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CCS Global

Prospects of Carbon Capture and Storage Technologies (CCS) in Emerging Economies

Final Report

to the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU)

Part III:

Country Study *China*

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Final Report

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Concluding Hypotheses / Zusammenfassende Thesen
I. General Status and Prospects of CCS
II. Country Study India
III. Country Study China
IV. Country Study South Africa
V. Comparative Assessment of Prospects of CCS in the Analysed Countries

Elaborated by

Wuppertal Institute
Dipl.-Umweltwiss. Andrea Esken
Dipl.-Umweltwiss. Samuel Höller
Dr. Daniel Vallentin
Dr. Peter Viebahn (Project Co-ordinator)

With subcontracts to
Dr. Pradeep Kumar Dadhich (The Energy and Resources Institute, New Delhi)
Prof. Dr. Can Wang (Tsinghua University, Beijing)
Prof. Dr. Rosemary Falcon (University of the Witwatersrand, Johannesburg)
Dr. Werner Zittel (Ludwig-Bölkow-Systemtechnik, Ottobrunn, Germany)
Teresa Gehrs (LinguaConnect, Osnabrück)

Assistance by
Holger Liptow (GIZ)
Christina Deibl, Bianca Falk, Florian Knüfelmann, Geo Kocheril (Wuppertal Institute)

Contact

Dr. Peter Viebahn
Wuppertal Institute for Climate, Environment and Energy
Research Group “Future Energy and Mobility Structures”
Döppersberg 19
42103 Wuppertal
Germany
Tel.: +49 202/2492-306
Fax: +49 202/2492-198
E-mail: peter.viebahn@wupperinst.org
Web: www.wupperinst.org/CCS/

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List of Abbreviations, Units and Symbols

Abbreviations

3E	Institute of Energy, Environment and Economy
ACCA 21	Administrative Centre for China's Agenda 21
ADB	Asian Development Bank
af	Annuity factor
$Al2O_3$	Aluminium oxide
AP	Acidification potential
APEC	Asia-Pacific Economic Cooperation
APP	Asia-Pacific Partnership
ARA	Amsterdam, Rotterdam and Antwerp
BAFA	German Federal Office of Economics and Export Control
BAU	Business as usual
BP	British Petroleum
CAGS	CO_2 Geological Storage Project
CAPPCCO	Chinese Advanced Power Plant Carbon Capture Options
CATF	Clean Air Task Force
CaO	Calcium oxide
CBM	Coalbed methane
CCICED	China Council for International Cooperation on Environment and Development
CCS	Carbon (dioxide) capture and storage
CCUS	Carbon (dioxide) capture, use and storage
CEEP	Centre for Energy and Environmental Policy
CERC	Clean Energy Research Centre
CIDA	Canadian International Development Agency
CIPC	China Investment Power Corporation
CH_4	Methane
CHDR	China Human Development Report
CML	Centrum voor Milieukunde in Leiden/Netherlands
CNPC	China National Petroleum Corporation
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2-EOR	CO_2-based enhanced oil recovery
$CO_{2\text{-eq}}$	CO_2 equivalents
COACH	Cooperation Action within CCS China-EU
CO2CRC	Cooperative Research Centre for Greenhouse Gas Technologies (AUS)
CPIC	China Power Investment Corporation
CRI	Coke reactivity index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSLF	Carbon Sequestration Leadership Forum
CTL	Coal to liquid
CUCBM	China United Coalbed Methane Corporation Ltd.

DECC	Department of Energy and Climate Change (UK)
DCL	Direct coal liquefaction
DGPC	Dongguan Power and Chemical Industry Holding Co. Ltd.
DOE	U.S. Department of Energy
EC	EmissionsControl
ECBM	Enhanced coalbed methane
ECUST	East China University of Science and Technology
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EP	Eutrophication potential
EPC	Engineering, procurement and construction
EREC	European Renewable Energy Council
ERI	Energy Research Institute
EU	European Union
EUA	EU emissions allowances
EXW	Price ex mine
FGDS	Flue gas desulphurisation units
FOB	Free on board
FOR	Free on rail
FOBT	Free On Board Trimmed
FWAETP	Fresh water aquatic ecotoxicity potential
FYP	Five-Year Plan
GB/T	Coke for metallurgy
GDP	Gross domestic product
GHG	Greenhouse gas
GIS	Geographic information system
GWP	Global-warming potential
H_2	Hydrogen
HTP	Human toxicity potential
HUST	Huazhong University of Science and Technology
IDC	Interest during construction
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas programme
IGCC	Integrated gasification combined cycle
IGG-CAS	Institute of Geology and Geophysics, Chinese Academy of Science
ISO	International Organization for Standardization
IMELS	Italian Ministry of Environment, Land and Sea
IPCC	Intergovernmental Panel on Climate Change
IRSM	Institute of Rock and Soil Mechanics
LBNL	Lawrence Berkeley National Laboratory
LBST	Ludwig-Bölkow Systemtechnik (GER)
LCA	Life cycle assessment
LCI	Life cycle inventory

LCIA	Life cycle impact assessment
LCOE	Levelised cost of electricity
LHV	Lower heating value
LLNL	Lawrence Livermore National Laboratory
LPS	Large point source
LR	Learning rate
MAETP	Marine aquatic ecotoxicity potential
MDEA	Methyl diethanolamine
MEA	Monoethanolamine
MEP	Ministry of Environmental Protection
METI	Ministry of Economy, Trade and Industry (Japan)
MIIT	Ministry of Industry and Information Technology
MIT	Massachusetts Institute of Technology
MLR	Ministry of Land Resources
MOF	Ministry of Finance
MOST	Ministry of Science and Technology
MWR	Ministry of Water Resources
N_2	Nitrogen
NaOH	Sodium hydroxide
NDRC	National Development and Reform Commission
NEA	National Energy Administration/Nuclear Energy Agency
NEC	National Energy Committee
NEPU	North China Electric Power University
NGO	Non-governmental organisation
N_2O	Nitrous oxide
NO_x	Nitrous oxides
NO_2	Nitrogen dioxide
NYMEX	New York Mercantile Exchange
NZEC	Near Zero Emissions Coal (China)
O_2	Oxygen
ODP	(Stratospheric) ozone depletion potential
OECD	Organisation for Economic Co-operation and Development
O&M	Operation and maintenance
OOIP	Original oil in place
PC	Pulverised coal
PCC	Pulverised coal combustion
PCCI	IHS CERA Power Capital Costs Index
POP	Photochemical oxidation potential
PR	Progress ratio
QHD	Qinhuangdao
RCIEP	Research Centre for International Environmental Policy
RB	Richards Bay
R&D	Research & development

RD&D	Research, development & demonstration
RET	Australian Department of Resources, Energy and Tourism
RITE	Research Institute of Innovative Technology for the Earth
R/P	Resource-to–production ratio
SASAC	State-owned Assets Supervision and Administration Commissions of the State Council
SC	Supercritical
SICCS	Sino-Italy CCS Technology Cooperation Project
SO_2	Sulphur dioxide
SO_x	Sulphure oxides
S&T	Science and technology
TETP	Terrestrial ecotoxicity potential
THCEC	BP Clean Energy and Education Centre at Tsinghua University
TPRI	Thermal Power Research Institute
UHV	Upper heating value
UNDP	China Human Development Report
UNFC	United Nations Framework Classification
USA	United States of America
USC	Ultra supercritical
USGS	United States Geological Survey
US-EPA	US Energy Administration
UN	United Nations
VAT	Value-added tax
w/o	without
WEC	World Energy Council
WI	Wuppertal Institute for Climate, Environment and Energy
WRI	World Resources Institute
WVU	West Virginia University
WWF	World Wide Fund for Nature
ZEP	Zero Emission Fossil Fuel Power Plants

Units and Symbols

°C	degree Celsius
a	annum
af	annuity factor
AUD	Australian dollar
bbl	barrel
bn	billion
C_{Cap}	specific capital expenditure
C_{fuel}	specific fuel costs
C_{min}	Minimum cost
C_{max}	Maximum cost
CNY	Chinese yuan
$C_{O\&M}$	specific operating and maintenance costs
C_{TS}	specific cost of CO_2 transportation and storage
d	day
E	efficiency factor
el	electric
EUR	euro
g	gramme
GJ	gigajoule
Gt	gigatonne (1 billion tonnes)
GW	gigawatt
h	hour
I	real interest
kcal	kilocalorie
kg	kilogramme
km	kilometre
kt	kilotonne
kWh_{el}	kilowatt hour electric
kWh_{th}	kilowatt hour thermal
m	metre
MJ	megajoule (0.278 kWh)
MPa	mega Pascal
Mt	megatonne (1 million tonnes)
MW	megawatt
n	depreciation
Scm	standard cubic metre
t	tonne
Tcf	trillion standard cubic feet
t-hce	tonnes of hardcoal equivalent
th	thermal
tkm	tonne-kilometre

TWh	terrawatt hour (1 billion kWh)
USD	United States dollar
USD-ct	United States cent
€	euro
%	per cent
%pt.	percentage point

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III. Country Study China

The aim of this study is to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries have been chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal.

The analysis is designed as an integrated assessment, and takes various perspectives. The main objective is to analyse how much CO_2 can potentially be stored securely and for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential is compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis is framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The following sections present the results of the *China* case study.

First of all, section 16 gives an overview of the status and development of CCS in China. Thereafter, China's potential for CO_2 storage in geological formations is estimated (section 17). Based on an assessment of existing studies, storage scenarios (S1–S3) are developed to show the range of possible storage capacities. Thirdly, coal development pathways for coal-fired power plants (E1–E3) and industrial sites (I) are developed for China (section 18). The aim of this section is to determine how much CO_2 would have to be stored underground in the long term after being captured from power plants and coal-to-liquid (CTL) plants. In the next step, the two estimates are combined (section 19). The aim is to determine how much of the estimated storage capacities could be used for storing CO_2 emissions separated from flue gas emitted from power plants and industrial sites. Due to the considerable uncertainty surrounding both sources and sinks, qualitative source-sink matching is conducted.

This main analysis is supplemented by an analysis from socio-economic, ecological and resource-strategic standpoints to reach an integrated assessment of the role CCS could play in China. First, the quality, quantity and geographic locations of coal reserves and resources in China are studied (section 20). This is followed by an assessment of the cost of electricity and CO_2 mitigation of coal-fired power plants in China, considering CCS and comparing it with the same power plants without CCS (section 21). Next, the environmental (and social) aspects of coal-based power production are considered (section 22). In section 23, the constellation of key CCS stakeholders in China is assessed by applying semi-standardised, qualitative research interviews together with a standardised survey. The aim is to reflect the willingness of decision-makers to embrace CCS technology in China.

Finally, conclusions are drawn from the integrated assessment of CCS in China in section 24. Both sections on the provision of coal development pathways and on CO_2 storage capacities in China are based on a general introduction to global CO_2 mitigation scenarios and CO_2 storage issues. These can be found in sections 1 and 4 of Part I of this study, respectively.

16 Status and Development of CCS in China

16.1 General Energy Situation in China

As the largest developing country in the world with a population of 1.37 billion (National Bureau of Statistics 2011), China covers an area of 9.6 million square kilometres. Ever since its Open Door Policy and economic reform in 1978, China has experienced an average 9.9 per cent annual growth of gross domestic product (GDP) (National Bureau of Statistics 2010). It became the world's largest emitter of CO_2 in 2007 (The Netherlands Environmental Assessment Agency 2007), and this growing trend is set to continue in the years ahead. The major reason for China's considerable CO_2 emissions is the country's strong dependence on coal as its fundamental energy source to fuel economic growth (Fig. 16-1). This is not set to change for a considerable time to come. In its 11th Five-Year Plan (FYP), China reduced energy intensity by 20 per cent, requesting all regional governments to ensure this target is met and to establish specific energy efficiency targets for different sectors. In the future, it will face a more challenging task of CO_2 mitigation as the target of 16 per cent reduction of energy intensity was set for its 12th FYP period, and a 40 to 45 per cent reduction in CO_2 emissions per unit of GDP by 2020 compared to the 2005 level was announced at the Copenhagen conference in 2009 (Xinhua Net 2011).

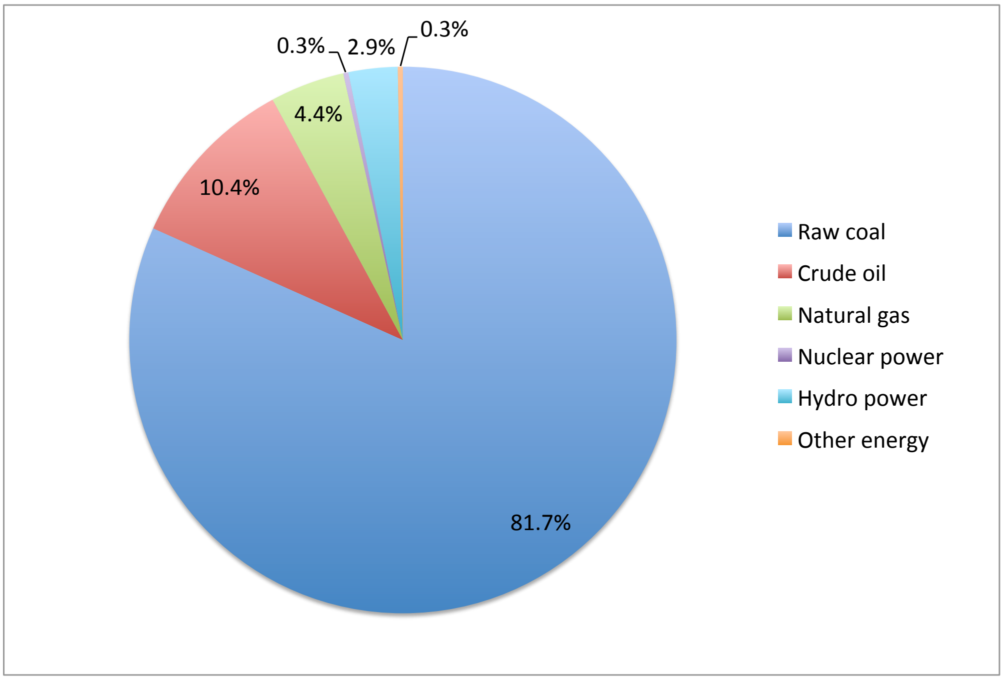


Fig. 16-1 Primary energy structure in China in 2009

Source: Authors' illustration, based on Energy Department of National Bureau of Statistics (2011)

CCS, which first appeared in China's 11th FYP, is regarded as one of the promising options of clean coal technology. It is assumed that China will enhance its endeavours to develop CCS (Chen 2011; Liang et al. 2011; Liu and Gallagher 2009; Seligsohn et al. 2010). Of the countries considered in this study, CCS research, development and demonstration (RD&D) activities are most advanced in China. Several projects related to CCS are being conducted under the National High-Tech Research and Development Programme (also called "863 Programme") and the National Basic Research Programme (also called "973 Programme"), mainly controlled by the Ministry of Science and Technology. The overall budget available for CCS-related research in the 863 and 973 Programmes totalled CNY 30 million; a total of CNY 36 million was made available in the period from 2008 to 2010 (Liu 2009).

In the following section, the fields of CO_2 capture processes and usage for CO_2 capture in which China is active are described, as well as ongoing and planned research projects (see section 2 of Part I for a general overview of technologies). At the end of the section, Tab. 16-1 will present a summary of the projects, divided into capture technology and emissions sources. In addition, the development stage of each capture technology is included. These are described as either ongoing, if operations commenced in 2011 or 2012, or in their infancy if the project is still at an early stage of development.

16.2 Research, Development and Demonstration Projects on CO_2 Capture in China

16.2.1 CCS Activities

Post-Combustion

The most relevant research activities in the field of post-combustion capture technology were pooled in the “Development of Carbon Capture and Storage” project under the 863 Programme. The project ran from May 2008 to December 2010, with CO_2 capture technologies based on absorption and adsorption representing two of three research topics:

- *Absorption-related research:* explores the applicability of high-efficiency CO_2 absorption solvents, fillers for the absorber, new high-efficiency absorption/separation equipment and technologies, CO_2 absorption process simulation technology and integration and optimisation technologies.
- *Adsorption-related research:* focuses on high-efficiency adsorption materials, CO_2 adsorption process simulation technology and new integration and optimisation technologies.

Seven operating or planned projects are related to post-combustion, most of which use monoethanolamine (MEA) in the capture process (see Tab. 16-1). Most of the projects are being undertaken by industrial companies such as Huaneng, Sinopec and CPIC. In two commercially operational projects, the CO_2 captured is supplied to the food and beverage industry (Shidongkou and Gaobeidian). Two projects at the early stage are to be linked with CO_2-based enhanced oil recovery (CO_2-EOR) (Shengli and Harbin). Most of these projects are on a small scale comprising kilotonnes of CO_2; only the enhanced oil recovery (EOR) projects realised by Shengli and Harbin are on the one megatonne scale.

Oxyfuel Combustion

Departments at several Chinese universities, including Tsinghua University, Huazhong University of Science & Technology, Zhejiang University, Southeast University and North China Electric Power University, are researching and developing oxyfuel combustion technologies in China. The Department of Thermal Engineering at Tsinghua University is testing a 25 kW experimental furnace system for oxy-combustion; Huazhong University has developed a 300 kW system. Southeast University and Zhejiang University have developed pilot designs for circulating fluidised bed oxyfuel combustion. R&D activities encompass both pulverised coal oxyfuel combustion, circulating fluidised bed oxyfuel combustion and the production of oxygen for oxyfuelling. Regarding pulverised oxyfuel combustion, Tsinghua University aims at testing the impact of different oxygen shares (30, 35 and 40 per cent) in the oxidising medium on the composition of the flue gas and CO_2 concentration. For O_2 production, Tsinghua University is conducting research on using O_2/CO_2 gases with an oxygen share of 30 to 40 per cent as an oxidising medium to reduce the costs of energy-intensive oxygen production via cryogenic air separation (Cai 2009).

There is only one early-stage project involving oxyfuel combustion (Daqing). This project, undertaken by Datang Power and Alstom, is planned to be linked with CO_2-EOR.

Pre-Combustion

Going against the current international trend, pre-combustion technologies are a prominent element of China's R&D strategy on CCS, as the national government has a great interest in coal-fired poly-generation systems based on coal gasification. Under 973 Programme, a syngas production project based on coal gasification and pyrolysis has been proposed to ameliorate the problem of gas emission and pollution in China's coal industry. The aim of the project is to develop a poly-generation system based on coal gasification, enabling low-cost, high-efficiency, clean power generation. The technology problems under investigation deal primarily with designing coal gasification and optimising dual gas systems (NZEC 2009a). In general, Chinese technology providers have made rapid progress in the field of coal gasification, enabling Chinese research institutes and universities to commence exporting their technologies to industrialised nations. Two recent cases include the licensing of petroleum coke gasification technology to the U.S. refiner Valero Energy Corporation by East China University of Science and Technology (ECUST) and an agreement by the Thermal Power Research Institute to provide the U.S. firm FutureFuels with gasification technology (Gallagher 2009).

Four larger scale (mostly 0.1 to 1 Mt of CO_2) pre-combustion projects are being planned. Within 863 Programme, the development and construction of three integrated gasification combined cycle (IGCC) demonstration power plants has been commissioned and partially funded. These projects are not as well developed as the post-combustion power projects – only the GreenGen project was inaugurated in September 2011. The other three projects are still at the early planning stage. The IGCC projects are being realised by authorities and industrial partners. All four projects include the possibility to use captured CO_2 for EOR either close by or within a radius of 200 km.

Research and Development

In addition to these examples, two further large research projects are being realised in China: the NZEC project and the COACH project. The joint UK-China Near Zero Emissions Coal (NZEC) initiative comprises a large number of UK and Chinese project partners. Launched in 2007, it is mainly funded by the UK government's Department of Energy and Climate Change (DECC) in partnership with China's Ministry of Science and Technology (MOST). Research is divided into three phases. The first phase comprised capacity-building and knowledge sharing between China and the UK, as well as options for demonstrating the technology. The second phase will involve work being carried out on capture and storage options, leading to phase 3, in which a demonstration plant will be constructed by 2015.

The other large research project, closely linked to NZEC, is the COACH project (COoperation Action within CCS CHina-EU). This project is funded in part by the European Union (EU) under the 6th Framework Programme. It involves the development of large-scale coal gasification for poly-generation of energy, hydrogen and synthetic fuels. In addition, potential geological sinks are identified and funding mechanisms, regulatory frameworks and public acceptance analysed and developed.

16.2.2 Fields of Use

New Fossil-Fired Power Plants

China's installed power generation capacity has undergone impressive growth over the last decade from 338 GW in 2001 and 508 GW in 2005 to 713 GW and 793 GW in 2007 and 2008, respectively. In 2008, the annual growth rate was 11 per cent, compared to 22 and 15 per cent in 2006 and 2007 (Minchener 2010). Coal-fired units accounted for more than 75 per cent of the capacities installed in 2007 and for about 80 per cent of total power production. In 2007, subcritical pulverised coal plants with efficiencies ranging from 30 to 36 per cent represented the largest proportion (464 GW) of China's installed coal-fired generation capacity. The number of supercritical (91 GW, 112 units) and ultra supercritical (9 GW, 10 units) plants is significantly smaller. Furthermore, the coal-fired power plant fleet is characterised by a large share of small units with capacities below 600 MW (327 GW), representing about 72 per cent of capacities installed in 2006 (Minchener 2010). 600 MW plants with supercritical or ultra supercritical technology dominate the new power plant projects (IEA 2009a). At present, about 60 per cent of all newly built power generation units are supercritical. Modernisation of China's power sector is expected to increase the average efficiency of coal-fired power generation from 32 per cent in 2005 to 39 per cent in 2030 (IEA and OECD 2007). Fig. 16-2 illustrates the current and projected mix of technologies of China's coal-fired power capacities.

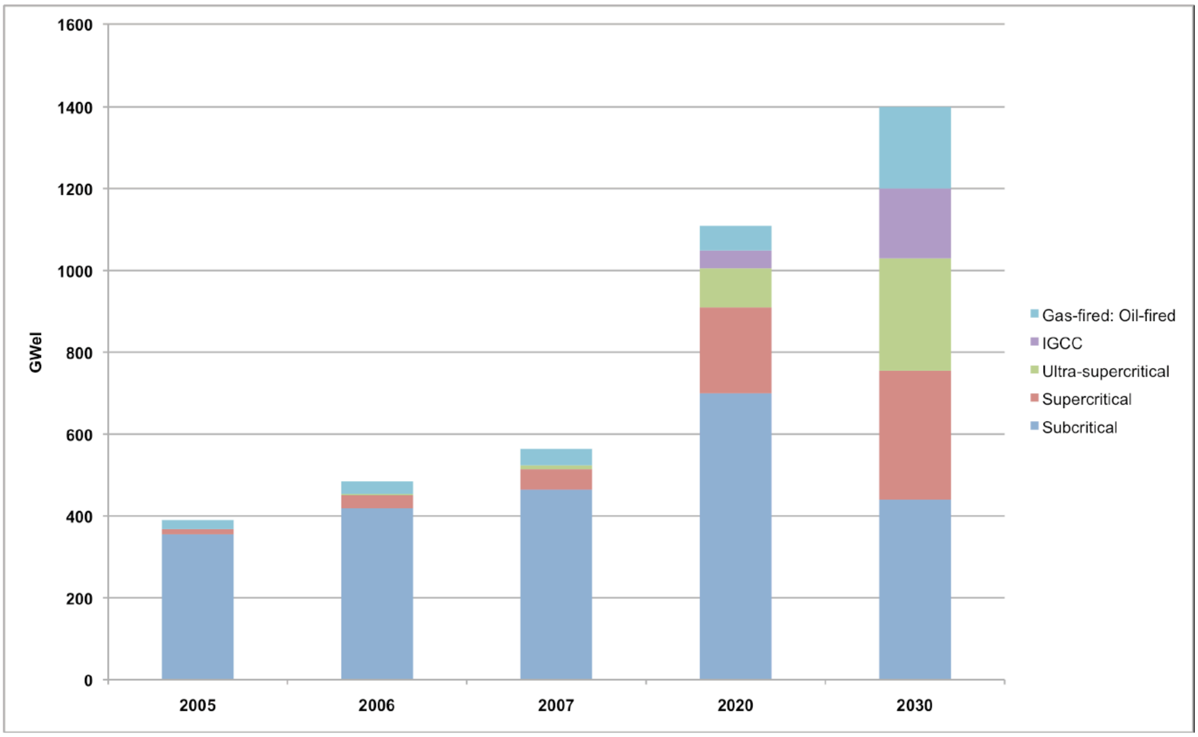


Fig. 16-2 Current and expected coal-fired power technologies in China, 2005–2030

Source: Authors' illustration, based on IEA (2009b)

The ongoing modernisation of China's power plant capacities enhances their technical compatibility with carbon capture technologies, which should be installed in large-scale, highly efficient plants to alleviate the economic penalty of CCS. Since numerous new fossil-fired power plants will be erected before and after CCS becomes available, there is high demand for CO_2 capture-ready plants or retrofits at existing plants and new facilities. At present, there is no commercial-scale power plant equipped with CCS in China. The Chinese government recognises the technology as a future technological option for greenhouse gas mitigation and is willing to participate in international RD&D and networking efforts to that end. However, there is not yet an incentive system, such as the European emission trading system, that could potentially stimulate the commercial launch of CCS in China.

Retrofitting CO_2 Capture at Operating Fossil-Fired Power Plants

In 2008, China's total installed thermal power capacity was 601 GW, which is equivalent to nearly 80 per cent of its overall power generation. In recent years, the number of large power plants has increased due to government regulations. In January 2007, the National Development and Reform Commission (NDRC) announced the closure of a total of 50 GW of small coal-fired generation units by 2010 to reduce coal consumption and local air pollution. Meanwhile, NDRC has indicated that any new coal-fired plants should have at least the capacity and the electrical efficiency equivalent to a 600 MW supercritical (SC) plant or an ultra supercritical (USC) unit if at all possible. As a consequence, supercritical and ultra supercritical coal-fired units have become the main fleet of the newly installed power capacity. For this reason, new power plants feature greater electrical efficiency, making them more suited for CCS retrofits.

A survey of key stakeholders in China's power sector and industry conducted by Reiner and Liang (2009) indicates that the key elements of the capture-ready definition introduced by the International Energy Agency Greenhouse Gas Programme (IEA GHG 2007) – reserving sufficient space, considering future retrofit in plant design and building a plant near a geological storage site – were advocated by around half of the Chinese respondents. The majority of the Chinese stakeholders interviewed (78 per cent) declared their willingness to make new power plants capture ready if the required pre-investments were equivalent to about 1 per cent of the plant's total fixed capital expenditures. About two thirds of respondents claimed that they would also accept a 2 per cent cost increase relative to plant investment costs to make plants capture ready. Such a cost increase would be equivalent to USD 7.2 to 9.6 million in the case of a 600 MW plant, assuming that its capital costs are USD 600 to 800 per kW (Reiner and Liang 2009).

At present, the Chinese government provides no incentives for power utilities to design their power plant fleet to be capture ready. The development is limited to a number of demonstration plants, many of which are being realised in bilateral collaborative projects. Japan and China are planning to retrofit two 600 MW coal-fired power plants in Heilongjiang Province with post-combustion capture equipment, linked by pipeline to a nearby oil field. The project is scheduled to be commissioned by 2011. The aim of the "Chinese Advanced Power Plant Carbon Capture Options" (CAPPCCO) project is to create a database on the carbon capture characteristics of existing and planned power plants, and to evaluate their suitability for CO_2 capture retrofits. The project is funded jointly by the UK government's Department of Energy and Climate Change (DECC) and China's Ministry of Science and Technology (MOST) (NZEC 2009a).

16.2.3 Industrial Processes

Not only is CCS of interest to the power sector, it also plays a crucial role in discussions with Chinese experts regarding industrial processes. Many respondents mentioned the *utilisation* of CO_2 in industry branches (carbon capture, use and storage, CCUS). For instance, CO_2 is used for chemical and fuel production, in the food and beverage industry and for enhanced oil recovery (CO_2-EOR). Both governmental institutions and industry players are investing in CCS demonstration research (compare Tab. 16-1).

16.2.4 Fuel Production

Coal to Liquid

Globally, China has advanced the furthest in fostering the commercialisation of coal-to-liquid (CTL) technologies. Although China tested Fischer-Tropsch technologies in the 1950s and 1960s, the country failed to bring about the technology's commercialisation due to economic constraints. However, owing to the growing gap between national oil demand and domestic oil production, the conversion of coal into liquid hydrocarbons has gained new prominence and is considered a promising near- to medium-term alternative fuel option. Furthermore, CTL is a good option for mine-mouth plants in remote coal-producing regions since coal-derived liquids can be distributed using existing pipelines, avoiding bottlenecks for coal transportation. The Reference Scenario of the World Energy Outlook 2007 (IEA and OECD 2007) projects that China's CTL production capacity will reach 184,000 barrels per day by 2015, 250,000 barrels per day by 2020 and 750,000 barrels per day by 2030.

Two indirect facilities with a total initial capacity of 8,000 barrels per day are currently under construction. Two additional plants – one indirect and one hybrid facility – with a total capacity of 84,000 barrels per day are at the planning stage (Vallentin 2009). A large-scale direct coal liquefaction plant is already in operation. The plant, owned by Shenhua, China's leading coal mining company, is located in Erdos, Inner Mongolia. A first trial run was completed in January 2009. A second trial run was scheduled for completion by September 2009 (Su and Fletcher 2010). Plant capacity is planned to be expanded to 66,000 barrels per day if the first operating phase is successful.

The Shenhua direct coal liquefaction plant will produce nearly 3.4 million tonnes of CO_2 per year. In 2008, the Chinese government curtailed the coal liquefaction programme due to concerns about pollution and excessive water consumption. Several projects were suspended. Hence, Shenhua is considering capturing the CO_2 produced during the liquefaction process and storing it in the adjacent Ordos basin. For other CTL plants currently under construction, CCS is not considered a mandatory precondition due to the insufficient momentum of climate policy in China. Nonetheless, Synfuels China, a leading Chinese manufacturer and developer of Fischer-Tropsch technology, is assessing CCS for the long term. It has a preference for plant sites close to oil fields suitable for enhanced oil recovery (Vallentin 2009).

Ongoing or Planned Projects

Seven projects address CO_2 capture from industrial sources. These very diverse projects include two coal-to-liquid plants with IGCC capture (funded by 863 Programme), hydrogen production, a methanol plant and natural gas processing. The CO_2 captured is then used not only for EOR projects and onshore storage, but also for chemical and biodiesel production. So far, most of the projects have been planned as small scale with regard to the amount of CO_2 captured (tonnes to kilotonnes). Only two CTL plants are being considered for upscaling to megatonnes of CO_2. The projects in this section are financed by industry, research institutes and the government.

16.2.5 Storage Projects

Several storage projects are at the planning stage, underlining China's intention to demonstrate the entire CCS chain alone. However, most of these projects are linked to EOR or coalbed methane production (ECBM).

PetroChina is planning ten wells in the Jilin oil field for EOR. A number of CO_2 capture projects are being planned to provide the EOR operation with the necessary CO_2. Another EOR project is being realised in the heavy oil field of Daqing, Heilongjiang, operated by an industry and science consortium, where the assumed total storage capacity is estimated to be 150 Mt of CO_2. The third EOR project is planned to be implemented at Bohai basin (Tianjin), where the long projected GreenGen IGCC plant (to start in 2017) shall be used as a CO_2 source. The amount of CO_2 to be stored has not yet been specified.

ECBM projects are being planned in Shanxi Province by the Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) and China United Coalbed Methane Corporation Ltd. (CUCBM) with a total of 2,000 tonnes of CO_2 being injected. Since this project commenced as early as in 2003, 1,100 tonnes of CO_2 have already been injected. This year, the small ECBM project at Qinshui basin is supposed to start operating, with just 150 tonnes of CO_2 to be injected.

In addition, Shenhua Group and General Electric are planning a CCS plant in Inner Mongolia (Ordos basin). It is thought that 2.9 million tonnes of CO_2 will be injected annually by 2011.

Tab. 16-1 Overview of CCS RD&D projects in China

Project name/ location	**Project developer/ operator**	**Plant type (capacity)**	**Capture process**	**CO_2 captured**	**CO_2 utilisation or sequestration**	**Project status/ description**
Post-combustion (in operation)						
Huaneng Gaobeidian Experimental Unit, Power Plant, close to Beijing	Collaboration China-Australia Chinese consortium members: Huaneng Group, Xi'an Thermal Power Research Institute Australian consortium members: Commonwealth Scientific and Industrial Research Organisation (CSIRO)	845 MW installed capacity AUD 4 million cost estimate	Retrofit, MEA	3(–5) kt/a; so far, the capture rate was about 80 to 85%; the captured CO_2 will be purified to 99.5% and sold to the food/ beverage industry		Operations started in summer 2008. By the end of January 2009, about 900 tonnes of CO_2 had been captured Commercial
CPIC Chongqing Hechuan Pilot Unit at Shuanghuai Power Plant, Chongqing	China Power Investment Corporation (CPIC) and Chongqing Energy Investment Co., Ltd.	Phase I: 2x300 MW subcritical (2006) Phase II: 2x660 MW ultra supercritical (first 660 MW unit in operation Feb. 2011) Total installed capacity will be 4,000 MW Budget Phase II: USD 740 million Total investment: >USD 1.5 billion		10 kt/a with concentration of >99.5%. CO_2 capture rate exceeds 95% of CO_2 from a total of 500 million Scm gas/a		Capture operations started on 20 January 2010. Relies completely on Chinese technology and equipment
Shidongkou No. 2 Power Plant (Baoshan district), North Shanghai	Huaneng Power International and TPRI	2,660 MW PC USC units; USD 22 million investment	MEA	100–120 kt/a with purity >99.5%	Reuse of CO_2 in food/beverage industry	Capture equipment started operating at end of December 2009 Commercial
Post-combustion (operations starting in 2011/2012)						

Project name/ location	Project developer/ operator	Plant type (capacity)	Capture process	CO_2 captured	CO_2 utilisation or sequestration	Project status/ description
Flue gas capture from Shengli power plant and EOR in Shengli Oilfield, Shandong Province	Sinopec			0.1 kt/d pilot; 14% CO_2 in waste gas (purifying to 99.5%); 1 Mt/a demo is under construction	EOR and storage of 80 t/d in Shengli Oilfield (low-permeability reservoirs)	July 2010: started capture and EOR with 0.1 kt/d 2013–2014: 1Mt/a demo plant
Dongying, Shandong (near Shengli Oilfield)	Alstom Power and Datang Power	Partial post-combustion capture at 1,000 MW plant			Purification, displacement and sequestration with 100 Mt/a	In discussion; operation in 2015
Guodian CO_2 capture and utilisation pilot project, Tianjin Beitang Power Plant, Tianjin	China Guodian Corporation			20 kt/a; capture rate >95%; purity >99.5%	Usage in the beverage industry	Operations set to start at the end of 2011
Post-combustion (early project stage)						
Harbin Thermal Power Plant / Heilongjiang Province	Collaboration between China and Japan. Japanese consortium members: Ministry of Economy, Trade and Industry (METI), JGC Corporation, Japan Coal Energy Center, Toyota Motors, Mitsubishi, Research Institute of Innovative Technology for the Earth (RITE). Chinese consortium members: NDRC, CNPC-PetroChina, Daqing Oil Field Ltd., Harbin district government, Harbin Utilities Company, China	Harbin Thermal Power Plant: PCC, 600 MW Plus potentially one other PCC 600 MW plant	Retrofit	1–3 Mt/a	EOR; CO_2 will be transferred by pipeline to an oil field for EOR	

Project name/ location	Project developer/ operator	Plant type (capacity)	Capture process	CO_2 captured	CO_2 utilisation or sequestration	Project status/ description
	Huadian Corp.					
Oxyfuel combustion (early project stage)						
Daqing, Heilongjiang	Datang Power, Alstom	350 MW oxyfuel power plant in Daqing			Use of CO_2 for EOR	Companies are in discussion
Pre-combustion IGCC (starting operation in 2011/2012)						
GreenGen / Tianjin Binhai New Area (Bohai basin), Tianjin	GreenGen Consortium (China Huaneng Group (52%); China Datang Corp., China Huadian Corp., China Guodian Corp., China Investment Corp., Shenhua Group, China National Coal Group, State Development and Investment Co., Peabody Energy (USA)	IGCC/H_2 plant Phase I (2005–2011): 250 MW with TPRI's dry feed gasifiers Phase II (2012/2013–2017): add capture unit Phase III (2017–2020): 2x 400 MW Producing syngas		Phase I: 25–30 kt test injection (power); 1 Mt/a in Phase III	2 MW pilot system for testing coal to hydrogen, fuel cells and CCS; sequestration plan is under development, including EOR in Dagang Oilfield (Bohai basin)	Start-up date for Phase 1 is September 2011 (for CSLF meeting in Beijing), USD 3.3 bn costs; funding from 863 Programme and Asian Development Bank (USD 1 million for CCS part, USD 135 million loans) Mainly Chinese technology, only turbines from Siemens
***Pre-combustion IGCC** (early project stage)*						
Clean Energy Technology Demonstration Project; Lianyungang City, Jiangsu Province	Chinese Academy of Science, Jiangsu Province and Lianyungang City Municipality	1,200 MW IGCC plant, two 1,300 MW USC PC power plant, 10 MW solar thermal power generation and chemical co-production plant	Pre- and post-combustion	0.1–1 Mt/a	Aquifer storage; EOR at Subei Oilfield, 200 km north of plant site.	Approval in 2011, construction 2012–2015, to be operational by 2016
Hongmei Taiyangzhou, Dongguan City, Guangdong Province	Collaboration between Southern Company/Dong Guan Power and Chemical Industry Co.	800 MW (IGCC)		0.1–1 Mt/a	100 km from Baoyue oil and gas field and Zhushangang oil field, both within the Sanshui basin Suitable for EOR/EGR	To be operational by 2015; plant will be based on technology by Southern Company developed in cooperation with the U.S. Department of Energy (DOE)

Project name/ location	**Project developer/ operator**	**Plant type (capacity)**	**Capture process**	**CO_2 captured**	**CO_2 utilisation or sequestration**	**Project status/ description**
CPIC Langfang Plant, near Beijing and Tianjin, Hebei Province	China Power Investment Corporation (CPIC)	Two 488 MW IGCC units		Capture from syngas (8% CO_2 concentration in syngas)	Adjacent oil field in North China Oilfields only 1 km away (e.g. Huabei field), making EOR a prime possibility	Waiting for final green light from NDRC
Industry sources (in operation)						
Jinlong-CAS CO_2 utilisation in chemical products, Taixing, Jiangsu Province	Jiangsu Jinlong-CAS Chemical Co., Ltd.	CO_2 capture from ethanol production plants	CO_2-based resin loop reactor	8 kt/a	Production of 22 kt/a CO_2-based poly(propylene (ethylene)carbonate) polyol	2010: 10 kt/a biodegradable plastics (expansion to 30 kt in 2013); 2011: 50 kt/a production of poly(propylene(ethylene) carbonate) (100 kt in 2016)
Industry sources (operations starting in 2011/2012)						
Microalgae Bio-Energy and Carbon Sequestration Pilot, Dalate, Inner Mongolia Province	ENN Group	Coal-derived methanol plant and coal-derived dimethylether production (Pilot system: production of 20 t of biodiesel and 5 t of proteins per year)	Absorption of CO_2 in flue gas by microalgae	Pilot system: 0.11 kt/a absorption; Pilot plant: 320 kt/a absorption	Production of biodiesel and feeds from microalgae	Pilot plant to be completed in 2011
China CO_2 sequestration and enhanced coalbed methane Recovery Project, Qinshui basin, Shanxi Province	CUCBM (funding from NDRC and MOST)		No capture: purchase of CO_2 from other plants and transportation to injection site		240 t of CO_2 to be injected (April/May 2010 for injection test); CO_2 sequestration and ECBM; Depth 400 to 600m; Injection in horizontal wells in Qinshui basin	Project has been underway since 2004; Next step is to increase depth to 1,000 m

Project name/ location	Project developer/ operator	Plant type (capacity)	Capture process	CO_2 captured	CO_2 utilisation or sequestration	Project status/ description
					(east of Ordos)	
Shenhua DCL project, Majiata coal mine in Ordos basin of northern Inner Mongolia	Shenhua (cooperation with Lawrence Berkeley National Laboratory LBNL and Lawrence Livermore National Laboratory (LLNL) in West Virginia)	Direct coal liquefaction (DCL) project with 1–3 Mt/a transportation fuels	Pre-combustion; CO_2 is captured after coal gasification for hydrogen production (high temperature in process)	2.9 Mt/a emitted; 0.1 Mt of CO_2 is captured and stored in first phase; upscaling to 1 Mt possible	Storage in adjacent saline aquifer in Ordos basin; single injection well for 100 kt/a (plus two monitoring wells); depth: 2,000 to 3,000 m EOR was considered but abandoned due to uncertain CO_2 provision and very close aquifer (<10 km)	Operation started in 2011 Investment of USD 30.8 million; operation at USD 50/t of CO_2 Other source: USD 1.4 bn investment
Industry sources (early project stage)						
Yulin City, Shaanxi Province	Chinese-U.S. collaboration: U.S.: Dow Chemical China: Shenhua	Coal-to-liquid plant with 1–6 Mt/a fuel production	Pre-combustion	5–10 Mt/a	Storage onshore	Very early planning stage; to be operational by 2020
CO_2 EOR Research and Pilot Project, Jilin Oilfield, Jilin Province	PetroChina (supported by MOST and CNPC)	Capture from carbonated natural gas reservoir (22% CO_2 content in gas)		Separate and capture from highly-carbonated natural gas 200 kt/a	122 kt of CO_2 injected by May 2010 for EOR; 80 kt of which are stored; 51 kt of CO_2 used to displace oil	Operation of first phase started in 2008; 2nd phase (2015) 500 kt oil flooding capacity; with storage of 0.8 to 1 Mt/a
Liaohe Oilfield, Inner Mongolia	Huafu High-Tech Group, China Liaohe Petroleum Exploration Bureau		Unknown	Flue gas from steam and oil-fired boiler is injected with 12 to 13% CO_2	CO_2-EOR and aquifer storage	Tests have been conducted since 1998; research is part of the CAGS programme

Source: Authors' compilation

17 Assessment of China's Potential for CO_2 Storage

17.1 Introduction

The aim of this section is to provide an overview of the potential for the geological sequestration of CO_2 in China. After briefly describing the geology of China, existing storage capacity calculations will be explained. Since these vary considerably, certain basin- and site-specific assessments for five basins will be explored in detail, along with their different formations (oil fields, gas fields, saline aquifers and unmineable coal seams). Although the site-specific assessments do not contain information on all fields and basins, these results are compared with assessments for the whole country to verify the certainty of the total storage capacity results. In this manner, the most realistic storage capacity calculation for each formation is chosen as the base value for potential storage site capacities in China. Finally, sensitivity analyses for higher and lower capacities are introduced, which are used to develop storage scenarios.

A general remark concerning geological and reservoir data must be made at this point because there is a great reluctance in China to publish and share data. The petroleum companies control a lot of the geological data, especially for oil and gas fields, but they are unwilling to make them publicly available. Data is very scarce for saline aquifers, which puts China on a par with virtually all other countries of the world. Some researchers disclosed that they are permitted to work with confidential data, but may not publish them. For this reason, this confidential data could not be considered in this study.

17.2 Geological Situation in China

China is one of the largest countries in the world and has very diverse geology. It consists of 34 terranes, formed from the Late Paleozoic to the Early Tertiary. These terranes are fragments of continental, oceanic or island crusts with specially preserved geology. Terranes are different to their surroundings and are usually bounded by faults. When the Indian subcontinent collided with Central Asia 65 million years ago, the terranes were accreted and the Himalayan Ridge started to emerge. Sedimentary basins were formed whilst they moved together. Most sedimentary basins in China are Mesozoic (Jurassic, 150 to 200 million years ago) or Cenozoic (Tertiary and Quaternary, less than 65 million years in age). The sediments were deposited in fluvial-lacustrine environments. The basins are very heterogeneous due to local tectonics and climatic variations. These neotectonic events are the reason why there are diverse multi-layer sediment systems, with ten or even more layers. Fig. 17-1 provides an overview of China's geology. The country's coal resources are mainly concentrated in northeast China (Moores and Fairbridge 1997).

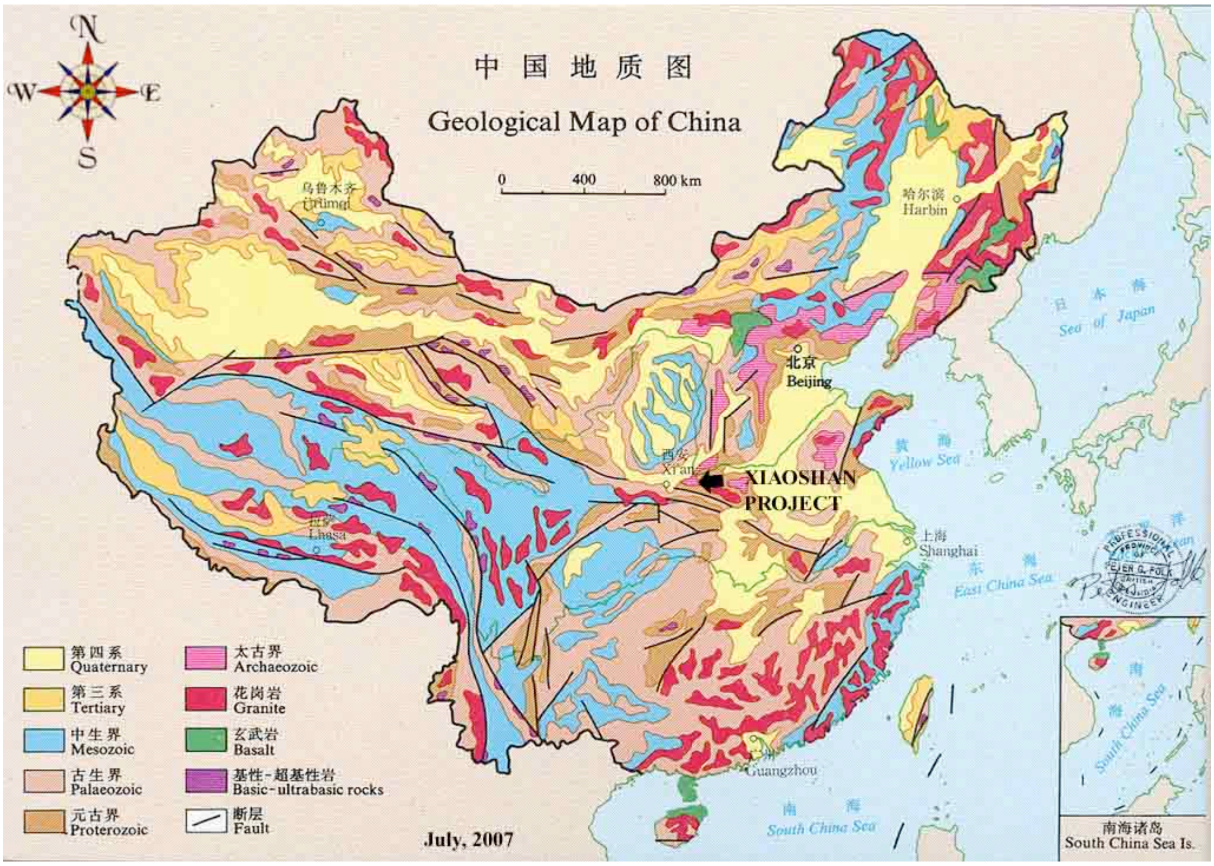


Fig. 17-1 Geological map of China

Source: Folk (2007)

17.3 Overview of Existing Studies on China's CO_2 Storage Potential

17.3.1 Existing Country-Specific Studies

Following an intensive literature review, only three detailed studies deal with total storage capacity and provide information on all of the sedimentary basins of China where CO_2 could be stored. These are:

- The U.S.-based study entitled "Regional Opportunities for Carbon Dioxide Capture and Storage in China" (Dahowski et al. 2009) for which the geological expertise was provided by the Institute of Rock and Soil Mechanics in Wuhan;
- A study issued by the Asia-Pacific Economic Cooperation (APEC) conducted by the Australian Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) (CO2CRC and APEC 2005);
- An assessment by the China Geological Survey published in a short paper (Zhang et al. 2005a);
- For comparison, the estimate by Dooley et al. (2005) is included, which provides a total capacity for China, but lacks further detail.

All four assessed studies evaluate the CO_2 storage capacity at a theoretical level, which must therefore be classified as *theoretical capacity* on the techno-economic resource-reserve pyramid (see Fig. 4-6 of Part I). Tab. 17-1 gives a summary of the main studies. Whereas theoretical capacities in oil and gas fields are more or less in the same range (3–10 Gt), saline aquifer capacities vary between 16 and 3,068 Gt of CO_2. The most comprehensive assessment by Dahowski et al. (2009) delivers the highest estimate, but also includes sensitivity analyses to yield lower values for onshore aquifers (23, 230 or 1,150 Gt). The results for coal seams range between 0 and 12 Gt.

It should be noted that the *effective capacity* cannot be derived because none of the relevant parameters are given in the studies assessed. The effective capacity is usually lower than the theoretical capacity.

Tab. 17-1 Overview of existing storage capacity calculations for China

		CO2CRC & APEC	**Zhang et al.**		**Dooley et al.**	**Dahowski et al.**			
		2005	2005a, 2005b		2005	2009			
			Volumetric /proven	Solubility/ unproven		Solubility	S1	S2	S3
Oil fields		6.3	3.6 *)	7.8 *)	1	4.8			
Gas fields		3.5			2	5.1			
Coal seams		-	12		4	12.0			
Saline aquifers	Onshore	?	16.2	1,435	90	2,289	1,150	230	23
	Offshore	?			9	779			
Total		?	32	1,455	106	3,090	1,951	1,031	824

All quantities are given in Gt CO_2

*) Includes oil and gas fields.

S1, S2, S3 are sensitivity analyses with 50%, 10% and 1% of onshore saline formations.

Source: Authors' compilation

Study 1: Assessment by the Institute of Rock and Soil Mechanics in Wuhan

Dahowski et al. (2009) provide quantitative theoretical values for capacities in *aquifers*. The total pore volume of each basin is assumed by estimated bulk volume of the basins, an average porosity and net sand thickness (Tab. 17-2 and Tab. 17-3). Subsequently, CO_2 solubilities at various salinities of the formation water are applied to derive the dissolution trapping potential of the aquifer basins. Equilibrium is expected to be achieved after storage and a 100 per cent residual water saturation is yielded, meaning that no free phase CO_2 will remain in the formation. A specific storage density of 28 kg CO_2/m^3 of pore volume is calculated, leading to a total storage capacity of 3,067 Gt of CO_2 in 25 formations, roughly three quarters of which are onshore (2,288 Gt CO_2). Although the authors call their estimate a conservative capacity calculation, they also include a sensitivity analysis at 50 per cent (S1), 10 per cent (S2) and 1 per cent (S3) of the onshore capacity in aquifers (compare Tab. 17-1 for sensitivity results). This leads to values of 1,150, 230 and 23 Gt of CO_2, respectively, for onshore aquifers.

The calculation of capacity in *gas fields* is based on the original gas in place resource and a sweep efficiency of 75 per cent. As indicated in Tab. 17-3, only fields that can hold more than 2 Mt of CO_2 are included in the calculation. In total, 17 gas fields offer a capacity of 5.2 Gt of CO_2, one fifth of which is offshore.

The authors also provide estimates for capacity in *oil fields*. It is assumed that coupling CO_2 flooding for enhanced oil recovery with CO_2 storage leads to cost benefits for operators. Thus, first, the potential for enhanced oil recovery is estimated per oil field (these fields are situated in the basins shown in Tab. 17-3). This number is then taken to determine the amount of CO_2 required to extract the estimated oil available (0.34 to 0.56 tonnes of CO_2 per barrel of oil). A total of 7,020 million barrels of additional oil recovered using CO_2 is estimated for China, yielding a storage potential of 4.8 Gt of CO_2 in oil fields with a CO_2 capacity of more than 2 Mt. Most of this capacity is available onshore.

A similar approach is used for *coalbeds,* where the potential to enhance coalbed methane production is estimated first. It is assumed that 10 per cent of each coal basin contains coal-bed methane and that this can be extracted entirely by displacing the methane using CO_2. The storage capacity in coalbeds is derived from this fraction. The authors identified 45 potential coal basins with a CO_2 storage capacity of more than 2 Mt. This leads to a capacity of roughly 12 Gt of CO_2 (Tab. 17-3).

A total capacity of 3,089 Gt of CO_2 is derived. This figure would be slightly less if the minimum storage space per site is set at 100 Mt instead (3,087.5 Gt).

Tab. 17-2 Capacities of offshore sedimentary basins in China

	Closest province /region	**Thick-ness**	**Porosity**	**Saline aquifers**	**Oil fields**	**Gas fields**	**Coal seams**
		m	%	Gt CO_2	Gt CO_2	Gt CO_2	Gt CO_2
East China Sea	Fujian, Zhejiang, Jiangsu	300	0.15	341.8		0.2	
Southern Yellow Sea	Jiangsu, Shan-dong	300	0.15	133.8			
Bohai Bay	Shandong, Jing-Jin-Ji, Liaoning	300	0.2	109.2	0.1	0.0	
Zhujiangkou (Pearl River Mouth)	Guangdong, Hainan	300	0.15	69.7	0.0	0.0	
Yinggehai	Hainan	300	0.15	56		0.7	
Northern Yellow Sea	Jiangsu, Shan-dong	300	0.2	31.5			
Beibu Gulf	Guangxi, Guang-dong	300	0.15	23.8	0.0		
Western Taiwan	Fujian	100	0.1	11			
Luzhoudao	?	100	0.15	1.9			
Total offshore				*778.7*	*0.1*	*0.9*	

Source: Dahowski et al. (2009)

Tab. 17-3 Capacities of onshore sedimentary basins in China

Basin	Province/ region	Thickness	Porosity	Saline aquifers	Oil fields *)	Gas fields *)	Coal seams *)
		m	%	Gt CO_2	Gt CO_2	Gt CO_2	Gt CO_2
Tarim	Xinjiang	300	0.15	745.8	0.1	0.6	0.1
Ordos	Inner Mongolia, Ningxia Hui, Shaanxi, Shanxi, Gansu	300	0.15	256.5	0.4	1.1	4.5
Bohai	Shandong, Jing-Jin-Ji, Liaoning, Henan	200	0.2	233.3	1.9	0.3	
Songliao	Inner Mongolia, Jilin, Heilongjiang	200	0.15	227.8	1.6	0.6	
Zhunggar	Xinjiang	300	0.15	197.1	0.2	0.1	
Hehuai	Henan, Anhui	300	0.2	178			
Subei	Jiangsu	300	0.2	89.9	0.1	0.0	
Erlian	Inner Mongolia	200	0.15	85	0.0		
Sichuan	Sichuan	300	0.05	77.6	0.0	1.1	
Turpan-Hami	Xinjiang	300	0.15	54.3	0.1	0.0	2.2
JiangHan - Dongting	Hubei	150	0.2	52.8	0.0		
Sanjiang	Heilongjiang	200	0.15	44.9			0.2
Qaidam	Xinjiang, Qinghai	50	0.15	21.5	0.1	0.4	
Hailaer	Inner Mongolia	100	0.15	16.1			
Nanxiang	Henan	100	0.15	7.5	0.1		
Jiuxi - Jiudong - Huahai	Gansu				0.0	0.1	
Yilanyitong	Jilin				0.0		
Yanqi	Xinjiang				0.0	0.0	0.1
Santang Lake	Xinjiang						1.0
Eastern Junggar	Xinjiang						0.7
Qinshui	Shanxi						0.6
Ili	Xinjiang						0.6
Northern Junggar	Xinjiang						0.5
Southern Junggar	Xinjiang						0.3
Datong - Ningwu	Shanxi						0.2
Huainan	Anhui						0.1
Liupanshui	Guizhou						0.1
Other coal basins (<100 Mt of CO_2)							0.8
Total onshore				*2,288*	*4.7*	*4.3*	*12.0*
Total onshore + offshore				**3,067**	**4.8**	**5.2**	**12.0**

*) oil/gas fields and coal seams > 2 Mt CO_2

Source: Dahowski et al. (2009)

Study 2: Assessment by the Asia-Pacific Economic Council (APEC)

In this study, undertaken four years earlier than Study 1, CO2CRC and APEC (2005) classified China's sedimentary basins only qualitatively as having high, intermediate or low prospectivity concerning CO_2 storage in *saline aquifers*. In Fig. 17-2 the analysed basins are compared to significant point sources less than 300 km away. Most of the sources are concentrated in the more developed eastern part of the country. For this reason, the figure does not contain all of the basins listed in Tab. 17-3. Most of the evaluated basins consist of delta sandstones from lakes or rivers. The sediment layers are heterogeneous, but are sealed by continuous mudstone layers as sufficient cap rock.

According to this study, Bohai basin, Songliao basin and Subei basin in north-east China have the highest prospectivity for storing CO_2. Songliao is ranked first. Offshore basins in south-east China and close to Wuhan have intermediate or unresolved prospectivity. Other central Chinese basins such as Ordos, Sichuan and Nanpanjiang basins are assigned lower prospectivity (compare Tab. 17-4). These basins consist of complex polycyclic basins that are strongly faulted. What is more, their permeability and porosity values are poor. However, Ordos basin has the best prospectivity for storing CO_2 in coal seams. Most of the information on these basins originates from drilling for oil and gas exploration.

Tab. 17-4 CO_2 storage capacity and prospectivity of saline aquifers, oil, gas and coalfields in sedimentary basins of China

Name of basin	Site	Saline aquifers	Oil fields	Gas fields	CBM-based
		Prospectivity	Fields > 2 Mt CO_2		
Bohai	Onshore	High	3.2	1.3	-
Songliao	Onshore	High	2.0	0.1	-
Subei	Onshore	High	-	-	-
Pearl River Mouth	Offshore	Intermediate	-	-	-
East China Sea	Offshore	Intermediate	-	-	-
Taixinan	Offshore	Intermediate	-	-	-
Beibuwan	Offshore	Intermediate	-	-	-
Hehuai	Onshore	Intermediate	-	-	-
Shiwan Dashan	Onshore	Intermediate	-	-	-
Jianghan	Onshore	Intermediate	-	-	-
Nanyang	Onshore	Intermediate	-	-	-
Sanshui	Onshore	Intermediate	-	-	-
Junggar	Onshore	-	0.8	0.2	-
Tarim	Onshore	-	0.1	0.5	-
Sichuan	Onshore	Low	0.0	1.0	-
Nanpanjiang	Onshore	Low	-	-	-
Ordos	Onshore	Low	0.1	0.4	-
Yinggehai	Offshore	Low	-	-	-
Total		?	6.3	3.5	-
All quantities are given in Gt CO_2					

Source: Authors' compilation based on CO2CRC and APEC (2005)

China's known oil reserves total 48.4 billion barrels, which is converted to a storage capacity of 6,292 Mt of CO_2 in *oil fields* (0.1 billion barrels = 13 Mt CO_2 stored underground). The capacity in *gas fields* is estimated at 3,504 Mt of CO_2 from a total of known gas amounting to 43.8 trillion standard cubic feet (Tcf; 1 Tcf methane = 80 Mt CO_2 stored underground).

A large proportion of methane is released from *coalfields*, creating a large potential to capture the gas. In addition, although ECBM projects may be introduced in the future, at the moment they are the most uncertain way to store CO_2. For this reason, no capacity is assumed for coalbeds in this study.

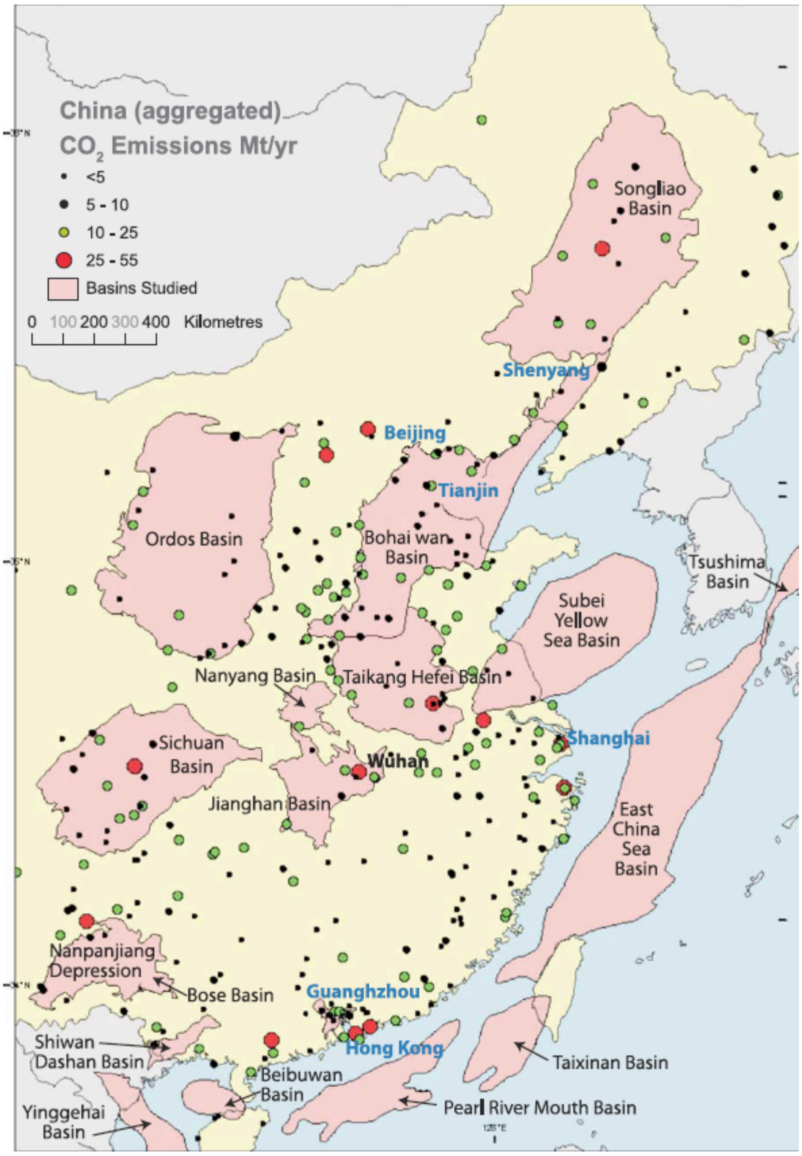


Fig. 17-2 CO_2 sources and geological sinks in eastern China

Source: CO2CRC and APEC (2005)

Study 3: Assessment by China Geological Survey

China Geological Survey also investigated storage capacities in China, the results of which are reported in a short paper (written in Chinese) (Zhang et al. 2005a). Regarding CO_2 storage in *deep saline aquifers*, the authors derive a total area of 70 million km^2. On the one hand, a storage capacity of 56,000 Gt of CO_2 is estimated when an average thickness of 200 m and a porosity of 10 per cent are assumed. If a higher average porosity of 20 per cent is assumed, capacities of 100,000 to 200,000 Gt of CO_2 would be available. When, on the other hand, the authors applied the following limitations, the impressive usable aquifer area declined to 340,000 km^2 (compare section 4.2.3 of Part I):

- Storage is limited to a depth where CO_2 is in a supercritical state (deeper than 1,000 m, ideally between 1,200 and 1,500 m);
- Only aquifers with sufficient porosity and permeability are taken into account;
- Aquifers are capped by a sealing rock;
- There are no ancient or active faults within the rock.

Suitable aquifers are located in four different regions of China: the Eastern Plain, the Yangtze Delta, the north-west arid inland basin and Sichuan basin. In all, 24 aquifer basins are selected, including Songliao basin, Bohai basin, Ordos basin, Sichuan basin, Dzungarian basin, Tarim basin, the Northern Yellow Sea basin, the Southern Yellow Sea basin and the Pearl River Mouth basin. The total storage capacity in these basins' deep saline aquifers is 1,435 Gt of CO_2.

Further information on the methodology applied and the parameters for potential basins can be found in a presentation by Zhang et al. (2005b). The storage capacity in *saline aquifers* is calculated in two ways. Firstly, the solubility method is used, which is comparable to Study 1. Based on a basin area of 2.7 million km^2, this method yields a total capacity of 14,350 Gt of CO_2 in all basins. Assuming saline aquifers make up 10 per cent of the total basin area, the capacity of 1,435 Gt of CO_2 mentioned above is yielded, which is roughly half of that determined in Study 1, despite taking a similar approach. Secondly, an enclosed volumetric method is used which is comparable to Equation 4.3 in Part I. The average thickness is assumed to be 100 m and a porosity of 20 per cent is chosen, referring to Hendriks et al. (2004). These assumptions lead to a capacity of only 16.2 Gt of CO_2. Compared to the calculation generated using the other method, resulting in 1,435 Gt of CO_2, this is a difference of approximately factor 100.

In addition, the authors estimate storage space in *oil and gas fields*. In particular, 46 oil fields are declared suitable for CO_2 injection, including Daqing, Shengli, Liaohe, Sichuan, Dagang and Jilin oil fields. CO_2-EOR operations are already being investigated or planned in some of these fields, which could bring further economic benefit in addition to CO_2 storage. Capacities in gas fields are estimated to be much lower.

The capacity in *oil fields* is calculated by estimating China's oil reserves and additional recovery from EOR operations using CO_2, comparable to Study 1. A factor of 75 per cent is applied, indicating that three quarters of the oil will be in contact with CO_2. This contact leads to a mixture of CO_2 with oil, which decreases the oil's viscosity.

A capacity of 7.8 Gt of CO_2 in oil and gas fields is yielded. The presentation also includes a slide showing proven CO_2 storage capacity. The total proven capacity is only 3.65 Gt of CO_2. In both cases, the highest capacities are offered by Songliao basin, Jiyang depression (Bohai basin) and Ordos basin.

The major *coalbed* areas in China are situated in Shanxi, Shaanxi and Inner Mongolia. Unmineable coal seams in these areas could be the target of CO_2 injection to increase the production of coalbed methane and to retain CO_2 in the subsurface. The CO_2 storage capacity in

Chinese coalfields is based on this potential of producing coalbed methane. The authors assume a total of 68 major promising coalbeds, categorised into ten different coal ranks (compare section 20). This yields a capacity of 12 Gt of CO_2 storage capacity in coalbeds.

