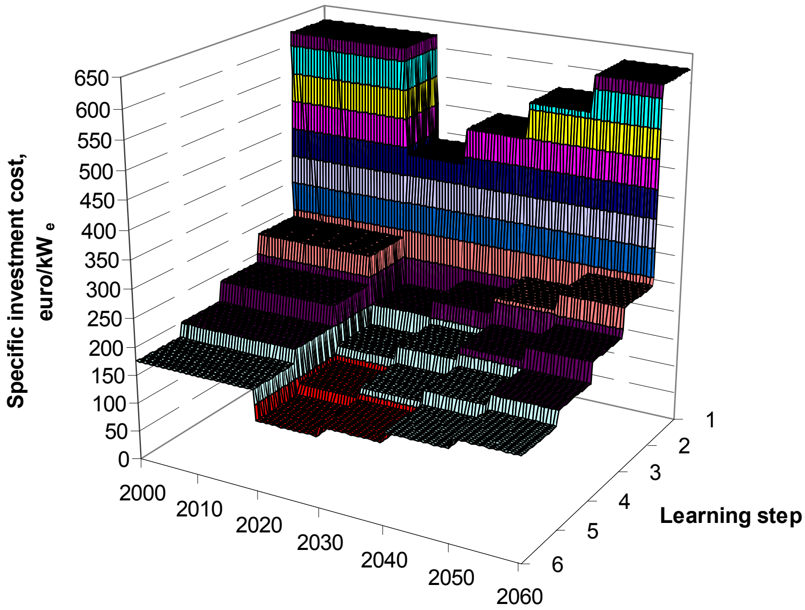


Figure 3.8 *The combined effect of subsidy and learning on specific investment cost*
Note: CCS for gas fuel cell as an example. 'Learning step' refers to a cost step on the linearized version of the learning curve.

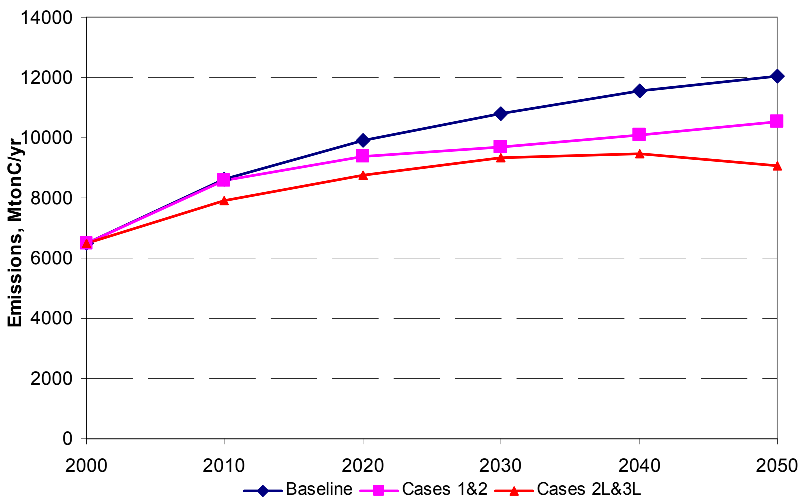


Figure 3.9 *Global CO_2 emission path for baseline and constrained case*

Table 3.3 gives the data for the CCS technologies for power plants. In addition to these technologies, carbon capture from coal and gas based hydrogen production is also feasible. Storage costs are assumed to be constant throughout the study.

Table 3.3 *Technical and economic characteristics of the carbon capture technologies*

	Investment cost [€/kW]	O&M costs [€ct/kWh]	Energy penalty [%]	Efficiency of Carbon capture [%]	Learning rate [%]
CC coal	1261	1.14	25	90	13
CC gas	775	0.35	13	90	13
CC gas FC	683	0.50	15	90	13
CC oil	1261	1.14	25	90	13

Source: Riahi et al., 2004.

3.2.2 Results

3.2.2.1 Primary energy use

Implementing a policy that requires all new fossil fuel power plants to be equipped with carbon capture technologies makes fossil fuel fired power plants more expensive and therefore makes the use of fossil fuels in other sectors more preferable. Overall, renewable energy sources do increase their share in total primary energy use, although this phenomenon is even stronger in the cases where a carbon constraint (and subsidy for Cases 3 and 3L) is used to encourage CCS technology penetration. Figure 3.10 shows the changes in the share of renewables in primary energy use for Cases 1, 2, 2L and 3L in relation to the baseline. Case 3 is left out, because the CO_2 constraint derived from Case 1 does not result in CCS penetration even with subsidies. Because of this, Cases 2 and 3 are identical and Case 3 is left out also from further results.

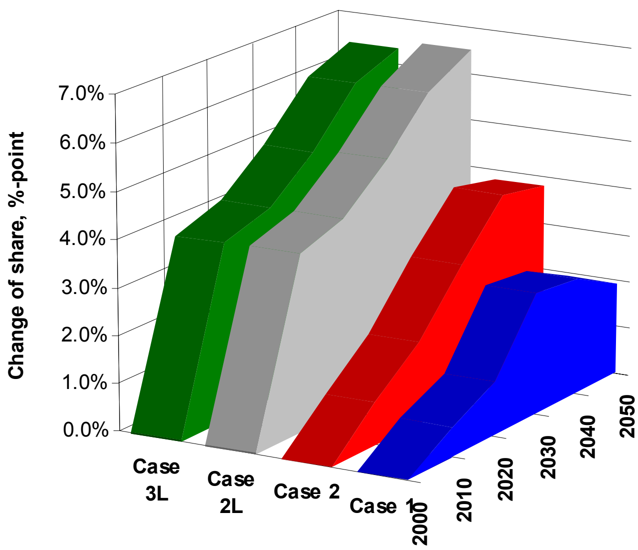


Figure 3.10 *Changes in renewables share in primary energy use compared to the baseline*

Since in the baseline 24.3% of the primary energy use in 2050 was from renewables, Figure 2 illustrates that for Case 1 the share of primary energy from renewables is approximately 26% and over 30% for Cases 2L and 3L in 2050.

Figure 3.11 shows the changes in primary energy use by fuel for the cases studied. Although Figure 3.10 seems to indicate that the use of renewables grows the least in Case 1, one observes in Figure 3.11 that the lowest growth occurs in Case 2. This apparent contradiction is explained by the massive penetration of CCS technologies in Case 1, which, because of the energy penalty connected to CCS technologies, then leads to increased total primary energy use in this case.

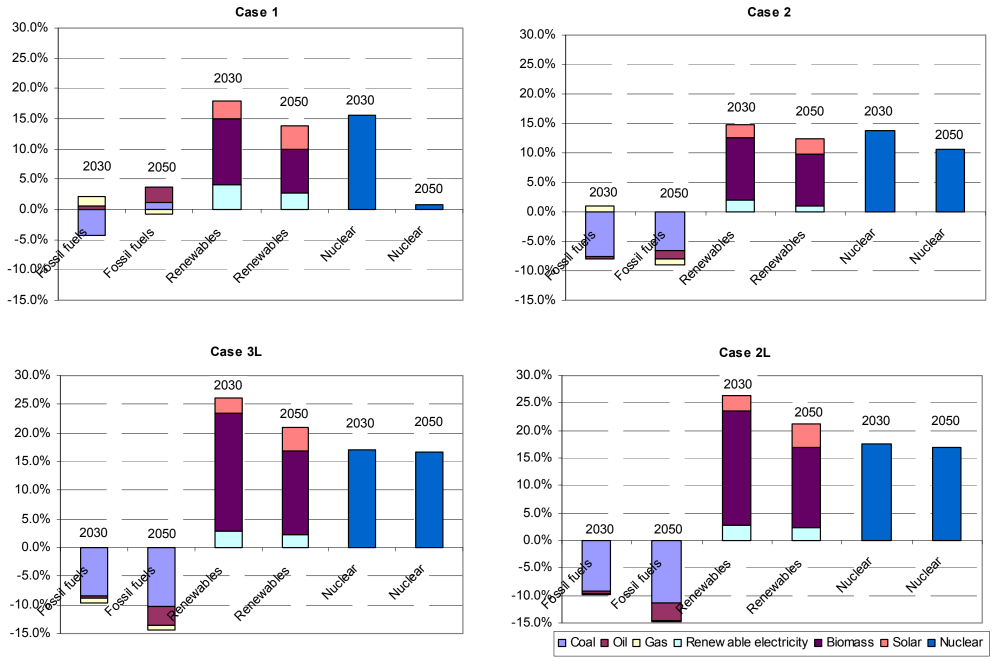


Figure 3.11 *Changes in relation to the baseline in global primary energy use in 2030 and 2050 for the cases studied*

The general trends are similar in all cases; fossil fuel use is reduced and the use of CO_2 free sources is increased. There are, however, also clear differences between the cases. Case 1 does not have an emission constraint, but it does require the use of CCS technologies in the power sector. Because of this, the use of CO_2 free sources in other sectors is not encouraged and fossil fuels are therefore used more than in the other cases, in 2050 even more than in the baseline. An example concerning the use of methanol and ethanol in the transport sector is shown in Figure 3.12. The role of nuclear is also more clearly emphasized in the cases with an emission constraint. Cases 2L and 3L differ only slightly, but one interesting observation can also be made concerning these two cases; in Case 3L also gas use is reduced and coal use is reduced less than in Case 2L. The reason for this is that the subsidy given to CCS technologies in Case 3L increases the competitiveness of CCS technologies for coal power plants enough to make them preferable over similar solutions for gas-fired power plants.

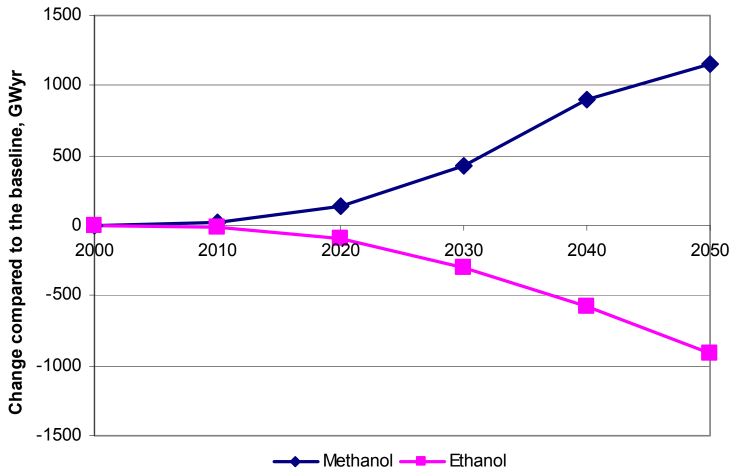


Figure 3.12 *Methanol and ethanol use in transport in Case 1, baseline used as the reference level*

3.2.2.2 Electricity production and synthetic fuels

Due to the different structure of the policies introduced, the electricity sector can be seen as the driving force for the differences between Case 1 and other cases. Due to the requirement of CCS for fossil-fuel fired power plants in Case 1, by 2050 emissions from electricity generation are about 90% below the levels of the year 2000 and some 95% below the levels of the year 2050 in the baseline scenario. This huge reduction does not, however, follow from the use of CCS technologies alone; the increased cost of electricity produced with fossil fuels leads to a much higher share of renewables in the electricity sector, see Figure 3.13. In 2050 the baseline had a renewables share of 25%, which means that in Case 1 almost 50% of electricity is produced with renewable sources in 2050.

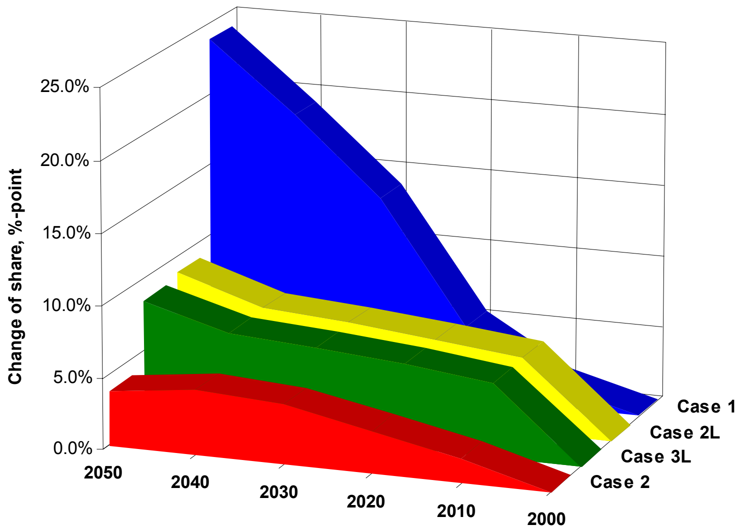


Figure 3.13 *Change in the share of renewable energy in electricity production*

All cases follow the same trends and technologies that have lower emissions are chosen. However, since the policy in Case 1 is concentrated only on the power sector, the use of biomass for electricity generation is much more important in this case than the others. Gas use is increased in Case 2, and to some extent in Case 2L, but by 2030 the cases with high CO_2 constraint are reducing its use. Figure 3.14 presents the changes in the electricity mix for the cases studied.

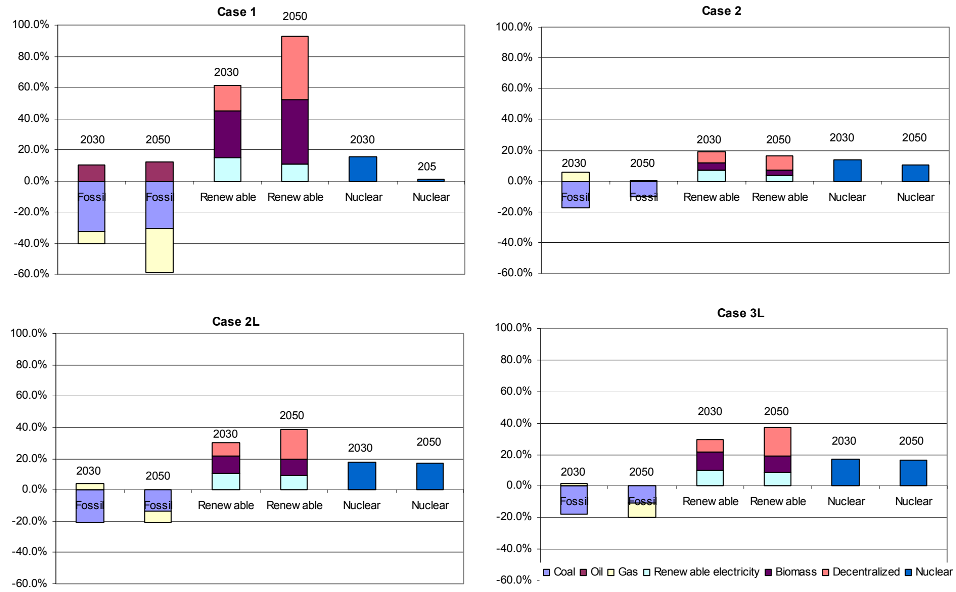


Figure 3.14 *Changes in the global electricity mix in 2030 and 2050 for the cases studied*

The relative increase in value for the renewables in the electricity sector and the following increased use means that in case of competition over fuel between sectors, some other sector will increase the use of fossil fuels in Case 1. Synthetic fuel production (ethanol, methanol and hydrogen, mainly) is such a sector, as Figure 3.15 shows. Not only is ethanol replaced by methanol, but also hydrogen production from fossil fuels is increased and that from biomass decreased. Policies studied in other cases increase the contribution from renewables also in this sector, but the tighter constraint in Cases 2L and 3L compared to Case 2 does not lead to a further significant increase.

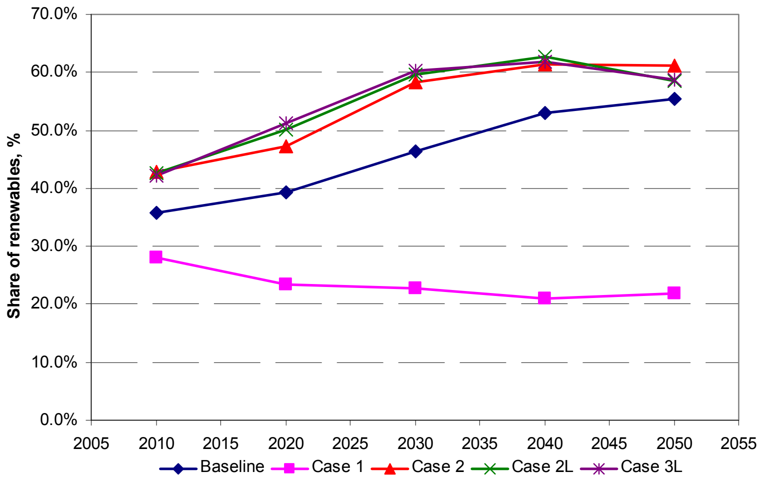


Figure 3.15 *Share of renewables in synthetic fuel production (ethanol, methanol and hydrogen)*

3.2.2.3 CO_2 emissions and carbon capture and sequestration technologies

Figure 3.9 exhibited emissions for all cases studied. The path that is the result of Case 1 and used as a constraint in Case 2 has in 2050 annual emissions about 12% lower than in the baseline. Reduction is about 25% in Cases 2L and 3L. As mentioned previously, there is a considerable leakage of emissions from the power sector in Case 1. Figure 3.16 shows the magnitude of this.

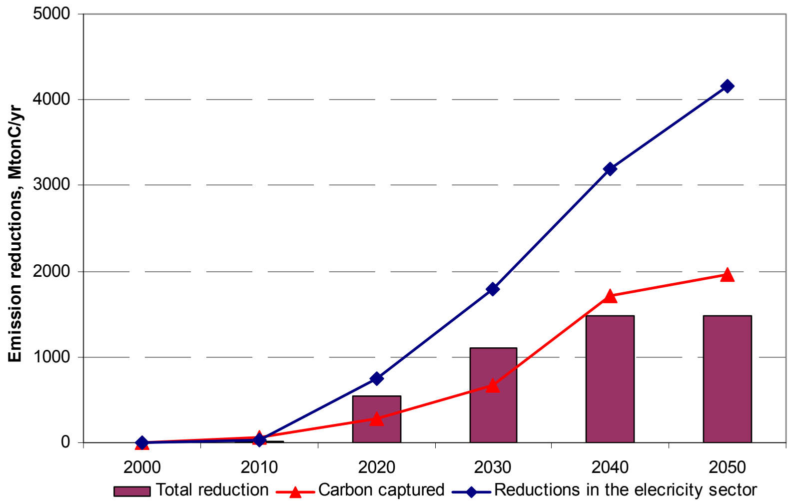


Figure 3.16 *Global emission reductions for Case 1; total, electricity sector and carbon captured*

The bars in Figure 3.16 show the total annual carbon reductions, reaching some 1.5 Gton of carbon in 2050. However, the reductions done in the power sector, described by the blue line, were over 4 Gton of carbon annually and the same number for scrubbed carbon (red line) was also clearly higher, almost 2 Gtons per year. This means that 2.5 Gtons, more than 60%, of the carbon emissions avoided in the power sector were only moved to other sectors. Slightly less than half of the reductions in the power sector can be attributed to CCS technologies, while the other half is achieved through the increased use of non-fossil energy sources. Other cases have no leakage due to the global carbon constraint. About 45% of reductions in Cases 2, 2L and 3L are from the power sector. Regionally, OECD is contributing most to the reductions in Cases 1 and 2, while in Cases 2L and 3L ASIA is equally important.

Unsurprisingly, Case 1 results in by far the highest penetration of CCS technologies. Due to the carbon leakage between the sectors, the emission path derived from Case 1 is not enough to encourage CCS investments in power plants in Case 2. Adding a stricter constraint increases the use of these technologies, but they still only have a complimentary role in 2050. During the latter part of the century, however, the strict constraint used in Cases 2L and 3L leads to a considerable use of carbon scrubbers in not only the power sector, but also in hydrogen production. Figure 3.17 shows the annual amount of scrubbed carbon. Note that the only CCS technology used in Case 2 is connected to hydrogen production. Figure 3.18 shows the market shares of different CCS technologies in 2050.

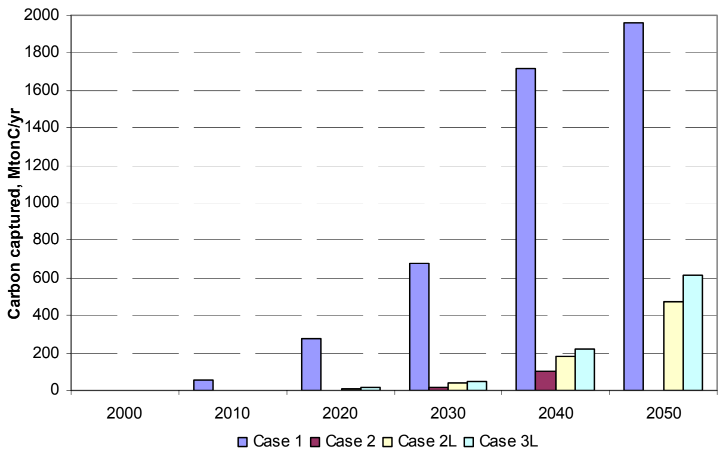


Figure 3.17 *Annual global carbon capture and storage*

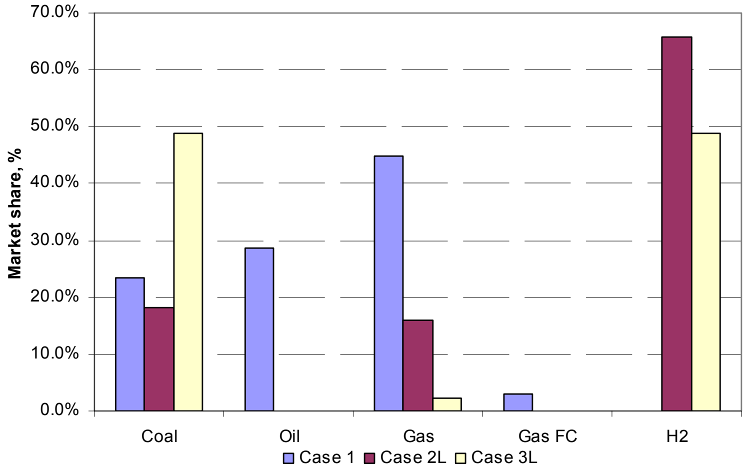


Figure 3.18 *Global market shares of CCS technologies in 2050*

3.2.2.4 Carbon prices and mitigation costs

As we have noted, Case 1 proves to be quite inefficient at reducing CO_2 emissions. Case 2 has similar emissions, but the price per ton of carbon mitigated is only a fraction of what was achieved in Case 1. Cases 2L and 3L require more reductions, but they are still able to accomplish reductions with much lower prices than what is done in Case 1. Figure 3.19 shows the average reduction costs calculated from cumulative reductions and cumulative cost changes (blue bars). The purple line shows the shadow price in 2050 for a ton of C emitted. This can be interpreted as the market price for an emission-trading scheme, when an emission target is defined. Since Case 1 has no specific target, the reduced carbon emissions do not have a value per se.

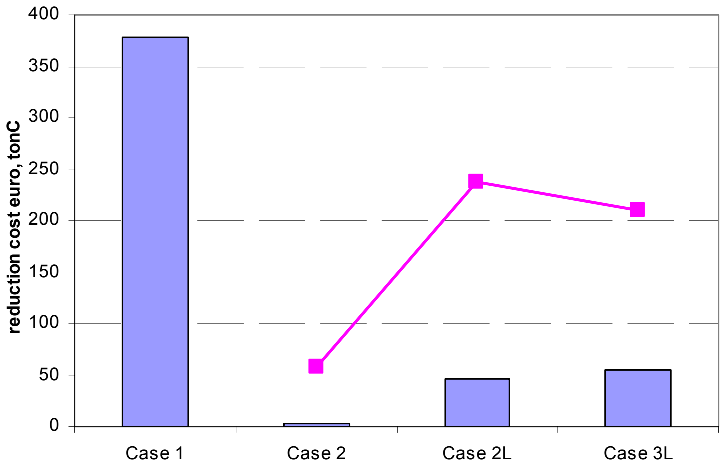


Figure 3.19 *Specific CO_2 reduction costs in studied cases, average price (blue bars) and shadow price (purple line) of carbon*

3.2.3 Conclusions and recommendations

The cases studied have shown that although it is possible to move to a practically carbon free electricity production with power plant standards, this option is a highly costly and not very efficient one because of the increased use of fossil fuels in other sectors. When no such standard is enforced, but an emission constraint leading to a similar emission path is applied, almost no CCS technologies appear in the solution. It therefore seems that unless the mitigation target is very ambitious, in the short term CCS technologies remain a complimentary and rather marginal option to renewables and nuclear, which are used more evenly in all sectors.

Investment subsidies increase the total use of CCS marginally in the short term, but according to our results, such subsidies can have a strong effect on which particular technology is entering the markets first. Due to the inertia in the energy system as well as the relatively high initial cost of the technologies, most of the impact of CCS technologies is visible only during the latter part of the century.

3.3 DNE21+

3.3.1 Introduction

3.3.1.1 CO_2 Capture and Sequestration

Table 3.4 lists the assumed facility costs and the energy requirements for CO_2 capture technologies. The cost reduction and energy efficiency improvement of CO_2 capture technologies are exogenously assumed to proceed with time; this is based on several sources. In this model, the cost of electricity generation is endogenously determined by the region, time point, and type of time period in the model, and therefore, costs per ton of avoided CO_2 emissions are also determined within the model, although the energy requirements are exogenous.

For CO_2 sequestration, ocean sequestration and geological sequestration are explicitly modeled, and geological sequestration is further divided into four types: injections into oil wells (EOR), depleted gas wells, coal bed (ECBM), and aquifers. The potentials of most types of the sequestration are estimated through GIS data. Table 3.5 summarizes the assumptions of the potentials and costs of CO_2 sequestration in the world. The cost of CO_2 transportation inside the divided model region is included. The details are provided by Akimoto et al., 2004.

Table 3.4 *Assumed facility costs and energy required for CO_2 capture*

	Facility cost [US$/(tC/day)]	Energy requirement [MWh/tC]
CO_2 chemical recovery from coal-fuelled power	59,100 - 52,000	0.792 - 0.350
CO_2 chemical recovery from gas-fuelled power	112,500 - 100,000	0.927 - 0.719
CO_2 physical recovery in gasification plants	14,500	0.902 - 0.496
	Facility cost [US$/kW]	Generation efficiency [% LHV]
IGCC with CO_2 capture (physical recovery)	1,700 - 1,470	34.0 - 49.0

Note: Cost reduction and energy efficiency improvement are assumed to proceed with time.
The parameters for CO_2 chemical recovery from oil, biomass and methanol-fuelled power are same as that from gas-fuelled power.

Table 3.5 *Assumed CO_2 sequestration potentials and sequestration costs in the world*

	Sequestration potential [GtC]	Sequestration cost† [$/tC]
Oil well (EOR)	30.7	81 - 118‡
Depleted gas well	40.2 - 241.5††	34 - 215
Coal-bed (ECBM)	40.4	113 - 447‡‡
Aquifer	856.4*	18 - 143
Ocean	-	36**

† Cost of CO_2 capture is excluded. Cost of CO_2 transportation inside the divided model region is included.
‡ The proceeds from recovered oil are excluded.
†† 40.2 is the initial value in 2000, and the capacity increases with natural gas production.
‡‡ The proceeds from recovered gas are excluded.
* The potential is the 'practical' one, i.e. 10% and 20% of the 'ideal' potentials for onshore and offshore, respectively.
** The cost includes the cost of CO_2 liquefaction.

3.3.1.2 Vintages of technology facilities

DNE21+ model has the historical vintages of technology facilities such as fossil fuel based power plants by region. The lifetime of each facility is assumed exogenously and the capacities of new installed facilities to meet demands at each time point are determined endogenously. The lifetime of each fossil fuel based power plant is commonly assumed as 30 years in this report.

3.3.1.3 Case Study Setup

CCS standards case (Case 1) and CO_2 constraint case (Case 2) are analyzed by using DNE21+ model. Final energy demands are fixed for all the three cases. The setup is summarized as follows.

- Case 1: All new fossil fuel based power plants have to be equipped with CO_2 capture and storage. The beginning years are 2015 for Annex I and 2025 for Non-annex I, respectively.
- Case 2: The world total CO_2 emission path obtained from Case 1 is given as an upper limit. CCS standards are no longer used and no further political constraints such as the carbon value are introduced.

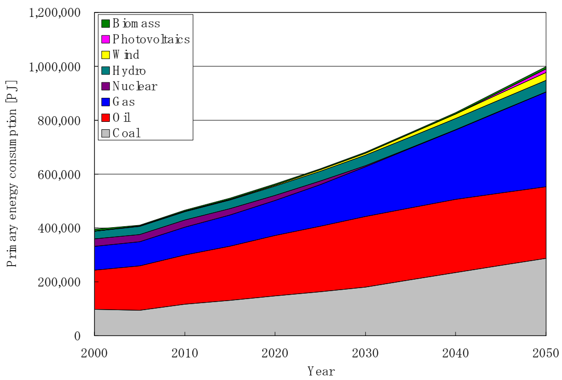
3.3.2 Results

3.3.2.1 Primary energy consumption

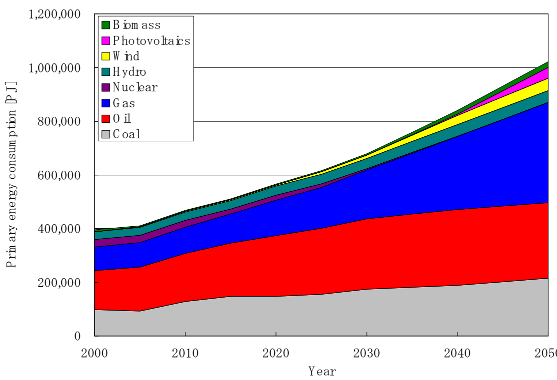
The world primary energy consumption for each case is shown in Figure 3.20. Nuclear and renewables are expressed in primary equivalent by using conversion factor of 0.33.

Compared with Baseline, the decrease in coal is observed in the latter half of the 50 years for Case 1. In 2050, the coal consumption in Case 1 is 215 EJ, and the decrease relative to Baseline is 73 EJ (decrease ratio: 25%). On the other hand, the increases in oil, gas and renewables relative to Baseline are observed. Although the target of CCS standard is all new fossil fuel based power plants, only the coal consumption is decreased relative to Baseline.

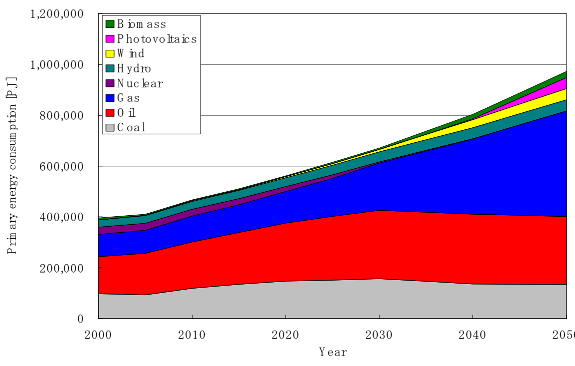
For Case 2, the switching among the energy sources is more conspicuous than that in Case 1. The decrease in coal and the increase in gas are particularly large. In 2050, the decrease in coal relative to Baseline is 153 EJ and the coal consumption is approximately half of that for Baseline. For the gas consumption, the increase is 63 EJ (increase ratio: 18%).



(a) Baseline



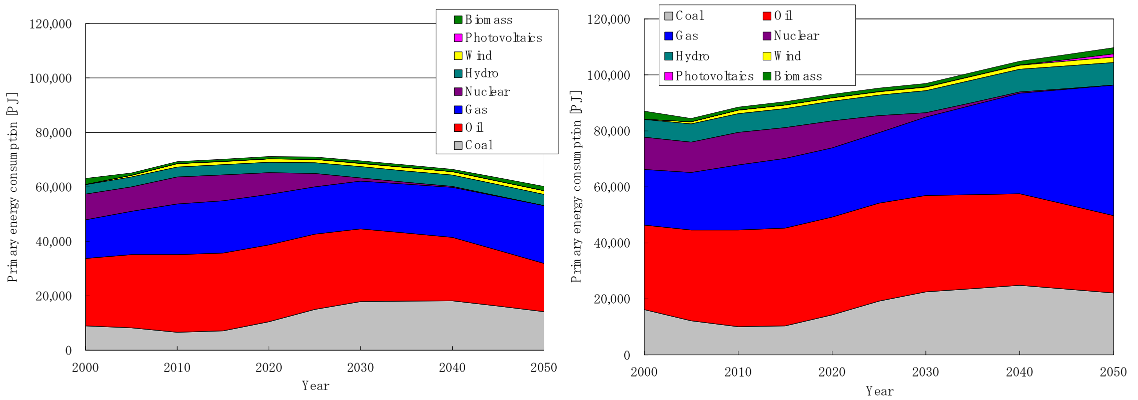
(b) Case 1



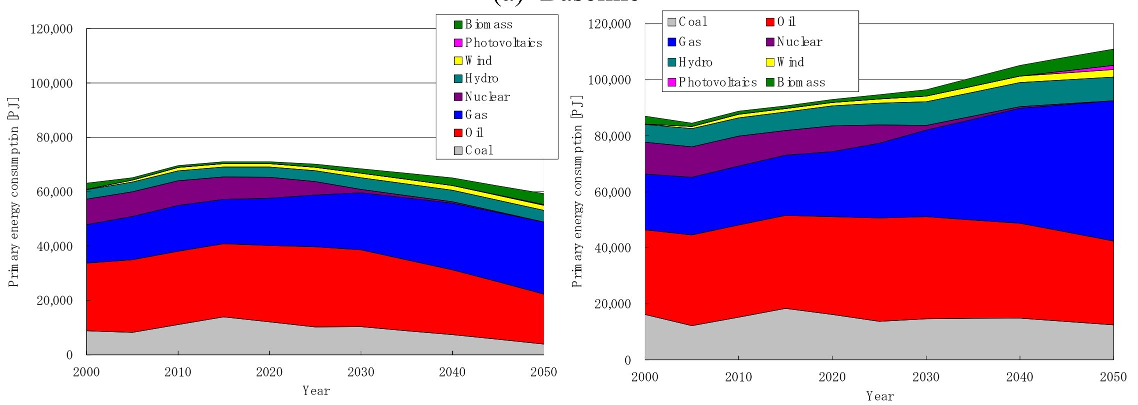
(c) Case 2

Figure 3.20*Primary energy consumption (World total)*

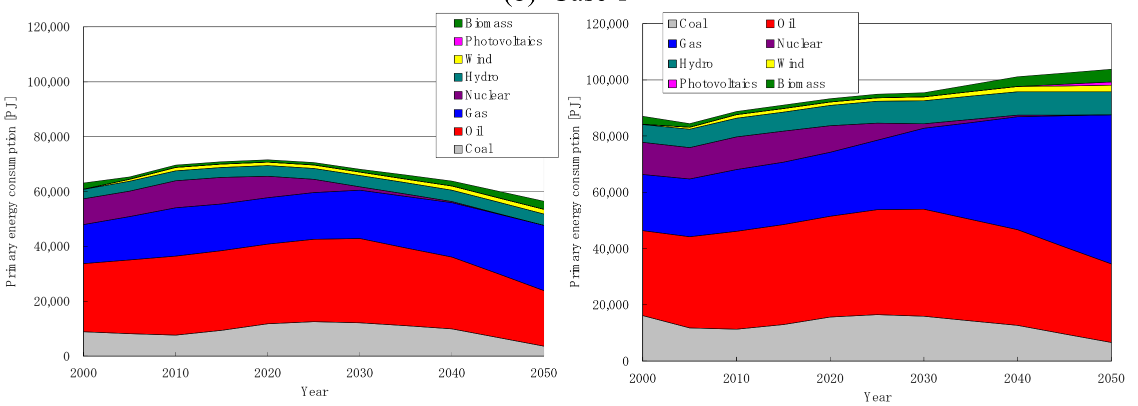
Figure 3.21 shows the primary energy consumption for EU-15 (left side) and EU-30 (right side), respectively. The decrease in coal that is observed feature in Figure 3.20 is also observed for EU-15 and EU-30. For EU-15, the coal consumptions in 2050 in Cases 1 and 2 are 3.9 EJ and 3.6 EJ, respectively. Those decrease ratios relative to Baseline are 72% in Case 1 and 74% in Case 2. The decrease ratio in Case 1 is higher than that for the world total and the influence of CCS standard on the coal consumption for EU-15 becomes larger than that for the world.



(a) Baseline



(b) Case 1



(c) Case 2

Figure 3.21 *Primary energy consumption*
Note: left side: EU-15, right side: EU-30.

3.3.2.2 CO_2 emissions and sequestrations

Figure 3.22 shows the global net CO_2 emission for each case. The CO_2 reduction by the CCS standard (Case 1) is mainly achieved after the year 2030. That amount in 2050 is 4.7 GtC/yr. Contrary to the CO_2 reduction in the time period, the slight increase in CO_2 emission relative to Baseline is observed between 2010 and 2020.

These effects are better understood using Figure 3.23 which shows the capacity of new installed fossil fuel based plants in Baseline and Case 1. Although the beginning year of CCS standard is 2015 for Annex I as above mentioned, the capacity of the power plants with CO_2 capture between the year 2015 and 2025 is small as shown in Figure 3.23 (b). As mentioned in Section 1.1, the cost reduction of CO_2 capture is exogenously assumed to proceed with time and it is perfectly foresighted in our model. Therefore, the installation of the plants with CO_2 capture tends to be delayed and that of the plants without CO_2 capture before the beginning year of CCS standard tends to increase to meet the demand. This is one of the reasons for small or negative effect on net CO_2 emission before the year 2030.

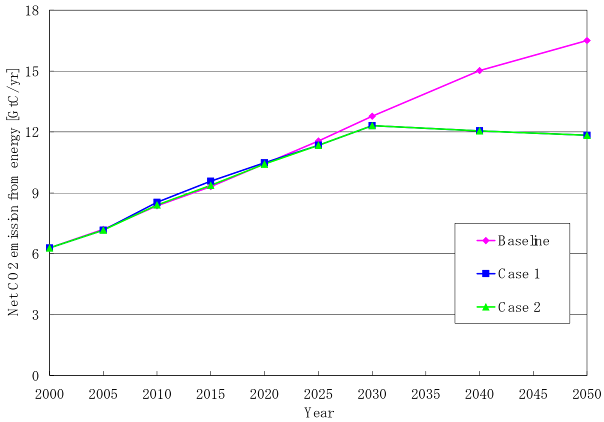
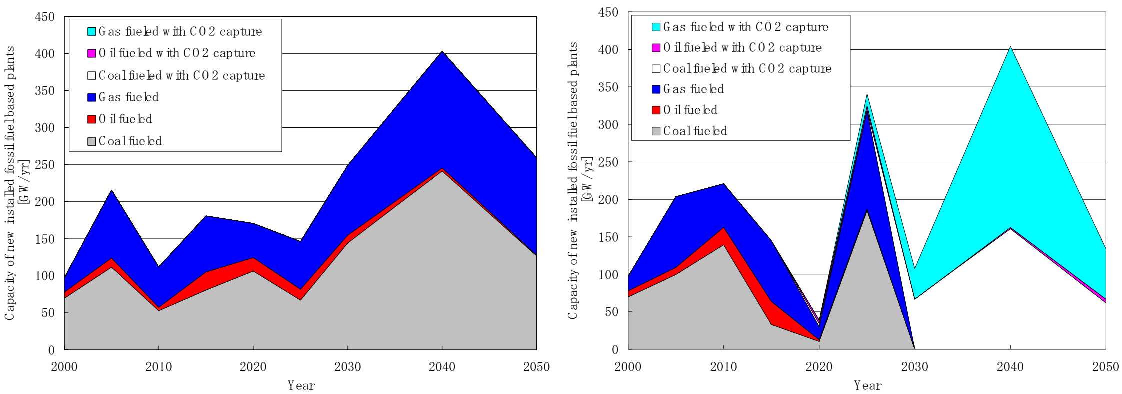


Figure 3.22 *Global net CO_2 emission from energy use*

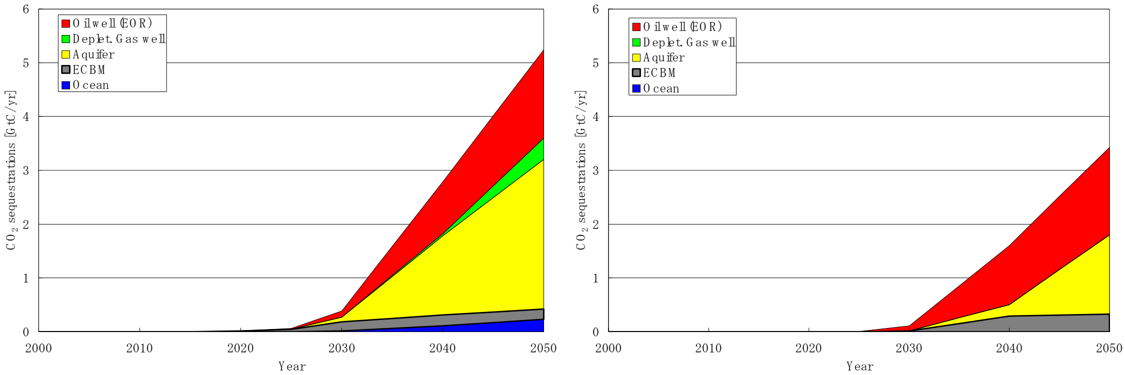


(a) Baseline (b) Case 1

Figure 3.23 *Capacity of new installed fossil fuel based plants (World total)*

Figure 3.24 shows the world CO_2 sequestrations by options for Cases 1 and 2. For Case 1, 5.2 GtC/yr is sequestrated in 2050. The sequestrations into aquifers and oil wells are relatively larger than those into other types of reservoirs, and they are 2.8GtC/yr and 1.6GtC/yr in 2050, respectively. For Case 2, although the amount of sequestrated CO_2 is decreased compared with that in Case 1, the total amount of sequestrated CO_2 is 3.4 GtC/yr in 2050 and it is considered that CCS plays an important role for the cost effective CO_2 reduction. The utilized options for sequestration are mainly oil wells and aquifers as same as Case 1. The sequestration into ocean and depleted gas well are not required in Case 2.

The role of CO_2 sequestration options is very different among the regions because of the regional circumstantial differences as same as the fuel mix. Figure 3.25 shows the cumulative amounts and shares by option of CO_2 sequestration between 2000 and 2050 for Case 1. The share of aquifers in the total CO_2 sequestration in EU-15 is 93%, and it is highest among those in other regions. For Middle East & North Africa and Russia & Other FUSSR, EOR is very important. The share of ECBM is large in Oceania (75%). The sequestration into the ocean is mainly utilized in Japan and the share in the total CO_2 sequestration in Japan is 90%.



(a) Case 1 (b) Case 2

Figure 3.24 *CO_2 sequestrations (World total)*

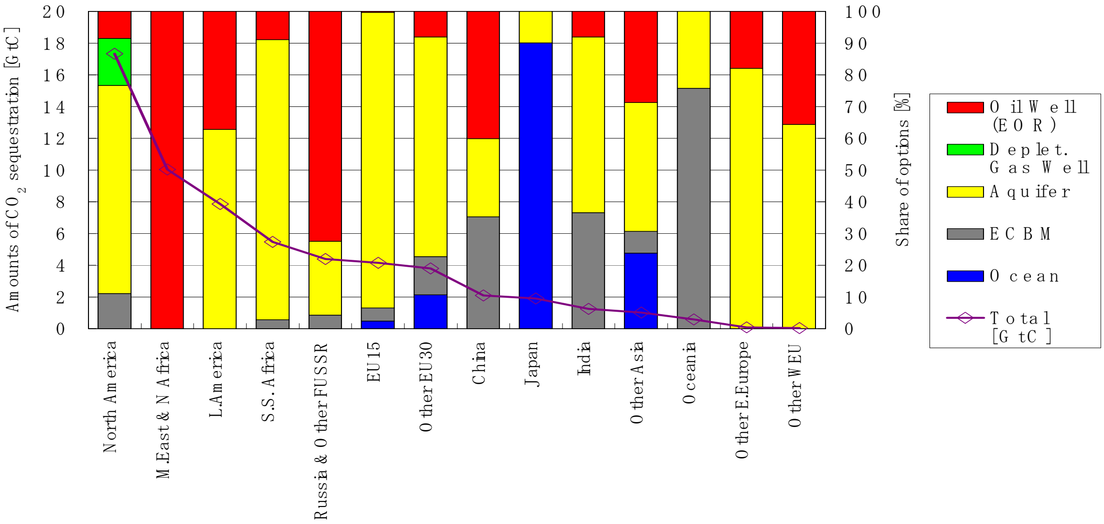
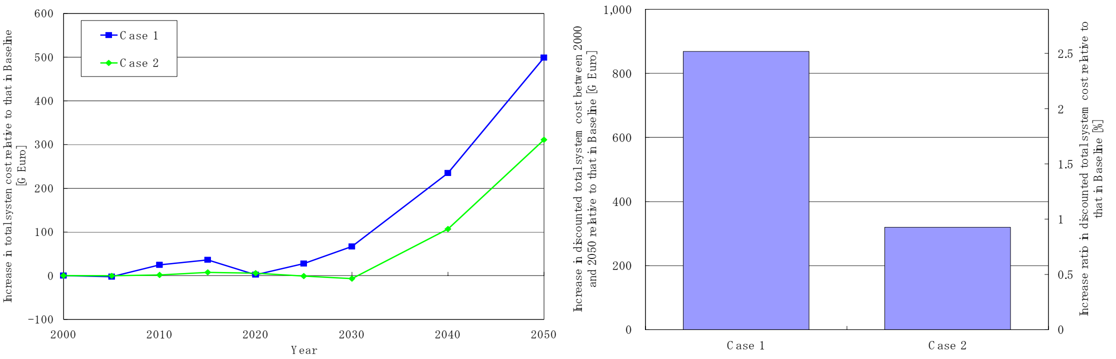


Figure 3.25 *Cumulative amounts and shares by option of CO_2 sequestration between 2000 and 2050 (Case 1)*

3.3.3 Consequences

Figure 3.26 shows the increase in total system cost relative to that in Baseline for Cases 1 and 2. The total system cost increases with time after 2030 for both cases and the increase costs in 2050 are € 500 bln in Case 1 and € 310 bln in Case 2.

The discounted cost increases are € 870 bln (Increase ratio: 2.5%) in Case 1 and € 320 bln (Increase ratio: 0.9%) in Case 2. It means that there are more cost effective CO_2 reduction options such as the switching among fossil fuels, the introducing renewables, etc. Although the policy of the CCS standard may be easy to practice from a viewpoint of the simplicity of the contents, it is important to consider the other CO_2 reduction options with regional circumstances.



(a)Time series (b) Discounted

Figure 3.26 *Increase in cost (World total, Case 1 and Case 2)*

3.3.4 Conclusions and recommendations

The effectiveness of the CCS standard policy for CO_2 emission reduction was analyzed by using DNE21+ model. The results are summarized as follows.

1. By introducing CCS standards, only the coal consumption is decreased and the oil and gas consumptions are increased relative to Baseline.
2. The CO_2 reduction under the CCS standards is mainly achieved after the year 2030. The amount of CO_2 reduction in 2050 is 4.7 GtC/yr.
3. Although the amount of sequestrated CO_2 in Case 2 is decreased compared with that in Case 1, the sequestrated CO_2 is still large (3.4 GtC/yr in 2050). CCS plays an important role for the cost effective CO_2 reduction.
4. The role of CO_2 sequestration options is very different among the regions. For EU, the sequestration into aquifers is the most important option.
5. The increase in total system cost rise up with time after 2030. The increase in discounted total system cost between 2000 and 2050 in Case 1 is € 870 bln and the difference in that between Case 1 and Case 2 is € 550 bln. Although CCS is an important option for the cost effective CO_2 reduction, it is important to also consider the other CO_2 reduction options with regional circumstances.

3.4 PROMETHEUS

3.4.1 Introduction

This report is the ICCS/NTUA contribution to the Cascade Mints Part 2 CCS case study using the PROMETHEUS stochastic model. The analysis focuses on electricity production.

3.4.1.1 CO_2 capture technologies

CO_2 capture technologies are considered both in electricity and hydrogen production sectors. In electricity production, the fossil fuel technologies equipped with a CO_2 capture facility are:

- Supercritical Pulverised Coal + Post-combustion CO_2 capture
- Integrated Coal Gasification + Pre-combustion CO_2 capture
- Gas Turbine Combined Cycle + Post-combustion CO_2 capture
- Biomass Gasification plus Combined Cycle + Pre-combustion CO_2 capture.

In hydrogen production, the CO_2 capture equipped technologies considered are:

- Natural Gas Steam Reforming + Pre-combustion CO_2 capture
- Coal Partial Oxidation + Pre-combustion CO_2 capture.

One ‘generic’ CO_2 storage technology is considered.

A general remark is applicable to the baseline and all case studies considered below: the PROMETHEUS model incorporates stochastic climate policy intensities for the different regions identified in the model including joint probabilities of such intensities across regions and over time. Were things to be specified otherwise it would be tantamount to considering that in a projection where everything is stochastic (uncertain) only climate policy is an absolute certainty. This specification would violate the very principles of stochastic modeling. An important implication of the above is that carbon capture and sequestration has appreciable probabilities of being competitive even under baseline conditions (in those cases where very high carbon values occur). Probabilities for CCS competitiveness under baseline assumptions are given in Table 3.9. Case studies that required alternative climate policy stances have been implemented by altering expected effective carbon values while retaining their variability and co-variance.

3.4.1.2 Case Study Setup

Three policy cases were implemented, according to the CCS case study proposal, as follows:

Case 1: CCS Standards

From 2015 in the developed countries the new fossil-based power plants have to be equipped with a capture facility. Less developed countries will apply the standards ten years later in 2025. The standards were applied both to the electricity and hydrogen production sectors.

However, these standards were not applied for CHP plants and fuel cells on the assumption that most of these plants will be relatively small in size. Moreover, peaking devices (oil and gas open cycle turbines) are also excluded because such plants have low utilization rates and a requirement that capture is included would make their cost, and consequently the cost of peak shaving, prohibitive. Finally, biomass gasification is considered to be a renewable option and no specific requirement of fitting it with capture is introduced and it is free to compete with the remaining technology options, although PROMETHEUS includes a pre-combustion CO_2 capture option for this technology.

Case 2: CO_2 constraint
In this case there are no standards and the emission path corresponding to the results of Case 1 is considered as a constraint. However, the idea of a fixed CO_2 emissions target that is always met is contrary to PROMETHEUS philosophy, which allows for many policy stances and variable success rates in policy implementation. The assumptions of the case were introduced in the model by multiplying the carbon values pertaining to the reference by a fix coefficient in order to obtain the same average cumulative CO_2 emissions as in Case 1.

Case 3: CO_2 constraint + Subsidies in the capital cost of CO_2 capture and storage components
In this case the capital cost of the CO_2 capture and storage facilities is subsidized from 2015 to 2050 in all world regions. The subsidy is set at 35% of the investment cost in 2015 and it is reduced gradually to 0% by 2050. The same CO_2 constraint as in Case 2 is applied and it was implemented through a process similar to the one adopted for Case 2, i.e. multiplication of reference carbon values by the same scalar until the same cumulative CO_2 emissions would be obtained. Clearly in this case, the scalar is smaller than the one in Case 2.

3.4.2 Results in the electricity production technology mix

Figure 3.27 presents the cumulative distribution of the share of the technologies equipped with a CO_2 capture facility in total electricity production. The results clearly reflect that the imposition of standards implied in Case 1 is highly focused on CCS technology choice, while the other cases involve higher flexibility. Consequently, in Case 1 there is a ~82% probability for a share of more than 10% in electricity production, while the probabilities for the same share in Cases 2 and 3 are 20% and 23% respectively. In the reference case the probability of a share of more than 10% is only ~0.2% (the 10% limit is denoted in the graph by the bold vertical line).

It is worth noting that for all cases, even for Case 1, the probability of attaining higher shares quickly collapses (for example, in Case 1 the probability of a share of more 20% is ~48%, of more than 30% is ~25% and of more than ~40% is ~10%). In fact the probabilities of attaining high shares in the margin (annual replacements) are much higher, but capital stock turnover effects mean that the shares in total equipment are much more modest. This is also due to the fact that Case 1 implies high probabilities of 'leakage': considerable shift from fossil fuel generation towards nuclear and renewable forms, where they are clearly cost attractive compared to expensive capture options (see Figure 3.28).

The close similarity of distributions for Cases 2 and 3 in Figure 3.27 can be explained by the fact that the subsidy is higher in early years when the CCS technologies are rather immature to gain a significant share in electricity production. Thus, although Case 3 brings the introduction of CCS technologies earlier than the simple CO_2 constraint case, the share of the CCS technologies in the electricity production remains limited.

Table 3.6 presents the distribution of the shares in electricity production of the technologies equipped with Post-combustion CO_2 capture and Pre-combustion CO_2 capture. Pre-combustion CO_2 capture shows better prospects than the Post-combustion CO_2 capture. In fact, the best prospects are associated with the Integrated Coal Gasification with CO_2 capture technology.

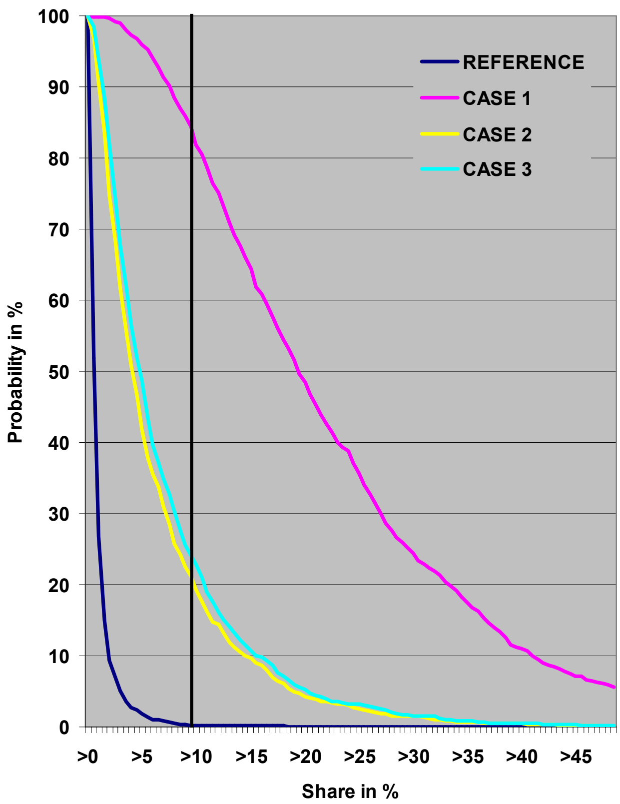


Figure 3.27 *Cumulative distribution of the production share of the technologies with CO_2 capture facility in total world production in 2050*

Table 3.6 *Share of technologies equipped with Post and Pre combustion CO_2 capture in the electricity production in 2050 (World)*

[%]	Reference			Case 1		
	Total	Post combustion CO_2 capture	Pre combustion CO_2 capture	Total	Post combustion CO_2 capture	Pre combustion CO_2 capture
Mean	0.9	0.2	0.7	22.3	10.0	12.4
Median	0.5	0.1	0.3	19.4	6.9	8.2
Lower 5%	0.1	0.0	0.1	5.7	1.4	1.4
Upper 5%	3.0	1.0	2.5	50.2	27.9	38.0
	Case 2			Case 3		
Mean	6.3	2.2	4.1	7.0	2.5	4.5
Median	4.1	1.0	2.4	4.8	1.3	2.8
Lower 5%	0.7	0.1	0.4	0.9	0.2	0.5
Upper 5%	19.0	8.2	13.3	20.2	8.9	14.5

In Table 3.6, it is worth noting that in all cases mean values are considerable higher than medians. This reflects the fact that all the distributions of the shares obtained from PROMETHEUS were highly skewed to the right (possibility of very high shares albeit with low probabilities, while most of the cases exhibiting very low shares).

Renewable and nuclear are considered as the main competitors of the CO_2 capture and sequestration technologies under an effective climate policy. It is clear from Figure 3.28, that the results suggest considerably higher probabilities for high shares for renewables and nuclear in

Case 1 than in the two other cases. This occurs despite the fact that, as it was mentioned earlier, Case 1 exhibits the highest prospects for CCS among all cases. This seeming paradox is due to the extreme character of the case as defined, blocking almost entire fossil fuel options if they are not fitted with CCS facilities. It is clear that a very considerable share of fossil fuel generation is passed on to non-fossil fuel options rather than the CCS ones. It should be mentioned that the large hydro and Biomass Gasification with Combined Cycle are included in the renewable technologies in the graphs, while the Biomass Gasification with Combined Cycle and CO_2 capture is included under CCS technologies.

3.4.3 Costs

The issue of costing the different case studies poses formidable theoretical and practical problems. This is mainly due to the very diverse nature of the definition of the cases: standards, subsidies, emission constraints. Trying to measure cost to the consumer opens questions on inclusion or exclusion of carbon values, subsidies, additional capital costs, etc. In fact, the only theoretically consistent way of making such comparisons will be through a general equilibrium approach (unlikely to contain the micro-detailed required for technology characterization and, anyway, not consistent with the PROMETHEUS specification).

In the event, a compromise solution has been adopted. It consists of considering the electricity produced as a benefit and the generation cost (free of interventions, such as carbon values and subsidies) as cost. This results in a ratio of discounted costs by discounted benefits in the form of mills €/kWh. The explicit inclusion of electricity generated as benefit was necessary, because many of the scenarios imply lower electricity generation, which should clearly not lead to lower costs. Concerning costs, in Case study 1 straight generation costs (including capital cost, fixed O&M cost, variable cost and fuel cost) are considered. For Case study 2, the carbon value has been netted out. For Case study 3, the carbon value has been netted out but the subsidy in the capital cost has been added back in. In this way, the measurement always concerns the cost of re-allocation (i.e. moving from a cheaper generation mix to a more expensive one).

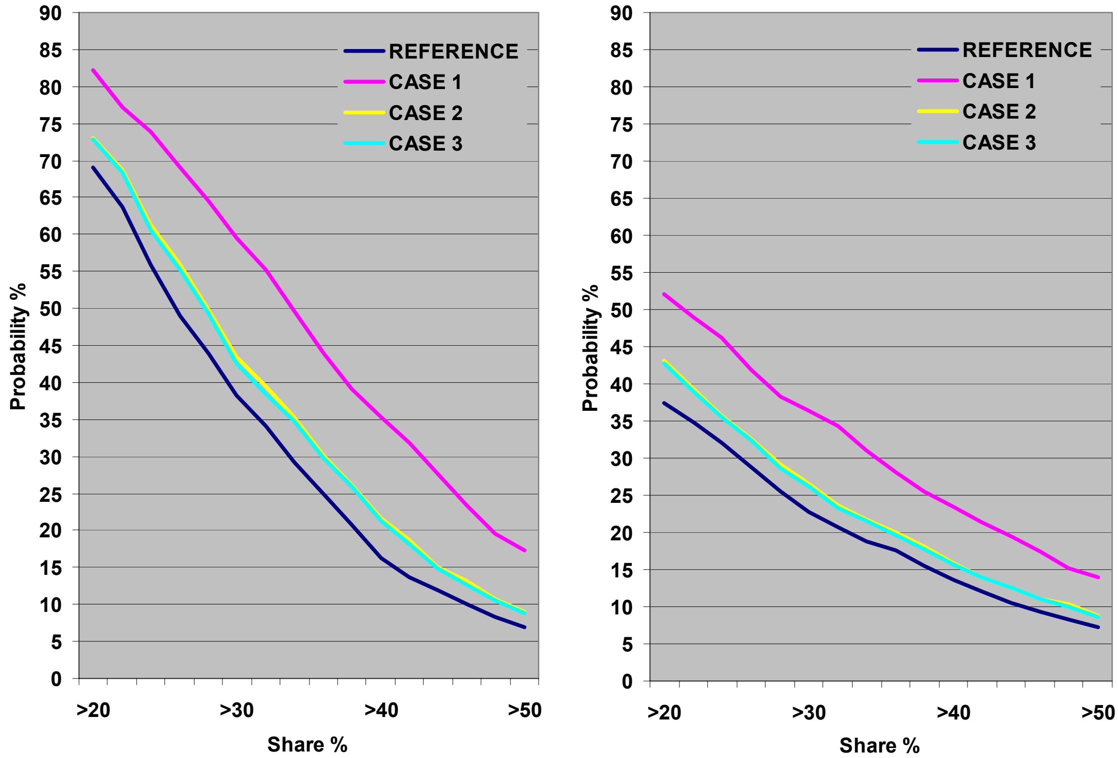


Figure 3.28 *Share of Renewable (incl. Large Hydro) and Nuclear in electricity production in 2050 (World)*

It is clear from Table 3.7 that all statistics in Case 1 imply around six times higher costs than either Case 2 or Case 3. It is also clear that there is a non-negligible probability that the cost implied in the alternative cases, as defined for cost comparison, is lower than in the reference case. This is mainly due to the fact that, as already mentioned, the PROMETHEUS reference implies non-negligible probabilities that carbon values are eventually sufficiently high so as to make at least some CCS options economically attractive. Since all cases, one way or the other, involve an early or even forced introduction of CCS it happens in some instances that the seemingly uneconomic choice at the early stages results in a more economic generation park in subsequent periods when carbon values are higher.

Table 3.7 *Distribution of the discounted electricity generation average cost increases in the three cases compared to the reference scenario*

[Mills€$_{2000}$/kWh]	Case 1	Case 2	Case 3
Mean	1.09	0.17	0.18
Median	1.01	0.15	0.16
Lower 5%	-0.38	-0.36	-0.31
Lower 20%	0.28	-0.06	-0.04
Upper 20%	1.85	0.38	0.39
Upper 5%	2.85	0.79	0.79

Table 3.8 *Probabilities that a policy case is cheaper than another policy case*

% Probability that the cost of the case in the row is lower than the cost of the case in the column	Reference	Case 1	Case 2	Case 3
Reference	-	87.9	72.0	74.7
Case 1	12.1	-	13.7	13.7
Case 2	8.0	86.3	-	72.9
Case 3	25.3	86.3	27.1	-

Table 3.8 shows that Case 1 has a probability of 12% to be cheaper than reference and 13.7% to be cheaper than Cases 2 and 3, which represent the lowest chances of cost effectiveness among the cases examined. Case 2 has a probability of 28% to be cheaper than reference, 86.3% to be cheaper than Case 1 and 73% to be cheaper than Case 3. Finally, Case 3 probabilities are ~25% to be cheaper than reference, 86.3% to be cheaper than Case 1 and 27.1% to be cheaper than Case 2.

CO_2 capture associated with coal technologies stands better chances of being competitive to the horizon of 2050, with pre-combustion approaching even odds of competitiveness. CO_2 capture associated with biomass gasification represents a considerable addition in cost and, according to PROMETHEUS reference case results, nearly certainly will not be cheaper than the equivalent biomass gasification w/o CO_2 capture, even though the value of CO_2 sequestrated from biomass combustion is accounted as a negative cost of the whole system.

Table 3.9 shows the probabilities of lower production costs from the CO_2 capture technologies compared to the production cost of the corresponding technologies without CCS facilities. The probabilities in Cases 2 and 3 are much higher than in Case 1 and reference due to the higher (on average) carbon value imposed, since the higher the carbon value level the faster the convergence of the production costs. However, in Case 1 the higher probabilities (compared to the reference case) are attributed to the learning by doing effect. Moreover in Case 1, the probability for supercritical coal with capture being cheaper than without CO_2 capture is less than the reference, implying that this option is not the most cost effective among CO_2 capture and sequestration options in the longer term.

3.4.4 Conclusions

- According to the PROMETHEUS reference case the probability of carbon capture and sequestration making significant inroads in power generation system before 2025 is very small.
- By 2050, the prospects of coal-based CCS, and especially in association with Integrated Coal Gasification, improve considerably but are less than even.
- Policies designed to encourage the introduction of CCS have a probability of being less costly than no action in that they may anticipate high carbon values in the more distant future. Such probabilities are around 12% for the standards case and around 25% in the combined subsidy and carbon value case.
- The introduction of stringent requirements for CCS with fossil fuel plants improves the chances of penetration considerably but the policy risks being costly.
  - The prospects of renewables and nuclear are just as likely to improve from such requirements.
- The main element determining the chances of CCS making major inroads is the possibility of intensive climate policy in general.
  - Subsidies work equivalently but to the extent that they enable lower overall policy intensity the effect tends to be neutralized.
- Biomass gasification combined with CCS offers prospects for negative costs in cases of very high carbon values. However, in probability terms, it is the least likely option for major CCS introduction because of considerable risks of high capital cost.

Table 3.9 *Probability that the base load production cost of a technology with a CO_2 capture facility is lower than the production cost of a technology w/o CO_2 capture facility (Europe, 2050)*

	Summary results 2025 (% probability)				Summary results 2050 (% probability)			
	Reference	Case 1	Case 2	Case 3	Reference	Case 1	Case 2	Case 3
Supercritical Coal	0.3	0.3	66.5	68.8	22.2	21.8	81.6	80.9
Integrated Coal Gasification	3.1	4.8	73.9	74.6	39.7	41.1	84.0	83.9
Gas Turbine Combined Cycle	0.1	0.1	62.7	64.5	3.6	4.1	74.7	73.9
Biomass Gasification	0.0	0.0	13.9	18.7	0.0	0.0	57.0	55.0

4. Synthesis: world models

4.1 Introduction

This document describes and summarises five contributions to the Cascade-Mints project, produced with, respectively, the DNE21+ model, the GMM model, the MESSAGE model, the ETP model and the PROMETHEUS model. The main focus is on the role of CO_2 capture and storage (CCS) technologies in the electricity sector. This synthesis report mainly compares three policy approaches, all three related to the question how to achieve significant CO_2 emission reductions through the application of CCS technologies. The uniform terminology employed in this synthesis for these three policies is:

- Case 1: CCS standards
- Case 2: CO_2 constraint
- Case 3: CCS subsidies.

This introduction explains the meaning of these three cases, as well as how they are set up and analysed in each of the five models, as well as the differences that exist in assumptions regarding e.g. storage capacities and costs among the models.

4.1.1 Cases and assumptions

In principle all models assess the three mentioned policy scenarios: CCS standards for fossil-fuelled power plants, global greenhouse gas (GHG) emissions constraint, and investment subsidies for CCS technologies. Still, in addition to differences in the way these policies are interpreted, elaborated and modeled, there are differences in which cases precisely are analyzed by the five models (see Table 1): DNE21+ does not analyze the subsidies case and MESSAGE investigates two additional cases (Cases 2L and 3L) in which a tighter CO_2 emissions constraint is imposed. This global emission constraint leads to a GHG concentration of only slightly above 500 ppmv in 2100.

Furthermore, DNE21+, PROMETHEUS and ETP introduce the standards in 2015 for industrialized countries and from 2025 for developing countries, while GMM and MESSAGE apply these standards in 2020 and 2030 for the corresponding groups of countries. In the standards case, GMM and PROMETHEUS make an exception for peak load and/or CHP plants, because the addition of capture technology would make these plants with low utilization rates too expensive.

Table 4.1 *The cases analyzed in the five different global models*

	DNE21+	*GMM*	*MESSAGE*	*ETP*	*PROMETHEUS*	Policy Instrument
Case 1	●	●	●	●	●	CCS standards
Case 2	●	●	●	●	●	CO_2 constraint
Case 2L			●			Tight CO_2 constraint
Case 3		●	●	●	●	Case 2 + subsidies
Case 3L			●			Case 2L + subsidies

For all models, an inspection of Case 1 shows in principle how fossil-based power plants equipped with CCS may compare to other CO_2-free power production options when no CO_2-emitting power options are available anymore, that is, when even the options that usually emit CO_2 (i.e. fossil-fuelled power stations) are ‘decarbonised’ through CCS technology application. A comparison between Cases 1 and 2 may show whether cheaper CO_2 emission reduction may be achieved with other electricity options, which other options are more likely to develop, and how much lower the overall costs of the achievable emission reduction level thus may be. A comparison between Cases 2 and 3 demonstrates if a subsidy could be helpful in introducing more CCS into the power sector.