In total, a capacity of 1,455 Gt of CO_2 is estimated if the solubility method for aquifers is applied and both proven and unproven oil and gas fields are included. If the volumetric method is used for aquifers and only proven oil and gas fields are considered, a much lower total capacity of 32 Gt is yielded.

Tab. 17-5 Storage capacity estimate based on the volumetric and solubility approach by China Geological Survey

		Chosen approach	
		Volumetric/proven	Solubility/unproven
Oil and gas fields	46 fields	3.65	7.8
Coal seams	68 major fields	12	
Saline aquifers	Onshore and offshore	16.2	1,435
Total		32	1,455
All quantities are given in Gt CO_2			

Source: Based on Zhang et al. (2005a, 2005b)

Other assessments

In addition to these detailed reports, a fourth study by Dooley et al. (2005) is included for comparison. However, this study lacks a scientific background, as it is only a very rough estimate without any country-specific characteristics. It results in a storage capacity of 106 Gt, whereby onshore aquifers offer the greatest capacity.

A brochure compiled by the Administrative Centre for China's Agenda 21 gives an overview of ongoing storage capacity assessments in China (ACCA21 2010). These include:

- The "Potential Capacity and Evaluation of CO_2 Geological Storage in China" project realised by China Geological Survey (2009);
- The "Investigation and Evaluation of CO_2 Geological Storage Capabilities" study by the Ministry of Land and Resources, included in the Monitoring and Evaluation of Global Climate Change (2009);
- The "Geological Mineral Support Engineering Program (2010–2020)", including investigations of underground storage resources;
- The "Potential Capacity Evaluation and Demonstration Project of CO_2 Geological Storage in China" study initiated by the Centre for Hydrogeology and Environmental Geology in the China Geological Survey (2010);
- A ranking of sedimentary basins for potential storage sites in China.

Unfortunately, these studies have not yet been completed, or the results are not available for inclusion in this study. Thus, the comparison of available studies for China's geological storage capacity needs to be updated with these results as soon as they become available.

17.3.2 Existing Site-Specific Assessment Studies

In addition to these studies, which explore China's total storage capacity, several research projects, such as NZEC, COACH and GeoCapacity, have conducted site- and basin-specific investigations. These studies deliver a much higher geographical resolution in their project results. The analysed formations are situated in the north-eastern part of China at the Bohai, Songliao and Subei basins. These are the three highly prospective basins according to CO2CRC and APEC (2005). Apart from these studies, Chinese researchers have conducted assessments of Ordos basin and the Pearl River Mouth basin. These two basins were evaluated as having intermediate (Pearl River Mouth basin) and low prospectivity (Ordos basin) (CO2CRC and APEC 2005). Since these five basins were studied the most intensively, they are selected for further analysis. The three largest are Bohai, Songliao and Ordos basins (see Fig. 17-2).

Bohai basin is situated in north-east China, mainly in Shandong Province and the Jing-Jin-Ji region, which includes the three provinces of Bei*jing*, Tian*jin* and Hebei (*Ji*). Much of the basin is offshore, off the coast of these provinces in the Bohai Sea. Smaller parts are located in the region of Liaoning and Henan provinces. Bohai basin is divided into several depressions called the Bozhong, Cangxian, Chengning, Huanghua, Jiyang, Jizhong, Liaohe, Linqing-Dongpu, Neihuang and Xingheng depressions. The Dagang oil field complex is located within the Huanghua depression. The Shengli oil field is located in the Jiyang depression.

Songliao basin comprises the three north-easternmost provinces Jilin, Inner Mongolia and Heilongjiang. Jilin oil field complex is in the Jilin Province; Daqing oil fields are located in Heilongjiang. *Ordos basin* covers Shaanxi, Shanxi and Gansu provinces, as well as the autonomous regions of Ningxia Hui and Inner Mongolia.

The two smaller basins are *Subei basin* in Jiangsu Province, as well as offshore areas (East China Sea), and the Pearl River Mouth basin offshore of Guangdong in south-east China. The location of all five basins is shown in Fig. 17-2.

Tab. 17-6 shows both the storage potentials derived by Dahowski et al. (2009), Zhang et al. (2005b) and CO2CRC and APEC (2005) for *saline aquifers* in these sedimentary basins (differentiated by solubility and volumetric approach as well as storage prospectivity) and the results available for *oil*, *gas* and *coalfields*, including IEA GHG (2009). The following interpretations are derived:

- For saline aquifers, the difference in the results yielded by the volumetric and the solubility method by Zhang et al. (2005b) is enormous;
- Using the solubility approach, a high storage potential in aquifers between 230 and 260 Gt of CO_2 is calculated for Bohai, Songliao and Ordos basins;
- As mentioned in CO2CRC and APEC (2005), Bohai, Songliao and Subei basins are highly prospective. Ordos basin is not very prospective, although other authors estimate the capacity to be high;
- The only offshore basin amongst these five is the Pearl River Mouth basin, which offers the lowest capacity in aquifers according to Dahowski et al. (2009), but the highest according to Zhang et al. (2005b) who used the solubility approach;
- Studies for oil fields do not vary as much as estimates for saline aquifers;

- The Bohai and Songliao basins also provide the highest storage capacity in oil fields (1.6 to 1.9 Gt CO_2);
- Gas fields offer less capacity. The largest capacities can be found in Bohai basin (up to 1.3 Gt CO_2) and Ordos basin (1.1 Gt CO_2);
- Subei basin and the Pearl River Mouth basin do not have any substantial hydrocarbon reservoirs;
- Of the selected basins, only Ordos basin has coalbed methane-based storage potential. It also has the highest storage capacity in coal of all Chinese basins (Dahowski et al. 2009).

17.4 Storage Potential Assessments by Formation

Whilst section 17.3.2 contained a selection of five Chinese sedimentary basins and an overview of their storage capacities for CCS as presented in the country-specific studies, this section provides an in-depth exploration of these basins. The aim is to validate the country-specific studies using site- and basin-specific assessments. Firstly, specific studies for entire basins are compared to country-wide results. Secondly, if these were unavailable, as was the case for most basins, site-specific studies for parts of the basins only were considered.

For *oil fields*, the four overall studies for China are compared with the specific studies of the five selected basins to select the most realistic assessment. It is assumed that this assessment is also valid for other parts of China, yielding an estimate of the total storage capacity of China's oil fields.

For *saline aquifers*, the theoretical capacity proposed by Dahowski et al. (2009) is selected as the basis for further study because most details are provided, unlike in Study 2. The existing site- and basin-specific studies on aquifers within the five selected basins are analysed to obtain an overview of the choice of crucial parameters, namely CO_2 density and the efficiency factor. The results are set in context to the Dahowski study.

The presentation of the results for *gas fields* and *coal seams* in the five selected basins is much shorter because little information is available. It was not possible to select a realistic assessment for these formations using these methods.

Tab. 17-6 Storage capacity of saline aquifers in the five most researched sedimentary basins in China

Name of basin	**Site**	**Prospectivity**	**Deep saline aquifers**			**Oil fields**					**Gas fields**		**CBM-based**
		CO2CRC and APEC 2005	Zhang et al. 2005b		Dahowski et al. 2009a	IEAGHG 2009	Zhang et al. 2005b *)		Dahowski et al. 2009a	CO2CRC and APEC 2005	Dahowski et al. 2009a	CO2CRC and APEC 2005	Dahowski et al. 2009a
			Volumetric	Solubility	Solubility			Prov-en	Fields > 2 Mt CO_2		Fields > 2 Mt CO_2		
Bohai	Onshore	High	0.4	1,715	233	2.0	1.4	1.3	1.9	3.2	0.3	1.3	-
Songliao	Onshore	High	0.3	444	228	1.2	1.9	1.3	1.6	2.0	0.6	0.1	-
Subei	Onshore	High	0.9	73	90	-	0.3	0.1	0.1	-	0.0	-	-
Pearl River Mouth	Offshore	Intermediate	0.2	2,371	69	-	0.3	0.1	0.0	-	0.0	-	-
Ordos	Onshore	Low	0.4	733	257	-	0.7	0.4	0.4	0.1	1.1	0.4	4.5

All quantities are given in Gt CO_2

*) Includes oil and gas fields.

Source: Authors' compilation

17.4.1 Oil fields

Applied Methodology

- In the first step, the four country-specific studies are analysed and compared for oil fields in the five selected basins. Capacity within these basins ranges from 0.04 (Pearl River Mouth basin) to 3.19 Gt of CO_2 (Bohai basin).
- Secondly, the basin-specific studies for all oil fields in the five basins are analysed. If no basin-specific estimate is available, site-specific studies are additionally taken into account.
- In the third step, the results of basin- and site-specific assessments are compared for each of the five basins to identify which of the four general studies fits the results of the site- and basin-specific studies best. It must be mentioned that Zhang et al. (2005a) also include gas fields in their estimate. Since gas fields play only a minor role in their assessment, it is selected for comparison with other oil field estimates in this section.
- Finally, the general study that matches the detailed analyses best in most of the basins is selected. It is then assumed that this assessment is also valid for other parts of China, enabling the total storage capacity of China's oil fields to be estimated.

Bohai Basin

Although no specific studies on all oil fields in Bohai basin exist, several detailed oil field-specific investigations are available (Tab. 17-7). These site-specific studies could be used for comparison (Poulsen et al. 2011; Vincent et al. 2011, 2009; Zhang et al. 2005a, 2005b; Vangkilde-Pedersen et al. 2009; Chen et al. 2009b; Li et al. 2009c; Zheng et al. 2009). The Dagang oil field complex in the Huanghua depression, Shengli oil field in the Jiyang depression and Huabei oil field in the Jizhong depression are analysed in these studies. However, it is unclear what percentage of the total basin they cover.

- Dagang oil field situated in the Huanghua depression provides a very low capacity of 0.022 to 0.18 Gt. It is questionable whether this amount is sufficient to play an important role in CO_2 storage. However, it may be sufficient for CO_2-EOR operations.
- The highest potential is offered by Shengli oil field in Shandong Province, which is estimated to have a storage potential of 0.4 to 1.2 Gt of CO_2. In this field complex, a large EOR project is being realised in which CO_2 is captured from the flue gas of a power plant and injected into the field to enhance oil production. This project yields data on the underground at this site, which could be important for the future use of larger-scale CO_2 injection.
- The Jizhong depression in Hebei Province is the largest depression in the Jing-Jin-Ji region. In total, it offers a capacity of less than 0.54 Gt of CO_2, and possibly only 0.064 Gt. The capacity offered by Huabei oil field alone is only 0.184 Gt (GeoCapacity).

Tab. 17-7 Storage capacity of different oil fields in Bohai basin as estimated by different authors

Depression	Name of oil field complex	Author	Storage capacity
Entire Bohai basin	*All oil fields*	Dahowski et al. 2009	1.93
		Zhang et al. 2005b *)	1.256 (proven) to 1.445
		CO2CRC & APEC 2005	3.192
		IEAGHG 2009	2.039
		Assumed average	*2.0*
Huanghua	*Dagang*	Vincent et al. 2009	0.077
		Vincent et al. 2011	0.022
		Zhang et al. 2005b	0.109 (proven) to 0.175
		Assumed average	*0.1*
Jiyang	*Shengli*	Mingyuan Li 2009	0.7–1.2
		Poulsen et al. 2011	0.401–0.483
		Vincent et al. 2011	0.463–0.473
		Zhang et al. 2005b	0.505 (proven) to 0.500
		Assumed average	*0.5*
Jizhong	*Huabei*	GeoCapacity 2009	0.184
	Jing-Jin-Ji region	Zheng et al. 2009	< 0.54
		Zhang et al. 2005b	0.113 (proven) to 0.064
		Assumed average	*0.2*
	Assumed average for three selected depressions		*0.8*

All quantities are given in Gt CO_2

*) Includes oil and gas fields.

Source: Authors' compilation

Methodologically, these studies include different assumptions, most of which are explained in detail in publications within the COACH project (Poulsen et al. 2011; Vincent et al. 2009, 2011). The following issues are relevant in discussions when comparing these estimates:

- Two different methods are applied: the volumetric method based on the Carbon Sequestration Leadership Forum (CSLF) (Bachu et al. 2007) and a dissolution-based method that relies on the work of Tanaka et al. (1995). Both methods deliver a similar result in magnitude for Shengli oil field, with a variation between 401 and 483 Mt of CO_2 (Poulsen et al. 2011), although this too implies a 20 per cent variation;
- CO_2 density is set at 620, 650 or 700 kg/m^3. This is a variation of approximately 10 per cent;
- The formation volume factor is set at either 1.1 or 1.2, which is also a variation of 10 per cent;
- Water invasion is included in some authors' estimates by considering a discount factor. It is set at 0.3 or 0.4, but is not applied in all studies.

Unfortunately, these parameters are not available for all studies, making it difficult to compare and describe the differences in Tab. 17-7. However, it is apparent that, with the exception of water invasion, none of the parameters taken individually change the result considerably. However, it is not sufficiently clear which on factors authors base their calculations.

Taking this problem into account, the average value is chosen for each depression in Tab. 17-7. If the average capacities of the three depressions are taken together, a cumulative storage capacity of 0.8 Gt is estimated (added together from average capacities of 0.1 Gt for Huanghua, 0.5 Gt for Jiyang and 0.2 Gt for the Jizhong depression). Since these site-specific assessments refer to only parts of Bohai basin, the total capacity of oil fields in this basin is probably higher. Comparing this sum of 0.8 Gt with estimates for *all oil fields* in Bohai basin (1.3–3.2 Gt) does not furnish an adequate result. Thus the approach of comparing site-specific results with total basin results is not applicable here. Instead, the average of site-specific values for Bohai oil fields given in Tab. 17-6 is selected, resulting in 2.0 Gt of CO_2. This average value is achieved best by two studies (Dahowski et al. 2009; IEA GHG 2009).

Songliao Basin

The total capacity in the oil fields of Songliao basin is estimated at 1,189 to 2,025 Mt of CO_2 (compare Tab. 17-6). Jilin oil field in Jilin Province and Daqing oil field in Heilongjiang Province are analysed in more detail because no basin-specific assessments exist for all of the Songliao oil fields. The Daqing complex is thought to be an enormous field containing most of the basins' hydrocarbons (CO2CRC and APEC 2005). Li et al. (2008) provide an overview of potential storage capacities and EOR application in these two oil field complexes. Depending on the method of calculation, it is assumed that 48 to 71 Mt of CO_2 can be stored in Jilin oil fields. The seven fields at the Daqing oil complex provide a much larger storage capacity of 459 to 648 Mt of CO_2 (compare Tab. 17-8). The higher values are related to the CSLF's method, which probably overestimates the capacity (Li et al. 2008).

These site-specific assessments give a good initial indication of the basin's entire capacity, as Daqing is by far the biggest field complex in Songliao basin. Regarding the classification given above, it is assumed that twice the estimated capacity for these fields is the greatest possible capacity. This would amount to between 1 and 1.4 Gt of CO_2, which is best matched by two studies: IEA GHG (2009) and the proven estimate by Zhang et al. (2005b).

Tab. 17-8 Overview of storage capacity in Songliao basin oil fields by different authors

Name of oil field	Author	Storage capacity
Entire Songliao basin	IEAGHG 2009	1.2
	Zhang et al. 2005b (proven)	1.3
	Dahowski et al. 2009b	1.6
	Zhang et al. 2005b	1.9
	CO2CRC and APEC 2005	2.0
Jilin oil field complex	Li et al. 2008	0.05–0.07
Daqing oil field complex	Li et al. 2008	0.46–0.65
All quantities are given in Gt CO_2		

Source: Authors' compilation

Subei Basin

There are only small oil fields in Subei basin; the estimated storage capacity is rather low at 69 to 263 Mt of CO_2 (compare Tab. 17-9). Pearce et al. (2010) explore the Jiangsu oil field complex in further detail, analysing 108 oil reservoirs. These account for over 70 per cent of the original oil in place estimated to be in the basin. However, there are no detailed studies on all of the fields. Applying conservative assumptions due to the complicated geology in these oil fields, a capacity of 20 Mt is derived. Using the CSLF's method, the capacity is doubled to 40 Mt of CO_2.

If 20 to 40 Mt is the estimated capacity of 70 per cent of the oil fields, the total capacity would total roughly 28 to 57 Mt. The figure of proven fields given by Zhang et al. (2005b) of 70 Mt is chosen as the best fit.

Tab. 17-9 Overview of storage capacity in Subei basin oil fields estimated by different authors

Name of oil field	Author	Storage capacity
Entire Subei basin	Zhang et al. 2005b (proven)	0.07
	Dahowski et al. 2009b	0.10
	Zhang et al. 2005b	0.26
Jiangsu oil field complex (108 oil reservoirs)	Pearce et al. 2010	0.02–0.04
All quantities are given in Gt CO_2		

Source: Authors' compilation

Pearl River Mouth Basin

The CO_2 storage capacity in the Pearl River Mouth basin in Guangdong is given for oil and gas fields together, since Zhou et al. (2011a) do not differentiate between these formations. In total, a storage capacity of 40 to 266 Mt of CO_2 is estimated (Tab. 17-10).

In their preliminary basin-specific assessment, Zhou et al. (2011a) cover only the Pearl River Mouth basin. They suggest a storage capacity of 60 Mt of CO_2 based on proven reserves (original oil in place, OOIP). This is a conservative estimate because newly proven and unproven fields are not included. Assuming higher resources in oil equivalents would increase the capacity to 150 to 210 Mt of CO_2. This calculation is based on a volume factor of 1.03, a CO_2 density of 566 kg/m^3 and a storage coefficient of 25 per cent. This assessment by Zhou et al. (2011a) is then compared with the studies by Dahowski et al. (2009) and Zhang et al. (2005b). Taking the estimate of Dahowski et al. (2009) for proven oil and gas fields (OOIP) of the Pearl River Mouth basin into account, a storage capacity of 53 Mt of CO_2 is derived (41 Mt in oil fields, 12 Mt in gas fields). This is similar to the proven capacity calculated by Zhang et al. (2005b), which totalled 57 Mt of CO_2. The same authors also suggest a greater capacity of 266 Mt of CO_2.

Comparing the three studies, all assessments based on *proven* hydrocarbons yield almost identical results. This means that both Dahowski et al. (2009) and Zhang et al. (2005b) provide good estimates. Thus storage capacity in the Pearl River Mouth basin is estimated to be between 53 and 60 Mt of CO_2.

Tab. 17-10 Overview of storage capacity in the oil and gas fields of the Pearl River Mouth basin

Name of oil field	Author	Resource oil equivalent	CO_2 storage capacity
Entire Pearl River Mouth basin	Zhou et al. 2011 *)	0.9 (= OOIP)	0.06
		2.3	0.15
		3.2	0.21
	Zhang et al. 2005b	6.8	0.266
	proven		0.057
	Dahowski et al. 2009b	OOIP	0.053

All quantities are given in Gt CO_2

OOIP = original oil in place

*) Volume factor (B_0) = 1.03, CO_2 density = 566 kg/m^3, storage coefficient = 25%.

Source: Authors' compilation

Ordos Basin

The oil fields in Ordos basin have not yet been studied in detail, which is why no basin- or site-specific assessments are available. This basin is not included in the comparison of detailed and general studies.

Summary of oil fields

Tab. 17-11 Best approach when matching storage potential assessments for China as a whole and for individual formations

Name of basin	Best approach			
	IEAGHG 2009	Zhang et al. 2005b	Dahowski et al. 2009a	CO2CRC and APEC 2005
Bohai	X	---	X	---
Songliao	X	X	---	---
Subei	---	X	---	---
Pearl River Mouth	---	X	X	---
Ordos	No basin- or site-specific assessments exist for oil fields			

Source: Authors' compilation

Regarding oil fields, it was possible to validate the general results of site- and basin-specific assessments in four of the selected five basins (Tab. 17-11). For Bohai basin, Dahowski et al. (2009) and IEA GHG (2009) are selected as the best approaches, yielding 2.0 Gt of storage capacity. About 1.0 Gt of CO_2 could be stored in the Songliao basin, which was derived best by site-specific assessment by IEA GHG (2009) and Zhang et al. (2005b). Subei basin was estimated best by Zhang et al. (2005a). For the Pearl River Mouth Basin, both Dahowski et al. (2009) and Zhang et al. (2005b) provide similar results as the basin specific assessment. Ordos basin could not be compared due to a lack of suitable studies.

To summarise, the proven capacities of Zhang et al. (2005b) yield the best estimate in three out of four cases. Thus it is assumed that this assessment is also the most valid one for China's other oil fields.

17.4.2 CO_2-Based Enhanced Oil Recovery

The storage potential for oil fields was calculated in section 17.4.1. In many cases, this figure is based on the potential for EOR. Thus no differentiation can be made between storage in oil fields and storage linked to EOR. This means that the storage potential for CO_2-EOR will not be used separately from oil fields. Nonetheless, the potential linked to EOR generates interesting findings, as analysed in detail for two oil fields.

It is commonplace in the Chinese CCS community to talk of CCUS rather than of CCS, where U stands for the additional Use part of CO_2. In fact, CO_2 can be used in the food and beverage industry, chemical production, micro-algae growth for bio energy, fire fighting and refrigeration or to enhance the production of oil or coalbed methane (EOR, ECBM) (ACCA21 2010). EOR is a major issue in China. It is becoming increasingly popular to apply CO_2 as a medium for EOR. It is considered an early opportunity to develop a pipeline infrastructure for CO_2 and to implement CCS in China (WRI 2011). Many companies such as Sinopec, Petro-China and Shenhua are involved in developing CO_2-EOR projects, which could combine large-scale CO_2 utilisation with potential storage. Two pilot projects are being realised in China: in Shengli and Jilin oil fields (compare Tab. 16-1). There is an economic advantage of CO_2 separation from natural gas production. In Jilin oil field, the CO_2 content of natural gas is very high, amounting to 22 per cent. The CO_2 must be separated from the gas in order to be sold. The separation costs incurred to purify the natural gas are therefore included in the gas price on the market. The CO_2 captured from gas processing is a waste product generated at virtually no cost. If this gas could be sold to an EOR operator, additional benefit is achieved (CUP-B 2011).

In section 4.2.2 of Part I, the capacity calculation for oil fields is described based on the CSLF approach. It relies on the principle of replacement, i.e. the prevailing oil, gas or formation water is replaced by injected CO_2. Study 1 in section 17.3.1 by Dahowski et al. (2009) calculates the capacity in oil fields based on EOR potential. This amounts to 7,020 million barrels of additional oil to be recovered in China.

The Chinese University of Petroleum introduced a different methodology, based additionally on dissolution. The capacity is calculated from the displaceable and dissolved volume of CO_2. But it does not consider a specific time by which the injected CO_2 is totally dissolved in the formation water. Poulsen et al. (2011) give a comprehensive comparison of both methodologies.

The two ongoing CO_2-EOR projects in China are located in Bohai basin (Shengli oil field) and Songliao basin (Jilin oil field). Both basins are classified by IEA GHG (2009) as amongst the world's top 10 basins for EOR. The storage capacities and EOR possibilities for Shengli and Jilin oil field complexes are described below in greater detail.

Shengli Oil Complex, Bohai Basin

IEA GHG (2009) assumes additional oil recovery of 7,443 million barrels for Bohai basin, which equates to 2 Gt of CO_2 storage capacity in this basin. This can be considered very optimistic, as Dahowski et al. (2009) estimated a potential of 7,020 million barrels for the whole of China. The greatest capacity in Bohai basin is offered by the Shengli oil field complex. In section 17.4.1, the storage potential of this field complex is assumed to be between 0.4 and 0.5 Gt of CO_2. The corresponding amount of oil that can be recovered additionally from Shengli fields by CO_2-EOR is calculated by (Vincent et al. 2011). The authors apply an oil recovery rate of 2 to 10 per cent, yielding 23 to 112 Mt (168 to 820 million barrels) of additional oil. One barrier to the large-scale implementation of EOR and CCS operations in the Shengli oil field complex is the region's highly compartmentalised stratigraphy with many faults. Poor injectivity is expected in the field.

Jilin Oil Field Complex, Songliao Basin

For Songliao basin, IEA GHG (2009) assumes an additional oil recovery of 4,495 million barrels of oil. This refers to a storage capacity of 1.2 Gt in Songliao basin. Intensive research on EOR is currently being undertaken, particularly at Jilin oil field (see section 16.2 for more information). Li et al. (2008) assume that 48 to 71 Mt of CO_2 can be stored in Jilin oil fields by performing CO_2-EOR. Applying an oil recovery rate of 2 to 10 per cent for EOR, 46 to 230 million barrels of oil can be still recovered. In comparison, the Daqing oil complex (with seven fields in Songliao basin) yields a considerably higher additional oil recovery of 269 to 1,343 million barrels. Again, a recovery factor of 2 to 10 per cent is applied. This leads to a storage capacity of 459 to 648 Mt of CO_2 (compare description of Songliao basin in section 17.4.1).

Other Basins

In contrast to the considerable storage capacity of Shengli and Jilin oil fields, CO_2 storage capacity combined with EOR in Subei basin is assumed to offer a capacity of only 16 Mt (Pearce et al. 2010). This is aligned with an incremental oil recovery of 35 million barrels. Although Ordos basin has oil fields that could be used for CO_2-EOR, no estimates are available for this region yet.

17.4.3 Deep Saline Aquifers

Methodology Applied

Tab. 17-12 provides an overview of storage capacity in deep saline aquifers in the selected basins. Only three studies that provide results for all five basins are included. The APEC study classifies the aquifers qualitatively, meaning that no quantities are reported in CO2CRC and APEC (2005). Dahowski et al. (2009) and Zhang et al. (2005a) calculate very different storage capacity values. This difference is due in part to the use of different methodologies (volumetric versus solubility). However, even when a similar methodology (solubility) is used, different capacities are yielded. There is no clear indication of the methodology used in Dooley et al. (2005), making it difficult to compare it with other studies. It has therefore been excluded from the comparison in Tab. 17-12.

The general assessments for China's oil fields were verified using basin- and site-specific studies. This approach cannot be used for saline aquifers because:

- There are only two general studies available, both yielding very different figures (see Tab. 17-12);
- (Zhang et al. (2005b) provide insufficient background on their calculation to identify any advantages;
- In most cases, no site-specific assessments are available.

In this case, therefore, the available site- and basin-specific studies are analysed with regard to identifying the parameters applied for CO_2 density and efficiency and deriving a useful range for these factors. In additional, important findings generated by the comparison are summarised and used to select the parameters. Since it is assumed that the existing specific studies focus on the most promising and relevant parts of the basins, the results of this exercise shall be used to develop storage scenarios for the whole of China.

Tab. 17-12 Storage capacity of saline aquifers in the five most intensively researched sedimentary basins in China

Name of basin	Site	Prospectivity	Theoretical storage capacity		
		CO2CRC and APEC 2005	Zhang et al. 2005b		Dahowski et al. 2009a
			Volumetric	Solubility	Solubility
Bohai	Onshore	High	0.4	1,715	233
Songliao	Onshore	High	0.3	444	228
Subei	Onshore	High	0.9	73	90
Pearl River Mouth	Offshore	Intermediate	0.2	2,371	69
Ordos	Onshore	Low	0.4	733	257
All quantities are given in Gt CO_2					

Source: Authors' compilation

Methodology Used in Reviewed Studies

Zhang et al. (2005a) apply two methodologies to estimate the capacity in aquifers – the volumetric approach (see section 4 of Part I) and the solubility approach (dissolution of CO_2). Dahowski et al. (2009) also work with the solubility approach and explain it in detail. They assume that the entire saline aquifer water can be used to dissolve CO_2. Thus only dissolution trapping (see section 4.1.2.3 of Part I) is considered. Since the authors select maximum assumptions, very high theoretical values are calculated that even exceed the global capacity for aquifers estimated in the Intergovernmental Panel on Climate Change's (IPCC) special report on CCS (IPCC 2005). These high figures are called into question by a number of other studies and by many of the respondents, who argue that they were not as realistic as they should be. In addition, modelling studies revealed that dissolution trapping fails to increase the short-term storage potential and that the dissolution of CO_2 is only assumed to be effective in the long term (see section 4.1.2.3 of Part I).

According to CUP-B (2011), most Chinese scientists disagree with these figures and express the need for more detailed theoretical calculations. They are working on a new estimate with higher resolution geographical data and more reliable methodology (CUP-B 2011). According to these scientists, the methodology applied in China should differ to those used in other countries due to China's unique geology.

Bohai Basin

Dahowski et al. (2009) used the solubility approach to calculate a theoretical storage capacity of 233 Gt of CO_2 for Bohai basin. A large range, and thus a high degree of uncertainty surrounding theoretical storage capacity, is provided by Zhang et al. (2005b) who calculated their assessments using both the solubility and the volumetric approach. The authors divided the basin into three parts – Bohai Gulf-Liaoning, Bohai North and Bohai Gulf – with an area of 270,000 km^2. In Tab. 17-13, these parts are combined to make their comparison with the other assessments easier. Use of the solubility method led to a capacity of 1,715 Gt of CO_2, which is much higher than the assessment by Dahowski et al. (2009). Use of the volumetric approach yields a capacity of only 0.4 Gt of CO_2. This shows the extent to which the methodologies applied yield different results.

Tab. 17-13 Overview of storage capacity in saline aquifers in Bohai basin

Depression	Formation	Author	Storage capacity	Efficiency E	Density	Remarks
			Gt CO_2	%	kg/m^3	
Entire Bohai basin	-	Dahowski et al. 2009a	233.3	100	604	Solubility method
	-	Zhang et al. 2005b	1,714.5			Solubility method
			0.419			Volumetric method
Jing-Jin-Ji *	-	Zheng et al. 2009	5.489			15 sinks in Jing-Jin-Ji region
Jizhong	Guantao – Raoyang and Baxian sub-basins	Chen et al. 2009, GeoCapacity D35 WP6 2009	0.371	0.16	670	Closed aquifer
			0.747	3		Open aquifer; water discharge for pressure control is a prerequisite
	Guantao	Chen 2008	3.5	10		Preliminary results
Jiyang	Guantao - Huimin Sag	Zeng 2009	22.75	20	700	Open aquifer; traps only
			61.25	2	700	Closed aquifer; total volume
	Guantao – Huimin Sag	Vincent et al. 2011	23	2	650	Refers to Zeng 2009 but mentions different assumptions
			0.7			Area with thick sand stones only

* Jing-Jin-Ji comprises Jizhong, Cangxian, Huangha, Xingheng and LingqingDongpu depressions (approximately half of Bohai's depressions).

Source: Authors' compilation

As is the case for CO_2 storage assessments in oil fields, Bohai basin has been the subject of many site-specific investigations in saline aquifers. The storage efficiency and CO_2 density are given in most cases for these assessments (compare Tab. 17-13). The Jing-Jin-Ji region, which contains half of Bohai's depressions, has been studied by Zheng et al. (2009). These depressions are Jizhong, Cangxian, Huangha, Xingheng and LingqingDongpu. They contain 15 potential sinks with a capacity of 5.5 Gt of CO_2, which is much less than the results yielded by Dahowski et al. (2009) and Zhang et al. (2005b).

Of these depressions, *Jizhong* is analysed in further detail. This depression includes the Guantao formation, which stretches beyond Jizhong to the Jiyang depression. Jiyang is the other area where site-specific assessments are being conducted. Based on the GeoCapacity report, Chen et al. (2009b) calculate the capacity in Jizhong using two different assumptions: in the first case, open aquifers are assumed and CO_2 is injected into traps; in the second case, all aquifers are defined as closed. The authors apply 3 per cent efficiency for open aquifer structures in highly permeable horizons, where storage is limited to traps. This leads to a capacity of 747 Mt of CO_2. It is mentioned, however, that an active pressure control of the storage site is required with this efficiency factor, which could be achieved by discharging water or by pumping out the reservoir water. This is not the case if closed aquifers are assumed and storage is not limited to traps. In this case, the total formation below a depth of 850 m is deemed to be closed and an efficiency factor of 0.16 per cent is used, based on the maximum pressure increase in the reservoir. This method reduces capacity to 371 Mt of CO_2. Tab. 17-13 also includes the preliminary results generated by the same research group, which have been updated and redefined for the new study. Chen (2008) calculated a much higher capacity for the Jizhong depression, amounting to 3.5 Gt of CO_2. This is basically due to the assumption of a different efficiency factor of 10 per cent. In general, the different studies again reveal the large degree of uncertainty surrounding capacity calculations, particularly for Bohai basin.

For the *Jiyang depression*, Zeng (2009) applies more optimistic parameters for the Huimin sag in the Guantao formation. Assuming open aquifers, an efficiency of 20 per cent is used, leading to a capacity of 22.75 Gt. If all aquifers are considered as closed, a capacity of 61.25 Gt of CO_2 is derived by applying an efficiency of 2 per cent. The argumentation is similar to the calculation for the Jizhong depression explained above, although higher efficiency factors and a slightly higher CO_2 density are chosen (700 kg/m^3 in contrast to 670 kg/m^3 above). What is interesting is the finding that a lower efficiency factor linked to the assumption of closed formations leads to a higher result with the Jiyang depression, which is vice versa with Jizhong, where lower efficiency leads to lower capacity. In both cases, the difference is about double. This could be related to a different ratio between the formation and trap area applied. Vincent et al. (2011) refer to the assessment by Zeng (2009) and provide a similar result of 23 Gt for Huimin sub-basin in Jiyang. This study is not very comprehensible because the parameters chosen are very different, with an efficiency factor of 2 per cent instead of 20 per cent and a lower CO_2 density of 650 instead of 700 kg/m^3. Again, the difference could be due to the different trap volume applied. If available storage space is limited to areas where thick sand layers can be found, the storage potential would decrease to 0.7 Gt of CO_2.

These site-specific assessments for the Jizhong and Jiyang depressions deliver *efficiency coefficients* of 0.16 to 20 per cent. *CO_2 density* ranges from 604 to 700 kg/m^3. Since half of the basin (5.5 Gt, (Zheng et al. 2009)) is located in the Jing-Jin-Ji region, the total capacity would be around 11 Gt. Hence, the excessive values of 233 to 1,714 Gt of CO_2 can be considered unrealistically high.

One *key finding* is the necessity to undertake active pressure control if an efficiency of 3 per cent were selected (Chen et al. (2009b)). Thus low capacities should be selected for safety reasons. If more realistic limitations are chosen, such as the necessity of the storage area to have thick sand layers, the capacity is reduced considerably. Again, lower efficiencies are more pertinent.

Songliao Basin

Songliao basin in north-east China contains many oil fields that could be used to store CO_2 (see section 17.4.1). The Qingshankou formation, close to the Jilin oil field complex, has been studied in detail, particularly the Daqingzi area where a deep saline aquifer is located. These site-specific assessments are described below, following estimates for storage capacity in aquifers in the entire Songliao basin. These are calculated using both the solubility method and the volumetric method based on an area ranging from 260,000 to 270,000 km^2 (see Tab. 17-14).

Tab. 17-14 Overview of storage capacity in saline aquifers in Songliao basin

Formation	Author	Storage capacity Gt CO_2	Efficiency E %	CO_2 density kg/m^3	Remarks
Entire Songliao basin (Qingshankou and Quantou)	Dahowski et al. 2009a	227.8	100	604	Solubility method
	Zhang et al. 2005b	444.4			Solubility method
		3.2			Volumetric method
	Li and Yang 2010	4,149	100		Volumetric method
		414.9	10		
		83.0	2		
		41.5	1		
Qingshankou	Li et al. 2009a	69.2	100	700	Volumetric method
		6.9	10		
		1.4	2		
		0.7	1		
	Pearce et al. 2011	0.7	2		
Daqingzi area within Qingshankou	Li and Yang 2010	0.4	60	600	
		0.3	40		
		0.1	20		Is equal to E = 40% and water saturation of 50%
	Li et al. 2009b	4.0	100		
		0.4	10		
		0.2	10		With water saturation 50%

Source: Authors' compilation

Dahowski et al. (2009) calculate a theoretical storage capacity in Songliao basin using their solubility approach. This results in a capacity of 228 Gt of CO_2. Zhang et al. (2005b) use a similar methodology based on dissolution to yield an even higher theoretical capacity of 444 Gt of CO_2. In additional, these authors perform a capacity calculation using the volumetric method, yielding 3.2 Gt. Another assessment within the NZEC project performed by Li and Yang (2010) differs to this result. This assessment is based on a volumetric capacity calculation with efficiency factors of 10, 2 and 1 per cent, which lead to effective capacities of 415, 83 and 41.5 Gt of CO_2, respectively.

The NZEC project also includes region-specific investigations. The *Qingshankou* formation is analysed using the volumetric capacity calculation. The CO_2 density is set at 700 kg/m^3. The formation yields a theoretical capacity of 69 Gt of CO_2 and an effective capacity of 0.69, 1.4 and 6.9 Gt if an efficiency of 1, 2 and 10 per cent is chosen, respectively (Li et al. 2009a). Pearce et al. (2011) also study the Qingshankou formation as part of NZEC research. They yield exactly the same capacity of 0.69 Gt of CO_2, but apply a higher efficiency factor of 2 per cent. This finding may be explained by taking into account water saturation, which will be described below in the site-specific calculation of the Daqingzi area within this formation.

Daqingzi is thought to be the most promising area for CO_2 sequestration in Songliao basin (Li and Yang 2010). The authors estimate Daqingzi's effective capacity to be between 0.1 and 0.4 Gt of CO_2, applying efficiencies of 20, 40 and 60 per cent. One year previously, the same research group yielded very different results up to 4 Gt of CO_2 (Li et al. 2009b). However, if an efficiency of 10 per cent is applied, the capacity is reduced to 401 Mt of CO_2, which equals 60 per cent efficiency in the more recent publication. In addition to this difference, both sources utilise two different equations each. First, the capacity is calculated using the CSLF method (compare section 4.2.3 of Part I). The results yielded by modelling for sweep efficiency and dissolution of CO_2 are then taken into account to modify the equation with irreducible water saturation. Water saturation is assumed to be 50 per cent, which leads to a bisection of the estimates. Thus an efficiency factor of 20 per cent within the first calculation yields the same result as an efficiency of 40 per cent including 50 per cent water saturation.

Efficiencies of between 1 and 60 per cent have been applied for site-specific assessments in Songliao basin. *CO_2 densities* of 600 and 700 kg/m^3 are used. A *key finding* is that the solubility method does not necessarily lead to higher capacity calculations. It is more important to note which efficiency factor is selected and whether or not irreducible water saturation is applied.

Subei Basin

There is much less information available for Subei basin, located south-east of Bohai, than for Bohai and Songliao basins. Only Dahowski et al. (2009) and Zhang et al. (2005b) deliver capacity calculations; (Pearce et al. 2011) report that insufficient information was available to execute a detailed calculation.

The solubility approach yields a capacity of 73 to 90 Gt of CO_2 if no efficiency factor is used (compare Tab. 17-15). The volumetric calculation conducted by Zhang et al. (2005b) results in 0.9 Gt. Thus, the calculation of CO_2 storage capacity in the Subei basin is rather uncertain because little is known about the geology of the region. Also, the existing volumetric estimate yields a rather low storage capacity of less than 1 Gt. The Subei basin would therefore not be very prospective for large-scale CO_2 storage, which contradicts the high prospectivity classification by APEC (compare Tab. 17-12).

Due to the lack of detailed studies for Subei basin, *no key findings* have been derived and the discussion failed to identify realistic *parameters*.

Tab. 17-15 Overview of storage capacity in saline aquifers in Subei basin

Formation	Author	Storage capacity	Efficiency E	Remarks
		Gt CO_2	%	
Entire Subei basin	Dahowski et al. 2009a	89.9	100	Solubility method
	Zhang et al. 2005b	73.0		Solubility method
		0.9		Volumetric method
	Pearce et al. 2011	Little known		

Source: Authors' compilation

Pearl River Mouth Basin

The Pearl River Mouth basin is located off the coast of Guangdong Province in south-east China. Since no onshore storage is available in this economic and industrial area, this basin may be important if CCS is applied large-scale in China. This basin relies to an even greater extent on saline aquifers because storage capacities in oil and gas fields are negligible (compare section 17.4.1).

Tab. 17-16 shows the existing storage capacity estimates for saline aquifers. The variation is very high, ranging from 0.2 to 2,371 Gt of CO_2, depending on the method applied (Zhang et al. (2005b)). Dahowski et al. (2009) use the solubility approach to calculate a capacity of 70 Gt of CO_2, which is considerably lower than the results gained by Zhou et al. (2011a) using the volumetric approach. There, efficiency factors of 1, 2.6 and 4 per cent are obtained from the statistical distribution of E. The overall mean value with a probability of 50 per cent is 2.6 per cent. The other efficiencies are linked to 15 per cent (E = 1 per cent) and 85 per cent probability. In addition, a very low range of CO_2 densities from 300 to 600 kg/m^3 is chosen. The authors also specify different depth ranges. The capacity decreases if only the depth range of 800 to 2,500 m is used for CO_2 sequestration rather than the entire sediment below 800 m. If 1 per cent efficiency is applied, effective storage capacities of 81 and 118 Gt of CO_2 are achieved, respectively. An efficiency of 4 per cent leads to 324 and 473 Gt of CO_2, respectively. The mean probability of 2.6 per cent efficiency yields storage capacities of 210 and 308 Gt of CO_2, depending on the depth range.

Tab. 17-16 Overview of storage capacities in saline aquifers of the Pearl River Mouth basin

Formation	Author	Storage capacity	Efficiency E	CO_2 density	Remarks
		Gt CO_2	%	kg/m^3	
Entire Pearl River Mouth basin	Dahowski et al. 2009a	69.7	100	604	Solubility method
	Zhang et al. 2005b	2,371.3			Solubility method
		0.2			Volumetric method
	Zhou et al. 2011	473	4	300–600	Volumetric method; storage >800m depth
		308	2.6		
		118	1		
		324	4	300–600	Volumetric method; limited to 800–2,500 m
		210	2.6		
		81	1		

Source: Authors' compilation

Owing to these varying results, it is very difficult to choose an adequate capacity. This is underlined by CO2CRC and APEC (2005), where the Pearl River Mouth basin is classified as having intermediate or unresolved prospectivity. For the other aquifer basins discussed above, the estimates of Dahowski et al. (2009) were considered to be rather high. In this case, they cover the lower range of the available scale. Thus, comparing the results with the other basins, it can be interpreted that Zhou et al. (2011a) may have calculated the capacity too optimistically, although the parameter selection, if given, is conservative. If the volumetric capacity generated by Zhang et al. (2005b) of 0.2 Gt of CO_2 were realistic, the Pearl River Mouth basin would offer insufficient storage space to justify large investments for offshore injection facilities.

One basin-specific study is available for the Pearl River Mouth basin in which *efficiency factors* of 1, 2.6 and 4 per cent are applied (Zhou et al. 2011a). The *CO_2 density* ranges from 300 to 604 kg/m^3. A *key finding* is that when the volumetric method is applied with low efficiencies, higher effective capacities are yielded than with theoretical capacities provided by the solubility method. In this case, the estimate by Dahowski et al. (2009) may have underestimated the capacity, and higher efficiencies should be chosen.

Ordos Basin

The Shenhua DCL project was launched in 2011 to store captured CO_2 in a saline aquifer of Ordos basin (compare section 16.2.2). A geological site assessment is currently underway (December 2011). Although there are many potential reservoirs and seals, overall permeability is low. Thus CO2CRC and APEC (2005) describe the basin as less prospective. Although this could be a challenge when it comes to injectivity, it may help to increase residual-phase trapping over time (NRDC 2010).

Nonetheless, Dahowski et al. (2009) calculate a high theoretical storage capacity of 256 Gt of CO_2. Using the solubility approach, Zhang et al. (2005b) estimate an even higher capacity of 732 Gt of CO_2. This declines to 0.4 Gt of CO_2 when the volumetric approach is applied.

Tab. 17-17 Overview of storage capacity in saline aquifers of Ordos basin

Formation	Author	Storage capacity	Efficiency E	CO_2 density	Remarks
		Gt CO_2	%	kg/m^3	
Entire Ordos basin	Dahowski et al. 2009a	256.5	100	604	Solubility method
	Zhang et al. 2005b	731.6			Solubility method
		0.4			Volumetric method
Majiagou	Jiao et al. 2011	60	10	650	Depth of 1 to 4 km
		700	60		
		287	Mean		

Source: Authors' compilation

Only one site-specific assessment exists for the (northern) Ordos basin, where Jiao et al. (2011) calculated the CO_2 storage capacity in Shaanxi Province. This is where the Ordovician Majiagou formation, with a thickness of 700 m, is situated. The authors consider it a high-priority sequestration reservoir. A mean storage capacity of 287 Gt of CO_2 is achieved by modelling and Monte Carlo simulation. Applying a density of 650 kg/m^3 and storage efficiencies of 10 to 60 per cent, a range of 60 to 700 Gt is estimated. Their mean value of about 30 per cent efficiency and the solubility-based theoretical capacity by Dahowski et al. (2009) are similar in magnitude, at 287 and 257 Gt of CO_2, respectively.

The site-specific assessment yields *efficiency factors* of 10 to 60 per cent. The CO_2 density used ranges from 604 to 650 kg/m^3. Since the mean value (roughly 30 per cent) yields the same magnitude as Dahowski et al. (2009), it is likely that the chosen efficiency should be lower than that. Another *key finding* of the comparison is that Ordos basin has a very low permeability, making storage operations technically challenging and expensive.

Summary of Saline Aquifers

In this section, existing calculations of the storage capacity of saline aquifers in five selected basins were presented. The key findings from these calculations were derived and presented in Tab. 17-18. These calculations are based on different methodologies, i.e. dissolution or the volumetric method. However, it is not clear whether the solubility or the volumetric approach yields higher or lower results (see Songliao and Pearl River Mouth basins). This depends on which parameters were selected in the calculation. The huge variations between results are linked to different assumptions being made for storage efficiency and CO_2 density. It can hence be established that selection of the efficiency factor is the crucial part of the calculation.

It therefore comes as no surprise that very different findings can be extracted from the studies analysed when identifying the range of efficiency recommendations. Studies on Bohai basin recommend applying low efficiency values to prevent the operator from having to conduct active pressure control by pumping out saline water. Although this may not be the case in all basins, there is a risk of such a need occurring without more in-depth knowledge of the geology.

Tab. 17-18 Key findings from site- and basin-specific studies for deep saline aquifers in China

Name of basin	Key findings
Bohai	- If the aquifer is assumed to be a closed system, the efficiency selected should be at the low end of the percentage scale (0.16 to 4 per cent). - Higher efficiencies would necessitate active pressure control. To cope with potential water discharge, irreducible water saturation should be included in the efficiency factor. - If more realistic limitations are chosen, such as the need for thick sand layers in the storage area, capacity declines considerably. Thus lower efficiencies are more reasonable.
Songliao	- The solubility method chosen does not necessarily lead to higher capacities. What is crucial is which efficiency factor is selected.
Subei	- No site-specific assessments exist.
Pearl River Mouth	- Volumetric method with low efficiencies (1 to 4%) lead to higher effective capacities than theoretical capacities yielded by the solubility method. Thus in some cases, (Dahowski et al. 2009) may have underestimated the capacity and higher efficiencies should be chosen.
Ordos	- Ordos basin has a very low permeability, which raises the technological challenges and costs of operation. - The mean value result with an efficiency of approximately 30 per cent is similar to (Dahowski et al. 2009). Thus the efficiency should be lower than that.

Source: Authors' compilation

In contrast, the basin-specific study for the Pearl River Mouth basin yields higher effective capacity values than the theoretical capacity generated by Dahowski et al. (2009). This theoretical capacity may therefore have underestimated capacity, and if low efficiency values were applied, this difference would become even larger. The studies analysed for Ordos basin demonstrate that the efficiency should be below 30 per cent.

In addition, the studies argue that geological constraints could reduce the capacity considerably or would increase operating costs. This depends on the thickness of the sand layers at potential storage sites and the low permeabilities identified in promising formations.

It can be concluded from the key findings that the efficiency values are the most important aspect when calculating effective storage capacities. Nonetheless, it is not clear which efficiency should be applied. Thus the efficiency factors used in the studies concerned are analysed in greater detail (see Tab. 17-19). In addition, the CO_2 density is included in the comparison. This figure varies between 300 and 700 kg/m^3, averaging at 603 kg/m^3. Regarding the efficiency factor, the overview reveals a range from 0.16 to 60 per cent.

Tab. 17-19 Overview of the parameters used to calculate CO_2 storage capacities in saline aquifers in China

Author	**E**	**CO_2 density**	**Remarks**
	%	kg/m^3	
Zeng 2009	2	700	Closed aquifer; total volume
	20		Open aquifer; traps only
Chen et al. 2009	0.16	670	Closed aquifer
	3		Open aquifer; water discharge for pressure control is a prerequisite
Vincent et al. 2011	2	650	
Li et al. 2009b	10	600	
Li et al. 2009a	1		
	2	700	For regional aquifers
	10		
Li and Yang 2010	20		
	40		For site-specific assessment
	60		
Zhou et al. 2011	1		
	2.4	300–600	
	4		
Dahowski et al. 2009a	1		
	10	604	
	50		
Jiao et al. 2011	10–60	650	Delta p = 40–55 MPa
Jiang and Xu 2010	1 to 4		Delta p = 9.25 MPa
Zhang 2010		560	Delta p = 10 MPa; rock compressibility = 10^{-9} Pa^{-1}
Weighted average	16	603	
Delta p is the maximum permitted pressure increase in the formation			

Source: Authors' compilation

A frequency distribution is used to determine which efficiency values were used most frequently to calculate capacities for deep saline aquifers in China (see Fig. 17-3). For this reason, the information contained in Tab. 17-19 has been modified as follows:

- 2.4 per cent is considered as 2 per cent;
- 1 to 4 per cent is included as 1, 2, 3 and 4 per cent separately;
- 10 to 60 per cent is included as 10, 20, 30, 40, 50 and 60 per cent separately.

In conclusion, efficiencies of 1, 2 and 10 per cent were applied most frequently. In addition, three efficiency ranges can be identified. These are, in order of decreasing frequency:

- From 0.16 to 4 per cent, with a weighted average of 2 per cent;
- From 10 to 30 per cent, with a weighted average of 16 per cent;
- From 40 to 60 per cent, with a weighted average of 50 per cent.

Thus the efficiency values of 2, 16 and 50 per cent are chosen to develop storage scenarios in section 17.6. The weighted average of all efficiencies in Tab. 17-19 is also 16 per cent.

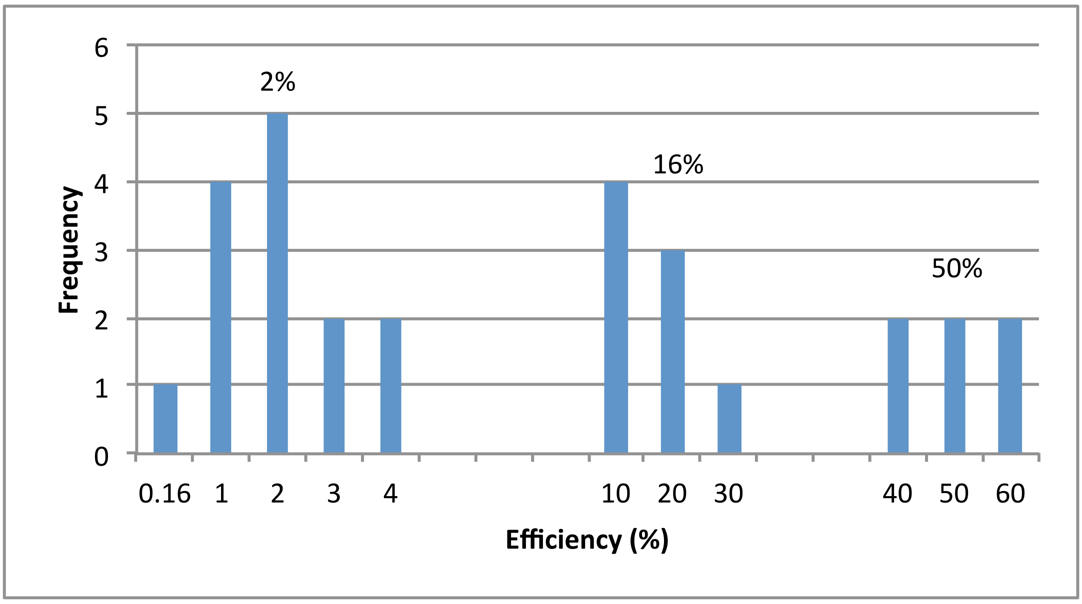


Fig. 17-3 Frequency distribution of efficiency factors for deep saline aquifers in Chinese storage capacity studies

Source: Authors' illustration

17.4.4 Gas Fields

The storage capacity in natural gas fields is lower than that in aquifers and oil fields in the five selected basins. Since China does not have very large gas reserves and CO_2-based enhanced gas recovery (EGR) has not yet been applied, detailed investigations on storing CO_2 still have to be conducted. If more R&D work is carried out on CO_2-based EGR, additional studies will be available to identify potential sequestration sites. Zhang et al. (2005b), which is assumed to be the best fit for oil fields, did not differentiate between oil and gas fields in their study. Thus the potential of gas fields is already included, and is considered to be of only minor importance.

The highest capacities are estimated to be 1.3 Gt of CO_2 by CO2CRC and APEC (2005) for Bohai basin and 1.1 Gt of CO_2 for Ordos basin (Dahowski et al. 2009) (compare Tab. 17-20). Songliao basin offers a lower capacity and Subei basin offers none at all. The storage capacity in hydrocarbon fields for the Pearl River Mouth basin was already described in section 17.4.1 together with oil fields. The very low capacity for gas fields was included there.

Taking the two existent capacity estimates into account, they total 1.8 and 2.0 Gt of CO_2, respectively, for fields larger than 2 Mt. Dooley et al. (2005) estimate the entire capacity for China's gas fields to be 2 Gt, although a description is lacking. This result implies that no large difference can be found between the two estimates of Dahowski et al. (2009) and CO2CRC and APEC (2005). Zhang et al. (2005b) was selected as the best estimate for oil fields in which gas fields are also included. If this report is selected as the base case for storage scenarios, no additional estimate for gas fields would be required.

Tab. 17-20 Overview of the storage capacity of gas fields in five selected basins in China

Name of basin	**Site**	**Gas fields (> 2 Mt CO_2)**	
		Dahowski et al. 2009a	CO2CRC and APEC 2005
Bohai	Onshore	0.3	1.3
Songliao	Onshore	0.6	0.1
Subei	Onshore	0.0	-
Pearl River Mouth	Offshore	0.0	-
Ordos	Onshore	1.1	0.4
All quantities are given in Gt CO_2			

Source: Authors' compilation

17.4.5 Coal Seams

Taking the study of Dahowski et al. (2009) into account, of the five selected basins only Ordos basin provides storage capacity in coal seams. This capacity, related to coalbed methane production, amounts to 4.45 Gt of CO_2. China United Coalbed Methane Corporation Ltd. investigates the potential to enhance coalbed methane recovery using CO_2 in Eastern Ordos basin in Shanxi Province (CUCBM 2011). Even if Bohai basin is not assumed to provide capacity for coalfield sequestration by Dahowski et al. (2009), other studies investigate the capacity in Keiluan field in Hebei Province. Zheng et al. (2009) yield a capacity of 0.7 Gt of CO_2. Vincent et al. (2011) assume a capacity of 0.5 Gt of CO_2 in Keiluan mining areas, although it is an active coal mine with a low permeability and porosity. The coal reserve needs to be prevented from being contaminated by CO_2. Zhang et al. (2005a) estimate a capacity of 12 Gt of CO_2 for China, but do not define the basins where suitable coalfields can be found. CO_2 storage has not yet been proven in any coalfield to date (CO2CRC and APEC 2005). Thus it is rather uncertain whether the total potential of around 5 to 12 Gt of CO_2 will be available in the event of launching CCS in China. Thus the storage potential in coal seams is excluded from this report.

17.5 Summary of Research Results

The five most promising sedimentary basins in China, which have also been studied in the most detail, were selected and compared to discover more about storage capacities. Tab. 17-6 gives an overview for oil fields, gas fields, saline aquifers and coalbeds.

Regarding oil fields, the proven capacity generated by Zhang et al. (2005b) is considered to be the most reasonable calculation. Comparing site- and basin-specific studies with results for these basins from general studies for China, this estimate provides the best solution in three out of four cases. Hence, this study is assumed to be the most valid assessment for all oil fields in China. In total, a capacity of 3.6 Gt of CO_2 is yielded, including an estimate for China's gas fields. Thus none of the other few detailed studies available on gas fields need to be selected as the base case. To enhance oil production, CO_2-based EOR can be applied, which is already included in many estimates. This technique has been tested recently at two sites in China. For deep saline aquifers, large variations can be found in the assessments, which range from 0.2 to 2,371 Gt of CO_2 (Tab. 17-6). Taking the key findings into account, the storage efficiency applied is the most important aspect for the assessment. Efficiencies used in the available studies on storage in deep saline aquifers in China are compared by frequency distribution. Three efficiency ranges were identified with the weighted average of 2, 16 and 50 per cent. The average CO_2 density was set at 603 kg/m^3. These parameters are used to develop storage scenarios.

With regard to CO_2 storage in coal seams, there is insufficient information to discuss this formation type properly. Since it is not yet certain whether or not coal seams are feasible for CO_2 storage, this possibility is excluded.

17.6 Development of Storage Scenarios

An overall storage capacity estimate is provided based on the intense debate on existing storage capacity assessments for China, and in particular five selected basins. For *oil and gas fields*, the proven capacity generated by Zhang et al. (2005b), in which 3.6 Gt is assumed, was chosen. *Coal seams* were excluded due to the uncertainty of whether or not storage is possible in these formations. For *saline aquifers*, parameters were selected for efficiency and CO_2 density. Only two studies for saline aquifers in China's basins are available to apply these parameters: first the detailed analysis of theoretical capacity by Dahowski et al. (2009); second the estimates by Zhang et al. (2005b) generated by two different methodologies and yielding very divergent results. Unfortunately, insufficient background information is provided about the calculation used by Zhang et al. (2005b), meaning that it is impossible to identify the advantages and disadvantages involved. Thus the theoretical estimate yielded by Dahowski et al. (2009), based on the solubility approach (Tab. 17-1), is taken to be the most accurate figure, and the parameter values selected above are applied to it.

The average of selected CO_2 densities in China's aquifers is 603 kg/m^3 (compare Tab. 17-19). Dahowski et al. (2009) use a very similar density of 604 kg/m^3, rendering it unnecessary to change that input parameter due to the general existence of much greater uncertainties. The authors provide a theoretical storage capacity, and efficiency factors are required to gain effective capacity values. As shown above, efficiencies of 2, 16 and 50 per cent were derived (see Fig. 17-3). The figure of 16 per cent is assessed as the overall weighted average and hence used as the base case.

Dahowski et al. (2009) apply efficiency factors of 1, 10 and 50 per cent to estimate effective onshore aquifer capacity. These factors are not applied to offshore aquifers. In the literature analysis conducted above, similar efficiency factors are applied both onshore and offshore (Tab. 17-19). For this reason, no such differentiation is made for the storage scenarios. Instead, the estimated efficiency factors are applied to both onshore and offshore basins. This yields a capacity of 491 Gt of CO_2 for saline aquifers. Tab. 17-21 provides an overview of these results. The total effective capacity amounts to 498.6 Gt of CO_2 for China.

Tab. 17-21 Base case effective storage capacity calculation for China

Formation	Location	Storage capacity
Oil and gas fields	Onshore and offshore	3.6
Coal seams	Onshore	-
Saline aquifers	Onshore	366
	Offshore	125
Total		495
All quantities are given in Gt CO_2		
The efficiency factor for saline aquifers is 16%.		

Source: Authors' compilation

This is taken as the base case scenario, and is assumed to be an intermediate estimate. In addition, both a high and a low estimate are compiled to generate three different effective storage capacity estimates (compare Tab. 17-22). All scenarios are developed in the sense of a sensitivity analysis; this does not imply that one calculation is more accurate than another.

1. The *high estimate* (S1) includes the aquifer storage capacity generated by Dahowski et al. (2009) with a 50 per cent efficiency for onshore and offshore basins. This results in a capacity of 1,534 Gt. For oil and gas fields, the higher estimate by Zhang et al. (2005b) including non-proven fields (7.8 Gt) is assumed. Storage in coal seams is not included. Scenario S1 yields a total of 1,542 Gt of CO_2 storage capacity.

2. As described above, the *intermediate* (*base) case* (S2) includes 3.6 Gt of CO_2 proven storage capacity in oil and gas fields based on Zhang et al. (2005b). The main contributor is saline aquifers, which is estimated from Dahowski et al. (2009) by applying the weighted average efficiency of 16 per cent for both onshore and offshore aquifers. The potential capacity in coal seams is deemed to be too uncertain and is therefore excluded from the estimate. A total capacity of 495 Gt of CO_2 is assumed.

3. The *low estimate* (S3) includes the same proven capacity for oil and gas fields as used in the base case (3.6 Gt) because it is at the lower end of the available range and provides basin-specific capacities. The effective capacity estimate for aquifers is taken from Dahowski et al. (2009) by applying a 2 per cent efficiency. This leads to a capacity of 61.4 Gt. Storage in coalfields is excluded. This leads to a total of 65 Gt of CO_2.

Tab. 17-22 Scenarios of effective CO_2 storage capacity in China

		S1: high	S2: intermediate (base)	S3: low
Oil fields **Gas fields**		7.8	3.6	3.6
Saline aquifers	Onshore	1,145	366	45.8
	Offshore	390	125	15.6
Total		1,542	495	65

For aquifers, efficiencies of 50% (S1), 16% (S2) and 2% (S3) are applied.
All quantities are given in Gt CO_2

Source: Authors' compilation based on Zhang et al. (2005b) and Dahowski et al. (2009)

18 CCS-Based Development Pathways for China's Power and Industry Sector

18.1 Introduction

The aim of this section is to determine how much CO_2 may have to be stored underground, depending on different development pathways of the Chinese power plant and industry sector. The *coal development pathways* provided for this purpose indicate a development between a "low carbon" and a "high carbon" strategy in these sectors. For each decade up to 2050, the amount of coal-fired power plant capacities that could potentially be installed including CCS or retrofitting with CO_2 capture once CCS is commercially available is investigated. In addition, the contribution of the industrial sector is considered by developing a rough pathway sketching the possible application of CCS in China's industry.

Captured CO_2 emissions resulting from power plants and industrial sites are added together. Whereas the annual figures of CO_2 emissions determine the maximum scope of pipeline infrastructure required for CO_2 transportation, the total amount enables the possible storage capacity required to be determined for China.

The analysis is performed as follows: firstly, a comprehensive analysis of coal-fired power plants currently under operation and officially planned in the near future is conducted (section 18.2). Secondly, this analysis forms the basis for sketching coal development pathways and for determining how many coal-fired power plants could be installed in the future (section 18.3). In section 18.4, an estimation is given of how much CO_2 could be separated from these power plants in the decades ahead. The potential role of the industry sector is then examined by providing rough CCS-based industrial coal development pathways (section 18.5). Finally, the results are summarised and conclusions drawn (section 18.6).

18.2 Current and Projected Coal-Fired Power Plants in China

To consider possible development pathways of China's coal-fired power plants, it is necessary to begin the investigation with a comprehensive analysis of power plants currently under operation and officially planned in the near future. The analysis, conducted by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, is based on the commercially available power plant database of Platts (2009). The approach applied is as follows:

- Firstly, the power plants currently in operation are analysed with regard to their age. Assuming 40 years of regular operation yields the year of decommissioning. Considering the decades ahead and adding together the capacity of only those power plants that are assumed to be in operation according to this calculation results in the "curve of decommissioning" of the current power plant fleet.
- Secondly, all power plants that are officially expected to be installed are added to the capacity of existing power plants, yielding the total capacity in operation per year. In China's case, only the scarce data reported in Platts (2009) can be used because there is no publicly available data on the development of the power plant sector at the regional level. This data shows a total increase of 9 GW to be newly installed in 2012, spread over six administrative divisions (Anhui, Hebei, Henan, Inner Mongolia, Shandong, Shanxi).

Fig. 18-1 illustrates the resulting development between 2010 and 2050 for most Chinese provinces and regions. States with only minor generation capacities (smaller than 15 GW) are subsumed as "remaining states." In total, the installed capacity of coal-fired power plants was 567 GW in 2010. The constantly high level up to 2020 and the only slight decrease by 2030 show that much of the power plant fleet has been built recently. The proportion of known power plants to be newly installed is only 1.4 per cent, which is why they are not shown separately. In the analysis, no differentiation is made between hard coal and lignite because only a few lignite-fired power plants are in operation (20 GW, equalling 3.5 per cent in 2010).

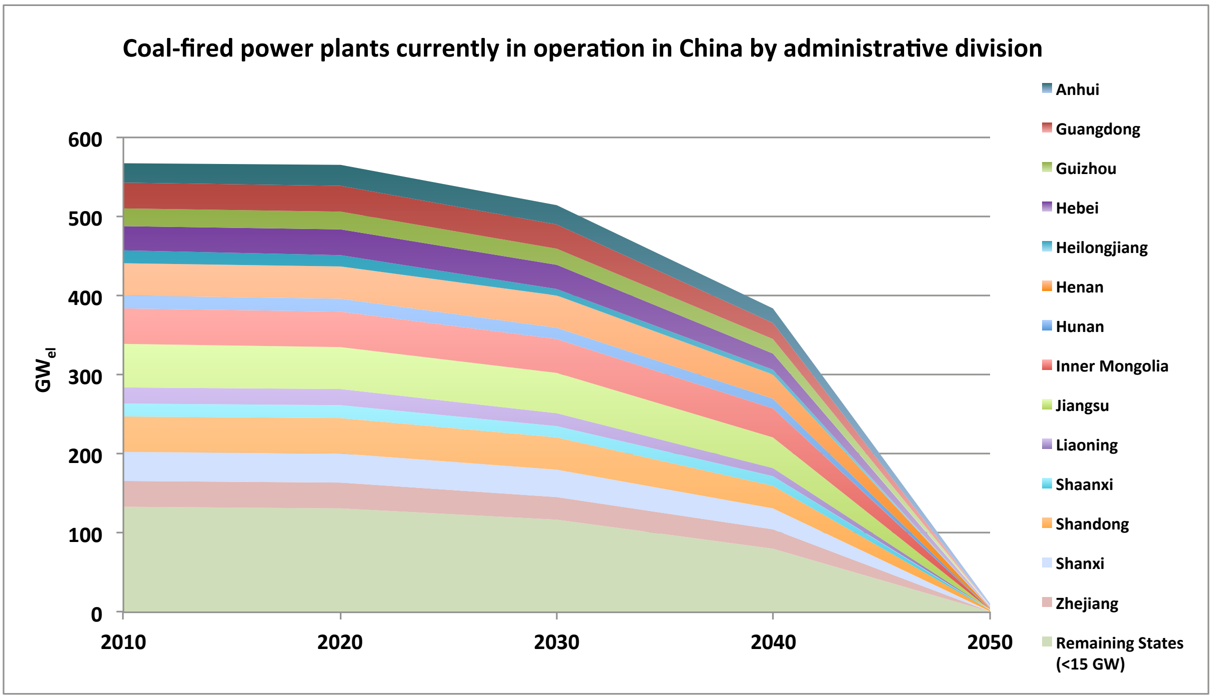


Fig. 18-1 Coal-fired power plants currently in operation in China, by year, according to an analysis of a commercial power plant database

Source: Authors' illustration

Fig. 18-2 illustrates where the different administrative divisions (provinces, autonomous regions, federal cities and special administrative regions) are located in China.