The PROMETHEUS model is different from the other models due to its stochastic methodology. It uses stochastic climate policy intensities for the different regions identified in the model including joint probabilities of such intensities across regions and over time. An important implication of this is that CCS has considerable probabilities of being competitive even under baseline conditions (in those cases where very high carbon values occur). Cases 2 and 3, that required alternative climate policy stances, have been implemented by altering expected effective carbon values while retaining their variability and co-variance.

Assumptions on costs of CCS technologies are highly determining for their penetration into the energy system. All models have made assumptions regarding variables like investments costs[3], O&M costs, the energy penalty, the carbon capture efficiency, and the learning rate of CCS technologies for power plants.

Two of the models (DNE21+ and ETP) involve some level of diversification in terms of the storage medium used to store carbon dioxide. In the DNE21+ model, only geological and ocean storage are explicitly modeled. Geological storage is divided into four types: injection into oil wells (EOR), depleted gas wells, coal beds (ECBM), and aquifers. Assumptions on the potentials of most storage types are based on GIS data. Assumptions on the costs of different CO_2 storage options cover a wide range. Also in the ETP model, a number of CO_2 storage options have been considered. Onshore and offshore potentials have been characterized separately, as the acceptance for these may differ. The potentials differ by region, as some storage options are not available in certain regions. IEA analysis suggests that the choice for underground CO_2 storage with or without fossil-fuel recovery will depend on site-specific factors, falling beyond the scope of the ETP model. Oceanic storage and mineralization have not been considered. In the other models, no limits are assumed for CO_2 that can be stored in any kind of reservoir. The level of carbon storage, however, is controlled by the annual growth rates of technologies that operate with CO_2 emissions removal.

[3] Note that for the purpose of this paper all costs in $ are converted into euros (€), using an assumed constant exchange rate of € 1 = 1.2$. Furthermore, below all amounts of carbon dioxide are expressed in tCO_2 rather than tC.

4.2 Global results and consequences

Below, global modelling results are summarised, as well as the possible consequences of these findings. The figures provided, in which the combined results of these models are depicted, include the first three of these models only, and not the latter. The ETP model results are referred to only in the accompanying text so as to contrast them with those of the other three models. The time frame considered for all the global modelling results stretches from 2000 to 2050. Among the results and their consequences described are notably: the effects on primary energy supply and the fuel mix in electricity production (as compared to the baseline), the effects on CO_2 emission patterns, the amounts of CO_2 captured and stored, shifts between sectors of the distribution of CO_2 emissions, effects on overall energy system costs and the costs of CO_2 reduction efforts. Also of interest in principle are effects on aspects like security of supply and other macroeconomic variables (such as welfare, growth, employment, and competitiveness), consequences in terms of potential limitations of regional storage capacity, and global implications such as international spill-over effects. However important and interesting, these aspects have received only limited attention in the model study reports, partly as a result of the fact that these bottom-up models are not particularly fit for the analysis of variables like

4.2.1 Primary energy supply

The world primary energy supply for coal, combined for the three models, for Cases 1 and 2, is shown in Figure 1. For natural gas combined with oil (the two fossil fuels that can be used both for electricity production and as transportation fuels) the world primary energy supply, for these three models and for Cases 1 and 2, is shown in Figure 2. Figure 3 presents the same graphs for renewables[4]. From these three sets of figures one can see that there are a number of striking similarities between the three models analysed. On the other hand, there are some clear differences as well between the three models, notably when considering the end-years of the simulation period (up to 2050). The differences are largest for the primary supply of renewables, as depicted in Figure 3. These graphs also and especially point out that there are large differences between Cases 1 and 2, if one considers primary coal supply, but that these differences are only moderate in terms of primary gas+oil supply or that of renewables.

In the *DNE21+ model*, one finds a clear decrease in coal use (compared to the baseline) in Case 1, during the latter half of the 50 years considered. In 2050, coal consumption in Case 1 is 215 EJ, and the decrease relative to the baseline is 73 EJ (i.e. a decrease by about 25%). On the other hand, increases in the use of oil, gas, and renewables, relative to baseline, are observed. Although in principle the target of the CCS standards policy concerns all new fossil-fuel-based power plants, in practice it appears that only coal consumption is decreased relative to the baseline. For Case 2, the switching among energy sources is similar but more conspicuous than in Case 1. The decrease in coal and the increase in gas consumption are particularly large. In 2050, the decrease in coal relative to the baseline is 153 EJ, so that coal consumption is approximately half that in the baseline. For the consumption of gas, the increase is 63 EJ compared to the baseline (i.e. an increase by 18%). Also the primary energy consumption is simulated for the EU-15 and EU-30, with results similar (but more pronounced) to those observed worldwide.

[4] Renewables and nuclear are expressed in primary energy equivalents by using the conversion factor of 0.33.

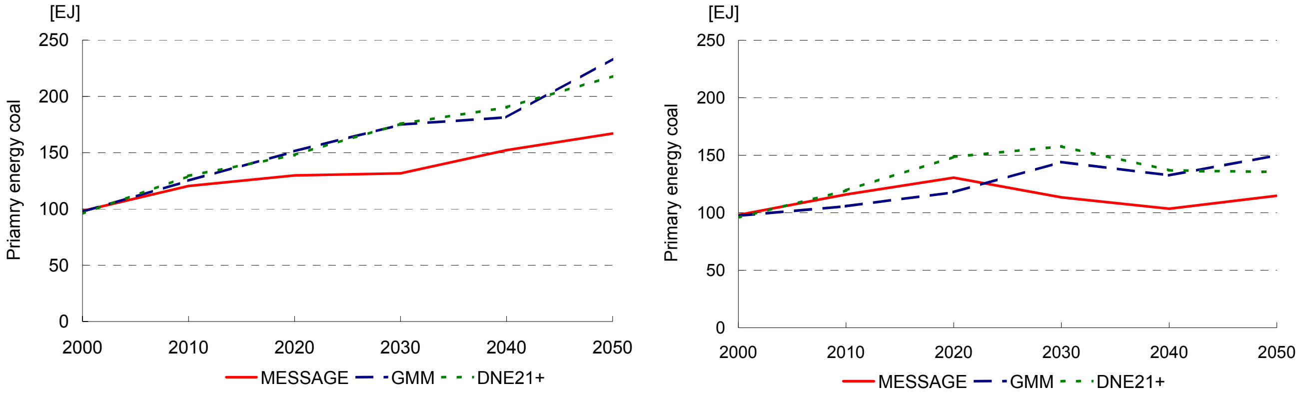
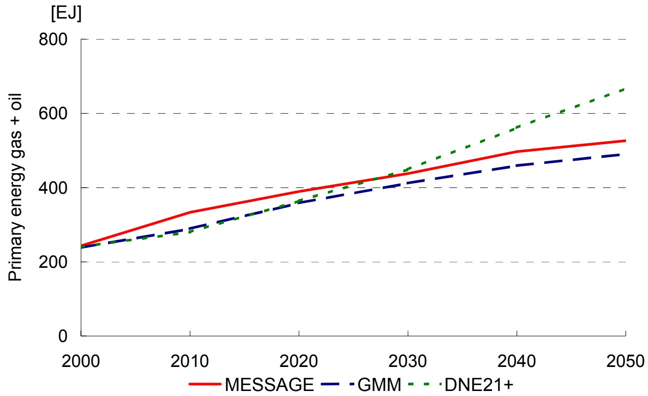


Figure 4.1 a) *Primary energy: coal (Case 1) in EJ from 2000-2050, for Message, GMM and DNE21+*
b) Primary energy: coal (Case 2) in EJ from 2000-2050, for Message, GMM and DNE21+

Also in the *GMM model*, the introduction of CCS standards for the electricity production sector (in Case 1) leads to changes in the primary energy fuel use. The changes are most pronounced for coal consumption, which is reduced by nearly 30% relative to the baseline in 2050. This reduction is associated with the reduced use of coal in the power sector. The consumption of the other fossil fuels, natural gas and oil, is affected to a lower extent. The use of natural gas is reduced only by 4% in 2050, despite a substantial drop in gas demand for power generation, especially with NGCC power plants. The reduction in the use of natural gas for power production from NGCC plants is balanced by an increase in the use of gas for GFC, hydrogen production, and in various end-use markets. The contribution of carbon-free fuel supplies (i.e. nuclear and renewables) increases by about 40% in 2050 in comparison to the baseline scenario. The carbon constraint imposed over the reference case in Cases 2 and 3 results in larger reductions in coal and oil use as compared to Case 1. Coal consumption in 2050 is halved relative to the baseline, and oil use is lower by more than 6%. The global use of natural gas remains basically unchanged under the CO_2 cap. In Cases 2 and 3, nuclear and renewable energy sources increase their shares by 50% with respect to the baseline in 2050. Overall global primary energy demand is also reduced at the end of the computation period by 5% as compared to the baseline. The higher share of coal consumption in Case 1, as compared to the CO_2 constrained scenarios, is due to the structural changes in the power sector, in which gas-based power generation is almost eliminated under the CCS standards case and substituted with CCS-based coal plants. In addition, the efficiency loss associated with CCS contributes to the higher use of coal under the CCS standards policy.



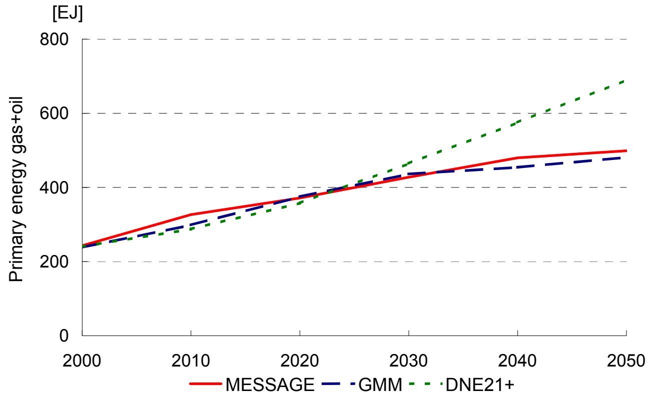


Figure 4.2 *a) Primary energy: gas + oil (Case 1) in EJ from 2000-2050, for Message, GMM and DNE21+*
b) Primary energy: gas + oil (Case 2) in EJ from 2000-2050, for Message, GMM and DNE21+

The *MESSAGE model* demonstrates that, overall, renewable energy sources increase their share in total primary energy use, and that this phenomenon is stronger in the cases where a carbon constraint (and subsidies, for Cases 3 and 3L) is used to encourage CCS technology penetration. The reason is that implementing a policy that requires all new fossil fuel power plants to be equipped with carbon capture technologies (Case 1) or introducing a carbon constraint (Cases 2 and 3) makes fossil-fuel-fired power plants more expensive, thereby promoting the use of non-fossil fuels. In Case 1, in relative terms, the use of fossil fuels in other sectors is made more preferable, as the use of fossil fuels in the power sector alone is 'punished' by additional CCS investments. In the other scenarios, on the other hand, emission reductions can be made in any sector and hence there is no intrinsic asymmetry or policy bias between sectors. The CO_2 constraint derived from Case 1 proves not to result in CCS penetration, even with subsidies. Hence, Cases 2 and 3 are identical (and Case 3 may be left out from the results). While in the baseline 24.3% of primary energy use in 2050 was from renewables, for Case 1 this share becomes approximately 26%, and over 30% for Cases 2L and 3L (all in 2050). Note that although the share of renewables in primary energy is higher in Case 2 than in Case 1, the use of renewables compared to the baseline increases more in Case 1. This apparent contradiction follows from the increased total primary energy use in Case 1 - a result of the energy penalty connected to the widespread use of CCS in this case. A number of general trends can be observed, among which especially that the use of fossil fuels is reduced and the use of CO_2-free sources is increased in all cases. Among the differences between the cases, is, first of all, that in Case 1 the use of CO_2-free sources in sectors other than the power sector is not encouraged, and that fossil fuels are therefore used more in these sectors than in the other cases (in 2050 even more than in the baseline). The reason is, of course, that Case 1 does not have an emissions constraint, but imposes the use of CCS technologies in the power sector. Also, the role of nuclear is more clearly emphasized in the cases with an emission constraint in comparison to the cases without. Cases 2L and 3L differ only slightly. A difference occurs in that in Case 3L gas use is reduced, while coal use is reduced less than in Case 2L. The reason for this is that the subsidy given to CCS technologies in Case 3L increases the competitiveness of CCS technologies for coal power plants enough to make them preferable over similar solutions for gas-fired power plants.

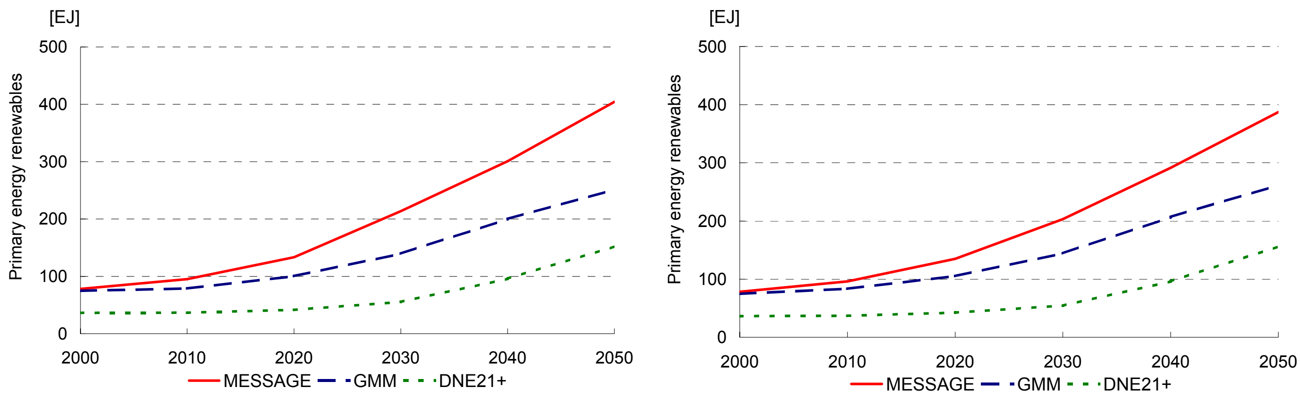


Figure 4.3 *a) Primary energy: renewables (Case 1) in EJ from 2000-2050, for Message, GMM and DNE21+*
b) Primary energy: renewables (Case 2) in EJ from 2000-2050, for Message, GMM and DNE21+

4.2.2 Electricity generation

All models report the total amount of energy-related emissions and carbon captured (see Figure 7 for an overview for all models and all cases). Three of the models inspected, however, report the contribution of different sources to total primary energy consumption (see Figure 8), and specifically report detailed results on the nature of changes in the power production sector.

The stochastic model PROMETHEUS reports on the distribution of the share of the technologies equipped with a CO_2 capture facility in total electricity production (Figure 7). The results clearly reflect that the imposition of standards implied in Case 1 is highly focused on CCS technology choice, while the other cases involve higher flexibility. Consequently, in Case 1 there is a ~82% probability for a share of more than 10% in electricity production, while the probabilities for the same share in Cases 2 and 3 are 20% and 23% respectively. In the reference case the probability of a share of more than 10% is only ~0.2% (the 10% limit is denoted in the graph by the vertical line).

It is worth noting that for all cases, even for Case 1, the probability of attaining higher shares quickly collapses. The probabilities of attaining high shares in the margin (annual replacements) are much higher, but capital stock turnover effects mean that the shares in total equipment are much more modest. This is also due to the fact that Case 1 implies high probabilities of 'leakage': considerable shift from fossil fuel generation towards nuclear and renewable forms, where they are clearly cost attractive compared to expensive capture options.

The close similarity of distributions for Cases 2 and 3 in Figure 4.4 can be explained by the fact that the subsidy is higher in early years when the CCS technologies are rather immature to gain a significant share in electricity production. Thus, although Case 3 brings the introduction of CCS technologies earlier than the simple CO_2 constraint case, the share of the CCS technologies in the electricity production remains limited.

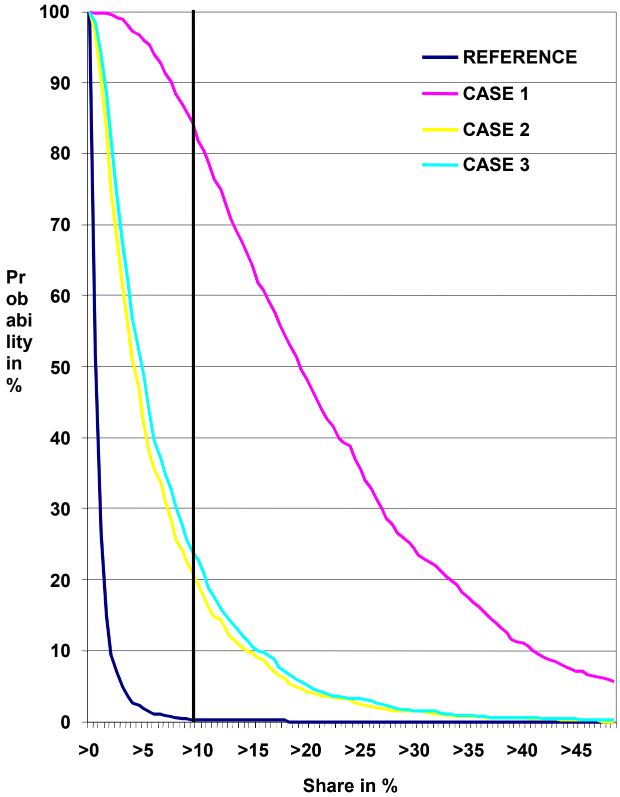


Figure 4.4 *Cumulative distribution of the production share of the technologies with CO_2 capture facility in total world production in 2050*

In the <u>*GMM model*</u>, if the CCS standards are implemented in the power sector, the electricity production based on fossil-fired power plants is reduced substantially as a result of policy-induced phase-out of technologies without CCS. On the global level, about 50% of power production from non-CO_2-scrubbed plants is substituted with technologies equipped with CCS, relative to the baseline scenario in 2050. To compensate for the fallback in fossil-based power production, the contribution of nuclear power plants increases by more than 80% in comparison to the baseline in 2050. Similarly, power plants based on renewable energy sources and fuel cells increase their market share by about 85%. Technologies with CCS contribute by 40% to global power generation in 2050, while nuclear and renewable electricity production corresponds to almost 60% of the total generation mix.

Case 2 allows for a larger flexibility in achieving the carbon reduction target. The reduction in fossil-based power generation, therefore, occurs to a much lower extent in comparison to Case 1. In Case 2, there is an overall reduction by 54% over the baseline case in 2050, which can be associated mainly with the decreased production from coal-fired technologies. Power plants with CCS contribute significantly to overall CO_2 reduction and their share in the global electricity mix increases from 4% in 2030 to 14% in 2050. The second largest increase in carbon-mitigation options in Case 2 comes from nuclear energy, which growths from a 10% market share in the baseline in 2050 to 22% under the carbon constraint. This increase in nuclear power production is 23% higher than in Case 1. On the other hand, the increase in the market share of renewable electricity sources over the baseline for Case 2 is halved in comparison to Case 1.

In Case 3, the reduction in fossil-based systems without CCS and the increase in nuclear power relative to the baseline remain at the same level as in Case 2. Subsidies provided for the portfolio of CCS technologies result in an increased global contribution from these systems by 15% as compared to the no-subsidy case. A larger penetration of CCS is balanced by a proportionally lower contribution from renewables and fuel cells. The feedback from subsidies provided for CCS systems in Case 3 is the most pronounced for IGCC+CCS and NGCC+CCS technologies. Penetration of advanced coal plants with CCS remains at the same level as in Case 2. For Case 3, the contribution of NGCC and nuclear power plants remains the same as in Case 2, but the penetration of other capital-intensive systems (such as PV and hydrogen fuel cells) is lowered.

In the *Message model*, given the different structures of the policies introduced, the electricity sector can be seen as the driving force for the differences observed between Case 1 and the other cases. Due to the requirement of CCS application in fossil-fuel-fired power plants in Case 1, by 2050 emissions from electricity generation are about 90% below the levels of the year 2000 and some 95% below the levels of the year 2050 in the baseline scenario. This large reduction does not follow from the use of CCS technologies alone: the increased cost of electricity produced with fossil fuels leads to a much higher share of renewables in the electricity sector. In 2050 the baseline has a renewables share of 25% in 2050, while in Case 1 almost 50% of electricity is produced with renewable sources in 2050. All cases generally follow the same trends and types of chosen technologies with lower emissions. However, since the policy in Case 1 is concentrated only on the power sector, the use of biomass for electricity generation is much more important in this case than in the others. Gas use is increased in Case 2, and to some extent in Case 2L, but by 2030 the cases with the more stringent CO_2 constraints are reducing its use.

4.2.3 CO_2 emissions

The global emissions of CO_2, for each of the three models, for Cases 1 and 2, are depicted in Figure 4. With the *DNE21+ model* one finds that global net CO_2 emission reductions, in the CCS standards scenario (Case 1), are mainly achieved after the year 2030 (because the standards regime starts relatively late and a high degree of inertia exists in the energy system). In 2050 the emissions reduced amount to about 17 $GtCO_2$/yr.

In the *GMM model*, the adoption of the CCS standards policy induces a strong decarbonisation effect for both global and regional energy systems. The emission reduction is a result of the large-scale introduction of CCS systems in the electricity sector, and of the accelerated penetration of carbon-free nuclear and renewable energy sources. The overall reduction in global energy-related CO_2 emissions for Case 1, relative to the baseline, is about 15% and 40%, in 2030 and 2050 respectively. At the end of the time horizon, global CO_2 emissions are stabilised at 35 $GtCO_2$/yr. Even while the CO_2 constraint scenario imposes the same emission reduction trajectory (from 2030 onwards) as resulting from the CCS standards case, the distribution of CO_2-mitigation options is different in Case 2 as compared to Case 1. The reason is the enhanced flexibility offered in means available to reach the emission reduction target in Case 2. In Case 2, inter-fossil fuel switching, nuclear energy and end-use demand reductions play a dominant role in the CO_2 abatement realised, while Case 1 projects significantly larger contributions of CCS and renewables to the total emission abatement process. Both carbon-constrained scenarios (Cases 2 and 3) project a larger emissions reduction for the period 2010-2020 than in Case 1. This early reduction occurs because of structural shifts and the adjustment of the energy system to the carbon cap under the perfect foresight assumptions.

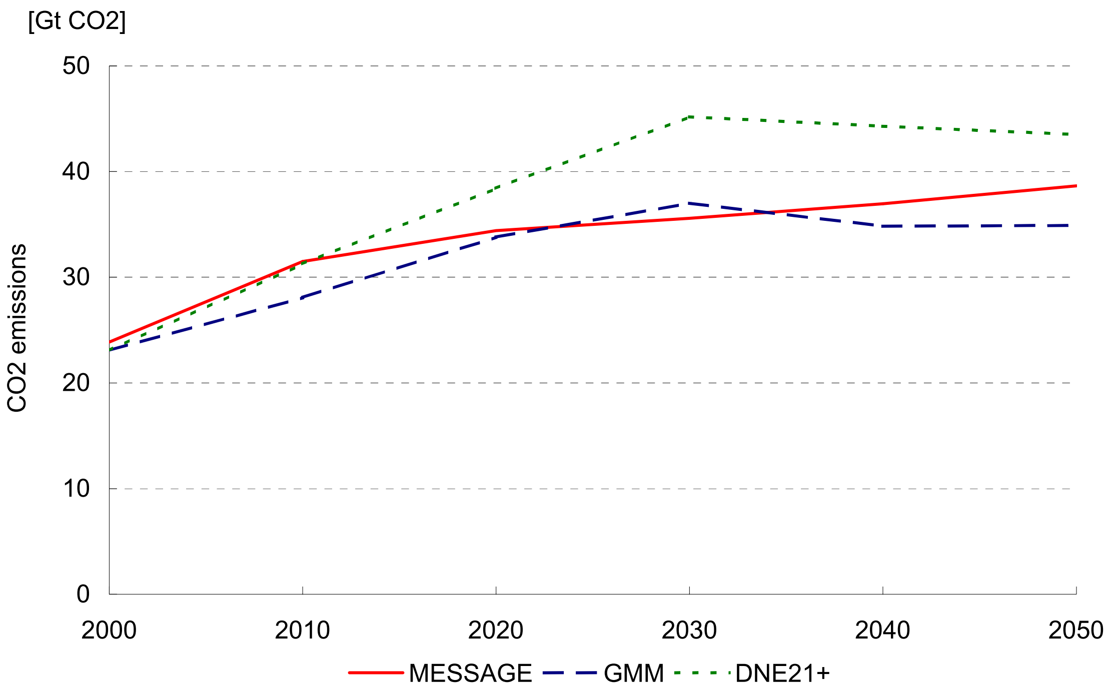


Figure 4.5 *CO2 emissions (Cases 1 and 2) in Mt CO_2, from 2000-2050, for Message, GMM and DNE21+: the emissions derived endogenously in Case 1 are imposed exogenously in Case 2*

In the *MESSAGE model*, the emissions path of Case 1 (used as constraint in Case 2) has, in 2050, annual emissions about 12% lower than in the baseline. The emissions reduction is about 25% in Cases 2L and 3L. Unsurprisingly, the assumptions under Case 1 result in (by far) the highest penetration of CCS technologies. Due to the carbon leakage between the sectors, the emission path derived from Case 1 is not enough to encourage CCS investments in power plants in Case 2. Adding a stricter constraint in Case 2 (leading to Case 2L) increases the use of these technologies, but they still only have a complimentary role in 2050. During the latter part of the century (MESSAGE is run until 2100), on the other hand, the strict constraint used in Cases 2L and 3L leads to a considerable use of carbon scrubbers, not only in the power sector, but also in hydrogen production.

In the *ETP model*, the global CO_2 emission reduction level is almost the same for all three cases. This level increases to 7 Gt per year in 2050, which is lower than the amount of CO_2 *captured* (as opposed to *avoided*). This can be explained by the additional energy needs for the CO_2 capture and storage processes themselves, resulting in additional energy use and thus additional emissions. Emission reduction patterns for Europe are similar and reach 1 Gt of CO_2 emissions reduction in 2050. Worldwide over 95% (in Europe even 100%) of the CO_2 capture technology is coal-related, implying limited CO_2 capture applied at gas-fired power plants. This result is in line with expectations, given the high costs associated with CO_2 capture technology as applied to gas-fired power plants.

4.2.4 CO_2 captured and stored

The global amounts of CO_2 captured and stored, for each of the three models, are depicted and compared between Cases 1 and 2 in Figure 5. In the *DNE21+ model*, for Case 1, 19 $GtCO_2$/yr is stored in 2050. As storage medium, mostly aquifers and oil wells are used (more than other types of reservoirs), with 10 $GtCO_2$/yr and 6 $GtCO_2$/yr in 2050, respectively. For Case 2, the amount of CO_2 stored is 12 $GtCO_2$/yr in 2050, a decrease compared to Case 1. Hence, also here, CCS plays an important role in cost-effectively reducing CO_2 emissions. Again, like in Case 1, mainly aquifers and oil wells are used for storage. Storage in the ocean or depleted gas wells is not required at all in Case 2. The way CO_2 is stored may vary widely between the regions considered, because of the differences in regional circumstances. For example, in terms of the cumulative amounts and shares by option of CO_2 stored between 2000 and 2050 in Case 1, the share of aquifers in the total amount of CO_2 stored in the EU 15 is 93%. This is the highest share among all regions investigated. For the Middle East & North Africa, as well as Russia & Other FUSSR, EOR is very important. The share of ECBM is particularly large in Oceania (75%). The storage of CO_2 into the ocean is mainly applied in Japan, where its share in total CO_2 storage is 90%.

In the *GMM model*, the cumulative amount of CO_2 captured and stored at the global level in the period 2020-2050 for Case 1 is nearly 260 $GtCO_2$.[5] This amount is reduced by 67% and 64% in the carbon-constraint scenarios Cases 2 and 3, respectively. In these cases much of the emissions reduction is obtained through fuel switches, in particular by the deployment of nuclear energy and demand reductions. The cumulative impact of subsidies to CCS systems, in terms of the additional amount of CO_2 captured, corresponds to 6.3 $GtCO_2$ for the period 2020-2050. It proves that CO_2 capture from coal-fired power plants prevails largely over the natural gas related emissions capture. Globally the coal-related capture represents some 96% of the total amount captured in 2050 for the Case 1. Coal-related CCS is not the dominant source of CO_2 capture in all regions and in all policy cases. For example, NGCC+CCS power plants contribute more to the capture process in Case 2 than coal-related CCS for the regions OOCD, LAFM and NAME. This is explained by the relatively low electricity generation costs of NGCC plants in these regions. Also the optimistic assumptions on endogenous learning for this technology contribute to this result. In Case 1, the industrialised regions contribute by about two thirds of the total amount of CO_2 captured in 2030. The fraction of CO_2 captured in the developing world increases to 72% by 2050. In Cases 2 and 3, dominant contributors to the overall CCS process are the coal-intensive regions of Asia, Eastern Europe and the Former Soviet Union. As a result of CCS subsidies, the regions Asia, North America and Latin America, Africa and the Middle East increase their share in the global amount of CO_2 captured.

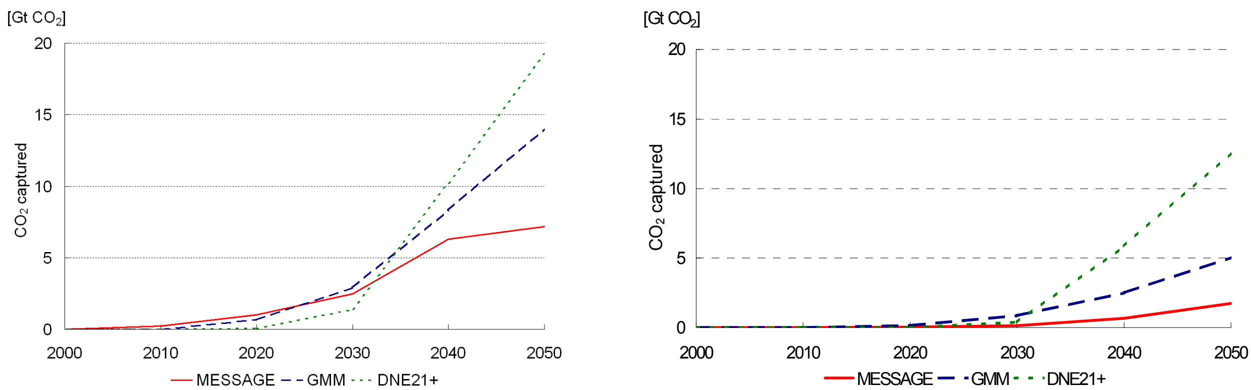


Figure 4.6 *a) CO2 captured (Case 1) in Mt cO2, from 2000-2050, for Message, GMM and DNE21+*
b) CO2 captured (Case 2; 2L for Message) in Mt co2, from 2000-2050, for Message, GMM and DNE21+

The *MESSAGE model* finds that, in Case 1, there is a considerable shift ('leakage') of emissions from the power sector to other sectors. The total annual carbon reductions reach some 5.5 $GtCO_2$ in 2050. However, the reductions realised in the power sector are over 15 $GtCO_2$ annually. The carbon capture realised with scrubbing amounts to some 7 $GtCO_2$ per year. This means that 9 $GtCO_2$ (more than 60%) of the emissions avoided in the power sector are only

[5] For comparison, the IEA (2004) estimates that the cumulative potential for CO_2 storage in all depleted gas and oil fields will be some 800-920 $GtCO_2$ by the year 2050.

moved to other sectors. Slightly less than half of the reductions in the power sector can be attributed to CCS technologies, while the other half is achieved through the increased use of non-fossil energy sources. Other cases analysed have no leakage as a result of the global carbon constraint. About 45% of reductions in Cases 2, 2L and 3L are realised in the power sector. Regionally, the OECD is contributing most to the reductions in Cases 1 and 2, while in Cases 2L and 3L ASIA is equally important.

The *ETP model* allows for determining the amounts of CO_2 captured on both a global level and in Europe. In Case 1, globally a gradual increase from 1.5 Gt in 2030 to 8.5 Gt in 2050 can be observed. These are substantial quantities, compared to the baseline emissions that increase to about 60 Gt in 2050. One of the possible explanations for this result is that fossil-fuelled power plants with CCS pose a cheaper and more likely alternative than other CO_2-free power plants; others may have to do with the impossibility to close down all fossil-based power production, or the intrinsic inertia, potential-limits and growth-constraints associated with renewables and nuclear energy. Note that no expansion of nuclear power plants is considered, and the assumed cost reductions for renewables are limited. Different assumptions for competing electricity supply options result in lower CCS use. In Case 2, the level of CO_2 captured in 2030 is about 1.2 Gt and increases to 6 Gt in 2050. This is 2.5 Gt lower than in Case 1. This suggests that other emission reduction options, e.g. in other sectors, are used more in Case 2, in comparison to Case 1. This is in line with expectations, as it is a well-known fact that significant emission reduction opportunities exist at cost levels well below 21 €/tCO_2, which is the cost level at which CCS is expected to 'kick in'. The use of CCS in Case 3 is almost the same as in Case 2. This suggests that this level of subsidy at least has generally little impact, in line with expectations. Of course, a higher subsidy might result in higher CCS uptake: the findings with ETP are not so much a negative assessment of the subsidy instrument as such.

4.2.5 Energy system costs

The total energy system costs are depicted, both for Cases 1 and 2, in Figure 6. As one can see, the data of only two of the three models described below are available in the database used. The *DNE21+ model* calculates the increase in total energy system costs, relative to those in the baseline, for Cases 1 and 2. The total system costs increase with time after 2030 for both cases: the increase in system costs in 2050 are € 500 bln in Case 1 and € 310 bln in Case 2. The discounted cost increases are € 870 bln in Case 1 (a relative increase of 2.5%) and € 320 bln in Case 2 (an increase of 0.9%). This means that, in comparison to CCS, more cost-effective CO_2 reduction options exist, such as the switching among fossil fuels or the introducing of renewables. Although the CCS standards policy may be practically easy to implement (from a viewpoint of e.g. regulatory simplicity), it is important to also consider the other CO_2 reduction options, especially in view of prevailing regional circumstances.