Fig. 18-2 China's administrative divisions

Source: Chinaservice (2011)

In the next step, the states are grouped into six geographic regions according to the (former) official classification, illustrated in Fig. 18-3. These are North (Huabei), North-East (Manchuria), East (Huadong), Central & South (Zhongnan), South-West (Xinan) and North-West (Xibei).

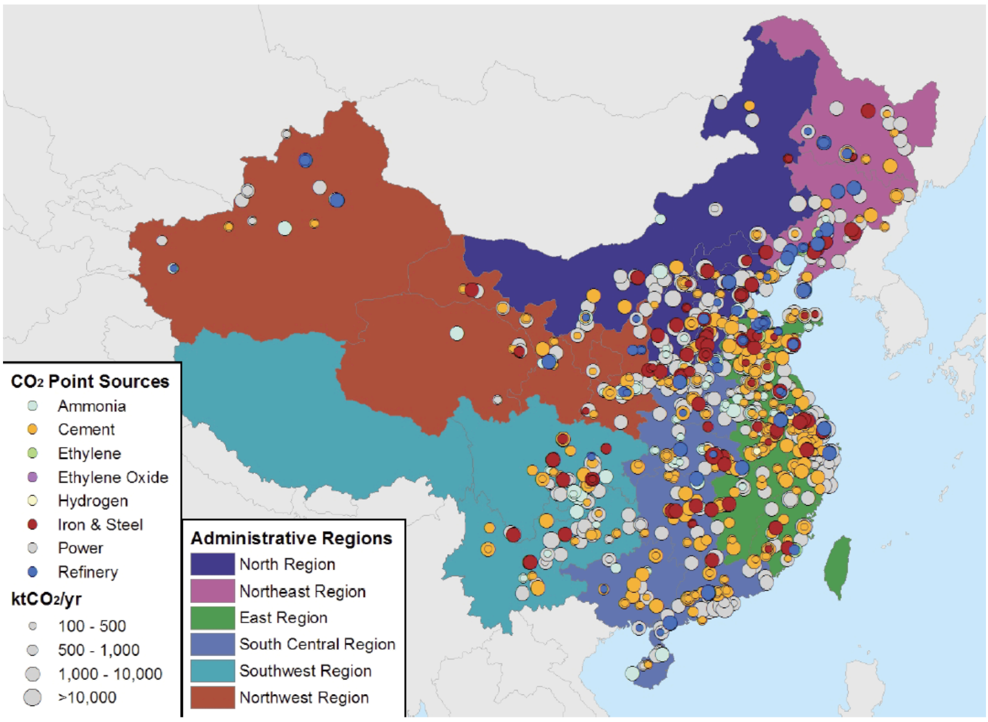


Fig. 18-3 Geographic regions in China (and their large point sources)

Source: Dahowski et al. (2009)

Fig. 18-4 shows how the currently installed power plant capacity is distributed over these regions and how it will develop in the future, resulting in curves of decommissioning for each region.

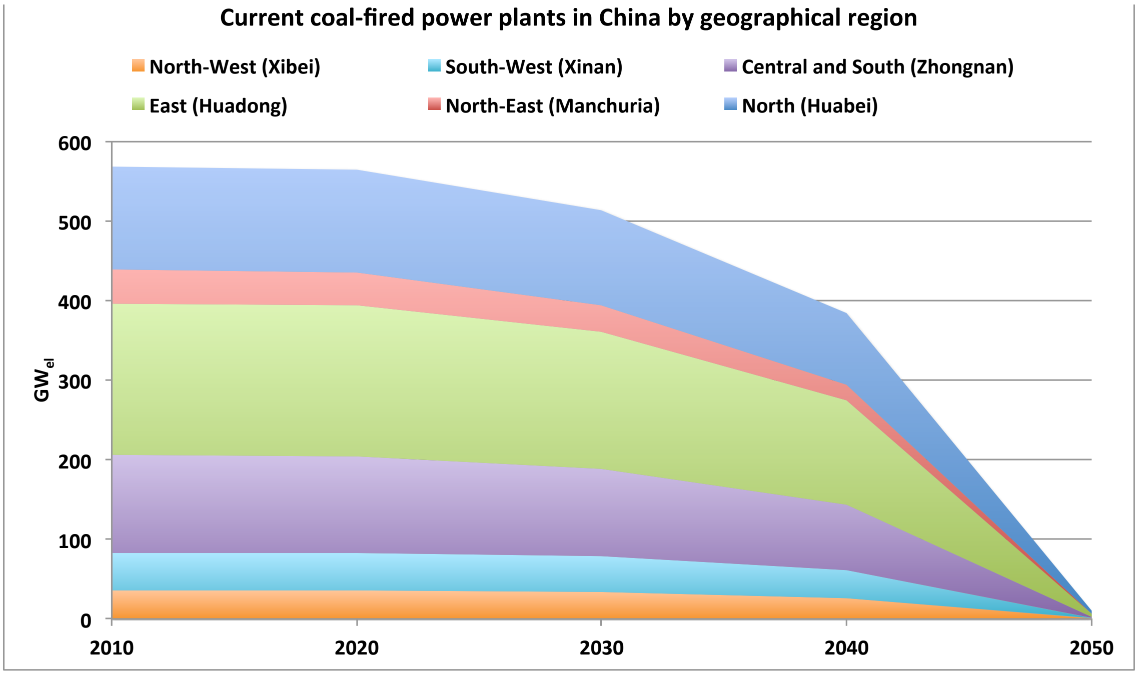


Fig. 18-4 Current coal-fired power plants in China (by geographic region)

Source: Authors' illustration

Considering the regional allocation in 2010 and in 2040 (see Fig. 18-5), the East (Huadong) is the region with the highest proportion (190 GW, 33 per cent), which is in line with its high economic power. It is followed by the North (Huabei) and Central & South (Zhongnan), which have a respective share of 23 per cent (128 GW) and 22 per cent (123 GW).

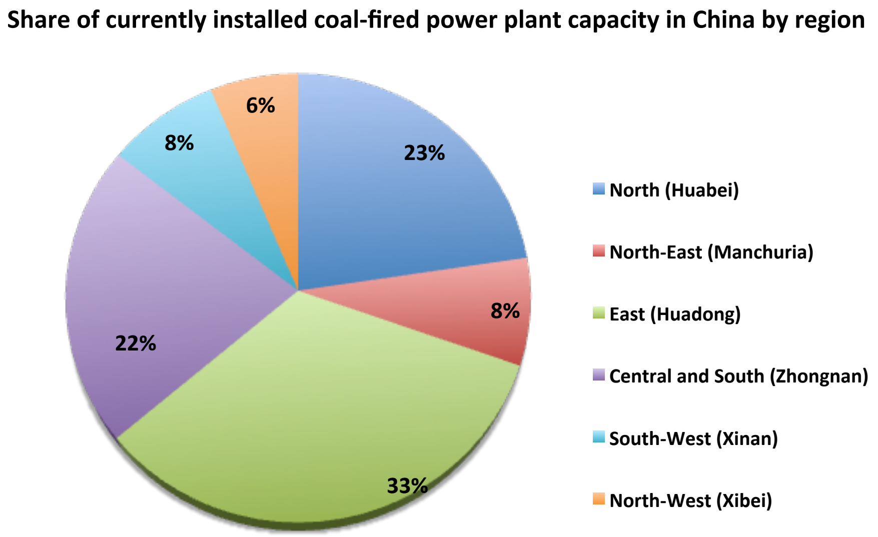


Fig. 18-5 Share of geographic region in current and installed coal-fired power plant capacity in China

Source: Authors' illustration

The following analysis of the possible development of CCS power plants is based on this regional approach.

18.3 Long-Term Coal Development Pathways for the Power Plant Sector

18.3.1 Methodological Approach

The amount of CO_2 emissions potentially available for storage is assessed by applying three substantially different long-term coal development pathways for China. The pathways indicate a power plant development between a “high carbon” and a “low carbon” strategy, as indicated by their names *E1: high*, *E2: middle*, *E3: low*. The aim is to investigate the level of CO_2 emissions required for storage with each pathway for each decade up to 2050. To this end, the capacities of coal-fired power plants, both newly built as CCS-based power plants or retrofitted with CO_2 capture from when CCS is commercially available, has to be explored. The annual levels of CO_2 emissions to be captured in China are derived from key parameters such as efficiency, penalty load, construction time of capture facilities and capture rate. The total amount of CO_2 to be captured and stored is determined considering the lifetime of CCS-based power plants. Whereas the *annual figures* determine the maximum scope of the pipeline infrastructure required for CO_2 transportation, the *total amount* yields the possible storage capacity required per power plant, state, region and for the whole of China. This cumulated amount is compared with the storage capacities provided in section 17.

It should be noted that coal development pathways differ from energy scenarios: whilst energy scenarios provide a consistent framework for the analysis of long-term energy strategies, the pathways applied here are taken from different existing scenario studies. They are only used to illustrate the different CCS development pathways to obtain an understanding of the level of separated CO_2 emissions that could be available for storage. The extent of the project did not allow new energy scenarios including CCS to be developed from scratch for China.

First of all, a review of all existing energy scenario analyses is undertaken. The preconditions for selecting a study as the basis for the coal development pathway are as follows:

- The scenarios must cover a period up to at least 2050;
- The installed capacity of coal-fired power plants must be published at least for each decade, otherwise the scenarios cannot be used to estimate CCS capacity;
- The scenarios must be published in English.

After applying these conditions, seven studies, all published between 2009 and 2011, remain for the analysis. Fig. 18-6 shows a plurality of long-term energy scenarios within these studies.

- *China Human Development Report 2009/10* (UNDP China 2010);
- *China's Low Carbon Development Pathways by 2050: Scenario Analysis of Energy Demand and Carbon Emissions (WWF China 2011a)*, based on a study by ERI (Energy Research Institute);
- *China’s Pathway Towards a Low Carbon Economy* (CCICED 2009);

- *Energy [R]evolution – A Sustainable World Energy Outlook 2010* (EREC and Greenpeace International 2010);
- NZEC's *National Scenario Analysis* (Chen 2009);
- Tyndall's *China's Energy Transition – Pathways for Low Carbon Development* (Wang and Watson 2009, 2010);
- *World Energy Outlook 2009* (IEA and OECD 2009a), updated to 2050.

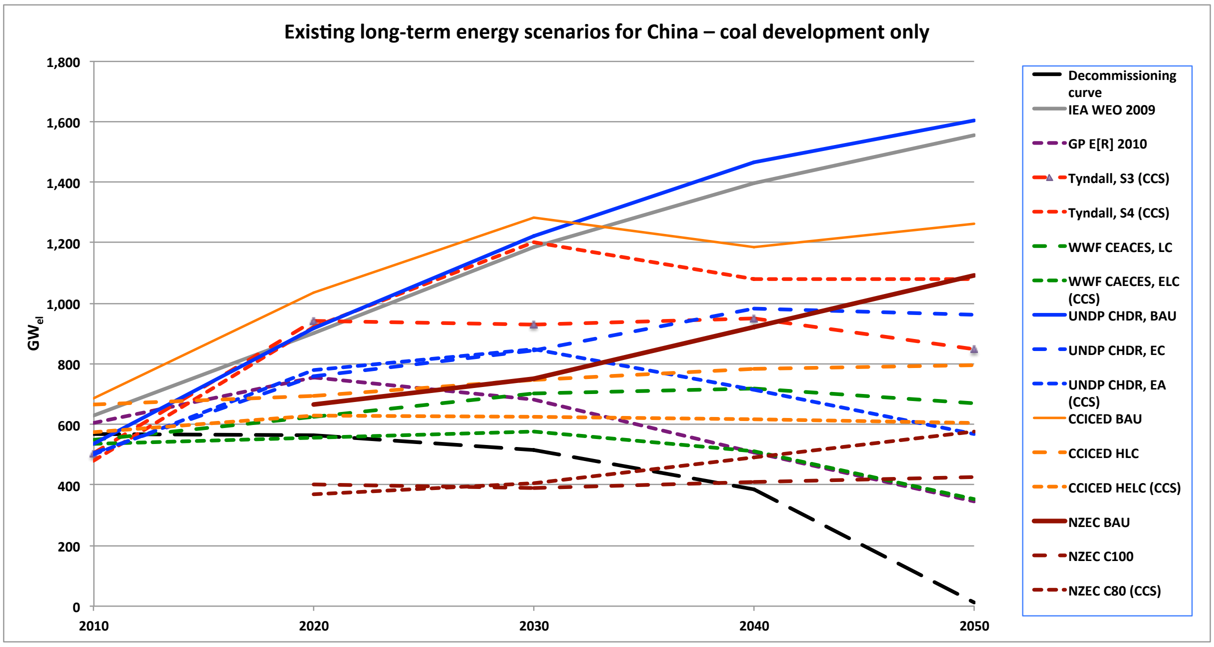


Fig. 18-6 Evaluated long-term energy scenarios for China

Source: Authors' illustration analysing CCICED (2009); Chen (2009); EREC and Greenpeace International (2010); IEA and OECD (2010); UNDP China (2010); Wang and Watson (2009, 2010); WWF China (2011)

To obtain a better understanding, the evaluated scenarios are divided into business as usual (BAU), middle and low scenario variants, illustrated in Fig. 18-7.

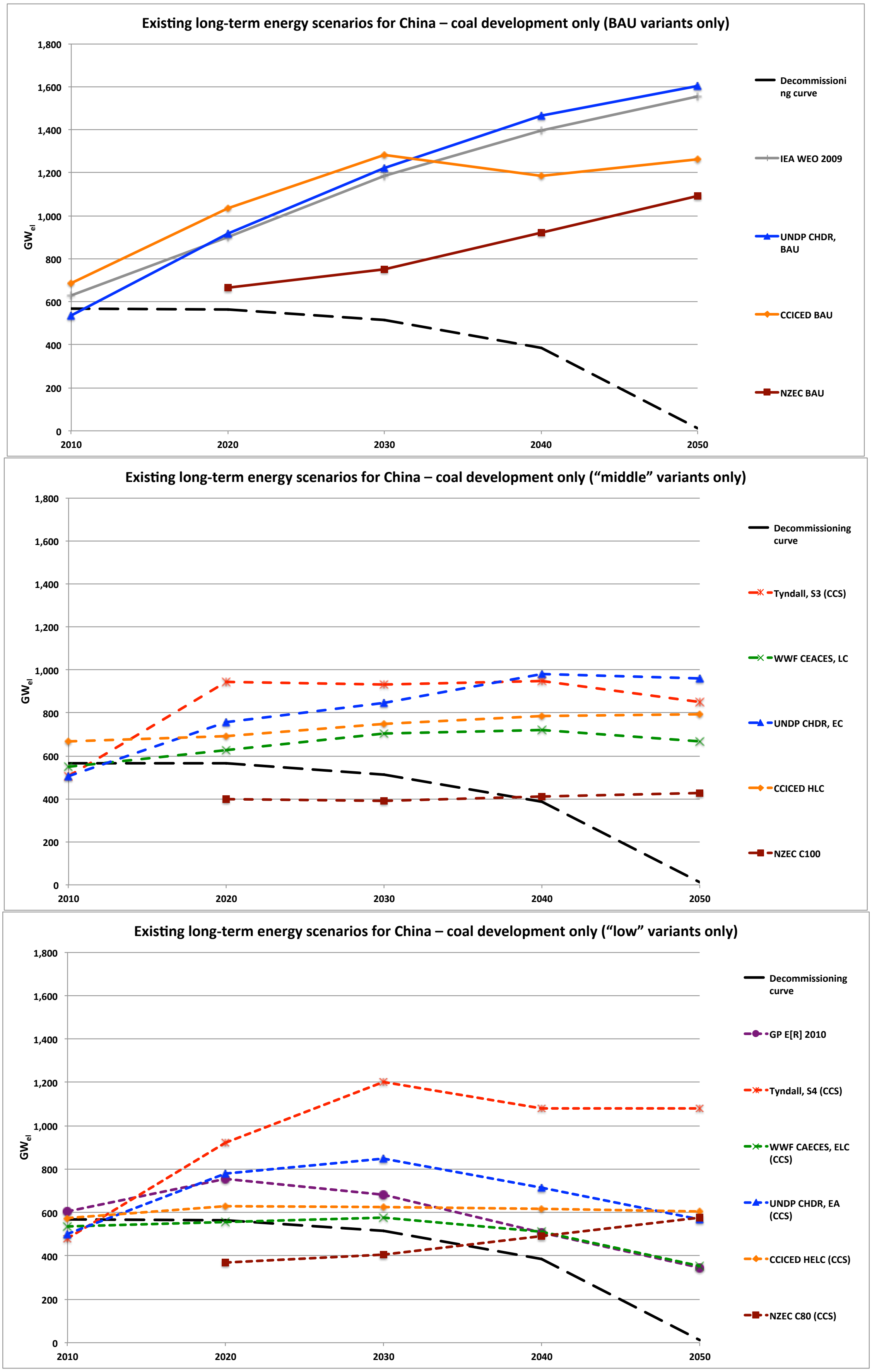


Fig. 18-7 Evaluated long-term energy scenarios for China – divided into BAU (business as usual), middle and low variants

Source: Authors' illustration

Regarding the consideration of CCS, a number of general conclusions can be drawn:

- Only four of the seven studies illustrate *BAU scenarios* (UNDP, CCICED, IEA, NZEC) without the use of CCS, resulting in an installed capacity for coal-fired power plants of 1,100 to 1,600 GW in 2050.
- Five of the seven studies develop *"middle" scenarios* (UNDP, CCICED, NZEC, Tyndall, WWF), showing how to reduce greenhouse gas (GHG) emissions at a lower level. After an increase in emissions, they start reducing CO_2 from 2030 or 2040 and result in an installed coal capacity of 428 to 962 GW in 2050. One of these studies (Tyndall) considers the use of CCS. Three studies underestimate the current development of power plant capacity and start with lower values (505 GW instead of 567 GW in 2010) or do not illustrate how to decrease the installed capacity from 567 GW in 2010 to the assumed figure of 400 GW in 2020.
- Six of the seven studies develop *low carbon scenarios* (UNDP, CCICED, GP&EREC, NZEC, Tyndall, WWF), five of which use CCS. Only one study (GP&EREC) achieves the emission target without CCS (and without nuclear energy). The studies result in an installed coal capacity of 346 to 1080 GW in 2050 (346 to 603 GW if excluding Tyndall's high capacity study). The high capacity figures can be explained in part by the use of CCS.

However, none of the existing scenarios that include CCS suffice for the intended use:

- Most of the *low carbon scenarios* that include CCS underestimate the development of power capacity in 2010 by 40 to 90 GW (UNDP, NZEC, Tyndall, WWF). For one scenario (NZEC), no figures are given for 2010. This scenario does not reach the current capacity (567 GW) before 2050. The capacity development of these studies is therefore probably too low for the decades ahead.
- One scenario (CCICED) meets the 2010 figure exactly, but suggests only a slight increase up to 2020 (also visible in the WWF scenario). This seems to be unrealistic, regarding the huge capacity deployment programme already at the planning stage in China.
- The Tyndall scenario development is similar to the BAU scenarios in the first two decades and starts with a very low figure for 2010 (480 instead of 567 GW). It is therefore regarded more as a cross between a low and a middle scenario than a low carbon scenario.
- Only the GP&EREC scenario yields the correct starting value in 2010. It also considers the current power plant deployment programme with an increasing development pathway up to 2030 and reduces the capacity from 2030, yielding 346 GW in 2050 (similar to the WWF scenario). However, it does not include CCS.
- The only CCS-based scenario in the *"middle"* scenario variants (Tyndall) is similar to the BAU scenarios in the first decade and also starts with a quite low figure for 2010.

There are other studies written in English that include CCS in at least one scenario. However, they do not give the capacity figures by decade. These include:

- *Energy Technology Perspectives 2010* (IEA 2010) – only the 2050 capacity figure is given, not the pathway how to get there;

- *China's Emissions Trajectories to 2050* (Zhou et al. 2011b);
- *Low Carbon Technology Development Roadmap for China* (Qiang et al. 2011), *Potential Secure, Low Carbon Growth Pathways for the Chinese Economy* (Kejun 2011) and further studies by Kejun et al.;
- *Going Clean - The Economics of China's Low-carbon Development* (Stockholm Environment Institute and Chinese Economists 50 Forum 2009);
- *Role for carbon capture and storage in China* (Chen et al. 2009a) and further studies by Wenying et al.

The extent of this project did not allow new energy scenarios to be developed from scratch. For this reason, any existing energy scenarios that meet the current development but do not consider use of CCS are taken as background scenarios for applying CCS. An estimate is made of how much of the outlined coal-based capacity could be deployed with CCS:

- *World Energy Outlook 2009* (IEA and OECD 2009a), reference scenario, updated to 2050;
- *China Human Development Report 2009/10* (UNDP China 2010), EmissionsControl (EC) Scenario;
- *Energy [R]evolution – A Sustainable World Energy Outlook 2010* (EREC and Greenpeace International 2010), Energy [R]evolution scenario.

These scenarios are described in detail below.

18.3.2 Description of Underlying Basic Scenarios

The following approaches are chosen to establish coal development pathways:

- *Pathway E1: high*: The "high carbon" pathway E1 is based on the *World Energy Outlook 2009 Reference Scenario*, published by IEA and OECD (2009a). This scenario takes into account existing international energy and environmental policies. Examples are continuing progress in electricity and gas market reforms, the liberalisation of cross-border energy trade or recent policies designed to combat environmental pollution. However, no further policies to considerably reduce greenhouse gas emissions are included. For this study, the *Reference Scenario for China* is used. Since World Energy Outlook scenarios extend only to 2035, the scenario was extrapolated to 2050 in EREC and Greenpeace International (2010).

  The *Reference Scenario* assumes an increase in installed power plant capacity from 909 GW (of which coal: 628 GW, 69 per cent) in 2010 to 2,309 GW (of which coal: 1,557 GW, 67 per cent) by 2050 (see Fig. 18-8).

  The assumption behind the application of CCS in coal development pathway E1 is that the deployment of CCS must be as high as possible in the future to decrease the high CO_2 emissions resulting from a strong development of coal-fired power plants.

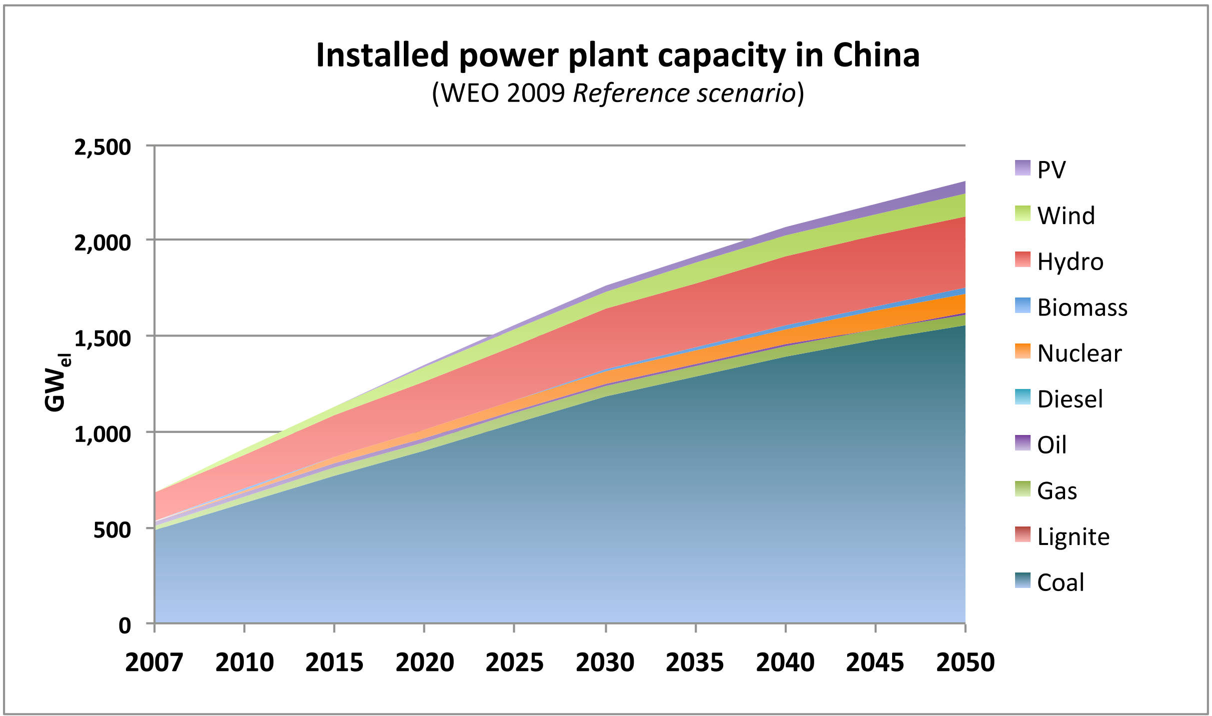


Fig. 18-8 Development of installed power plant capacity in China in the *WEO 2009 Reference scenario* used as the basis for coal development pathway *E1: high*

Source: Authors' illustration based on IEA and OECD (2009a); adapted in EREC and Greenpeace International (2010)

- *Pathway E2: middle*: The "middle carbon" pathway E2 is based on the *EmissionsControl (EC) Scenario*, developed within the China Human Development Report (UNDP 2010). It is characterised by improvements in energy efficiency, a diminished increase in coal (the share of coal in the primary energy mix will decrease to 44 per cent by 2050) and a huge increase in nuclear power (from 60 TWh in 2005 to 1,930 TWh by 2050). This leads to an increase in the installed capacity of nuclear energy technologies to 281 GW in 2050, but also to a strong increase in hydro and wind energy (see Fig. 18-9). "Expensive technologies of CCS, solar power generation, electric mobiles, etc. on a large scale" will not be used in this scenario. The coal-fired power plant capacity increases from 523 GW in 2010 to 765 GW in 2020 and further to 978 GW in 2040, the latter two decades at diminished deployment rates. It peaks in 2040 and decreases slightly by 2050 to 968 GW.[1]

[1] It should be noted that the individual figures on installed capacities are not reported but were read manually from the appropriate figures.

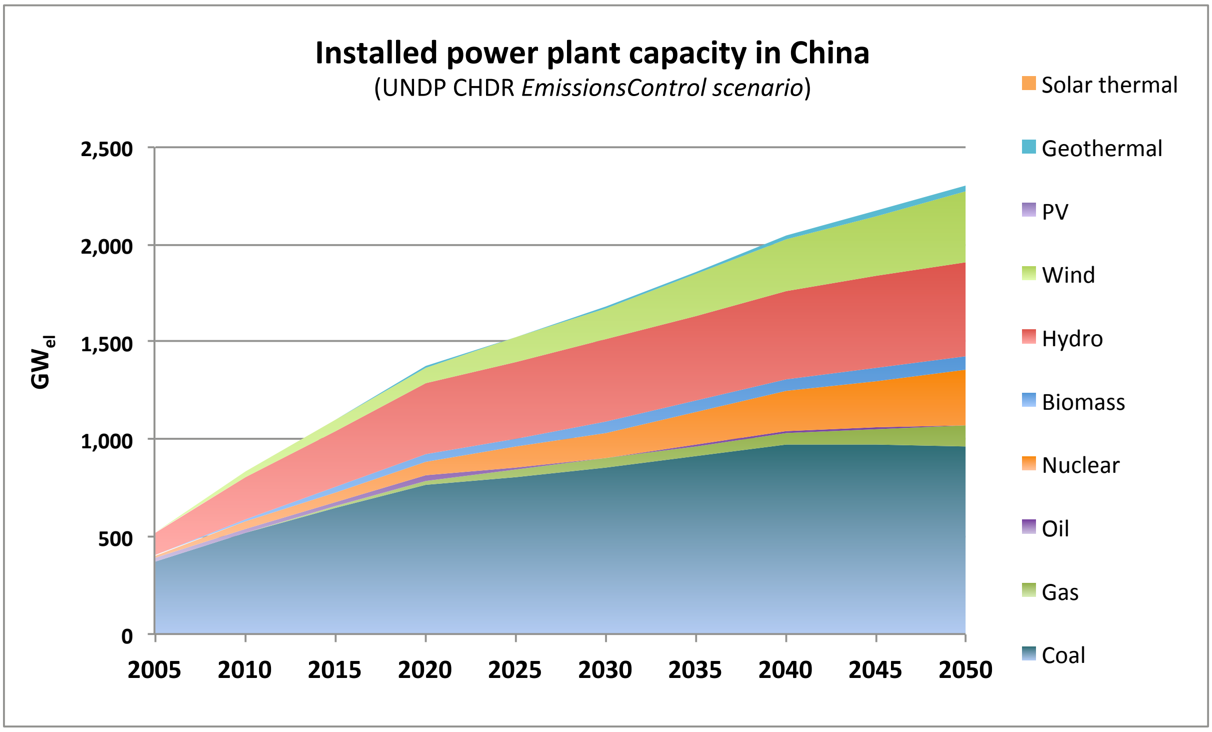


Fig. 18-9 Development of installed power plant capacity in China in the UNDP CHDR *EC scenario* used as the basis for coal development pathway *E2: middle*

Source: Authors' illustration based on UNDP China (2010)

Despite a diminished increase in coal-fired power and the use of low-carbon energies, "it is still unlikely" that CO_2 emissions will peak before 2050 in this scenario (UNDP 2010). Therefore, the assumption behind the use of CCS in pathway E2 is that in the underlying scenario

- a much stronger need for greenhouse gas reduction may eventually be required before 2050;
- the strong increase in nuclear energy will not be realisable for safety reasons;
- the efforts to raise energy efficiency will not be achieved as quickly as required.

In each of these cases, the deployment of CCS could be a "fall back" option to achieve the required CO_2 reduction as outlined in the scenario or even earlier.

- *Pathway E3*: *low*: The "low carbon" pathway E3 is based on the *Energy [R]evolution Scenario 2010*, published by Greenpeace and the European Renewable Energy Council (EREC) (EREC and Greenpeace International 2010; Teske et al. 2010). The target of this scenario is to reduce worldwide CO_2 emissions by 50 per cent below the 1990 level by 2050. This means that per capita emissions are reduced to less than 1.3 tonnes per year, which is necessary to prevent the rise in global average temperature from exceeding a threshold of 2°C. Whilst the scenario is based only on proven and sustainable technologies (renewable energy sources, efficient decentralised cogeneration and energy-saving technologies), both CCS power plants and nuclear power plants are excluded. For this study, the *Sustainable China Energy Outlook* part of the global *Energy [R]evolution Scenario* is applied.

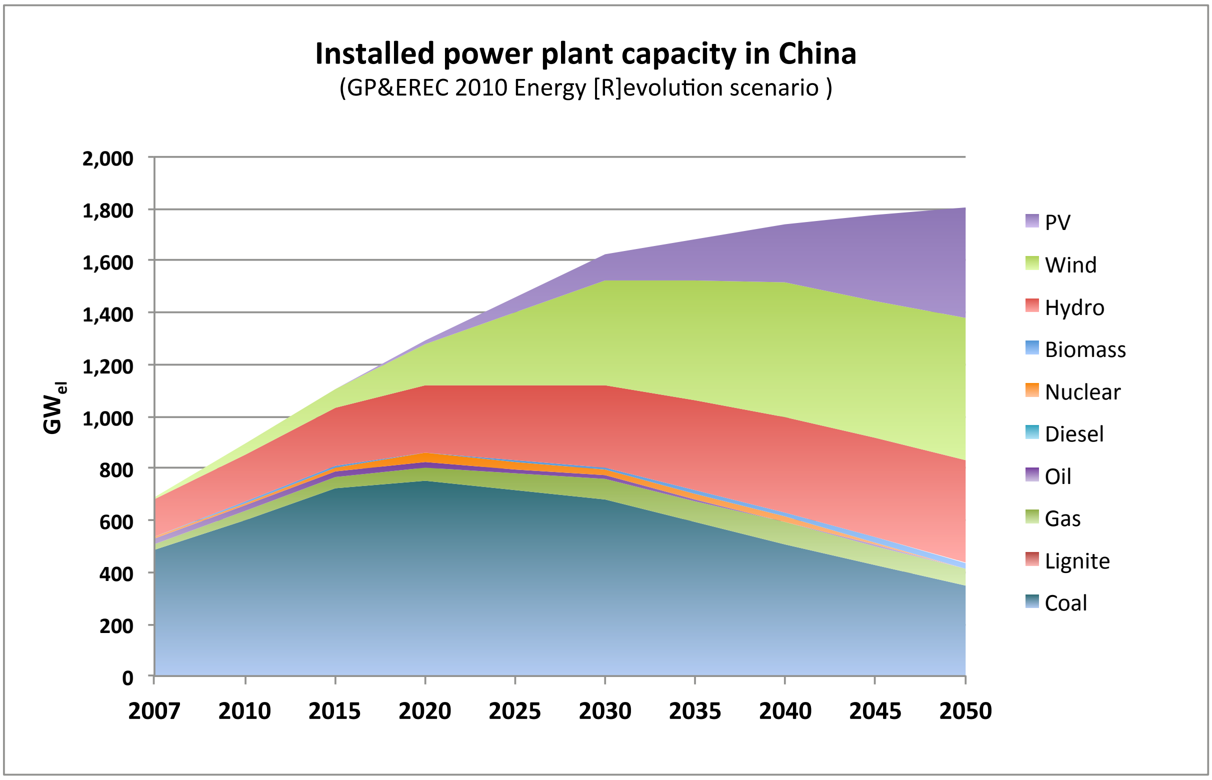


Fig. 18-10 Development of installed power plant capacity in China in the Greenpeace and EREC *Energy [R]evolution Scenario 2010* used as the basis for energy scenario *E3: low*

Source: Authors' illustration based on EREC and Greenpeace International (2010)

Whilst the *Energy [R]evolution Scenario* is based on the same projections of population and economic development as the *IEA Reference Scenario*, a faster decrease in energy intensity due to more ambitious energy efficiency measures is assumed. Energy intensity will decline by 80 per cent between 2005 and 2050 (in contrast to IEA's assumption of a 65 per cent reduction).

In contrast to the *IEA Reference Scenario*, about 80 per cent of the electricity produced in China will come from renewable energy sources in 2050. This leads to an increase in the installed capacity of renewable energy technologies from 229 GW in 2010 to 1,633 GW in 2050 (see Fig. 18-10). The installed coal-fired power plants based on a capacity of 603 GW in 2010 will increase, too, but peak in 2020 at 753 GW, before finally decreasing to 346 GW in 2050.

The assumption behind the application of CCS in coal development pathway E3 is that the strong increase in both the energy efficiency and the deployment of renewable energies may not take place as quickly as required in the underlying basic scenario. In this case, the deployment of CCS could be a "fall back" option to compensate for the slowing CO_2 reduction.

18.3.3 Comparison of Coal Development Pathways

In Fig. 18-11 and Tab. 18-1 coal development pathways E1–E3 are compared with regard to their assumptions on the development of coal-fired power plant capacity. In addition, the currently installed power plant capacity development is given. The figure illustrates that all pathways meet the currently installed capacity more or less adequately, but *E3: low* meets it best.

Whilst all pathways assume a continuous increase in installed coal-fired power plants by 2020, in the long term they develop according to their specific characteristics: pathway *E1: high* shows a strong increase in coal-based capacity whilst *E2: middle* increases continuously until it peaks in 2040. In pathway *E3: low,* the coal-based capacity decreases continuously after peaking in 2020.

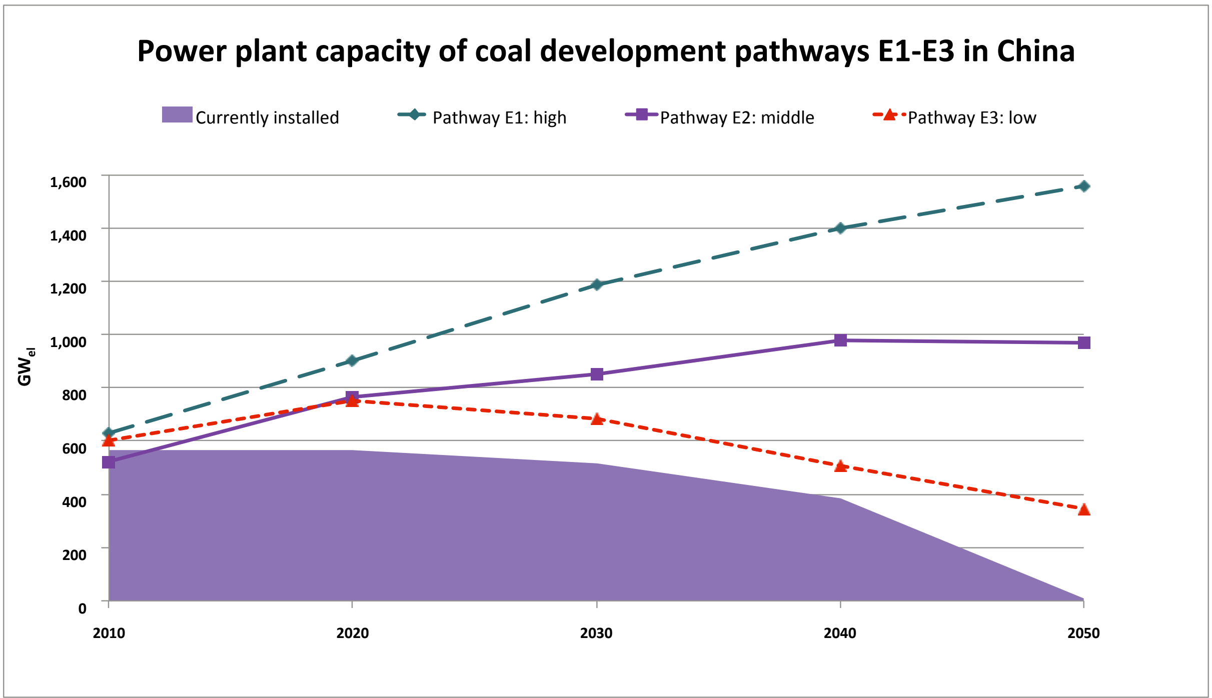


Fig. 18-11 Coal-fired power plant capacity in China, currently installed and envisaged according to three coal development pathways E1–E3

Source: Authors' illustration

Tab. 18-1 Coal-fired power plant capacity in China, currently installed and envisaged according to coal development pathways E1–E3

	2010	2020	2030	2040	2050
Current	567	565	514	385	10
E1: high	628	903	1,187	1,398	1,557
E2: middle	523	765	852	978	968
E3: low	603	753	682	509	346
All quantities are given in GW of installed capacity					

Source: Authors' composition

In Fig. 18-12, pathways E1–E3 are compared with single figures from other scenarios explored for China. In its Energy Technology Perspectives, IEA (2010) yields 1,136 GW for the *Reference Scenario* and 276 GW for the *Blue Map Scenario* in 2050, which comply with the middle and low scenarios E2 and E3, respectively. NZEC reports 28 GW in its *C80 Scenario* for 2050 (Chen 2009).

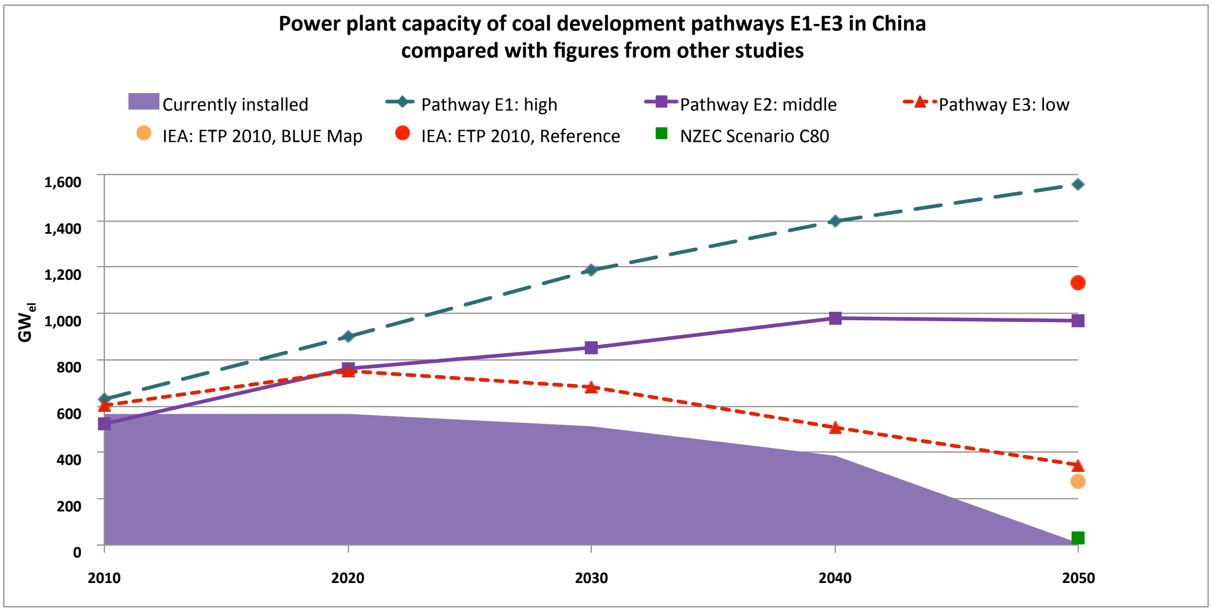
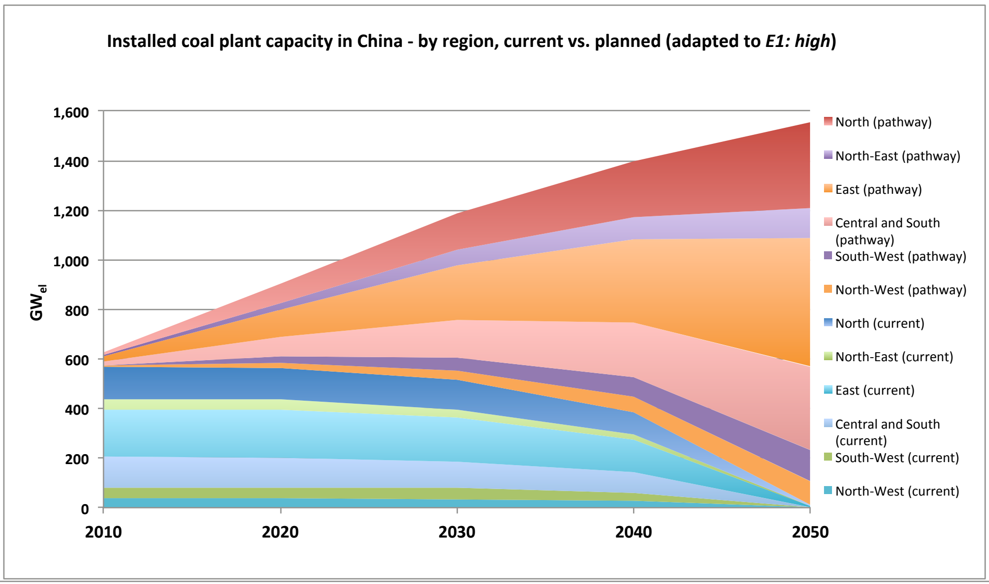


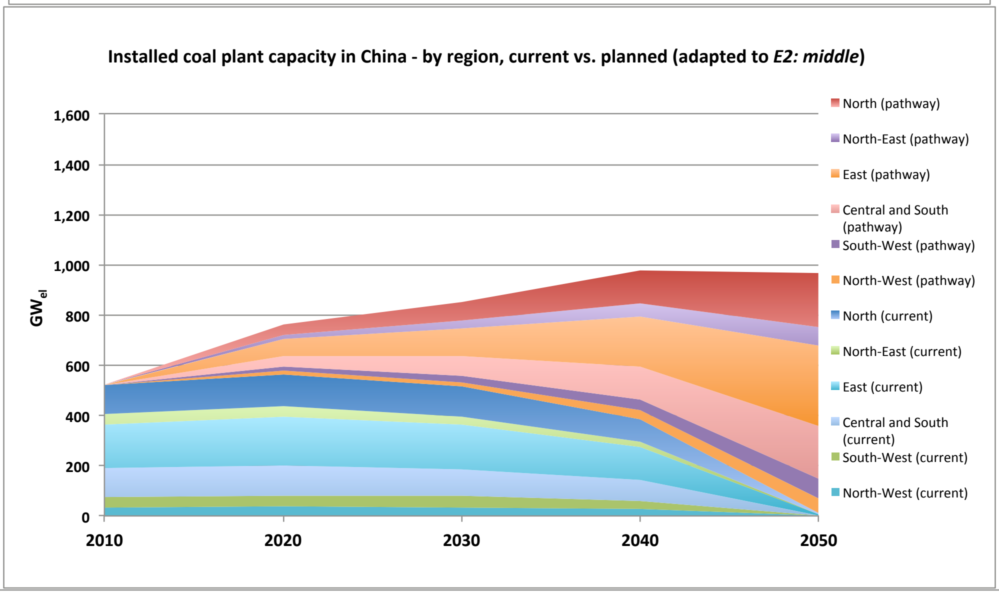
Fig. 18-12 Comparison of coal development pathways E1–E3 with figures from other scenarios in China

Source: Authors' illustration

The coal capacity development illustrated in pathways E1–E3 is taken as the basis for the next step in which an investigation is made into how much CO_2 could be separated in each pathway from the time CCS will be commercially available.

Fig. 18-13 illustrates both the current and the planned capacities resulting for each of the three scenarios, divided by geographic region. Tab. 18-2 also displays the numbers on which the figures are based. Each geographic region's share is based on the current proportion because no data exist on future regional developments.





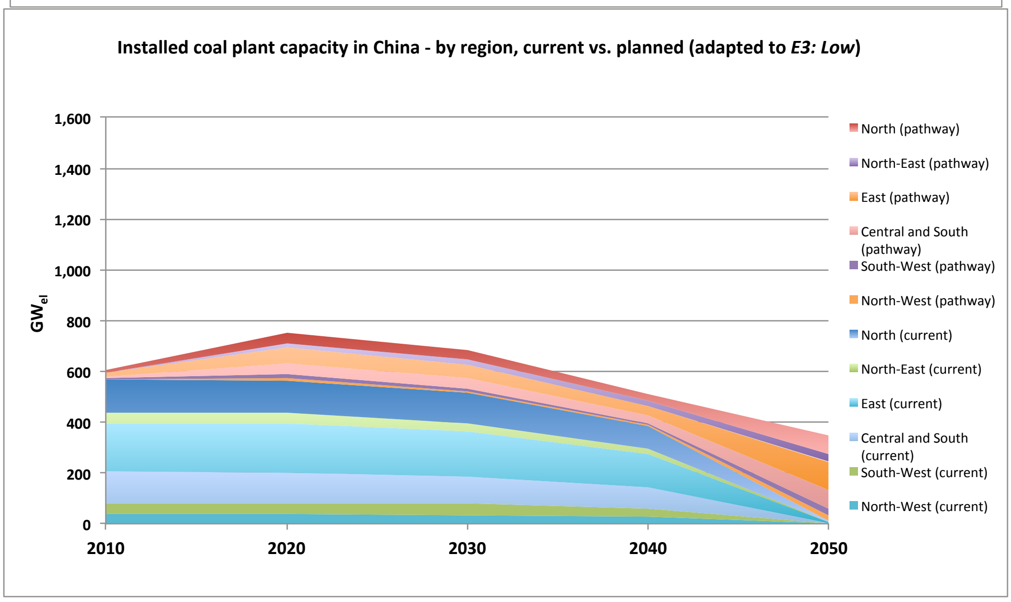


Fig. 18-13 Coal-fired power plant capacity in China according to energy scenarios E1–E3 (by geographic region)

Source: Authors' illustration

Tab. 18-2 Coal-fired power plant capacity in China, currently installed and envisaged according to energy scenarios E1–E3 (by geographic region)

	2010	2020	2030	2040	2050
E1: high					
North (current)	128	129	120	91	4
North (pathway)	14	75	149	225	348
North-East (current)	44	42	33	20	0
North-East (pathway)	5	27	59	88	120
East (current)	190	189	173	131	4
East (pathway)	20	113	224	337	518
Central & South (current)	123	121	109	81	1
Central & South (pathway)	13	75	148	223	338
South-West (current)	46	46	44	35	0
South-West (pathway)	5	27	52	78	126
North-West (current)	36	36	34	27	1
North-West (pathway)	4	21	41	62	97
Total	628	903	1,187	1,398	1,557
E2: middle					
North (current)	118	129	120	91	4
North (pathway)	0	44	73	130	215
North-East (current)	40	42	33	20	0
North-East (pathway)	0	17	33	56	75
East (current)	175	189	173	131	4
East (pathway)	0	67	112	196	320
Central & South (current)	114	121	109	81	1
Central & South (pathway)	0	45	76	131	210
South-West (current)	42	46	44	35	0
South-West (pathway)	0	16	25	44	78
North-West (current)	33	36	34	27	1
North-West (pathway)	0	12	19	35	60
Total	523	765	852	978	968
E3: low					
North (current)	128	129	120	91	4
North (pathway)	8	41	35	24	74
North-East (current)	44	42	33	20	0
North-East (pathway)	3	16	20	20	27
East (current)	190	189	173	131	4
East (pathway)	12	63	55	39	112
Central & South (current)	123	121	109	81	1
Central & South (pathway)	8	42	39	30	75
South-West (current)	46	46	44	35	0
South-West (pathway)	3	15	11	6	28
North-West (current)	36	36	34	27	1
North-West (pathway)	2	11	9	6	21
Total	603	753	682	509	346
All quantities are given in GW of installed capacity					

Source: Authors' composition

18.4 CO_2 Captured from Coal-Fired Power Plants

18.4.1 Capacity of CCS-Based Power Plants Depending on Coal Development Pathways

Basic Assumptions

- **Time of commercial availability** To determine the amount of CO_2 that could potentially be captured in the future, the possible number of CCS-based power plants is first calculated. Since the time of the commercial availability of CCS is one of the most crucial parameters, this date is varied by way of a sensitivity analysis. *Commercial availability* means the time when the complete CCS chain could be in commercial operation: large-scale CCS-based power plants, transportation and storage. Commercial availability before 2030 seems improbable in China for different reasons:

  Due to delayed demonstration projects and a lack of public acceptance in the potential storage regions, experts from scientific institutions and NGOs expect a later large-scale availability of CCS at the international level (MIT 2007; Greenpeace International 2008; Vallentin et al. 2010; Viebahn et al. 2011). Even the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP) does not expect early commercial projects to be in operation before 2025 in the “standard case” because fully integrated CCS projects, including transportation and storage, would take 6.5 to 10 years to become operational (ZEP 2008). Recently, von Hirschhausen et al. (2012) determined that most demonstration projects planned in the EU have been halted or cancelled or their completion dates are indefinite. However, it seems unlikely that CCS will be applied in China on a broad scale before its deployment has taken off in the industrialised world.

  Furthermore, the Chinese government mainly considers CCS as a reserve technology for CO_2 mitigation (CEEP 2011; Tsinghua 2011a; WWF China 2011b).

  The year 2030 is therefore chosen as the “base case” of the given analysis. This means that CCS will be applied to power plants being built or retrofitted from 2030. To consider possible further delays in the development of the technology, in both industrialised countries and in China, as well as delays in the exploration of storage sites, 2035 and 2040 are regarded as sensitivity cases. Tab. 18-3 gives an overview of the resulting combinations.

Tab. 18-3 Sensitivity Analysis I: Varying the time of commercial availability of CCS in China

Commercial	**Coal development pathway**		
availability	**E1: high**	**E2: middle**	**E3: low**
2030	**Base case**	**Base case**	**Base case**
2035	Sensitivity case	Sensitivity case	Sensitivity case
2040	Sensitivity case	Sensitivity case	Sensitivity case

Source: Authors’ composition

Furthermore, the following assumptions are considered to be valid for all coal development pathways:

- **Type of power plants** Supercritical, ultra supercritical and IGCC power plants are foreseen for CCS, either retrofitted or newly built. Subcritical power plants are excluded due to their low degree of efficiency (and would be too old to retrofit in any case). The share of power plants is considered only for calculating the amount of separated CO_2, not for the preceding capacity analysis.

- **Old power plants** Power plants are only retrofitted if they are no older than 12 years (McKinsey 2008). Regarding power plants to be built after 2020 and retrofitted later, the following assumptions are made: in the base case, one third of suitable power plants built between 2020 and 2030 will be retrofitted from 2030. In sensitivity case two (CCS from 2040), 50 per cent of suitable power plants built between 2030 and 2040 and 10 per cent of those built between 2020 and 2030 are considered, respectively. The reason for this assumption is that it is unclear whether capture-ready power plants will be built and whether a retrofit is possible in all cases. Retrofitting would be quite costly and the power plant would have to stand idle for months.
- **New power plants** No subcritical power plants are expected to be built from 2030, so that all new power plants could theoretically be equipped with CCS. They are all expected to be large point sources (LPS). For this reason, their total number is not reduced further with regard to the minimum size that would be required for CCS. From the time of commercial availability, all LPS will be built as CCS-based power plants.

Tab. 18-4 summarises all figures for the proportions assumed above.

Tab. 18-4 Share of power plants in China assumed to determine CCS-based power plant capacity

	2010	2020	2030	2040	2050
Share of power plant type (newly built)					
Subcritical		46	0	0	0
Supercritical		31	27	17	7
Ultra supercritical		14	44	49	54
IGCC		9	29	34	39
CCS commercially available from 2030					
Resulting theoretical CCS share of newly built power plants		54	100	100	100
Share of CCS application if starting in 2030		0	0	100	100
Assumed retrofitting rate of CCS		10	33	0	0
Share of CCS application if starting in 2030		5	33	0	0
CCS commercially available from 2040					
Resulting theoretical CCS share of newly built power plants		54	100	100	100
Share of CCS application if starting in 2040		0	0	0	100
Assumed retrofitting rate of CCS		0	10	50	0
Share of CCS application if starting in 2040		0	10	50	0

All quantities are given in %

The share of power plant type amongst newly built power plants for 2020 and 2030 is derived from figures given in (IEA 2009b) on the mix of coal-fired power generation technologies between 2007 and 2030. The figures for 2040 and 2050 are the authors' estimates.

Source: Authors' composition

- **Location of new power plants** Future CCS-based power plants are distributed in the same relation as currently operating power plants, since no plans for any future allocation are known.
- **Type of fuel** No differentiation is made between hard coal and lignite because lignite currently only makes up a small proportion (3.5 per cent in 2010) of the fuel mix. Lignite is expected to play only a minor role in the future, too.

The Base Case: CCS available from 2030

Fig. 18-14 shows the resulting CCS-based power plant capacity according to the base case in pathways E1–E3. The figures consist of both newly built CCS power plants and retrofitted power plants. Furthermore, the resulting CCS penalty is illustrated. It should be noted that the figures represent the stock of power plants at the respective time. In the event of CCS, this means, for example, that the capacity shown for 2040 is built up between 2030 and 2040. In each of the pathways, the penalty requires an additional power plant capacity of 7 to 13 per cent compared to the total load assumed in the pathways and of 17 to 31 per cent compared to the load of power plants equipped with CCS. Tab. 18-5 provides the detailed values.

Tab. 18-5 Coal-based power plant capacity (with and without CCS), according to coal development pathways E1–E3 in the base case in China (CCS available from 2030)

	2010	2020	2030	2040	2050
E1: high					
Currently installed	567	565	514	385	10
Newly built without CCS	60	338	658	548	548
Newly built with CCS	0	0	0	340	873
Retrofitted with CCS	0	0	15	126	126
[CCS in total	*0*	*0*	*15*	*465*	*999]*
CCS penalty load	0	0	3	74	139
Total	628	903	1,191	1,472	1,696
E2: middle					
Currently installed	523	565	514	385	10
Newly built without CCS	0	200	327	281	281
Newly built with CCS	0	0	0	255	620
Retrofitted with CCS	0	0	11	56	56
[CCS in total	*0*	*0*	*11*	*311*	*676]*
CCS penalty load	0	0	2	48	93
Total	523	765	854	1,026	1,061
E3: low					
Currently installed	567	565	514	385	10
Newly built without CCS	35	188	184	183	183
Newly built with CCS	0	0	0	0	143
Retrofitted with CCS	0	0	8	10	10
[CCS in total	*0*	*0*	*8*	*10*	*153]*
CCS penalty load	0	0	2	2	20
Total	603	753	708	579	366
All quantities are given in GW					

Source: Authors' composition

Fig. 18-14 Share of CCS-based power plant capacity and penalty load on total capacity to be installed in the base case in China (CCS available from 2030)

Source: Authors' illustration

18.4.2 Calculating the Quantity of CO_2 to be Captured from Power Plants

Basic Assumptions

In the second step, the quantity of CO_2 that could be separated from both newly built and retrofitted CCS-based power plants is calculated. The calculation is based on the following assumptions:

- **Efficiency of power plants** Several sources provide quite different figures for the future efficiency of power plants in China. From the total range of these figures, those given in Tab. 18-6 are selected. Compared with supercritical power plants, ultra supercritical ones perform two percentage points better, whilst the efficiency of IGCC increases by 6 percentage points.

Tab. 18-6 Efficiencies assumed for future newly built coal-fired power plants in China

	2010	2020	2030	2040	2050
Subcritical	37				
Supercritical (SC)	40	41	42	44	46
Ultra supercritical (USC)	42	43	44	46	48
Average of SC and USC	41	42	43	45	47
IGCC	46	47	48	50	52
All quantities are given in %					

Source: Authors' composition

- **Efficiency losses through CCS** For CO_2 capture and compression an efficiency loss ranging from 8.5 to 5 percentage points for the period from 2020 to 2050 is assumed for post-combustion. Pre-combustion ranges from 6.5 to 6 percentage points. This results in an increase in coal consumption between 23 and 14 per cent for the assumed mix of CCS-based power plants between 2030 and 2050. The efficiency losses are derived from various sources (Alstom 2011; IEA and OECD 2009b, 2009c; IEA 2009c, 2011; Imperial College 2010; Viebahn 2011). Retrofitting power plants would cost further efficiency losses of 1.5 percentage points (Viebahn et al. 2010). Combining these figures with the efficiencies of newly built power plants without CCS and the future share of coal-fired power plants (Fig. 18-3) yields the efficiencies for future mixes with and without CCS, given in Tab. 18-7.

Tab. 18-7 Efficiencies assumed for future newly built coal-fired power plants in China (mix, with and without CCS)

	2010	2020	2030	2040	2050
Mix newly built w/o CCS		40	44.6	47	49.4
Efficiency penalty post-combustion	12	8.5	7	6	5
Efficiency penalty pre-combustion	8	6.5	6	6	6
Mix newly built, with CCS			37.9	41	44
Mix newly built, with CCS, retrofit			36.4	39.5	42.5
Efficiencies are given in %, efficiency penalties are given in % points					

Source: Authors' composition

- **Lifetime of power plants** The technical lifetime, and hence the time available for capturing CO_2 from new power plants, is assumed to be 40 years (Tsinghua 2011a). In the event of retrofitting, this equates to a remaining lifetime of a minimum of 28 years. This is partly contrary to other studies, which assume a shorter average lifetime of power generating capacities in China, ranging from 20 years (Zhao et al. 2008) and 25 years (NZEC 2009b) to 35 years (Minhua and Wang 2011). This, however, is mainly due to the fact that, in many cases, the national government requires power plant operators to shut down small and inefficient power stations in order to gain approval for erecting new coal-fired capacities. Thus, the average lifetime of China's power plant fleet is relatively low (Siemens Ltd. China 2011). In the decades ahead, investment cycles in China's power sector can be expected to expand due to the steadily growing share of modern, large generating capacities with high efficiency levels. Thus, this study assumes a longer lifetime of operating power plants.
- **CO_2 capture rate** A CO_2 capture rate of 90 per cent is assumed because it is used most frequently in CCS studies, for example in (Dahowski et al. 2009) and Wang et al. (2010).
- **Cumulated CO_2** The cumulated amount of CO_2 separated per power plant is calculated by adding the annual CO_2 emissions captured by each power plant over its lifetime.
- **Load factor, capacity factor** Since another crucial parameter is the load factor, this parameter is also varied by way of a sensitivity analysis. As the base case, the figure of 7,000 full load hours (which corresponds to a capacity factor of 80 per cent) is chosen for newly built power plants. 6,000 h (69 per cent) and 8,000 h (91 per cent) are regarded as sensitivity cases. This range is covered by several sources (Dahowski et al. 2009; Siemens Ltd. China 2011; Tsinghua 2011a). Tab. 18-8 gives a summary of the resulting pathway combinations.

Tab. 18-8 Sensitivity Analysis II: Varying the full load hours (capacity factor) of coal-fired power plants in China

Commercial	**Coal development pathway**								
availability	**E1: high**			**E2: middle**			**E3: low**		
2030	6,000	**7,000**	8,000	6,000	**7,000**	8,000	6,000	**7,000**	8,000
2035	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000
2040	6,000	7,000	8,000	6,000	7,000	8,000	6,000	7,000	8,000

All quantities are given in h

Cells printed in bold illustrate the base case

Source: Authors' composition

All parameters, including those described above, are summarised in Tab. 18-9.

Tab. 18-9 Basic parameters assumed for calculating CO_2 emissions captured from power plants in China

	Unit	Value	Comment
CO_2 capture			
Efficiency loss post-combustion	%pt.	12–5	2010 to 2050
Efficiency loss pre-combustion	%pt.	8–6	2010 to 2050
Additional efficiency loss retrofit	%pt.	1.5	Only if power plant is not older than 12 years
Capture rate	%	90	
Efficiency			
Mix newly built w/o CCS	%	40–49	2020 to 2050
Mix newly built, with CCS	%	38–44	2030 to 2050
Mix newly built, with CCS, retrofit	%	36–43	2030 to 2050
Load factor	%	69–91	In Sensitivity Analysis II (equalling 6,000 to 8,000 full load hours)
Technical lifetime	a	40	
Coal quality for China	MJ/kg	23	
CO_2 emissions of coal	g/kWh_{th}	350	
Commercial availability of CCS		2030/35/40	In Sensitivity Analysis I

Source: Authors' composition

The Base Case: CCS available from 2030, operating with 7,000 Full Load Hours

The result of the pathway analysis is presented in Tab. 18-10 and Fig. 18-15. For each pathway, the figure shows the increasing amount of separated CO_2 as well as the remaining CO_2 that will not be separated due to the age of the power plants. Tab. 18-10 shows that – depending on the pathways – between 34 and 221 Gt of CO_2 may be available for sequestration in total (second row). These figures are calculated assuming only newly built power plants with a technical lifetime of 40 years. Considering only the annual figures (first row), between 0.87 and 5.7 Gt would have to be transported between sources and sinks in 2050.

Regarding primary resources, between 0.9 and 4 Gt of coal would be required in 2050. Cumulated over the lifetime of all CCS-based power plants, between 68 and 125 Gt of coal would be necessary, calculated using an average net calorific value of the domestically produced coal feedstock of 23 MJ/kg (Minhua and Wang 2011).

Tab. 18-10 Separated CO_2 emissions and consumption of coal in China, according to coal development pathways E1–E3 in the base case (CCS available from 2030, operation with 7,000 full load hours, lifetime of 40 years)

	Unit	E1: high	E2: middle	E3: low
CO_2 separated annually in 2050	Gt/a	5.73	3.86	0.87
CO_2 separated, cumulated	Gt	221	151	34
Coal consumed annually in 2050	Gt/a	4.03	2.61	0.89
Coal consumed cumulated	Gt	125	91	68
Coal consumed cumulated, w/o CCS	*Gt*	119	88	65

A net calorific value of 23 MJ/kg for Chinese coal was used to calculate the consumption of coal.