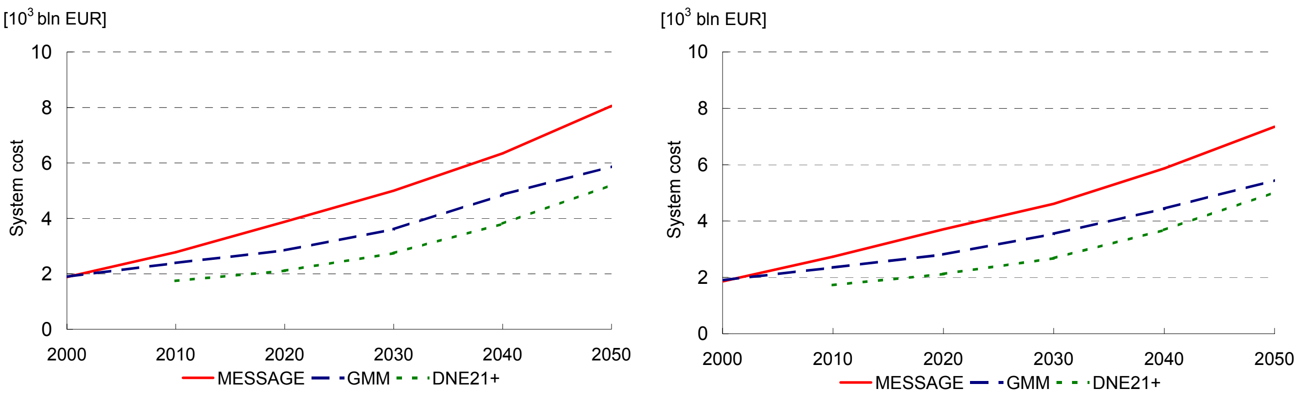


Figure 4.7 *a) Total system costs (Case 1) in bln/€, from 2000-2050, for Message and GMM*
b) Total system costs (Case 2) in bln/€, from 2000-2050, for Message and GMM

Costs of policies promoting CCS technologies in the electricity sector in the *GMM model* show an increase for all policy scenarios relative to the baseline, in terms of the cumulative discounted energy system costs. Two elements in the total cost increase can be distinguished: the cost associated with technology changes and system adjustments, and the cumulative cost of CO_2 storage in all types of reservoirs (i.e. at 2 €/tCO_2). The increase in total system costs for Case 1 is basically twice as high as the cost increase for Case 2. This result indicates that the implementation of stringent regulatory policy forcing CCS into the power sector might be costly in comparison to the more flexible policy of a carbon constraint (or tax) applied over the whole energy system and over all sectors, even when these different strategies achieve the same emission reductions. The cost impact of subsidies for CCS technologies under the CO_2-constrained regime is limited and corresponds to a penalty of 3% in terms of policy-invoked reduction costs. The marginal costs of CO_2 reduction for Cases 2 and 3, in which the global CO_2 cap is adopted, are subject to strong variations over time. These variations reflect the severity of the constraint in the specific time period, as well as the ability of the energy system to adjust its structure such as to reach the given emission target. Marginal costs for Case 2 vary between 8 €/tCO_2 in 2020 to 61 €/tCO_2 in 2040. One can observe a slight reduction in marginal costs in the year 2050, with respect to 2040. This can be attributed to the accelerated learning performance of technologies contributing to the abatement process (in the form of not only CCS, but also renewables and nuclear energy). The reduction in marginal costs resulting from subsidising CCS systems accounts for only 3-7% during the period 2030-2050. Note that the marginal costs for the period 2010-2020 are given by the baseline carbon tax of 10 €/tCO_2 as applied in the OOECD region.

In the *MESSAGE model*, Case 1 proves to be quite inefficient in reducing CO_2 emissions. Case 2 has similar emissions, but the price per ton of carbon mitigated is only a fraction of what is achieved in Case 1. Cases 2L and 3L require more CO_2 reductions, but they are able to accomplish these reductions with much lower prices than in Case 1. The average CO_2 reduction costs calculated from cumulative reductions and cumulative cost changes amount to over 95 €/tCO_2 in Case 1, below 1.4 €/tCO_2 in Case 2, and around 14 €/tCO_2 in Cases 2L and 3L. The shadow price in 2050 for a ton of CO_2 emitted can be interpreted as the market price for an emission-trading scheme when a specific emission target is defined. Since Case 1 has no specific target, the reduced carbon emissions do not have a value per se. The shadow price in 2050 amounts to some 14 €/tCO_2 in Case 2, almost 68 €/tCO_2 in Case 2L, and a little over 54 €/tCO_2 in Case 3L.

The PROMETHEUS model agrees that Case 1 shows higher costs than either Case 2 or Case 3. however, due to the stochastic nature of the model, there is a non-negligible probability that the cost implied in the alternative cases, is lower than in the baseline. This is mainly due to the fact that the PROMETHEUS baseline implies probabilities that carbon values are eventually sufficiently high so as to make at least some CCS options economically attractive. Since all cases, one way or the other, involve an early or even forced introduction of CCS it happens in some instances that the seemingly uneconomic choice at the early stages results in a more economic generation park in subsequent periods when carbon values are higher.

4.3 Conclusions and recommendations

From a comparison of the policies adopted and results obtained in Cases 1, 2 and 3 between the models investigated (DNE21+, GMM, MESSAGE, PROMETHEUS and ETP), a number of conclusions can be drawn. We here summarize the main findings from this comparison and attempt to formulate some recommendations. Our first and most general observation is that the models investigated produce results that have much in common and are broadly in agreement: they confirm that CCS is likely to play a role in cost-effectively reducing CO_2 emissions. We observed few and only relatively modest differences between the modeling results.

A second overall conclusion, shared by the models, is that a CCS standards policy for fossil-based power generation - however cost-inefficient and inappropriate from other points of view - still might constitute a powerful instrument to substantially reduce CO_2 emissions from the electricity sector. A prerequisite for the implementation of this type of regulatory measure, however, is that CCS technologies are both available and affordable for large-scale application. Therefore, it seems best to gradually adopt such a policy, in order to reduce the associated cost penalty. Most models indicate that the CO_2 reduction under the CCS standards case is mainly achieved after the year 2030, which is due to the inertia in the power sector, because plants built before the introduction of the standards regime are allowed to operate until the end of their lifetime. The amount of CO_2 captured, by the year 2050, ranges from 7-19 $GtCO_2$/yr.

Third, not surprisingly, all models find that among the three main cases studied, the amount of CO_2 emissions reduced through CCS implementation is largest in the CCS standards scenario. Even in this case, however, the cumulative amount of CO_2 captured globally is expected to remain well below the total available storage potential. For example, with the GMM model, the cumulative amount of CO_2 captured globally in the CCS standards case represents about 30% of the total storage potential in depleted oil and gas fields. Storage limitations may only perhaps occur at the regional level, for example because the local storage potential of depleted oil and gas fields is limited. The DNE21+ model finds that, although the amount of CO_2 stored in Case 2 decreases significantly in comparison to that in Case 1, the amount of CO_2 stored in the former is still large, at about 12.5 $GtCO_2$/yr in 2050. Note that for all models the relatively large contribution of power plants with CCS under the CCS standards scenario, and for some models to a lesser extent under the carbon constraint policy, is also influenced by assumptions on the baseline scenario. Typically, the projected energy development in the baseline scenario is largely based on fossil fuels and is especially coal-intensive.

Fourth, when a CCS standards policy is changed to a global emissions constraint instrument that reflects the same emissions reduction scheme across all sectors and options combined, CCS uptake declines significantly, and in some cases even disappears entirely. As pointed by the ETP results, the significant uptake of CCS is subject to assumptions on growth constraints for nuclear energy and limitations and scope for technological learning (in terms of cost reductions) for renewables. Under central values for assumptions on these, when the Case 1 policy is changed to the global emissions constraint Case 2, reflecting e.g. a trading scheme that would yield the same emissions reduction scheme across all sectors and options as in Case 1, then CCS uptake declines by about 25%. With MESSAGE, when no such CCS standards policy is enforced, but an emissions constraint policy is adopted instead, designed such that it leads to a similar emissions reduction path as in the CCS standards case, almost no CCS technologies appear in the solution. It therefore appears that, unless the mitigation target is very ambitious, in the short term CCS technologies remain rather marginal and at best will be a complimentary option in comparison to renewable and nuclear energy technologies. On the other hand, renewable and nuclear energy options are likely to be used significantly, and more evenly over all sectors. Due to the energy system inertia that have been built into MESSAGE, and as a result of the relatively high initial costs of CCS technologies, most of the impact of CCS technologies will anyways be visible only during the second part of the century. Also with GMM, the penetration of

CCS in the electricity sector is highly dependent on the cost assumptions made for competing CO_2-reduction technologies, among which predominantly nuclear and renewable energy sources. Other factors that influence the uptake of CCS in the CO_2 constraint case are the learning rate values for CCS systems and their maximum annual growth rates.

Fifth, and related to the previous point, the introduction of a CCS standards policy is often much more costly than imposing a CO_2 constraint that reaches the same cut in emissions. The reason is that the latter policy allows for the large-scale deployment of nuclear energy and renewables, which in many cases constitute cost-effective competitors to CCS technologies. With the GMM model, the modeling results show that the introduction of a CCS standards policy is two times more costly than imposing a CO_2 constraint that reaches the same emission cuts. In other words, when a more flexible selection of CO_2 abatement options is allowed for, the cost-effectiveness of policies aiming at reaching a given climate or CO_2-emissions reduction goal improves. The most pronounced in this respect is the MESSAGE model, whose analysis of the three cases has shown that, although it is possible to move to a practically carbon-free electricity production in a power-plant CCS standards scenario, this strategy is highly costly. Of course, the total system costs corresponding to these three policy cases, in comparison to the baseline scenario, increase over time, especially after 2030. In particular, for the DNE21+ model, the increase in total discounted system costs between 2000 and 2050 in Case 1, with respect to the baseline scenario, is about € 870 bln. In Case 2 this increase is less pronounced: one observes a decrease in system costs in going from Case 1 to Case 2 of about € 550 bln. This demonstrates that while CCS may be an important option for cost-effectively reducing CO_2 emissions, one should continue considering other CO_2 reduction options and employ mixes between the different options available, also depending on prevailing regional circumstances.

Sixth, imposing a strict standard requirement on one sector alone leads in some cases to moving the carbon intensive fuels to sectors where no such requirements are imposed. This reduces the effectiveness of such a policy in reducing CO_2 carbon emissions. In MESSAGE, for example, it proves that the CCS standards policy is not very efficient, because of the increased use of fossil fuels in other sectors. Also within the electricity sector shifts are observed between different fossil fuels. For example, in the DNE21+ model (that only allows inspecting the emission-reduction effectiveness of the CCS standards policy and the CO_2 constraint policy) it is found that the introduction of CCS standards decreases the consumption of coal, while the consumption of oil and gas increase relative to the baseline scenario.

Seventh, coal-based power plants seem usually the most preferable options to include CCS, rather than gas- or oil-based plants. Of course, the large usage of CCS in the regulatory standards policy Case 1 should not be interpreted as suggesting that (all) fossil-fuelled power plants including CCS technology will be cheaper than most competing CO_2-free electricity supply options. Quite on the contrary, practice proves to be different, as demonstrated by Cases 2 and 3. But as for the type of power generation involved, virtually all CO_2 capture appears to become implemented at coal-fired power plants, and little or no such capture is applied to gas-fired power plants. The reason is the relatively high cost associated with the latter and the affordability of the former. Also with the GMM model, on the global level the majority of CO_2 emissions captured will probably originate from coal-related CCS activities. Outcomes of the GMM modeling exercise suggest that particularly IGCC with CCS, advanced coal with CCS, and in some cases NGCC with CCS belong to the portfolio of technological options that will significantly contribute to curbing CO_2 emissions and thus mitigating climate change.

Eighth, the three models (all except DNE21+) capable of investigating subsidies as applied in Case 3 agree that subsidies given to CCS technologies improve their competitiveness only marginally. Therefore, these investment subsidies increase the total use of CCS only remotely, especially in the short term. In particular, the ETP study demonstrates that a subsidy covering up to 35% of the CCS equipment costs does not significantly change the modelling results. Still, as reported by the Message modeling exercise, CCS investment subsidies can have a strong effect on which particular CCS technology enters the energy market first.

Ninth, while not all models report explicit results on regional CCS particularities, there does not seem to exist disagreement in terms of the differences that may exist in the amounts of CCS applied and the types of storage mediums adopted. For example, the ETP exercise indicates that the results for Europe are more or less the same as for the world at large, in terms of quantities captured at least, with up to 1 $GtCO_2$/yr capture and storage in 2050.[6] Still, the method of CO_2 storage applied may vary significantly among the different regions modeled. The DNE21+ model, for example, reports that in the EU CO_2 storage into aquifers seems by far to become the most important option in the longer run. The GMM model in particular reports on region-related aspects of CCS: issues concerning regional availability and distribution of storage sites, related arguments concerning transport of CO_2 and associated costs, as well as leakage rates need to be further evaluated in order to gain full insight into the practical future role of CCS in overall CO_2-abatement efforts. Also, competitiveness of different CCS systems is likely to be very region-specific.

6 For more detailed results, sensitivities, capacities and regional results see IEA, 2004.

5. Europe and the US

5.1 POLES

5.1.1 Introduction

During 2004-2005 the POLES model has undergone significant changes. The model development included the following improvements:

- Further improvement of the geographical resolution from 38 to 47 regions.
- Extension of the time horizon from 2030 to 2050.
- Introduction of a detailed carbon capture and storage module.
- Introduction of a H_2 production module with 10 production technologies.
- Fully detailed personal road transport module with 11 car categories and 3 user types.

At the same time the model data base and model structure were also revised and as a result a new POLES version was created. Some of the changes were necessary for modelling work in the Cascade-Mints (CM) project, as the present scenario definitions require a detailed modelling of carbon sequestration and capture. For the CM project the application of the new model version has the advantage of more detailed reporting on sequestration and capture, H_2 production and use and the extended reporting period. There is, however a main drawback, namely that the reference scenario has been changed[7], due to the revised and updated datasets and model equations. In comparison with the earlier baseline the most important changes could be located in the fossil fuel markets, where the natural gas and oil markets face more dynamic price increases than earlier. Additionally, the power sector reaches a higher nuclear share by 2030 compared to the previous reference run. The dynamic growth of nuclear share further increases by 2050, mainly due to a quicker penetration of a new nuclear design technology available from 2030.

Case study setup

Case 1: CCS Standards

According to the scenario definition all new fossil fuel based power plants have to be equipped with capture facilities; in the industrialized countries starting from 2015, and 10 years later in the developing regions. In order to achieve a smooth shift in the model, a four year transitory period was granted for the regions to fulfil this obligation. Additionally, due to the load duration modelling in POLES, the criterion of 2190 hours of utilisation (25% utilisation rate) was used as a criterion for the peak load plants, which are exempted from the 'all capture' rule.

Case 2: CO_2 constraint

The global emission level from Case 1 is used as an upper bound for GHG emissions, without any other policy applied.

Case 3: Subsidies

The 35% investment subsidy with a decreasing trend over the time is employed to the technologies concerned.
No additional R&D policy is applied.

[7] Compared to the baseline used in previous case studies of the Cascade-Mints project.

Capture technologies in POLES

Because of the intensity of carbon dioxide emissions and capture performance, power and hydrogen production plants are potential sites for capture installations. The respective technologies are the following:

Power generation:
PSS - pressurised coal supercritical with capture
CGS - integrated coal gasification with combined cycle with capture
GGS - gas-powered gas turbine in combined cycle with capture.

Hydrogen production:
GSS - hydrogen from gas steam reforming with capture
CPS - hydrogen from coal partial oxidation with capture.

Each technology is assumed to be equipped with appropriate capture installation, and their costs are assigned to technology costs. Transport and storage are separated from capture.
Other sectors do not involve sequestration.

Storage potentials

The model considers both geological and ocean storage. The following types of geological reservoirs were considered: empty natural gas and oil fields, enhanced oil recovery (EOR), enhanced coal bed methane recovery (ECBM), and aquifers; some considered on- and off-shore. The potential as well as costs of transport and storage for underground reservoirs have been estimated for seventeen regions (Hendriks et al., 2004). These were mapped to the 47 POLES regions assuming that the potential is uniformly distributed across primal regions, and could be split proportionally to the surface. The basis for estimating the storage potential was the total volume of reservoirs, so that the curves are static, estimating the overall capacity. In total, terrestrial and offshore storage potential of geological formations is estimated up to 6000 Gt of CO_2 (Hendriks et al., 2004)[8].

The amount of inorganic carbon dissolved in ocean waters is estimated at 38,000 Gt, while terrestrial biosphere and atmosphere contain about 2950 Gt (IEA GHG R&D Programme, 1999). The ocean has therefore a nearly unlimited storage potential, comparing amount carbon in global recoverable fossil fuels reserves. Storage technologies, however yet not proven at commercial scale, are quite simple and should not hold ocean storage employment. Though there are uncertainties related to environmental impact on ocean biota and presently this mode is practically not accepted as a viable one. For this reason POLES makes it available after 2015.

All amount of captured carbon dioxide is 'transported' (with 2% losses) and 'stored'. The costs are the criteria for the selection of the storage mode. Firstly, the lowest costs sink (practically geological storage) is used, up to the saturation of its capacity. In rare cases of small countries the capacity limit is reached and CO_2 is stored in the other (ocean) reservoir. In the latter case there is no relation to the region, all countries, including those not having shore, could apply this mode. Carbon dioxide transport, even for long distances is considered as viable.

Cost data

For geological storage costs depend on type of sink and its depth (Table 5.1).

[8] Hendriks et al., 2004, give a range of 476 - 5880Gt. IEA (1999) estimates even a potential of up to 10,000 Gt of CO_2.

Table 5.1 *Storage costs by depth*

[€/tCO$_2$]	Depth of storage (m)		
	1000	2000	3000
Aquifers onshore	1.8	2.7	5.9
Aquifers offshore	4.5	7.3	11.4
Natural gas fields onshore	1.1	1.6	3.6
Natural gas fields offshore	3.6	5.7	7.7
Empty oil field onshore	1.1	1.6	3.6
Empty oil field offshore	3.6	5.7	7.7
	Low	Medium	High
EOR onshore	-10	0	10
EOR offshore	-10	3	20
ECBM	0	10	30

Source: Hendriks et al., 2004.

Costs of transport were estimated based on distances between potential sources and sinks within the region, and vary from 1 €/tCO$_2$ (<50 km) to 30 €/tCO$_2$ (>2000 km) (Hendriks et al*.*, 2004).

All costs merged with estimated storage potential of reservoirs in the region form transport and storage costs curves. Each region has its curve, estimating storage potential at a given cost, or transport and storing costs for a given amount of carbon dioxide stored. It is similar to the one representing marginal abatement costs. For example the curve for the Russia (Figure 5.1), the country of one of the largest potential years of store, shows that the costs are up to 40 €/tCO$_2$ and potential of 277 Gton CO$_2$.

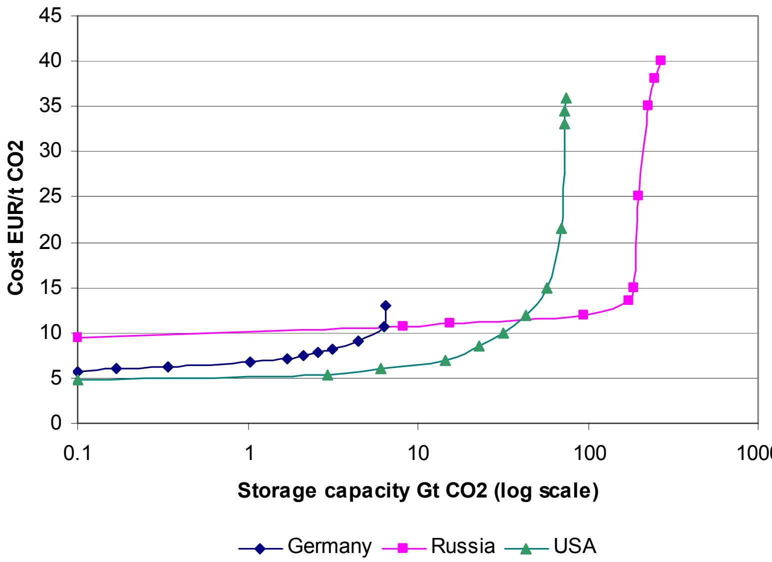


Figure 5.1 *Examples of transport and storage costs curves*

For the ocean storage, costs of CO$_2$ transport to the shore and then discharge to the deep oceans have been assumed at 50 €/tCO$_2$ regardless of the technology. This is relatively high cost, but given mentioned uncertainties, it is considered as 'last resort', in case of failure of other measures of carbon emissions reduction.

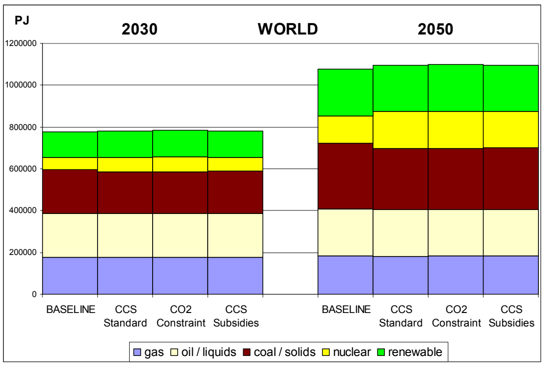
In both cases: geological and ocean storage, the data do not provide diversification of costs elements, and the numbers could be considered as annualized costs.

5.1.2 Results

In the presentation the results of the WORD and the WEUR regions of POLES are used, as they give the closest comparative basis with the other CM models (global and European). In POLES the WEUR region includes the present EU-25, Romania, Bulgaria, Turkey and the Rest of Europe region (Switzerland, Norway, Iceland, and the former Yugoslav countries).

5.1.2.1 Primary energy

Concerning the primary energy consumption the changes induced by the scenarios are rather minor. Coal use considerably reduces, while energy consumption from nuclear and renewable resources increases. The most significant changes take place in the nuclear share, mainly after 2030. This is due to the availability of new nuclear design technology, which assumes smaller environmental cost burden on the technology compared to the conventional one. Interestingly, there is a slight increase in primary energy consumption in the three scenarios, which could be attributed to the increase of the energy demand from the sectors other than power generation. Although the scenario definitions place the burden mainly on the power sector, the changes induced (less demand for oil and natural gas and slight price cuts for these fuels) impact also other sectors which could gain a somewhat higher market shares in energy consumption. These trends are valid for both the WORD and WEUR regions, but in the latter one the changes are more apparent.



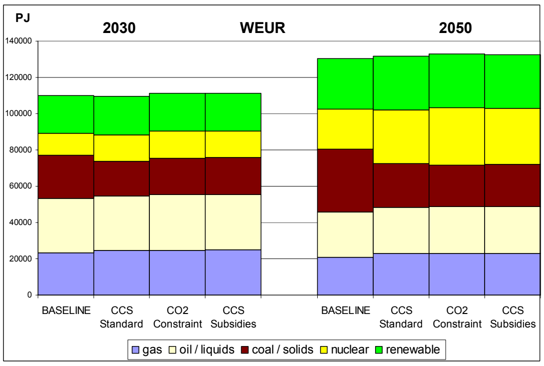


Figure 5.2 *Primary energy consumption in 2030 and 2050 in the WORD and WEUR regions*

Figure 5.2 indicates that the policy cases are almost identical, suggesting that the CCS standard and the carbon constraint are the determining factors, while the subsidy has rather minor impact on the energy consumption. The match between Case 2 and 3 shows, that the subsidy has rather negligible additional impact.

The share of the nuclear energy in the portfolio significantly increases in both regions. It indicates, that when the coal based energy sources are penalised - either by a carbon value, or by technological standards - the nuclear technologies could gain higher shares. The other sources are limited either by the availability of fuel resources (natural gas, oil), or by reaching the long-term economic potential[9] in case of renewable resources.

5.1.2.2 Electricity production

The changes implied by the technology standard and by the subsidy (Case 1 and 3) have their impact concentrated on the power sector, thus the most significant changes are expected here. The carbon constraint case has a high impact on the power sector, as well as on the other sectors.

[9] The economic potential and technical potential are different in POLES. Economic potential gives the economically attainable share of the renewables with the given cost structure and performance, while the technical potential is the maximum saturation level. The earlier one is continuously (and in an endogenously determined way) approaches the latter level.

It has to be noted that POLES projects a high share (48% at world level) of renewable and nuclear sources in the electricity generation mix already in the baseline. At the same time, as renewable sources approach their economic potential (which is lower than the technical potential), it could be expected that the changes will be rather limited to the shifts between conventional coal and gas electricity generation to the capture technologies. However, the changes are not limited to these 'shifts' - which take place in the gas and coal based electricity generation - but there is also a significant expansion in nuclear generation.

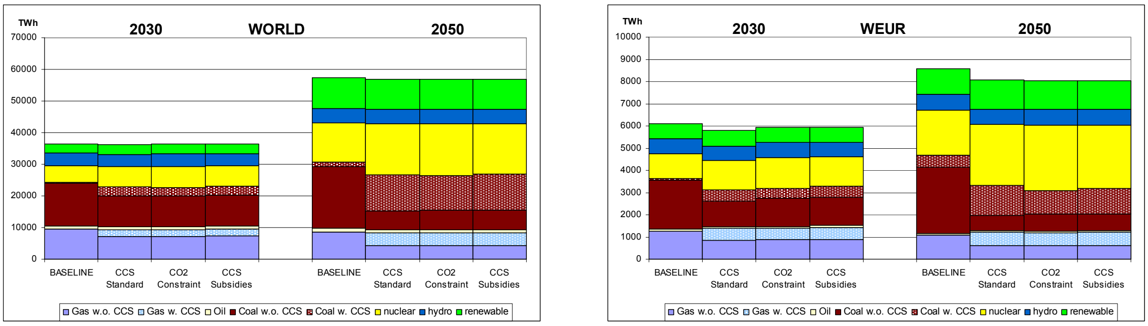


Figure 5.3 *Electricity generation mix*

Figure 5.3 illustrates carbon capture technologies that take off after 2030. The main reason for this delayed effect is the timing of the Case 1, as for most of the world regions the changes start as late as 2025. The effect is further delayed by four year in POLES to enable smooth transition period. On the world level of electricity generation hardly changes, while the effects in Europe are more significant. Here not only the coal based generation, but also the overall level of electricity generation goes down. Again, nuclear has significantly higher share in the policy cases, which are almost identical. Interestingly, the subsidy (which diminishes by 2050) has no real impact on the technology share with capture; it reaches similar level as in the carbon constrain case. This shows that the subsidy has a rather short-lived impact on the electricity generation, carbon capture contracts with the diminishing subsidy. Additionally, the carbon based generation capacities face significant decline, further reducing the number of available 'suitable' sites for carbon capturing installations. Thus, it might indicate that this policy is not the most efficient way to achieve carbon emission targets.

Concerning the capture technologies, their share for coal-generated electricity is more than 2/3, while in the case of natural gas this share is around 50% in 2050. This indicates that even in Case 1, sizeable capacities without capture technologies remain in the system till 2050. They are either the peak load capacities (mainly gas fired ones) which explains the smaller share of carbon capture in the gas fired units, or some remaining coal capacities close to the end of their lifetime.[10]

5.1.2.3 CO_2 emissions

The policy cases - where the emissions are limited to the emissions of Case 1 - have significant impacts on the carbon emissions both at World and European levels. By 2050 carbon emissions are reduced by 20% at world level, and more than 25% at European level. However these figures are based on the net emissions, on gross emissions level (net emissions + sequestration) the reductions are much smaller (4% and 14% accordingly).

[10] Additionally, Turkey and the rest of Central Europe regions overtake the obligation to install capture equipment later.

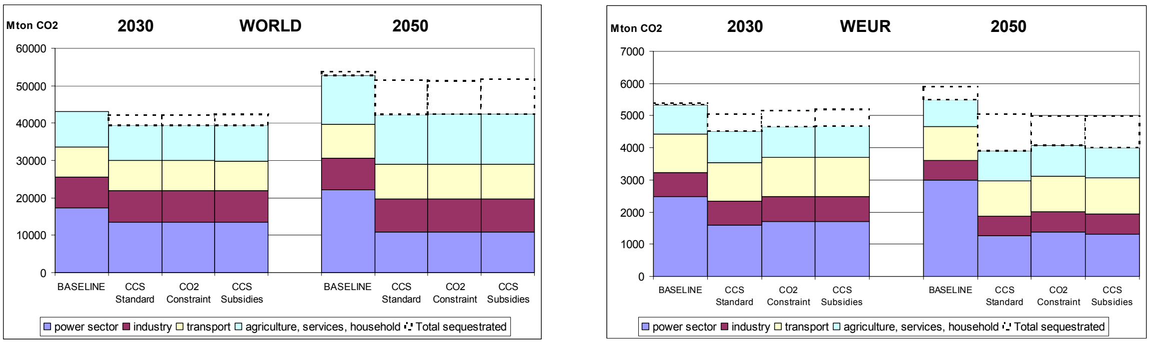


Figure 5.4 *Gross and net CO_2 emissions in Word and WEUR regions*

Figure 5.11 illustrates that high share of carbon emission reduction is reached through sequestration options. This is almost exclusively true at world level (except for the 4% net reduction), while in Europe other factors (reduced energy consumption, efficiency improvement, fuel change) play considerable role. The reduction is mainly achieved in the power sector, not only in Case 1 (CCS standard), but also in the carbon constraint case. The other sectors, mainly transport and services even increase their emissions to some extent. As the decreasing demand of the power sector slightly reduces oil and gas prices the transport sector and services could increase their activities compared to the baseline, and the emissions in these sectors rise accordingly. It must be noted however, that this 'reverse' effect is not very significant.

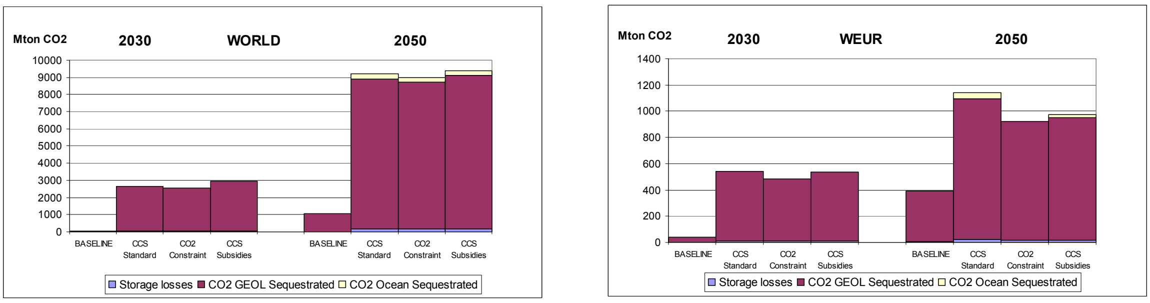


Figure 5.5 *Carbon capture and storage*

As Figure 5.5 shows that most of the carbon sequestration takes place in geological formations, ocean storage is negligible. According to the literature the storage potential is far from depletion. Even in Case 1, the cumulated geological capture is around 130 Gt compared to the estimated potential of 476-10,000 Gt. In this case ocean storage occurs only in countries of low geological storage potential (Belgium/Luxemburg, Netherlands, Japan, South Korea).

It is interesting to note, that at world level the policy cases lead to similar capture and sequestration level. However, by regional level there are significant differences among the cases, indicating that this is only a coincidence. The figure illustrates the extra impact of the subsidy, compared to the carbon constraint case, its effect is rather minor. It must be emphasised, that there is no learning (or other R&D effect) modelled in POLES in this respect.

Concerning the security of energy supply indicators there are no significant differences amongst the scenarios compared to the reference case in the WEUR region. The existing variations are caused by the different level of nuclear generation penetration. As in the model there is no information about the origin of the nuclear fuel, it is fully accounted as import. Therefore the index does not give a perfect comparison between the different regions, but it gives reliable information on the trend of the security of supply indicators within regions.

5.1.3 Conclusions

The design of the scenarios makes it difficult to analyse the cost-effectiveness of the different scenarios with an (partial-equilibrium) energy model. Case 1 and 2 lead to the same carbon emission level and additionally they produce the same level of carbon capture and sequestration. Therefore, in principle the efficiency of the different policies could be compared based on cost of unit carbon emission reduction. But the regional differences show that the similarities between Case 1 and 2 are a mere coincidence, it is not possible to draw solid conclusions in this respect for Europe.

The results in Case 3 indicate that a subsidy policy reaches similar emission (and sequestration) level as the carbon constraint case, indicating that it could lead to rather temporary achievements, thus the efficiency of this policy - if applied alone - is questionable.

An important insight provided by the case study is the significant role of the nuclear electricity generation in the future energy mix. If the fossil fuel based electricity generation is penalised by a certain policy - either by a CCS standard or by a carbon constraint - an obvious response (at least in the model) is the increasing competitiveness of the nuclear capacities. As many of the renewable energy resources approach their economic potential by the end of the modelling period, the electricity system responds in two distinct - though interconnected - channels. There is not only a shift between conventional fossil fuel based power plants and installations with carbon capture, but also nuclear power gains a considerably higher share. This conclusion, however, should be considered with reservation, as an indispensable assumption behind this development is the availability of the new nuclear design technology, characterised by an improved safety characteristics as compared to the conventional nuclear plants.

5.2 MARKAL Western Europe

5.2.1 Introduction

This case study focuses on the potential contribution of carbon capture and storage to CO_2 emission reduction. For this the following three related policy cases are implemented.

Case 1: CCS standards
From 2015 all new power plants have to be equipped with a capture facility. These standards are not applied to peaking plants with a utilisation rate of 20% and small CHP-plants. For the MARKAL-WEU model it was decided that the criterion of 20% should be increased to 25%, since the peaking plants in the model have a 25% utilisation rate. Moreover, MARKAL does not use unit size for technologies, so the exclusion from the standard was made for all industrial CHP-plants producing high temperature process steam. Forced phase out of CHP-plants without CCS could have large consequences for the industry, and is not likely to be acceptable to industry.

Case 2: CO_2 constraint
In the second case the global emission level from the standards case is taken as an upper bound for the overall emissions. No other policies are assumed.

Case 3: Subsidies
The same emission path as in Case 2 is used. Moreover, a subsidy on CO_2 capture technologies is given. This subsidy is 35% of the investment cost by its introduction in 2015 and will be reduced by one percent each year. In the MARKAL WEU implementing this subsidy is not that easy due to the way the capture technologies are modelled. How exactly the over time declining subsidy is modelled will be explained further on in this section.

CCS Technologies
In the MARKAL WEU model CO_2 capture is applied mainly in the power sector, but also some industrial technologies are equipped with CCS. Six types of reservoirs to store the captured CO_2 are available in the model.

CO_2 capture in industry occurs in processes such as cement clinkers, cokes and ammonia production. Also CO_2 is captured in two hydrogen production processes. In all these applications CO_2 occurs as a process stream of almost pure carbon dioxide for which no special filter techniques are needed. Therefore, the CO_2 capture equipment is not modelled a separate technology. Since the subsidy in Case 3 is restricted to capture technologies in the power sector, this is no problem.

In the power sector CO_2 can be captured before the input fuel is combusted (pre-combustion) or the CO_2 can be removed from the flue gas (post-combustion). Two types of post-combustion can be distinguished: flue gas coal and flue gas gas. A capture equipment is modelled as separate key-technology (key-component) that is used by several power plants. So is the flue gas coal capture equipment used in six types of power plants, the input gas coal- and the flue gas gas-equipment are both used in eight types of power plants. Moreover, the three components are endogenously learning. This means that the model decides itself how much each technology contributes to the capacity built-up of a component and consequently how fast the cost of the key-component decline, and by this how fast the cost of all technologies sharing this key-component decline.

Table 5.2 gives an overview of the characteristics of the key-components for CO_2 capture.

Table 5.2 *Characteristics of CO_2 capture technologies*

		Flue gas coal	Input gas coal	Flue gas gas
Annual growth factor	[%]	10	10	10
Discount rate	[%]	8	8	8
Initial cumulative capacity	[GW]	10	10	10
Initial investment cost	[€/kW]	817	430	595
Progress ratio	[%]	90	90	90
Lifetime	[yr]	30	30	30
Start year	[yr]	2020	2020	2020

A maximal growth factor of 10% per year is assumed on all three key-technologies.

Storage options

For the storage of CO_2 the model has the following reservoirs to its disposal: aquifers, depleted gas and oil fields, enhanced coal-bed methane recovery (ECBM) and enhanced oil recovery (EOR). The storage potential as well as the costs data of each option is given in Table 5.3.

Table 5.3 *Characteristics of CO_2 storage options*

	Potential [Mton CO_2]	Investment costs [€/tCO_2 stored]	Fixed O&M costs [€/tCO_2 stored]	Variable O&M costs [€/tCO_2 stored]	Energy recovery rate [GJ/tCO_2]
Aquifers	250,000	10.00	0.375	0.30	
Depleted gas fields	3,000	7.50	0.350	1.35	
Depleted oil fields	1,500	7.50	0.250	1.35	
ECBM	15,000	7.50	0.250	12.50	9
ECBM deep	15,000	12.50	0.500	12.50	5
EOR	17,000	13.33	0.170	0.90	2.22

To put the CO_2 into a reservoir, CO_2 injection technology is used. Table 5.4 shows the characteristics of this an endogenously learning key-component that is used in all six storage options.

Table 5.4 *Data on CO_2 injection*

		CO_2 injection
Discount rate	[%]	8
Initial cumulative capacity	[GW]	100
Initial investment cost	[€/kW]	7.5
Progress ratio	[%]	90
Lifetime	[yr]	20
Start year	[yr]	2020

Subsidising

Since each CO_2 capture option is modelled as a learning component, just the initial cost is given. Because the model itself decides how much capacity of each technology will be used, the model endogenously determines the cost curve and one cannot give a subsidy as a percentage of the investment cost each year on forehand. A 35% decrease of the initial investment costs would lead to a specific cost curve that is 35% lower than the initial one, at least as a function of the cumulative capacity. The specific cost (SC) as a function of the cumulative capacity (CC) are given by:

SC(CC) = SC0 * (CC/CC0)^(-b),

where

SC0 = initial investment cost,
CC0 = initial cumulative capacity,
b = -ln(PR)/ln(2).

Where PR$\in$[0,1] is the progress ratio. Note that: SC(2*CC) = PR*SC(CC). So by each doubling of the cumulative capacity the investment costs decline by the progress ratio.

To implement a subsidy of 35% in 2015 such that the subsidy relatively decreases after 2015, the initial investment cost are artificially lowered by increasing the initial cumulative capacity by a dummy technology. The extra cumulative capacity can be seen as a large number of extra prototypes for which a lot of extra research and development cost should be made.

By increasing the initial cumulative capacity to say CC0'=CC0+dCC, the new initial investment cost are 'further' on the cost curve. Here dCC>0 is the fixed capacity of the dummy and dCC is chosen such that SC0' = SC(CC0') = SC(CC0+dCC) = 0.65 * SC0. So, the investors see lower cost by which the technology can be more favourable. On the other hand, since the cumulative capacity is higher it takes longer for a doubling of the cumulative capacity and so the cost decline per new unit installed will be smaller, consequently the SC(CC) and SC(CC+dCC) will converge for increasing CC. So the 35% subsidy given in the begin will decreases relatively after 2015 by increasing capacity. How fast the new specific cost curve will converge to the cost curve of the Baseline over the years is of course unsure, since it is still the model that decides how the capacity is built up.

5.2.2 Results

5.2.2.1 Primary energy

Generally the primary energy consumption in the CCS cases does not show large shifts with respect to the Baseline. Most interesting are the decrease of coal consumption compared to its Baseline value in 2030 in the CO_2 constraint, and the increase of nuclear energy in 2050 when applying the CCS standards, see Figure 5.6. The other resources do not differ much among the three policy cases. Below the differences of the three cases with respect to the Baseline are described in more detail.

Case 1 leads to a 3% increase of the total primary energy consumption in 2030. This increase is mainly due to a higher consumption of gas and more electricity from wind. 60% of the increased gas consumption is caused by a higher demand for gas in the power sector. The coal consumption is almost the same as in the Baseline.

Applying the CO_2 emission level from the standards case as an upper bound causes a decrease of the coal consumption with respect to the Baseline in Case 2. Also energy from hydro plants decreases in Case 2 with respect to the Baseline. The decrease of coal and hydropower leads to a decrease of the total primary energy despite the increased contribution of other resources.

In Case 3 the emission cap does not show large changes on the use of coal compared to the Baseline, but more power plants are equipped with a CO_2 capture unit.

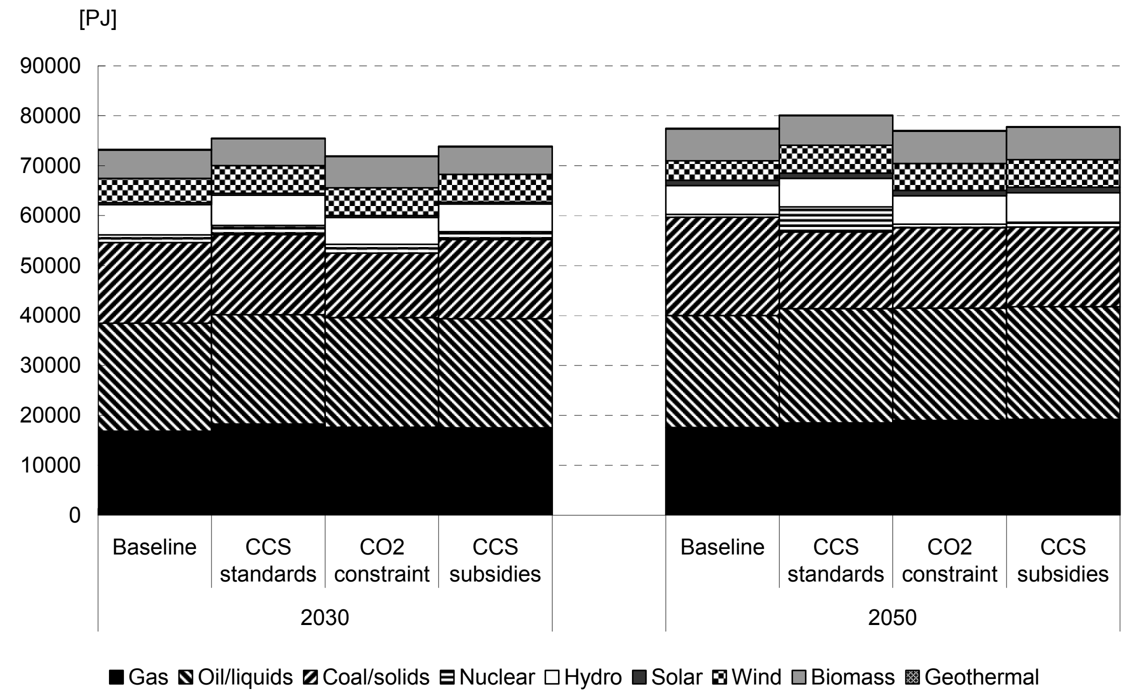


Figure 5.6 *Primary energy consumption in 2030 and 2050*

By 2050 the use of coal has decreased in all policy scenarios. In Case 1 the use of nuclear energy and wind power, as well as the consumption of gas increase that much that the total primary energy is higher than in the Baseline.

The fact that Case 2 and Case 3 are almost the same in 2050 means that subsidising CO_2 capture-technologies has no lasting impact on the primary energy consumption. A decrease in coal consumption in both cases, compared to the Baseline, is compensated mainly by gas and wind energy.

Whereas wind decreases after 2030 in the Baseline, the energy produced from wind is constant after 2030 in the three CCS cases.

5.2.2.2 Electricity production

Obviously the impacts of the different policies are more visible in the power sector. Moreover, the power sector is interesting since besides the differences in fuel used also a difference in electricity from plants with and without capture can be made, see Figure 5.7.

Notable is that even in the Baseline CO_2 capture from coal fired power plants occurs in 2030 and increases in time. Since in the Baseline already coal plants with CCS are active it was to be expected that by excluding new plants without CO_2 capture their share would grow in Case 1. Interesting to see is that in 2030 also gas fired power plants are equipped with a post combustion capture facility. The captured CO_2 is stored in unminable coal seams from which methane can be recovered (enhanced coal bed methane recovery, ECBM). This cheap gas supply makes it profitable to use gas-powered plants with CCS. However, in the course of time the increasing demand of gas and the exhaustion of these coal mines make that investments in new gas plants with CO_2 capture do not take place.

The high costs for these plants make that in the other two scenarios no gas fuelled plants with CCS are built at all.

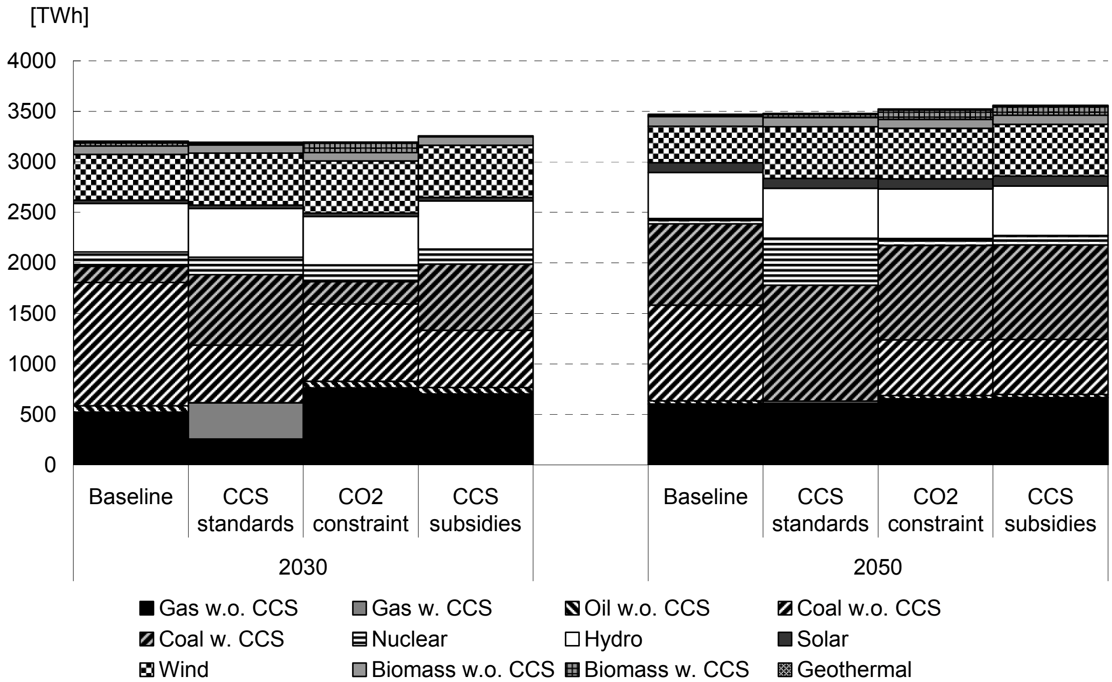


Figure 5.7 *Electricity generation mix*

Applying the CO_2 cap in Case 2 leads to a decrease of electricity production from coal plants without CCS. The total electricity produced remains the same due to an increase of electricity from gas plants and biomass and coal plants with CO_2 capture. The decrease of coal for power production is responsible for half of the decrease of the total coal consumption.

Stimulating carbon capture by a subsidy is effective in its introduction phase. In 2030 a lot of coal power plants with CCS are installed in Case 3, almost as many as in Case 1.

In 2050 the differences between the three policy cases are not that large as in 2030. Like in the primary energy consumption, the electricity mix in Cases 2 and 3 are almost the same.

Most interesting are the results of Case 1. By excluding the CHP plants for industrial steam production from the standards, as mentioned in the case set up, electricity from gas plants without CCS still exists and is even a little higher than in the Baseline. This means that the market seeks solutions to get around the stringent standards. Another remarkable observation is the increase of electricity from nuclear power plants. Nuclear power seams to be another cheap alternative for coal-powered plants and has a share of 15% of the total electricity production in 2050. One of the reasons is that the competitive onshore wind technology has reached its potential of 200GW.

5.2.2.3 CO_2 emissions

Figure 5.8 gives an overview of the sector contributions to the net emissions. As a consequence of the standards the total net CO_2 emissions decrease with 11%. However, the gross emissions in 2030 of Case1 are 65 Mton higher than in the Baseline. From the difference in captured CO_2 between Case 1 and Case 2 it can be concluded, that is more cost effective to avoid CO_2 emissions rather than to capture and store the CO_2.

In 2050 the amount of CO_2 captured and stored roughly is the same in all scenarios. Noticeable is that in 2050 the industrial CO_2 emissions of the Case 1 are lower than in the Baseline, see Table 5.5. This is mainly due to the substitution of low temperature heat for small industries from coal boilers to heat from CHP plants. These CHPs are the ones that are excluded from the standards. Their emissions are counted to the power sector.

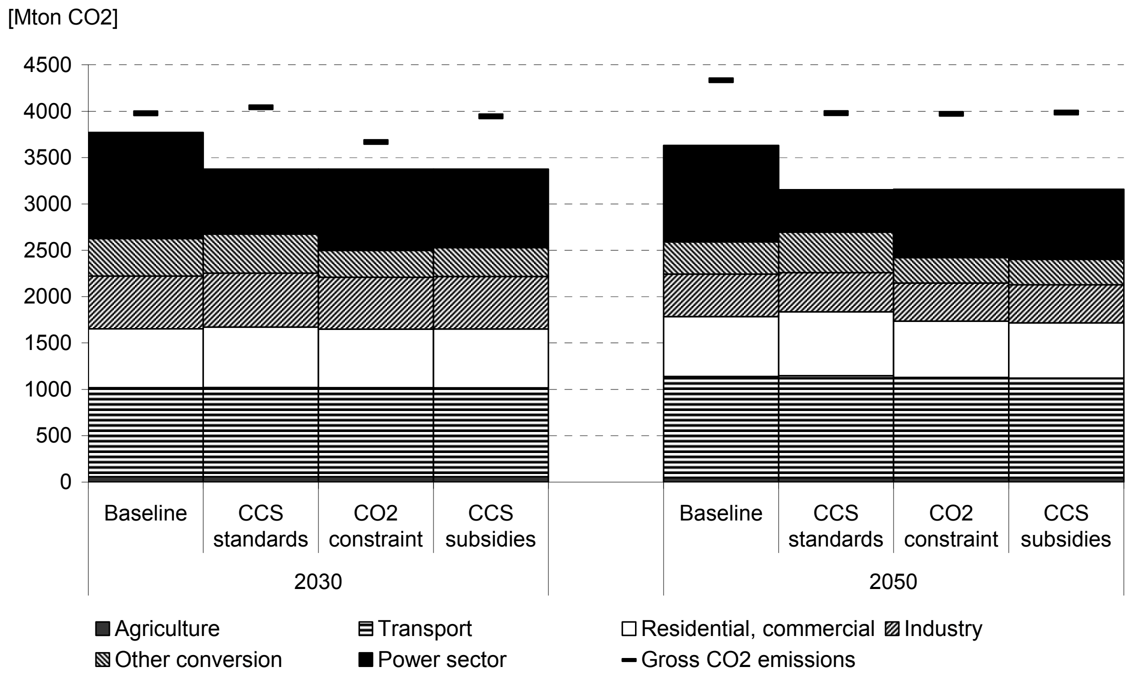
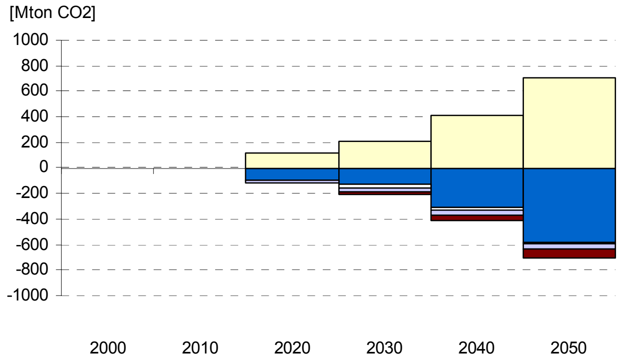


Figure 5.8 *Gross and net CO_2 emissions over sectors in 2030 and 2050 in Mton CO_2*

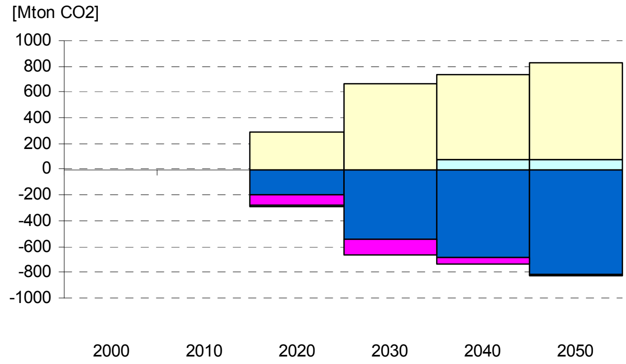
Table 5.5 *Differences in CO_2 emissions with respect to the Baseline*

[Mton CO_2]	2030			2050		
	CCS standards	CO_2 constraint	CCS subsidies	CCS standards	CO_2 constraint	CCS subsidies
Power sector	-444	-267	-298	-583	-303	-285
Other conversion	19	-113	-90	90	-72	-73
Industry	13	-9	-4	-38	-50	-49
Residential, commercial	14	-6	-1	43	-37	-51
Transport sector	3	0	-2	10	-10	-16
Agriculture	0	0	0	0	0	0

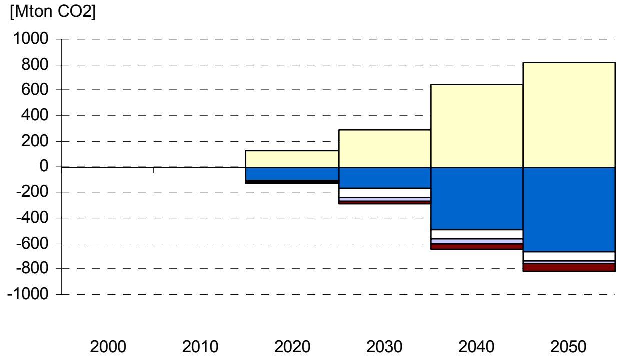
Another remarkable thing is that in Case 1 the forced capture of CO_2 in the power sector has negative effects on the capture in other sectors. In the standards case the capture in industry is very limited, whereas no CO_2 is captured at all in synthetic fuels production, see figure below.



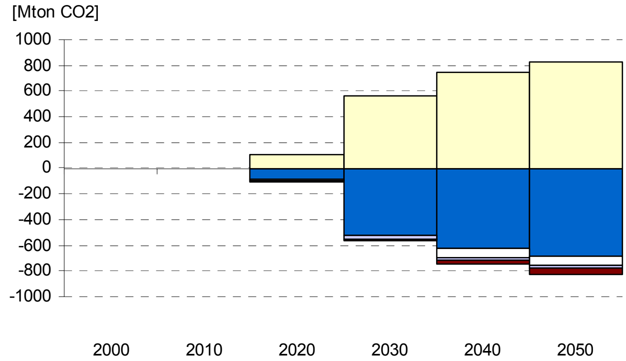
(a) Baseline



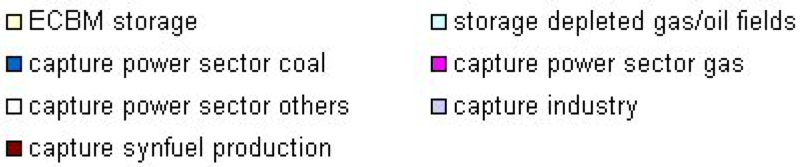
(b) CCS standards



(c) CO_2 constraint



(d) CCS subsidies



[lp1]

In this figure it becomes again visible that applying a CO_2 cap already induces an increase of the capture capacity and the subsidy on CCS in Case 3 is almost effective as excluding power plants without CO_2 capture in Case 1. Moreover, the capture is distributed over more sectors in Cases 2 and 3, because the choice of sectors is not restricted to the power sector but left to the model. CO_2 capture at biomass plants is the main source of 'Capture power sector others'.

As already mentioned in the section on the electricity mix, post-combustion of CO_2 emissions in the flue gas from gas power plants occurs only from 2020-2040 in the standards case. The contribution of post- and pre-combustion CO_2 capture from coal power plants differs among the scenarios. In the Baseline and in Case 2 CO_2 is captured mainly before combustion. In the standards case (Case 1) post-combustion capture in the beginning is the dominating option, while the preference gradually shifts to pre-combustion capture on coal fired power plants and plants with co-firing of biomass. Contrarily, CO_2 is captured almost exclusively from the flue gas in Case 3. The explanation for this is that the subsidy favours expensive but more efficient technologies. Due to the steady growth of pre-combustion capture technologies in the Baseline and the Cases 1 and 2, the costs of pre-combustion CO_2 capture from coal power plants are in 2050 almost as high as in the subsidies case.

Besides information where CO_2 is captured the above figure gives information on how the captured CO_2 is stored. In all scenarios this is mainly in enhanced coal bed with methane recovery (ECBM). Due to the combination of limited capacity of ECBM and high utilization of capture technologies, CO_2 is also stored in depleted gas and oil fields in the standards case.

5.2.3 Consequences

Some indication of the costs of the different policy options is given by a comparison of the total discounted system costs. As can be expected, the cheapest option proves to be Case 2, where it is left to the market to find the most cost-effective way of reducing CO_2 emissions. Not only is this the cheapest way in which the target can be met, but due to reduced expenditures on CO_2 taxes the overall costs do not differ much from the Baseline costs. The standards case turns out to rank as an intermediate policy in terms of costs, as the total system costs are higher than in Case 2, yet lower than in Case 3. The latter ranks as most expensive policy, due to the necessity of large investments in the 2020-decade. The investments, which can be viewed as R&D spending necessary to achieve the costs reductions of the technologies, are high in absolute terms, but also fall in relatively an early period in the time horizon. Hence, these weigh heavier in the discounted costs than expenditures in the other cases, which tend to arise in later periods. However, as the costs are related to RD&D expenditures, and these are generally carried to a large extent by government, this case could be less expensive for industry than the standards case.

Since in each period the CO_2 emission reduction is the same in all three CCS cases, the cost per reduced Mton CO_2 are lowest in the CO_2 constraint case, much higher in the standards case and highest in the subsidies case.

Concerning the security of supply indicators no large shifts with respect to the Baseline can be reported. Due to the increase of nuclear power in the standards, the Shannon diversity index is a few percents higher at the end of the sight period than in the Baseline and the other two CCS cases.

Most interesting is the share of gas import in the total natural gas consumption. The import fraction of gas is strongly related to the utilization of CCS technologies by the recovery of natural gas from CO_2 storage through ECBM. The higher levels of CO_2 capture and storage in 2030, especially in Cases 1 and 3, leads to a decrease of the share gas import/gross gas consumption from 60% to 40%. Thus, CCS may cause an enduring prevalence of domestic gas over imports for some time. By 2050 methane recovery from coal beds gets exhausted in the three policy cases, whereas ECBM has not reached its potential in the Baseline. In the long run, the early deployment of CCS technologies and the increased reliance on gas therefore will lead to an increased import share.

5.2.4 Conclusions and recommendations

- The obligation of carbon capture equipments on new power plants leads to a decrease of 11% of the total CO_2 emissions.
- The standards stimulate a relatively high use of industrial CHP's, as a consequence of excluding these from the standard. Also nuclear power increases under the standards policy.
- A calculation using the emissions from the standards case as a cap (Case 2, CO_2 constraint) shows that particularly in the period 2020-2030 capturing and storing CO_2 is not the most cost-effective way of reducing CO_2 emissions.
- Subsidising CO_2 capture technologies is most effective in stimulating application of CCS technologies on a short time. The subsidy leads to almost the same amount CO_2 capture as in Case 1. The CCS subsidies case is the most expensive case of this study.

In 2050 the annual amount of CO_2 captured is almost the same in all scenarios.

5.3 TIMES_EE

5.3.1 Introduction

In the long-term perspective and under extensive GHG emission targets CCS might play a major role in the energy system of the EU. Therefore it is necessary that the R&D programs in the power plant sector will be continued and the technology feasibility and practicability will be demonstrated in different demonstration projects. Based on the assumption that the R&D programs will be successful, the important types of different fossil power plants and combined heat plants with sequestration technology are included in the TIMES EE model.

Table 5.6 shows an overview of the input data of the power plants with CCS possibility for the year 2015.

Table 5.6 *Technical and economical data of different fossil power plants with CO_2 Capture (in 2015)*

	Unit	IGCC with CO_2 capture	IGCC with CO_2 capture	CC with CO_2 capture	CC with an extraction condensing turbine and CO_2 capture
		Hard coal	Lignite	Gas	
Electrical capacity	[MW_e]	425	425	450	200
Net thermal efficiency	[%]	45	43	54	50
Specific capital investment costs	[€/kW]	1500	1500	625	1070
Specific decommissioning costs	[€/kW]	58.5	55	15.8	15.8
Specific fixed O&M costs	[€/kW/yr]	68.9	65	52.5	60
Specific variable operating costs without fuel costs	[€/MWh]	3.8	3.6	1.7	1.7

The listed fossil fuel-fired power plants are all designed to fulfill environmental protection standards. For coal-fired power plants with CO_2 capture a degree of segregation of 88% is taken into account.

The CO_2 capture potentials within the European countries vary significantly. Table 5.7 shows the used values for Denmark, Germany, Greece, the Netherlands, Norway and UK based on the results of the GESTCO project (Gesteco, 2004). In total there is a European CO_2 storage potential of approximately 826 GT CO_2 assumed in TIMES EE (see Table 5.8).

Table 5.7 *CO_2 storage potential in different countries*

	Oil Fields [Mt CO_2]	Gas Fields [Mt CO_2]	Aquifers [Gt CO_2]
Denmark	176	452	16
Germany	103	2,227	43
Greece	17	0	2,2
Netherlands	54	10,907	1,6
Norway	3453	9,156	13
UK	3005	7,451	15
Sum	6808	30,193	91

Source: GESTCO, 2004.

Table 5.8 *CO_2 storage potential in Europe*

[Gt CO_2]	Gas fields	Oil fields	Aquifers	Coal seam	Sum
	42	7	773	4	826

In order to analyze the influence of CCS in the energy systems different scenarios were calculated. In the scenario CCS standards (CCS) all fossil based electricity generation technologies with a capacity bigger than 10 MW will have a CCS technology included after 2015. In scenario CCS constraint the total CO_2 emissions are limited to the level of the CCS standard scenario. In the scenario CCS subsidies additionally to the given CO_2 constraint the investment cost of the electricity generation units are subsidised by 35% in 2015. The subsidy will be reduced linearly by 1%-unit per year to achieve a subsidy level of 20% in 2030.

5.3.2 Results

Until 2030 in all three CCS scenarios the role of electricity generation based on natural gas and nuclear energy will grow much more than in the reference case. Additionally the share of renewable electricity generation will be higher in the scenario CCS in comparison with the other scenarios. In the CCS case the electricity generation by fossil fuel power plants will be 560 TWh lower and in the other two scenarios respectively about 510 TWh lower than in the reference scenario. In the CCS scenario the electricity generation by renewables will be approximately 350 TWh higher than in the reference case for the EU-25 in 2030.

Starting in 2010 the electricity generation structure of the CCS scenarios differs compared to the reference scenario.. Due to the perfect foresight inside the model the availability of the CCS standard starting or the CO_2 constraint after 2015 will already influence the building capacity decision in the year 2010.

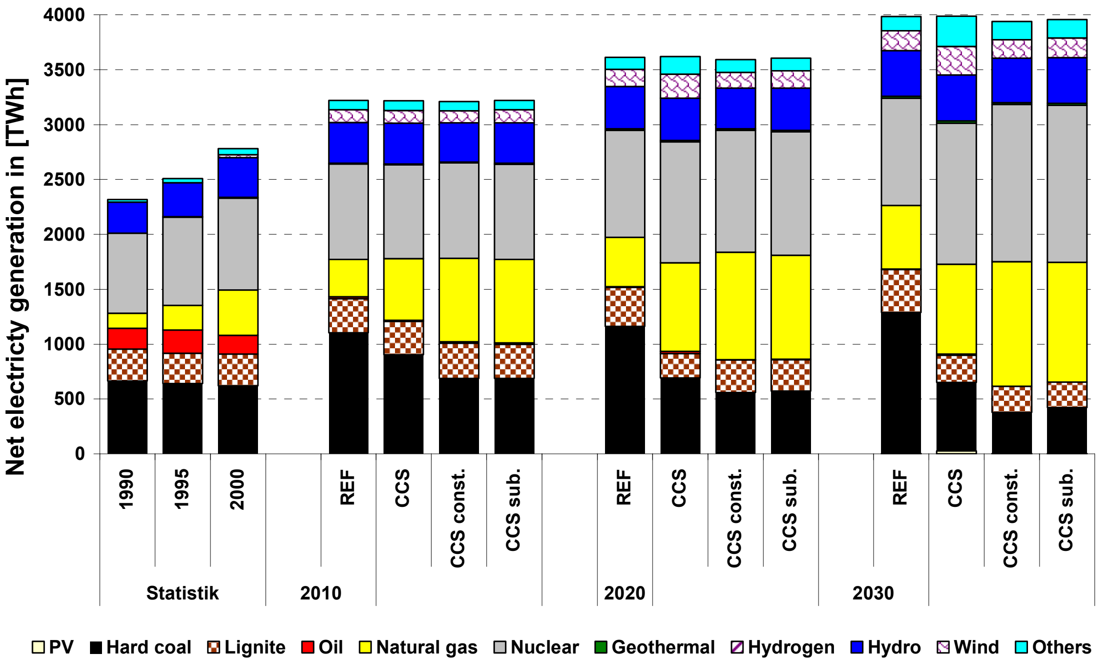


Figure 5.9 *Net electricity generation in the EU-25 by energy carriers in different cases*

The comparison of newly installed net electricity generation capacities in Figure 5.9 shows that depending on the CCS standard starting in 2015 12 GW of additional gas power plants will be built up in the period between 2010 and 2015. They remain unused until 2015. This will be cost efficient because of the lower investment costs of gas plants and the avoided additional investment costs for the CCS technology in power plants starting after 2015. This is a principal effect which happens in the case of policy measures which are well-known before and with the possibility to circumvent them.

In the scenarios constraint and subsidies the installation capacities of gas power plants instead of coal power plants in the year 2010 will be even higher than in the other scenarios in order to prepare the electricity generation sector for fulfilling the CO_2 constraint. This is one reason why the share of electricity generation based on natural gas is higher in the CCS scenarios compared to the reference case. In terms of electricity generation (as shown in Figure 3.27) till the year 2030 the installed new capacities of gas and nuclear power plants will be much higher than in the REF and CCS scenarios.