Source: Authors' composition

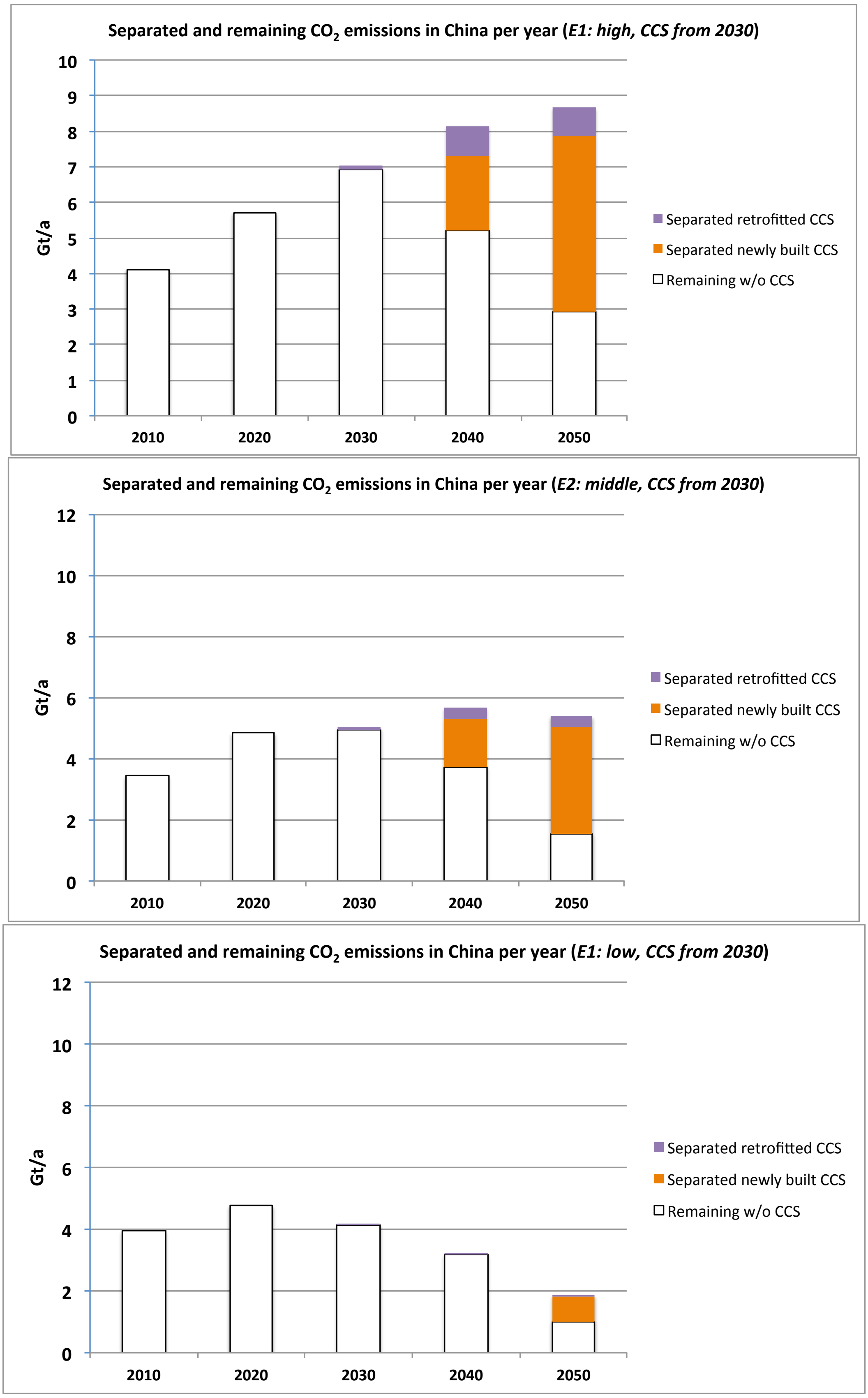


Fig. 18-15 Separated and remaining CO_2 emissions from coal-based electricity production in the base case in China (CCS available from 2030)

Source: Authors' illustration

Tab. 18-11 illustrates the allocation of cumulated separated CO_2 emissions to the individual administrative divisions. About one third of emissions are produced in East China (34 per cent) and nearly 22 per cent each in North and Central & South China, which is in accordance with the distribution of power plants (as already illustrated in Fig. 18-5).

Tab. 18-11 Separated CO_2 emissions (cumulated) in China by administrative division, according to coal development pathways E1–E3 in the base case (CCS available from 2030, operation with 7,000 full load hours)

Administrative Region	**E1: high**	**E2: middle**	**E3: low**	**Geographic region**
Beijing	0.57	0.39	0.09	North
Hebei	12.97	8.87	1.98	North
Inner Mongolia	18.32	12.53	2.79	North
Shanxi	14.17	9.69	2.16	North
Tianjin	4.22	2.89	0.64	North
Heilongjiang	4.45	2.96	0.54	North-East
Jilin	3.59	2.38	0.43	North-East
Liaoning	8.09	5.37	0.97	North-East
Anhui	10.07	6.88	1.57	East
Fujian	5.22	3.57	0.82	East
Jiangsu	21.33	14.58	3.34	East
Jiangxi	3.86	2.64	0.60	East
Shandong	17.00	11.62	2.66	East
Shanghai	4.05	2.77	0.63	East
Zhejiang	12.73	8.70	1.99	East
Guangdong	13.55	9.25	2.14	Central & South
Guangxi	3.63	2.47	0.57	Central & South
Hainan	0.95	0.65	0.15	Central & South
Henan	17.32	11.82	2.74	Central & South
Hong Kong	0.46	0.31	0.07	Central & South
Hubei	5.76	3.93	0.91	Central & South
Hunan	6.31	4.31	1.00	Central & South
Chongqing	2.28	1.58	0.37	South-West
Guizhou	8.51	5.88	1.38	South-West
Sichuan	3.97	2.74	0.65	South-West
Yunnan	3.65	2.52	0.59	South-West
Gansu	2.96	2.03	0.46	North-West
Ningxia Hui	3.08	2.12	0.48	North-West
Qinghai	0.51	0.35	0.08	North-West
Shaanxi	6.34	4.36	0.99	North-West
Xinjiang	1.34	0.92	0.21	North-West
Total	221	151	34	
All quantities are given in Gt				

Source: Authors' composition

Sensitivity Cases

Finally, all sensitivity cases are presented. Tab. 18-12 illustrates the large spectrum between the lowest value (28 Gt CO_2, marked green) and the highest value (253 Gt CO_2, marked red). A general conclusion is that the more CO_2 is separated, the higher the full load hours are and the earlier CCS is available. Considering the two sensitivity cases, the following differences can be seen:

- Varying the operation time by 1,000 full load hours decreases or increases the amount of CO_2 captured by 14 per cent;
- Launching CCS in 2035 or 2040 instead of in 2030 decreases the amount of CO_2 captured by 15 or 17 per cent, respectively. In the case of pathway *E3: low*, a low decrease of only 3 per cent is visible.

Tab. 18-12 Separated CO_2 emissions in China (cumulated), according to coal development pathways E1–E3 in all sensitivity cases

	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**
CCS from 2030	190	129	29	**221**	**151**	**34**	253	173	39
CCS from 2035	162	111	**28**	189	129	33	216	148	38
CCS from 2040	134	92	**28**	157	108	32	179	123	37
All quantities are given in Gt CO_2									

Source: Authors' composition

The same is true for the consumption of coal, presented in Tab. 18-13. Depending on the coal development pathways and sensitivity cases, between 58 and 143 Gt of coal will be required.

Tab. 18-13 Consumption of coal in China (cumulated), according to coal development pathways E1–E3 in all sensitivity cases

	6,000 full load hours			7,000 full load hours			8,000 full load hours		
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**
No CCS	102	75	56	119	88	65	137	100	74
CCS from 2030	107	78	**58**	**125**	**91**	**68**	**143**	104	78
CCS from 2035	106	77	**58**	123	90	68	141	103	77
CCS from 2040	104	76	**58**	122	89	68	139	102	77
All quantities are given in Gt coal									
A net calorific value of 23 MJ/kg for Chinese coal was used to calculate the consumption of coal									

Source: Authors' composition

18.5 CO_2 Captured from Industrial Sites

18.5.1 Methodological Approach

To develop an industrial development pathway, two existing approaches are combined:

- Firstly, the spatial distribution of Chinese industrial sites is used (Bai et al. 2006). Unfortunately, the data covers the existing situation only; no long-term projections to future situations are attempted. The study considers industrial sources emitting 1,100 Mt/a of CO_2 in total (as of 2004), including refineries, ammonia, fertiliser, cement and iron and steel production.
- Secondly, the *BLUE Map Scenario* of Energy Technology Perspectives 2010 contains two different scenarios for developing CO_2 emissions by industry sector (IEA Clean Coal Centre 2010). However, these scenarios only provide data on the whole of China, rather than by state or region. Furthermore, the data are only given for 2007 and 2050, differentiated into a *BLUE low 2050 scenario* and a *BLUE high China scenario*. Again, the potential proportion of CCS in the total emissions reduction between 2007 and 2050 is only presented for the *BLUE low 2050 scenario* and only illustrated by figure, not by data (see Fig. 18-16 and Tab. 18-14).

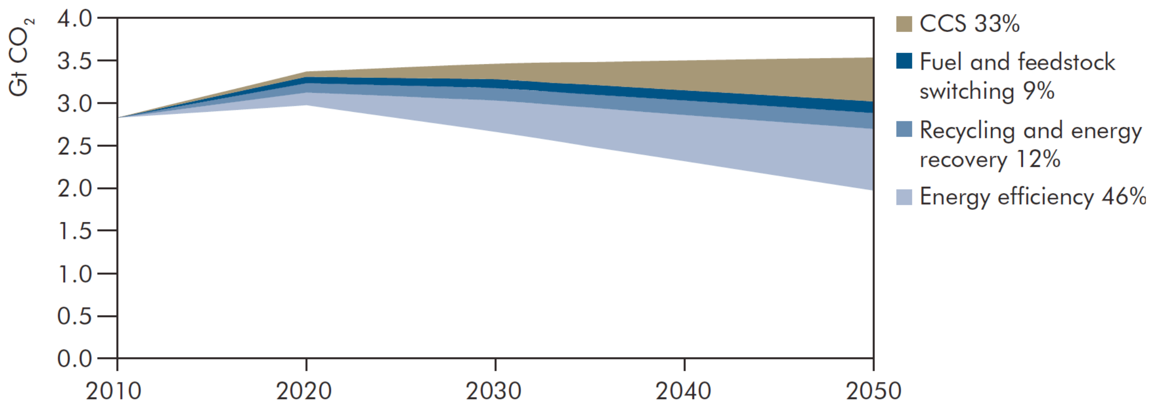


Fig. 18-16 Options for reducing direct CO_2 emissions from China's industry (*BLUE low 2050 scenario*)

Source: IEA (2010)

The two studies are then combined. The projection of IEA Clean Coal Centre (2010) is first assigned to the emission sources accounted for in Bai et al. (2006) and then the CCS-based emission reduction rate from IEA Clean Coal Centre (2010) is applied to determine the total annual emissions of CO_2 that could potentially be separated by carbon capture. As with the power sector, 2030 is considered to be the earliest time for the commercial availability of CCS (base case). Later availability in 2035 or 2040 is covered in a sensitivity analysis.

The lifetime of the industrial sites must be known to calculate the cumulated CO_2 emissions. In contrast to the power sector, no "curve of decommissioning" is considered. Instead, it is assumed that the industrial sites will exist for several decades. Since the latest CCS-based power plants (which will have been built by 2050) will be decommissioned in 2090, CO_2 will be separated by then. This time span is therefore also applied to industry, meaning that industrial sites will separate CO_2 between 2030 (2035, 2040) and 2090.

Tab. 18-14 Direct energy and process CO_2 emissions from China's industry (*BLUE low 2050 scenario*)

	2007	Increase factor	Baseline low 2050	Reduction factor	BLUE low 2050	Reduction	Share of CCS
	Mt CO_2	-	Mt CO_2	-	Mt CO_2	Mt CO_2/a	Mt CO_2/a
Aluminium	63	*2.3*	148	*89%*	131	*17*	*6*
Iron and steel	1,095	*1.1*	1,197	*54%*	645	*552*	*182*
Chemicals	212	*2.6*	557	*48%*	267	*290*	*96*
Cement	953	*0.7*	640	*75%*	480	*160*	*53*
Pulp and paper	40	*3.5*	141	*54%*	76	*65*	*21*
Other	286	*3.0*	863	*44%*	382	*481*	*159*
Total	2,650	*1.3*	3,545	*56%*	1,981	*1,564*	*516*

Authors' figures added to the original table are printed in italics.

The figures provided in the last column are calculated under the assumption that the given CCS share of 33 per cent in the total emission reduction is true for all industrial sectors to the same extent. There is therefore no differentiation at plant level.

Source: Authors' composition based on IEA (2010)

18.5.2 Quantity of CO_2 Captured from Industrial Sites

Finally, the total amount of separated CO_2 emissions is derived as follows:

- The corner points of the area grey marked that illustrates the share of CCS in the total efficiency effort are scanned manually from Fig. 18-16. The integral of the area between 2030 as the earliest year when CCS will start and 2050 is calculated. The result is enhanced by emissions avoided between 2050 and 2090, that is the 2050 reduction figure (524 Mt/a) multiplied by 40 years.

  The same is carried out for the sensitivity cases where CCS is assumed to start no earlier than 2035 or 2040. Tab. 18-15 shows the results, which do not differ much. The reason for this is that most emissions occur between 2050 and 2090, when CCS will fully be explored. Compared to that time span, the difference between 2030 and 2040 carries no weight. It should be noted that no penalty for the capturing process is included in the given calculation, meaning that the real amount of CO_2 captured would be higher than that reported below.

Tab. 18-15 Separated CO_2 emissions from industry in China (cumulated), according to industrial development pathway I in the three sensitivity cases

	Pathway I
CCS from 2030	28.4
CCS from 2035	27.3
CCS from 2040	25.8

All quantities are given in Gt

Source: Authors' composition

- In the second step, the emissions are allocated to each administrative division, which is necessary for the source-sink match carried out subsequently in section 19. The share per state is derived from its share of the current emissions situation given in Bai et al. (2006).

Performing this analysis leads to Tab. 18-16, which shows the estimated CO_2 emissions separated in each administrative division.

Tab. 18-16 Separated CO_2 emissions from industry in China by administrative division, according to the industrial development pathway in the base case (CCS available from 2030)

Administrative division	Pathway I	Geographic region
Beijing	0.3	North
Hebei	2.1	North
Inner Mongolia	1.1	North
Shanxi	1.4	North
Tianjin	0.4	North
Heilongjiang	0.7	North-East
Jilin	0.5	North-East
Liaoning	1.7	North-East
Anhui	1.1	East
Fujian	0.5	East
Jiangsu	2.5	East
Jiangxi	0.5	East
Shandong	3.6	East
Shanghai	1.1	East
Zhejiang	1.7	East
Guangdong	1.5	Central & South
Guangxi	0.4	Central & South
Hainan	0.1	Central & South
Henan	1.6	Central & South
Hong Kong	0.0	Central & South
Hubei	1.0	Central & South
Hunan	0.7	Central & South
Chongqing	0.3	South-West
Guizhou	0.6	South-West
Sichuan	0.7	South-West
Yunnan	0.4	South-West
Gansu	0.5	North-West
Ningxia Hui	0.3	North-West
Qinghai	0.1	North-West
Shaanxi	0.7	North-West
Xinjiang	0.5	North-West
Total	28.4	
All quantities are given in Gt		

Source: Authors' composition

The largest quantity of CO_2 (11 Gt) is separated from the East, followed by the North and Central & South with 5 Gt each.

18.6 Conclusions

Finally, all sensitivity cases regarding both coal development pathways E1–E3 and industrial development pathway I were presented (Tab. 18-17). In the base case, the CO_2 emissions separated in industry amounted to 22 to 42 per cent of those emitted from the power sector. Considering all sensitivity cases, between 20 and 45 per cent of the power sector's emissions originate from industry. However, it has to be borne in mind that emissions from industry are calculated on a different basis because – unlike with the power sector – no decommissioning or penalty is considered.

Tab. 18-17 Separated CO_2 emissions in China (cumulated), according to coal development pathways E1–E3 and industrial development pathway I in all sensitivity cases

	6,000 full load hours			**7,000 full load hours**			**8,000 full load hours**			
	E1: high	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**E1: high**	**E2: middle**	**E3: low**	**I**
CCS from 2030	190	129	29	**221**	**151**	**34**	**253**	173	39	**28.4**
CCS from 2035	162	111	**28**	189	129	33	216	148	38	27.3
CCS from 2040	134	92	**28**	157	108	32	179	123	37	25.8
All quantities are given in Gt CO_2										

Source: Authors' composition

As mentioned above, the figures are not based on the authors' energy scenario analysis. Instead, individual coal development pathways based on different existing energy scenarios were selected. No long-term energy scenarios based on CCS that meet the actual development of power plants in China are available at present. The presented figures should therefore be updated as soon as complete long-term energy scenarios exist for China. These should consider different deployment pathways of CCS and their interaction with an increasing amount of renewables and nuclear energy.

Furthermore, it should be noted that, due to the large uncertainty of the future development of China's energy system, an "if … then" approach was performed. The analysis shows which consequences would have to be accounted for if different strategies (coal development pathways) were realised. In the event of a "high coal" strategy, this would mean the huge deployment of facilities for CO_2 capture, transportation and storage within a short period of time; the "low coal" strategy would imply an 85 per cent lower deployment, which in itself is ambitious, too.

19 Matching the Supply of CO_2 to Storage Capacities

19.1 Introduction

After having developed and presented possible opportunities for storing CO_2 (section 17) and future coal development pathways for China (section 18), these two estimates are now combined. Due to the large uncertainty surrounding both sources and sinks, a very preliminary source-sink match is conducted, leading to a matched capacity. In section 19.2, the storage scenarios are briefly covered. This is followed by a summary of the coal development pathways and the resulting CO_2 emissions (section 19.3). In section 19.4, the methodology for the source-sink match is given and explained thoroughly for both power plants and industrial sources. The results of this match are discussed in section 19.5 and a conclusion of the theoretical source-sink match is given in section 19.6.

19.2 Overview of Storage Scenarios

In section 17, the existing storage capacity estimates for China were presented and compared with one another and with basin- and site-specific studies. The few existing estimates for China yield a wide range of available theoretical capacities from 32 to 3,090 Gt of CO_2, due mainly to variations for saline aquifers. This demonstrates the high uncertainty and lack of detailed geological data. Three scenarios are developed to select effective storage capacities. None of these scenarios are more realistic than the others, although the intermediate scenario S2 is defined as the base case. A high (S1) and a low scenario (S3) were estimated using sensitivity analysis. The total effective storage capacity ranges in these scenarios from 65 to 1,542 Gt of CO_2 (compare Tab. 19-1). The main difference between these scenarios is the efficiency applied for onshore and offshore saline aquifers. The theoretical storage capacity assessment by Dahowski et al. (2009) was taken as the basis for this calculation. The efficiencies chosen are 2 per cent for the low scenario S3, 16 per cent for the intermediate scenario S2 and 50 per cent for the high scenario S1. For oil and gas fields, the proven capacity of Zhang et al. (2005b) was taken as the base case (S2). This was also assumed for scenario S3, as it is at the lower end of the range and also provides basin-specific capacities. Scenario S1 uses the higher capacity reported by the same authors, including fields that are not proven. Storage in coal seams was excluded from all scenarios due to the high level of technical uncertainties. This storage possibility is still at the laboratory stage and has not yet been proven to work in situ.

Tab. 19-1 Scenarios for effective CO_2 storage capacity in China

		S1: high	S2: intermediate (base)	S3: low
Oil fields **Gas fields**		7.8	3.6	3.6
Saline aquifers	Onshore	1,145	366	46
	Offshore	390	125	16
Total		1,542	495	65
All quantities are given in Gt CO_2				

Source: Authors' compilation based on Zhang et al. (2005b) and Dahowski et al. (2009)

As is always the case in scenario modelling, it should be borne in mind that a value given in a scenario does not necessarily mean that this value will be realised at some point. Scenario analyses are usually conducted to illustrate roughly how the situation could develop.

19.3 Overview of Coal Development Pathways

The three coal development pathways described in section 18 are based on different long-term scenario studies for China's future energy situation. However, in contrast to energy scenarios, the pathways are only used to illustrate the different CCS development possibilities to obtain an understanding of the level of separated CO_2 emissions that could be available for storage in the future. The extent of the project did not allow new and consistent energy scenarios including CCS to be developed from scratch for China. Furthermore, it was assumed that the current spatial distribution of the power plants and CTL plants will be maintained in the future.

Of the different cases considered in the pathways, only the base case is used for source-sink matching (CCS commercially available from 2030, 7,000 full load hours of operation per year). It is assumed that CCS-based power plants will be built up to 2050, when the last power plant with a CO_2 capture unit will be constructed. The emissions are added together for 40 years of operation, meaning that CO_2 is captured from 2030 for the first plants up until 2090, when the units built last will be decommissioned. The cumulative emissions between 2030 and 2090 are derived in three pathways: a high coal pathway E1, a middle coal pathway E2 and a low coal pathway E3. In total, it is estimated that 221, 151 and 34 Gt of CO_2 would be captured from power plants for CO_2 sequestration in pathways E1, E2 and E3, respectively.

Including industrial sites, the amounts increase to 250 (E1+I), 178 (E2+I) and 60 Gt of CO_2 (E3+I). In Tab. 19-2, the results of these pathways are displayed by administrative division. The highest emissions occur in Inner Mongolia (North), Henan (Central & South) and Shandong and Jianghsu (East).

Tab. 19-2 Overview of CO_2 emissions (cumulated) separated from coal-fired power plants in coal development pathways E1, E2 and E3 and from power plants plus industry (E1+I, E2+I, E3+I) by administrative division

State	E1: high	E2: middle	E3: low	E1+I: high	E2+I: middle	E3+I: low	Region
Beijing	0.6	0.4	0.1	0.9	0.7	0.4	North
Hebei	13.0	8.9	2.0	15.1	10.9	3.9	North
Inner Mongolia	18.3	12.5	2.8	19.4	13.5	3.8	North
Shanxi	14.2	9.7	2.2	15.5	11.0	3.4	North
Tianjin	4.2	2.9	0.6	4.6	3.3	1.0	North
Heilongjiang	4.5	3.0	0.5	5.2	3.6	1.2	NE
Jilin	3.6	2.4	0.4	4.1	2.9	0.9	NE
Liaoning	8.1	5.4	1.0	9.8	7.0	2.5	NE
Anhui	10.1	6.9	1.6	11.2	8.0	2.6	East
Fujian	5.2	3.6	0.8	5.7	4.0	1.2	East
Jiangsu	21.3	14.6	3.3	23.8	17.0	5.6	East
Jiangxi	3.9	2.6	0.6	4.4	3.1	1.1	East
Shandong	17.0	11.6	2.7	20.6	15.0	5.9	East
Shanghai	4.0	2.8	0.6	5.2	3.8	1.6	East
Zhejiang	12.7	8.7	2.0	14.4	10.3	3.5	East
Guangdong	13.6	9.2	2.1	15.1	10.7	3.5	C&S
Guangxi	3.6	2.5	0.6	4.0	2.8	0.9	C&S
Hainan	0.9	0.7	0.2	1.0	0.7	0.2	C&S
Henan	17.3	11.8	2.7	18.9	13.4	4.2	C&S
Hong Kong	0.5	0.3	0.1	0.5	0.3	0.1	C&S
Hubei	5.8	3.9	0.9	6.7	4.9	1.8	C&S
Hunan	6.3	4.3	1.0	7.0	5.0	1.6	C&S
Chongqing	2.3	1.6	0.4	2.6	1.8	0.6	SW
Guizhou	8.5	5.9	1.4	9.1	6.5	1.9	SW
Sichuan	4.0	2.7	0.6	4.7	3.4	1.3	SW
Yunnan	3.7	2.5	0.6	4.1	2.9	1.0	SW
Gansu	3.0	2.0	0.5	3.5	2.6	1.0	NW
Ningxia Hui	3.1	2.1	0.5	3.4	2.4	0.8	NW
Qinghai	0.5	0.3	0.1	0.6	0.4	0.1	NW
Shaanxi	6.3	4.4	1.0	7.0	5.0	1.6	NW
Xinjiang	1.3	0.9	0.2	1.8	1.4	0.6	NW
Total	221	151	34	250	178	60	

All quantities are given in Gt CO_2

NE = North-East, C&S = Central & South, SW = South-West, NW = North-West

Source: Authors' calculation

19.4 Methodology of Source-Sink Matching

The expert interviews did not add much to the discussion of source-sink matching. It was said that, due to the developing character of China, it may be easier to adapt the infrastructure (for example, move power plants closer to coal mines or storage sites) in favour of CCS than in developed countries. All recommendations for studies focus on two works: the source-sink match by Dahowski et al. (2009) and the regional modelling results by Chen et al. (2009b) for Bohai basin.

Dahowski et al. (2009) matched CO_2 sources to reservoirs, including a geospatial match and a cost curve analysis. The proximity analysis of 1,623 CO_2 sources in China with the location of potential onshore sinks delivers promising results (assuming very high storage capacities). About 50 per cent of emissions would not have to be transported because they would already be situated above a sink. Within a distance of 160 km, 91 per cent of all emission sources could be matched with potential sinks. The maximum distance from a CO_2 source to a potential onshore sink is reported to be 375 km.

The cost curve analysis is estimated for a 20-year period starting with full-scale CCS deployment. It concludes that 2.9 Gt of CO_2 could be stored each year within a maximum distance of 240 km at costs below USD 10 per tonne of CO_2. The authors also analysed the differences between six major regions in China. South-West and North-West China have the fewest matches while the sources and sinks in the East, North and North-East regions fit best.

Sensitivity analyses are performed with lower capacities. If efficiencies of 10 or 50 per cent are applied to the aquifer capacity, the results do not change much, with only a marginal reduction of the amount of CO_2 stored per year. This changes dramatically if a 1 per cent efficiency is included. Then the cost curve would change substantially, making the deployment of CCS considerably more difficult.

Chen et al. (2009b) performed a source-sink matching calculation for emissions from Hebei Province with storage in Bohai basin. The authors provide two models using similar methodology. In the first step, transport costs from sources to sinks were estimated. These costs are then ranked for each source-sink pair. In the third and final step, the emissions are transported to fill the sinks, starting with the best-ranked pair. The first model, including only straight connections between sources and sinks, is based on the methodology used by Dahowski et al. (2009). The second model uses a GIS-based algorithm to match sources to sinks by calculating least-cost pathways.

These examples provide important information on source-sink matching for CCS in China. Taking this information into account, the main differences between the existing results and the analysis of this study are that:

- The latter is based on long-term energy scenarios that include power plants operating for 40 years and industrial sites installed up to 2050;
- Different efficiency factors are used, derived from existing site-specific storage capacity calculations;
- The source-sink match is based on emissions at the administrative division level.

The geographic match of sources and sinks is undertaken in two steps. Initially, matching is limited to emissions from power plants (section 19.4.1), after which projected industrial emissions are included in the match (section 19.4.2).

19.4.1 Matching Emissions from Power Plants with Storage Sites

For the first source-sink match, only emissions from power plants are taken into account. Thus the three coal development pathways E1 to E3 are combined with storage scenarios S1 to S3. This is undertaken on a division-by-basin basis. Firstly, emission sources are linked to the administrative division in which they occur. Hence cumulative emissions from 40 years of operation are estimated. Secondly, capacities within the storage scenarios are listed for each basin. Thirdly, divisions are attributed to these basins. This is carried out in two steps: provinces in which at least parts of basins are situated are first selected and then a qualitative geographical overlap is conducted between storage basins and emission clusters in each selected division based on figures by Dahowski et al. (2009). A considerably good overall fit is found (compare Fig. 19-1).

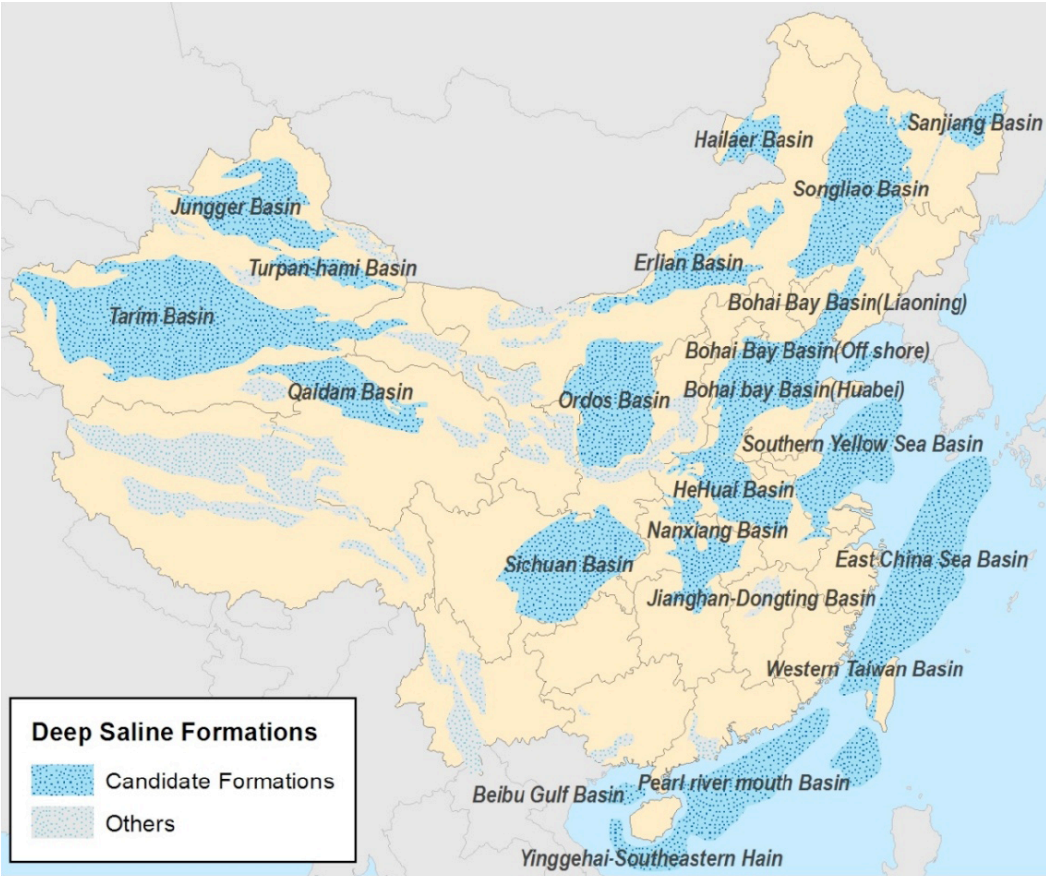


Fig. 19-1 Major sedimentary basins in China

Source: Dahowski et al. (2009)

It should be noted that neither the exact position of sources nor that of storage wells are specified. The aquifer basins extend for several hundred kilometres, and the exact position of sub-basins is not available. The maximum distance between sources and sinks is therefore defined as roughly 500 km via pipeline. Economic analyses suggest that this pipeline transport distance is feasible (IPCC 2005). If this maximum distance is assumed, only Qaidam and Hailaer basins are a long distance from emission sources. By clustering emissions by administrative division, details are lost on where exactly in the division emissions sources occur. But since no detailed geographic data exists on specific storage sites, a more detailed match cannot be provided at this stage, although this would be crucial when matching sources to sinks. Due to the lack of data and the consequential heuristic approach, matching is carried out manually, without using a geographic information system (GIS). However, a GIS-based detailed analysis should be performed beyond the results presented here once more geological information is made available. The results provided here can be considered as a theoretical match of effective capacities at the division-to-basin level.

The source-sink match starts with onshore basins because they are more easily accessible. For all basins, effective capacities in aquifers as well as in oil and gas fields are considered together. These basins are filled with the emissions calculated in pathways E1 to E3. Basins in China are very large and, in several cases, emissions from more than one province could potentially be stored in one basin. Thus once emissions from the first closest province have already been stored, emissions from the next province are sequestered until either all emissions have been stored or the sink is full. After filling onshore basins, the same process is repeated for offshore basins. Finally, a total matched capacity is yielded for each combination of storage scenario and development pathway. If capacity exceeds the total emissions of neighbouring divisions, this storage site is not filled entirely.

This is shown using the example of combining the low storage scenario S3 with pathways E1, E2 and E3. The other possible combinations are explained briefly; detailed calculations can be found in the annex (Tab. 25-1 and Tab. 25-2).

Low storage scenario S3

Tab. 19-3 portrays the above-mentioned approach. Each coal development pathway is matched with the lowest storage scenario:

- Bohai basin takes in emissions from the Jing-Jin-Ji region (Beijing, Tianjin, Hebei). All emissions from Tianjin and Beijing could be stored, as well as, in pathway E3, all emissions from Hebei. Thus an additional quantity of 2.7 Gt of CO_2 from Shandong Province could be stored in Bohai basin. In pathways E1 and E2, only some emissions from Hebei could be stored.
- Considering Songliao basin, emissions from Jilin Province are first stored there. Any remaining space is then filled with CO_2 from Heilongjiang. For pathways E2 and E3, all emissions from these two provinces could be stored, meaning that Songliao basin is not fully exploited. In the case of pathway E1 the basin is filled and emissions from Heilongjiang would have to be stored at a different site (i.e. Sanjiang basin).
- Subei basin is located in Jiangsu Province, where major emission sources are located. Thus in this low storage scenario, Subei basin provides insufficient space for all emissions, meaning it is entirely filled in all three pathways. Additional emissions from Jiangsu can be stored offshore in the East China Sea (E3) and Southern Yellow Sea basins (E1 and E2).
- Ordos basin in north China is located in Inner Mongolia and Shaanxi and Shanxi provinces. For pathway E3, emissions from these three provinces can be stored in this basin. In pathways E1 and E2, Ordos basin is completely filled with emissions from Inner Mongolia. In these scenarios, emissions from Shanxi and Shaanxi provinces could not be sequestered at all because there are no other sinks in the vicinity. However, additional emissions from Inner Mongolia could be stored in Erlian basin.
- HeHuai basin in central-east China comprises emissions from Henan and Anhui provinces. For Anhui, only emissions from low coal pathway E3 can be stored in this basin be-

cause there is still space after sequestering emissions from Henan. For pathways E1 and E2, additional emissions from Henan Province can be stored in the small Nanxiang basin.

- In Xinjiang Province there are three sedimentary basins: Tarim, Junggar and Turpan-Hami basins. The largest of the three –Tarim basin – is closest to emissions. Even in the lowest storage scenario, it contributes enough storage space for the estimated cumulative 40 years of emission for all pathways. Hence Junggar and Turpan-Hami basins are not used at all.
- Sichuan basin is closest to emissions from Sichuan Province. The low emissions from E3 can be fully stored there, whereas not all emissions from E1 and E2 are sequestered.
- JiangHan-Dongting basin is filled with emissions from Hubei Province. It is entirely filled in E1 and E2; in E3, all emissions can be stored.
- Qaidam and Hailaer basins are too far from emissions clusters in the selected provinces and are therefore unsuitable for CO_2 storage.
- Offshore basins are particularly important because China's major emission sources are close to the shore. Thus emissions from Shandong, Jiangsu and Zhejiang can be stored in the Bohai Bay, Southern Yellow Sea and East China Sea basins.
- The industrialised region of Guangdong could use the Pearl River Mouth basin for CO_2 sequestration, which is too small in S3 for the high level of emissions.
- Other offshore basins such as Yinggehai, Northern Yellow Sea, Beibu Gulf and Western Taiwan basins provide only limited capacity for Hainan, Jiangsu, Guangxi and Fujian provinces.

A matched capacity for onshore basins of 29.4, 27.6 and 19.0 Gt of CO_2 is calculated for pathways E1, E2 and E3, respectively. Offshore basins add another 15.5, 15.3 and 10.0 Gt of CO_2 to the matched capacity, respectively. In total, a matched capacity of 44.9, 42.8 and 29.1 Gt of CO_2 is derived, respectively.

If the source-sink match is divided by region, the highest match is achieved in the East China region, due mainly to offshore storage. The second highest region is North China, where only onshore storage is applicable. A very low match is obtained in North-West and South-West, where Xinjiang and Sichuan provinces, respectively, contain only small sources. North-East and Central regions provide an intermediate share. These results are summarised in Tab. 19-4. The source-sink match undertaken by Dahowski et al. (2009) yields the same results, with a good match for East, North and North-East China and a lower match for emissions and sinks in the South-West and North-West regions.

Tab. 19-3 Source-sink match for storage scenario S3 with coal development pathways E1, E2, E3 in China

Basin	Effective storage capacity		Available for	E1	E2	E3
	Saline aquifer	Oil and gas	emissions from	high	middle	low
Onshore						
Bohai	4.7	1.2	Beijing	0.6	0.4	0.1
			Tianjin	4.2	2.9	0.6
			Hebei	1.0	2.5	2.0
			Shandong			2.7
Songliao	4.6	1.3	Jilin	3.6	2.4	0.4
			Heilongjiang	2.2	3.0	0.5
Sanjiang	0.9	0.0	Heilongjiang	0.9		
Subei	1.8	0.1	Jiangsu	1.9	1.9	1.9
Ordos	5.1	0.4	Inner Mongolia	5.5	5.5	2.8
			Shaanxi			1.0
			Shanxi			1.7
Erlian	1.7	0.0	Inner Mongolia	1.7	1.7	
HeHuai	3.6		Henan	3.6	3.6	2.7
			Anhui			0.8
Nanxiang	0.2	0.1	Henan	0.2	0.2	
Tarim	14.9	0.1	Xinjiang	1.3	0.9	0.2
Junggar	3.9	0.2	Xinjiang			
Turpan-Hami	1.1	0.1	Xinjiang			
Sichuan	1.6	0.0	Sichuan	1.6	1.6	0.6
JiangHan - Dongting	1.1	0.0	Hubei	1.1	1.1	0.9
Qaidam	0.4	0.1	Qinghai			
Hailaer	0.3	0.0	Inner Mongolia			
Total onshore	45.8	3.5		29.4	27.6	19.0
Offshore						
East China Sea	6.8	0.0	Zhejiang	6.8	6.8	2.0
			Fujian			0.8
			Jiangsu			1.5
Southern Yellow Sea	2.7		Jiangsu	2.7	2.7	
			Shandong			2.7
Bohai Bay	2.2	0.1	Shandong	2.3	2.3	
			Liaoning			1.0
Zhujiangkou (Pearl River Mouth)	1.4	0.1	Guangdong	1.5	1.5	1.5
Yinggehai	1.1		Hainan	0.9	0.7	0.2
Northern Yellow Sea	0.6		Jiangsu	0.6	0.6	
Beibu Gulf	0.5	0.0	Guangxi	0.5	0.5	0.5
Western Taiwan	0.2		Fujian	0.2	0.2	
Total offshore	15.6	0.2		15.5	15.3	10.0
Total matched capacity	**61.3**	**3.6**		**44.9**	**42.8**	**29.1**

All values are given in Gt CO_2. The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

Tab. 19-4 Regional distribution of source-sink matching for storage scenario S3 and coal development pathways E1, E2 and E3 in China

Regional distribution	E1: high	E2: middle	E3: low
North	13.0	13.0	7.2
East	14.5	14.5	12.3
North-East	6.7	5.3	1.9
Central & South	7.7	7.4	5.8
North-West	1.3	0.9	1.2
South-West	1.6	1.6	0.6
Total	44.9	432.8	29.1
All quantities are given in Gt CO_2.			

Source: Authors' calculation

Intermediate storage scenario S2

The intermediate storage scenario includes much higher capacities for deep saline aquifers in China but the same proven capacity in oil and gas fields as in S3. Tab. 25-3, Tab. 25-4 and Tab. 25-5 in the annex show the match in this storage scenario S2 with all three coal development pathways.

Conducting the same comparison as described in detail above, a total matched capacity of 185.8, 130.7 and 29.3 Gt of CO_2 is calculated for pathways E1, E2 and E3, respectively. The higher available storage capacity leads to much higher values of sequestered CO_2, particularly in pathways E1 and E2. For pathway E3, the quantity of matched capacity increases only by 0.2 Gt compared to pathway S3. If the share of onshore and offshore matched capacity is analysed, a significant difference is achieved. In all coal development pathways, the share of onshore capacity increases dramatically. This is due to the method chosen in which these basins are filled with CO_2 first. For pathways E1 and E2, the quantity of matched capacity both onshore and offshore increases in effective terms. For E3, onshore capacity increases to 23.6 Gt; offshore capacity offers only 5.7 Gt of CO_2, which is about half of the capacity when matching with S3.

A comparison of the regional distribution of the source-sink match provides similar results to those indicated above in Tab. 19-4.

Intermediate storage scenario S1

Storage scenario S1 yields even higher emissions than S2, especially for saline aquifers (Tab. 25-2). For the source-sink match, oil and gas fields are not required because aquifers provide sufficient space for all emission clusters close to basins. Nevertheless, CO2 could be injected into oil and gas fields prior to sequestration in saline aquifers since the geology in these fields is better understood.

In total, matched capacities amount to 191.6, 130.7 and 29.3 Gt of CO_2 for pathways E1, E2 and E3, respectively. Compared to scenario S2, only the high coal pathway E1 provides a higher matched capacity (192 Gt over 186 Gt). E2 and E3 remain the same. Regarding the proportions for onshore and offshore sedimentary basins, the difference is even more pronounced because onshore basins increase in importance (with the exception of E3).

19.4.2 Matching Emissions from Industrial Point Sources with Storage Sites

After having analysed the matched capacity for the power sector, industrial emissions are included in the calculation in this section. Thus source-sink matching for power and industrial emissions is conducted using the three storage scenarios. The CO_2 emissions potentially separated from cement, iron and steel, refineries, ammonia and fertiliser plants are included in the industrial development pathway. This extension of the pathways with industrial emissions up to 2090 leads to an increase of captured emissions by 26 to 28 Gt of CO_2. In total, cumulated emissions from 2030 amount to 250 (E1+I), 178 (E2+I) and 60 Gt of CO_2 (E3+I).

The match is conducted the same way as explained in detail for power plant emissions only, that means using the division-by-basin approach. Detailed tables are provided in the annex (Tab. 25-3, Tab. 25-4, Tab. 25-5). The low storage scenario S3 leads to a slightly higher matched capacity of 45 (E1+I), 44 (E2+I) and 36 Gt of CO_2 (E3+I) compared to 45 (E1), 43 (E2) and 29 Gt of CO_2 (E3) without industrial emissions. This is only a notable increase for E3.

The higher storage volumes available in scenarios S2 and S1 lead to a considerable increase in matched capacity. In both cases, the amount of CO_2 stored is augmented identically for E2+I (154 Gt CO_2) and E3+I (52 Gt CO_2). In contrast, matching these storage scenarios with high development pathway E1+I leads to different results (S2/E1+I: 205 Gt CO_2 and S1/E1+I: 216 Gt CO_2). This difference between both scenario couples is more significant than for development pathways excluding industry emissions.

19.5 Results of Source-Sink Matching

In this section, the overall results of the matched capacity calculations are given. Tab. 19-5 shows the results based on power plant emissions. In Tab. 19-6, the results are based on power plant and industrial emissions. The separated CO_2 emissions in each development pathway are given at the top of the tables. The theoretically available effective storage capacities are shown on the left. The tables are divided into three parts with the calculated matched capacities in the upper part. The middle part shows the percentage of available storage space exploited; the lower part shows the quantity of emissions from captured CO_2 that could be sequestered. In both cases, the results of the match are taken into account for the comparison.

Power Plants

In Tab. 19-5, the matched capacity increases with higher storage scenario assumptions. It can also be seen that, in most cases, captured emissions play a more restrictive role than storage capacities. The space available for CO_2 sequestration is fully used. This can be seen in the percentage values of “share of effective storage capacity,” which range from 2 to 69 per cent. The “share of emissions” is higher than the share of storage capacity in seven out of nine scenarios. The share of storage capacity is only remarkably higher when the high and intermediate coal development pathways are compared with the low storage scenarios (E1/S3 and E2/S3).

Tab. 19-5 CO_2 emissions in China that can be stored as a result of matching potential storage sites with power plant supply sites and their share in total effective storage capacity and supply

	Power plant emissions from coal development pathways		
Effective storage capacity scenarios	**E1: high** (221 Gt CO_2)	**E2: middle** (151 Gt CO_2)	**E3: low** (34 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (1,541 Gt CO_2)	192	131	29
S2: intermediate (494 Gt CO_2)	186	131	29
S3: low (65 Gt CO_2)	45	43	30
	Share of effective storage capacity used (%)		
S1: high (1,541 Gt CO_2)	12	8	2
S2: intermediate (494 Gt CO_2)	38	26	6
S3: low (65 Gt CO_2)	69	67	45
	Share of emissions that can be stored (%)		
S1: high (1,541 Gt CO_2)	87	87	86
S2: intermediate (494 Gt CO_2)	84	87	86
S3: low (65 Gt CO_2)	20	29	87
The maximum transport distance is assumed to be 500 km.			

Source: Authors' calculation

Different conditions occur when the high and intermediate storage scenarios are taken together and compared with the low storage scenario:

- In the case of S1 and S2, over 80 per cent of captured emissions can be stored. The matched capacity in each development pathway is very similar in both cases. Hence it can be concluded that if the high efficiency factors associated with these storage scenarios are proven, storage space would not be a major restriction for CCS in China. The quantity of emissions available is restricted due to the long distance between sources and sinks.
- For the low storage scenario S3, which is based on an efficiency factor of 2 per cent, this is not the case because insufficient space is available for emission clusters in several provinces. In the case of coal development pathways E1 and E2, around 70 per cent of storage space is used; even in pathway E3, 45 per cent is used. However, only 20 and 29 per cent of emissions in pathways E1 and E2, respectively, could be sequestered. In addition, if storage is limited to onshore basins for reasons of expense and technology, the matched capacity is reduced further, meaning that a large quantity of emissions from industrial centres on China's coast could not be stored.

Combining Power Plants and Industrial Facilities

In Tab. 19-6, the comparison is extended by emissions from industry, meaning that each development pathway (E_i+I) provides higher captured emissions. The greater availability of emissions leads to higher matched capacities, especially in the low pathway E3+I, and to a lesser extent in pathway E2+I. Due to the additional emissions, percentage values for the share of emissions are slightly lower than in Tab. 19-5. In six out of nine cases, it exceeds 80 per cent. In contrast, the share of storage increases because there is a larger quantity of captured emissions available. This comparison confirms that the restricting factor for matched capacity is determined to a greater extent by available emissions than by storage capacity if the higher efficiency factors are taken into account (S1 and S2). If the cautious approach using the lowest efficiency factor is pursued, storage capacity is the restricting factor and only 18 and 25 per cent of emissions for pathways E1 and E2, respectively, could be sequestered.

Tab. 19-6 CO_2 emissions in China that can be stored as a result of matching potential storage sites with power plant and industrial supply sites and their share in the total effective storage capacity and supply

	Energy and industry emission pathways		
Effective storage capacity scenarios	**E1+I: high** (250 Gt CO_2)	**E2+I: middle** (178 Gt CO_2)	**E3+I: low** (60 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (1,541 Gt CO_2)	216	154	52
S2: intermediate (494 Gt CO_2)	205	154	52
S3: low (65 Gt CO_2)	45	44	36
	Share of effective storage capacity used (%)		
S1: high (1,541 Gt CO_2)	14	10	3
S2: intermediate (494 Gt CO_2)	41	31	10
S3: low (65 Gt CO_2)	70	68	55
	Share of emissions that can be stored (%)		
S1: high (1,541 Gt CO_2)	87	87	87
S2: intermediate (494 Gt CO_2)	82	87	87
S3: low (65 Gt CO_2)	18	25	60
The maximum transport distance is assumed to be 500 km.			

Source: Authors' calculation

19.6 Conclusion

The elaborations above show that the estimate of China's storage potential is very uncertain due to a lack of detailed geological data. The few existing estimates for China cover a wide range of available *theoretical* capacities, from 36 to 3,090 Gt of CO_2, due mainly to varying estimates of potential in saline aquifers. In order to provide *effective* storage capacities, three scenarios were developed. To assess aquifers, three different efficiency factors were derived (2, 16 and 50 per cent) and applied to the theoretical storage capacity assessment of Dahowski et al. (2009) in the sense of a sensitivity analysis. In addition, a small capacity in oil and gas fields was considered. Storage in coal seams was excluded from all scenarios, due to the high level of technical uncertainties. This storage possibility is still at the laboratory stage and has not yet been proven to work in situ. In total, the effective storage capacity of scenarios S1 to S3 ranges from 65 to 1,542 Gt of CO_2. However, due to the lack of geological data in China, any calculations of storage capacity quantity can only be highly speculative and therefore should be treated with caution.

For this reason, due to the considerable uncertainty surrounding both sources and sinks, the source-sink match could only be performed very roughly. Given these constraints, storage scenarios S1 to S3 were matched with three coal development pathways E1 to E3 and three coal and industrial development pathways E1+I to E3+I, taking into account a maximum transport distance of 500 km.

- With the *lowest effective storage capacity* (S3 = 65 Gt, based on an efficiency factor of 2 per cent), 20 to 87 per cent of CO_2 emissions captured from power plants (resulting in 30 to 45 Gt) and 18 to 60 per cent of emissions captured from power plants and industry (resulting in 36 to 45 Gt) could be sequestered. The storage sites would be filled to an extent of only between 45 and 69 per cent and 55 and 70 per cent, respectively.

- With the *intermediate effective storage capacity* (S2 = 494 Gt, based on an efficiency factor of 16 per cent), 84 to 87 per cent of CO_2 emissions captured from power plants (resulting in 29 to 186 Gt) and 82 to 87 per cent of emissions captured from power plants and industry (resulting in 52 to 205 Gt) could be sequestered. The storage sites would be filled to an extent of between 6 and 38 per cent and 10 and 41 per cent, respectively.

- With the *high effective storage capacity scenario S1 (*1,541 Gt, based on an efficiency factor of 50 per cent) the result is quite similar to the previous case: 86 to 87 per cent of captured CO_2 emissions (resulting in 29 to 192 Gt from power plants and 52 to 216 Gt from power plants and industry) could be sequestered. The storage sites would be filled to an extent of between 2 and 12 per cent and 3 and 14 per cent, respectively.

In general, 70 per cent or less of the effective storage potential is used in all cases and less than 50 per cent in most cases. In the case of the low storage scenario S3, between 45 and 70 per cent of sites are filled because of the long distance between most sources and the considered sinks, which exceed the maximum transport distance of 500 km. Utilisation of the separated CO_2 emissions is low with storage scenario S3, where only 18 to 29 per cent of emissions from coal development pathways E1 and E2 could be sequestered (60 to 87 per cent in the case of E3). In contrast, with the high and middle storage scenarios S1 and S2 it would be possible to store 82 to 87 per cent of all separated CO_2 emissions. One way to increase the matched capacity could be to relocate emission sources closer to potential sinks. In this case, an optimisation model is required to determine the cost optimal solution between the *transportation of electricity*, the *fuel*, the *separated CO_2 emissions* and even the *cooling water*. However, potential environmental and socio-economic problems must be taken into account in addition to the economic dimension.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case coal development pathways are considered, equating to a commercial availability of CCS from 2030 and an operation of 7,000 full load hours per year. If CCS is available later, in 2035 or in 2040, CO_2 emissions provided for storage will be 15 or even 17 per cent lower (see section (2009)). If an operation of only 6,000 full load hours is achieved (load factor of 69 per cent) or if the very optimistic level of 8,000 full load hours is realised (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.

- To date, CO_2 sources and sinks have only been preliminarily matched. The transport distances have not been verified in detail and are based only on rough estimates, taking into account a maximum distance of 500 km. In a further elaboration of this study, a geographic information system should be applied to achieve a more precise assessment, using the exact locations of power plants and industrial sites. This information could be coupled with more detailed information on geological basins, if available in the future, to reduce transport distances between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a "real" matched capacity to be derived:

- Investigate each basin and field in detail to obtain detailed information about the geological underground;
- Determine more detailed locations of possible storage sites within the basins to enable more precise, quantitative source-sink matching to be conducted;
- Derive a practical storage potential (top layer of the storage pyramid) considering economic conditions, possible acceptance problems in the regions concerned and technical feasibility problems.

Finally, the practical capacity will be lower than the matched capacity derived in this report. Until these details are explored, the *lowest effective storage capacity scenario* S3 should not be considered as an upper variant of what could be realised in China – the final figures, and therefore the final results, of source-sink matching may actually be considerably lower.

20 Assessment of the Reserves, Availability and Price of Coal

20.1 General Aspects

China possesses the largest coal resources in the world, although it only comes second with regard to reserves. However, reliable reserve and resource data are difficult to obtain because a number of different Chinese definitions exist that are not identical to international standards and that are partly mutually contradictory – which is even more problematic. For this reason, a large part of this section investigates coal reserves at the country and district level, followed by a discussion of coal production data. The development of imports and exports is also reviewed.

Finally, prices on important coal markets are discussed. IEA price trend scenarios to 2035 are used to estimate the price development of imported coal over the next 25 years. Concluding remarks at the end of this section round off this investigation.

20.2 Coal Quality and Coal Washeries

20.2.1 Coal Quality

The World Energy Council (WEC) and the United States Geological Survey (USGS) qualify coal bases into different quality classes according to heating value, moisture, ash content, sulphur content or other parameters. The most common method is to distinguish between lignite, subbituminous coal, bituminous coal and anthracite, which represents coal in its ascending order of energy content.

Chinese authorities and companies often use a more detailed classification, shown in Tab. 20-4. Long-flame coal corresponds to subbituminous coal. The further differentiation from “non-caking coal” to “meagre coal” covers the WEC classification “bituminous coal”, and anthracite is used identically in both classifications. The regional distribution of these coal types is presented later in section 20.3.5.

Based on reserve statistics, lignite accounts for about 12.7 per cent of proven coal resources, while subbituminous coal makes up around 42.6 per cent. Only 27.6 per cent is suitable for coking (PEW 2010).

On average, China’s coals have a high ash content of about 23.4 per cent and a low sulphur content (~1.06 per cent). The average heating value is approximately 22.7 MJ/kg. Average values of the distribution of coal resources are given in Tab. 20-1.

Tab. 20-1 Ash content of China’s coal resources

Ash content	<10%	10–20%	20–30%	30–40%	40–50%	>50%
Per cent of coal resource	9.2	39.8	33.6	13.7	2.2	1.5

Source: PEW (2010)

Tab. 20-2 Sulphur content of China’s coal resources

Sulphur content	<0.5%	0.5–1%	1–1.5%	1.5–2%	2–3%	>3%
Per cent of coal resource	40.2	31.5	14.3	3.4	4.6	6.1

Source: PEW (2010)

Tab. 20-3 Lower heating value (LHV) of China's coal resources

Lower heating value	**<12.5**	**12.5–17**	**17–21**	**21–24**	**24–27**	**>27**
Per cent of coal resource	1.6	7.9	12.7	25.4	35	17.5
All values are given in M/kg						

Source: PEW (2010)

Tab. 20-4 Definitions used to classify coal types

Coal type	**Heating value** MJ/kg	**Properties**	**Uses**
Lignite	<15	15–30% oxygen High moisture Ash contains CaO, Al_2O_3	Power generation at mine mouth Lignite wax extraction Organic fertiliser production CTL plants
Long-flame coal	16–23	High volatility High coal tar production	Power generation Locomotives Gasification Coal tar production CTL plants Heating purposes (boiler)
Non-caking coal	>18	Bituminous coal High moisture >10% oxygen	Power generation Locomotives Gasification Cement production Heating purposes (boiler)
Weakly caking coal	20	Between coking and non-coking Low coke quality (powder)	Power generation Blending for coke-making (substitute for gas coal, coking coal and lean coal)
½ medium caking coal	>20		Raw coal for coking coal blend Gasification Power generation
Gas coal	>20	High volatility	Coke production, chemical products
Gas-fat coal	>20	High volatility	Chemical production Gasification
Fat coal	>20		Chemical production Gasification
1/3 primary coking coal	>20		Fundamental coke for blending
Primary coking coal	>20		Large-scale coke production
Lean coal	>20		Coke production
Meagre lean coal	>20		Power generation, boilers
Meagre coal	~24		Power generation, boilers Synthetic ammonia and fuel
Anthracite	>25		Power generation Chemical industry

Source: Fenwei (2010)

At the practical level, coal is characterised according to its use for lower quality thermal applications (steam coal or thermal coal) and for higher quality industrial purposes (coking coal or metallurgic coal). Tab. 20-5 specifies the usual categories of metallurgic coal according to ash content, sulphur content and mechanical and chemical properties.

Tab. 20-5 Chinese standard of metallurgy coke (GB/T 1996–2003)

Grade	Ash %	Sulphur %	Mechanical strength		Abrasion strength	Reactivity CRI %
			M25	M40		
Grade I	<12	<0.6	>92	>80	<7	<30
Grade II	<13.5	<0.8	>88	>76	<8.5	<35
Grade III	<15	<1.0	>83	>72	<10.5	--

Source: Li (2009)

20.2.2 Coal Washeries

Due to the high ash content of China's coal, it would need to be upgraded or washed to reduce pollution.

In 2002, the coal output from coal washeries was 223 Mt of washed coal, equating to about 20 per cent of China's total coal production ((CCIY 2001), cited in (CCEIS 2002)). Up until 2010, coal output increased to about 3.2 billion tonnes. However – although no exact data is available – washing capacity remained at between 15 and 20 per cent, equating to about 450 to 600 Mt of washed coal (Yu 2009).

Approximately 156 Mt of coal was washed in 2003, representing 16 per cent of the total coal output. However, almost 90 per cent of the washed coal (138 Mt) is coking coal. Only 2 per cent of thermal coal for power plants is cleaned (Tsinghua 2006).

Due to the increase in coal production in recent years, it is very probable that coal washing also plays a minor role in thermal coal markets. Moreover, in 2010 Shanxi suspended a number of washeries because cheap coal prices made them uneconomical.

In Yunnan Province, approximately 10.5 Mt (2009: 9.62 Mt) of clean coal and 16.07 Mt of coke (2009: 24.56 Mt) out of 51.55 Mt of bituminous coal were washed in 2010, representing about 50 per cent of the total coal output in Yunnan.

20.3 Coal Resources and Reserves

There are various data sources concerning China's coal reserves and resources; the definitions and figures contained therein only partly coincide.

The World Energy Council (WEC) relies on data from the National Chinese section of the WEC. This data is used to represent "proven recoverable reserves".

However, these figures differ from those presented in Chinese statistics and in the official Chinese classification scheme, which distinguishes between reserve, basic reserve and resource. Figures quoted as "basic reserve" are identical to the "Ensured coal reserves" published in the Chinese Statistical Yearbook. Figures quoted as "reserves" correspond roughly to the UN classification of measured and indicated proven and probable reserves. They should therefore be higher than those published by the WEC, which include only "proven recoverable reserves."

Finally, the Chinese coal industry uses various classifications with overlapping definitions in the "China Coal Resource Atlas." These will be used below to break down aggregated data of coal reserves into detailed data, although the exact relationship between the different definitions is not obvious.

Most of these differing classifications of resources and reserves are based on rough estimates. In particular, large resource estimates and their sub-definitions do not include any technical and economic aspects of recovery. Their value is therefore of minor importance, although the figures for resources total 5,000 billion tonnes or more. For instance, much of these resources is believed to be deeper than 1,000 m below the surface. These quantities – whether realistic or not – will probably never be commercially produced.

The most reliable data or reserves are those based on technological and economic aspects. These range from 114 billion tonnes (proven recoverable reserves according to the WEC) to 319 billion tonnes (basic reserve or ensured reserves according to the Chinese Statistical Yearbook). Based on this investigation, Fig. 20-2, Fig. 20-5 and Fig. 20-6 summarise the most reliable data concerning reserves in China.

20.3.1 Reserves as Reported by the World Energy Council

Fig. 20-1 shows how proven recoverable coal reserves have developed, as reported by the World Energy Council (WEC) in its latest editions from 1989 onwards. Considerable downgrading occurred in 1992, combined with a reclassification of some reserves from bituminous to subbituminous coal. This downgrading is not explained in detail, but seems to be based in part on a reclassification from "proven amount in place" to "proven recoverable reserve."

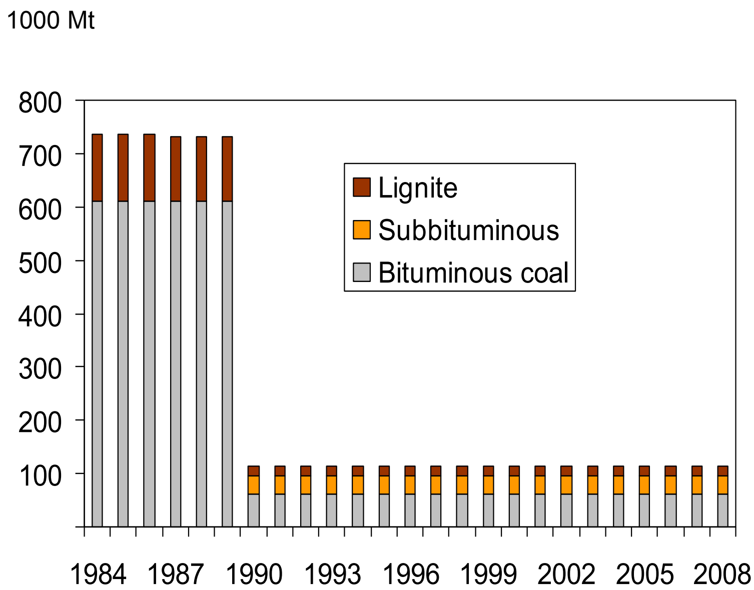


Fig. 20-1 Historical development of "proven recoverable coal reserves" in China as reported by the World Energy Council and reproduced in BP Statistical Review of World Energy

Sources: BP (2010); WEC (1989, 1992, 1995, 1998, 2001, 2004, 2007, 2009, 2010)

Since 1992, the WEC has reported unchanged reserve figures each year with respect to the preceding year. Obviously, these numbers cannot be correct. Figures published in 2010 for the year ending 2009 are exactly the same as those published in 1992 for the year ending

1990. Cumulative production between 1991 and 2010 amounts to 30 per cent of these reserve data (35 billion tonnes of cumulative production versus 114.5 billion tonnes of reserves). Either the reserves must be reduced by that amount, leaving a resource-to-production (R/P) ratio of only 25 years (based on 3.2 billion tonnes of production in 2010), or the reserve numbers are incorrect and have not been updated for 20 years.

20.3.2 Resources as Reported in the Chinese Statistical Yearbook

The Chinese Statistical Yearbook also provides data on coal reserves for the whole of China and for the country's individual regions. Since 1995, these figures have been downgraded from about 1,000 billion tonnes at the end of 1995 to 333.48 billion tonnes in 2006 and even further to 318.96 billion tonnes at the end of 2009. These figures are quoted as "ensured coal reserve." The time series is presented in Fig. 20-2. Missing figures due to a lack of access to the original literature are estimated by Ludwig-Bölkow Systemtechnik (LBST). The coal reserve declined by 4.3 per cent between 2006 and 2009. Although the approximately 70 per cent decline post 1999 is not explained, it could be due either to a change in definitions (as was the case for reporting by the WEC in 1992) or to enhanced data collection and analysis.

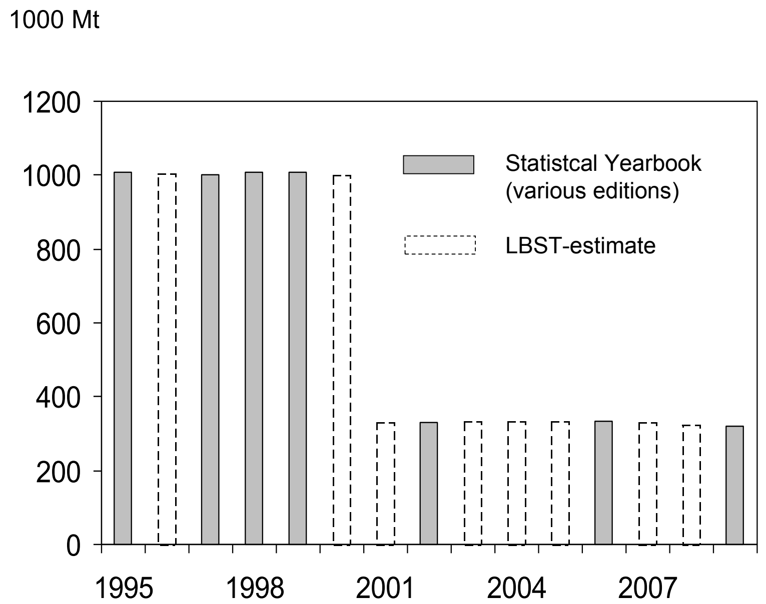


Fig. 20-2 Historical development of "ensured coal reserve" in China as reported in various editions of the Chinese Statistical Yearbook and estimates by LBST

Sources: CSY (1996, 1998, 1999, 2000, 2003, 2007, 2010)

The regional distribution of coal reserves is shown in Fig. 20-3 for 2006 and 2009. Around 66 per cent of China's coal reserves are located in three provinces or regions, namely Shanxi, Inner Mongolia and Shaanxi. Other important coal provinces in descending order are Xinjiang, Guizhou, Henan, Anhui and Shandong, which make up a further 17 per cent. The remaining 17 per cent of China's coal reserves are spread over the other provinces.

The figures above the bars represent the percentage difference in reserves between 2006 and 2009. As already mentioned, the total coal reserve declined by 4.3 per cent between 2006 and 2009. At the regional level, reserves increased in only four regions, namely

Chongqing, Xinjiang, Yunnan and Shanxi. Reserves declined in all other regions, partly up to 30 per cent, as in the case of Anhui.

According to the Ministry of Land and Resources, China added about 4.3 Mt of new coal reserves to its total in 2010 (Sxcoal 2011). This figure is about 1.3 per cent of annual production, resulting in a 1 per cent reduction of coal ensured reserves.

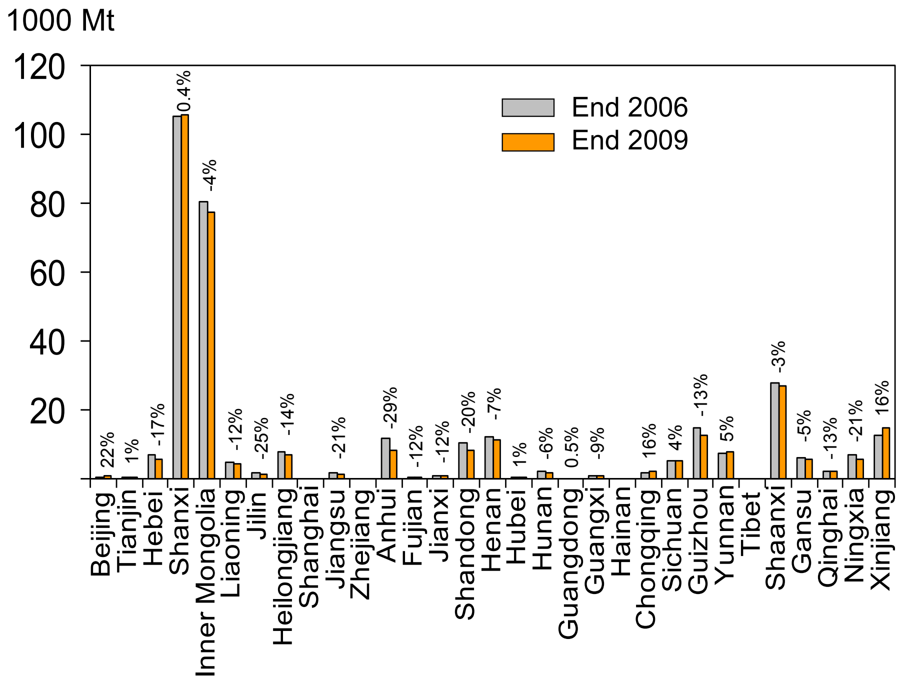


Fig. 20-3 Regional distribution of “ensured coal reserve” as published in Chinese Statistical Yearbooks 2007 and 2010

Sources: CSY (2007, 2010)

20.3.3 Chinese Reserve Classification Scheme

The Chinese Classification scheme used by Fenwei Energy Consulting is more complex, involving various reserve classes that are only partly compatible with typical reserve classification schemes. Even more confusing, in addition to the general scheme explained below, further definitions are in use that are not covered by this scheme. In section 20.3.5, these definitions and how they compare to other definitions are partly explained at the regional level.