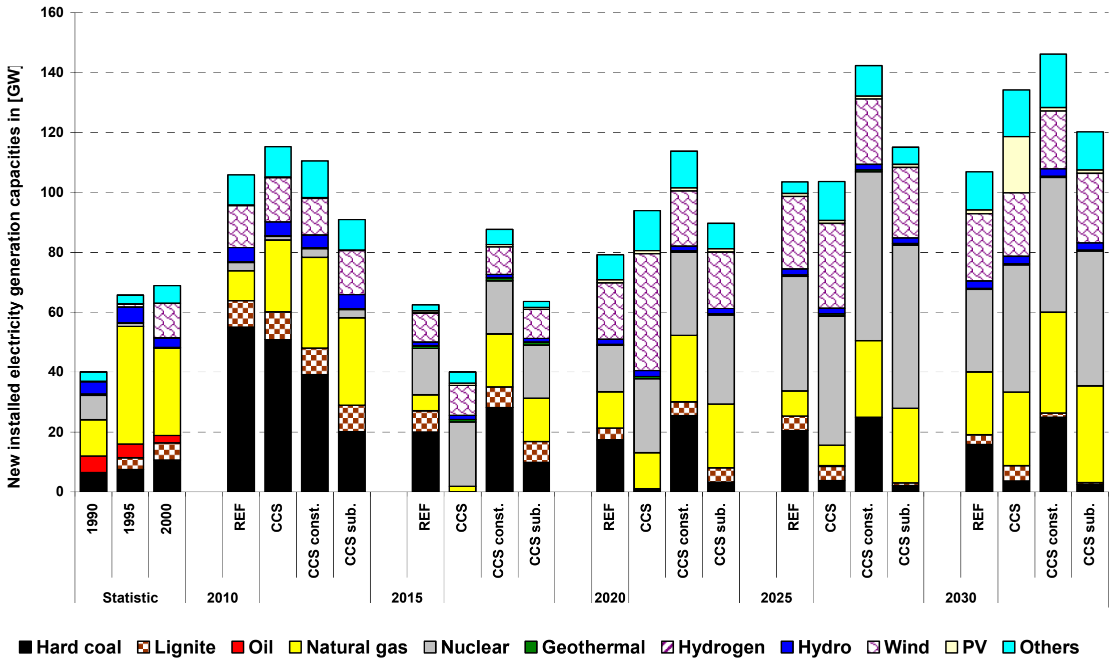


Figure 5.10 *Installed new net electricity generation capacity in the EU-25 by energy carriers in the different cases*

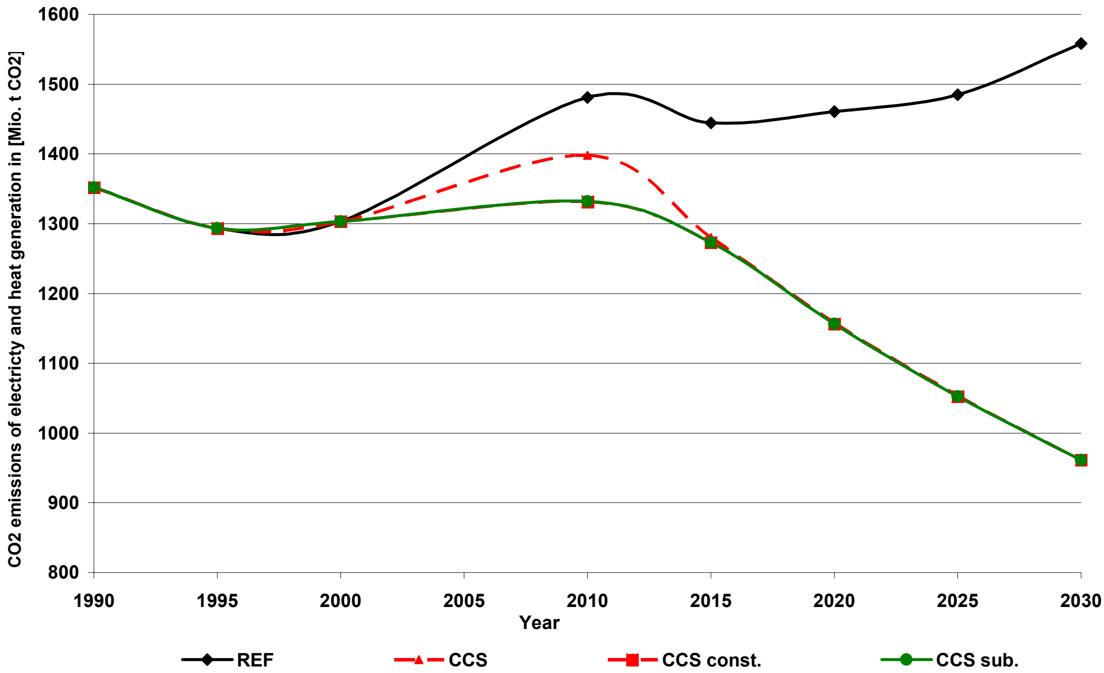


Figure 5.11 *CO_2 emissions of the electricity and heat generation in the EU-25*

In all CCS scenarios the total amount of CO_2 emissions reduction will be approximately 600 Mio. ton CO_2 until the year 2030 in compared to the reference case (see Figure 5.9). In the CCS scenario only approximately 22.5% of the CO_2 reductions caused by CO_2 sequestration. The other part of the CO_2 reductions are based on the fuel shift and the change of the structure of the electricity generation system.

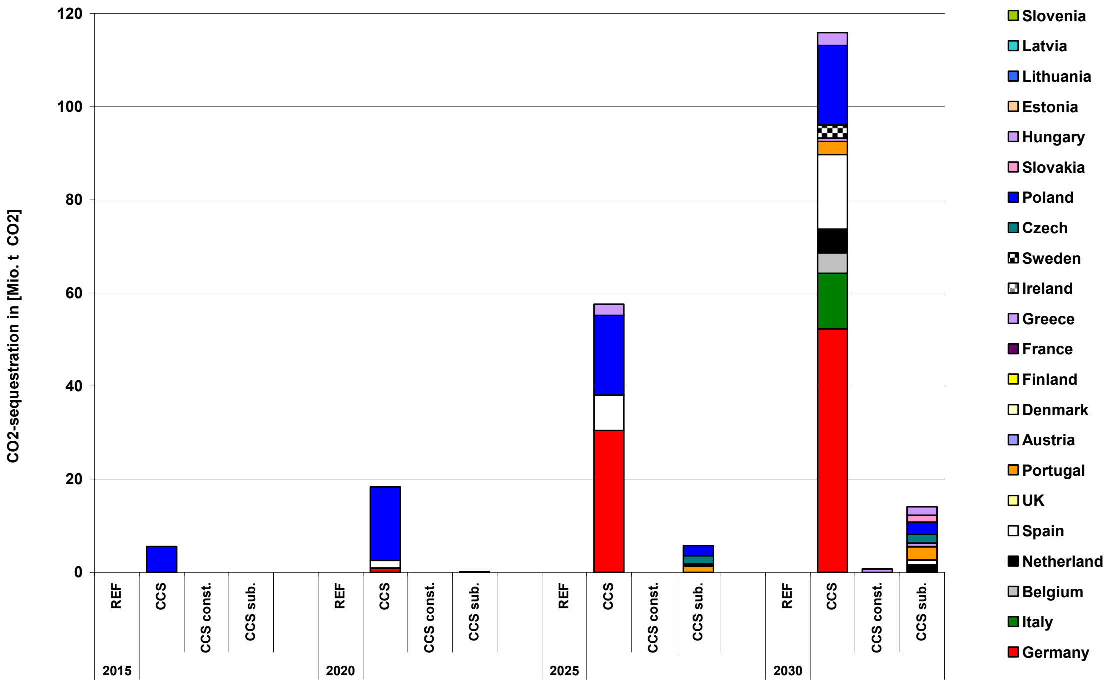


Figure 5.12 *CO_2 sequestration in the EU-25 by country*

In the scenario CCS the total amount of stored CO_2 will be 5.6 Mio. ton in the year 2015 in the EU-25. It will be increasing until 2030 to a level of 115.4 Mio. t CO_2. In the year 2030 most of the CO_2 will be stored in Germany (52.3 Mio. t CO_2) followed by Poland (17.1 Mio t CO_2) and Spain (16 Mio. t CO_2).

5.3.3 Consequences

Until 2030 the CO_2 storage capacity of all EU-25 countries is not the limiting restriction for the CCS scenario.

If a CCS standard will be implemented, the electricity exchange between the countries will be higher and the electricity balance for some countries will be changed in the future. This is caused by the different national policies concerning nuclear power and the differences of CO_2 storage potentials.

5.3.4 Conclusions and recommendations

Only if a CCS standard will be given as a policy measure the use of power plants with CCS will be significant in the electricity sector. The CO_2 reduction caused by a CCS standard will not be a cost efficient way. The same target can also be achieved mainly with a fuel shift to a higher share of electricity generation by gas and nuclear and slightly more electricity generation by renewables.

The comparison of the results of the scenario CCS constraint and CCS subsidies shows that a reduction of 35% of the investment cost for power plants with CCS technology will not be enough to reduce the costs and efficiency handicaps of power plants with integrated CCS technology.

5.4 NEWAGE-W

5.4.1 Introduction

Reaching the national emission targets agreed on by the Kyoto Protocol, various technological options for CO_2 mitigation are going to be further developed and deployed within the next decades. Especially regarding electricity generation, already existing and not even utilized options are going to be made available. Beside carbon free electricity generation technologies based on renewable energy sources and nuclear power plants one can also use Carbon Capture and Storage (CCS) technologies based on fossil fuel fired electricity generation for CO_2 mitigation. Approximately 29 % of global CO_2 emissions are induced by electric power generation, therefore this industry offers the largest potential for applying CCS technology. CCS provides an option to avoid CO_2 emissions from burning coal and gas, respectively. Due to the estimated additional cost for carbon capture and storage technologies, the effective application of this CO_2 mitigation technology strongly depends on e.g. high utilization rates. Therefore, the most likely application of CCS technologies in electricity generation will be for baseload production.

The deployment of Carbon Capture and Storage is determined by several economic, technical, geographical and geological parameters. Depending on the cost for electricity generation by CCS, which is determined by the type of the conversion process within the power plant, the loss of efficiency to capture CO_2, the transportation process and the possibilities of storing the gas, CCS competes with other CO_2 reduction options like energy-efficiency increase, nuclear power production and electricity generation from renewable energy sources.

Splitting the CCS process into its three parts of capture, transportation and storage, IEA estimates the cost for CO_2 capture (including pressurization) of 21-42 Euro per tonne CO_2. Due to further technology improvement and R&D expenditure, respectively, a decrease in cost for CO_2 capture can be expected. Within the next 25 years, cost could fall to 8-21 Euro per tonne CO_2 for coal and 21-25 Euro per tonne CO_2 for gas, respectively. Pre-combustion CO_2 capture, e.g. applied in Integrated Gasification Combined Cycle (IGCC) power plants can be considered to be one of the favored options, followed by post-combustion CO_2 capture, e.g. applied in Coal-fired Ultra Supercritical Steam Cycles (USCSC) power plants.

For the transportation stage, costs are estimated to 0.8-4 Euro per tonne CO_2 per 100 km by pipeline, whereas transportation by ship would amount approximately to 0.3-0.4 Euro per tonne CO_2 per 100 km. Cost for transportation are strongly influenced by the volumes and to a lesser extent by the distances covered.

Capacities for storing CO_2 can be found in different geological structures, like saline aquifers, depleted oil and gas fields and unmineable coal reservoirs. Depending on the type of geological structure, global storage capacities can vary heavily. Deep saline aquifers can offer storage capacity between 1000 and 10000 Gt CO_2 and depleted oil and gas reservoirs provide storage for approximately 920 Gt CO_2, respectively, whereas unmineable coal fields are on a much smaller capacity level. Cost for storing CO_2 in the various structures is estimated by IEA to 0.8-1.7 Euro per tonne CO_2, unconsidered the options for enhanced oil and gas recovery, which can yield a positive revenue from CO_2 storage.

Taking the different cost categories for the CCS technologies into account, it is obvious that economic and political parameters has to be appropriate to make the CCS technologies competitive. Economically, Carbon Capture and Storage technologies have to become more cost-effective, e.g. due to innovation processes induced by R&D expenditure and learning-by-doing effects, respectively. From the political point of view concerning energy and environmental issues, deployment of CCS technology options can be implicitly promoted by CO_2 reduction targets or rising cost for CO_2 emissions, e.g. within a certificate or taxation scheme. Under the current conditions, CCS is not a favorable option for CO_2 reduction regarding electricity generation technologies. Table 1 presents global CCS projects.

Table 1: Global Carbon Capture and Storage projects

Projects	Number of projects
CO2 capture demonstration projects	11
CO2 capture R'&D projects	35
Geological storage projects	26
Geological storage R&D projects	74
Ocean storage R&D projects	9

Whether CCS becomes a relevant and cost-effective option for CO_2 mitigation, is depending on technological, economical and political conditions within the economies. Public and private R&D expenditure and policies for financial support, e.g. subsidies for promoting investment in order to decrease capital cost, have to be taken into account within an analysis of potential market penetration and its economic impact of CCS.

5.4.2 Implementation of Carbon Capture and Storage technologies in NEWAGE-W

As IGCC CCS become more efficient within the electricity generation portfolio, due to higher CO_2 prices on the one hand side and increasing R&D efforts or cost reductions due to deigned subsidies on the other hand side, this technology will probably be an alternative to mitigate energy related CO_2 emissions. Based on hard coal the IGCC CCS technology might be operating within base and middle load segment. Figure 1 presents the structure of electricity production regarding middle and base load technologies in NEWAGE-W.

For analyzing the economic, environmental and technology related impact of a stronger deployment of Carbon Capture and Storage (CCS) technologies for electricity generation, using the multi-regional, multi-sectoral CGE model NEWAGE-W, economic and technology data for a Integrated Gasification Combined Cycle Power Plant with Carbon Capture and Storage (IGCC CCS) are implemented according the given top-down structure. Table 2 presents the cost shares by sector for a hard coal fired IGCC CCS power plant.

Table 2: Cost shares by sector for IGCC CCS and Hard Coal fired Power Plant

	Base Load		Middle Load	
	IGCC CCS	Hard Coal	IGCC CCS	Hard Coal
Cost of Power Generation [$ / MWh]	56.48	47.22	61.73	51.25
Capital	43.3%	41.5%	49.1%	47.4%
Labor	5.2%	5.1%	5.9%	5.8%
Machinery	2.1%	2.0%	2.4%	2.3%
Building	2.0%	2.0%	2.4%	2.3%
Trade and Transport	3.1%	3.1%	3.2%	3.2%
Chemical Products	1.1%	1.1%	0.9%	0.9%
Paper, Pulp, Print	1.1%	1.1%	0.8%	0.9%
Iron and Steel	1.1%	1.1%	0.8%	0.9%
Other Manufactures	4.8%	4.8%	5.2%	5.2%
Electricity	1.1%	1.1%	0.8%	0.9%
Coal	35.2%	37.1%	28.4%	30.2%

To support IGCC CCS technologies within the electricity generation portfolio, it had been assumed that R&D efforts will be increased to lower investment costs between 2010 and 2030. However, within this approach the financial aspects of enhancing R&D efforts has not been considered. To capture the financing effects within the economy, R&D investment induced cost reduction for IGCC CCS has also been modeled as a subsidy for investment expenditure. The subsidy has to be raised by the households and can be interpreted as a negative tax revenue.

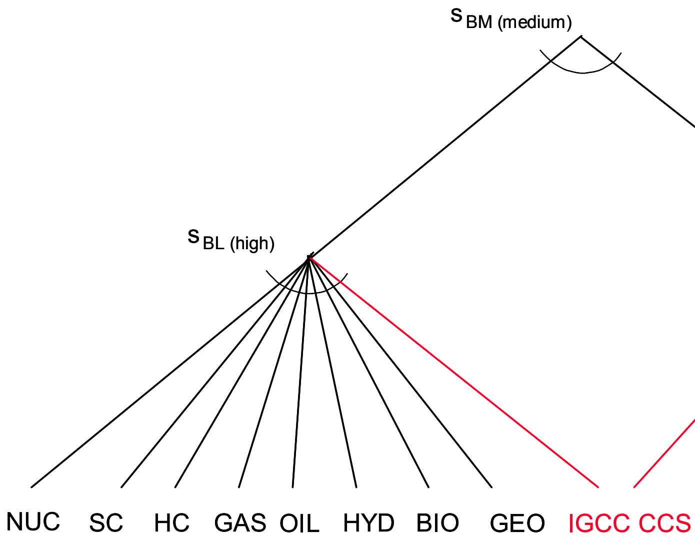


Figure 1: Structure of middle and base load electricity generation in NEWAGE-W

Modelling IGCC CCS power plants within a top-down CGE model can provide knowledge about effects on macro economic indicators due to a stronger deployment of the CCS technology. Beside the impact on macro economic indicators like GDP and welfare, sectoral and regional changes in output and prices, respectively has been analysed.

Due to the technology oriented representation of the electricity sector within NEWAGE-W, changes in electricity generation structure can be analysed. Increasing the share of IGCC CCS power plants will probably replace other conventional fossil fuelled power plants and more expensive electricity generation technologies based on renewable energy sources like wind, solar or geothermal. Depending on the deployment carbon capture and storage technologies induced by different levels of financial support, the analyses provide knowledge of economic, environmental and technology related effects within the regions.

5.4.3 Description of scenarios

To capture a range of possible policy scenarios regarding CCS related electricity generation in Europe three different cases, beside an Business as Usual (BaU), were calculated within the CASCADE-MINTS project. Covering environmental issues of the Kyoto Protocol a CO_2 constraint (Case 2) scenario was calculated. Additionally, a subsidy (Case 3) and a technology breakthrough (Case 4) scenario for CCS technologies were performed also. The specific assumptions made for the three scenarios are described in detail in the following.

Business as Usual: The Business as Usual scenario in NEWAGE-W is calibrated to the harmonized baseline assumptions made in the CASCADE-MINTS project. Regarding the structure of the regional electricity generation portfolios, IEA, EURELECTRIC and national data and projections are used. Figure 2 presents the baseline projections for electricity generation in Western Europe up to the year 2030.

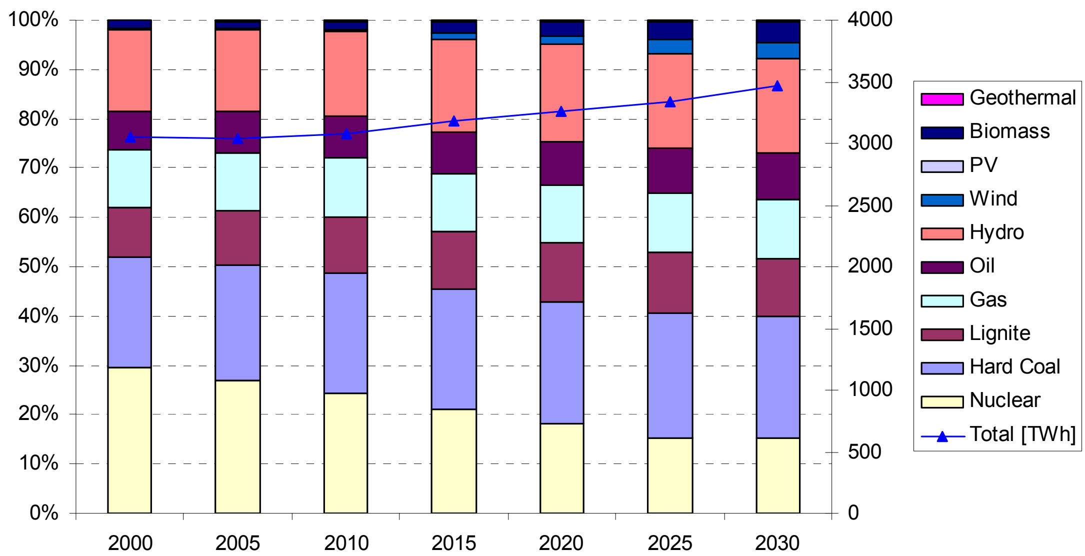


Figure 2: Electricity generation for Western Europe to 2030, Business as Usual scenario

Regarding Carbon Capture and Storage technologies, no capacity expansion can be observed in the Business as Usual scenario. Given the baseline assumption, IGCC CCS power plants are not competitive, compared to conventional fossil fueled generation technologies. Due to its high production costs, the share of IGCC power plants with CCS remains zero up to 2030.

Case 2 – BaU CCS standard : The CO_2 constraint scenario imposes a decrease of CO_2 emissions, computed by the bottom-up model TIMES-EE for Europe, due to CCS standards (Case 1) in electricity generation from 2015 up to 2030. Within the CCS standards scenario all new fossil fueled power plants have to be equipped with carbon capture and storage technologies starting in 2015. The calculated CO_2 emission reductions of Case 1 are used to determine an upper bound for CO_2 emissions for the analysis of Case 2 with NEWAGE-W.

Given the top-down structure of NEWAGE-W, the CCS standards (Case 1) can not be implemented directly. Therefore, the upper bound for CO_2 emissions from TIMES-EE has been implemented to analyze the development of economic, energy and environmental related parameters with NEWAGE-W endogenously. The development of the electricity generation portfolios is thus result of factor price as well as sectoral demand and production changes within the economies.

Case 3: Within the CCS subsidy scenario, an investment subsidy of 35 % starting in 2015 is assumed. The subsidy decreases linearly by 1 %-unit per year until it reaches a value of 20 % in 2030. The CO_2 constraint from Case 2 remains the same.

Case 4: The CCS technology breakthrough scenario assumes a decrease in investment cost, similar to Case 3, though technological development of IGCC CCS power plants leads to a reduction in specific investment cost instead of a subsidy.

5.4.4 Results

The implementation of a CCS Standard (Case 1) leads to decreasing CO_2 emissions in Western Europe. For analyzing the economic effects of the proposed CCS Standard within NEWAGE-W, model results from the bottom-up model TIMES-EE has been used. Concerning the common CGE methodology, potential options for the introduction of future electricity generation technologies are difficult to model. Due to this limitation, resulting CO_2 mitigation potentials induced by carbon capture and storage technologies have been adapted from TIMES-EE and considered by subtracting from the defined Business as Usual scenario.

Taking the TIMES-EE results as an upper bound for CO_2 emissions the impact on gross domestic product can be calculated. Figure 3 presents the change in CO_2 emission, induced by the CCS standards (TIMES-EE) and GDP for Western Europe between 2010 and 2030. It can be observed that the CO_2 emissions are proposed to decrease up to 25 % until 2030 by assuming a carbon capture and storage standard for all fossil fired power plants. Concerning the obliged technological enforcement to use CCS technologies for the conventional fossil power plants a decrease in GDP can be seen. Between 2010 and 2030 the gross domestic product for Western Europe decreases by approximately 1.5 % compared the Business as Usual scenario without a CCS standard.

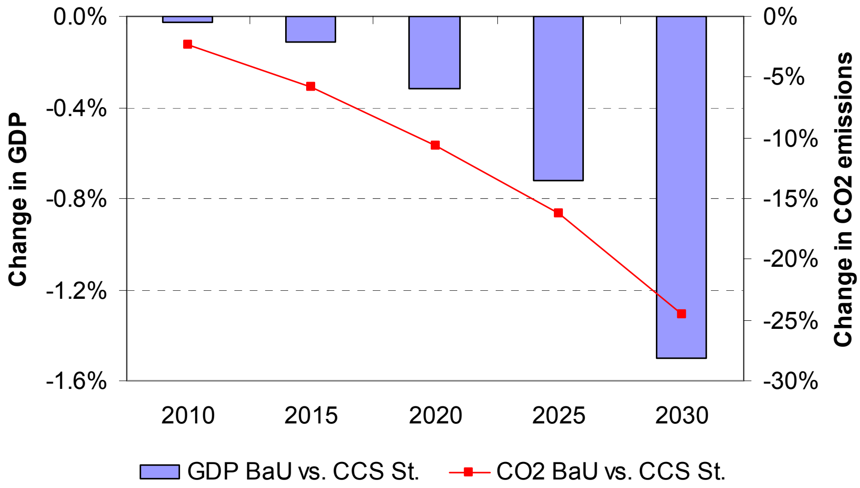


Figure 3: Change in GDP and CO_2 emission in Western Europe by implementing a CCS standard until 2030

Given the TIMES-EE results as a CO_2 emission reduction target, it can be observed that the deployment of the IGCC CCS technology is growing by a factor of approximately 5.5 (see Figure 4). The scenario taking the CCS standard into consideration is denoted by BaU CCS standard (Case 2).

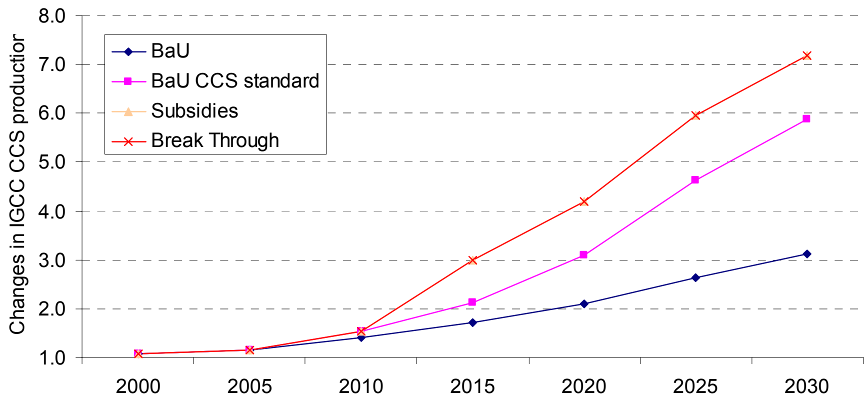


Figure 4: Development of production by IGCC CCS power plants in Western Europe to 2030

It should be noted that the relatively high growth rates of IGCC CCS production have to be evaluated considering the very low estimated values for CCS generation in the year 2000. Due to the given global installed generation capacity with a carbon capture and storage technology, the policy induced increase remains on a very low level regarding absolute capacity and production values.

Beside the CCS Standard related scenario (Case 2, BaU CCS standard) two additional scenarios have been calculated. Within a subsidy scenario (Case 3) the use of IGCC CCS power plants have been financially supported by a subsidy of 35 % starting 2015 which decreases linearly until 2030, reaching 20 % in 2030. The given CO_2 emission reduction path from the CCS standard remains the same in this scenario. The second additional scenario that has been analyzed using NEWAGE-W is a technology breakthrough scenario (Case 4) similar to the scenario analyzed within the Nuclear Case Study. Contrary to the subsidy case a decrease in the specific investment cost of IGCC CCS technologies is assumed within the technology breakthrough scenario by ignoring the subsidy induced financing effects.

Figure 4 presents the impact of decreasing investment cost due a subsidy and a technological breakthrough on the deployment of carbon capture and storage technologies. It can be observed that the differences in the two alternative scenarios are negligible. Both scenarios yield an increase in IGCC CCS production by a factor of approximately 7.2 between 2000 and 2030 (see Figure 4). Again, the relatively high growth rates have to be regarded with respect to a very low absolute level of electricity generation using carbon capture and storage technologies. Figure 5 presents the changes in electricity production by IGCC power plants with carbon capture and storage in Western Europe between 2015 and 2030 for the two additional scenarios. It can be seen that the differences in production between the subsidy and breakthrough case are substantially below 1 %.

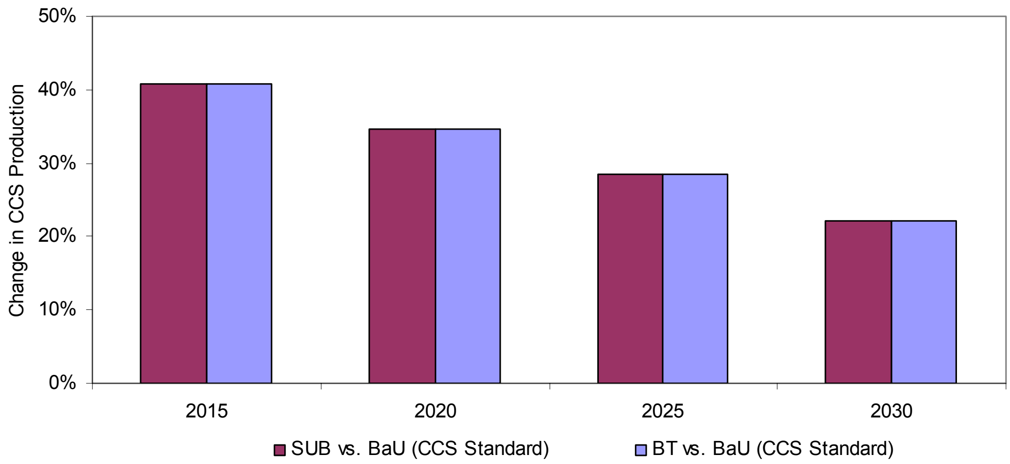


Figure 5: Change in IGCC CCS production in Western Europe to 2030

Comparing the changes in conventional electricity production from coal with the electricity generated using the IGCC CCS technology, it can be seen that conventional electricity generation is only slightly substituted by IGCC CCS production. Whereas IGCC CCS production increases by approximately 20 % to 40 % between 2015 and 2030 compared to the BaU CCS standard (Case 2), the conventional electricity production by coal fired technologies decreases by a maximum of approximately 0.002 %, see Figure 6.

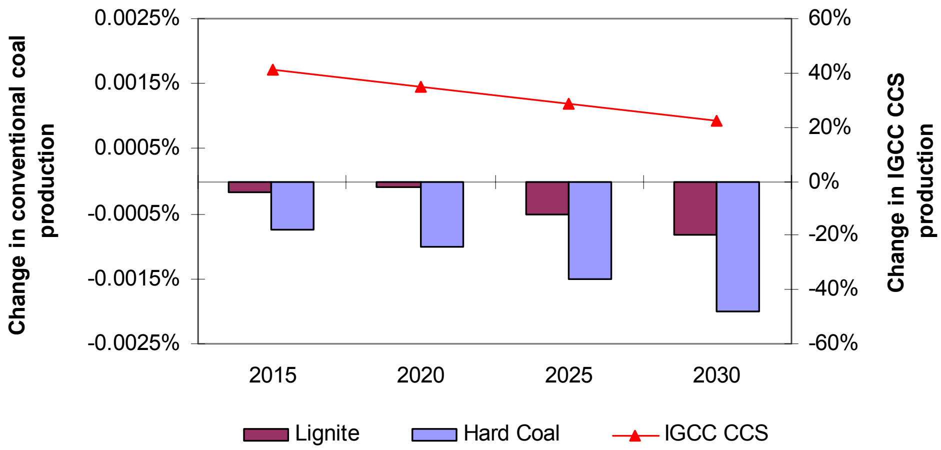


Figure 6: Change in conventional electricity production by coal and IGCC CCS in Western Europe to 2030, BaU CCS Standard (Case 2) vs. subsidy scenario

Due to the a very low absolute level of CCS technologies in Western Europe, the subsidy induced impact on income which lead to a shrinking effect of overall investment and consumption is unincisive. The little differences in economic activity due to the additional cost for the subsidy can also be seen in the development of gross domestic product in Western Europe for the two different scenarios which yields values of less than 1 %. Given the negligible differences in electricity generation due to a subsidy compared to a specific cost reduction induced by a technology breakthrough, the consideration of the economics effects regarding the financing aspects of subsidies can be ignored.

5.5 NEMS

5.5.1 Introduction

The purpose of this case study is to analyze potential energy market impacts of policies that are aimed at controlling carbon dioxide emissions - initially from the power sector and later in all U.S. energy markets. Three cases are analyzed in this report, see Figure 5.4. The first imposes CO_2 capture and storage (CCS) standards on all *new* fossil-fueled capacity additions completed after 2015, except for turbines which have a maximum capacity utilization factor of 20% and small distributed generation systems. Capacity that comes on line *before* 2015 is not required to meet the standard. The second case uses the carbon emissions path achieved in the standards case and sets that as the CO_2 target to be achieved by the entire U.S. energy market. The third case, like Case 2, uses the CO_2 target achieved in Case 1 and further assumes that an investment subsidy of 35% is applied to the new capacity costs of the carbon capture and sequestration components of fossil fuel technologies built after 2015. The subsidies are reduced by 1% per year thereafter. The Reference case is based on the *Annual Energy Outlook 2005* (*AEO2005*)[11] which was developed using the National Energy Modeling System (NEMS)[12]. The detailed assumptions of the Reference case are provided on the Energy Information Administration's (EIA) website.[13]

Table 5.9 *Scenario descriptions*

Scenario name	Description
Reference Case	The Annual Energy Outlook 2005 (*AEO2005*)
Case 1: *CCS Standards*	All new fossil fuel fired power plants are equipped with CCS from 2015 and beyond. The CCS standard is not applied to peak-load gas turbines with capacity factor below 20% and small distributed generation technologies.
Case 2: *CO_2 constraint*	The CO_2 emissions path resulting from the adoption of CCS standards is applied as a CO_2 constraint for all sectors of the U.S. energy market. Capacity additions of fossil-fuelled power plants without CCS are allowed as in the Reference case.
Case 3: *CCS subsidies*	Using the same CO_2 emissions path as Case 2, capital costs for the capture and sequestration component gets an investment subsidy starting at 35% in 2015. The subsidy is decreased by 1% per year thereafter, reaching 20% by 2025. The same CO_2 constraint as in Case 2.

Sources: Energy Information Administration runs. Reference case: MINTBASE.D082505A; CCS standards: MINTSEQ.D052005A; CO_2 Constraint: MINTSEQCAP.D071505A; CCS Subsidy: MINTSEQSUB.D071305A.

Table 5.12 illustrates the cost and performance assumptions for key generation technologies. It should be noted that all new coal generation capacity additions in the United States must meet strict sulfur and NO_x constraints as required by the Clean Air Act Amendment of 1992 and the State Implementation Plans. For integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) with carbon capture and sequestration, it is assumed that the CCS technology will remove 90% of carbon dioxide emissions from the CCS system exhaust stream.

[11] Energy Information Administration, *Annual Outlook 2005, with Projections to 2025*, DOE/EIA-0383(2005),(Washington, D.C., February 2005), web site http://www.eia.doe.gov/oiaf/aeo/index.html.

[12] Energy Information Administration, *National Energy Modeling System*, *An Overview 2003*, DOE/EIA-058(2003) (Washington, D.C., March, 2003), web site http://www.eia.doe.gov/oiaf/aeo/overview/index.html.

[13] Energy Information Administration, *Assumptions to the Annual Outlook 2005, with Projections to 2025*, (Washington, D.C., March 2005), website http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2005).pdf.

Table 5.10 *Cost and performance characteristics of new central station electricity generating technologies*

Technology	Online year[1]	Size	Leadtimes [yr]	Base Overnight Costs in 2004 [2000 EU/kW]	Contingency factors: Project Contingency Factor	Contingency factors: Technological Optimism Factor[2]	Total Overnight Cost in 2004[3] [2000 EU/kW]	Variable O&M[5] [2000 EU/MWh]	Fixed O&M[6] [2000 EU/kWh]
Scrubbed Coal New	2008	600	4	1,161	1.07	1.00	1,242	4.16	24.93
Integrated Coal-Gasification Combined Cycle (IGCC)	2008	550	4	1,341	1.07	1.00	1,435	2.65	35.01
IGCC with Carbon Sequestration	2010	380	4	1,863	1.07	1.03	2,053	4.02	41.21
Conv Gas/Oil Comb Cycle	2007	250	3	553	1.05	1.00	580	1.87	11.30
Adv Gas/Oil Comb Cycle (CC)	2007	400	3	529	1.08	1.00	571	1.81	10.59
ADV CC with Carbon Sequestration	2010	400	3	1,015	1.08	1.04	1,140	2.66	18.02
Conv Combustion Turbine[5]	2006	160	2	385	1.05	1.00	405	3.23	10.97
Adv Combustion Turbine	2006	230	2	365	1.05	1.00	383	2.87	9.53
Fuel Cells	2007	10	3	3,766	1.05	1.10	4,350	43.40	5.12
Advanced Nuclear	2013	1000	6	1,734	1.10	1.05	2,003	0.45	61.48
Distributed Generation - Base	2007	2	3	787	1.05	1.00	826	6.45	14.51
Distributed Generation - Peak	2006	1	2	946	1.05	1.00	993	6.45	14.51
Biomass	2008	80	4	1,650	1.07	1.02	1,799	3.03	48.29
MSW - Landfill Gas	2007	30	3	1,435	1.07	1.00	1,535	0.01	103.46
Geothermal[6, 7]	2008	50	4	3,030	1.05	1.00	3,182	0.00	107.46
Conventional Hydropower[6]	2008	500	4	1,350	1.10	1.00	1,485	4.70	12.46
Wind	2007	50	3	1,085	1.07	1.00	1,161	0.00	27.44
Solar Thermal[7]	2007	100	3	2,575	1.07	1.10	3,030	0.00	51.42
Photovoltaic[7]	2006	5	2	3,959	1.05	1.10	4,573	0.00	10.58

1 Online year represents the first year that a new unit could be completed, given an order date of 2004.
2 The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
3 Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2004.
4 O&M = Operations and maintenance.
5 Combustion turbine units can be built by the model prior to 2006, if necessary, to meet a given region's reserve margin.
6 Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.
7 Capital costs for geothermal and solar technologies are shown before the 10% investment tax credit is applied.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type.

The assumptions of *AEO2005* were based on laws, policies and regulations in force on October 1, 2004. Consequently, subsequent changes in U.S. laws (e.g., the Energy Policy Act of 2005[14]) and regulations (e.g., the Clean Air Interstate Rule[15] and Clean Air Mercury Rule[16]) enacted after that point are not included in the Reference case or in the sensitivity cases. The new laws and regulations set a schedule for meeting significantly tighter sulfur dioxide, nitrogen oxide, and mercury emissions nationally through a cap and trade system. These new laws and regulations are expected to have some impact on the projected generation technology choices in the mid-term but they will not be formally evaluated by the Energy Information Administration (EIA) of the U.S. Department of Energy until December 2005[17].

Since NEMS endogenously represents 'learning-by-doing' in the electricity sector by component and captures the spillover learning from alternative generation technologies which have the same 'component' (e.g., turbines are in both the IGCC and NGCC technologies and the carbon capture and sequestration component is in both the NGCC and IGCC with capture and sequestration technologies), the relative starting costs of the competing technologies could have a significant bearing on when (or if) a technology penetrates the market and how quickly it may do so.

5.5.2 Results

5.5.2.1 Primary energy consumption

In the Reference case for the United States, natural gas consumption is projected to increase from 24.2 exajoules (EJ) in 2003 to 32.9 EJ in 2025, an increase of 36% over the 2003 to 2025 period, largely through projected increases in natural gas consumption for electricity generation. Coal consumption is also projected to rise from 23.4 EJ in 2003 to 31.8 EJ in 2025, a 36% increase. Most of the increased coal consumption is expected to occur in the last decade of the projection due to projected cost increases of natural gas and the expanding demand for electricity. Petroleum consumption is projected to increase from 40.6 EJ in 2003 to 56.9 EJ in 2025 because of continued growth in transportation demand and renewable consumption grows from 5.9 EJ in 2003 to 8.4 EJ in 2025. While no new nuclear plants are added during the 2000 to 2025 period, nuclear generation increases through uprates (effective increases of existing nuclear plants) and the effective primary nuclear consumption increases from 8.4 EJ in 2003 to 9.1 in 2025 as shown in Figure 5.13. Table 5.12 provides a summary comparison of the key energy market indicators of the cases.

The introduction of CCS standards for electricity generation technologies leads to changes in primary energy consumption patterns after 2015, primarily in coal, renewables, and nuclear. In the CCS standards case, new fossil-fueled electric generation technologies with carbon capture and sequestration are largely uneconomic through 2025, except for the last three years of the case, compared to renewable, nuclear, and natural gas turbine (NGT) and DG generation technologies because of the high capital costs of CCS technologies. A total of 2.6 GW of IGCC with the CCS technologies becomes economic late in the projection period in the CCS standards case as the higher natural gas price outlook, lower turbine efficiency, and the restriction on the utilization rate begin to make the IGCC with CCS technology economic.

Distributed generation (DG) and natural gas turbines (NGT) with a maximum utilization rate of 20% are the only fossil-fueled technologies constructed in the CCS standards case after 2015. By 2025, the unplanned additions of DG and NGT are nearly twice that of the Reference case.

[14] Energy Policy Act of 2005,signed August 8, 2005, http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_reports&docid=f:hr190.109.pdf.
[15] U.S. Environmental Protection Agency, Clean Air Interstate Rule, March 10, 2005, http://epa.gov/cair/index.html.
[16] U.S. Environmental Protection Agency, Clean Air Mercury Rule, March 15, 2005, http://www.epa.gov/oar/mercuryrule/rule.htm.
[17] The analysis will formally be incorporated in the new Reference case of the Annual Energy Outlook 2006.

Consequently, the CCS standards case uses about 1.7% more natural gas in 2025 than the Reference case while generating about the same amount of electricity. Coal consumption is almost 14% lower than the Reference case in 2025. The reduction in coal consumption for generation is primarily offset by increases in renewable resource (49%) and nuclear (4%) fuel consumption in 2025. The CCS standards policy does not affect petroleum consumption in the United States.

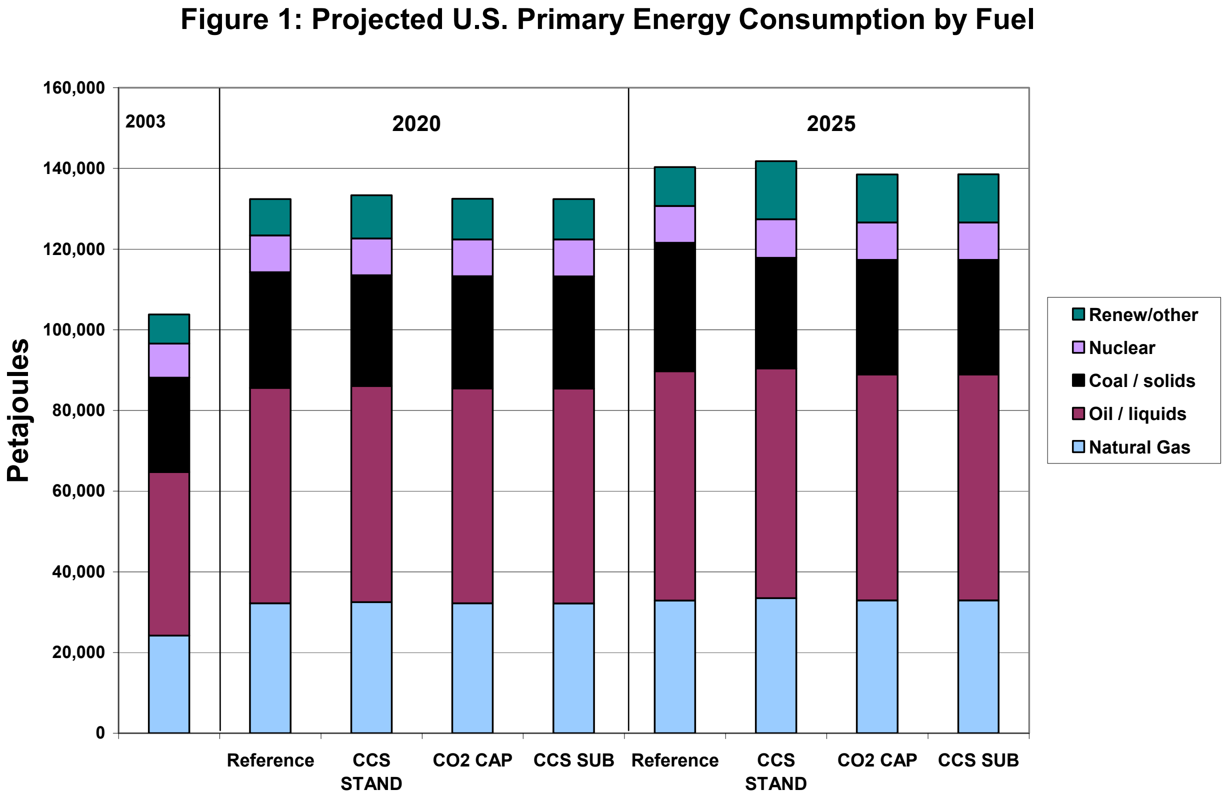


Figure 5.13 *Projected U.S. Primary Energy Consumption by Fuel*
Sources: Energy Information Administration runs. Reference case: MINTBASE.D082505A; CCS standards: MINTSEQ.D052005A; CO_2 Constraint: MINTSEQCAP.D071505A; CCS Subsidy: MINTSEQSUB.D071305A.

None of the CCS technologies become economic in the CO_2 constraint and CCS subsidy policy cases. In the CO_2 constraint and CCS subsidies cases where the carbon emissions derived from the CCS standards case is imposed as a constraint on the entire U.S. energy market, the quantity of and mix of fuels consumed changes in response to the carbon cap. Because the U.S. energy market is free to choose the most economic way to meet the national carbon dioxide target, the CCS technologies are uneconomic during the 2005 to 2025 period and, consequently, the CO_2 constraint and subsidy cases are virtually identical in all aspects[18]. Coal remains the main fuel impacted because it has the highest carbon content of all the fossil-fuels. However, the carbon cap results in a more distributed response by the U.S. energy markets. While the electricity generation market is the most price-responsive and makes the biggest contribution toward meeting the carbon cap, some of the burden of meeting the carbon cap is shared by the other sectors. The power generation sector shifts to lower carbon intensive fuels for electricity generation rather than forcing the use of CCS technologies. Compared to the Reference case in 2025, coal consumption in the CO_2 constraint and CCS subsidy cases is 10.7% lower, renewable energy consumption is about 25% higher, nuclear fuel consumption is about 1.7% higher, petroleum consumption is about 1.5% lower, and natural gas consumption is largely unchanged as shown in

[18] The solutions are slightly different because the solutions are derived iteratively.

Figure 5.14. The subsidy for the CCS technologies is projected to have no impact on their market adoption for the 2015 to 2025 period under Reference case scenario assumptions.[19]

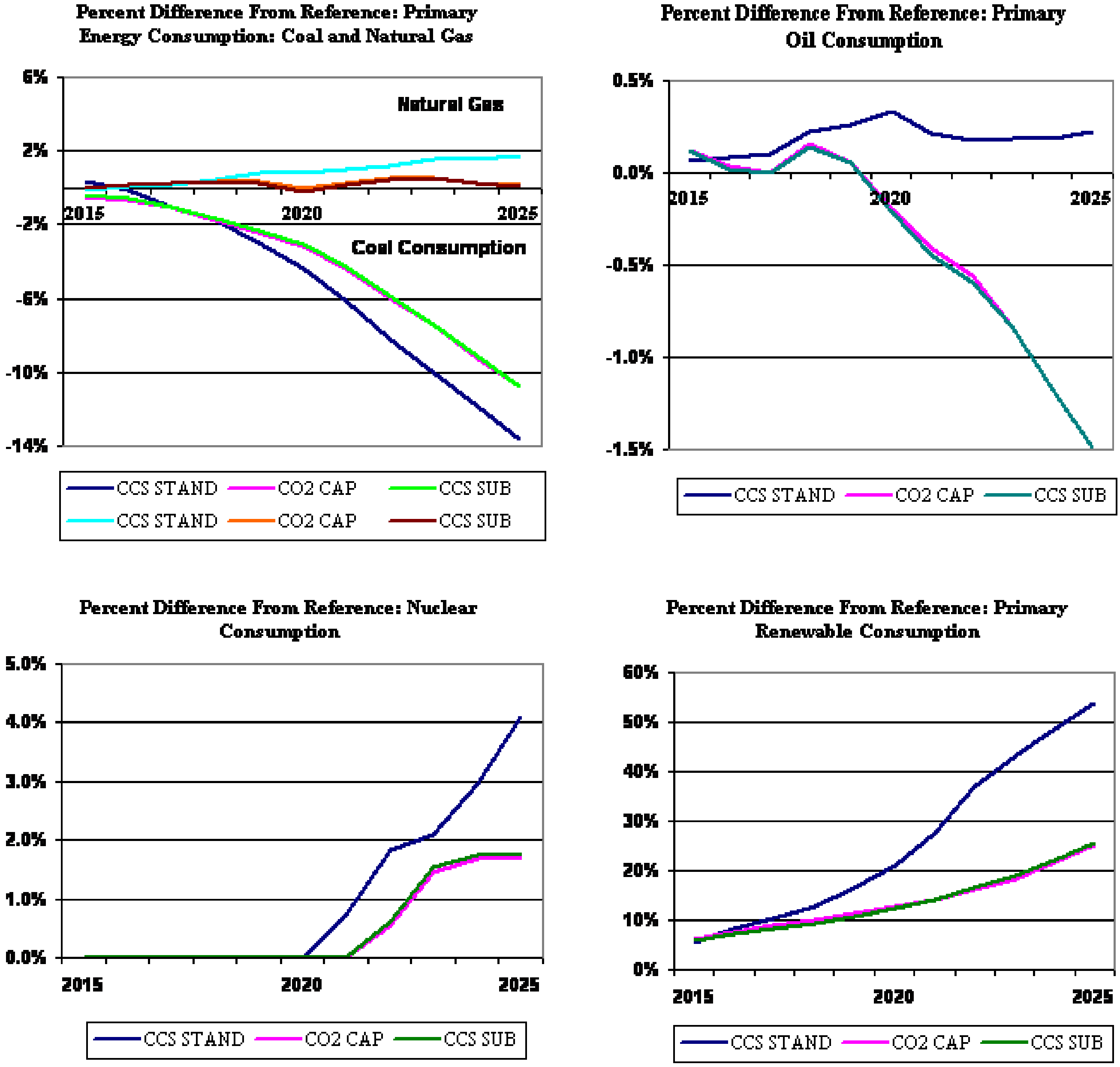


Figure 5.14 *Percentage difference of primary energy consumption of CCS policy cases from Reference, 2015-2025*

Sources: Energy Information Administration runs. Reference case: MINTBASE.D082505A; CCS standards: MINTSEQ.D052005A; CO_2 Constraint: MINTSEQCAP.D071505A; CCS Subsidy: MINTSEQSUB.D071305A.

The carbon cap generates a carbon allowance price (tax) on fossil fuels based on the carbon content of the fuel and reduces natural gas consumption in end-use sectors in 2025. However, additional advanced natural gas combined cycle is used to displace some of the less efficient coal-based generation. On net, natural gas consumption in the CO_2 constraint and CCS subsidy cases is largely unchanged from the Reference case.

[19] It should be noted that assumptions yielding significantly higher petroleum and natural delivered prices could materially alter the adoption of CCS technologies. Such a case, though useful, was not analyzed for this study.

Table 5.11 a) Summary of impacts for three cases: Reference case, CCS standards, CO_2 Constraint

			2020			2025	
	2003	Reference Case	CCS Standards	CO_2 Constraint	Reference Case	CCS Standards	CO_2 Constraint
Macro Indicators							
Nominal AA Utility Bond Rate (%)	6.39	8.34	8.36	8.44	8.59	8.61	8.73
GDP (10^9 US2000$)	10,381	17,636	17,623	17,618	20,288	20,264	20,206
Population	291	337	337	337	351	351	351
Primary fuel prices (2000 €/GJ)							
Natural gas - wellhead	4.70	4.19	4.35	4.29	4.57	4.70	4.54
Crude Oil Imports	4.64	4.77	4.77	4.77	5.07	5.07	5.07
Minemouth Coal	0.83	0.84	0.82	0.83	0.88	0.81	0.85
Avg del price (2000 €/GJ)							
Natural gas	6.65	6.02	6.17	6.34	6.42	6.57	7.07
Oil	10.20	9.99	9.96	10.29	10.34	10.32	11.20
Coal	1.26	1.23	1.20	1.64	1.27	1.19	2.44
Electricity (2000 €/MWh)	7.59	7.33	7.53	7.57	7.47	7.80	8.23
Gross inland consumption (PJ)	*103,771*	132,418	133,343	132,459	140,331	141,803	138,509
Gas	24,164	32,194	32,464	32,186	32,862	33,430	32,903
Oil / liquids	40,595	53,419	53,605	53,323	56,851	56,986	56,014
Coal / solids	23,386	28,660	27,423	27,759	31,809	27,455	28,387
Nuclear	8411	9143	9143	9143	9143	9516	9297
Renewables	5864	7753	9398	8766	8364	13,034	10,543
Other	1350	1248	1310	1282	1301	1382	1365
Fuel Cons. For Elec. Gen. (PJ)	*38,563*	50,049	49,677	49,332	53,521	52,512	51,258
Gas	5334	10,050	10,387	10,175	10,013	10,615	10,428
Oil / liquids	1193	1417	1636	1418	1489	1730	1364
Coal / solids	21,620	26,648	25,413	25,752	29,858	25,509	26,467

		2020			2025		
	2003	Reference Case	CCS Standards	CO_2 Constraint	Reference Case	CCS Standards	CO_2 Constraint
Nuclear	8411	9143	9143	9143	9143	9516	9297
Biomass: total	2004	2790	3098	2844	3018	5143	3702
Net electricity gen by fuel (TWh)	3850	5,319	5,295	5,297	5,767	5,720	5,655
Gas	632	1381	1364	1407	1415	1420	1493
Oil / liquids	124	143	167	144	151	177	140
Coal / solids	1970	2494	2339	2384	2872	2352	2489
Nuclear	764	830	830	830	830	864	844
Hydro	275	307	308	308	307	309	309
Solar	1	3.3	3.4	3.4	5.7	6.1	6.2
Wind	11	30.3	97.7	65.6	33.4	183	134.5
Biomass: total	37	72.9	108.5	79.9	85	312.8	160.5
Geothermal	13	27.5	44	43.6	38	61.2	48.3
Others	24	29.8	33.5	31.3	30.3	34.2	31.5

Table 5.13 b) *Summary of impacts for three cases: Reference case, CCS standards, CO_2 Constraint*

		2020			2025		
	2003	Reference Case	CCS Standards	CO_2 Constraint	Reference Case	CCS Standards	CO_2 Constraint
Net generation capacities electricity only (GW)	*920*	*1,052*	*1,059*	*1,054*	*1,141*	*1,160*	*1,140*
gas	268.1	389.3	389.4	391.7	423.4	429.0	428.4
oil / liquids	129.7	100.3	100.7	102.0	99.6	100.0	101.2
coal / solids	310.3	339.1	315.5	322.3	390.8	318.1	337.9
nuclear	99.2	102.7	102.7	102.7	102.7	107.2	104.4
hydro	77.9	78.2	78.4	78.6	78.2	78.6	78.6
solar	0.4	0.8	0.8	0.8	0.9	0.9	0.9
wind	6.6	10.1	28.5	19.4	11.0	52.0	38.9

		2020			2025		
	2003	Reference Case	CCS Standards	CO_2 Constraint	Reference Case	CCS Standards	CO_2 Constraint
biomass: total	1.8	2.9	12.0	5.5	5.2	41.2	19.0
geothermal	2.2	4.0	6.0	5.9	5.2	8.0	6.4
others	24.1	24.5	25.0	24.7	24.6	25.1	24.7
End-use Cogeneration (GW)	*27*	*39*	*40*	*39*	*45*	*47*	*46*
gas	14.4	22.9	23.3	22.8	26.8	28.1	27.6
oil / liquids	2.5	3.3	3.4	3.4	3.4	3.6	3.5
coal / solids	4.1	4.1	4.1	4.1	4.1	4.1	4.1
others	6.1	8.9	9.0	9.0	10.5	10.7	10.7
Final demand by sector (PJ)	*75,771*	*97,384*	*97,185*	*97,071*	*102,875*	*102,550*	*101,368*
industry	19,943	24,104	24,061	24,007	24,918	24,867	24,575
commercial	8742	12,029	11,984	11,976	13,180	13,108	12,941
households	12,246	14,585	14,537	14,516	15,044	14,968	14,677
traffic	28,557	39,446	39,402	39,371	42,227	42,135	41,811
agriculture	1240	1391	1390	1391	1452	1450	1440
non-energy uses	5043	5830	5811	5810	6053	6021	5923
Final energy demand by fuel (PJ)	*75,771*	*97,385*	*97,186*	*97,072*	*102,877*	*102,553*	*101,370*
electricity	12,532	17,343	17,254	17,275	18,789	18,622	18,430
gas	18,447	22,322	22,253	22,189	23,036	23,000	22,660
oil / liquids	40,048	52,632	52,597	52,526	55,871	55,764	55,141
coal / solids	2341	2107	2104	2103	2047	2037	2023
biomass	2327	2902	2898	2899	3052	3046	3033
hydrogen	0	2	2	2	4	4	3
others	77	78	78	78	80	80	80
CO_2 emissions (Mt CO_2)							
CO_2 total, from energy only	5789	7510	7430	7424	8028	7673	7676

			2020			2025	
	2003	Reference Case	CCS Standards	CO_2 Constraint	Reference Case	CCS Standards	CO_2 Constraint
CO_2 from power sector	2286	2995	2921	2923	3283	2936	2994
CO_2 from (other) conversion	200	284	282	281	288	285	284
CO_2 from industry	730	821	823	820	841	847	831
CO_2 from transport	1857	2589	2586	2584	2772	2766	2744
CO_2 from buildings and services	618	713	711	709	732	731	714
CO_2 from agriculture	98	108	107	107	113	109	109

5.5.2.2 Electricity generation

The pattern of responses of the power generation market to the three policy cases (CCS standards case, the CO_2 constraint case, and the CCS subsidy case) in the U.S. energy market for the period 2015-2025 are easily characterized.

- The *CCS standards* policy forces the use of CCS technologies on new coal-fired and gas-fired generation, except for DG and NGT with maximum capacity factor of 20%. As a result, after 2014, except for DG and NGT capacity additions, construction of new fossil-fuelled capacity additions are virtually eliminated (except for about 2.6 GW of new IGCC with the CCS technology) - a significant reduction in coal-fired capacity additions in the Reference case. The increases in NGT and DG capacity additions basically offsets the reduction in NGCC capacity additions while keeping natural gas-based electricity generation almost equal to the Reference case in 2025. The total consumption of natural gas is slightly higher than the Reference case because of the lower efficiencies of the NGT and DG technologies. New renewable capacity additions and, later, nuclear power capacity additions largely offset the generation losses from coal. The average electricity price is about 4% above the Reference case in 2025.
- None of the CCS technologies are projected to be economic in the United States through 2025 in the *CO_2 constraint* and the *CCS subsidy* cases. The additional CCS subsidy makes no difference to the adoption of CCS technologies through 2025 in U.S. energy markets under Reference case assumptions. Consequently, the behaviour of the *CO_2 constraint* and the *CCS subsidy* cases are very similar for the U.S. energy market for the period 2015 to 2025. Because the carbon constraint is imposed on the entire U.S. energy market, reductions of CO_2 emissions are made where they are the most economic. For example, carbon dioxide emissions in the power sector are 10.6% lower in the *CCS standards* case than the Reference case in 2025, but power sector CO_2 emissions in the *CO_2 constraint* and *CCS subsidy* cases are about 8.8% lower than the Reference case because the remaining CO_2 reductions are more economically made in the end-use energy markets. Electricity and delivered fossil fuel prices in the *CO_2 constraint* and *CCS subsidy* cases in 2025 are higher than in the Reference and the *CCS standards* cases because of the carbon allowance prices which are added to delivered fuel prices, based on their carbon content. In 2025, electricity prices in the *CO_2 constraint* case are about 10% above the Reference case and about 5.5% above the *CCS standards* case.

As is illustrated in Figure 5.15 and Table 5.13, if the CCS standards are implemented in the power sector, fossil-fired electricity generation is substantially reduced as a result of policy-induced phase out of technologies without CCS while renewable and nuclear power generation are increased. In 2025, coal-based generation is 2352 Bkwh, natural gas based generation is 1420 Bkwh, nuclear-based generation is 864 Bkwh, renewable-based generation is 872 Bkwh and petroleum based generation is 176.5 Bkwh. See Figure 5.15 for a comparison of the generation levels for the Reference and three policy cases. Figure 5.16 illustrates the capacity additions for 2020 and 2025.

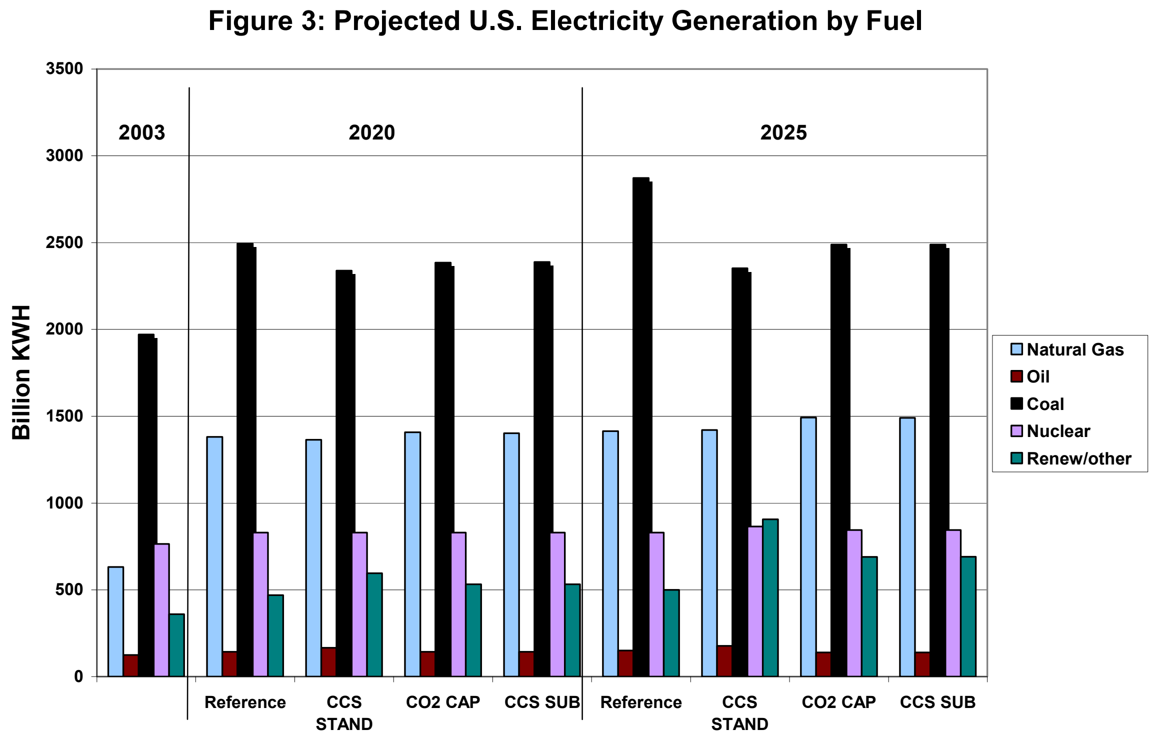


Figure 5.15 *Projected U.S. Electricity Generation by Fuel*

Sources: Energy Information Administration runs. Reference case: MINTBASE.D082505A; CCS standards: MINTSEQ.D052005A; CO_2 Constraint: MINTSEQCAP.D071505A; CCS Subsidy: MINTSEQSUB.D071305A.

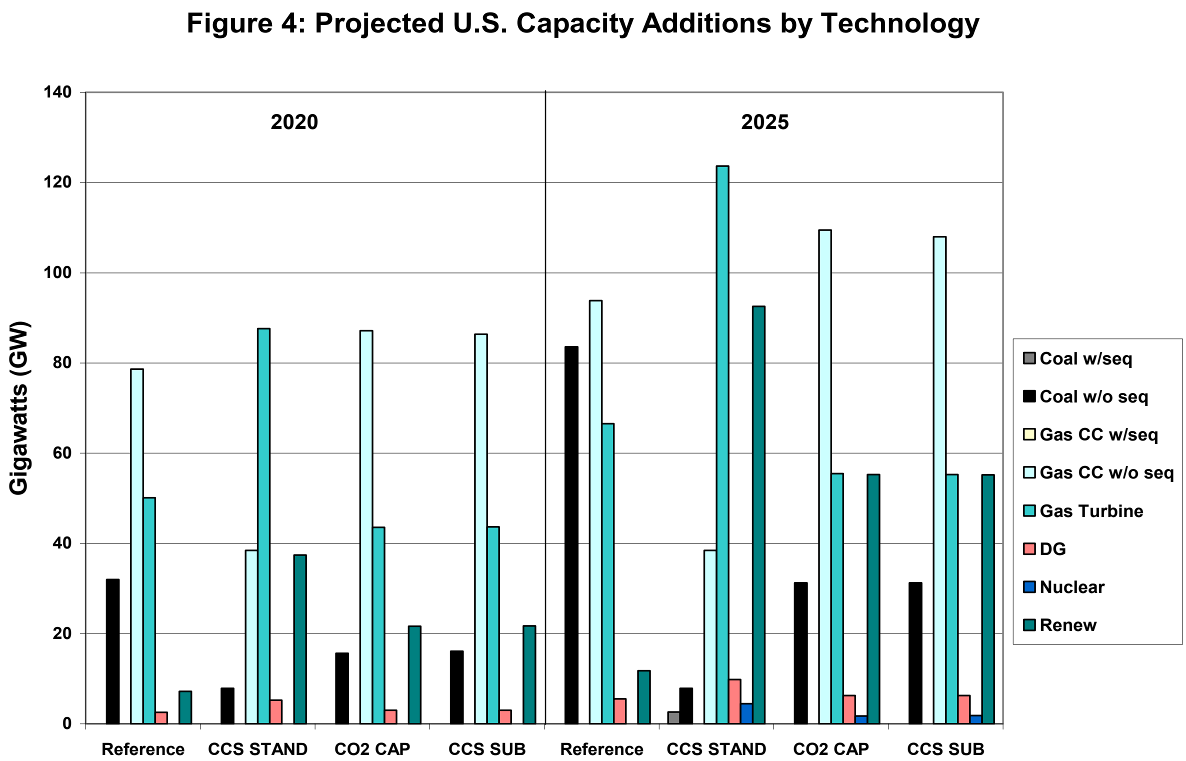


Figure 5.16 *Projected U.S. Capacity Additions by Technology*

Sources: Energy Information Administration runs. Reference case: MINTBASE.D082505A; CCS standards: MINTSEQ.D052005A; CO_2 Constraint: MINTSEQCAP.D071505A; CCS Subsidy: MINTSEQSUB.D071305A.

In the *CCS standards* case, the CCS technologies contribute a total of 2.6 GW of advanced IGCC to fossil fuelled CCS generation technologies. The only new fossil-fuelled capacity additions between 2015 and 2025 are DG (about 8 GW) and NGT (about 96 GW). In 2025, coal based generation is 519 Bkwh lower (18.1%) in the *CCS standards* case than the Reference case, and about 383 Bkwh lower (13.3%) in the *CO_2 constraint* and *CCS subsidy* cases. Renewable-fuelled generation in the *CCS standards* case in 2025 is 403 Bkwh higher (86%) than the Reference case and about 189 Bkwh higher (about 40.3%) in the *CO_2 constraint* and *CCS subsidy* cases. Nuclear generation is 33.9 Bkwh higher in the *CCS standards* case than the Reference and is only 14.0 Bkwh greater than the Reference in the *CO_2 constraint* case.

Renewable generation in the United States for the period 2005 to 2025, primarily from biomass and wind, is projected to be markedly more economic in all of the CCS policy cases than any other technology, including any of the carbon capture and sequestration technologies. Biomass generation is projected to increase the most in the *CCS standards* case, from 85 Bkwh in the Reference case in 2025 to 313 Bkwh, an increase of 228 Bkwh. The *CO_2 constraint* case, like the *CCS subsidy* case, projects an increase from biomass generation of about 76 Bkwh relative to the Reference case. Contributions from wind systems increase 150 Bkwh in the *CCS standards case* relative to the Reference case in 2025 but increase 101 Bkw in 2025 in the *CO_2 constraint* case. As was the case with biomass generation, wind systems increase the most in the *CCS standards* case relative to the Reference case. The lower levels of renewable generation in the *CO_2 constraint* case is due to the greater flexibility allowed in meeting the CO_2 constraint compared to the *CCS standards* case.

Because the efficiency of the NGCC is high and natural gas has the lowest carbon content per GJ of delivered energy than any other fossil fuel, NGCC is often the technology chosen to provide a feasible transition for the U.S. energy market to a lower carbon emissions world as defined by the by *CO_2 constraint* case. In such cases, NGCC often displaces some of the older coal-fired generation.

5.5.2.3 Effects on CO_2 emissions

Carbon dioxide emissions reach the same level in all three policy cases because they are required to do so by scenario design. In this analysis, each of the year-by-year CO_2 emission targets derived from the *CCS standards* case were required to be met in the *CO_2 constraint* and *CCS subsidy* cases. Banking of CO_2 emissions credits was not permitted. However, had banking of carbon dioxide emissions allowances been permitted, based on numerous other EIA related-analysis performed using NEMS, some banking of allowances would have occurred beginning in 2015.