China classifies solid fuels and mineral resources into three main classes:

- Reserve;
- Basic reserve;
- Resource reserve.

These three classes are subdivided into 16 subclasses, based on the economic significance, feasibility evaluation and geological reliability of the mineral resource. Although this detailed classification scheme endeavours to roughly follow the 3-dimensional United Nations Framework Classification (UNFC) scheme, it still differs from it. UNFC distinguishes between the following categories and subclasses (UNFC 2003):

- *Economy* with subclasses *commercial*, *contingent commercial*, *not commercial;*
- *Feasibility* with subclasses *committed*, *contingent project*, *exploration;*
- *Geology* with subclasses *proven*, *explored and delineated*, *discovered*, *prospective.*

The Chinese Classification scheme is portrayed in Tab. 20-6. The first number in parentheses indicates the degree of economic viability. The second figure indicates the feasibility evaluation stage (1 = feasibility study/measured; 2 = pre-feasibility study; 3 = geological study). The third figure represents geological assurance, where 1 = proven/measured, 2 = indicated, 3 = inferred and 4 = predicted. The letter b stands for basic reserves including design and mining losses; M stands for marginal economic and S for subeconomic). 'Inferred and predicted resources' are only quantified as "intrinsic economic."

Tab. 20-6 Solid fuel and mineral resources/reserves classification

	Identified mineral resources			**Undiscovered resources**
	Measured	**Indicated**	**Inferred**	**Predicted**
Economic	Proven reserves (111)	--	--	--
	Basic reserves (111b)	--	--	--
	Probable reserves (121)	Probable reserves (122)	--	--
	Basic reserves (121b)	Basic reserves (122b)	--	--
Marginal economic	Basic reserves (2M11)	--	--	--
	Basic reserves (2M21)	Basic reserves (2M22)	--	--
Submarginal economic	Resource (2S11)	--	--	--
	Resource (2S21)	Resource (2S22)	--	--
Intrinsic economic	Resource (331)	Resource (332)	Resource (333)	Resource (334)

Source: Fenwei (2008b)

Based on this scheme, the main classes seem to be composed as follows:

- *Reserves*: proven reserves (111) + probable reserves (121+122);
- *Basic reserves*: reserves + basic reserves (111b+121b+122b+2M11+2M21+2M22);
- *Resource reserves*: (2S11+2S21+2S22+331+332+333);
- *Identified reserves* = basic reserves + resource reserves.

It is important to note that the identified reserves include anything from proven reserves to resources. Only undiscovered predicted resources are excluded. The identifier "reserves" and "resources" are not clearly separated and sometimes used in parallel. For instance, identified reserves and identified resources are used synonymously. This is reflected in the use of "resource reserve," which sometimes appears to be identical to "resources."

The regional distribution of coal reserves according to this classification is given in Fig. 20-4.

These figures include thermal coal as well as coking coal. The share of thermal coal used for steam and power generation depends on the quality of the regional coal, and differs considerably from region to region. Fig. 20-5 shows the same content as Fig. 20-4, but for thermal coal only. Shanxi is the only region with extensive quantities of coke coal; approximately 50 per cent of its total reserve is of coke quality.

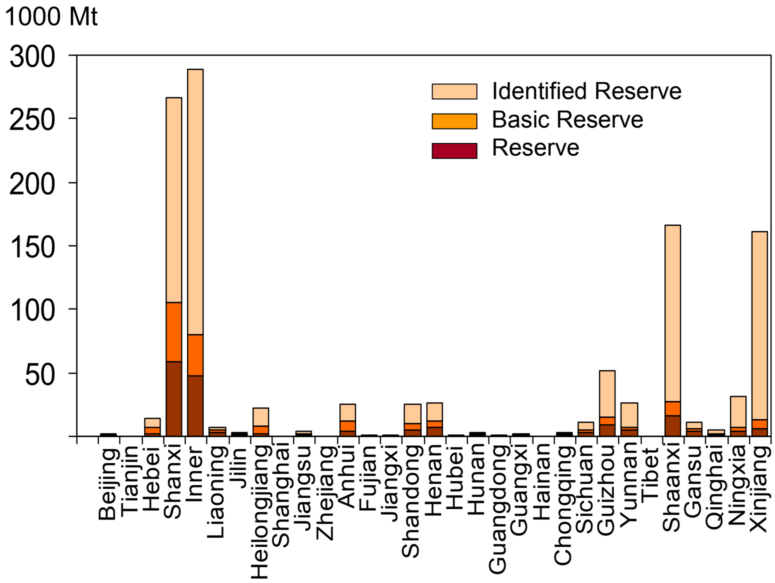


Fig. 20-4 Regional distribution of China's coal reserves, divided into reserves, basic reserves and identified reserves. Note that the upper bars in this figure include the quantities from the subclasses below, that is the basic reserves include the reserves, and the identified reserves include the basic reserves

Source: Fenwei (2009)

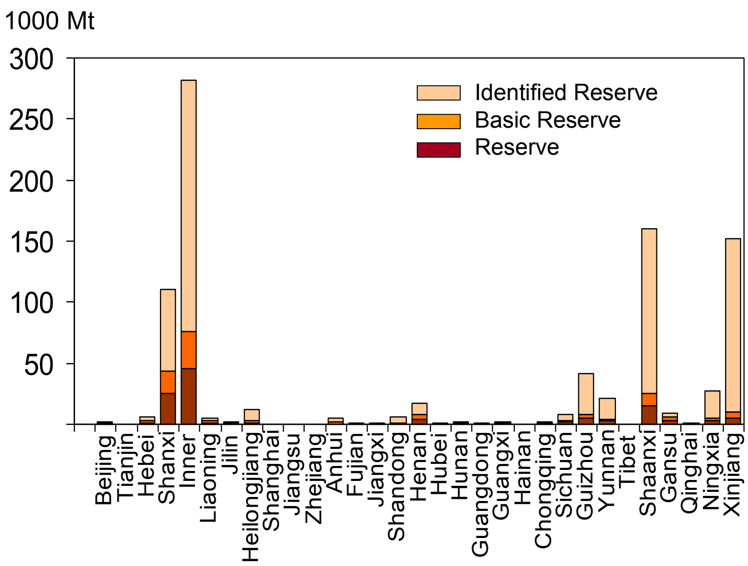


Fig. 20-5 Regional distribution of China's coal reserves, divided into reserves, basic reserves and identified reserves. Note that the upper bars in this figure include the quantities from the subclasses below, that is the basic reserves include the reserves, and the identified reserves include the basic reserves

Source: Fenwei (2009)

The total amounts of coal reserves in China at the end of 2006 were as follows:

- *Reserves*: 182.54 billion tonnes, 121.33 billion tonnes of which were thermal coal;
- *Basic reserves*: 333.48 billion tonnes, 212.03 billion tonnes of which were thermal coal;
- *Resources*: a total of 826.3 billion tonnes, 667.39 billion tonnes of which were thermal coal;
- *Identified reserves*: 1,159.8 billion tonnes, 879.4 billion tonnes of which were thermal.

The basic reserves were downgraded by 4.3 per cent to 318.96 billion tonnes in 2009. The exact data for reserves and identified reserves in 2009 were not published in the Chinese Statistical Yearbook 2010.

Fig. 20-6 shows the bars for reserves only, distinguishing between thermal coal and coking coal. The upper bar shows the additional quantities included in basic reserves. For the sake of simplicity, the basic reserves in this figure do not differentiate between coking and thermal coal.

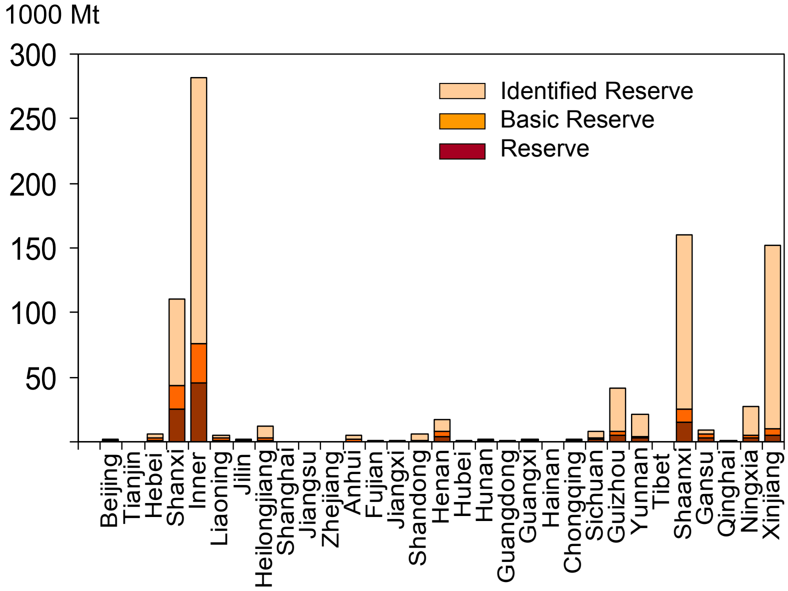


Fig. 20-6 Regional distribution of China's thermal and coke coal reserves, divided into reserves and basic reserves. Note that in this figure the distinction between coke and thermal coal is only for reserves, not for basic reserves. The latter includes thermal and coke coal

Source: Fenwei (2009)

The detailed figures are summarised in Tab. 20-7. The different definitions compare as follows:

- The Chinese Statistical Yearbook reports "ensured reserves", which are identical to "basic reserves".
- The WEC reports "proven recoverable reserves". According to the Chinese Classification scheme, this would coincide with "proven reserves" (see Tab. 20-6), making it a subclass of "reserves". In that sense, the 114.5 billion tonnes stated in WEC reports are consistent with the Chinese system, which reported 182.5 billion tonnes for reserves (including proven reserves) and 334.5 billion tonnes for basic reserves in 2006. The latter was downgraded to 319 billion tonnes in 2009.

Individual regions are analysed further in the following section. This includes a rough separation of lignite from thermal coal which – despite being irrelevant at country level – could constitute a relevant share of regional resources, reducing their energy potential.

Tab. 20-7 Identified coal reserves in China, divided into reserves, basic reserves and resources for total coal and thermal coal

	Identified coal reserves (end of 2006)				**Identified thermal coal reserves (end of 2006)**			
Region	**Reserve**	**Basic reserve**	**Resource**	**Identified reserve**	**Reserve**	**Basic reserve**	**Resource**	**Identified reserve**
Beijing	222	573	1,718	2,292	222	573	1,666	2,241
Tianjin	0	297	85	383	0	0	33	33
Hebei	2,475	6,815	7,765	14,580	1,159	3,285	2,683	5,968
Shanxi	58,743	105,166	160,904	266,070	25,830	43,861	67,025	110,886
Inner Mongolia	47,562	80,233	209,031	289,264	45,426	76,362	205,756	282,118
Liaoning	2,590	4,975	2,146	7,121	1,458	3,094	1,642	4,736
Jilin	1,047	1,711	1,212	2,923	857	1,397	971	2,368
Heilongjiang	1,813	7,767	14,214	21,981	911	2,969	9,512	12,480
Jiangsu	1,003	1,830	1,891	3,721	1	4	100	104
Zhejiang	16	49	45	94	0	3	15	18
Anhui	4,436	11,874	13,358	25,232	307	1,763	3,448	5,210
Fujian	272	479	723	1,201	270	475	722	1,197
Jiangxi	424	818	575	1,392	154	311	299	609
Shandong	4,858	10,325	14,577	24,902	709	1,250	4,814	6,064
Henan	6,810	12,330	13,694	26,024	4,447	8,488	8,237	16,725
Hubei	22	326	410	736	17	253	327	579
Hunan	1,029	2,012	1,047	3,059	842	1,595	744	2,339
Guangdong	63	189	441	630	60	184	425	609
Guangxi	447	846	1,447	2,293	437	778	1,389	2,167
Hainan	0	90	77	167				
Sichuan	3,350	5,026	5,752	10,777	2,412	3,518	4,491	8,009
Chongqing	1,028	1,826	1,206	3,032	700	1,201	604	1,805
Guizhou	9,136	14,826	36,539	51,364	5,284	8,514	32,848	41,360
Yunnan	4,734	7,357	19,432	26,789	2,808	4,447	17,009	21,456
Tibet	0	12	44	57	0	2	29	33
Shaanxi	16,143	27,757	138,021	165,778	14,994	25,728	134,740	160,468
Gansu	3,675	6,170	4,634	10,803	3,375	5,619	3,923	9,451
Qinghai	958	2,066	2,842	4,908	629	948	318	1,266
Ningxia	4,065	7,006	24,193	31,199	3,406	5,301	22000	27,302
Xinjiang	5,618	12,729	148,276	161,006	4,613	10,013	141,539	151,553
China	182,539	333,480	826,299	1,159,778	121,328	212,026	667,386	879,411
All figures are given in Mt								

Source: Fenwei (2009))

20.3.4 Chinese Coal Resource and Depth Distribution

Another widely used concept targets the total resource amount and how it is composed from forecast and identified resources. The general schematics are given in Fig. 20-7.

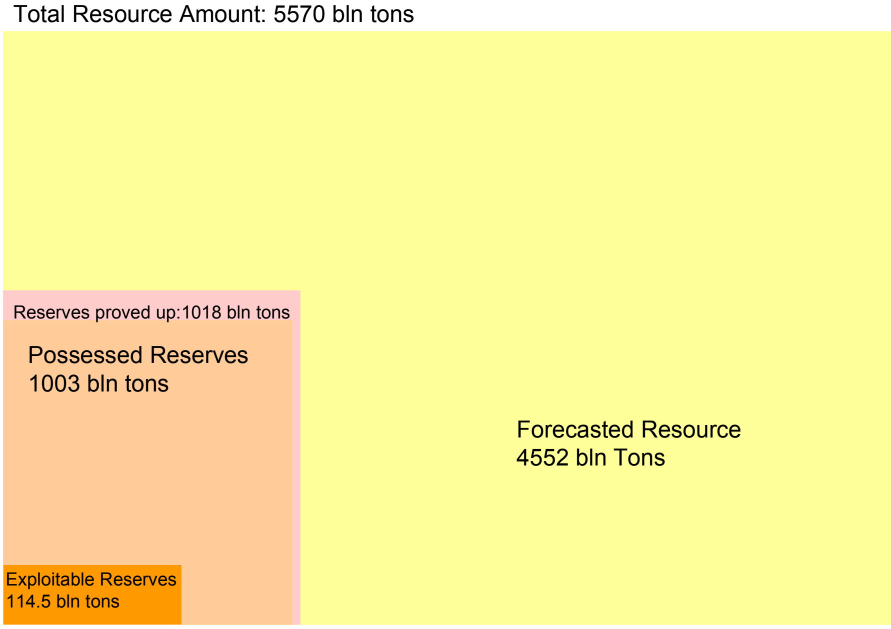


Fig. 20-7 Relation of total coal resources and composition from forecast resources and reserves proved up; the graphical size of the reserve classes in the figure corresponds roughly to physical volume

Source: Pan (2005)

From these relations, it becomes obvious that:

- Exploitable reserves are comparable to proven reserves (WEC);
- Possessed Reserves roughly resemble measured and indicated reserves (Tab. 20-6);
- Reserves proved up are comparable to identified reserves (Tab. 20-6);
- Forecasted resources are comparable to undiscovered or predicted resources (Tab. 20-6).

The figures stated in Tab. 20-7 cover different reserve classes, but are identical in total to “reserves proved up.” The slightly different figures are believed to be due to statistics being taken from different years.

No information is available on the depth distribution of China’s coal reserves. However, the average exploration depth indicates that these are predominantly situated in the layer no deeper than 500 to 600 m, although the deepest exploration well is 1,300 m below the surface (Pan 2005).

The forecast coal resource distribution is as follows:

- About 40 per cent is less than 1,000 m deep;
- About 30 per cent is at a depth between 1,000 and 1,500 m;
- About 30 per cent is at a depth between 1,500 and 200 m.

These resources seem to be irrelevant to future coal production. The average methane content of these seams is estimated to be between 10 and 20 m³/t (Pan 2005). For this reason, the regional distribution of identified reserves and undiscovered resources is given in the following for larger coal provinces.

20.3.5 Regional Distribution of Reserves

How coal reserves are attributed to individual fields is not obvious. Although the China Coal Resource Atlas (Fenwei 2008b) includes such details, definitions and classifications are not identical to the general scheme, and vary from region to region. Moreover, figures are compiled for 1992 to 1998, depending on the region. Due to a lack of further information, in this section these figures are used and analysed for the largest coal regions. How these figures compare to the schematics explained above is described when possible.

In most cases, these reserves are classified into "keeping reserves" and "further exploration," although definitions change from region to region. Compared to above, the definition of "keeping reserves" is used identically to "identified reserves." Keeping reserves are subdivided into "detailed exploration," "general exploration" and "seeking coal." The "detailed exploration" subclass seems to be identical to "reserves" as used in the previous section or to proven recoverable reserves as used by the WEC. "Further exploration" is identical to "undiscovered resources" and may be highly speculative.

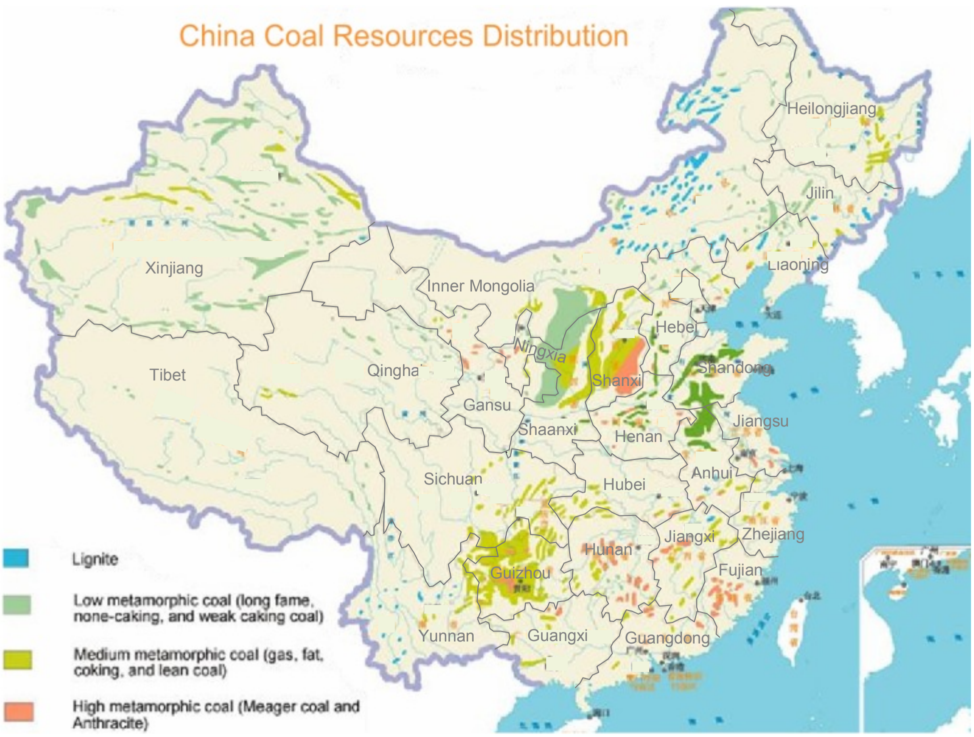


Fig. 20-8 Map of China's major coalfields

Source: Modified based on Fenwei (2011a)

Fig. 20-8 gives an overview of the distribution of China's coalfields according to the location and quality of coal. Lignite fields are predominantly in the north-eastern part of Inner Mongolia and throughout Yunnan in the south. Long-flame, non-caking and weak caking coal (low metamorphic) is generally concentrated in Inner Mongolia, Shaanxi and Xinjiang. Gas coal, fat coal, coking coal and lean coal (medium metamorphic) can be found in Guizhou, Shanxi, Shaanxi, Heilongjiang and Xinjiang, whilst high metamorphic meagre lean coal and anthracite are located in Shanxi and the south-eastern provinces.

20.4 Coal Production in China

Fig. 20-9 shows how coal production has developed in China since 1950. At the end of the 1990s, many small coal mines had to be closed down for environmental reasons. These closures are responsible for the dip in coal production volume around the year 2000. However, the extent to which these obligatory mine closures were realised at the regional level is not known. For this reason, the production data published at that time vary widely, reflecting different estimates. BP Statistical Review of Energy (orange line) published the highest estimates; data from the U.S. Energy Administration (US-EPA) are reproduced with areas subdivided into hard coal (grey area) and lignite (brown area). Other statistics by Fenwei and those in the "Kohlestatistik" report the strongest decline in production, probably repeating official figures. Although the various statistics differ concerning the recent years, coal production volumes are still rising considerably. Figures for 2010 suggest an increase to 3,240 Mt (BP)

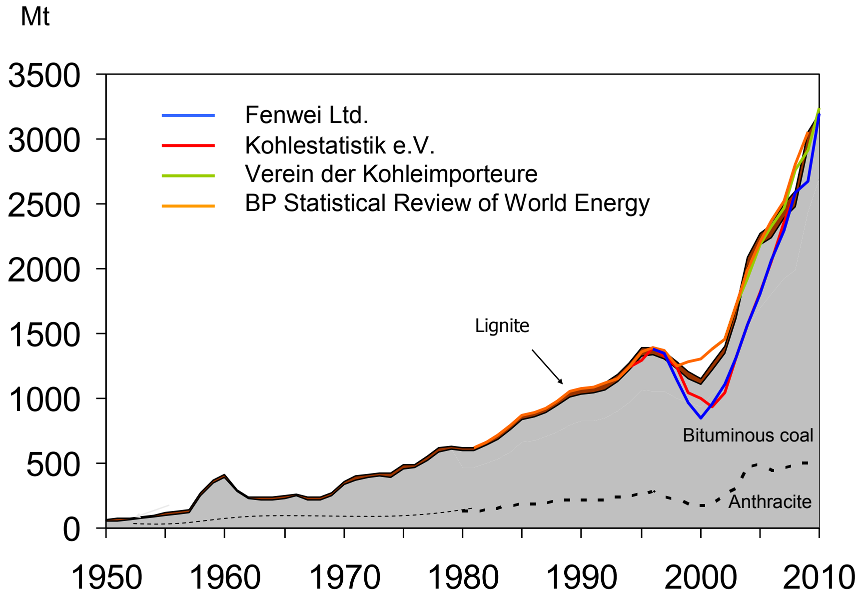


Fig. 20-9 Production of coal in China, subdivided into lignite (brown area), anthracite (broken line) and bituminous coal (grey area between anthracite and lignite)

Sources: 1950–1980 Lefohn et al. (1999), 1980–2008 U.S.-EIA (2011), BP (2011), VdKi (2011), Fenwei (2011a)

Lignite production makes up a small proportion, around 5 per cent. Production of coking coal, not shown in the figure, rose sharply from 550 Mt in 2001 to about 1 billion tonnes around 2005, where it stagnated until 2010 (Fenwei 2011a). In 2010, almost one third of China's coking coal (340 Mt) was produced in Shanxi (Fenwei 2009). Other producers of coking coal include Shandong, Anhui, Heilongjiang and Henan (Fenwei 2011a).

Production in 2011 is forecast to be 3.35 billion tonnes, 1.05 billion tonnes of which will be coking coal (Fenwei 2011a).

20.4.1 Regional Aspects of Coal Production in China

Since the year 2000, coal production in China has increased by more than 200 per cent, averaging 11 to 12 per cent annually. This growth, however, differed from region to region, as can be seen in Fig. 20-10. Despite representing a small quantity at national level, lignite output is concentrated in two provinces and regions: Yunnan, where lignite accounts for about 20 per cent, or 20 Mt, of its coal production of 98 Mt in 2010, and Inner Mongolia, which accounts for the rest, or almost 100 Mt, which constitutes 13 per cent of total coal production in Inner Mongolia in 2010 (780 Mt).

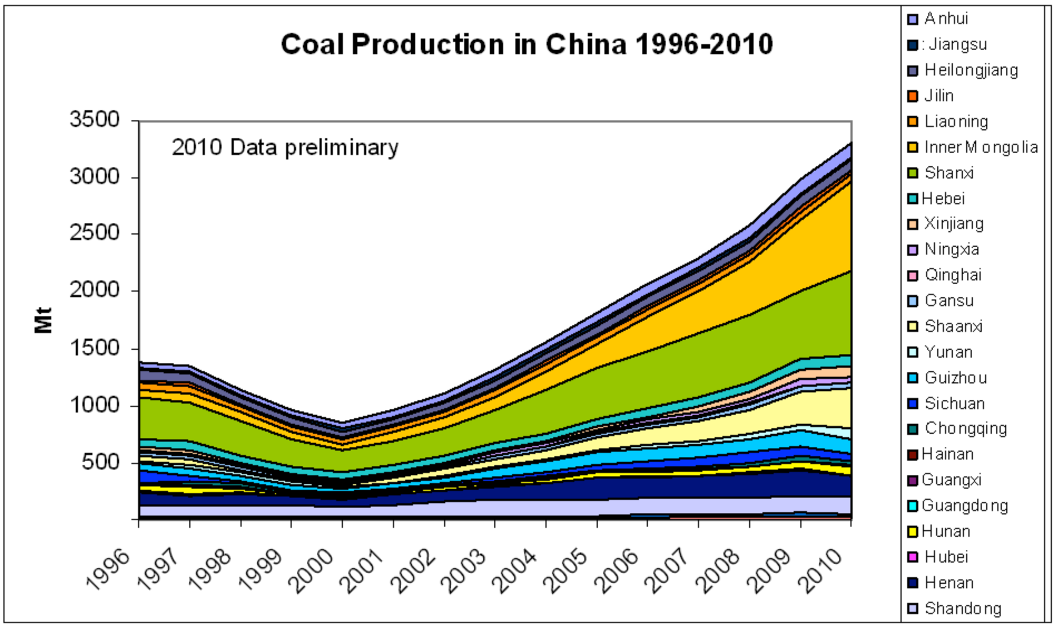


Fig. 20-10 Coal production in China and the proportion of coal produced by individual provinces

Sources: Fenwei (2011b) and LBST estimate 2011

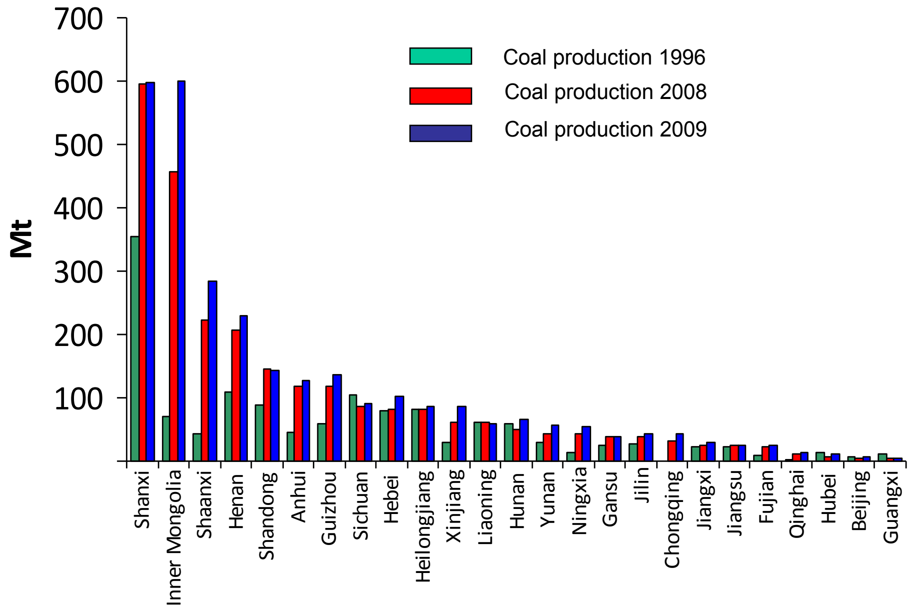


Fig. 20-11 Coal production in China's provinces in 1996, 2008 and 2009

Source: Fenwei (2011b)

Over the last ten years, coal production was increasingly concentrated in the three provinces of Inner Mongolia, Shanxi and Shaanxi, which together made up 55 per cent of production in 2010. Production volumes increased most rapidly in Inner Mongolia, making it China's largest producer of coal in 2010 (780 Mt). Production is expected to increase up to 1 billion tonnes by 2015. China's total consumption target for 2015 is around 4 billion tonnes (Fenwei 2011c).

20.4.2 Productivity

The labour productivity of coal production in China is very low, considerably below international standards. Labour productivity in 2006 was reported to be 4.25 tonnes per employee. This represents an annual increase of 8 per cent since 1995, when labour productivity was 1.8 tonnes per employee.

Tab. 20-8 Development of labour productivity in China's coal mining industry

Year	**Labour productivity** t/person	**Source**
1995	1.8	2002 China's Coal Exploitation Industry Survey, 16 Nov 2002
2001	2.5	2002 China's Coal Exploitation Industry Survey, 16 Nov 2002
2005	4.07	2006 China's Coal Exploitation Industry Survey, 4 June 2007
2006	4.26	2006 China's Coal Exploitation Industry Survey, 4 June 2007

Source: Höller (2009)

20.5 Price Development

20.5.1 General Aspects

The market price of coal depends primarily on the coal's quality, heat content and the efforts required to transport it. Prices for different coal categories should therefore not be compared. Basically, the price per tonne is valid for a specific coal grade. The higher the heating value, the lower the ash and sulphur contents, and the better the consistency of coal, the higher its market value.

Coking coal is traded at much higher prices than non-coking coal. Lignite with a much lower heating value is not usually transported over longer distances, but combusted close to the mine. Due to the much higher productivity of open pit mining, these mines perform economically better than underground mines. Lignite especially is mined at open pits; its production cost is lower than that of bituminous or sub-bituminous coal mining.

Nevertheless, for reasons of comparison, various regional benchmark prices are common. In Europe, the Amsterdam, Rotterdam, Antwerp (ARA) price acts as a benchmark. This is a weighted price for coal imports free on board (FOB) in Amsterdam, Rotterdam and Antwerp. The German Federal Office of Economics and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle – BAFA) publishes the monthly average price for coal imported at the German border, which is usually closely oriented to the ARA price.

Two other marker prices are the export price of South African coal at Richards Bay (the so-called RB Index) and the export price of Australian coal at the Port of Newcastle (the so-called Newcastle Index). In Asia, particularly at Chinese ports, prices are more specific. Import prices should therefore be compared individually for a specific port.

20.5.2 Historical Price Development

In recent decades, the price of coal developed roughly in line with the price of crude oil. It rose during the oil price shocks in 1973 and 1979, followed by an almost 50 per cent price drop after 1980. Around 2000, the price of coal in Europe was at an all-time low of about EUR 30 per tonne. Shortly after 2000, the coal price started to increase steadily, with an interruption around 2003. From 2007 to July 2008, the price of coal more than doubled, followed by a downturn in line with the global economic recession, triggered in part by the high oil and coal prices. In 2009 and 2010, however, the coal price rose again, and is still high compared to the pre-2008 level.

Fig. 20-12 shows this development for coal imported at the German border and the ARA price. The BAFA price is converted from its original units of t-hce (tonnes of hard coal equivalent) to physical tonnes by equating 1 t-hce (or tSKE in German) to 29.31 MJ.

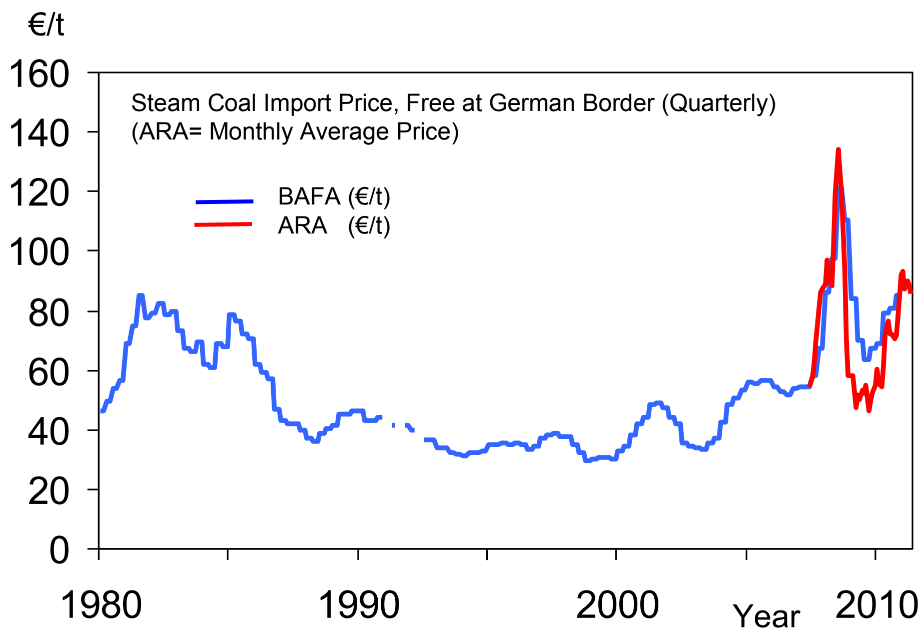


Fig. 20-12 Price development of coal imported to Europe: BAFA = price free at German border; ARA = price free at Amsterdam, Rotterdam, Antwerp

Sources: BAFA (2011) and Global Coal (2011)

Fig. 20-13 focuses the price comparison on the period 2007 to 2011. The price for coal imported to Europe (ARA) is compared with prices for coal exported from South Africa (Richards Bay) and the Port of Newcastle (Australia). The price of crude oil on the New York Mercantile Exchange (NYMEX) is shown for comparison.

The high price for importing coal to Europe in 2007 and 2008 reflects high American export prices combined with high shipping rates. In 2010, the European coal price was below the prices of coal exported from South Africa and Australia for a short period, illustrating the influence of regional market conditions: due to India and China’s growing import demand, coal at terminals with orders from these countries cost more than coal from terminals serving European countries, predominantly not in exchange with South Africa and Australia (coal from eastern USA and Canada or from Poland, Russia and Ukraine).

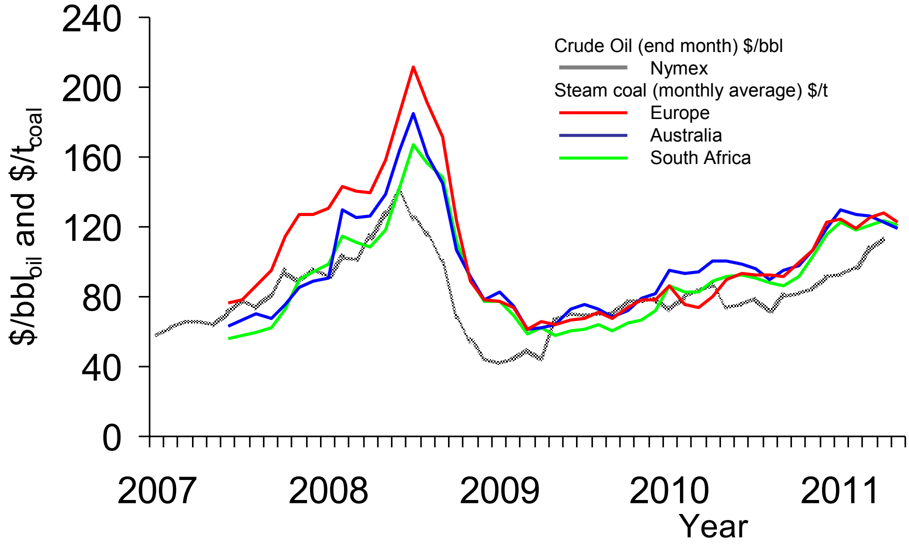


Fig. 20-13 Development of coal prices in Europe, Australia and South Africa compared to the price of crude oil (NYMEX)

Sources: Nymex (2011) and Global Coal (2011)

The price of coal developed roughly in line with the price of crude oil. However, during the price spike in summer 2008, the price of coal rose even more sharply than the price of oil. This could be an indication that the price increase was driven by a direct rise in demand in Asia in addition to the rising price of oil – which certainly triggered some substitution effects. During the second half of 2010, coal prices in Europe (ARA), South Africa (RB) and Australia (Newcastle) almost coincided. Even more importantly, however, during this period coal prices increased more rapidly than oil prices. On a rough scale, oil prices reflect demand for transport needs, whilst coal prices reflect demand for electricity. At that level, it seems that demand for electricity has risen more sharply than demand for fuel.

Due to the high import prices, China reduced its coal imports in the first four months of 2011 by about 25 per cent against the same period in 2009. According to news media, this resulted in severe electricity shortages in many parts of the country, forcing the government to facilitate imports by reducing taxes and harbour fees (Dradio 2011).

Fig. 20-14 gives a more detailed differentiation of the price of coal by adding prices in eastern USA (Appalachian) and Japan. Annual average prices are taken for this comparison. The price of coking coal is also shown for Japan. It is about 40 per cent above the price for steam coal. The cheap price of Japanese coal compared to European coal in 2008 could be due to shorter transport distances from Indonesia, the main source of Japan's coal supply. In 2009, however, the picture changed. Driven by the global recession, coal prices declined worldwide, except in Japan, where it was virtually identical to prices in the previous year. Japan is closest to the developing markets of Asia, where coal demand remained at a high level, even in 2009. Prices rose yet again in 2010. However, these prices are only included in the figure for Richards Bay (South Africa), Newcastle (Australia) and ARA (Amsterdam - Rotterdam - Antwerp), as the data for the other destinations are still incomplete. Only Japanese import coal prices from Indonesia are included as a new contract with Bumi Indonesia at the end of

May 2011 was chosen with a record import price of USD 134 per tonne for thermal coal with 24.3 MJ/tonne.

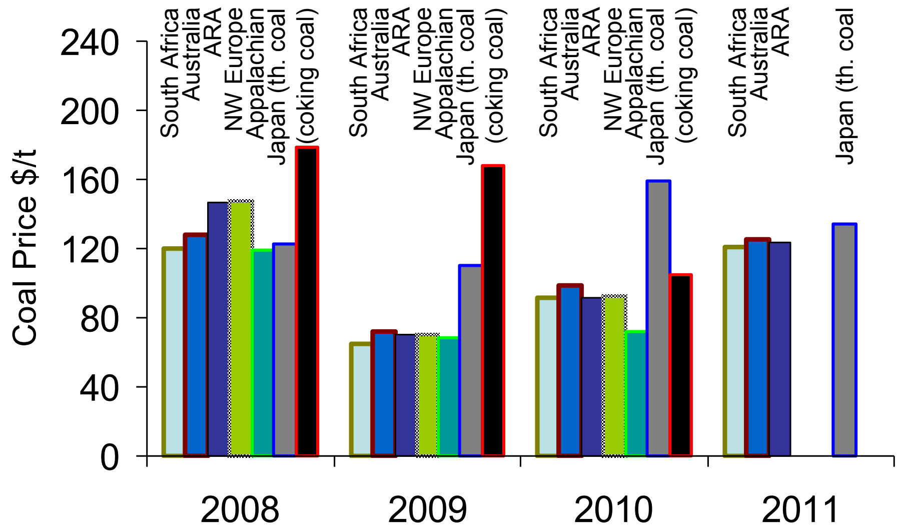


Fig. 20-14 Regional differences in average coal prices from 2008 to 2010. For 2011, only benchmark prices (South Africa, Australia and ARA) and the latest contract price for Japanese coal are given because no other figures are available yet

Sources: BP (2010), Global Coal (2011) and IFT (2011)

20.5.3 Present Prices of Domestic Chinese Coal

Typical price labels used in China are listed in Tab. 20-9.

Tab. 20-9 Typical price labels used in China

Price	Description
Ex-stock	Sold at warehouse of storage yard at loading ports, including pre-storage price, VAT and storage fee
CIF	All costs for coal delivered to port of destination, including cost, insurance and freight (only for sea freight or inland waterway transport)
FOBt	Price excluding loading coal onto vessel cabin and trimming charges, but including VAT
FOB	Price for coal already loaded onto vessels at named port, including FOR cost, rail or truck freight to port, port charge, VAT charge, profit, etc.
Ex-works	Price mainly for washed coal. Delivery at coal washery or coal yard, for coke at coking plant. Aggregate of mine mouth price of raw coal, transportation cost to coal preparation plant or coal yard, coal washing cost, profit and VAT
FOR	Price for coal already loaded onto rail cars, including all costs incurred beforehand (but not the transport cost to buyer’s destination). This price is commonly used across China. VAT is included
Ex-mine	Price for coal sold at mine sites. Includes mine mouth price plus a short-distance transport charge to bring the coal to the entrance of the mine. VAT is included

Source: Sxcoal (2012)

The seaborne freight rates in Chinese yuan per tonne (CNY/t) at Qinhangdao Port are shown in Fig. 20-15 for 2010.

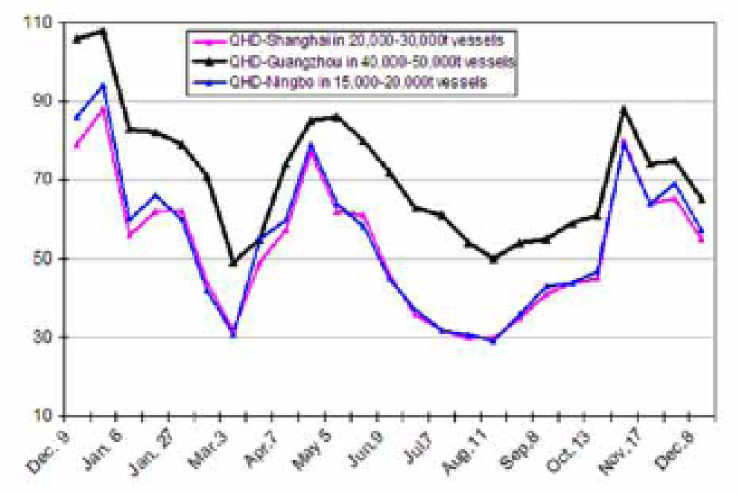


Fig. 20-15 Domestic seaborne freight rates in 2010 (in CNY/t)

Source: China Coal Monthly (2010)

Coal prices for various locations in China are shown in Fig. 20-16. Since coal prices have been subject to huge fluctuations in recent years, prices on a specific date (22 November 2010) are compared. Most often, the “free on rail” (FOR) price is quoted. Only two examples are before loading onto vessels (FOBt) and the mine (mine mouth). The black bars show the price ex mine (EXW). For reasons of comparison, prices –originally per tonne and heating value – are normalised per MJ of energy content. Prices are highest in Zhejiang, which has no or negligible domestic production.

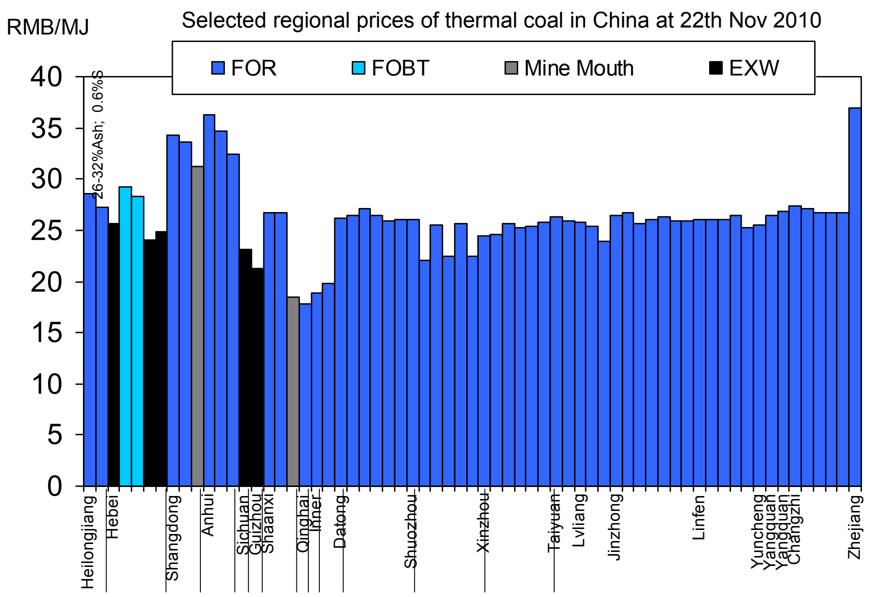


Fig. 20-16 Variation of coal prices at different locations in China and under different conditions

Source: Fenwei (2011b)

The price difference between mine mouth and FOR at the rail terminals in Shangdong and Hebei amounts to about 5 to10 per cent. However, in Shaanxi it could be up to 25 to 30 per cent. (Fenwei 2011b) compares different coal qualities at various destinations and production areas. The cheapest coal is domestic coal from Datong in Beijing, which has 5,800 kcal (24.3 MJ). The same Datong coal is about 15 per cent more expensive in Guangzhou and Shanghai. Coal is most expensive in Nanjing. Generally, coal with a higher heating value is slightly more expensive than coal with a lower calorific content.

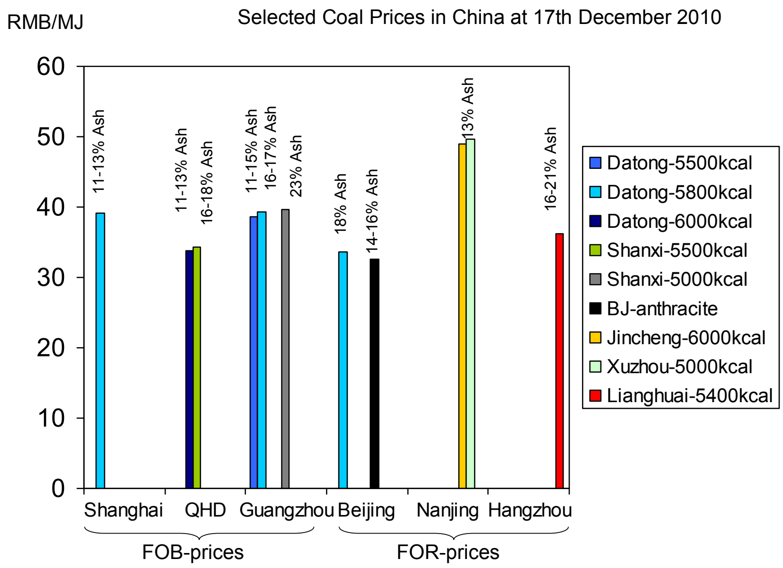


Fig. 20-17 Various free on board (FOB) prices at sea harbours in Shanghai, Qinhuangdao Port and Guangzou compared to free on rail (FOR) prices at Beijing, Nanjing and Hangzhou

Source: Fenwei (2011b)

20.5.4 Price Difference between Domestic and Imported Coal

To enable comparisons with international coal prices, Tab. 20-10 and Fig. 20-18 show the interbank exchange rate between the Chinese yuan (CNY), the euro (EUR) and the United States dollar (USD).

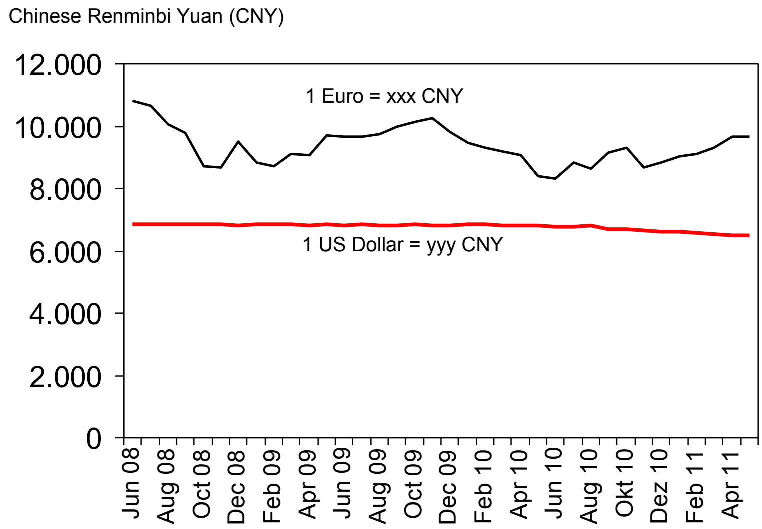


Fig. 20-18 Development of Interbank exchange rate from June 2008 to May 2011 from CNY to EUR and USD, respectively

Source: Bundesverband deutscher Banken (2010)

Tab. 20-10 Development of interbank exchange rate from CNY to EUR/USD since June 2008

	CNY 1 = EUR	EUR 1 = CNY	USD 1 = CNY
29/06/2008	0.093	10.805	6.854
31/07/2008	0.094	10.665	6.832
30/08/2008	0.1	10.048	6.845
29/09/2008	0.102	9.795	6.848
31/10/2008	0.115	8.725	6.840
29/11/2008	0.115	8.679	6.836
30/12/2008	0.105	9.496	6.823
30/01/2009	0.113	8.818	6.850
27/02/2009	0.115	8.695	6.849
31/03/2009	0.110	9.094	6.834
30/04/2009	0.110	9.057	6.823
30/05/2009	0.103	9.697	6.838
30/06/2009	0.104	9.655	6.831
31/07/2009	0.104	9.659	6.832
31/08/2009	0.103	9.749	6.831
30/09/2009	0.100	9.996	6.826
30/10/2009	0.099	10.125	6.838
30/11/2009	0.098	10.256	6.827
30/12/2009	0.102	9.835	6.827
31/01/2010	0.105	9.481	6.837
27/02/2010	0.107	9.321	6.837
31/03/2010	0.109	9.201	6.826
30/04/2010	0.110	9.088	6.825
31/05/2010	0.119	8.403	6.828
30/06/2010	0.120	8.322	6.781
30/07/2010	0.113	8.851	6.785
31/08/2010	0.116	8.632	6.807
30/09/2010	0.11	9.132	6.691
30/10/2010	0.107	9.308	6.682
30/11/2010	0.115	8.666	6.667
31/12/2010	0.113	8.822	6.602
31/01/2011	0.111	9.030	6.595
28/02/2011	0.11	9.091	6.572
31/03/2011	0.107	9.304	6.549
30/04/2011	0.104	9.645	6.499
30/05/2011	0.108	9.28	6.496

Source: Bundesverband deutscher Banken (2010)

The comparison with imported coal must also be performed for similar products. Heating value, humidity, ash and sulphur content, for instance, are relevant criteria. Tab. 20-11 portrays these values for India's most important supply sources: Indonesia, Australia and South Africa.

Tab. 20-11 Quality criteria of coal exported from South Africa, Australia and Indonesia

	Unit	RB (South Africa)	Newcastle (Australia)	Kalimantan (Indonesia)
UHV	kcal/kg	>5,850 (av. 6,000)	> 5,850 (av. 6,000)	5,300–6,200
	MJ/kg	>24.5 (av. 25.14)	>24.5 (av. 25.14)	22.2–26
Humidity	%	< 12	< 15 (av. 10)	9-16 (inherent)
Ash content	%	< 15	< 14 (av. 13)	7–16
Sulphur content	%	< 1	< 0.75 (av. 0.6)	< 1
Price on 22 Nov 2010	USD/t	103	107	n.a.
(comp to Fig. 20-17)	CNY/MJ	27.3	28.3	
Price on 17 Dec 2010	USD/t	115	119	n.a.
(comp to Fig. 20-18)	CNY/MJ	30.2	31.2	n.a.

Sources: Global Coal (2010) and (Borneo Coal Indonesia 2010)

In Tab. 20-12, prices at various destinations are compared in USD/t and with a similar heating value of 26.4 MJ/kg. Chinese domestic coal for export at Qinhuangdao (QHD) is much more expensive than coal imported from South Africa, Australia, Kalimantan or even Russia. This is related to enormous Chinese demand, which forced the government to limit export quantities. This is reflected by a corresponding price reaction.

Tab. 20-12 Quality criteria of coal exported from South Africa, Australia and Indonesia

	Unit	RB (South Africa)	Newcastle (Australia)	QHD (China)	Kalimantan (Indonesia)	Russia (Pacific)
UHV	kcal/kg	6,300	6,300	6,300	6,300	6,300
	MJ/kg	26.4	26.4	26.4	26.4	26.4
Price (1 January 2009)	USD/t	65	63	76	63	66
Price (31 December 2009)	USD/t	81	86	115	73	88
Price (1 April 2010)	USD/t	88	95	107	73	102

Source: VdKi (2010)

1.5.5 Structural Changes of Coal Import and Export Markets in Asia

The demand for coal has only substantially exceeded domestic production for a few years. Fig. 20-19 shows how China's coal imports and exports have developed, portraying major sources and destinations. In the near future, rising structural changes concerning import sources are to be expected because Indonesia – currently China's second most important supply source – will limit its exports. This will affect the prices of coal traded on global markets.

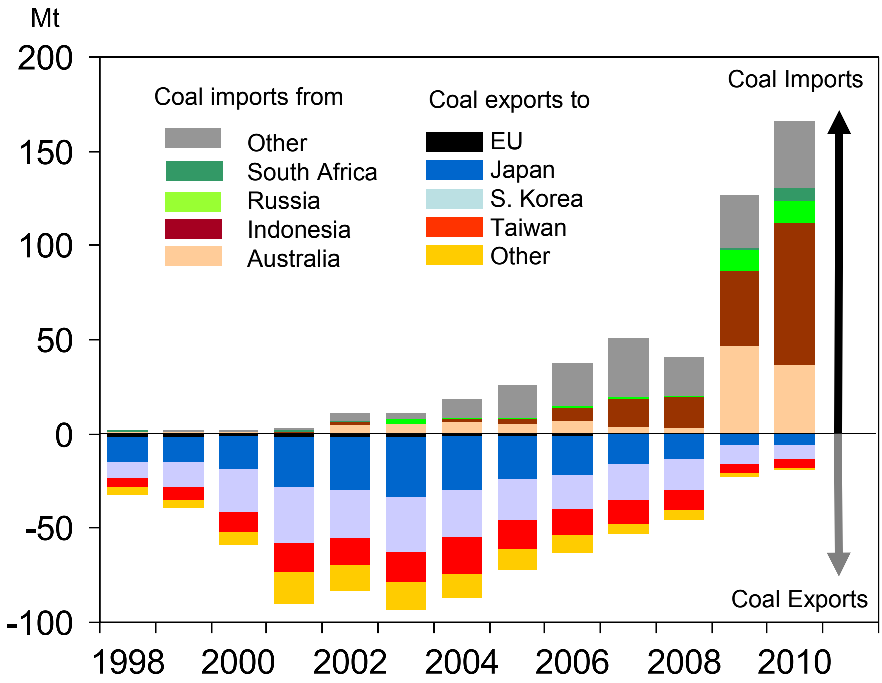


Fig. 20-19 Imports to and exports from China

Sources: VdKi (2006), VdKi (2010) and VdKi (2011)

Over the last decade, Indonesia was the preferred importer for non-coking coal, due to the short transport distances involved. In 2009, Indonesia exported a total of 230 Mt of predominantly non-coking coal quality to other countries. This figure cited by the "Verein der deutschen Kohleimporteure" is about 50 Mt above official figures.

The most important importers of Indonesian coal exports in 2010 were China (74.9 Mt), India (44.4 Mt), South Korea (43.2 Mt), Japan (33.1 Mt) and Taiwan (21.9 Mt). Chinese coal imports in particular have risen sharply in recent years, with imports from Indonesia more than quadrupling since 2007, as can be seen in Fig. 20-19 (VdKi 2010).

This demand pressure resulted in major increases in the price of coal exported from Indonesia. In addition, the rising domestic demand in Indonesia could lead to restrictions on exports. Whilst one year ago it was reported that the government intends to freeze coal exports at 150 Mt (Jakartapost 2009), the government's policy is now to reduce exports stepwise in order meet domestic demand (UPI 2010). In addition, Indonesia signed a Moratorium on Deforestation at the Deforestation Workshop in Oslo in May 2010, which will be valid for at least the next two years. Part of this agreement is not to allow any new permits for open pit mining areas (Hasan 2010).

Most Australian coal exports are imported by East Asia. In 2009, for instance, China was the largest importer of Australian coal (83 Mt). Thermal coal imports alone grew to 47 Mt, an eightfold increase over the previous year (VdKi 2010).

Not only India, but also China, Korea, Japan and Taiwan are seeking new sources for future coal imports. For this reason, huge amounts are being invested in constructing a new harbour to increase import capacities (HMS 2010).

20.5.5 Projection of Coal Price Development

Extrapolating these developments, it is very likely that future prices will increase. In this section, an attempt is made to determine a reasonable price extrapolation for the decades ahead. This is carried out in line with oil price projections of the International Energy Agency (IEA) in the latest World Energy Outlook 2009 (WEO) (IEA and OECD 2009). This seems to be more reasonable than directly taking the coal price projections in IEA and OECD (2009a), which are believed to be too moderate since they assume that cheap and abundant coal will continue to be available in 2030.

Tab. 20-13 shows the price assumptions for coal imported by Organisation for Economic Co-operation and Development (OECD) states in 2030 according to various editions of the World Energy Outlook of the IEA published between 1998 and 2009. Prices are given in nominal terms in USD per tonne. The base year of the calculations is printed in bold.

Tab. 20-13 Price assumptions for coal imported by OECD countries according to various editions of the World Energy Outlook since 1998

Reporting year	1996	1997	2000	2006	2007	2008	2009	2010	2020	2030	2035
WEO 1998	39.3	**37.2**						42	46		
WEO 2002			**35**					39	41	44	
WEO 2004			**38**					40	42	44	
WEO 2007			39,05	**62.87**				56.07	56.89	61.17	
WEO 2008			40.08		**72.84**			120	116.67	110.00	
WEO 2009			41.22			**120.59**		91.05	104.16	109.04	
WEO 2010							**97.3**		130.6	170.2	192.4

Sources: WEO, various editions

For many years, the price of imported coal in 2030 was estimated at USD 40 to 60 per tonne by the IEA. In 2008, it increased almost threefold to USD 110 per tonne. Against earlier projections in WEO 2002, the latest coal price adaption for 2030 in WEO 2010 increased by almost 300 per cent! Tab. 20-14 gives similar price projections for the OECD crude oil import price. Prices are given in nominal data with the price base of the year printed in bold. Prices are given in USD per barrel. Compared to coal imports, the price of crude oil in 2030 rose by 300 per cent between WEO 2002 and WEO 2009.

Tab. 20-14 IEA price assumptions for crude oil imported by OECD countries according to various editions of the World Energy Outlook since 1998 with real figures for each base year

Reporting year	1996	1997	2000	2006	2007	2008	2009	2010	2020	2030	2035
WEO 1998	17.5	**16.1**						17	25		
WEO 2002			**28**					21	25	29	
WEO 2004			**27**					22	26	29	
WEO 2007			32.49	**61.62**				59.03	57.3	62	
WEO 2008			33.33		**69.33**			100	110	122	
WEO 2009			34.3			**97.19**		86.67	100	115	
WEO 2010							**60.4**		127.1	177.3	204.1

Sources: WEO, various editions

Developments in recent years show that the price of coal almost increased in line with – or even more sharply than – the price of crude oil (see Fig. 20-13). The expected demand for imports, mainly by China and India, in combination with declining or flat export volumes from traditional export countries (Indonesia, Vietnam and South Africa), makes it probable that the price of coal will rise at least as sharply as the price of oil in the years ahead.

Tab. 20-15 outlines the development of the price of imported coal, which is in line with the development of oil prices up to 2030, as reported by the IEA in its World Energy Outlook 2010.

Tab. 20-15 Development of the price of coal imported by OECD countries up to 2035; the price of imported coal is adapted to the IEA's assumptions on the development of the price of imported crude oil

Reporting year	Unit	2009	2020	2025	2030	2035
WEO 2010 (oil price development)	USD/bbl	60.4	127.1	151.1	177.3	204.1
Coal price adaption	USD/t	97.3	204.7	243.4	285.6	328.8

Source: IEA and OECD (2010)

20.6 Conclusion

Although resource statistics suggest that China has coal resources of 5,000 billion tonnes or even more these figures draw attention to irrelevant aspects. It is not the *resources* that count, which include highly speculative estimates about potential resource deposits, but the more reliable *reserve* data combined with production and demand dynamics.

China's proven coal reserves are between 114.5 billion tonnes (IEA and OECD 2010) and 182 billion tonnes (Fenwei 2009). Including probable reserves, this figure increases to 319 billion tonnes, as reported for the end of 2009 in the Chinese Statistical Yearbook. Realistically, these figures set the frame for future production scenarios. Based on coal production of about 3,260 Mt in 2010, the static reserve-to-production ratio is between 35 and 100 years. Even the upper figure would not allow China's coal production to continue to increase at the present growth rate for more than one or two decades. Unavoidably, this rise will come to an end in the not too distant future, possibly even in the next decade.

Applying such a scheme, it is apparent that the proven recoverable reserves may not suffice to meet demand in the high coal development pathway (*E1: high,* see Tab. 18-13). Even though it covers only power plants installed up to 2050, this pathway would require 102 to 137 billion tonnes of coal, which would rise to 110 to 146 billion tonnes if CCS is applied. The pathway with the lowest cumulative demand (56 to 74 billion tonnes for *E3: low*) may still allow the production rate to increase.

Even more problematic is the rising demand for coal imports. Ten years ago, China was one of the largest coal exporting countries supplying Asia and even the EU. This has dramatically changed. In 2010, China became the world's second largest importing country, requiring 166 million tonnes. Indonesia is the most important country for Chinese coal imports. China's coal supply will probably encounter serious restrictions once Indonesia limits or reduces its exports, as already announced, and no other country can compensate for this deficit.

21 Economic Assessment of Carbon Capture and Storage

21.1 Introduction

This section analyses the levelised cost of electricity (LCOE) production and CO_2 mitigation of hard coal-fired, supercritical pulverised coal (PC) power plants in China up to 2050. The basic parameters and assumptions of the cost calculation are summarised in section 21.2. Section 21.3 presents the main outcomes of the assessment. All cost figures are given in United States dollars in 2011, abbreviated to USD_{2011}.

21.2 Basic Parameters and Assumptions

21.2.1 Power Plant Types and Plant Performance

The economic assessment concentrates on hard coal-fired, supercritical PC plants because they operate at thermal efficiencies that make CO_2 capture viable. In 2007, 90.7 GW_{el} (112 units) of supercritical (SC) PC plant capacities and 8.8 GW_{el} (10 units) of ultra supercritical (USC) capacities were in operation in China. This represents approximately 18 per cent of China’s currently operating coal-fired power plant fleet. At the same time, about 25 GW (66 units) of SC and 57 GW (65 units) of USC capacities had been ordered or were at the design stage (Minchener 2010). This development suggests a successive shift from SC to USC designs for new capacities. Nonetheless, this cost assessment focuses on SC plants because most of the cost data available for coal-fired PC power plants, which serve as the basis for this analysis, consider SC plants. Furthermore, SC plants are still expected to remain a relevant plant type in China in the decades ahead because they constitute a widely deployed, mature and reliable technology.

Retrofitting CO_2 capture equipment to operate coal-fired power plants is not considered here. For newly built SC plants, an average net thermal efficiency of 41 per cent is assumed for the period prior to 2020 and 44 per cent for after 2030 per cent due to anticipated process optimisations. These efficiencies of China’s supercritical PC plants are based on studies quoted and assumptions made in section 18.4. The efficiency level chosen for post-2020 reflects the mean of the assumed development of thermal efficiencies of supercritical PC plants in the period from 2030 to 2050.

IGCC technology has attracted longstanding interest in China’s power sector (Minchener 2010). A consortium of the Huangeng Group and seven other Chinese companies has formed the GreenGen Corporation in order to erect an IGCC plant with a final power generating capacity of 650 MW_{el}. Construction started in 2009, completion was scheduled for the end of 2011. If successful, Huaneng intends to roll out additional similar IGCC-CCS plants (Hsu 2010). However, since IGCC technology is still at the demonstration stage involving rather high uncertainties, it remains unclear when the technology will become commercially viable. In China, the National Development and Reform Commission (NDRC) treated the acceptance of the technology rather cautiously, due to the higher capital costs involved compared to advanced PC plants (Minchener 2010). Because of these uncertainties, IGCC is not included in this assessment.

The following basic parameters are used for the cost assessment:

- Capturing CO_2 from the flue gas of a supercritical PC power plant triggers a significant efficiency penalty. The efficiency penalty adopted in this cost assessment also refers to the basic assumptions in section 18.4 of this study. The penalty is set at 6 percentage points for post-2020. The chosen percentage reflects the mean value of the efficiency penalties from 2030 to 2050, as efficiency losses continuously decrease due to technical improvements of capture processes.
- As for the other case studies in this project, the typical CO_2 capture rate is assumed to be 90 per cent. This rate is also used in Chinese studies such as Dahowski et al. (2009) and Wang et al. (2010).
- The average technical lifetime of coal-fired power plants is assumed to be 40 years (see section 18.4).
- By similar reasoning, the depreciation period in this assessment is assumed to be 25 years, which is longer than that calculated by Zhao (2008), for example (15 years).
- The plant load factor applied is 80 per cent (equivalent to 7,000 full-load hours per year on average), corresponding to the base case defined in section 18.4.
- In the base case, the commercial availability of CCS systems in China is expected to be achieved by 2030 (compare section 18.4.1), which means that power plants built later than 2030 can be equipped with CCS. Consequently, no CCS capacities are expected to be operating yet in 2030.

21.2.2 Coal Development Pathways for the Expansion of Coal-Fired Power Plant Capacities in China

In accordance with the projected development of coal-fired power plant capacities in China and the resulting quantity of CO_2 emissions to be captured by 2050, the economic assessment encompasses three energy scenarios E1–E3, derived from three basic scenario studies (see section 18.3.2). As mentioned above, only newly installed capacities are taken into account due to the focus on supercritical PC technology. The energy scenarios are based on the following scenario studies:

- *Pathway E1: high*: Based on the World Energy Outlook 2009 Reference Scenario, published by the International Energy Agency (IEA) and the Organisation for Economic Co-operation and Development (OECD), which elaborates country-specific scenarios for India and China (IEA and OECD 2009a). The pathway foresees a massive expansion of China's coal-fired power generating capacity.
- *Pathway E2: middle*: Based on the EmissionsControl (EC) Scenario, developed within the China Human Development Report (UNDP 2010). This pathway is characterised by improvements in energy efficiency, a diminished increase in coal and a massive increase in nuclear power. The coal-fired power plant capacity is assumed to peak in 2040 and decrease slightly by 2050.
- *Pathway E3: low*: Based on the Energy [R]evolution Scenario 2010, published by Greenpeace and EREC, which provides country-specific scenarios for India, China and South Africa (EREC and Greenpeace International 2010). The pathway indicates a strong focus

on renewable energy technology and energy efficiency. The pathway expects a decreasing coal-fired power capacity from 2020.