The *CO_2 constraint* case imposes the same emission reduction trajectory as resulting from the *CCS standards* case. Nevertheless, due to an enhanced flexibility in reaching the reduction target, the distribution of CO_2 mitigation options is different under the *CO_2 constraint* as compared to the *CCS standards* case. In the former case, the inter-fossil fuel switching (renewables, natural gas NGCC, and nuclear substituting for some of the coal-fired generation), and end-use demand reductions play a dominant role in the CO_2 abatement. The *CCS standards* case projects significantly larger contribution of renewable and nuclear generation to the emission abatement process and a small contribution by CCS technologies through 2025.

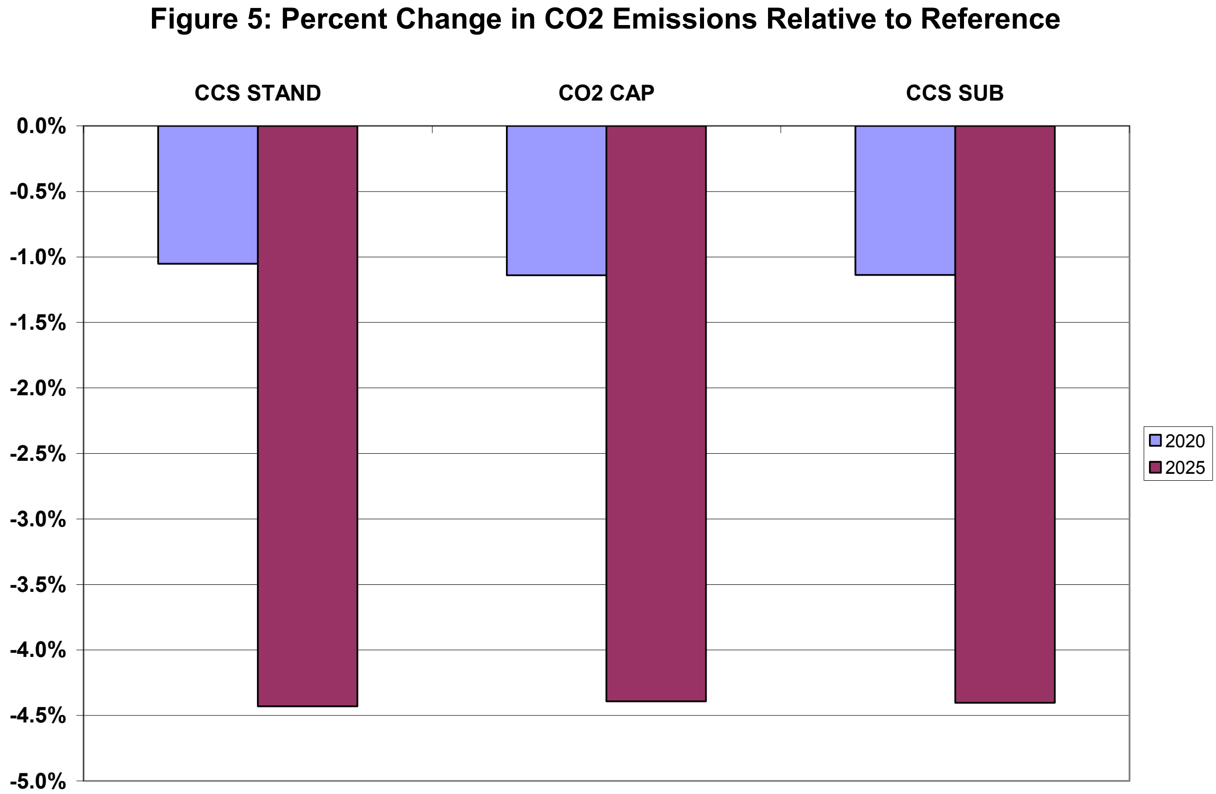


Figure 5.17 *Percent Change in CO_2 Emissions Relative to Reference*

Carbon dioxide emissions are reduced by about 353 mln metric tons in 2025 relative to the Reference case with a carbon allowance price of € 13.72 (year 2000) per metric ton CO_2.

5.5.2.4 Amounts and the distribution of CO_2 emissions captured and stored

Analysis of the three CCS policy cases on U.S. energy markets through 2025 shows that the CCS technologies are generally not economic except for the *CCS standards* policy case in the last few years of the forecast horizon when 2.6 GW of IGCC with CCS technology are added. None of the CCS technologies are projected to be economic in the *CO_2 constraint* or *CCS subsidy* cases through 2025 in the United States.

5.5.3 Consequences

The economic consequences of the CCS standards case show a linear decline rate in real GDP of $ 2-3 bln per year relative to the Reference case. Real GDP losses relative to the Reference case in 2025 are about $ 20 bln (undiscounted year 2000 U.S.) or about 0.1% of real GDP. The economic losses in the CO_2 constraint case are much larger, reaching $ 82 bln in 2025. The decline rate of real GDP relative to the Reference is between $ 15-20 bln per year.

The subsidies for carbon capture and sequestration technologies are not a sufficient inducement for adoption in the U.S. energy market for the period 2005 to 2025 time frame. None are expected to enter the market as a result of the subsidy or the allowance prices through 2025. Previous analysis suggests that carbon dioxide allowance prices in excess of € 50 per metric ton would be required to make the CCS technologies economic under Reference case assumptions.

Relative to the Reference case, energy prices increase the least under the CCS standards case and the most under the CO_2 constraint case because the carbon dioxide allowance costs are directly added to the delivered fuel prices based on the carbon content of the fuel that is not being captured and sequestered. In the CCS standards case, the projected average delivered coal price is expected to be about 6.7% lower, the average delivered natural gas price is 2.4% higher, average delivered motor gasoline price is unaffected, and the average delivered electricity price is expected to be about 4.4% higher than the Reference case in 2025.

In the CO_2 constraint case, because of the CO_2 allowance price, average delivered coal prices are 92% higher, the average delivered natural gas prices are about 10% higher, average delivered electricity prices are 10.1% higher, and average delivered gasoline prices are about 7.2% higher than the Reference case in 2025.

5.5.4 Conclusions and caveats of the study

The potential impacts of the policies proposed are highly dependent on the assumptions of the study. Some of the most important and uncertain factors for this type of study are the future oil, natural gas, and coal resources and prices. In light of recent run-ups in the imported refiner's acquisition cost (IRAC) of crude oil prices, it might have been wise to add an additional case, a high oil and natural gas price baseline, to see how the potential impacts might change. Hindsight, of course, is perfect.

- If a cap and trade system for carbon emissions were implemented in the United States, advanced natural gas generation technologies are likely to be an important transition to the lower carbon future.
- Renewable and nuclear generation are also likely to play a critical role, provided their actual capital costs are low enough, renewable resources remain unconstrained, and public acceptance is improved (e.g., the not in my back yard (NIMBY) syndrome).
- Advanced natural gas turbines (NGT) with a maximum utilization factor of 20% are sufficiently efficient that the prohibition on NGCC and IGCC without CCS technologies makes the NGT very economic relative to the CCS technologies, even at a 20% maximum utilization.

The level of subsidies adopted for CCS technologies does not improve the competitiveness of CCS in the U.S. through 2025. Through 2025, none of the CCS technologies are competitive with renewable and nuclear technologies. Factors that influence the uptake of CCS under the CO_2 constraint are the learning rates for all technologies that may compete with CCS systems. In this case, the costs and performance of renewable, natural gas, and nuclear generation technologies are projected to remain more economic than the CCS technologies.

6. Synthesis: Europe and the US

6.1 Introduction

This chapter provides an overview and synthesis of results of the following models: MARKAL, POLES, TIMES-EE, NEWAGE-W, and NEMS (US). Except for the NEMS model, which describes the US, all models have focused on Europe. The POLES model has placed the European developments in a global perspective.

This report concentrates on the role of CO_2 capture and storage (CCS) technologies in the power sector. Three policy approaches are compared in order to address the question how to achieve significant CO_2 emission reductions through the application of CCS technologies.

- Case 1: 'CCS standards' requires that from 2015 onwards, all new power plants have to be equipped with a CO_2 capture facility[20]. These standards are not applied to peaking plants with a utilisation rate of 20% and small CHP-plants.
- Case 2: 'CO_2 constraint' takes the emission level from the standards case as an upper bound for the overall emissions. No other policies are assumed.
- Case 3: 'CCS subsidies' uses the same emission path as in Case 2. Moreover, a subsidy on CO_2 capture technologies is given. This subsidy is 35% of the investment cost at its introduction in 2015 and will be reduced by one percent each year until it is back to zero in 2050.

6.1.1 Assumptions

Most models have applied approximately the same set of capture technologies. Additionally, the technologies that prove to be most important are also the most common. Post-combustion systems, that separate CO_2 from the flue gases after combustion, are generally coupled to supercritical pulverised coal (PC) plants, or to natural gas combined cycle power plants (NGCC). Pre-combustion systems, which extract the CO_2 and combust or use the resulting hydrogen, are used in combination with an integrated coal gasification combined cycle plant (IGCC), or with a biomass gasification plant. Oxyfuel combustion, which is still in a demonstration phase, has not been modelled. Some models have also included CO_2 capture in hydrogen production processes (gas steam reforming or coal partial oxidation) and in industry, in the production of cement, cokes, and ammonia.

There are differences in how transportation and storage of carbon is modelled. Some models have a wide array of storage options with capacities whereas others have a generic storage technology with infinite capacity. This also has an effect on the results, since for some models some storage options seem to be essential for making CCS viable. Also the modelling of transportation costs varies.

The case set-up differs somewhat between models and this probably also has some effect on the results. Small CHP plants and peak-load facilities were left outside the standards required in Case 1 by those models that were able to define plants according to these characteristics. It is unclear how large an effect these plants have in general, but at least in two cases (NEMS and MARKAL) these plants left outside the policy play a significant role. Since many models were not able to make these exceptions to the policy, it is not known whether similar developments would have occurred in these models as well.

[20] Turkey and the rest of Central Europe regions overtake the obligation to install capture equipment later, in 2025. This is apparent in the results of the POLES model.

6.2 Results Europe and US

6.2.1 Primary energy consumption

Figure 6.1 presents the primary energy consumption in 2030 for three of the models. Most other models indicate similar tendencies. The introduction of CCS standards for electricity generation technologies leads to a reduction in coal use and an increase in less carbon intensive fuels - particularly renewables and nuclear. The standards cause carbon-free technologies to be more competitive against the fossil fuel technologies in the power sector, which face an increased cost due to the additional CCS investment. In addition, there is a shift towards those fossil fuel options that were excluded from the standards policy.

For Cases 2 and 3, the shifts are due to the carbon value following from the imposed CO_2 constraint. Again, a reduction in coal consumption for power generation is primarily offset by increases in renewable resources and nuclear fuel consumption. For some models this increase in carbon free fuels is larger in Cases 2 and 3 and for some in Case 1. The tendencies become stronger towards 2050.

According to the NEMS model (US), none of the CCS technologies become economic in Case 2 and 3, where the U.S. energy market is free to choose the most economic way to meet the CO_2 target. Consequently, these two cases are virtually identical.

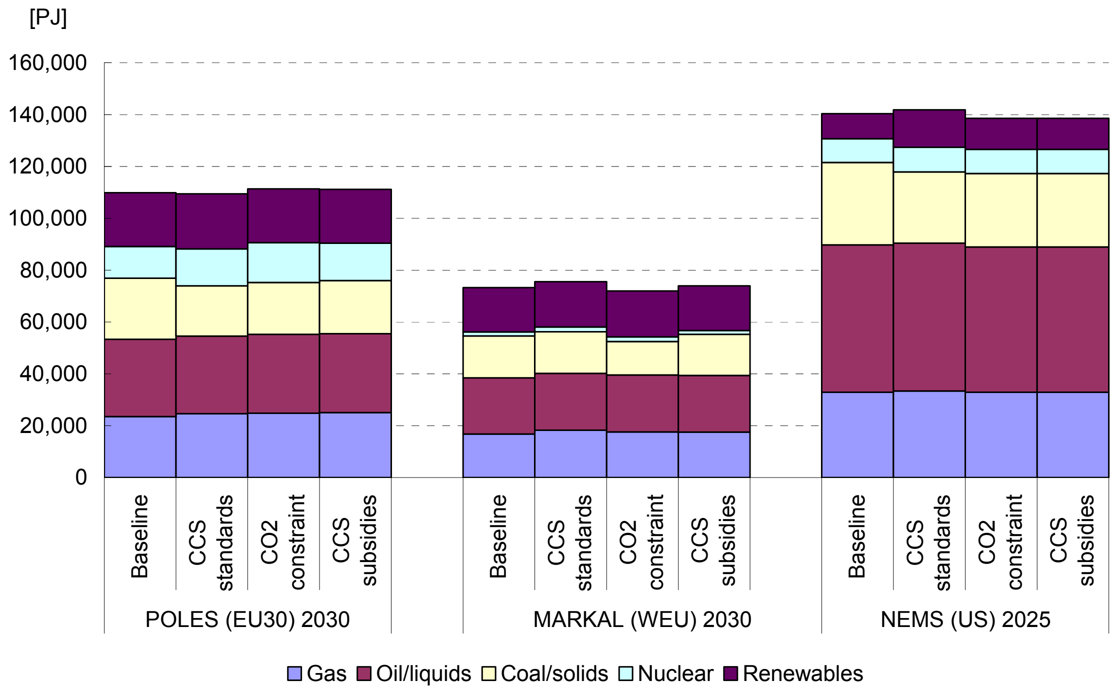


Figure 6.1 *Primary energy consumption in 2030*[21]

6.2.2 Electricity production

As most changes occur in the power sector, it is interesting to look in more detail to the effect of the different scenarios on the electricity generation mix. Figure 6.2 compares this for three of

[21] POLES results are presented for the region EU-30, which contains the EU-25, Romania, Bulgaria, Turkey and the Rest of Europe region (Switzerland, Norway, Iceland, and the former Yugoslav countries. The MARKAL region WEU (Western Europe) encompasses the EU-15, Norway, Switzerland and Iceland.

the models, and shows the shifts towards the CCS options. It becomes apparent that there are large differences among the models in expected size of the CCS contribution in 2030. To a large extent, these differences are already present in the respective baselines. MARKAL, for instance, shows even in the baseline CO_2 capture from coal fired power plants in 2030, while TIMES-EE and POLES have a much larger share of nuclear power in their baseline.

CCS standards

The fossil fuel plants used in Case 1 are mostly advanced coal based power plants (i.e. IGCC + CCS). Carbon capture from coal fired power plants is preferred over carbon capture in natural gas using power plants, although in 2030 also some gas fired power plants are equipped with a post combustion capture facility. In Cases 2 and 3, where the CO_2 constraint is imposed, more natural gas power plants are installed instead of coal capacity in the baseline. Only the TIMES-EE model shows a growth in natural gas capacity in Case 1. These natural gas plants were built before the standards were implemented. Although the latter effect is a consequence of the 'perfect foresight' feature in the model, it indicates that the market may try to circumvent anticipated policy measures.

Even in Case 1, sizeable capacities without capture technologies remain in the system until 2050. They are either the (mainly gas fired) peak-load capacities excluded from the standard, or (only in the POLES projections) some remaining coal capacities close to the end of their lifetime.

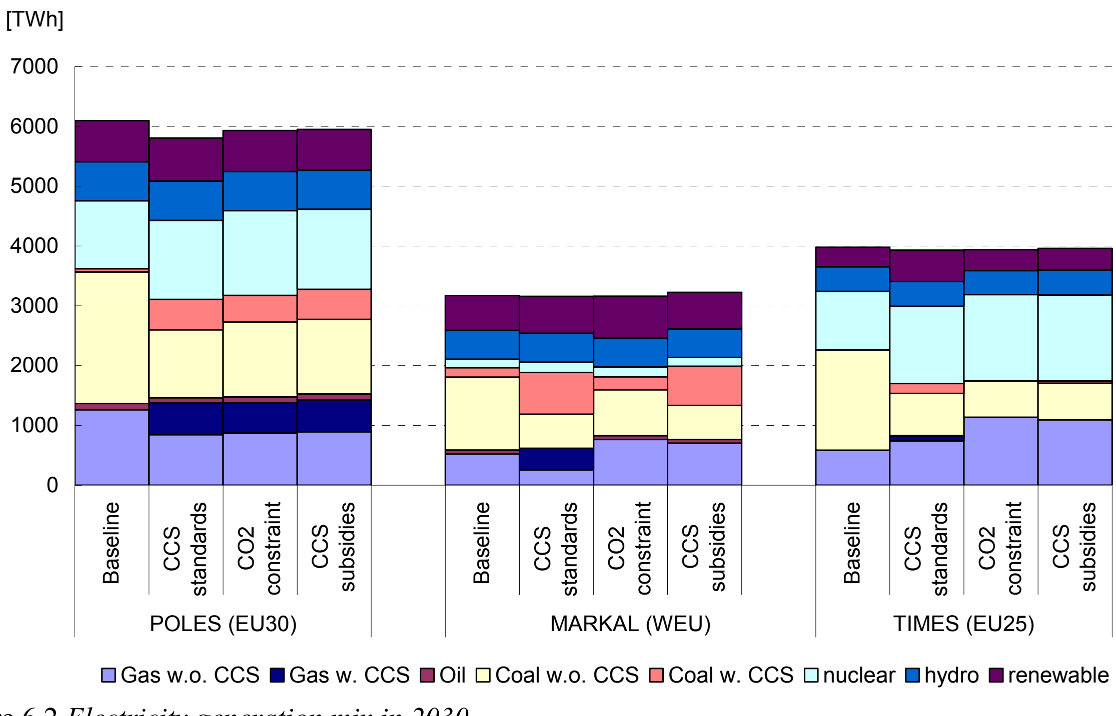


Figure 6.2 *Electricity generation mix in 2030*

CO_2 constraint and CCS subsidies

The effect of subsidies is relatively minor. The subsidy considered here starts in 2015 at 35% of investment costs, and decreases with 1% per year to zero in 2050. As illustrated in Figure 6.2, in 2030, when the subsidy covers still 20% of investment costs, it induces more CCS to be installed than in Case 2, although it obviously has a less direct effect than the standard. By 2050, most models show hardly any difference between Case 2 and 3 anymore. This demonstrates that the subsidy level as analysed in this case study is instrumental in speeding up the introduction of the CCS technologies, but it suggests that a slower decrease of subsidy level would probably have a more lasting impact.

Thus, although Case 3 brings the introduction of CCS technologies earlier than the simple CO_2 constraint case, the share of the CCS technologies in the electricity production remains limited.

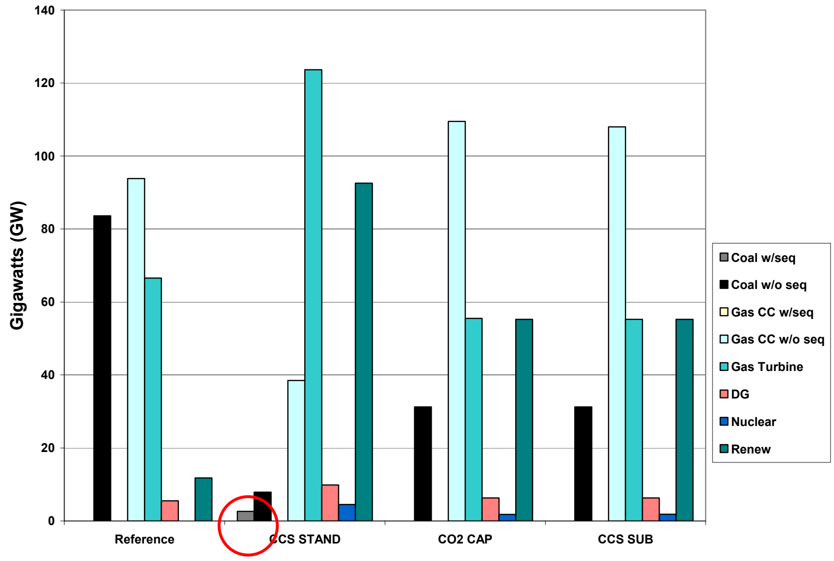


Figure 6.3 Projected US capacity additions in 2025

Similarly, in the US (NEMS model), as shown in Figure 6.3, the implementation of the CCS standards in the power sector causes fossil-fired electricity generation to be substantially reduced while renewable and nuclear power generation are increased. There is also a clear shift towards the gas turbines and DG, which were left outside the standard. In Case 2 and 3, none of the CCS technologies are projected to be economic in the United States through 2025.

The NEWAGE-W model has compared the economic impact of providing a CCS subsidy to the case where a cost reduction occurs thanks to a 'technology breakthrough'. Due to the very low absolute level of CCS technologies in Western Europe, there is no significant subsidy-induced impact on income. There is less than 1% small difference in economic activity due to the additional cost for the subsidy. Given the negligible differences in electricity generation due to a subsidy compared to a specific cost reduction induced by a technology breakthrough, the consideration of the economics effects regarding the financing aspects of subsidies can be ignored.

6.2.3 Effects on CO_2 emissions

By definition of the policy cases, the emissions are nearly the same in Cases 1, 2 and 3. The CCS standards, as imposed in Case 1, do have significant impacts on the carbon emissions. By 2050 carbon emissions are reduced by 13% and 29% at European level (MARKAL and POLES respectively). However these figures are based on the net emissions, and the reductions are much smaller (8% and 14% respectively) when looking at gross emissions level (i.e. net emissions + capture). Figure 5.8 illustrates that the emission reduction is mainly achieved in the power sector, not only in Case 1, but also in the carbon constrained cases, although these provide more flexibility for the system to adjust to the carbon limit.

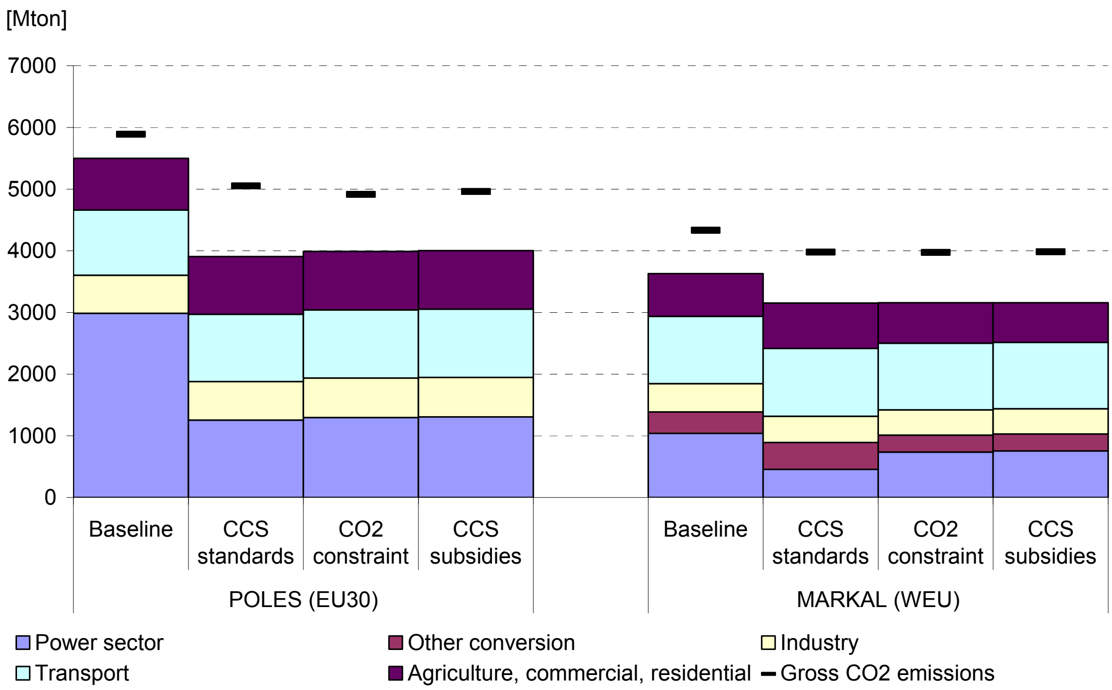


Figure 6.4 *Gross and net CO_2 emissions over sectors in 2050*

The TIMES-EE model reports that in 2030, the total amount of CO_2-emissions reduction *in the power sector* will be almost 600 Mton CO_2 (37%) for the EU-25 compared to the baseline. However, in Case 1, only some 22% of this reduction is caused by CCS, the rest is based on shifts towards renewables, nuclear power and towards natural gas plants, which were built before the standards were implemented.

NEMS also reports that, due to an enhanced flexibility in reaching the reduction target, the distribution of CO_2-mitigation options is different under Case 2 compared to Case 1. In the former case, the inter-fossil fuel switching (renewables, natural gas NGCC, and nuclear substituting for some of the coal-fired generation), and end-use demand reductions play a dominant role in the CO_2 abatement. The *CCS standards* case projects a significantly larger contribution of renewable and nuclear generation to the emission abatement process and a small contribution by CCS technologies through 2025.

6.2.4 CO_2 storage

Figure 6.5 shows the storage options employed in the different models. The POLES model projects most of the CO_2 to be stored in geological reservoirs, particularly remaining oil fields (some 55%) and depleted oil and gas fields (45% by 2050). Although MARKAL agrees on the choice of geological reservoirs, it projects most of the storage to be done in enhanced coal beds with methane recovery (ECBM). This is economically attractive because of the revenues related to the recovered methane (natural gas). Due to the combination of limited capacity of ECBM and high utilization of capture technologies, CO_2 is also stored in depleted gas and oil fields in the standards case.

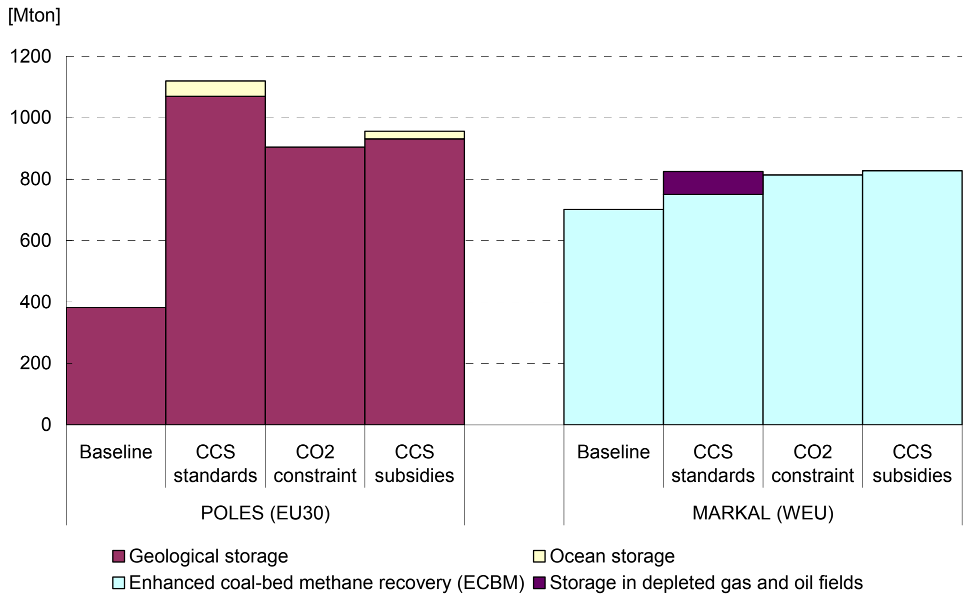


Figure 6.5 *Amount of CO_2 stored by type of reservoir in 2050; POLES and MARKAL*

The TIMES-EE model projects much less CO_2 to be stored by 2030 than POLES and MARKAL; 115 Mton compared to some 500-700 Mton respectively. TIMES-EE expects most of this 115 Mton CO_2 to be stored in Germany (52 Mton CO_2) followed by Poland (17 Mton CO_2) and Spain (16 Mton CO_2). Main reason for this lower estimate is probably the regional division of storage capacity used in TIMES-EE. This is based on regional differences in storage capacity and takes into account the contribution of coal in the electricity production. It is furthermore important to note that some countries lack the possibility of shifting to nuclear or renewables.

The availability of storage capacity does not impose limits to the amount of CO_2 stored in the time frame to 2050. Estimates range from 300 Gton (MARKAL, WEU) to 825 Gton (TIMES, EU-25). The different use of storage reservoirs and the differences in amounts stored among the models seems significant, but is closely related to the uncertainties in storage potentials. An important issue rests with non-economic parameters (or not directly economic) such as proximity of the reservoir to a source of CO_2, and physical potential.

6.3 Consequences

6.3.1 Effects on system costs and the costs of CO_2 reduction

Case 1, where standards are imposed, is for most models by far the most expensive one and Case 2, where it is left to the market to find the most cost-effective way of reducing CO_2-emissions, the cheapest. Since the carbon emissions are similar in all three cases, Case 1 has also higher average reduction costs per ton of CO_2.

In MARKAL, due to model specific restrictions, the subsidy in Case 3 is basically a function of capacity, thus making the investment cost a function of only cumulative capacity (instead of cumulative capacity and time from the introduction of subsidy). The inclusion of additional costs from assumed prototypes and R&D make this case quite expensive; even if the model decides to make no investment in the technologies there is still a considerable cost included from these R&D efforts. With a normal subsidy no additional costs would be included if no investments were made by the model.

NEWAGE-W reports that in Case 1, the obligation to use CCS technologies for conventional fossil power plants leads to a decrease in GDP. Between 2010 and 2030 the gross domestic product for Western Europe decreases approximately 1.5% compared the Business as Usual scenario without a CCS standard.

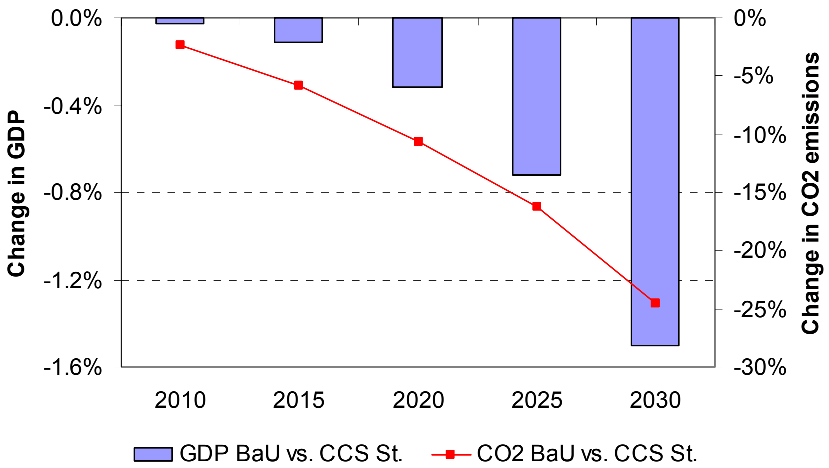


Figure 6.6 NEWAGE - CO_2 constraint (Case 2) compared to baseline

6.3.2 Security of supply

The fuel shifts caused by the CCS scenarios affect the import dependency for natural gas, particularly in the situation that CO_2 storage in ECBM leads to recovery of natural gas. This is shown by the MARKAL model, where the import fraction of gas is strongly related to the utilization of CCS technologies and ECBM. The higher levels of CO_2 capture and storage in 2030, especially in Cases 1 and 3, lead to a decrease of the gas import share from 60% to 40%. However, by 2050, methane recovery from coal beds becomes exhausted in the CCS scenarios, and the import share increases again, even further than in the baseline because the early deployment of CCS technologies has induced an increased reliance on gas.

According to the POLES model, the CCS scenarios do not induce significant differences in security of supply indicators compared to the baseline.

6.4 Conclusions

The analysis presented here shows that CCS can provide an important contribution to mitigating climate change. The models project up to 30% CO_2 net emissions reduction in the EU-25 in 2050, due to a policy that obliges new fossil power plants to install CCS as of 2015. However, the uncertainties, particularly in storage options and potentials, are large. This section gives the main conclusions of the comparison of model results.

Three policy instruments have been compared. First, obliging CCS for new fossil fuelled power plants, as in Case 1, is neither a very effective nor a cheap option for carbon mitigation. Due to the strict nature of such standards, fossil based systems that are able to stay outside this policy benefit greatly. As expected, CCS standards do, however, guarantee a rather high level of CCS penetration in most models. Secondly, cross sectoral policy schemes introducing a carbon cap, like Case 2, not only provide cheaper mitigation options but also prevent a ‘carbon leakage’ between sectors. Both these policy instruments also strongly encourage an increase in the use of renewable energy sources and nuclear power. An exception is the third instrument studied here, a direct subsidisation of capture technology. Subsidies can have a strong impact on short-term investments. However, investment subsidies of the level and design considered here, are not sufficient to have a very lasting effect on CCS technology development and other variables (i.e. emission target, price of other mitigation options) seem to have a stronger impact.

The uncertainties related to the amount of CCS installed, and when, are large. Storage potentials in Europe seem sufficient for a long period of time - although there is a large range in estimates. Different models estimate different schedules for the introduction of CCS technologies. For some models almost no CCS can be expected during the next few decades, unless rather tight emission targets are set, while for others already a CO_2 tax of 10 €/tCO_2 - as assumed in the baseline - is enough to bring these technologies in. One of the explanatory factors is whether there are other benefits to be gained by storing CO_2 in depleted gas or oil fields.

The single motivation for stimulating CCS remains in mitigating climate change. CCS has no security of supply benefits, except when used in combination with hydrocarbon recovery, where this benefit can even induce a greater (temporary) reliance of fossil fuels.

Finally, it should be noted that there are several important aspects to CCS that models do not take into account. The importance of infrastructure and the availability of reservoirs near a point source of CO_2 was already mentioned. Furthermore, several legal and regulatory issues, related to risks and liabilities still need to be dealt with, and not much is known yet about public acceptance. Finally, CCS has not yet established itself in the climate change negotiations, and it needs an accepted accounting methodology in the Kyoto regime. The actual deployment of CCS will greatly depend on how these aspects are addressed.

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[lp1]Martine, er ontbreekt hier een figuurtitel.

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[lp2]Martine, er staan 3 verschillende publicaties van IEA in 2004 in het rapport. Kun jij kijken welke a - b en welke c is en dit in de tekst ook aanpassen?