21.2.3 Levelised Cost of Supercritical Pulverised Coal Plants in China

21.2.3.1 Method of Calculation

The levelised cost of electricity (LCOE) generated by a CCS-based fossil-fired power plant in China is calculated using the following equation:

$$LCOE = \frac{\left(C_{Cap} + C_{O\&M}\right) \cdot af}{capacity} + C_{TS} + C_{fuel} \qquad \text{21-1}$$

where

$$af = \frac{I \cdot (1+I)^n}{(1+I)^n - 1} \qquad \text{21-2}$$

and

LCOE	= levelised costs of electricity generation, [LCOE] = US-ct/kWh_{el}
C_{Cap}	= specific capital expenditure, [C_{Cap}] = USD/kW_{el}
af	= annuity factor, [af] = %/a
I	= real interest rate, [interest] = %
n	= depreciation period, [n] = a
$C_{O\&M}$	= specific operating and maintenance costs, [$C_{O\&M}$] = USD/kW_{el}
C_{TS}	= specific cost of CO_2 transportation and storage, [$C_{O\&M}$] = USD/kW_{el}
C_{fuel}	= specific fuel costs (including CO_2 penalty), [C_{Fuel}] = USD/kWh_{el}
capacity	= full load hours, [operating life] = h/a

21.2.3.2 Power Plants without CO_2 Capture

Two important cost elements for calculating the LCOE of coal-fired power plants are capital costs and costs of operation and maintenance (O&M). The plant *capital costs* without CO_2 capture (C_{Cap}) referred to in this assessment represent an average value of several publicly available cost assessments of coal-fired power plants with and without CCS in China. This screening of existing cost assessments and data included the China Electric Power Yearbook 2011 as well as studies by the International Energy Agency (IEA) and the Nuclear Energy Agency (IEA and NEA 2010), Finkenrath (2011), Liu et al. (2009), Minhua and Wang (2011), NZEC (2009) and Zhao et al. (2008) because they all factor in China's country-specific conditions. Of these studies, the papers by Minhua and Wang as well as NZEC proved to be most useful. Changes in costs of large-scale investments in the power sector, for example due to cost changes for key materials such as steel, equipment or labour, were taken into account by factoring in the IHS CERA Power Capital Costs Index (PCCI) to available cost figures. For example, the PCCI shows that plant capital costs rose by 14 per cent from 2008 to 2011.

Capacities of the supercritical PC plants considered range from 559 MW_{el} to 1,320 MW_{el}. Capital costs of the reference plants taken into account range from 520 to 874 USD/kW_{el}, due to the effect of economies of scale and differing basic assumptions, such as plant designs with or without flue gas desulphurisation units (FGDS). Taking into account these cost parameters, the following calculations are based on the mean value of the given range of investment costs. On the one hand, the average size of coal-fired power units in China is expected to grow, involving cost reductions through economies of scale, whilst on the other hand, an increasing share of plants will be equipped with FGDS units, leading to higher capital costs.

In general, capital cost figures of available economic assessments of Chinese coal-fired power plants tend to be significantly lower than cost figures of equivalent plants in industrialised countries and other emerging countries, such as India and South Africa. This is mainly due to cheaper labour and equipment costs and steadily improving manufacturing capabilities. By comparison, the IEA estimates that most coal-fired power plants in OECD countries have overnight investment costs[2] ranging from 900 to 2,800 USD/kW_{el} (IEA and NEA 2010). Due to the limited scope of this study, current cost figures are used as the basis for long-term cost projections. However, it must be borne in mind that Chinese labour costs are expected to rise gradually in the decades ahead. As a consequence, plant capital costs are set to increase, diminishing the gap between investment costs of coal-fired power plants in China and in industrialised nations.

Operation and maintenance costs ($C_{O\&M}$) describe expenditures for any auxiliary and operating materials required as well as annual maintenance costs. O&M costs are given as a percentage rate of plant capital costs. In this cost assessment, O&M costs are assumed to be 4 per cent, based on Finkenrath (2011).

21.2.3.3 Power Plants with CO_2 Capture

CO_2 capture is by far the most cost-intensive step within the CCS chain. In the following, the increase in capital expenditures and O&M costs resulting from integrating post-combustion capture is added as a relative extra charge to plant capital costs. It is assumed to be equivalent to 75 per cent of plant capital costs. This percentage represents the average of additional capital costs required for PC plants with post-combustion capture calculated in studies conducted by Massachusetts Institute of Technology (MIT 2007), Global CCS Institute (2009) and Viebahn et al. (2010). The same studies indicate average increases in O&M expenditures of 83 per cent due to post-combustion CO_2 capture.

21.2.3.4 Annuity Approach

The total capital costs for the power plants considered are allocated to individual years on an annuity basis and related to a kilowatt hour. Both the expected real interest rate and the depreciation period are included in the annuity formula. The annuity factor (af) is calculated using Equation 21-2.

[2] Overnight capital costs as defined by IEA include owner's cost, EPC (engineering, procurement and construction) and contingency, but exclude interest during construction (IDC).

In this study, an interest rate of 10 per cent per annum and a 25-year depreciation period are calculated. The assumed interest rate is based on the cost report by NZEC (2009). It was confirmed as a realistic estimate in an expert interview with Siemens China (Siemens Ltd. China 2011). For European plant projects, interest rates are much lower and are estimated at about 6 per cent (Viebahn et al. 2010). The given depreciation period is significantly higher than, for example, that estimated by Zhao et al. (2008) who use a depreciation period of 15 years. As mentioned above, the chosen assumption is guided primarily by the projection of longer investment cycles in China's power sector, resulting from a growing share of modern, large generating capacities with high efficiency levels. The given depreciation period and interest rate lead to an annuity factor of approximately 11 per cent per annum.

21.2.3.5 Costs of CO_2 Transportation and Storage

Estimates of the costs of CO_2 transportation and storage from international sources and studies available on China yield very different results. International studies conducted by Massachusetts Institute of Technology (MIT 2007), Global CCS Institute (2009) and McCoy (2008) estimate the costs of CO_2 transportation via pipeline to average approximately USD 2 per tonne of CO_2 for a distance of 100 km. Transport costs depend on pipeline capacity, specific terrain conditions (for example, mountainous areas, populated areas, water crossings) and, in particular, transport distance.

Due to China's immense geographic dimension, the average distance for CO_2 transportation is estimated at 250 km. As a consequence, costs of CO_2 transportation would total approximately USD 5 per tonne of CO_2 based on the international studies quoted above.

Only very few figures are available on the costs of CO_2 transportation in China, taking into account country-specific cost parameters. The Executive Report of the COACH project (COACH group 2010) includes a rough cost assessment for CO_2 transportation by pipeline. Average CO_2 transport costs over a distance of 250 km are estimated at about USD 3.30 per tonne of CO_2 and are thus significantly lower than international figures. It can be assumed that this is partly the case due to the lower costs for labour, in particular, and equipment. Since the calculation conducted in the COACH project explicitly takes into account country-specific conditions in China, these Chinese cost figures are applied here as the main basis, despite prevailing uncertainties.

The costs of CO_2 storage are also based on figures by COACH group (2010). COACH calculated CO_2 storage costs for different potential storage sites in China, including one exemplary saline aquifer: Huimin sub-basin. This study uses this storage site as a basis for calculating the average costs of CO_2 storage in China because saline aquifers represent by far the largest share of the national CO_2 storage potential. However, it must be borne in mind that costs may differ when taking into account specific characteristics of each storage site. The storage costs as calculated within the COACH project encompass expenditures for a seismic appraisal of the storage site and its environment (USD 1.22/t CO_2) plus the drilling of wells for CO_2 injection (USD 2.15/t CO_2) and a monitoring programme (USD 1.21/t CO_2). Consequently, overall storage costs total USD 4.72 per tonne of CO_2.

21.2.3.6 Learning Rates

In order to project the costs of PC plants with and without CCS for the decades ahead, experience curves and learning rates are used to model mass market effects and improvements in technology. An experience curve describes how unit costs decline with cumulative production. The progress of cost reduction is expressed by the progress ratio (PR) and the corresponding learning rate (LR). For example, a 90 per cent progress ratio means that costs are reduced by 10 per cent each time cumulative production is doubled. The learning rate is therefore defined as 10 per cent. In this study, LRs are applied from 2010 for supercritical PC plants without CCS and from 2030 for supercritical plants with CCS.

Supercritical PC plants without CCS are deployed internationally and are technically mature, meaning that only minor improvements are expected to occur in the decades ahead. No experience curves specific to Chinese conditions are available yet. For this reason, the cost assessment presented uses experience curves based on international plant development and deployment. This is considered an adequate approach because supercritical PC plants are a well-established technology, also in China (Minchener 2010).

The LR and PR for PC plants with and without CO_2 capture are calculated based on a report of the IEAGHG programme (IEA GHG 2006). The study develops learning rates for PC plants with CO_2 capture. Technology learning is assumed to begin at a capacity of 1 GW_{el} (C_{min}) and is projected up to a cumulative capacity (C_{max}) of 729 GW_{el} for PC plants without CCS and 663 GW_{el} for PC plants with CCS. Both C_{max} figures are derived from the development of coal-fired power generating capacities foreseen in the most recent Blue Map Scenario of the IEA (IEA 2010). The scenario implies a 50 per cent reduction of CO_2 emissions by 2050, compared to 2005. By 2050, coal-fired power capacities are estimated to total 729 GW_{el}. This figure encompasses an overall installed capacity of coal-fired CCS plants of 663 GW_{el} – including both newly built and retrofitted PC plants with CCS. The capacity of remaining coal-fired plants without CCS in 2050 totals 66 GW_{el}. Assuming a plant lifetime of 40 years, all plants operating in 2050 were added during the scenario period. Since the power blocks of PC plants with and without CCS plants are virtually identical, PC plants without CCS benefit from learning effects gained from the deployment of PC-CCS units. Hence, C_{max} for PC plants allows for both the envisaged capacities of PC plants with and without CCS in 2050 (729 GW_{el}).

The resulting LR for a complete PC plant with CCS is 2.5 per cent (capital costs) and 5.8 per cent (O&M). Regarding individual plant components, the post-combustion CO_2 capture unit and the CO_2 compression plant indicate rather high LRs, whereas the conventional power block is a mature technology with a low learning potential. Hence, the overall LR of PC plants without CCS is significantly lower, totalling 1.7 per cent (capital costs) and 3.9 per cent (O&M).

Since they are commonplace in the oil and gas industry, pipelines for CO_2 transportation and storage technologies are mature technologies and, hence, offer only limited cost reductions (Junginger et al. 2010). For this reason, this analysis focuses on the learning effects of power plants and CO_2 capture units and excludes learning involved in the transportation and storage of CO_2.

21.2.3.7 Fuel Costs

Long-term scenarios for the price development of domestic Chinese hard coal are very difficult to find. Most available cost studies either assume constant coal prices or calculate sensitivity cases. This assessment follows the assumption by Minhua and Wang (2011) that the price of domestic hard coal in China increases at a growth rate (exponent) of 0.9 per cent. The starting value for domestic hard coal used in power plants in 2010 is assumed to be USD 86.34 per tonne, based on cost data provided by the IEA and the Nuclear Energy Agency (IEA and NEA 2010). Coal prices are presented in USD per kilowatt hour, factoring in the lower efficiency level of CCS plants. The type of coal considered as the reference is steam coal (bituminous coal) produced by the Shenhua Group, China's largest coal producer. The average net calorific value of the coal is 23.03 GJ/t (6,396.5 kWh_{th}/t) (Minhua and Wang 2011).

In the years and decades ahead, China is projected to import a growing share of its coal demand, particularly high-quality coal. Particularly for coastal coal-fired power plants, the shipping of imported coal will become an important option due to a shortage of railway capacity for transporting domestic coal from the coal-producing provinces in the west or north of China to the east coast. Thus, the price development of coal imports needs to be factored into this analysis. However, it must be borne in mind that the bulk of coal used to generate power in China is also projected to be produced in domestic mines in the future. The IEA (IEA and OECD 2007) estimates that by 2030, China's national steam coal production will rise to about 3,740 million tonnes, whilst steam coal imports are projected to increase to approximately 300 million tonnes in the same year. Consequently, steam coal imports would be equivalent to approximately 8 per cent of China's steam coal production volume. Based on this relation, this cost assessment calculates the following balances of domestic and imported bituminous coal by 2050:

- A: 100% domestic coal;
- B: 5% imported coal, 95% domestic coal;
- C: 10% imported coal, 90% domestic coal;
- D: 15% imported coal, 85% domestic coal.

Referring to section 20 of this report, it is assumed that prices of imported hard coal will grow significantly more rapidly than expected in recent World Energy Outlooks by the IEA. It is assumed that the international price of hard coal will follow the growth rate of the international price of oil based on evidence from previous decades. The average net calorific value of hard coal imports to China is estimated at 21.98 GJ/t (6,105.6 kWh_{th}/t). The latter figure corresponds to the balanced net calorific value of hard coal imports from Indonesia and Vietnam, which together cover nearly 80 per cent of China's hard coal imports (Sagawa and Koizumi 2008; U.S.-EIA 2011b). Indonesian coal imports represent 36 per cent of this figure and those from Vietnam about 64 per cent.

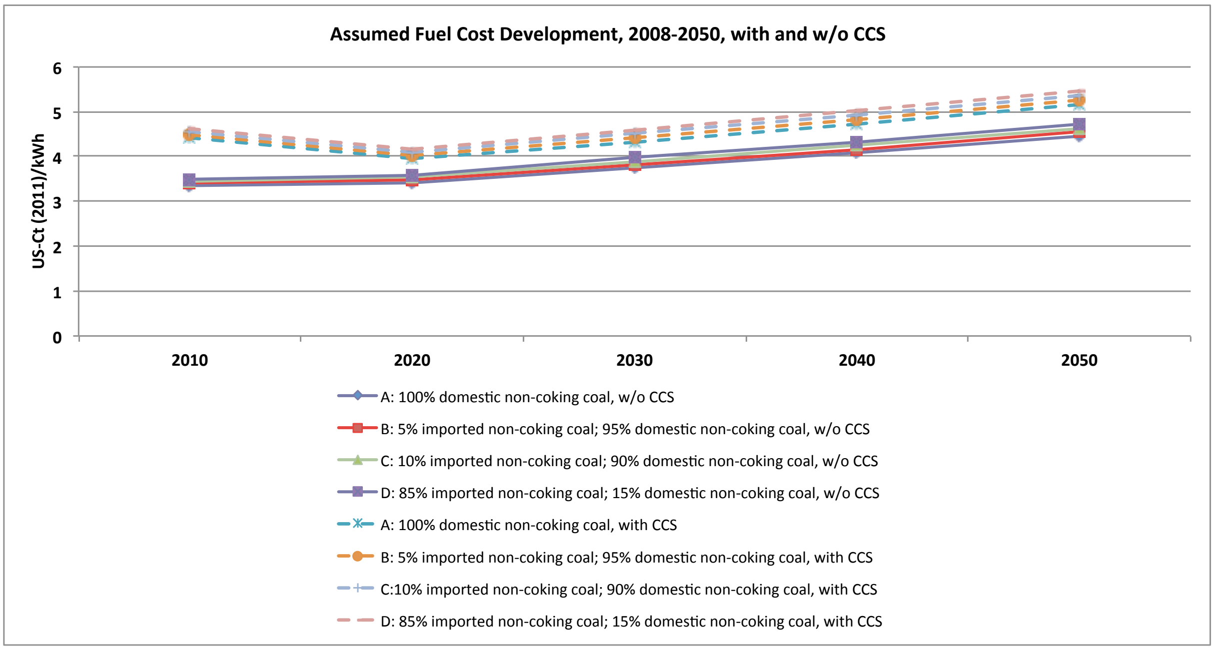


Fig. 21-1 Assumed fuel cost development of Chinese non-coking coal and mixes of domestic and imported non-coking coal for plants with and without CCS

Source: Authors' illustration

Fig. 21-1 illustrates the assumed course of specific fuel costs for the aforementioned coal mixes from 2010 to 2050 – both for plants with and without CCS. The dashed lines illustrate fuel costs of CCS plants. The illustration shows that the cost development of all sensitivity cases for either CCS plants or non-CCS plants is very similar. For this reason, case C (10 per cent imported coal; 90 per cent domestic coal) is used as a reference case in the following.

21.2.3.8 CO_2 Discharge of Coal-Fired Power Plants with and without CCS

The average emission factor of Chinese bituminous coal used in the power sector is estimated at 351 g CO_2/kWh_{th} (Cai et al. 2009; Gao 2007). The average CO_2 emission factor of imported hard coal is estimated at 341 gCO_2/kWh_{th} (IEA and OECD 2009a).

Tab. 21-1 exemplifies the specific discharge of CO_2 from supercritical PC power plants in China with and without CCS for coal mix C (10 per cent imported coal; 90 per cent domestic coal).

Tab. 21-1 Specific CO_2 emissions of supercritical PC plants in China with and without CCS (based on 10 per cent hard coal imports and 90 per cent domestic hard coal)

Plant type	Time frame	Plant efficiency	Specific CO_2 emissions
		%	g/kWh_{el}
Supercritical PC w/o CCS	Up to 2020	41	853
	From 2020	44	795
Supercritical PC with CCS	From 2030	31	113

Source: Authors' compilation

21.2.3.9 CO_2 Penalty

The economic viability of CCS is strongly affected by the existence or absence of a CO_2 price. In order to indicate the impact of a CO_2 price on the cost of electricity and CO_2 mitigation of supercritical PC plants with and without CCS, a CO_2 price was factored into coal development pathway E2. According to Greenpeace and EREC (2010), emission trading in Kyoto non-annex B countries is assumed to begin by 2020. The Chinese government is currently discussing the introduction of a nation-wide carbon tax. However, when such a tax will be implemented and how the regulations would be designed are yet to be clarified (The Climate Group 2011a). Thus, the incorporation of a CO_2 price into the cost assessment is highly hypothetical. The assumed CO_2 price development up to 2050 was therefore derived from the medium price path for CO_2 certificates assumed in Viebahn et al. (2010), BMU (2009) and Horn and Dieckmann (2007). CO_2 prices are added as a penalty to the costs of electricity production, taking into account plant efficiency and the CO_2 emission factor of the feedstock mix used. Tab. 21-2 summarises the assumed CO_2 prices and cost penalty.

Tab. 21-2 CO_2 prices and CO_2 cost penalty assumed for China, 2020–2050

	Unit	2020	2030	2040	2050
CO_2 price	USD_{2011}/t CO_2	42	49	56	63
*CO_2 penalty**					
w/o CCS	USD_{2011}/kWh_{el}	3.32	3.88	4.43	4.99
with CCS	USD_{2011}/kWh_{el}	0.38	0.45	0.51	0.58

* Fuel balance: 10% imported coal; 90% domestic coal

Source: Authors' compilation

21.3 Impact of CCS on the Cost of Electricity Generated by Coal-Fired Power Plants in China

21.3.1 Levelised Cost of Electricity Generated by Supercritical Coal-Fired Power Plants with and without CCS up to 2050 (without CO_2 Penalty)

In the following, the LCOE of supercritical PC power plants in China with and without CCS up to 2050 will be presented, based on the parameters and assumptions outlined in the previous sections. The possibility of a CO_2 penalty is not considered in this section, but in section 21.3.2. In some graphs in this and the following sections, coal development pathway *E2: middle* is used as a reference case, whereas pathways *E1: high* and *E3: low* are not explicitly considered to facilitate the discussion of the results of the cost assessment.

Fig. 21-2 illustrates the LCOE of the plant configuration considered in coal development pathways *E1: high*, *E2: middle* and *E3: low* with and without CCS based on a coal mix of 10 per cent imported coal and 90 per cent domestic coal. Without CCS, the figures indicate a moderate growth of LCOE from US-ct 4.37/kWh in 2010 up to US-ct 5.73/kWh in 2050 across the different pathways. The growing path of LCOE is mainly due to the minor cost reduction potential of supercritical PC power plant technologies through learning effects, since these are mature and widely deployed. Hence, the remaining cost reductions are more than outweighed by increasing feedstock costs. The cost development of supercritical PC plants without CCS is very similar in the scenarios considered due to a limited amount of new capacities without CCS that are assumed will be commissioned in the analysed timeframe.

No new coal-fired power plants without CCS are expected to start operation after 2030 in any of the coal development pathways.

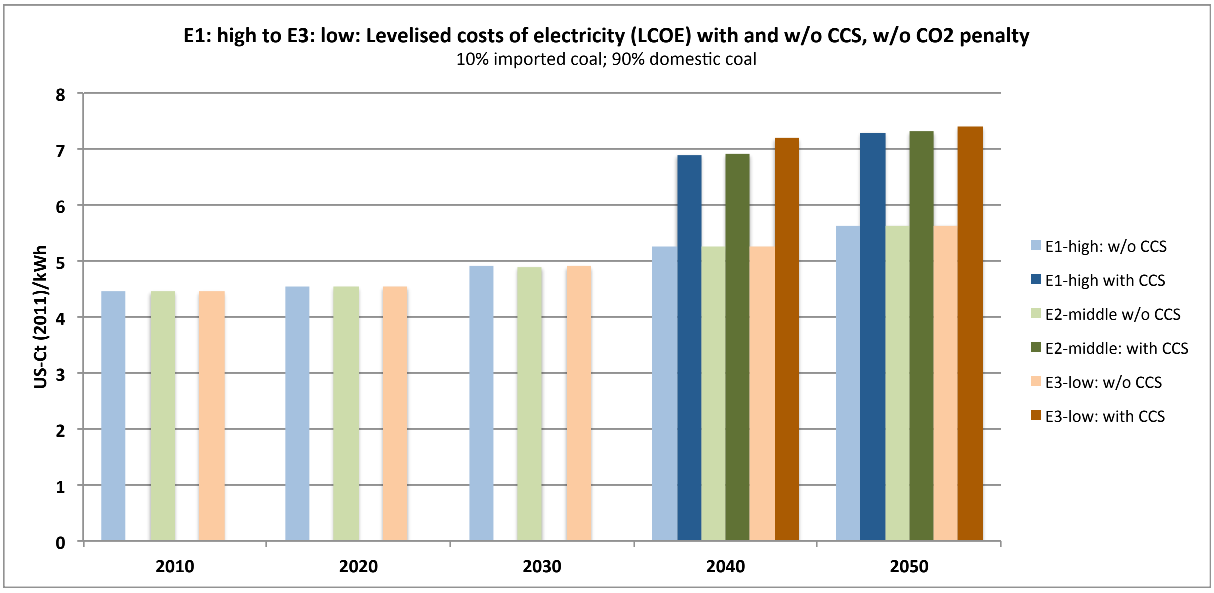


Fig. 21-2 Levelised cost of electricity in China with and without CCS in coal development pathways *E1: high* to *E3: low* up to 2050 without CO_2 penalty

Source: Authors' illustration

CCS plants enter the scene after 2030, when the technology is assumed to be commercially available. Despite the higher learning potential of CCS plants compared to supercritical PC plants without CCS, which leads to a decrease in capital and O&M costs, pathways *E1: high* and *E2: middle* indicate a growing LCOE in the period from 2040 (US-ct 6.72/kWh_{el}) to 2050 (US-ct 7.31/kWh_{el}) as cost reductions are overcompensated by increasing fuel costs. Pathway *E3: low* reveals a cost increase from US-ct 7.01/kWh by 2040 to US-ct 7.50/kWh by 2050. The LCOE of CCS plants in this coal development pathway is slightly higher than in the other two pathways as it projects a significantly lower overall capacity of CCS plants and, thus, lower cost reductions.

By 2050, the LCOE of supercritical power plants with CCS will exceed those of equivalent plants without CCS by 29 to 32 per cent in the analysed development pathways. The cost increase is caused by high additional capital costs due to cost-intensive CO_2 capture equipment, leading to an average increase in plant capital costs of 75 per cent. However, increasing fuel costs due to the efficiency penalty of CCS are the major cost driver.

Fig. 21-3 illustrates the increase in the LCOE resulting from CCS specified by cost category for development pathway E2. In 2050, CCS leads to an additional LCOE of US-ct 1.69/kWh, which is equivalent to about 30 per cent of the total LCOE of supercritical power plants without CCS.

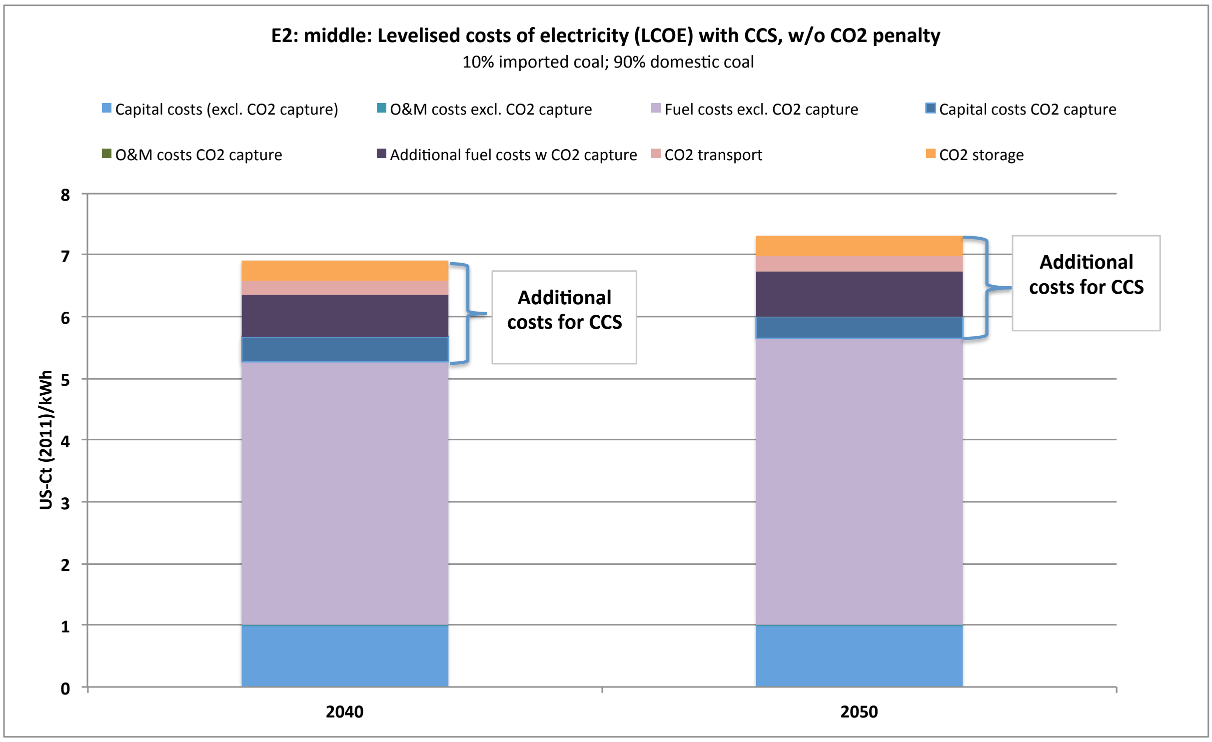


Fig. 21-3 Additions to the levelised cost of electricity in China resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 without a CO_2 penalty

Source: Authors' illustration

Additional fuel costs represent the largest single share (44 per cent) of the cost penalty resulting from CCS, followed by capital expenditures for CO_2 capture equipment (22 per cent). The high economic relevance of fuel costs compared to capital costs is due to the significantly lower capital intensity of large-scale plants in China than in industrialised countries based on cheaper labour and equipment costs (see above). Furthermore, the lower cost impact of capital costs in China is due to national or regional conditions for power plant operation, for example available coal qualities, water resources, and so on. For instance, in India, capital costs represent a significantly larger proportion of the additional costs of CCS (35 per cent) because capital costs of Indian power plants tend to be higher compared to international standards mainly due to the specific requirements of India's ambient conditions and coal qualities (BHEL 2010). The high impact of fuel costs on the economic performance of China's CCS plants implies that Chinese CCS projects would benefit significantly from efficiency improvements of CO_2 capture processes. CO_2 transportation and storage account for 14 per cent and 20 per cent, respectively, of the cost penalty. O&M costs have only a minor impact on the LCOE.

21.3.2 Levelised Cost of Electricity Generated by Supercritical Power Plants with and without CCS up to 2050 (with CO_2 Penalty)

Being an energy- and cost-intensive CO_2 mitigation technology, the introduction of a carbon pricing system, such as an emissions trading scheme or a CO_2 tax, would be likely to significantly affect the economic viability of coal-fired power plants with CCS in China. The Chinese government is currently discussing the possibility of imposing a carbon tax. Recently, the Public Finance Research Institute, which is linked to the Ministry of Finance, published a report that assesses the potential economic impact of a carbon tax (The Climate Group

2011a). This development suggests that the vision of a carbon-pricing scheme in China is becoming more likely. In the following, the impact of a CO_2 penalty on the LCOE of super-critical plants without CCS will be compared with its impact on CCS plants. The CO_2 penalties assumed in this study are described in section 21.2.3.9 and subsequently integrated into coal development pathway E2.

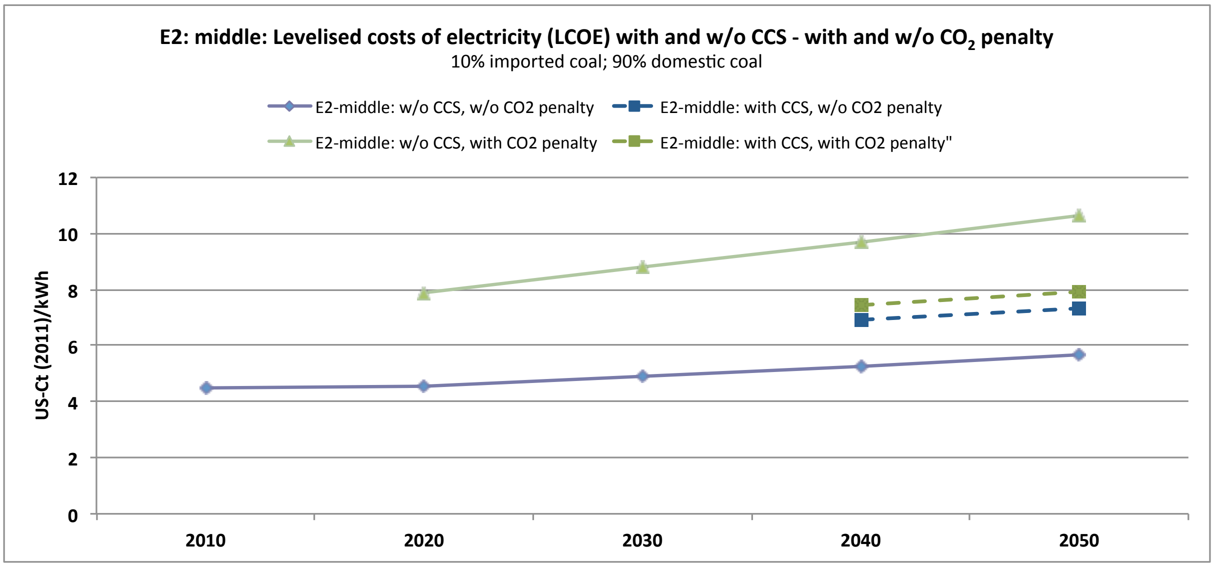


Fig. 21-4 Levelised cost of electricity in China with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

In the absence of a CO_2 penalty, the LCOE of supercritical PC plants with CCS clearly exceed the LCOE of equivalent coal-fired power plants without CCS (see Fig. 21-2). In Fig. 21-4, this comparison is illustrated by the blue lines. However, it also becomes apparent that a carbon price path as assumed in this scenario, starting at USD 42 per tonne of CO_2 in 2020 and reaching USD 63 per tonne of CO_2 in 2050, would make CCS plants clearly more cost competitive (both in 2040 and 2050) than the same type of coal-fired power plants without CCS (green lines). In 2050, the LCOE of a supercritical PC plant without CCS totals US-ct 10.63/kWh$_{el}$, whereas the LCOE of an equivalent CCS plant is US-ct 7.89/kWh$_{el}$. Consequently, the LCOE of non-CCS plants exceeds those of CCS plants by US-ct 2.74/kWh$_{el}$, or approximately 35 per cent.

Fig. 21-5 shows the LCOE of CCS plants in scenario E2 (middle) specified by cost category including a CO_2 penalty. In 2050, the CO_2 penalty amounts to US-ct 0.58/kWh$_{el}$, or about 7 per cent of the total LCOE. By comparison, in the same year the CO_2 penalty of a supercritical PC plant without CCS totals US-ct 4.99/kWh$_{el}$, which is equivalent to 47 per cent of the overall LCOE. This comparison emphasises the conclusion drawn above that the economic performance of CCS plants is clearly affected less negatively by a carbon-pricing scheme than non-CCS power stations. In the latter case, the CO_2 penalty represents by far the largest single cost parameter of the LCOE (see Fig. 21-6). Consequently, a CO_2 pricing scheme would provide a strong incentive for installing CCS equipment in Chinese coal-fired power stations.

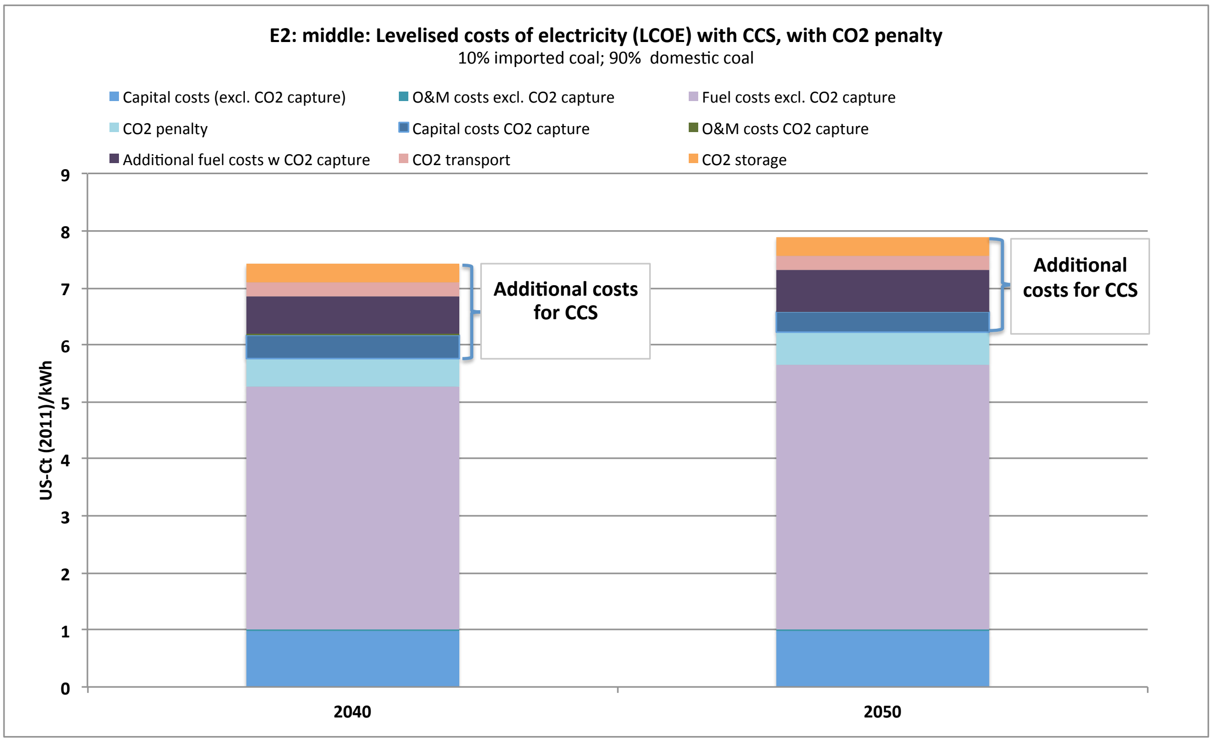


Fig. 21-5 Additions to the levelised cost of electricity in China resulting from CCS by cost category in coal development pathway *E2: middle* up to 2050 including a CO_2 penalty

Source: Authors' illustration

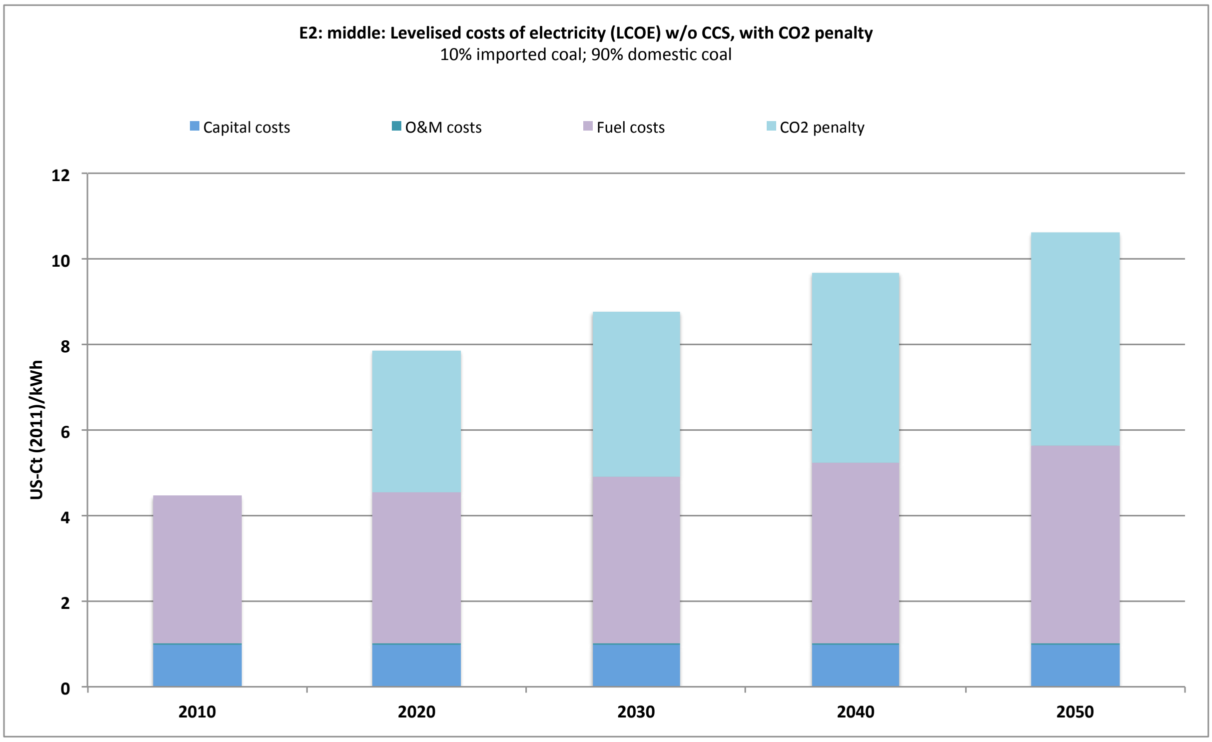


Fig. 21-6 Levelised cost of electricity generated by supercritical PC plants without CCS in China by cost category in coal development pathway *E2: middle* with CO_2 penalty

Source: Authors' illustration

21.3.3 Comparison of CO_2 Mitigation Costs of Supercritical Coal-Fired Power Plants in China up to 2050 with and without CO_2 Penalty

The economic viability of carbon mitigation technologies is often measured in costs per tonne of CO_2 avoided. Fig. 21-7 shows the carbon mitigation costs per tonne of CO_2 of supercritical PC plants with CCS in China in 2040 and 2050 for all three coal development pathways in the absence of a CO_2 penalty. For the considered horizon, CO_2 mitigation costs range from USD 23 to 28 per tonne of CO_2. Pathways *E1* and *E2* indicate lower CO_2 mitigation costs than *E3* as higher quantities of CCS plant capacities are added compared to pathway *E3*, leading to more significant technology learning effects.

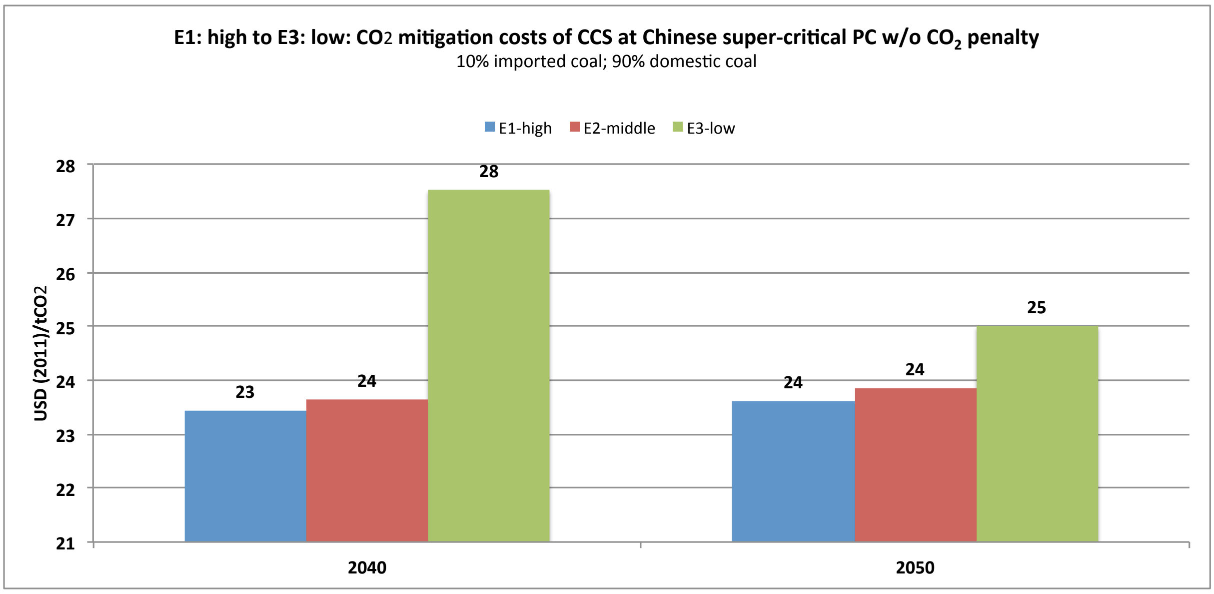


Fig. 21-7 CO_2 mitigation costs of supercritical PC plants in China with CCS without a CO_2 penalty in scenarios *E1: high* to *E3: low*, 2040–2050

Source: Authors' illustration

In comparison to cost assessment studies for CCS plants in industrialised countries or India, Asia's other major emerging economy, the given level of CO_2 mitigation costs is rather moderate due to significantly lower plant capital costs in China. For example, CO_2 mitigation costs for CCS plants in India, as calculated in another country report of this project, amount to between USD 50 and 56 per tonne of CO_2 by 2050. A CCS study edited by the German Federal Ministry for the Environment (Viebahn et al. 2010) estimates the CO_2 mitigation costs of German hard coal-fired PC plants with CCS, assuming a very conservative price development of CO_2 certificates and significantly growing energy costs, at USD 49 per tonne of CO_2 (EUR 36/t of CO_2). By comparison, throughout 2011, the price of EU emissions allowances (EUA) was clearly below the level of USD 27 per tonne of CO_2 or EUR 20 per tonne of CO_2, respectively) (CO2 Handel 2011). Consequently, a stronger financial incentive would be required to induce the deployment of CCS.

If a CO_2 price path as summarised in Tab. 21-2 is integrated into the calculation of CO_2 mitigation costs, the picture changes significantly. Using the example of scenario E2, Fig. 21-8 compares the CO_2 mitigation costs of China's CCS plants with and without a CO_2 penalty. The graph indicates that, in the presence of a CO_2 pricing scheme, CCS plants would operate at highly negative CO_2 mitigation costs in both 2040 and 2050. This outcome corresponds to the message contained in Fig. 21-4 that CCS plants would be more economically viable than the same plant type without CCS within the assumed CO_2 pricing regime.

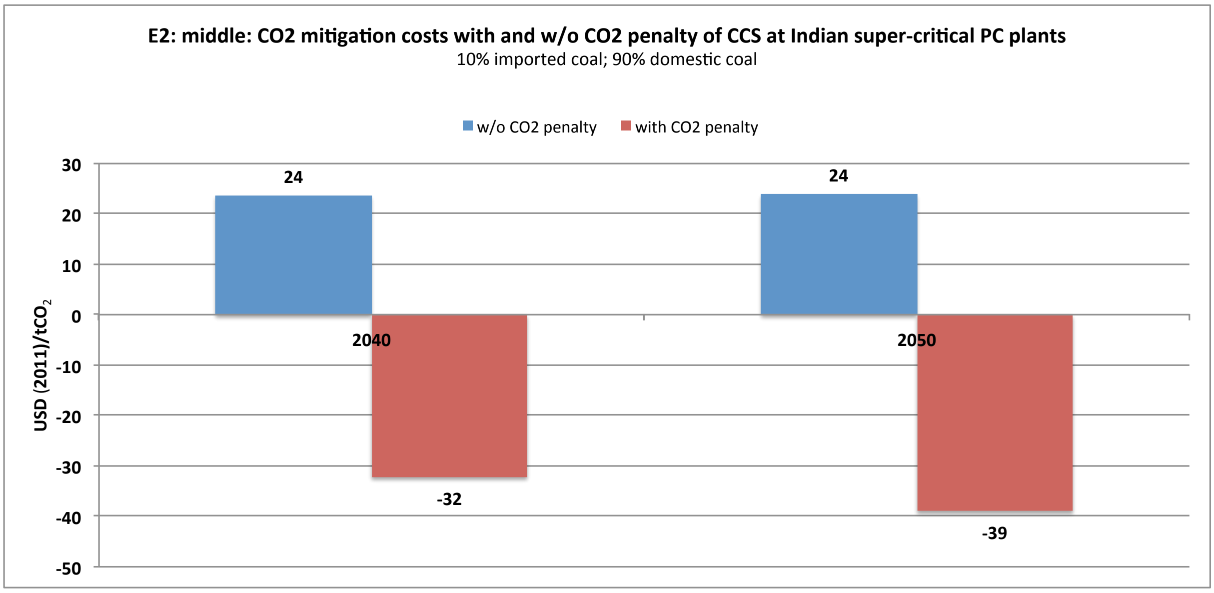


Fig. 21-8 CO_2 mitigation costs of supercritical PC plants in China with CCS in scenario *E2: middle* including a CO_2 penalty, 2040–2050

Source: Authors' illustration

21.4 Conclusions

These cost projections are based on three different pathways for the development of coal-fired power generating capacities in China with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition for policy frameworks involving climate and sustainable energy. Whereas pathway *E1: high* is based on reference conditions and climate policies, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways are used as input for calculating learning rates and cost reductions of coal-fired power plants with and without CCS.

The cost assessment indicates that the learning effects and, thus, cost reductions of super-critical PC plants both with and without CCS are more or less minor in all three outlined coal development pathways because supercritical PC plants represent a mature, widely deployed technology. As a consequence, reduced capital and O&M costs are overcompensated by increasing fuel costs, leading to an increasing levelised cost of electricity in the considered timeframe. For example, the LCOE of non-CCS plants is projected to increase from US-ct 4.37/kWh in 2010 to US-ct 5.73/kWh in 2050 across the different development pathways. Although CCS plants have a higher learning rate than conventional PC plants, they have a clearly higher LCOE, ranging from US-ct 6.72/kWh by 2040 to US-ct 7.50/kWh by 2050, mainly due to additional fuel and capital expenditures. In the same year, CO_2 mitigation costs incurred by China's CCS plants range from USD 24 to 25 per tonne of CO_2.

The outlined results suggest that there is a significant economic barrier to the economic viability of CCS, making policy incentives a crucial precondition for CCS commercialisation. However, due to lower plant capital costs, the cost penalty of CCS in China is significantly lower than in industrialised countries or other emerging economies. For this reason, introducing a carbon price could significantly improve the competitiveness of CCS plants over non-CCS plants and outweigh the cost penalty of CCS plants. In the presence of a CO_2 price as assumed in the presented analysis, CCS plants would be more competitive than plants without CCS in both 2040 and 2050. However, the stimulating economic framework conditions in China may be alleviated in the decades ahead as Chinese labour and equipment costs are expected to increase continuously. Furthermore, it needs to be taken into account that CCS plants will face strong competition from other low carbon technologies, especially renewable energy technologies, which have much higher learning rates than supercritical PC plants with CCS. Thus, CCS plants would need to be compared with other low carbon technology options to draw profound conclusions on the economic viability of CCS in a low carbon policy environment.

22 Life Cycle Assessment of Carbon Capture and Storage and Environmental Implications of Coal Mining

22.1 Introduction

No life cycle assessments (LCA) of CCS-based power plants have been undertaken yet for China. To remedy this, an LCA according to the international standard ISO 14 040/44 is performed. An LCA illustrates a "cradle-to-grave" approach in which all energy and material flows that occur during the manufacture, use and disposal of products are modelled (see section 5.3 of Part I). Section 22.2.1 explains the methodological approach whilst section 22.2.2 provides the basic assumptions and the set of parameters assumed for the LCA. The results are presented in section 22.2.3 and conclusions drawn in section 22.2.4.

Several environmental and social impacts cannot be evaluated in an LCA. For this reason, some implications especially concerning coal mining are highlighted in section 22.3. The commercialisation of CCS would reinforce this impact because CCS-based power plants require 20 to 30 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

22.2 Life Cycle Assessment of CCS

22.2.1 Methodological Approach

Life cycle assessments are usually performed for existing products or services to enable the best technology with regard to a certain environmental impact category to be selected. To date, however, no commercial CCS-based power plants exist. Instead, a *prospective LCA* has to be performed that considers a future situation by updating crucial parameters, such as the power plant's efficiency, to a future situation. A twofold approach is therefore chosen:

- Firstly, a future coal-fired power plant is balanced by updating an existing LCA to future conditions;
- Secondly, the future coal-fired power plant is extended by CO_2 capture facilities, and the transportation and storage of CO_2 is added.

The system boundary of the LCA comprises the complete life cycle, which means mining, power generation and upstream and downstream activities such as the supply of raw material and consumables and the handling of waste. With CCS, the life cycle additionally includes CO_2 capture, transportation and storage (see Fig. 22-1). All material and energy flows are scaled to the output of 1 kWh electricity.

It should be noted that no individual power plant at a selected site is considered because, if at all available, the data only describes the average situation of coal mining or transportation. Hence, the given LCA refers to an average situation in the considered country, as is usually the case in LCA studies.

The following assumptions and results refer to Deibl (2011), who developed the basic model and performed the LCA.

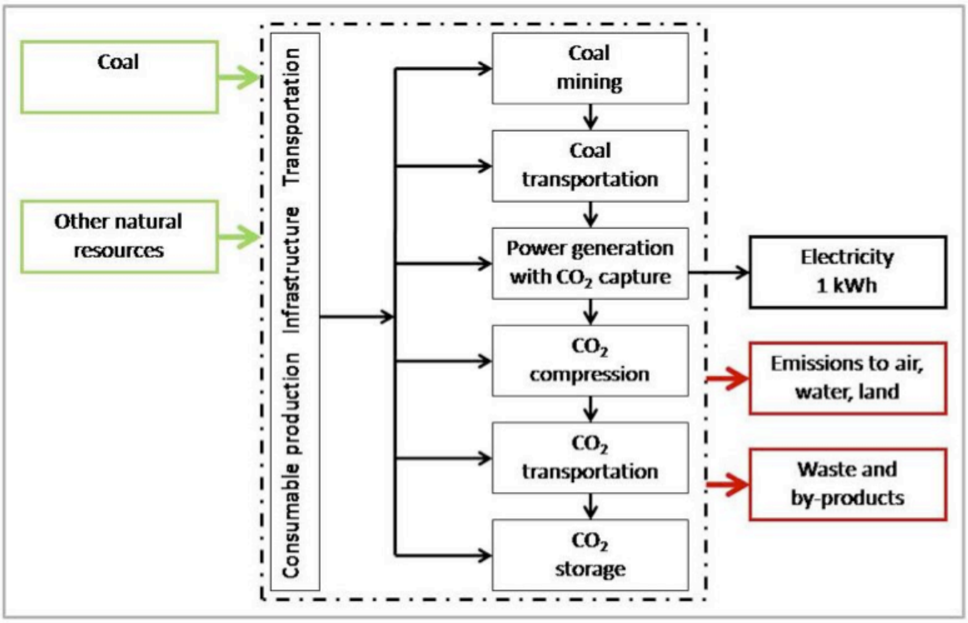


Fig. 22-1 System boundary of the life cycle assessment of coal-fired power plants in China

Source: Deibl (2011) based on Korre et al. (2010)

22.2.2 Basic Assumptions and Parameters

Basic Assumptions

- **Reference Year** The LCA refers to 2030, the year from which CCS power plants are assumed to become commercially available in China (see section 18).
- **Type of power plant** The LCA is performed for supercritical pulverised coal (PC) power plants and for integrated gasification combined cycle (IGCC) power plants because these two types are the power plants considered in the coal development pathways for China.
- **CO_2 capture** It is assumed that CO_2 is captured post-combustion using the solvent monoethanolamine (MEA) and pre-combustion using the solvent methyl diethanolamine (MDEA). Although the state-of-the-art solvent for pre-combustion is Selexol (physical absorption) (Walspurger et al. 2011), it is not chosen because no LCA module is available for it in the database used. The manufacture of post- and pre-combustion components is not considered in the LCA because no data is available. However, as Koornneef et al. 2008 showed, the infrastructure contributes only 0.3 per cent to the greenhouse gas emissions of a CCS life cycle. According to the assumptions on decreased energy penalties in 2030 (see Tab. 18-7), the energy required for capture is reduced by 60 per cent in the case of post-combustion and by 50 per cent in the case of pre-combustion capture, compared to the figures implemented in the ecoinvent dataset.
- **Storage medium** Deep saline aquifers are assumed to be the storage medium because they offer the greatest potential in China.
- **Leakage** It is assumed that no leakage of CO_2 takes place from the underground storage site. A leakage rate of 0.026 per cent per 1,000 km is applied for transportation, which is similar to the leakage rate of natural gas pipelines (Wildbolz 2007).

- **LCA modules** Most of the basic LCA datasets were taken from the international LCA database ecoinvent 2.2 and modified, if necessary (see Tab. 22-1). The LCA dataset for coal-fired IGCC was taken from Fischedick et al. (2008), where an LCA given by Briem et al. (2004) was implemented and updated with efficiencies assumed for 2030.

Tab. 22-1 Basic LCA modules for China taken from the database ecoinvent 2.2

Parts of life cycle	Module name in ecoinvent	Remark	Modifications
Coal-fired power plants without CCS			
Hard coal supply	Hard coal, at mine [CN]	100% indigenous coal assumed in China; includes GHG and SO_2 emissions from uncontrolled coal fires (countrywide)	Amount of GHG emissions assumed for coal fires removed
	Hard coal supply mix [CN]	Average transport distance specified for China	
Upstream process of power plant; electricity production	Hard coal, combusted in power plant [CN]	Modelling the combustion process of a power plant in China	Modification of SO_2, NO_x and particulate emissions; modification of calorific value
	SO_x retained, in hard coal flue gas desulphurisation [RER]		
	NO_x retained, in SCR [GLO]		
Power plant	Electricity, hard coal, at power plant [CN]	Modelling efficiency	Update of efficiency for 2030
Components for CCS			
MEA scrubber	Monoethanolamine, at plant [RER]	Production of MEA	
	Sodium hydroxide, 50% in H_2O, production mix, at plant [RER]	Production of NaOH	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
MDEA scrubber	Monoethanolamine, at plant [RER]	Production of MDEA	
	Disposal of raw sewage sludge to municipal incineration [CH]	Incineration of residues	
CO_2 transportation and storage			
CO_2 transportation	Pipeline, nature gas, long distance, low capacity, onshore [GLO, Infra]	Distance: 250 km; no recompression station	
CO_2 storage		Only energy required for storage is balanced (see parameter definition)	
CN = China; GLO = Global; CH = Switzerland; RER = Europe			

Source: Authors' composition based on Deibl (2011)

Parameters

Tab. 22-2 shows the parameters used for the LCA in China. These are adjusted by the parameters used in other sections of this study (for example, the power plants' efficiency).

Tab. 22-2 Parameters used in the LCA of coal-fired power plants in China

Parameter		**PC power plant**	**IGCC power plant**	**Source**
Coal-fired power plants without CCS				
Installed capacity	MW_{el}	300	451	Deibl 2011
Net efficiency	%	43	48	This study
Full load hours	h/a	7,500		Deibl 2011
Capacity factor	%	85		
Plant lifetime	a	25		Deibl 2011
Type of cooling		Wet		Deibl 2011
Calorific value of coal	MJ_{th}/kg_{coal}	23.03		This study
Methane emissions from coal mining	kg CH_4/kg_{coal}	0.0169		ecoinvent
CO_2 emissions from coal	kg/MJ_{th}	0.0974		This study
CO_2 capture				
Type of capture process		Post-combustion	Pre-combustion	
Concentration of solvent	kg/t of CO_2	1.958	0.011	Deibl 2011
Energy required for capture	kWh_{el}/t of CO_2	178	119	Deibl 2011
Energy required for compression	kWh_{el}/t of CO_2	92.84		Deibl 2011
CO_2 capture rate	%	90		This study
CO_2 transportation and storage				
CO_2 transport distance	km	250		This study
Energy required for recompressor	kWh/tkm	0.011		Wildbolz 2007
Energy required for CO_2 injection into 800 metre deep saline aquifer	kWh/kg CO_2	0.00668		Wildbolz 2007

Source: Authors' composition based on Deibl (2011)

Emissions from Mining

Two main sources of greenhouse gas (GHG) emissions must usually be considered in particular when regarding coal mining: carbon dioxide and other GHG emissions from underground coal fires, and coalbed methane emissions.

- In China, large uncontrolled *coal fires* emit substantial amounts of carbon dioxide and other GHGs (see section 22.3.3). Whilst in India one large coal fire is known – at Jhairia coalfield – six extensive coal fire areas were mapped by Prakash (2007) in China. These fires occur within a region stretching over 5,000 km from east to west and 750 km from north to south. Apart from toxic gases such as carbon monoxide and nitrogen oxide, GHGs including carbon dioxide, methane and nitrous oxides are emitted (Sino-German Coal Fire Research 2012). In the ecoinvent dataset "hard coal, at mine [CN]", these GHG emissions are factored in with an emission coefficient of 0.33 kg $CO_{2\text{-eq}}$ per kg coal produced. The figure is related to the coal production situation in 1999, in which it is assumed that 200 million tonnes are consumed annually by coal fires in China (Dones et al. 2003, 2004, 2007). Applying this factor to a power plant's coal consumption of 300 to 400 g/kWh electricity produced (depending on the calorific value and the power plant's efficiency), the coal fires cause additional GHG emissions of 100 to 130 g $CO_{2\text{-eq}}$/kWh.

Furthermore, sulphur dioxide emissions caused by coal fires, assuming an average 1 per cent sulphur content, are included in the ecoinvent dataset.

However, coal fires are not only ignited naturally, but usually through human influence (van Dijk et al. 2009). Another major cause is illegal mining (Dozolme 2012; Zhong and Fu 2008), making it difficult to explore which coal fire-related emissions are caused by power production and which are not. However, this proportion must be known to be able to consider these emissions within an LCA of power plants. As (van Dijk et al. 2009) state, coal fire-related emissions have not yet been regarded within the Kyoto protocol anywhere in the world, and no reliable basis exists for determining the "CO_2 equivalent a certain coal fire releases to the atmosphere over a certain amount of time." In the analysis given in this report, therefore, emissions from coal fires are disregarded. This means that the emissions coefficient originally included in the ecoinvent dataset is excluded for the LCA conducted in this report.

- Another source of GHG emissions in China is *coalbed methane emissions*. Worldwide, coal mining contributes 8 per cent to global anthropogenic methane emissions, mainly caused by China, the United States and India. The largest increases in these emissions by 2020 are expected to be in China and India (Greenpeace International 2009).

  In the ecoinvent dataset "hard coal, at mine [CN]," coalbed methane emissions are factored in with an emission coefficient of 0.0169 kg CH_4 per kg coal produced. Weighted with a global-warming potential (GWP) of 25 kg $CO_{2\text{-eq}}$ per kg CH_4, this figure results in a GHG emission coefficient of 0.42 kg $CO_{2\text{-eq}}$ per kg coal. The figure, adopted from Rui (1994), represents the average coalbed methane emissions from underground mining in China in 1990 (Dones et al. 2003, 2004, 2007). Applying this factor to a power plant's coal consumption of 300 to 400 g/kWh electricity produced (depending on the calorific value and the power plant's efficiency), coalbed methane emissions cause additional GHG emissions of 127 to 170 g $CO_{2\text{-eq}}$/kWh.

22.2.3 Results of the Life Cycle Assessment

After determining the material and energy flows occurring in the whole system, all flows that enter and leave the system are summarised in a life cycle inventory (LCI). The LCI is the basis of the life cycle impact assessment (LCIA) in which the flows are weighted and aggregated to several environmental impact categories. This study applies the internationally acknowledged LCIA method *CML 2001* (Guinée et al. 2002), developed by the Centrum voor Milieukunde in Leiden/Netherlands. Categories – subdivided into GHG emissions and other environmental impacts – are presented below the results of the particular impact.

22.2.3.1 Global-Warming Potential (Greenhouse Gas Emissions)

The impact category global-warming potential (GWP) comprises the impact of all GHGs emitted from the considered system, weighted and aggregated to the unit CO_2-equivalents ($CO_{2\text{-eq}}$). In the case of energy technologies, the most important GHGs are CO_2, methane (CH_4) and nitrous oxide (N_2O), which are weighted with a GWP of 1, 25 and 298 kg $CO_{2\text{-eq}}$ per kg substance, respectively (IPCC 2007). Since the reduction of CO_2 is usually discussed in the CCS debate, both the total GWP and the CO_2 emissions as part of the GWP are shown in this report (Fig. 22-2).

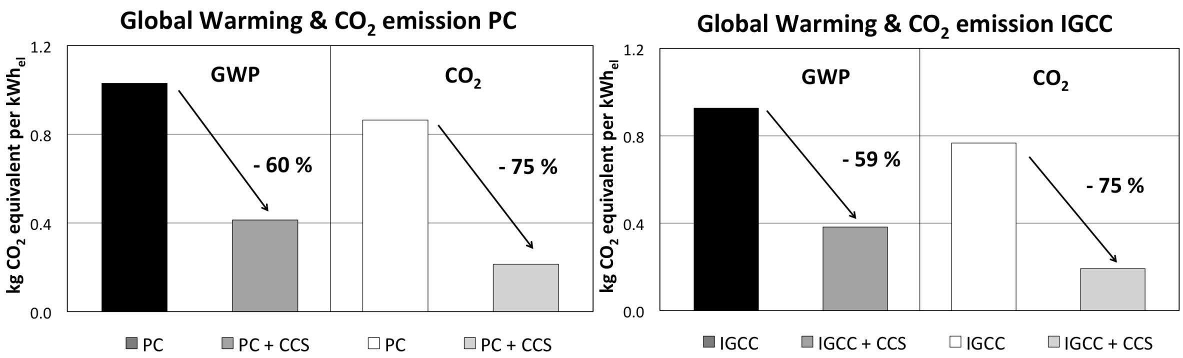


Fig. 22-2 Global-warming potential and CO_2 emissions for PC and IGCC with and without CCS in China from a life cycle perspective

Source: Authors' composition based on Deibl (2011)

CO_2 Emissions

Considering the whole system, CO_2 emissions from a CCS-based power plant are reduced by 75 per cent for both PC power plants and IGCCs (second and fourth chart) compared to a power plant without CCS.

The specific emissions without CCS amount to 864 g CO_2/kWh (PC) and 766 g CO_2/kWh (IGCC). These are reduced to 214 g CO_2/kWh (PC) and 192 g CO_2/kWh (IGCC).

Total Greenhouse Gas Emissions

Considering the total GHG emissions in the whole system, the reduction rate is 60 per cent for PC power plants (first chart) and 59 per cent for IGCCs (third chart) compared to a power plant without CCS.

The specific GHG emissions without CCS amount to 1,030 g $CO_{2\text{-eq}}$/kWh (PC) and 930 g $CO_{2\text{-eq}}$/kWh (IGCC). These are reduced to 410 g $CO_{2\text{-eq}}$/kWh (PC) and 380 g $CO_{2\text{-eq}}$/kWh (IGCC).

The overall reduction rates of both CO_2 and GHG emissions are much lower than expected, when considering a CO_2 separation rate of 90 per cent at the power plant's stack. The reasons behind this are: the life cycle perspective and China's large coalbed methane emissions and coal fires. First of all, it is important to consider not only the CO_2 emissions potentially avoided at the power plant's stack. A CO_2 capture rate of 90 per cent, as assumed in most studies does not include:

- The excess consumption of fuels that causes more CO_2 emissions meaning that separated CO_2 emissions are higher than avoided CO_2 emissions;
- The CO_2 emissions released into the upstream and downstream parts of the system;
- Other GHG emissions which are released into upstream and downstream processes, the most relevant one of which is methane emitted during coal mining.

Regarding the life cycle perspective, an overall reduction of GHG emissions between 67 and 75 per cent can be expected when applying post-combustion and pre-combustion to hard coal-fired power plants in 2020/25 (results of a meta-analysis conducted by Viebahn (2011) in which he compared five LCA studies performed for European conditions, supplemented by a more recent study by Singh et al. (2011)). However, in the case of China upstream emissions play a much larger role than in other countries. As mentioned above, large coalbed methane emissions occur during mining in China. This means that each kilogramme of coal is burdened with a certain amount of underground emissions which, at the end of the life cycle, increase the emissions per kilowatt hour electricity. Due to the excess consumption of coal in the event of CCS, coalbed methane emissions also increase. In contrast to direct emissions at the power plant, these emissions cannot be captured, so they ultimately increase GHG emissions per kilowatt hour.

Fig. 22-3 shows the contribution of individual life cycle phases with PC power plants. The specific emissions caused by the coal supply increase by 19 per cent whilst those caused by power plants decrease by 85 per cent. The coal supply share increases from 22 per cent without CCS to 66 per cent in the case of power plants with CCS. Emissions from the transportation and storage of CO_2 play a minor role (4 per cent) whilst the share of power plants including CO_2 capture drops to 30 per cent (power plant plus penalty).

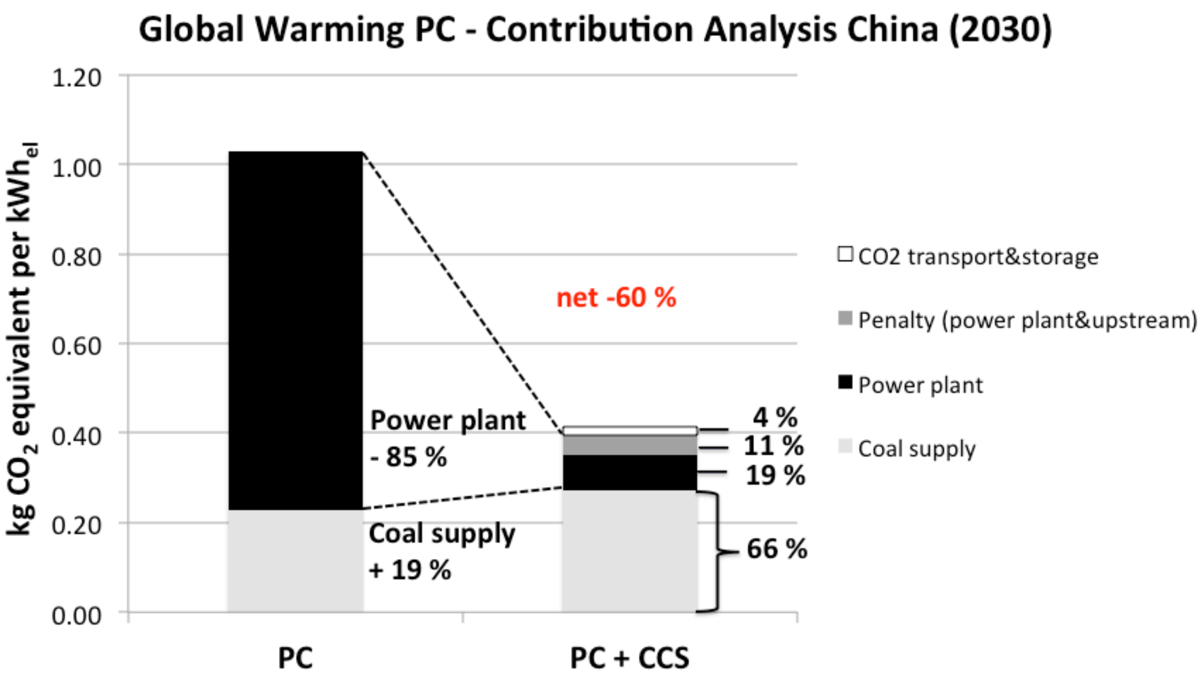


Fig. 22-3 Contribution of individual life cycle phases to the global-warming potential for PC with and without CCS in China

Source: Authors' composition based on Deibl (2011)

22.2.3.2 Further Impact Categories

Fig. 22-4 illustrates the results of the LCIA for other environmental impact categories, described below.

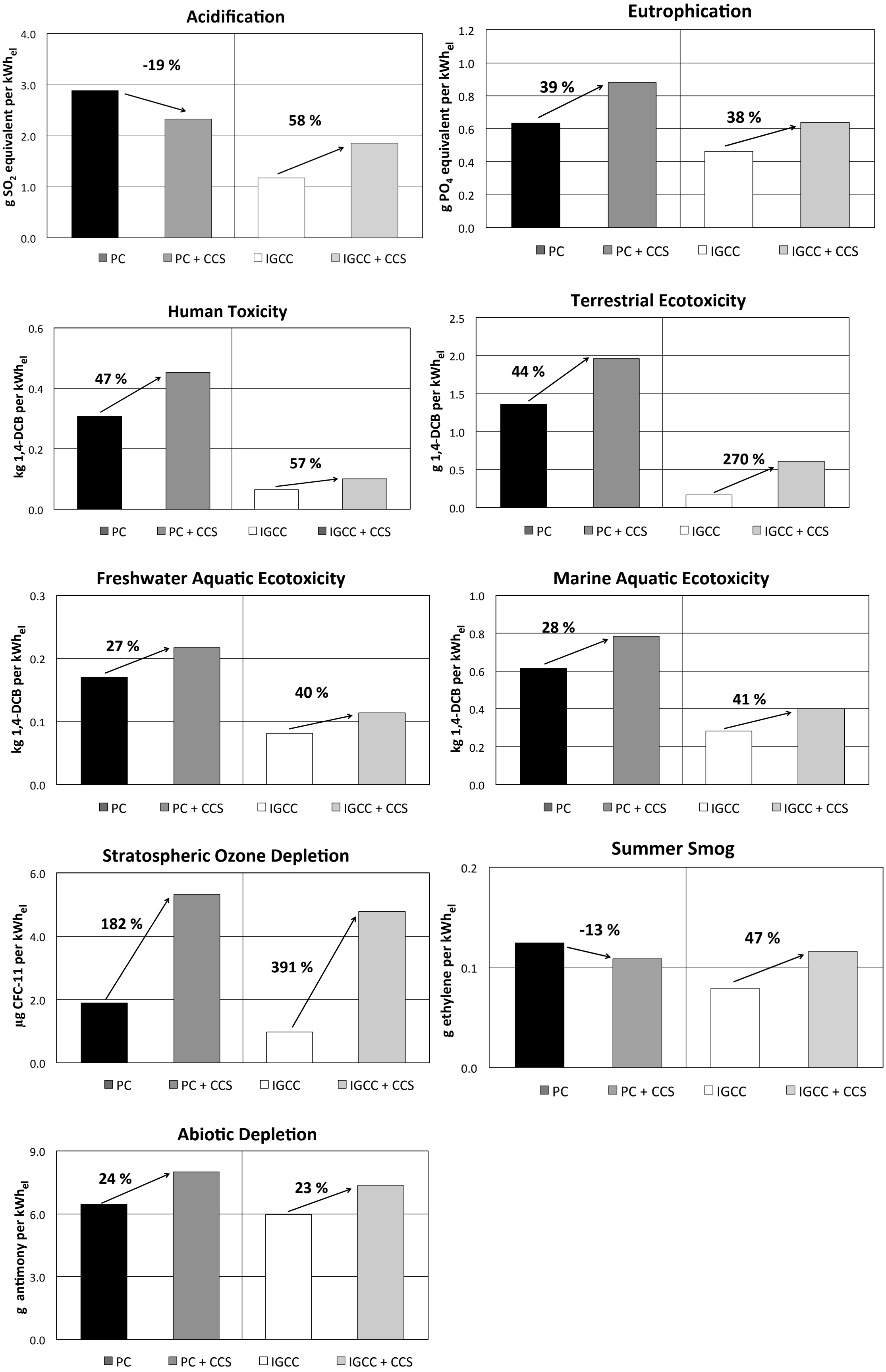


Fig. 22-4 Results of nine impact categories for PC and IGCC with and without CCS in China from a life cycle perspective (per kilowatt hour electricity)

Source: Authors' composition based on Deibl (2011)

Acidification and Eutrophication

With *acidification potential (AP)*, the environmental performance of PC decreases by 19 per cent with CCS; that of IGCC increases by 58 per cent with CCS. However, IGCC with CCS scores less than PC without CCS. The *eutrophication potential (EP)* shows a 39 and 38 per cent increase for PC and IGCC, respectively.

The increases can be explained by the additional consumption of fuel in the case of CCS. Although the direct SO_2 and NO_X emissions, which cause AP and EP, are also reduced during the CO_2 scrubbing process, their decrease is outweighed by an increase during the upstream process. Other studies also predict a 36 to 80 per cent increase for eutrophication in PC. In the case of decreasing emissions, the increase due to fuel consumption is outweighed by removal during scrubbing. For acidification, a 10 per cent reduction up to a 46 per cent increase can be found in the literature (Viebahn 2011).

Human Toxicity and Terrestrial Ecotoxicity

Considering the *human toxicity potential (HTP)*, the environmental performance of PC and IGCC increases by 47 and 57 per cent with CCS, respectively. However, IGCC with CCS scores less than PC without CCS. In the case of PC, electricity production is the main contributor to HTP; with IGCC the coal supply dominates the equation. Concerning impact caused directly by CCS, the scrubbing phase (production of MEA) is the main contributor in PC; that in IGCC is the CO_2 transportation and storage phase.

The *terrestrial ecotoxicity potential (TETP)* shows a 44 and 270 per cent increase for PC and IGCC, respectively. Since IGCC with CCS scores less than PC without CCS, the high percentage increase is put into perspective. IGCC with CCS has 69 per cent less impact than PC with CCS. The increase is due mainly to the CO_2 transportation and storage phase.

Other studies report a 157 to 210 per cent increase in HTP scores and a 57 per cent rise in TETP scores for PC (Viebahn 2011).

Freshwater and Marine Aquatic Ecotoxicity

The results obtained for the *fresh water aquatic ecotoxicity potential (FWAETP)* are similar to those for the *marine aquatic ecotoxicity potential (MAETP)*. Both FWAETP and MAETP increase by 27 to 28 per cent for PC and 40 to 41 per cent for IGCC with CCS. The increase is mainly caused by the energy penalty and the CO_2 transportation and storage phase. A 29 per cent reduction in the MAETP and a 46 per cent increase in the FAETP for PC systems can be found in the literature (Viebahn 2011). Again, IGCCs perform noticeably better than conventional power plants.

Stratospheric Ozone Depletion

With the *stratospheric ozone depletion potential (ODP),* a sharp rise is visible when comparing power plants with and without CCS: the environmental performance of PC and IGCC increases by 182 and 391 per cent with CCS, respectively. A contribution analysis reveals that the reasons for this increase are the transportation (250 km) and storage phase of the system and – in the case of PC – the scrubbing phase, whilst for power plants without CCS the ODP is dominated by the coal supply. An increase of only 55 per cent for other PC systems is reported by Viebahn (2011).

Summer Smog

The summer smog impact category (*photochemical oxidation potential, POP*) differs slightly to the other impact categories, as the score for IGCC with CCS is virtually the same as that of PC with CCS. CCS decreases the POP by 13 per cent for PC and increases it by 47 per cent for IGCC. The increase in POP is caused by increasing SO_2 and CH_4 emissions released by additional coal transportation and mining and in the transportation of CO_2 – with PC this increase is outweighed by the removal of SO_2 during scrubbing. Other studies calculate a range of -13 to +94 per cent for PC systems. (Viebahn 2011).

Abiotic Depletion

The scores for *abiotic depletion* increase by 24 and 23 per cent when CCS is applied for PC and IGCC, respectively. The reasons for this include the more extensive occupation of land by coal mines and CO_2 pipelines.

22.2.4 Conclusions

A prospective life cycle analysis (LCA) of future CCS-based power plants in China was performed to assess the environmental impacts of CCS. Taking into account a CO_2 capture rate of 90 per cent, PC and IGCC power plants with and without CCS were compared. The results show a 75 per cent decrease in CO_2 emissions for both PC and IGCC systems. Total GHG emissions are reduced by 59 and 60 per cent. However, most other environmental impact factors increase (eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity and stratospheric ozone depletion) whilst only acidification and summer smog decrease with the PC power plant. These results are in line with LCAs performed by other authors, as Viebahn 2011 showed in a meta-analysis of LCAs for future CCS systems in Europe.

In general, two issues are responsible for these results. Firstly, the additional energy consumption of CCS-based power plants (energy penalty) creates greater emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, the additional emissions caused by upstream and downstream processes have to be considered. Both the excess consumption of fuels and additional processes such as the production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant's stack, upstream and downstream emissions dominate the respective impact categories.

However, the GHG reduction rates are much lower than expected. In general, an overall reduction of GHG emissions between 67 and 75 per cent can be expected if applying post-combustion and pre-combustion to hard coal-fired power plants in 2020/25. In the case of China, upstream emissions play a much greater role than in other countries. Firstly, large uncontrolled coal fires exist in China, emitting huge amounts of carbon dioxide and other GHGs. Secondly, mining causes much higher coalbed methane emissions than in other countries. Both effects place additional emissions burdens on each kilogramme of coal that will not be captured in the event of CCS.

However, the absolute scores and the general framework of the LCA model have to be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies (Viebahn 2011). Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results substantially. Regarding the presented study, further limitations must be borne in mind: only little data on the performance of power plants exists in China. The uncertainty on future technical developments up to the reference year 2030 necessitates the use of assumptions, which could mislead the results. This particularly concerns the assumed power plants' efficiencies and the datasets for modelling the upstream process of coal mining. GHG emissions from coal fires and coalbeds included in the ecoinvent dataset were modelled for the whole of China, but are based on the situation in 1990 and 1999, respectively. This reveals a general need to update existing LCAs of coal-based electricity production in China.

22.3 Further Environmental Implications of Coal Mining outside LCA

There are over 30,000 coal mines in China, 17,000 of which are small. In addition, thousands of further illegal mines exist. Most of China's coal reserves (see Fig. 20-8) are located deep underground; 36 per cent are within 300 m of the surface, 45 per cent between 300 and 600 m, and the remainder between 600 and 1000 m. The coal mining sector in China is strikingly antiquated compared to the coal mining industry in developed countries. Not only is outdated equipment used in most small mines – mechanised excavation is commonplace and investments in scientific research and miner safety are quite low (Yang 2007). Small mines are a major source of the country's environmental and health problems. The lack of safety in small mines in particular causes the most coal mining fatalities and serious injuries. These types of mine cause considerable environmental damage because small mines are poorly equipped to address the environmental impacts of coal and lead to the suboptimal exploitation or waste of resources (The World Bank 2009).

22.3.1 Land Consumption

Coal is produced in 27 of China's provinces. 65 per cent of the nation's proven coal reserves are located in Shanxi, Shaanxi and Inner Mongolia in northern China; only 13 per cent of reserves are found in the southern part of the country, in Guizhou and Yunnan (IEA 2009b). China has about 13.3 million hectares of wasteland, and coal mining destroys approximately 46,667 hectares of land every year – nearly 67 per cent of which is arable land. Coal mining is also an important cause of increasing desertification in northern China (IEA 2009b).

22.3.2 Water Consumption

The need for water to wash coal is already putting water-scarce regions in northern China under stress, particularly Shanxi, the largest coal-producing province. The reason why water shortages are experienced in the north is that 80 per cent of China's rainfall and snow-melt occurs in the south; only 20 per cent occurs in the mostly desert regions of the north and west. For most of the coal reserves in the north, there is insufficient water to mine, process and consume the reserves. Fresh water required for mining, processing and consuming coal accounts for the largest share of industrial water use in China, or roughly 120 billion cubic metres annually, a fifth of all water consumed in the whole of China (Schneider 2011).

The demand for power generation is growing in countries such as China, India and South Africa, hence there is a growing need for alternative cooling technology that can operate efficiently in arid areas. To minimise water consumption in power plants, China has started to install indirect dry cooling towers (Xing 2010).

22.3.3 Other Environmental Impacts of Coal Mining

Air quality

Coal mines in China release about 395.43 billion m^3 of gases, such as CO_2, methane, NO_x, SO_2 and soot, which have a rapid and significant effect on the global climate. Methane in mines is also responsible for countless explosions. The NO_x, SO_2 and soot emitted create many serious environmental problems: SO_2 and NO_x are the main contributors to acid rain, which plagues two thirds of China, and soot emissions cause local and global climate change (Yang 2007). Acid rain has repercussions on vegetation, soils, crop yields, buildings and public health.

Another problem is the carbon dust caused by coal transport: China's main coal mines are in the north and north-west of the country, whilst energy demand is greatest in the eastern and south-eastern coastal areas. The coal must therefore be transported long distances from west to east and from north to south. Three transport options exist – rail, water and road, whereby rail is the most important mode of transporting coal.

Every day, over 80,000 coal trains haul an annual total of 1.8 billion metric tonnes of coal on China's railways from existing mines. The capacity is approaching the railway's limit.

Coal Ash

Coal ash is the inevitable waste product from coal combustion. Due to the lack of high-quality coal and China's outdated power generation technology, the combustion of 1 tonne of coal produces 250 to 300 kg of fly ash and 20 to 30 kg of bottom ash. Coal ash is the country's largest cause of solid industrial waste. In 2009, China produced in excess of 375 million tonnes of coal ash (Greenpeace International 2008). Greenpeace estimates that the total ash waste produced annually by China's coal power sector contains 358.75 tonnes of cadmium, 10,054 tonnes of chromium, 9,410 tonnes of arsenic, 4.42 tonnes of mercury and 5,345 tonnes of lead, totalling 25,000 tonnes of heavy metals. A lot of precious land space is required to deposit fly ash, posing a potential threat to the environment. After all, many disposals of coal ash are carried out without adequate measures to prevent dust dispersal and the leakage and run-off of pollutants into the environment (Lan and Yuansheng 2007). To date, only less than one third of coal ash is reutilised, for example as cementitious material for cement and concrete production. Additional research is being undertaken to identify a sustainable use of cover soil for the agricultural reclamation of coal mining waste and fly ash deposits to compensate for the subsidence of the surface caused by coal mining activities (Makowsky et al. 2010).

Coal fires

China's underground coal fires are the worst in any coal-producing country of the world. These fires destroy as much as 20 million tonnes of coal annually, nearly the equivalent of Germany's entire annual production, causing major economic losses and enormous CO_2 emissions in China. There are two types of coal fire: surface fires in coalfields and fires in subsurface coalmines. One of the most frequent reasons for coal fires is spontaneous combustion, when coal reacts with oxygen from air in an oxidation process, which increases the temperature. Coal fires release large volumes of CO_2, CO, CH_4, NO_x, NO_2, SO_2, ash, particles and aerosols, leading to both global warming and local pollution. Several sources estimate that coal fires in China produce as much as 2 to 3 per cent of global CO_2 emissions. The soil, ground and air become polluted, and the fires are a hazard to humans, animals and buildings alike (Bellona Foundation 2007).

The main coal fire areas stretch along the coal mining belt in China, which extends for 5000 km from east to west along the north of the country. Over 50 coalfields affected by coal fires have been identified here (see Fig. 22-5).

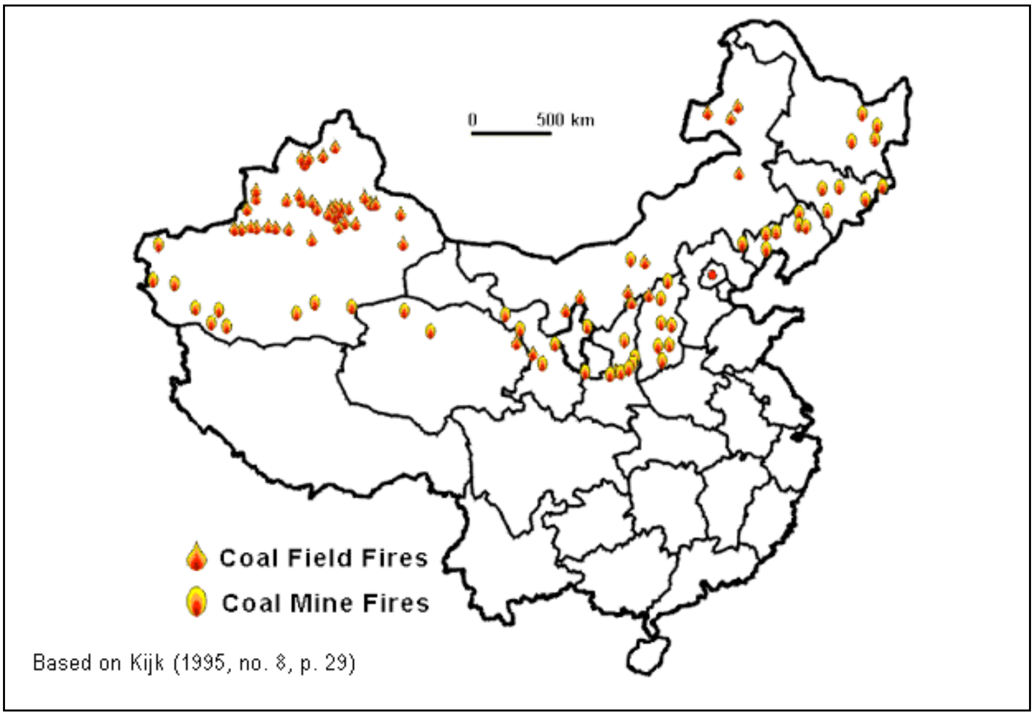


Fig. 22-5 Localisation of major known coal field fires and coal mine fires in China

Source: Prakash (1999)

Mine Waste

In China, large amounts of toxic wastewater are discharged from mines without being treated. 70 per cent of such untreated wastewater drains into rivers. This discharged wastewater, combined with runoff from mine tailings, has considerably polluted surface water and groundwater in mining areas, often contaminating soils and crops (Yang 2007).

Health Risks

Mine workers face many health risks, including dust-related lung diseases, hearing loss, neuromuscular disorders and rheumatism. Pneumoconiosis – a deadly respiratory disease, also known as “black lung,” caused by inhaling coal dust – is one of the most serious occupational diseases facing coal miners (IEA 2009b). According to China’s Ministry of Health figures, of the approximately one million people in China suffering from this disease, 600,000 are miners. But it is not only workers who are affected by these health risks. Linfen is an extreme example of a Chinese city that has been polluted by coal mining: the city has the worst air pollution in the country. Residents of Linfen – a major coal mining city in Shanxi Province –

suffer from respiratory illnesses from the severe pollution of coalmines surrounding the city (Greenpeace International 2008). In Gaojiagao – another town in Shanxi – a number of birth defects, including neural tube defects, additional fingers and toes, cleft palates, congenital heart diseases and mental retardation, are linked to the harmful substances generated by coal mining activities.

In addition, several thousands of miners lose their lives each year through coal mining accidents. In 2009, 1616 accidents occurred, causing the death of 2,631 miners (Chinadaily 2011). However, the total number of fatalities has dropped in recent years, a tribute to the government's health and safety laws and regulations. The main causes of coal mine accidents are gas leaks, roof cave-ins, fires, transportation mishaps, blasts, floods and water bursting (Yang 2007).

23 Analysis of Stakeholder Positions

23.1 Overview

This section summarises the positions of key players in the Chinese discourse on CCS, aiming at sketching a constellation of key stakeholders. The analysis is mainly based on research interviews conducted with experts from science, non-governmental organisations (NGOs), industry and the government. The structure and course of the interviews were defined by a questionnaire that contained open questions, giving respondents the opportunity to freely express their positions and to identify parameters affecting the prospects of CCS in China. However, the questionnaire merely acted as a guideline, and was expanded by supplementary or more detailed questions, matching each respondent's expertise. Hence, the questions posed to the respondent and the course of the interviews were only partially standardised. Comparability of the interviewees' responses is ensured by key questions discussed in all interviews.

In total, Wuppertal Institute discussed CCS with 22 experts from 19 Chinese institutions. Tab. 23-1 lists the organisations interviewed. The stakeholders interviewed were identified and selected after screening existing studies on CCS in China. The analysis of stakeholders' positions covered in the following sections but not by the experts interviewed is based mainly on publicly available statements or documents on CCS issued by the stakeholders. As previously mentioned, the analysis focuses on key stakeholders, and does not claim to give a full picture of relevant CCS stakeholders in China.

The described semi-standardised qualitative interviews were complemented and rounded off by a standardised survey to reflect respondents' views on general issues related to CCS, such as the expected rate of technology adoption in 2050. The survey proved to be an excellent way of summarising the views of the experts interviewed on key questions regarding CCS, and presents a clear picture of the expected market prospects of CCS in China, as well as potential barriers.

23.2 Key Players

23.2.1 National Government

China's national government recognised CCS as a potentially relevant technology option for mitigating CO_2 emissions from large-scale, fossil-fired plants in 2007 when President Hu Jintao highlighted research on CCS as one element of a research agenda towards the introduction of a low carbon development (Seligsohn et al. 2010). In the same year, Premier Wen Jiabao hosted a workshop on reducing CO_2 emissions, which further boosted the attraction of CCS as a mitigation pathway. The Premier and the chairman of the Chinese National Development and Reform Commission (NDRC) acknowledged CCS as a potential element of their climate change and environmental policy strategy.

The above statements by China's national leaders were translated into national plans and policy initiatives in the ensuing years. CCS was called a cutting-edge technology in China's National Medium- and Long-Term Science and Technology Development Plan, published in 2005 (Seligsohn et al. 2010), and categorised as a key research area for reducing greenhouse gas emissions in the 2007 National Climate Change Programme of the national government (Seligsohn et al. 2010). In June 2007, the Chinese government issued China's Scientific & Technological Actions on Climate Change, in which it outlined its plan to develop key technologies and measures for CCS. The government announced its intention to design a roadmap for CCS development and to implement capacity building, engineering and technical demonstration projects (National Development and Reform Commission 2007).

Tab. 23-1 List of stakeholders interviewed in China (face-to-face interviews)

Organisation	Date of interview
Government bodies	
Administrative Centre for China's Agenda 21	22/09/2010
Industry	
Siemens Ltd., China Fossil Power Generation Division	18/04/2011
China Shenhua Coal Liquefaction Co. Ltd.	26/04/2011
China United Coalbed Methane	27/04/2011
Civil society	
Natural Resources Defense Council, China Office	05/07/2010
Greenpeace China	05/07/2010
World Resources Institute	20/04/2011
The Climate Group	21/04/2011
WWF China	26/04/2011
Science and advisory bodies	
Institute of Energy, Environment and Economy, Tsinghua University	08/07/2010
Clean Air Task Force	20/04/2011
Centre for Climate and Environmental Policy in the Chinese Academy of Environmental Planning	20/04/2011
Institute of Geology and Geophysics, Chinese Academy of Science	21/04/2011
State Key Laboratory of Coal Resources and Safe Mining, China University of Mining and Technology	22/04/2011
Centre for Energy and Environmental Policy (CEEP), Beijing Institute of Technology	22/04/2011
Department of Thermal Engineering, Key Laboratory for Thermal Science and Power Engineering of the Ministry of Education, Tsinghua University	25/04/2011
EOR Research Center, China University of Petroleum	26/04/2011
Research Center for International Environmental Policy (RCIEP), Tsinghua University	26/04/2011
Tsinghua-BP Clean Energy & Research Education Center	27/04/2011

Source: Authors' compilation

For the period of the 12th Five-Year Plan, the national government has increased its R&D budget for CCS-related activities. The budget for the first year of the 12th Five-Year Plan period is estimated to be nearly as high as the overall budget for CCS in the whole of the 11th Five-Year Plan period (WWF China 2011b). Although CCS is gaining prominence and support, it still is an evolving issue, but not a top priority on China's climate and technology policy agenda. Several respondents stated that the Chinese government considers CCS a reserve technology that may be required in the future, whilst its large-scale application is expected to be some time away (WWF China 2011b). Possible future binding CO_2 mitigation obligations arising from international climate negotiations are thought to be a potential trigger for the future deployment for CCS in China (CEEP 2011; Tsinghua 2011a; WWF China 2011b). The focus of the national government's efforts, though, is not merely on CCS but on CO_2 capture, use and storage (CCUS), aiming at exploiting additional value creation opportunities. The export of CCS equipment and processes is considered a potential additional benefit of the technology (The Climate Group 2011a).

The regulatory and political responsibility for CCS at the national level is highly fragmented and shared by numerous government authorities. Strategic guidelines for energy and climate policy are developed by the National Energy Administration (NEA) as part of the National Development and Reform Commission (NDRC)[3]. At the national level, NDRC and NEA are authorised to take final decisions on the approval of CCS projects proposed by domestic and foreign investors. Their decisions, however, must be supported by the provincial government concerned.

The Ministry of Environmental Protection (MEP) is mainly involved in regulating the potential long-term environmental impacts of CCS and developing a methodology for the environmental risk assessment of the technology. Closely linked to responsibilities of the MEP, the Chinese Ministry of Water Resources (MWR) and the Ministry of Land Resources (MLR) focus on issues related to subsurface and groundwater impacts of CCS, land use and planning, exploration of storage sites, and so on. MLR advocates a monitoring programme for geological CO_2 sequestration and is cooperating with the Shenhua Group on Shenhua's recently launched CO_2 storage operation at its direct coal liquefaction plant in Inner Mongolia. Furthermore, MLR is coordinating a programme for the evaluation of China's national geological storage capacity (The Climate Group 2011a).

The Ministry of Science and Technology (MOST) administers the national budget for research, development and demonstration (RD&D) projects, including energy-related science and technology (S&T) programmes. MOST, one of the drivers aiming at shifting the government's perspective from CCS to CCUS (Tsinghua 2011b), issued China's Scientific and Technological Actions on Climate Change in collaboration with other governmental authorities. The Ministry coordinates CCS-related activities under the umbrella of China's main R&D programmes, 863 and 973 Programmes. One of the sub-topics of 973 Programme (National Basic Research Programme) is resource utilisation and the underground sequestration of greenhouse gases for enhanced oil recovery. This sub-topic encompasses eight tasks, including the development of a methodology to assess the CO_2 storage potential and monitoring of CO_2 storage operations as well as the exploration of technical options for separating CO_2 from industrial waste gas (The Climate Group 2011a). Furthermore, CCS is one of the focus areas of the research theme "Clean Coal Technology" of 863 Programme (National High-Tech Programme).

Other relevant authorities include the Ministry of Finance (MOF), the Ministry of Industry and Information Technology (MIIT), the State-owned Assets Supervision and Administration Commissions of the State Council (SASAC) and the National Energy Committee (NEC) (Tsinghua 2011b). MIIT, for example, is responsible for evaluating and exploiting market opportunities attached to CCUS and for analysing their potential impact on traditional industries.

In addition to the aforementioned ministries, the Administrative Centre for China's Agenda 21 (ACCA 21) plays an important role in fostering the development and demonstration of CCS in

3 The National Energy Administration was established in 2008 to replace the former Energy Bureau.

China. ACCA 21's prior responsibility was to coordinate programmes related to China's Agenda 21 on issues such as environmental protection and climate change. In the field of CCS, ACCA 21 is coordinating a nation-wide capacity-building programme on CO_2 capture, use and storage in order to connect ongoing R&D projects. Over 100 CCS experts are currently involved in the project (Seligsohn et al. 2010).

In addition to domestic activities, the Chinese government is involved in several international CCS initiatives and networks, including the Carbon Sequestration Leadership Forum (CSLF), FutureGen, the Sino-European Near Zero Emissions Coal project (NZEC), the COACH project (Cooperation Action within CCS China-EU), Asia-Pacific Partnership and GeoCapacity (Sizhen 2011).

Another important initiative is the U.S.-China Clean Energy Research Centre (CERC), launched in November 2009 during President Obama's visit to China. The primary purpose of CERC is to facilitate the joint research, development and commercialisation of clean energy technologies between the USA and China. CERC focuses on three research areas, one of which is clean coal, including CCS. The CCS programme addresses technology and practices for clean coal utilisation and CCUS. The USA has chosen West Virginia University (WVU) and China Huazhong University of Science and Technology (HUST) to lead teams of experts from public and private institutions. Both teams have identified key research tasks, including clean coal power generation and transformation, the development of low-cost capture technologies and the development of geological sequestration practices (Liu and Gallagher 2009).

23.2.2 Industry

In recent years, China's industrial stakeholders have become increasingly active in the field of developing, testing and demonstrating carbon capture, use and storage technologies. Although China was a late starter in CCS and CCUS technology compared to other countries, Chinese companies have since accumulated significant technical know-how, especially in post- and pre-combustion capture technologies (U.S.-China Clean Energy Research Center 2011). The activities of key industrial stakeholders and their positions on the prospects of CCUS are briefly discussed below. Only stakeholders actively engaged in ongoing or planned pilot or demonstration projects are included in the analysis.

Huangeng Group and GreenGen

The China Huaneng Group, China's largest power producer, is currently China's most active industrial company in the field of CCS – on both the national and international stage. Huaneng was part of the initial U.S. FutureGen alliance. Together with seven other Chinese companies (China Datang Group, China Huadian Corp., China Guodian Corp., China Power Investment Corp., Shenhua Group, State Development & Investment Co., China National Coal Group), it established the GreenGen Corporation in 2005 to promote coal-fired power generation with CCS. All the major players in GreenGen are active in China's coal and electricity generation industry, and hope to gain valuable knowledge and experience from their participation in the GreenGen consortium (Sizhen 2011). The U.S.-based corporation Peabody Energy joined the consortium in 2007 as the only foreign investor. GreenGen is supported by the National Development and Reform Commission (NDRC) and the Chinese Ministry of Science and Technology (MOST). The project also receives funding from the Asian Development Bank (ADB), specifically for analysis and capacity building.

As part of the first phase of the GreenGen project, a 250 MW IGCC plant producing power, heat and syngas is currently under construction and scheduled for completion by the end of 2011. Construction started in 2009. A CO_2 capture unit will be installed in the second project phase. The third phase is envisaged for completion by 2020, when the plant should have a total capacity of 800 MW. If successful, Huaneng intends to roll out additional similar IGCC-CCS plants (Natural Resources Defense Council 2010).

Huaneng's strong interest in developing and demonstrating CCS is emphasised by its commitment to further CCS pilot and demonstration projects. In total, Huaneng is pursuing the development of the post-combustion capture technology in three pilot projects. In 2008, an amine-based post-combustion capture retrofit to Huaneng's Gaobeidian power plant near Beijing went into operation. The project was managed by the Thermal Power Research Institute (TPRI) – which is owned and operated mainly by the Huaneng Group – in collaboration with Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO). TPRI is a national leader in capture technology, both at the laboratory scale and in industrial pilots. It also built and operates the pulverised coal (PC) plant at the Huaneng Beijing Thermal Power Plant, using domestically manufactured amine capture equipment based on technology licensed by CSIRO. The plant will capture approximately 3 to 5 kilotonnes of CO_2 per year (about 1 per cent of the plant's total CO_2 discharge) for use in the soft drinks industry (Hsu 2010).

The Huaneng Group has erected another post-combustion PC plant at the Huaneng Shidongkou No. 2 Power Plant in Shanghai, which became operational at the end of 2009 (Hart and Liu 2010). The project is expected to capture 100 to 120 kilotonnes of CO_2 annually, which is equivalent to about 3 per cent of the total CO_2 emitted from the plant. The captured CO_2 will be used for industrial purposes (Natural Resources Defense Council 2010).

The pilot plants described above are operated mainly using Chinese equipment. TPRI has gained significant experience and expertise in the field of post-combustion capture technologies in recent years and intends to market its technology and engineering services outside of China (Hart and Liu 2010).

Shenhua Group

Shenhua, the largest player in China's coal mining sector, is an integrated energy company whose business activities include not only coal production, but also coal transportation, power generation, chemicals production and coal liquefaction (Natural Resources Defense Council 2010). Shenhua has launched a small-scale CCS operation at its direct coal liquefaction plant in Inner Mongolia. The liquefaction plant started operating at limited capacity in December 2008 and became fully operational in early 2011. The direct coal liquefaction process requires hydrogen, which is produced via coal gasification in a hydrogen facility combined with CO_2 capture. The capture component of the plant was designed by the China National Petroleum Corporation (Vallentin 2009). Captured CO_2 is injected into an adjacent saline aquifer. Injection commenced in January 2011, with the aim of injecting a total of 100,000 tonnes of CO_2 annually. The project was prepared in a five-year process in collaboration with the Lawrence Berkeley National Laboratory (LBNL) and Lawrence Livermore National Laboratory (LLNL). Its implementation was hampered by difficulties in organising the off-take of the captured CO_2. Initially, Shenhua offered the CO_2 to PetroChina for its enhanced oil recovery operations. PetroChina, however, showed little interest, as the CO_2 from Shenhua's coal liquefaction plant would have been far more expensive than acquiring CO_2 from an ammonia plant. Furthermore, the coal liquefaction process is still at the demonstration stage and is not yet fully mature. For this reason, Shenhua was unable to provide sufficiently reliable delivery information required by PetroChina (Hart and Liu 2010).

In addition to the aforementioned logistical and technical barriers, several respondents suggested that integrated CCS projects are being hampered by a lack of cross-sectoral cooperation and communication (WRI 2011). For example, China's national oil companies have exclusive access to geological information on China's underground and are authorised to expand and oversee the national pipeline network. PetroChina was unwilling to build a pipeline from Shenhua's liquefaction plant to the aquifer storage site located 10 km from the CO_2 source. Thus, any CO_2 captured at the coal liquefaction facility is currently being transported to the storage site by truck (Clean Air Task Force 2011; EOR 2011; The Climate Group 2011a).

China Guodian Corporation

China Guodian Corporation is one of China's five largest power utilities, with a total installed electricity generating capacity of over 82 GW. China Guodian Corp. is a vertically integrated corporation with a total coal reserve of 13.2 billion tonnes and an annual coal production of more than 25 million tonnes (WRI 2011). Furthermore, the company is active in the field of plant development and construction. One of the company's key missions, using CCS amongst other things, is to develop clean coal power generation technologies. The company plans to commission a post-combustion capture unit at Beitang power plant, Tianjin, by the end of 2011. The facility is to achieve a capture rate of 95 per cent and recover a total of 20,000 tonnes of CO_2 per year (China Guodian Corp. 2011).

China Investment Power Corporation (CIPC)

China Investment Power Corporation was established in 2009 as an integrated energy group involved in the power, coal, aluminium, railway and shipping industries (Department of Social Development et al. 2010). In 2009, CIPR operated a total thermal generation capacity of 41,123 MW in China. CIPC is part of the GreenGen consortium and intends to develop and demonstrate the technology as a future option to increase the share of clean energy in its overall power generation portfolio (China Power Investment Corp. 2011). To this end, the company began constructing a post-combustion capture facility at its coal-fired Hechuan Shanghuai Power Plant in Chongqing in 2008; the plant became operational in January 2010. The system, based wholly on Chinese equipment and technologies, can capture up to 10,000 tonnes of CO_2 per year.

In addition to post-combustion capture, CIPC has been pursuing the development of IGCC technology for several years as an option for clean coal-fired power generation. In this context, CIPC plans to construct two 488 MW IGCC-CCS plants in the city of Langfang, not far from Beijing and Tianjin (Natural Resources Defense Council 2010). Two feasibility studies were completed in 2006, the electricity delivery system design was approved in June 2007 and the environmental and water source assessments were approved in mid-2008 (Modern Power Systems 2010).

23.2.3 Oil Industry

Major Chinese oil companies, such as PetroChina and Sinopec, are key players in fostering the research, development and demonstration (RD&D) of CO_2 storage, especially enhanced oil recovery. PetroChina is China's largest national oil- and gas-producing company. PetroChina is interested in developing CCS with an end to increasing output from its oil fields using enhanced oil recovery (EOR). It has already conducted CO_2 injections for EOR in cooperation with MOST and several research institutes, and performed experimental EOR operations in Jiangsu oil fields, Jilin fields, Changun fields, Zhongyuan fields, Ordos basin and Northern Tarim basin (Natural Resources Defense Council 2010).

Sinopec uses CO_2 capture technology to process natural gas at its Songnan gas field. Some of the captured CO_2 is used for EOR and some is re-injected into the gas reservoir to raise the formation pressure (Hart and Liu 2010). In 2008, Sinopec launched another EOR project combined with a post-combustion CO_2 capture plant: CO_2 recovered at Shengli coal-fired power station will be purified and injected into the adjacent Shengli oil field for EOR. The daily amount of CO_2 to be injected will be about 80 tonnes (Sinopec 2010).

The national petroleum companies' commitment to the development and demonstration of CCS is considered essential because they possess exclusive access to the geological data required to identify and assess potential CO_2 storage sites for CO_2 underground storage (ACCA21 2010) and are authorised to expand and operate China's pipeline network (Clean Air Task Force 2011; WRI 2011). Consequently, the implementation of integrated CCS projects requires cross-sectoral cooperation between the operator of the CO_2 source and the oil industry. However, cooperation beyond sectoral boundaries is considered a major challenge in China (WRI 2011). The oil industry's relevance in the Chinese CCS debate is further reinforced because EOR operations are essential in creating demand for captured CO_2. For this reason, the oil industry's overall bargaining power in the process is considered to be higher than that of the power companies due to its exclusive geological knowledge and potential role as a user of captured CO_2. PetroChina's main interest, and that of other oil companies, is to secure a reliable and affordable supply of CO_2, which most integrated CCS pilot or demonstration projects cannot guarantee, due to a lack of technical maturity (Clean Air Task Force 2011; The Climate Group 2011a).

ENN Group

The ENN Group, located in Hebei Province in the north-east of China, is a company that develops technology. A microalgae system that absorbs CO_2 is part of ENN's low carbon technology portfolio. The company operates a pilot facility that is capable of absorbing 110 tonnes of CO_2 and of producing 20 tonnes of bio diesel and 5 tonnes of proteins per year. By the end of 2011, ENN plans to commission a microalgae pilot plant with an annual capacity of 320,000 tonnes of CO_2. The CO_2 to be recovered, which will originate from the coal-based production of methanol and dimethyl ether, will be used to produce 20 tonnes of biodiesel and 5 tonnes of proteins per year (The Climate Group 2011a).

China United Coalbed Methane Co. Ltd. (CUCBM)

China United Coalbed Methane is a state-owned company that has exclusive rights to explore, develop and produce China's coalbed methane resources in collaboration with international partners. The corporation has been involved in CCS-related R&D projects since 2002, because it considers enhanced coalbed methane recovery (ECBM) to be a highly promising business opportunity (Department of Social Development et al. 2010). Thus, the company focuses on CO_2 utilisation and underground injection; it is not involved in CO_2 capture-related R&D projects. Supported by the Ministry of Science and Technology, CUCBM has implemented the “CO_2 Sequestration and Enhanced Coal Bed Methane Recovery (CO_2-CBM) in Unmineable Deep Coal Seams Project” (CUCBM 2011).

From 2002 to 2007, China United Coalbed Methane joined forces with the Canadian International Development Agency (CIDA), Alberta Research Council and other institutions to conduct China’s first ECBM pilot project. In 2004, China United Coalbed Methane and CIDA injected 193 tonnes of liquefied CO_2, doubling coalbed methane production compared to before the underground injection of CO_2 (Department of Social Development et al. 2010). CUCBM has also been involved in other international partnerships, such as with the Australian CSIRO in a project under the umbrella of the Asia-Pacific Partnership (APP). China United Coalbed Methane is currently implementing further ECBM tests, including injecting CO_2 into horizontal wells in Shanxi Province (CUCBM 2011).

Jiangsu Jinlong-CAS Chemical Co.

Jiangsu Jinlong-CAS Chemical Co. Ltd. is a chemical company located in Taixing City in Jiangsu Province, eastern China. The company is interested in utilising CO_2 because it produces both CO_2-based new materials and CO_2-based polymer modified materials. Jiangsu Jinlong-CAS Chemical Co. has built a production line to produce 22,000 tonnes of propylene carbonate based on CO_2 captured from an ethanol plant. The project aims to use about 8,000 tonnes of CO_2 per year. Jiangsu Jinlong-CAS intends to expand its CO_2 utilisation activities in the future (CUCBM 2011).

Dongguan Taiyangzhou Power Corporation

The Dongguan Taiyangzhou Power Corp. – a subsidiary of Dongguan Power and Chemical Industry Holding Co. Ltd. (DGPC) – operates four power plants with a total capacity of 880 MW. DGPC considers coal gasification-based plants to be a promising option for combining power and chemical production. It is engaged in the FutureGen Alliance, and considers the combination of IGCC and CCS to be a long-term path towards a zero emission energy system.

In 2009, DGPC partnered with the U.S.-based power utility Southern Company to build an 800 MW IGCC power plant in Dongguan City, Guangdong Province. The project aims at adjusting and optimising the power mix structure and energy-saving development in Guangdong Province (Department of Social Development et al. 2010). The plant, which will be based on a design by Southern Company, received financial support from the budget for IGCC-related R&D within 863 Programme during the 11th Five-Year Plan period (2005–2010).

23.2.4 Civil Society

WWF China

The WWF has been active in China since 1980. Today, over 120 members of staff work on a wide range of environmental issues for WWF China (Natural Resources Defense Council 2010). CCS is not one of WWF China’s priorities (WWF China 2011c). It enters the scene as an element of a potential future low carbon energy system. In general, the WWF is pursuing a vision of meeting the world's energy demand 100 per cent from renewables by 2050 (WWF China 2011b).

In the meantime, however, CCS is considered a "necessary evil" and a potential backup option if the 100 per cent target for renewable energies cannot be achieved. In countries with a high share of coal in their national energy supplies, such as China, India, South Africa, the USA and Germany, CCS is expected to play a major role in reducing CO_2 emissions at the rate required by climate scientists. In China, the relevance of CCS is expected to increase further from a political perspective as the national government continues to shift the focus of its climate policy strategy from energy intensity to CO_2 intensity targets. However, such a development is perceived as strongly dependent on developments on the international stage (WWF International et al. 2011).

The Climate Group

The Climate Group, founded in 2004, is a UK-based NGO, working internationally with governmental and industrial decision-makers to foster the deployment of policies, technologies and finance for cutting global greenhouse gas emissions. In 2007, the Climate Group started operating in China and now maintains offices in Beijing and Hong Kong. CCS is one of the low carbon technologies on which the Climate Group focuses. It has published blogs, briefing papers and reports on the technology's prospects in China.

The Climate Group considers CCS to be a technical option to alleviate the carbon footprint of coal combustion, especially in countries where a lot of coal is used to generate power (WWF China 2011b). CCS in China is perceived as a long-term option to achieve substantial CO_2 reductions, with post-combustion being considered the most relevant capture option. The reason for this perception is mainly that, unlike pre-combustion and oxy-fuelling processes, post-combustion equipment can be retrofitted to existing plants (The Climate Group 2011b). The possibility to reconcile coal utilisation and CO_2 mitigation, at the same time assuring energy security, is seen as a major driver for CCS in China. Furthermore, CCS could provide potential commercial opportunities, such as technology export, and function as a trigger for basic research in geology, geophysics and geochemistry, generating benefits beyond CCS (The Climate Group 2011a). However, the deployment and industrialisation of CCS in China are expected to be determined to a great extent by energy efficiency and the costs involved (The Climate Group 2011c).

Greenpeace China

CCS technology is not one of Greenpeace China's top priorities. In line with Greenpeace International, Greenpeace China generally opposes coal utilisation. It is also very sceptical about the impact and environmental benefits of CCS and is concerned that it could be used as an excuse for prolonging coal utilisation. Nonetheless, CCS is accepted as a potential back-up solution to alleviate the negative climate impact of continuous coal utilisation in China due to the dominating role of coal in the country's power supply (The Climate Group 2011a).

Natural Resources Defense Council (NRDC)

The NRDC is one of the largest environmental NGOs in the USA, with about 1.3 million members and online activists. In the mid-1990s, NRDC established a clean energy programme in China. It maintains an office in Beijing (Greenpeace China 2010). Carbon capture and storage is an important working field of the NRDC Beijing office. It coordinated and edited an extensive study entitled “Identifying Near-Term Opportunities for Carbon Capture and Sequestration (CCS) in China.” The study was finalised in cooperation with several highly reputed experts and institutes that are exploring CCS in China, such as the Institute of Rock and Soil Mechanics of the Chinese Academy of Sciences, the Clean Air Task Force, World Resources Institute and Tsinghua University (Natural Resources Defense Council China 2011).

The NRDC Beijing office considers CCS to be a potentially important option for CO_2 mitigation in China due to the country’s heavy dependence on coal for power generation. However, it is emphasised that CCS is understood to be only one possible pathway in a portfolio of technical options. Furthermore, the high cost and energy intensity of the technology are seen as a considerable barrier to commercialisation. For this reason, NRDC clearly prefers renewable energy and energy efficiency improvements over CCS which, however, is seen as a bridging technology until other technologies become viable (Natural Resources Defense Council 2010).

NRDC’s CCS experts understand that China’s government is developing CCS cautiously, for example by floating research grants under 863 and 973 Programmes, due to the high cost and energy intensity of the technology. A government incentive scheme for the industrialisation of CCS is not expected to be established within the 12th Five-Year Plan period. For this reason, international collaboration, such as the NZEC initiative and the U.S.-China Energy Research Institute, is considered key to the further development and large-scale demonstration of CCS in China (NDRC 2011).

23.2.5 Think-Tanks and Advisory Bodies

World Resources Institute

The World Resources Institute (WRI) is a global environmental think-tank, launched in 1982 in the USA. WRI operates an office in China and places a strong emphasis on implementing research outcomes and ideas. To this end, it collaborates closely with governments, companies and civil society. WRI considers CCS to be a key option for mitigating CO_2 in China due to the country’s heavy dependence on coal. CCS is considered an important means for achieving a substantial drop in China’s CO_2 emissions. Thus, the technology needs to complement efforts that focus on energy efficiency, renewable energy or fuel switching (NDRC 2011).

WRI became engaged in the field of CCS by developing regulatory guidelines for implementing the technology in the USA. These guidelines were published in a report in 2008 (WRI 2011). The study concluded that, in order to make a major contribution to global CO_2 mitigation, CCS technology needs to be implemented and deployed on a global scale. Against this background, WRI joined forces with Tsinghua University to develop technical guidelines for a regulatory framework for implementing and deploying CCS in China. In 2010, WRI published a briefing paper entitled “CCS in China: Toward an environmental, health and safety regulatory framework” (World Resources Institute 2008). Furthermore, WRI is part of the U.S.-China Energy Research Institute – a major pillar of the U.S.-China energy partnership established in November 2009 that concentrates, amongst other things, on advanced clean coal technologies. WRI coordinates communications between Chinese and U.S. partners, thanks to its well-established network with Chinese partners (Seligsohn et al. 2010).

Clean Air Task Force (CATF)

CATF is a non-governmental organisation that aims to support the implementation of low-carbon technology projects. The Task Force receives funding from foundations, research institutes and individuals, and operates independently of industrial interests. CCS technology is an important part of the organisation's activities in China. CATF focuses on connecting decision-makers to foster and accelerate the implementation of CCS projects (WRI 2011).

CATF views CCS as an important technology option for CO_2 mitigation in China, and expects demonstration of the technology to be driven forward in the future. The interviewed representative of CATF projects that at least two large-scale integrated demonstration projects will be commissioned within this Five-Year Plan period. However, a strong government incentive is seen as a crucial precondition for the broad deployment of CCS. A nation-wide carbon price is considered the most suitable incentive scheme for encouraging use of CCS. Furthermore, industrial collaboration beyond sectoral boundaries, for example between the power sector and the oil industry, is considered vital to the implementation of fully integrated CCS demonstration projects (Clean Air Task Force 2011).

23.2.6 Science

Numerous Chinese universities and research institutes are conducting R&D activities on CCS. Many of these activities focus on technical issues, especially related to the capture part of the CCS technology chain. 'Soft' issues, on the other hand, such as regulatory issues, risk management standards, safety issues, seem to have a lower priority (Clean Air Task Force 2011). In addition to domestic R&D activities, Chinese research bodies are involved in numerous bilateral or multilateral scientific exchanges and cooperative activities with the USA, the EU, Australia, Italy, Japan, and others.

One of the most prominent science and technology collaborations is the Near Zero Emissions Coal (NZEC) initiative, launched at the EU-China Summit under the UK's presidency of the EU in September 2005. The aim of the NZEC initiative is to demonstrate CCS technology in China and the EU by 2020. This scheme is subdivided into three phases: Phase 1 involved exploring the options available for CCS demonstration and capacity building in China; Phase 2 will entail conducting further development work on CCS technology options; Phase 3 will see the construction of a demonstration plant by 2014. The NZEC consortium includes numerous well-reputed Chinese research institutes specialised not only in CO_2 capture technologies (for example, the Thermal Power Research Institute, BP Clean Energy Research and Education Centre at Tsinghua University) and CO_2 storage (for example, the Institute of Geology and Geophysics, China University of Petroleum) but also energy modelling (the Energy Research Institute and the Centre for Energy and Environmental Policy Research).

Other important international science and technology collaborations focusing on CCS are the China-Australia CO_2 Geological Storage Project (CAGS) and the Sino-Italy CCS Technology Cooperation Project (SICCS). The CAGS project is based on a Letter of Intent, signed in 2008, between the Department of Social Development of the Chinese Ministry of Science and Technology and Geoscience Australia, which is affiliated to the Australian Department of Resources, Energy and Tourism (RET). The project's budget totals AUD 2.8 million, funded by RET through the Asia-Pacific Partnership. The project centres around improving the understanding of underground CO_2 storage by developing site selection methods and indicators of CO_2 geological storage; identifying the EOR potential of Liaohe oil field; elaborating criteria for assessing CO_2 storage and investigating the environmental impacts and safety of CO_2 storage. The project is scheduled for completion by the end of 2011.

The SICCS project was set up in October 2009 by China's Ministry of Science and Technology, the Italian Ministry of Environment, Land and Sea (IMELS) and the Italian company Enel under the umbrella of a Cooperation Agreement on Clean Coal Technologies. A pre-feasibility study on an integrated CCS demonstration project encompassing all elements of the CCS technology chain will be conducted within the project. The study's outcome will be compared with that of Italian CCS projects to facilitate cooperation and knowledge exchange between Chinese and Italian experts. The project is funded mainly by IMELS and scheduled for finalisation by the end of 2011 (Sizhen 2011).

The activities of important scientific institutes in the field of CCS are summarised below. The analysis is limited to NZEC consortium partners – the most important Sino-European CCS initiative – since an analysis of all scientific bodies working on CCS would go beyond this study's remit. It must be emphasised that the research bodies and institutes discussed below are explicitly not understood to be stakeholders or agents, which intentionally aim to influence China's CCS debate in favour of or against the deployment of CCS. Scientific bodies are generally deemed to be technology neutral. Nonetheless, they have been included in this section to present a broad picture of the CCS community in China.

China University of Petroleum

China University of Petroleum was founded in 1953, and encompasses several faculties, laboratories and research centres. Education and research at the university involves the exploration, production and refining of oil. The possibility of using captured CO_2 for enhanced oil recovery constitutes an important link to the research field of CCS, and is mainly being investigated by the University's Enhanced Oil Recovery Centre and its Laboratory for CO_2 Storage and EOR.

The EOR Centre considers CCS to be an effective option for reducing CO_2, with EOR offering an early opportunity for CO_2 storage and use. Although the interviewed expert emphasises the technical and geological complexity of EOR operations, use of CO_2 from CCS plants for EOR is perceived as a feasible and economic option if the two processes are integrated from the very beginning. However, the high capital costs of CCS, the substantial energy penalty of CO_2 capture processes and the financing required for CCS projects are perceived as major barriers to the industrialisation of CCS in China. It is emphasised that China, as a developing country with limited financial resources, only has sufficient funding to implement large-scale demonstration projects focusing on CO_2 storage. Instead, Chinese decision-makers tend to focus on opportunities for using CO_2 that offer potential for economic value creation. For EOR projects, however, it is considered essential to ensure a stable CO_2 supply, requiring an adequate level of technical maturity and the continuous operation of CO_2 capture units (Department of Social Development et al. 2010).

The University of Petroleum is involved in several CCS research projects. Most prominently, it co-leads Work Package 4 "Carbon Dioxide Storage Potential" of the NZEC project and authored the NZEC WP4 report "Assessment of CO_2 storage potential in oil-bearing reservoirs of the Songliao Basin." At the international level, the University launched a joint project with Norwegian research institutes on CO_2 storage (EOR 2011).

Institute of Geology and Geophysics, Chinese Academy of Science (IGG-CAS)

The IGG-CAS, which is part of the Chinese Academy of Science, has been involved in CCS-related research for several years. The Institute contributed to the GeoCapacity project from 2006 to 2008. Furthermore, IGG-CAS is involved in the COACH and CAGS projects, and is a member of the NZEC consortium. Within the NZEC project, IGG-CAS contributed to Work Package 4 on China's carbon dioxide storage potential, aiming at developing evaluation criteria for CO_2 storage sites in China.

IGG-CAS considers CCS and CCUS to be an important technical option for mitigating CO_2 emissions in China. However, it emphasises the continued high level of uncertainty surrounding the potential for underground CO_2 storage in China because geological data are usually confidential and not available for publication (EOR 2011).

Tsinghua University

Several departments and research institutes at Tsinghua University are involved in R&D projects related to CCS. Interviews were conducted with experts from three of these institutes. The activities undertaken by these three institutes are summarised below.

The *Key Laboratory of Thermal Science and Power Engineering*, affiliated to the Department of Thermal Engineering, is part of the NZEC team that focuses on fundamental research and the further development of CO_2 capture processes. Its objective is to develop new solvents entailing a low energy penalty. To this end, the Key Laboratory is collaborating with international industry players such as Toshiba and Mitsubishi (CAS 2011). CCS is considered a highly dynamic topic that has attracted the interest of industry, government and scientists in recent years, mainly as a result of the climate conference in Copenhagen in December 2009 where the Chinese government promised to reduce its CO_2 intensity by 40 to 45 per cent. Thus, CCS is perceived as a technological option that may become highly relevant in the future and that should therefore be developed. Of the different CO_2 capture routes available, post-combustion is expected to be the most relevant technology option because IGCC technology is very complex and expensive. In addition to the power sector, industrial players – mainly the power utilities – are considered to be the main drivers in fostering the development of CCS. However, experts from the Key Laboratory of Thermal Science and Power Engineering believe that industrial plants – such as in the ammonia industry – producing a highly concentrated stream of CO_2, enabling low-cost CO_2 capture, are the most economic option for applying CO_2 capture processes at an early stage (Tsinghua 2011a).

The *BP Clean Energy and Education Centre* (THCEC) at Tsinghua University was launched by the former British Prime Minister Tony Blair in 2003. The Centre focuses on clean energy topics and aims to foster the implementation of clean energy projects (Tsinghua 2011a). It has been working on carbon capture and storage for several years, and is part of the NZEC consortium. It focuses on CO_2 capture technologies, such as simulating the impact of CO_2 capture on power plant performance. Furthermore, it integrates CCS into modelling studies on the future structure of China's energy supply, calculating the costs of capturing CO_2 at new and existing plants. Generally, CCS is perceived as a promising technology that could be used as a backup technology if efficiency improvements in coal-fired power plants, renewable energy technologies and nuclear energy fail to achieve sufficient CO_2 reductions.

The immense capital costs of CCS, however, are seen as a major barrier to the commercialisation of the technology (BP 2011).

The *Institute of Energy, Environment and Economy (3E)* at Tsinghua University is also intensely involved in CCS-related research. Its researchers have published several papers on the geographic match of CO_2 sources and sinks in China. The Institute is a member of several international project consortia, including the NZEC initiative and the GeoCapacity project (BP Clean Energy and Education Centre at Tsinghua University 2011).

Centre for Energy and Environmental Policy (CEEP)

CEEP, attached to Beijing Institute of Technology, was founded in 2009. In the research realm of climate and environmental change, carbon capture and storage is one of the Centre’s main research topics. CEEP also is part of the NZEC consortium, modelling the impact of macro-economic indicators on the prospects of CCS in China. Generally, CEEP advocates considering CCS as one of several mitigation technologies in a broad portfolio of options. However, measures to improve overall energy efficiency and other clean coal technologies to optimise the environmental performance of coal-fired power plants are perceived as more viable options due to the high costs incurred by CCS (Tsinghua 2011c).

Thermal Power Research Institute (TPRI)

TPRI is a leading research organisation in the field of thermal power engineering in China. It is not linked to a university, but is controlled by five major independent Chinese power generation groups. The Huaneng Group is the major shareholder. TPRI’s R&D efforts concentrate mainly on thermal power generation technologies with a strong focus on energy efficiency improvements. TPRI has accumulated substantial expertise on post-combustion capture processes. In collaboration with the Australian CSIRO, TPRI managed to design and construct a post-combustion capture retrofit at Huaneng’s Gaobeidian power plant (see above). Furthermore, TPRI also built and operates the pulverised coal combustion (PCC) plant at Huaneng Beijing Thermal Power Plant, using domestically manufactured amine capture equipment based on technology licensed by CSIRO.

In addition to its post-combustion capture expertise, TPRI possesses advanced expertise in coal gasification. It owns a coal gasification design which it licensed to the U.S.-based company Future Fuels in 2009 (CEEP 2011). This suggests that TPRI does not only act as a scientific body, but also promotes its technical know-how. Within the NZEC project, TPRI contributed to the analysis of different CO_2 capture processes.

Institute of Rock and Soil Mechanics (IRSM), Chinese Academy of Sciences

IRSM, founded in 1958, is specialised in geo-mechanics and geotechnical engineering. The Institute, with 313 full-time employees, hosts the State Key Laboratory of Geomechanics and Geotechnical Engineering. Both establishments are actively conducting research on carbon storage in China and contributed, amongst other things, to Dahowski’s frequently cited study on the preliminary cost curve assessment of China’s carbon dioxide capture and storage potential (Entrepreneur 2009). More recently, the two establishments published a joint paper on the cost effect of injecting N_2 into underground formations (Dahowski et al. 2009; Liu and Gallagher 2009).

Energy Research Institute (ERI) of the National Development and Reform Commission (NDRC)

ERI is one of seven research institutes administered by the Chinese NDRC. Rather than engaging in technical R&D projects, the Institute conducts holistic studies on the Chinese energy system with a strong focus on scenario modelling. CCS, especially in combination with IGCC, is an important element of ERI's long-term energy scenarios, which is why the Institute has become involved in the national discourse on CCS. Within the NZEC consortium, ERI has been involved in Work Package 2, which aims to identify technologies and fuels that could be deployed in China to meet the country's long-term energy needs by 2050.

North China Electric Power University (NEPU)

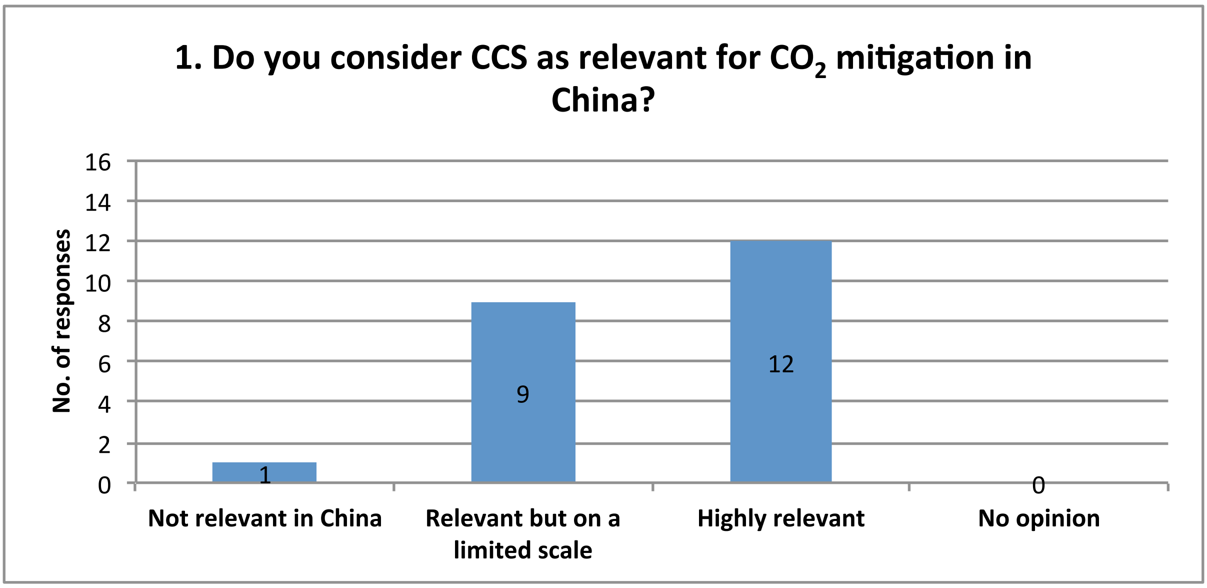
NEPU's focus with regard to CCS is the technical assessment and development of CO_2 capture processes. For example, NEPU is investigating the application and integration of CO_2 capture processes within coal-fired power generation processes. Accordingly, NEPU participated in Work Package 3 of the NZEC project, evaluating carbon capture technology options.

Zhejiang University

As part of the NZEC consortium, Zhejiang University contributed to NZEC Work Package 1 on knowledge sharing and capacity building and Work Package 3 focusing on carbon capture case studies. Furthermore, the University has hosted summer and spring schools on CCS in China, organised as part of the COACH project. Its contributions focus on post-combustion and oxyfuel processes.

23.3 Survey on the Prospects of CCS in China

The graphs presented below illustrate the responses of 22 Chinese CCS experts to a standardised survey encompassing six key questions on the prospects of CCS in China. The results indicate that, despite China's opposition to a global climate policy regime with binding CO_2 mitigation targets, most of the Chinese experts consulted consider CCS technology to be a relevant or even highly relevant CO_2 mitigation option for China. Responses to the second question of the survey suggest a broad mutual understanding that the Chinese government also perceives CCS as a potentially important CO_2 mitigation technology that is likely to be demonstrated using public funding. However, responses also suggest that international commitment and financial support are important prerequisites for the demonstration of CCS in China. This perception is in line with the current situation where many R&D projects on CCS in China are financed wholly or partially by international sources.



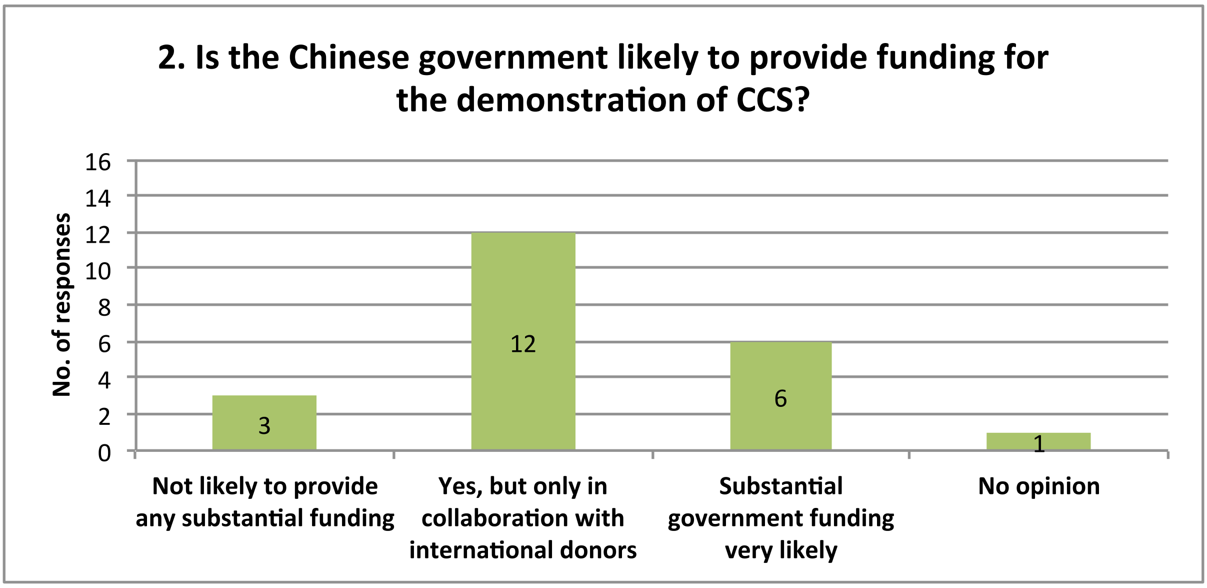
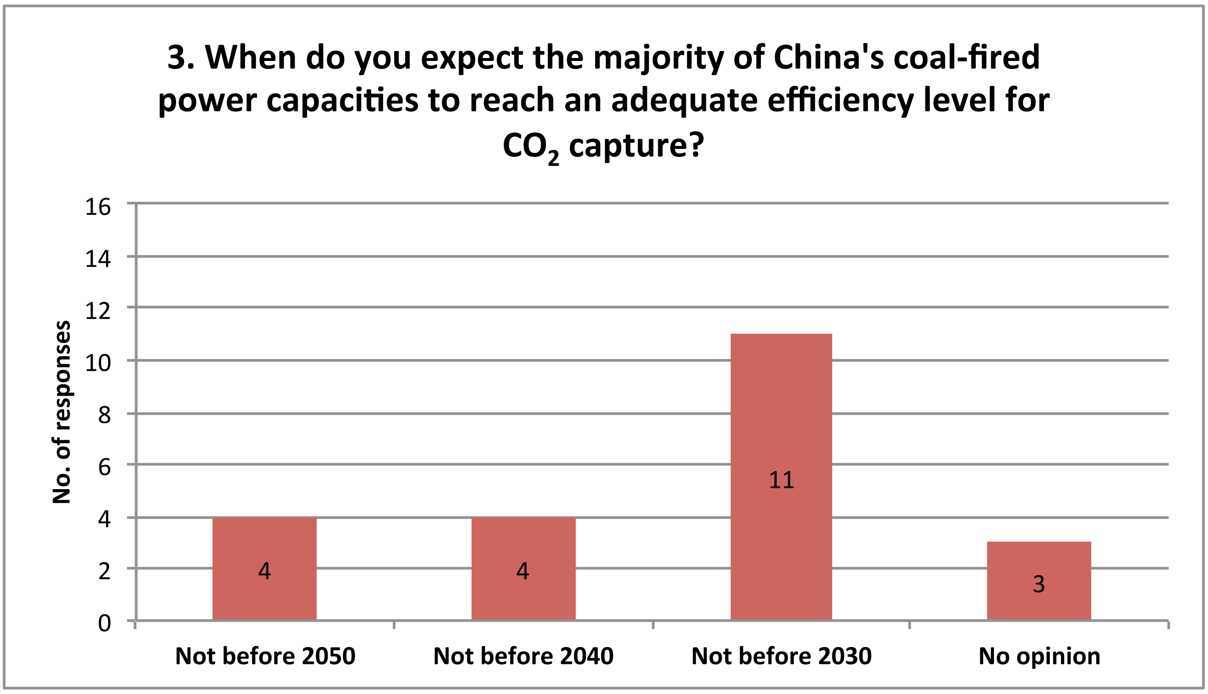


Fig. 23-1 Results of an expert survey on the perspectives of CCS in China – questions 1 and 2

Source: Authors' illustration

The deployment of CCS in China's power sector is considered as a medium- to long-term scenario and is not expected to be implemented before 2030. This outcome is widely compatible with the views of European and German CCS experts, who do not expect CCS technology to be ready for large-scale operation before 2025 or 2030 (Vallentin et al. 2010). In China, however, an even longer delay in the start of CCS deployment is considered relatively likely. Of the 22 Chinese experts interviewed, a total of eight respondents (four each) do not expect CCS to become widely applied in the national power sector before 2040 or 2050. Furthermore, the deployment of CCS is expected to remain restricted to a rather limited proportion of China's coal-fired power plant fleet. Most of the CCS experts consulted project that less than 50 per cent of China's coal-fired power plants will be equipped with CCS technology by 2050.



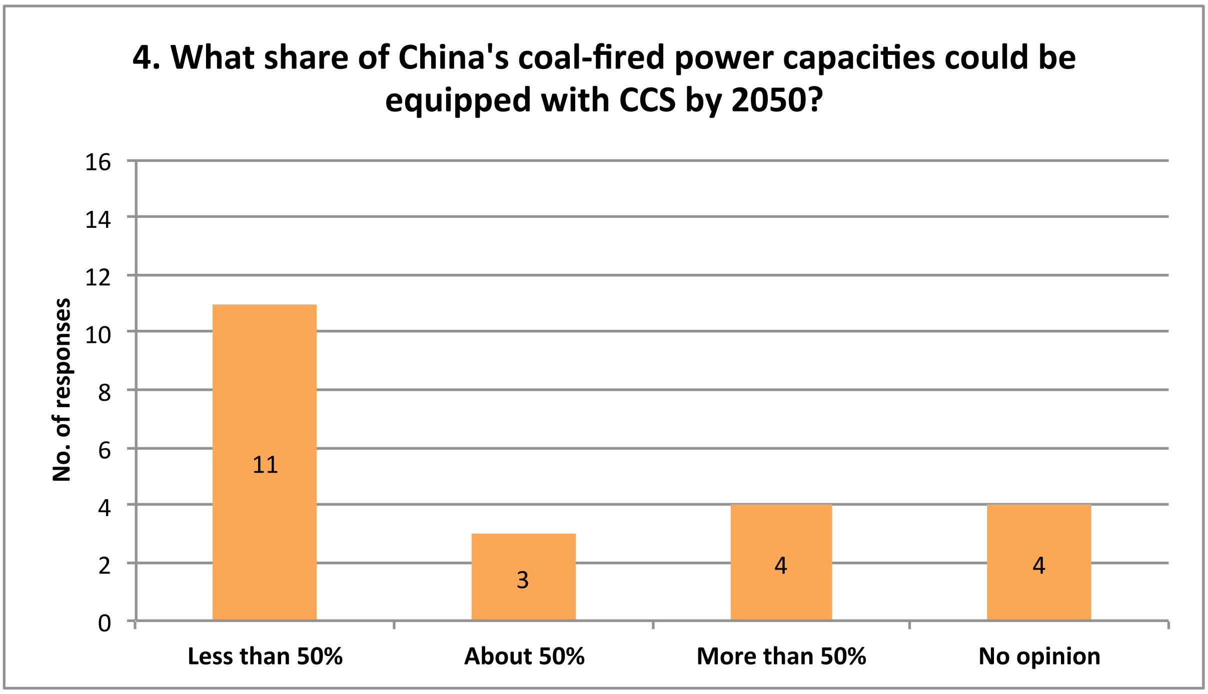
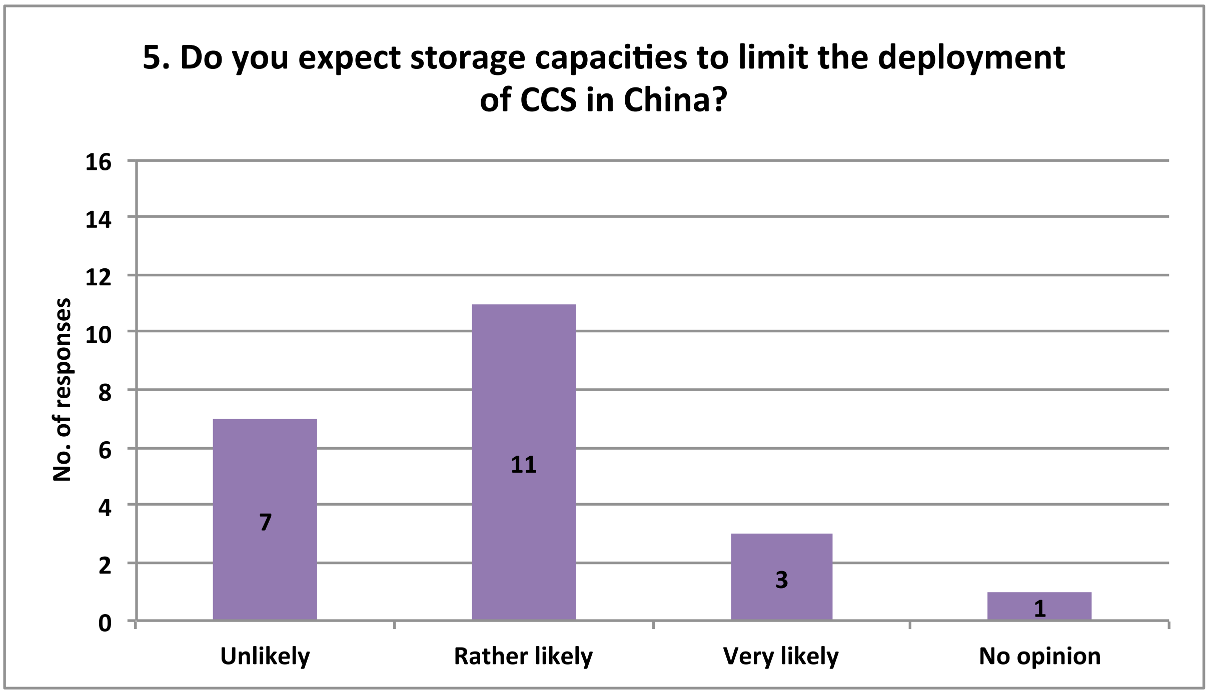


Fig. 23-2 Results of an expert survey on the perspectives of CCS in China – questions 3 and 4

Source: Authors' illustration

An important parameter for CCS deployment in China is the national potential for CO_2 storage. Existing estimates and assessments are highly uncertain and do not allow a qualified judgement to be made. Nonetheless, most respondents consider the capacity of potential national CO_2 storage formations and the distances between storage sites and CO_2 sources to be likely barriers to the deployment of CCS in China. The others experts, however, do not see the storage part of the CCS chain as a serious future obstacle to the technology's utilisation and deployment.



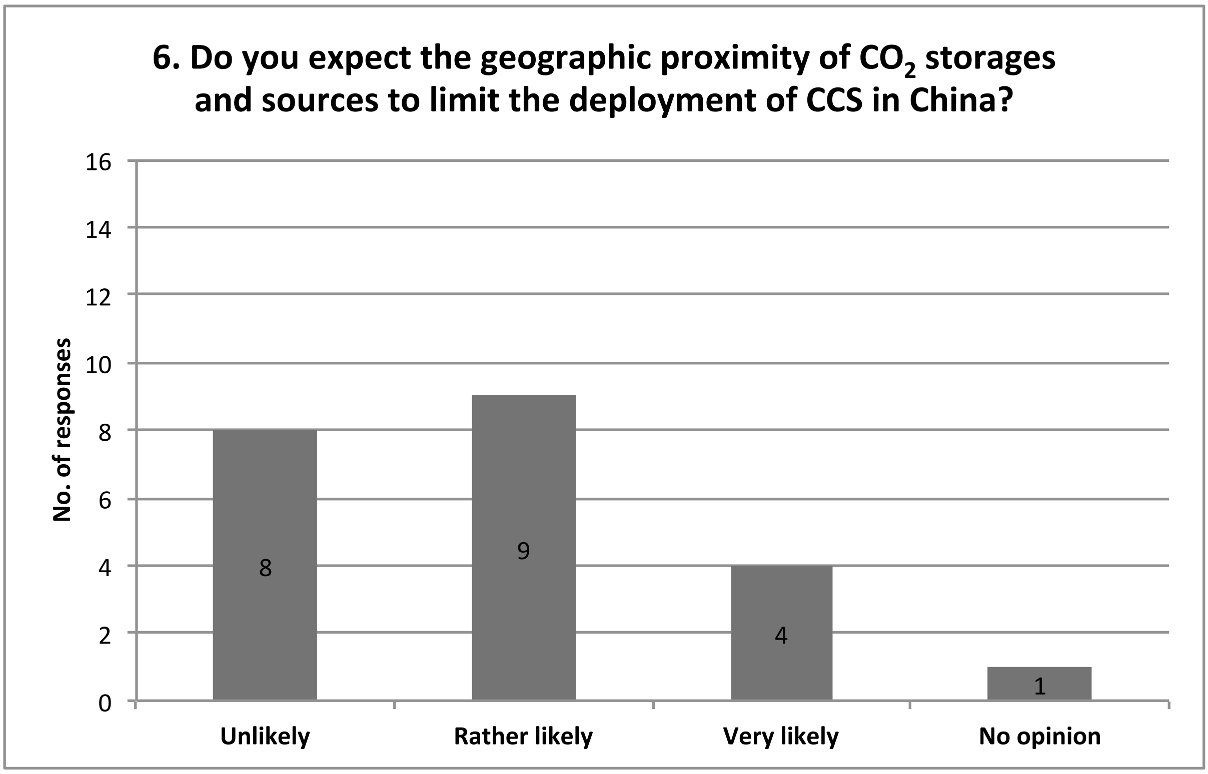


Fig. 23-3 Results of an expert survey on the perspectives of CCS in China – questions 5 and 6

Source: Authors' illustration

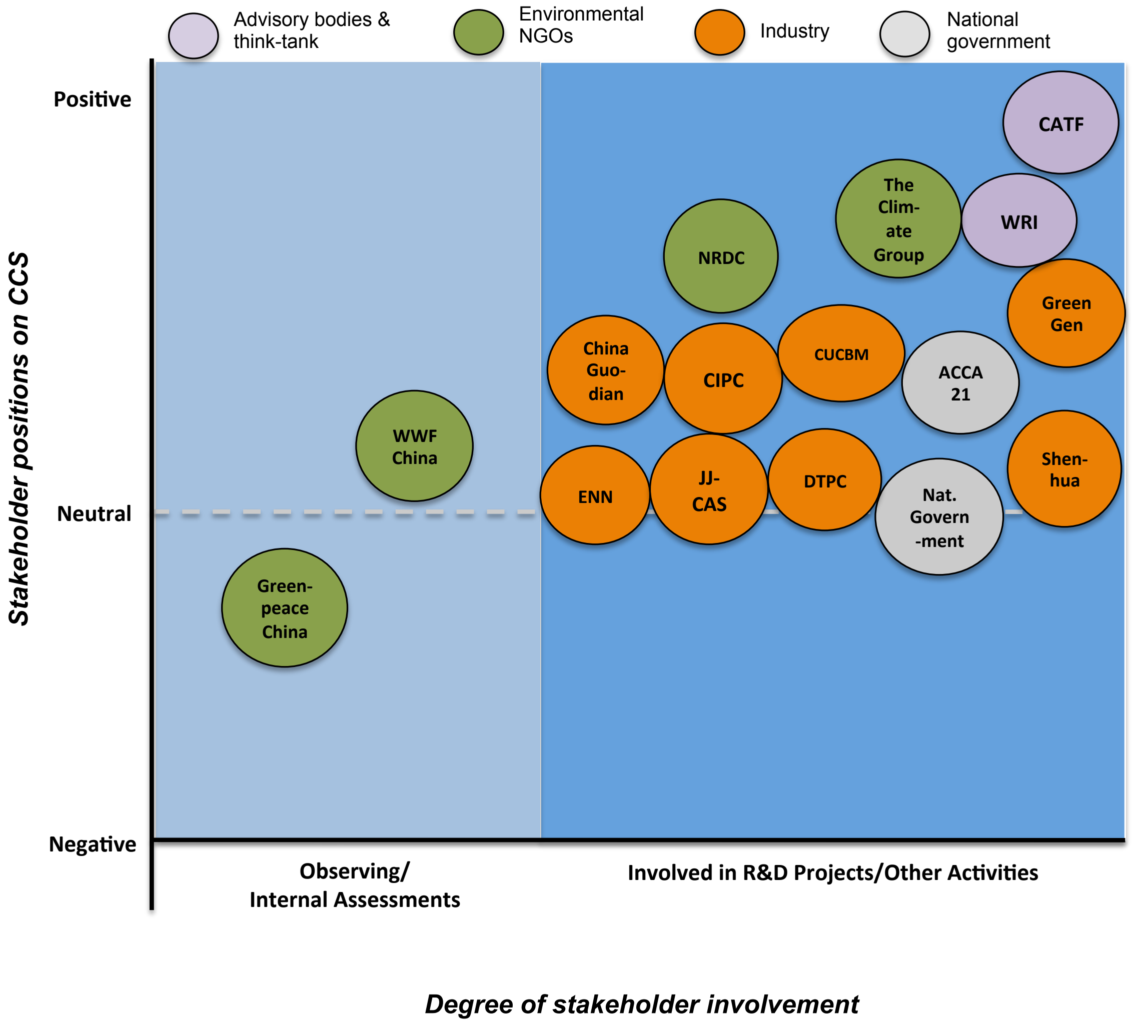
23.4 Conclusions

Overall, it can be concluded that a wide range of stakeholders are actively working on CCS and fostering the technology's demonstration and development. Fig. 23-4 illustrates the constellation of actors in the Chinese CCS discourse. The illustration omits scientific institutes because they are deemed per se to be technology neutral. Furthermore, it must be emphasised that this analysis focused on key stakeholders that already play an active role in the

Chinese discussion on CCS, whereas non-active actors were not considered in detail due to the large number of potentially relevant political, economic and scientific players in China. Consequently, the illustration suggests a high level of activity of the actors presented.

CCS is considered a potentially important future technology option, particularly in the power sector, that needs to be developed. National oil companies, namely PetroChina and Sinopec, are mainly interested in enhanced oil recovery. In the science sector, numerous universities and research institutes are involved in CCS-related research projects. To date, most research activities address technical issues, especially on the capture side of the CCS technology chain. CO_2 storage is being investigated by a number of geological research institutes with a particular focus on enhanced oil recovery. “Soft” issues, such as the political and socio-economic implications of CCS in China, are underrepresented.

The Chinese government pursues a rather cautious approach in developing and demonstrating CCS. With regard to international climate policy negotiations, CCS is considered a technology that could become relevant if ambitious CO_2 mitigation obligations were adopted by the international community. Furthermore, the government intends to develop technological know-how in the field of CCS in order to provide opportunities for the technology to be exported in the future. However, the government is certainly no enthusiastic advocate of CCS, mainly due to the high costs and energy intensity involved in the technology. To alleviate the economic drawbacks of CCS, the Chinese government attaches great importance to possibilities of CO_2 use. Nonetheless, the technology’s large-scale application and deployment is expected to proceed slowly, commencing no earlier than 2030. This projection is in line with statements made by numerous respondents that industrial and political decision-makers in China regard CCS as a back-up or emergency technology for complying with possible long-term CO_2 mitigation obligations.



Abbreviations

ACCA 21: Admin. Centre for China's Agenda 21
CATF: Clean Air Task Force
CIPC: China Investment Power Corporation
CUCBM: China United Coalbed Methane
DTPC: Dongguan Taiyangzhou Power Corp.
ENN: ENN Group
JJ-CAS: Jiangsu Jinlong-CAS Chemical Co.
WRI: World Resources Institute
WWF: World Wide Fund for Nature

Fig. 23-4 Constellation of key CCS stakeholders in China

Source: Authors' illustration

24 Integrative Assessment of Carbon Capture and Storage

24.1 Overall Conclusions on the Prospects of CCS in China

Aim of the Study

The aim of this study was to explore whether carbon capture and storage (CCS) could be a viable technological option for significantly reducing CO_2 emissions in emerging countries such as China, India and South Africa. These key countries were chosen as case studies because all three, which hold vast coal reserves, are experiencing a rapidly growing demand for energy, currently based primarily on the use of coal. For this reason, the study mainly focused on CO_2 emissions from coal-based electricity generation supplemented by a rough analysis of emissions from industry.

The analysis was designed as an integrated assessment, and takes various perspectives. The main objective was to analyse how much CO_2 can potentially be stored securely and for the long term in geological formations in the selected countries. Based on source-sink matching, the estimated CO_2 storage potential was compared with the quantity of CO_2 that could potentially be separated from power plants and industrial facilities according to a long-term analysis up to 2050. This analysis was framed by an evaluation of coal reserves, levelised costs of electricity, ecological implications and stakeholder positions. The study finally draws conclusions on the future roles of technology cooperation and climate policy as well as research and development (R&D) in the field of CCS.

The presented report shows that in the case of *China*, these questions cannot be answered fully on the basis of currently available data and expertise. The analysis reveals that the main constraint on the deployment of CCS in China is the lack of detailed knowledge about potential storage sites.

Results of Storage Capacity Assessment

The few existing estimates for China indicate a wide range of available *theoretical* capacities from 32 to 3,090 Gt of CO_2, mainly due to variations in saline aquifers. In order to yield *effective* storage capacities, which reduce the theoretical capacity of aquifers to the total pore volume that can effectively be used, efficiency factors have to be applied. Since the real efficiency factors are not known, an “if … then” approach was applied to show how the effective storage capacity will vary depending on different efficiency factors. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based on efficiency factors of 2, 16 and 50 per cent. In addition to aquifers, a small capacity of oil and gas fields was considered. The results range from 65 to 1,542 Gt of *effective storage potential*. However, due to the lack of geological data in China, any calculations of storage capacity quantities can only be highly speculative and therefore should be treated with caution.

Deriving of the Quantity of CCS-CO_2 available for Storage

This range of CO_2 storage capacities was compared with the cumulated amount of CO_2 emissions that could potentially be captured from power plants and industrial facilities in the long term. Due to the extent of uncertainty regarding the future development of China’s energy system, again, an “if … then” analysis was performed. Firstly, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were devised. These pathways, based on existing energy scenarios for China, project different trends of coal-based power plant capacities, ranging from 350 to 1,560 GW installed capacity in 2050. These pathways were supplemented by one single industrial development pathway (*I*). Secondly, the quantity of CO_2 that could be separated, based on the assumption that CCS may be commercially available from 2030 in China, was calculated for each pathway.

Results of Source-Sink Match

Finally, a source-sink match was performed assuming a maximum transport distance of 500 km because longer distances would significantly affect the cost balance and create infrastructural barriers. The results indicate that less than 70 per cent of the effective storage potential could be used in all cases, and less than 50 per cent in most cases. This result is due to the long distances between most sources and the sinks that are beyond the considered maximum distance. However, the effective storage potential was reduced further to a *practical storage potential* by taking into account economic conditions, potential problems concerning acceptance and technical feasibility problems. However, these parameters cannot be assessed properly until specific CCS projects are planned.

If, therefore, more detailed assessments of China's storage potential verify the high storage scenario S1 in the future and if the practical capacity is not considerably lower, a large quantity of CO_2 emissions derived from the high development pathways E1 and E2 could be stored. On the other hand, if the low storage scenario S3 reflects the country's effective storage potential most realistically and its practical capacity turned out to be much lower than the effective capacity, it would only be possible to sequester a fraction of the separable CO_2 emissions.

Further Assessment Dimensions

The matching of CO_2 sources and geological sinks provides an indicative framework illustrating how much CO_2 could be sequestered given technical and geological constraints. To complete the picture, a supplementary technology assessment considering socio-economic and ecological conditions in the respective countries was prepared in this study.

- First of all, there is a significant economic barrier to achieving the economic viability of CCS in China under current conditions (CO_2 price development), making policy incentives such as a CO_2 pricing scheme a crucial precondition for the commercialisation of CCS. However, due to lower plant capital costs, the cost penalty of CCS in China is significantly below that in industrialised countries or other emerging economies. In the presence of a CO_2 price as assumed in the presented analysis, CCS plants would be more competitive than plants without CCS in both 2040 and 2050.
- Since the proven recoverable coal reserves in China were significantly revised downwards, a high coal development pathway could lead to considerable constraints and rising coal prices in the medium term, exacerbated by the increased consumption of coal in the event of CCS.
- The coal penalty incurred by CCS associated with large methane emissions from coal mining and additional GHG emissions caused by huge uncontrolled coal fires in China also leads to a reduction in total GHG emissions of only 59 to 60 per cent. Even if emissions were reduced in the future, the negative impacts in all other environmental categories would rise.

- Last but not least, the Chinese government is not an enthusiastic advocate of CCS, mainly due to the high costs and energy penalty associated with the technology. However, political and industrial decision-makers in China regard CCS as a back-up or emergency technology for complying with possible long-term CO_2 mitigation obligations. Long-term strategies may therefore foster the deployment of CCS in China.

Results of Integrated Assessment of CCS in China

In Tab. 24-1 the results illustrating the individual assessment dimensions are assembled so that an integrated assessment can be undertaken. The effect of each assessment dimension on the future role of CCS is ranked between 1 and 5 in five categories. Whilst the highest score (5) illustrates a strong incentive for CCS, the lowest score (1) represents a strong barrier to CCS development.

Tab. 24-1 Integrated assessment of CCS in China – assessing the individual dimensions in a range from 1 (strong barrier to CCS) to 5 (strong incentive for CCS)

Assessment dimension	Categorisation of sub-dimensions	Incentive or barrier to the future role of CCS in China
Storage capacity	High storage scenario	5
and source-sink match	Intermediate storage scenario	5
	Low storage scenario	1
Assessment of coal reserves		2
Cost assessment	Low CO_2 price development	1
	Assumed CO_2 price development	4
	Higher CO_2 price development	5
Ecological assessment	Reduction in CO_2 emissions per kWh of electricity	4
	Reduction in total GHG emissions per kWh of electricity	3
	Impact on other environmental impact categories	1.5
	Impacts on local environment and health	2
Stakeholder analysis	Current perspective	2
	Long-term prospects	3

GHG = greenhouse gas

The classification is undertaken using indicators 1 to 5, where 5 illustrates a strong incentive for CCS development in each country and 1 represents a strong barrier to CCS.

Source: Authors' composition

Fig. 24-1 presents the results for China. For the crucial parameters – storage capacity and cost development – the lines above the columns illustrate the range within which these could develop in the event of different framework conditions or assumptions.

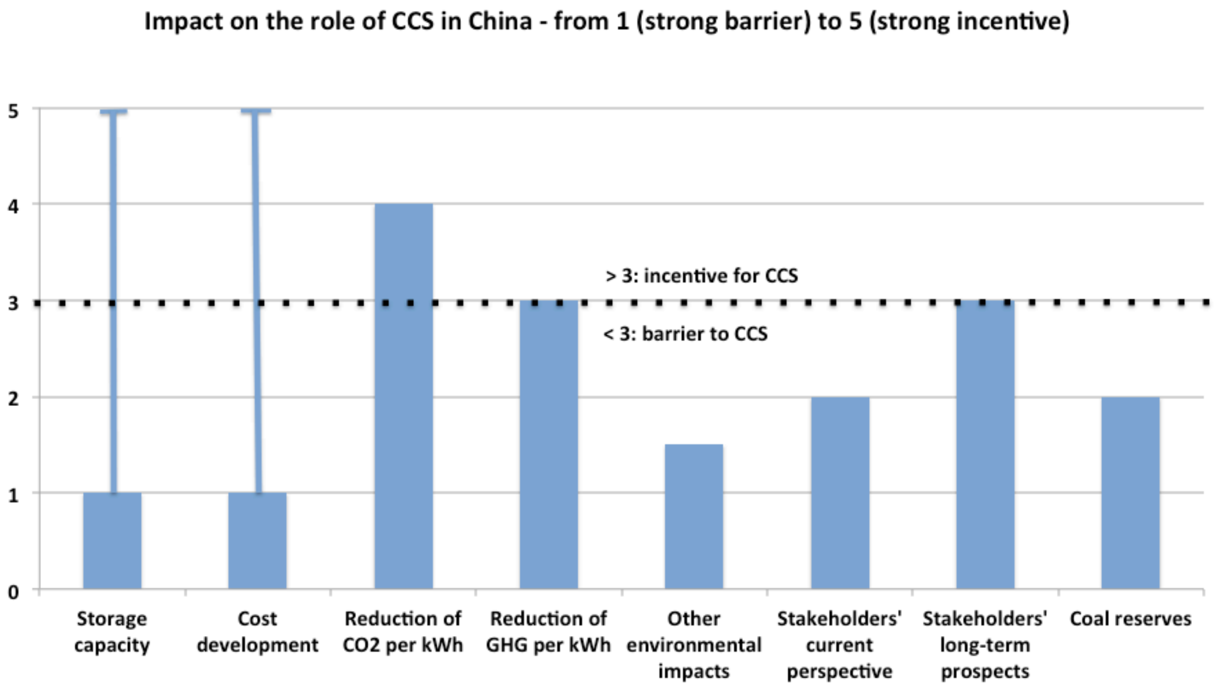


Fig. 24-1 Integrated assessment of the role of CCS in China, including the possible impact variations of storage capacity and cost development

Source: Authors' illustration

Need for Further Research in the Event of Coal-Based Strategies

Existing scenario studies for China reveal different strategies for meeting the future growing demand for electricity:

- One option is to make a considerable effort to achieve drastic improvements in *energy efficiency* together with an ambitious increase in the use of all forms of *renewable energy*. The *Energy [R]evolution Scenarios* from EREC and Greenpeace, for example, show that in such pathways would continue to need conventional coal-fired power plants in order to satisfy energy needs over the next two or three decades but, nonetheless, the climate targets calculated in these scenarios for China would be met without using CCS and nuclear energy. However, such a scenario poses a significant challenge in that renewable energies would have to be systematically integrated into the current energy system. This would be a complex process which would depend on numerous factors.
- The second option is to pursue a fossil fuel-based policy, supplemented by varying shares of nuclear energy or renewable energies as assumed, for example, in the *BLUE Map Scenario* of the IEA and as adopted in the CO_2 emission pathways used in this study. Due to the striking dominance of coal-fired power generation in the countries' electricity sector, this option would require the introduction of CCS at different levels and acknowledging the consequences shown in the integrated assessment. Without CCS, a coal-dominated path would be unable to reduce fossil-related carbon dioxide emissions as substantially as required by climate scientists. However, a precondition for opting for CCS would be the commercial viability of CCS, a decrease in CCS-based electricity costs, long-term policy support and a sufficient amount of proven and safe storage capacity

In order to overcome the existing barriers to the deployment of CCS in China, Chinese experts and decision-makers have made it very clear in the various interviews conducted within this study that the industrialised world would need to make a stronger commitment in terms of technology demonstration and implementation. Furthermore, a substantial cost reduction and mechanisms for technology cooperation and transfer to developing countries and emerging economies would be essential.

24.2 Summary of the Assessment Dimensions in Particular

24.2.1 CO_2 Storage Potential

Storage Assessment and Source-Sink Matching is Highly Speculative due to a Lack of Geological Data

The elaborations above show that the estimate of China's storage potential is very uncertain due to a lack of detailed geological data. The few existing estimates for China span a wide range of available *theoretical* capacities from 32 to 3,090 Gt of CO_2, due mainly to variations in saline aquifers. To yield *effective* storage capacities that reduce the theoretical capacity of aquifers to the total pore volume that can effectively be used, efficiency factors have to be applied. Since the real efficiency factors are not known, an "if … then" approach is applied to show how the results vary depending on different efficiency factors. To this end, three storage scenarios *S1: high*, *S2: intermediate* and *S3: low* were developed based on efficiency factors of 2, 16 and 50 per cent. These factors were applied to the theoretical storage capacities provided in the study by Dahowski et al. (2009), which is the most detailed and advanced study available. In addition to aquifers, a small capacity within oil and gas fields was considered. Storage in coal seams was excluded from all scenarios due to the extent of technical uncertainties. This storage possibility is still at the laboratory stage and it has not yet been proven to work in situ. The results range widely from 65 to 1,542 Gt of *effective storage potential* (see Dahowski et al. (2009)). However, due to the lack of geological data in China, any calculations of storage capacity quantities can only be highly speculative and therefore should be treated with caution.

Tab. 24-2 Scenarios for effective CO_2 storage capacity in China

		S1: high	S2: intermediate (base)	S3: low
Oil fields **Gas fields**		7.8	3.6	3.6
Saline aquifers	Onshore	1,145	366	46
	Offshore	390	125	16
Total		1,542	495	65
All quantities are given in Gt CO_2				

Source: Authors' compilation based on Zhang et al. (2005b) and Dahowski et al. (2009)

This range of CO_2 storage capacity was compared with the cumulated quantity of CO_2 emissions that could potentially be captured from power plants and industrial facilities in the long term. Due to the large degree of uncertainty on the future development of China's energy system, again, an "if … then" analysis was performed. First of all, three long-term coal development pathways for power plants *E1: high*, *E2: middle* and *E3: low* were provided. These pathways, based on existing energy scenarios for China, project different trends of coal-based power plant capacities, ranging from 350 to 1,560 GW installed capacity in 2050. These pathways were supplemented by one single industrial development pathway (*I*). Secondly, the quantity of CO_2 that could be separated, based on the assumption that CCS might be commercially available from 2030 in China, was calculated for each pathway.

A maximum transport distance of 500 km was assumed for the source-sink match because longer distances would significantly affect the cost balance and create infrastructural barriers. Storage scenarios S1–S3 were matched with pathways E1–E3 and the combination of power plant and industry pathways *E1+I: high*, *E2+I: middle* and *E3+I: low*. Tab. 24-3 shows the results in the case of coal development and industrial development pathways E1+I to E3+I.

Tab. 24-3 CO_2 emissions that could be stored as a result of source-sink matching in China

	Energy and industry emission pathways		
Effective storage capacity scenarios	**E1+I: high** (250 Gt CO_2)	**E2+I: middle** (178 Gt CO_2)	**E3+I: low** (60 Gt CO_2)
	Matched capacity (Gt CO_2)		
S1: high (1,541 Gt CO_2)	216	154	52
S2: intermediate (494 Gt CO_2)	205	154	52
S3: low (65 Gt CO_2)	45	44	36
	Share of effective storage capacity used (%)		
S1: high (1,541 Gt CO_2)	14	10	3
S2: intermediate (494 Gt CO_2)	41	31	10
S3: low (65 Gt CO_2)	70	68	55
	Share of emissions that could be stored (%)		
S1: high (1,541 Gt CO_2)	87	87	87
S2: intermediate (494 Gt CO_2)	82	87	87
S3: low (65 Gt CO_2)	18	25	60
The maximum transport distance is assumed to be 500 km.			

Source: Authors' calculation

In general, 70 per cent or less of the effective storage potential is used in all cases and less than 50 per cent in most cases. In the case of the low storage scenario S3, between 45 and 70 per cent of the sites are filled because of the long distance between most of the sources and the considered sinks, which exceed the maximum transport distance of 500 km. Utilisation of the separated CO_2 emissions is low with storage scenario S3, where only 18 to 29 per cent of the emissions from coal development pathways E1 and E2 could be sequestered (60 to 87 per cent in the case of E3). In contrast, with the high and middle storage scenarios S1 and S2 it would be possible to store 82 to 87 per cent of all separated CO_2 emissions.

One way to increase the matched capacity could be to relocate emission sources closer to potential sinks. In this case, an optimisation model is required to determine the cost optimal solution between the *transportation of electricity*, the *fuel*, the *separated CO_2 emissions* and even the *cooling water*. However, potential environmental and socio-economic problems must be taken into account in addition to the economic dimension.

Interpreting these results, two further constraints should be noted:

- In the given source-sink match, only the base case coal development pathways are considered, equating to a commercial availability of CCS from 2030 and an operation of 7,000 full load hours per year. If CCS is available later, in 2035 or in 2040, CO_2 emissions provided for storage will be 15 or even 17 per cent lower (see section (2009)). If an operation of only 6,000 full load hours is achieved (load factor of 69 per cent) or if the very optimistic level of 8,000 full load hours is realised (load factor of 91 per cent), the quantity of separated CO_2 emissions would decrease or increase by 14 per cent.
- To date, CO_2 sources and sinks have only been preliminarily matched. The transport distances have not been verified in detail and are only based on rough estimates, taking into account a maximum distance of 500 km. In a further elaboration of this study, a geographic information system should be applied to achieve a more precise assessment, using the exact locations of power plants and industrial sites. This information could be coupled with more detailed information on geological basins, if available in the future, to reduce transport distances between sources and sinks and to increase the certainty of estimates.

In the future, further steps must be taken to achieve a better and more detailed assessment, enabling a “real” matched capacity to be derived:

- Investigate each basin and field in detail to obtain detailed information about the geological underground;
- Determine more detailed locations of possible storage sites within the basins to enable more precise, quantitative source-sink matching to be conducted;
- Derive a practical storage potential (top layer of the storage pyramid) considering economic conditions, possible acceptance problems in the regions concerned and technical feasibility problems.

Finally, the *practical* capacity will be lower than the matched capacity discussed in this report. Until these details are explored, even the lowest effective storage capacity scenario S3 should not be considered as an upper variant of what could be realised in China – the final figures, and therefore the final results, of source-sink matching may actually be considerably lower, taking into account economic conditions, potential problems concerning acceptance and technical feasibility problems.

21.4.1 Further Assessment Dimensions

Decreasing Coal Reserves will Lead to Increasing Coal Prices in the Future

Chinese proven recoverable coal reserves total between 114.5 and 182 billion tonnes. Including probable reserves, this figure increases to 319 billion tonnes, as reported for the end of 2009 in the Chinese Statistical Yearbook. Both figures are the result of a massive downward revision by nearly 70 per cent between 1990 and 1999. Based on coal production of about 3.3 billion tonnes in 2010, the static reserve-to-production ratio is between 35 and 100 years. Even the upper figure would not allow China’s coal production to continue to increase at the present growth rate for more than one or two decades. Unavoidably, this rise will come to an end in the not too distant future – steadily increasing imports of coal are a first sign of this. The present analysis shows that the proven recoverable coal reserves are not sufficient to meet the demand for coal, at least in the high case coal development pathway E1 with

CCS, which would require 110 to 146 billion tonnes for all power plants installed up to 2050. The pathways with the lowest cumulative demand (56 to 74 billion tonnes for *E3: low*) may still enable the production rate to increase.

Even more problematic is the rising demand for coal imports. Ten years ago, China was one of the largest coal exporting countries supplying Asia and even the EU. This has dramatically changed. In 2010, China became the world's second largest importing country, requiring 166 million tonnes. Indonesia is the most important country for Chinese coal imports. China's coal supply will probably encounter serious restrictions once Indonesia limits or reduces its exports, as already announced, and no other country can compensate for this deficit.

Economic Advantage of CCS-Based Plants in a Carbon Pricing Regime

These cost projections are based on three different pathways for the development of coal-fired power generating capacities in China with and without CCS. The role of coal-fired power plants in these coal development pathways is influenced by different levels of ambition for policy frameworks involving climate protection and sustainable energy. Whereas pathway *E1: high* is based on reference conditions, pathways *E2: middle* and *E3: low* imply more ambitious policy settings. The capacity developments in these three pathways are used as input for calculating learning rates and cost reductions of coal-fired power plants with and without CCS.

The cost assessment indicates that the learning effects and, thus, cost reductions of supercritical PC plants both with and without CCS are more or less minor in all three outlined coal development pathways because supercritical PC plants represent a mature, widely deployed technology. As a consequence, reduced capital and O&M costs are overcompensated by increasing fuel costs, leading to increasing levelised costs of electricity production in the considered timeframe. For example, the LCOE of non-CCS plants is projected to increase from US-ct 4.37/kWh in 2010 to US-ct 5.73/kWh in 2050 across the different development pathways. Although CCS plants involve a higher learning rate than conventional PC plants, they have a clearly higher LCOE, ranging from US-ct 6.72/kWh by 2040 to US-ct 7.50/kWh by 2050, mainly due to additional fuel and capital expenditures. In the same year, CO_2 mitigation costs incurred by China's CCS plants range from USD 24 to 25 per tonne of CO_2.

The outlined results suggest that there is currently a significant economic barrier to the economic viability of CCS, making policy incentives a crucial precondition for the commercialisation of CCS. However, due to lower plant capital costs, the cost penalty of CCS in China is significantly less than that in industrialised countries or other emerging economies even if a future increase of coal prices is included. For this reason, introducing a carbon price could significantly improve the competitiveness of CCS plants against non-CCS plants and outweigh the cost penalty of CCS plants. In the presence of a CO_2 price as assumed in the given analysis, CCS plants would be more competitive than plants without CCS in both 2040 and 2050. Fig. 24-2 shows this by way of the middle coal development pathway E2.

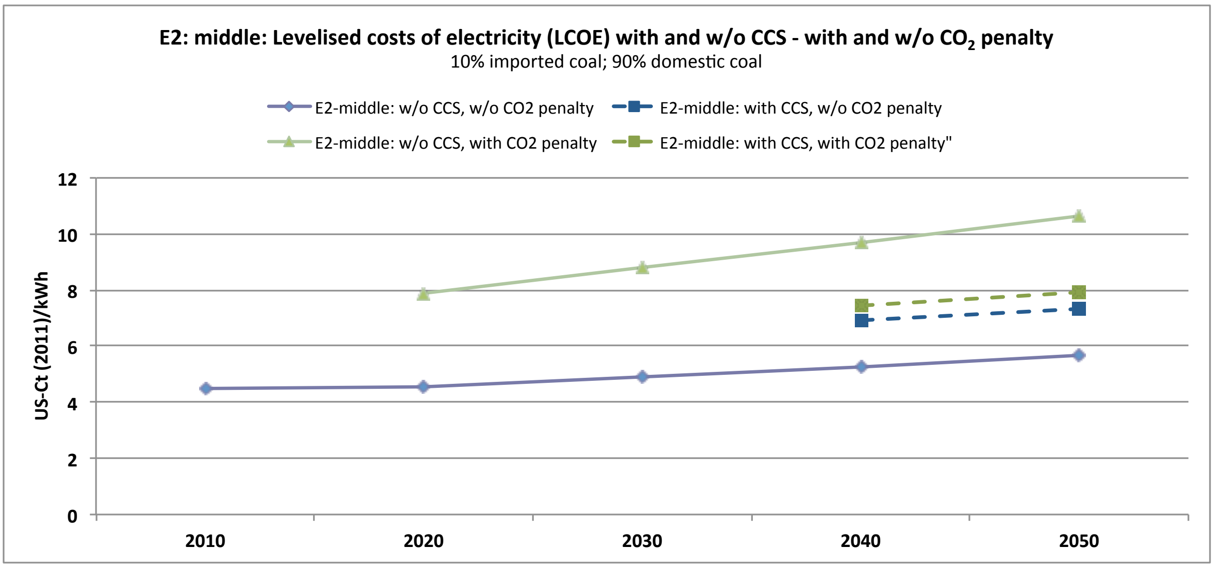


Fig. 24-2 Levelised cost of electricity in China with and without CCS and with and without a CO_2 penalty in coal development pathway *E2: middle* up to 2050

Source: Authors' illustration

However, the stimulating economic framework conditions in China may be alleviated in the decades ahead as Chinese labour and equipment costs are expected to steadily increase. Furthermore, it must be taken into account that CCS plants will face strong competition from other low carbon technologies, especially renewable energy technologies, which have much higher learning rates than supercritical PC plants with CCS. Thus, CCS plants would need to be compared with other low carbon technology options to draw profound conclusions on the economic viability of CCS in a low carbon policy environment.

Reduction of Greenhouse Gases but Increase of Environmental Impacts

A prospective life cycle analysis (LCA) of future CCS-based power plants in China was performed to assess the environmental impact of CCS. Taking into account a CO_2 capture rate of 90 per cent, PC and IGCC power plants with and without CCS were compared. The results show a 75 per cent decrease in CO_2 emissions for both PC and IGCC systems. Total GHG emissions are reduced by 60 and 59 per cent, respectively (Fig. 24-3). However, most other environmental impact factors increase for pulverised power plants and IGCC (eutrophication, human toxicity, terrestrial ecotoxicity, freshwater and marine aquatic ecotoxicity and stratospheric ozone depletion) whilst acidification and summer smog decrease in the case of pulverised power plants and increase in the case of IGCC.

In general, two issues are responsible for these results. Firstly, the additional energy consumption of CCS-based power plants (energy penalty) creates greater emissions per kilowatt hour of electricity generated in the power plant. Only CO_2, NO_x and SO_2 are removed from these emissions during the CO_2 scrubbing process. Secondly, the additional emissions caused by upstream and downstream processes have to be considered. Both the excess consumption of fuels and additional processes such as production of solvents or the transportation and storage of CO_2 cause an increase in several emissions. When these emissions are (partially) removed at the power plant's stack, the upstream and downstream emissions dominate the respective impact categories.

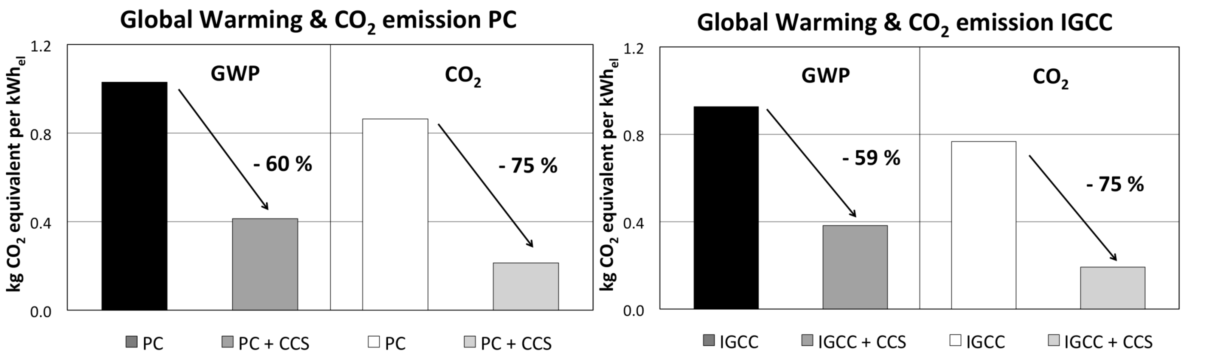


Fig. 24-3 Global -warming potential and CO_2 emissions for PC and IGCC with and without CCS in China from a life cycle perspective

Source: Based on Deibl (2011)

However, on a global perspective GHG reduction rates are lower than expected. In general, an overall reduction in GHG emissions of between 67 and 75 per cent can be expected if post-combustion and pre-combustion is applied to hard coal-fired power plants in 2020/25. In the case of China, upstream emissions play a much greater role since mining causes much higher coalbed methane emissions than in other countries. This effect places additional emissions burdens on each kilogramme of coal that will not be captured in the event of CCS. Fig. 24-4 shows the contribution of the individual life cycle phases for PC power plants – the coal supply share increases from 22 per cent without CCS to 66 per cent in the case of power plants with CCS.

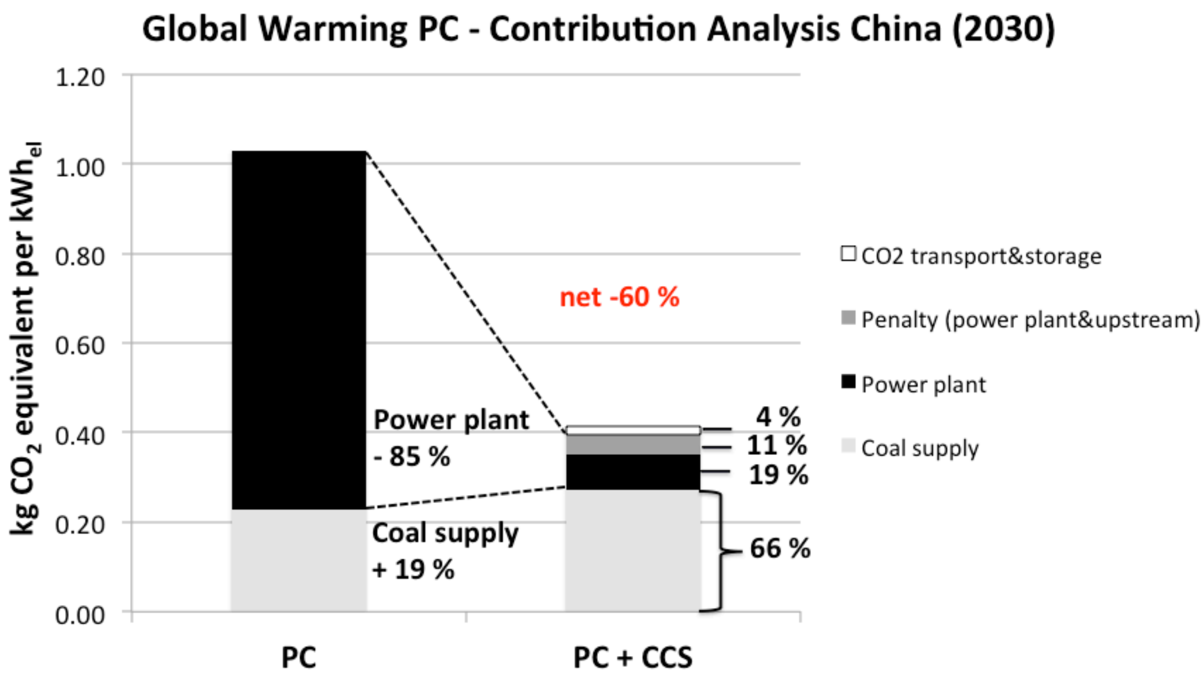


Fig. 24-4 Contribution of individual life cycle phases to the Global Warming Potential for PC with and without CCS in China

Source: Authors' composition based on Deibl (2011)

The absolute scores and general framework of the LCA model must be considered when interpreting the results. A wide range of assumptions for capture, transportation and storage, timing of the CCS process, type of reference power plant and choice of parameters makes it difficult to compare the results with LCAs performed in other studies. Furthermore, it is not possible at present to model the capture process in detail due to the lack of data. Variations of the removal rate of pollutants in particular could alter the results substantially. Regarding the present study, further limitations must be borne in mind: only little data on the performance of power plants exists in China. The uncertainty surrounding the future technical development up to the reference year 2030 necessitates the use of assumptions, which could mislead the results. This particularly concerns the assumed power plants efficiencies and the datasets for modelling the upstream process of coal mining. GHG emissions from coal fires may play a role, but it was not possible to estimate them on a reliable basis. This reveals a general need to update existing LCAs of coal-based electricity production in China and to consider the possible reduction of upstream emissions, for example by utilising methane emissions from mining for electricity production.

Furthermore, coal mining leads to manifold ecological and social problems, which are not covered by LCAs. A commercialisation of CCS would reinforce these impacts because CCS-based power plants require 30 to 35 per cent more fuel than those without CCS. Most problems refer to land use, water consumption, air pollution at the mining site and surrounding residential areas, noise, mine waste and – last but not least – social issues resulting from the displacement and resettlement of local communities.

Stakeholders' Cautious Approach to CCS

Overall, it can be concluded that a wide range of stakeholders are actively working on CCS and fostering the technology's demonstration and development. CCS is considered a potentially important future technology option, particularly in the power sector, that should be developed. National oil companies, namely PetroChina and Sinopec, are mainly interested in enhanced oil recovery. In the science sector, numerous universities and research institutes are involved in CCS-related research projects. To date, most research activities address technical issues, especially on the capture side of the CCS technology chain. CO_2 storage is being investigated by a number of geological research institutes with a particular focus on enhanced oil recovery. "Soft" issues, such as the political and socio-economic implications of CCS in China, are underrepresented.

The Chinese government pursues a rather cautious approach in developing and demonstrating CCS. With regard to international climate policy negotiations, CCS is considered a technology that could become relevant if ambitious CO_2 mitigation obligations were adopted by the international community. Furthermore, the government intends to develop technological know-how in the field of CCS in order to provide opportunities for future technology exports. However, the government is certainly no enthusiastic advocate of CCS, mainly due to the high costs and energy penalty involved in the technology. To alleviate the economic drawbacks of CCS, the Chinese government attaches great importance to possibilities of CO_2 usage. Nonetheless, the technology's large-scale application and deployment is expected to proceed slowly, commencing no earlier than 2030. This projection is in line with the statements made by numerous respondents that industrial and political decision-makers in China regard CCS as a back-up or emergency technology for complying with possible long-term CO_2 mitigation obligations. Long-term strategies therefore may foster the deployment of CCS in China.

25 Annex China

Tab. 25-1 Source-sink match of storage scenario S2 with coal development pathways E1, E2 and E3 in China

Basin	**Effective storage capacity**		**Available for emissions from**	**E1: high**	**E2: middle**	**E3: low**
	Saline aquifers	Oil and gas fields				
Onshore						
Bohai	37.3	1.2	Beijing	0.6	0.4	0.1
			Tianjin	4.2	2.9	0.6
			Hebei	13.0	8.9	2.0
			Shandong	17.0	11.6	2.7
			Liaoning	3.7	5.4	1.0
			Henan		9.4	2.7
Songliao	36.4	1.3	Jilin	3.6	2.4	0.4
			Heilongjiang	4.5	3.0	0.5
Sanjiang	7.2	0.0	Heilongjiang			
Subei	14.4	0.1	Jiangsu	14.5	14.5	3.3
Ordos	41.0	0.4	Inner Mongolia	18.3	12.5	2.8
			Shaanxi	6.3	4.4	1.0
			Shanxi	14.2	9.7	2.2
			Ningxia Hui	2.6	2.1	0.5
			Gansu		2.0	0.5
Erlian	13.6	0.0	Inner Mongolia			
HeHuai	28.5		Henan	17.3	2.4	
			Anhui	10.1	6.9	1.6
Nanxiang	1.2	0.1	Henan			
Tarim	119.3	0.1	Xinjiang	1.3	0.9	0.2
Turpan-Hami	8.7	0.1	Xinjiang			
Junggar	31.5	0.2	Xinjiang			
Sichuan	12.4	0.0	Sichuan	4.0	2.7	0.6
JiangHan - Dongting	8.4	0.0	Hubei	5.8	3.9	0.9
Qaidam	3.4	0.1	Qinghai			
Hailaer	2.6	0.0	Inner Mongolia			
Total onshore	366.1	3.4		140.9	105.9	23.6
Offshore						
East China Sea	54.7	0.0	Zhejiang	12.7	8.7	2.0
			Fujian	5.2	3.6	0.8
			Jiangsu	6.9	0.1	
Southern Yellow Sea	21.4		Jiangsu			
			Shandong			
Bohai Bay	17.5	0.1	Shandong			
			Beijing			

			Tianjin			
			Hebei			
			Liaoning	4.3		
Zhujiangkou (Pearl River Mouth)	11.2	0.1	Guangdong	11.2	9.2	2.1
			Hainan		0.7	0.2
Yinggehai	9.0	0.0	Hainan	0.9		
Northern Yellow Sea	5.0		Jiangsu			
			Shandong			
Beibu Gulf	3.8	0.0	Guangxi	3.6	2.5	0.6
			Guangdong			
Western Taiwan	1.8		Fujian			
Total offshore	124.3	0.2		44.9	24.8	5.7
Total matched capacity	**490.4**	**3.6**		**185.8**	**130.7**	**29.3**

All values are given in Gt CO_2

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

Tab. 25-2 Source-sink match of storage scenario S1 with coal development pathways E1, E2 and E3 in China

Basin	**Effective storage capacity**		**Available for emissions from**	**E1: high**	**E2: middle**	**E3: low**
	Saline aquifers	Oil and gas fields				
Onshore						
Bohai	116.7	1.3	Beijing	0.6	0.4	0.1
			Tianjin	4.2	2.9	0.6
			Hebei	13.0	8.9	2.0
			Shandong	17.0	11.6	2.7
			Liaoning	8.1	5.4	1.0
			Henan	17.3	11.8	2.7
Songliao	113.9	1.9	Jilin	3.6	2.4	0.4
			Heilongjiang	4.5	3.0	0.5
Subei	45.0	0.3	Jiangsu	21.3	14.6	3.3
Ordos	128.3	0.7	Inner Mongolia	18.3	12.5	2.8
			Shaanxi	6.3	4.4	1.0
			Shanxi	14.2	9.7	2.2
			Ningxia Hui	3.1	2.1	0.5
			Gansu	3.0	2.0	0.5
HeHuai	89.0		Anhui	10.1	6.9	1.6
Sichuan	38.8	0.1	Sichuan	4.0	2.7	0.6
JiangHan - Dongting	26.4	0.0	Hubei	5.8	3.9	0.9
Tarim	372.9	0.4	Xinjiang	1.3	0.9	0.2

Junggar	98.6	0.4	Xinjiang			
Turpan-Hami	27.2	0.3	Xinjiang			
Erlian	42.5	0.1	Inner Mongolia			
Sanjiang	22.5	0.1	Heilongjiang			
Qaidam	10.8	0.3	Qinghai			
Hailaer	8.1	0.1	Inner Mongolia			
Nanxiang	3.8	0.1	Henan			
Total onshore	1144.1	6.0		155.5	106.1	23.6
Offshore						
East China Sea	170.9	0.2	Zhejiang	12.7	8.7	2.0
			Fujian	5.2	3.6	0.8
			Jiangsu			
Southern Yellow Sea	66.9		Jiangsu			
			Shandong			
Bohai Bay	54.6	0.1	Shandong			
			Beijing			
			Tianjin			
			Hebei			
			Liaoning			
Zhujiangkou (Pearl River Mouth)	34.9	0.3	Guangdong	13.6	9.3	2.1
			Hainan	1.0	0.7	0.2
Yinggehai	28.0	0.2	Hainan			
Northern Yellow Sea	15.8		Jiangsu			
			Shandong			
Beibu Gulf	11.9	0.1	Guangxi	3.6	2.5	0.6
			Guangdong			
Western Taiwan	5.5		Fujian			
Total offshore	388.4	1.0		36.1	24.6	5.7
Total matched capacity	**1,532.5**	**7.0**		**191.6**	**130.7**	**29.3**

All values are given in Gt CO_2

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

Tab. 25-3 Source-sink match of storage scenario S3 with coal development and industrial development pathways E1+I, E2+I and E3+I in China

Basin	**Effective storage capacity**		**Available for emissions from**	**E1+I: high**	**E2+I: middle**	**E3+I: low**
	Saline aquifers	Oil and gas fields				
Onshore						
Bohai	4.7	1.2	Beijing	0.9	0.7	0.4

			Tianjin	4.6	3.3	1.0
			Hebei	0.3	1.9	3.9
			Shandong			0.5
Songliao	4.6	1.3	Jilin	4.1	2.9	0.9
			Heilongjiang	1.7	3.0	1.2
Sanjiang	0.9	0.0	Heilongjiang	0.9	0.7	
Subei	1.8	0.1	Jiangsu	1.9	1.9	1.9
Ordos	5.1	0.4	Inner Mongolia	5.5	5.5	3.8
			Shaanxi			1.6
			Shanxi			0.1
Erlian	1.7	0.0	Inner Mongolia	1.7	1.7	
HeHuai	3.6		Henan	3.6	3.6	3.6
			Anhui			
Nanxiang	0.2	0.1	Henan	0.2	0.2	0.2
Tarim	14.9	0.1	Xinjiang	1.8	1.4	0.6
Junggar	3.9	0.2	Xinjiang			
Turpan-Hami	1.1	0.1	Xinjiang			
Sichuan	1.6	0.0	Sichuan	1.6	1.6	1.3
JiangHan - Dongting	1.1	0.0	Hubei	1.1	1.1	1.1
Qaidam	0.4	0.1	Qinghai			
Hailaer	0.3	0.0	Inner Mongolia			
Total onshore	45.8	3.5		29.8	29.2	22.0
Offshore						
East China Sea	6.8	0.0	Zhejiang	6.8	6.8	3.5
			Fujian			1.2
			Jiangsu			2.1
Southern Yellow Sea	2.7		Jiangsu	2.7	2.7	1.6
			Shandong			1.0
Bohai Bay	2.2	0.1	Shandong	2.3	2.3	2.3
			Liaoning			
Zhujiangkou (Pearl River Mouth)	1.4	0.1	Guangdong	1.5	1.5	1.5
Yinggehai	1.1		Hainan	1.0	0.7	0.2
Northern Yellow Sea	0.6		Jiangsu	0.6	0.6	
Beibu Gulf	0.5	0.0	Guangxi	0.5	0.5	0.5
Western Taiwan	0.2		Fujian	0.2	0.2	
Total offshore	15.6	0.2		15.6	15.3	14.0
Total matched capacity	**61.3**	**3.6**		**45.5**	**44.5**	**36.0**

All values are given in Gt CO_2

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

Tab. 25-4 Source-sink match of storage scenario S2 with coal development and industrial development pathways E1+I, E2+I and E3+I in China

Basin	**Effective storage capacity**		**Available for emissions from**	**E1+I: high**	**E2+I: middle**	**E3+I: low**
	Saline aquifers	Oil and gas fields				
Onshore						
Bohai	37.3	1.2	Beijing	0.9	0.7	0.4
			Tianjin	4.6	3.3	1.0
			Hebei	15.1	10.9	3.9
			Shandong	17.9	15.0	5.9
			Liaoning		7.0	2.5
			Henan		1.6	4.2
Songliao	36.4	1.3	Jilin	4.1	2.9	0.9
			Heilongjiang	5.2	3.6	1.2
Sanjiang	7.2	0.0	Heilongjiang			
Subei	14.4	0.1	Jiangsu	14.5	14.5	5.6
Ordos	41.0	0.4	Inner Mongolia	19.4	13.5	3.8
			Shaanxi	7.0	5.0	1.6
			Shanxi	15.0	11.0	3.4
			Ningxia Hui		2.4	0.8
			Gansu		2.6	1.0
Erlian	13.6	0.0	Inner Mongolia			
HeHuai	28.5		Henan	18.9	11.7	
			Anhui	11.2	8.0	2.6
Nanxiang	1.2	0.1	Henan			
Tarim	119.3	0.1	Xinjiang	1.8	1.4	0.6
Turpan-Hami	8.7	0.1	Xinjiang			
Junggar	31.5	0.2	Xinjiang			
Sichuan	12.4	0.0	Sichuan	4.7	3.4	1.3
JiangHan - Dongting	8.4	0.0	Hubei	6.7	4.9	1.8
Qaidam	3.4	0.1	Qinghai			
Hailaer	2.6	0.0	Inner Mongolia			
Total onshore	366.1	3.4		146.9	123.4	42.4
Offshore						
East China Sea	54.7	0.0	Zhejiang	14.4	10.3	3.5
			Fujian	5.7	4.0	1.2
			Jiangsu	9.4	2.5	
Southern Yellow Sea	21.4		Jiangsu			
Bohai Bay	17.5	0.1	Shandong	2.7		
			Liaoning	9.8		
Zhujiangkou (Pearl River Mouth)	11.2	0.1	Guangdong	11.2	10.7	3.5
			Hainan		0.7	0.2

Yinggehai	9.0	0.0	Hainan	1.0		
Northern Yellow Sea	5.0		Jiangsu			
			Shandong			
Beibu Gulf	3.8	0.0	Guangxi	3.8	2.8	0.9
			Guangdong			
Western Taiwan	1.8		Fujian			
Total offshore	124.3	0.2		57.9	31.1	9.4
Total matched capacity	**490.4**	**3.6**		**204.8**	**154.4**	**51.7**

All values are given in Gt CO_2

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

Tab. 25-5 Source-sink match of storage scenario S1 with coal development and industrial development pathways E1+I, E2+I and E3+I in China

Basin	Effective storage capacity		Available for emissions from	E1+I: high	E2+I: middle	E3+I: low
	Saline aquifers	Oil and gas fields				
Onshore						
Bohai	116.7	1.3	Beijing	0.9	0.7	0.4
			Tianjin	4.6	3.3	1.0
			Hebei	15.1	10.9	3.9
			Shandong	20.6	15.0	5.9
			Liaoning	9.8	7.0	2.5
			Henan	18.9	13.4	4.2
Songliao	113.9	1.9	Jilin	4.1	2.9	0.9
			Heilongjiang	5.2	3.6	1.2
Subei	45.0	0.3	Jiangsu	23.8	17.0	5.6
Ordos	128.3	0.7	Inner Mongolia	19.4	13.5	3.8
			Shaanxi	7.0	5.0	1.6
			Shanxi	15.5	11.0	3.4
			Ningxia Hui	3.4	2.4	0.8
			Gansu	3.5	2.6	1.0
HeHuai	89.0		Anhui	11.2	8.0	2.6
Sichuan	38.8	0.1	Sichuan	4.7	3.4	1.3
JiangHan - Dongting	26.4	0.0	Hubei	6.7	4.9	1.8
Tarim	372.9	0.4	Xinjiang	1.8	1.4	0.6
Junggar	98.6	0.4	Xinjiang			
Turpan-Hami	27.2	0.3	Xinjiang			
Erlian	42.5	0.1	Inner Mongolia			
Sanjiang	22.5	0.1	Heilongjiang			
Qaidam	10.8	0.3	Qinghai			

Hailaer	8.1	0.1	Inner Mongolia			
Nanxiang	3.8	0.1	Henan			
Total onshore	1144.1	6.0		176.2	125.9	42.4
Offshore						
East China Sea	170.9	0.2	Zhejiang	14.4	10.3	3.5
			Fujian	5.7	4.0	1.2
			Jiangsu			
Southern Yellow Sea	66.9		Jiangsu			
			Shandong			
Bohai Bay	54.6	0.1	Shandong			
			Beijing			
			Tianjin			
			Hebei			
			Liaoning			
Zhujiangkou (Pearl River Mouth)	34.9	0.3	Guangdong	15.1	10.7	3.5
			Hainan	1.0	0.7	0.2
Yinggehai	28.0	0.2	Hainan			
Northern Yellow Sea	15.8		Jiangsu			
			Shandong			
Beibu Gulf	11.9	0.1	Guangxi	4.0	2.8	0.9
			Guangdong			
Western Taiwan	5.5		Fujian			
Total offshore	388.4	1.0		40.1	28.5	9.4
Total matched capacity	**1532.5**	**7.0**		**216.3**	**154.4**	**51.7**

All values are given in Gt CO_2

The maximum transport distance between sources and sinks is assumed to be 500 km.

Source: Authors' calculation

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