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Carbon Capture and Storage including Coal-Fired Power Plants

Todd P. Carington
Editor

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2010. ISBN: 978-1-60741-196-3

ENVIRONMENTAL SCIENCE, ENGINEERING AND TECHNOLOGY SERIES

CARBON CAPTURE AND STORAGE INCLUDING COAL-FIRED POWER PLANTS

TODD P. CARINGTON
EDITOR

Nova Science Publishers, Inc.
New York

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LIBRARY OF CONGRESS CATALOGING-IN-PUBLICATION DATA

Carbon capture and storage including coal-fired power plants / editor, Todd P. Carington.
p. cm.
Includes index.
ISBN 978-1-61209-870-8 (eBook)
1. Coal-fired power plants--Environmental aspects. 2. Carbon sequestration. 3. Carbon cycle (Biogeochemistry) I. Carington, Todd P.
TD195.E4C37 2009
628.5'3--dc22
2009035586

Published by Nova Science Publishers, Inc. ✢ New York

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PREFACE

Nationally-recognized studies and our contacts with a diverse group of industry representatives, nongovernmental organizations, and academic researchers show that key barriers to CCS deployment include (1) underdeveloped and costly CO2 capture technology and (2) regulatory and legal uncertainties over CO2 capture, injection, and storage. Among the key technological barriers are a lack of experience in capturing significant amounts of CO2 from power plants and the significant cost of capturing CO2, particularly from existing coal-fired power plants, which are the single largest source of CO2 emissions in the United States. Compounding these technological issues are regulatory and legal uncertainties, including uncertainty regarding liability for CO2 leakage and ownership of CO2 once injected. According to the IPCC, the National Academy of Sciences, and other knowledgeable authorities, another barrier is the absence of a national strategy to control CO2 emissions (emissions trading plan, CO2 emissions tax, or other mandatory control of CO2 emissions), without which the electric utility industry has little incentive to capture and store its CO2 emissions. Moreover, according to key agency officials, the absence of a national strategy has also deterred their agencies from addressing other important practical issues, such as resolving how stored CO2 would be treated in a future CO2 emissions trading plan.

Chapter 1 - Any comprehensive approach to substantially reduce greenhouse gases must address the world's dependency on coal for a quarter of its energy demand, including almost half of its electricity demand. To maintain coal in the world's energy mix in a carbon-constrained future would require development of a technology to capture and store its carbon dioxide emissions. This situation suggests to some that any greenhouse gas reduction program be delayed until such carbon capture technology has been demonstrated. However, technological innovation and the demands of a carbon control regime are interlinked; a technology policy is no substitute for environmental policy and must be developed in concert with it.

Much of the debate about developing and commercializing carbon capture technology has focused on the role of research, development, and deployment (technology-push mechanisms). However, for technology to be fully commercialized, it must also meet a market demand-a demand created either through a price mechanism or a regulatory requirement (demand-pull mechanisms). Any conceivable carbon capture technology for coal-fired powerplants will increase the cost of electricity generation from affected plants because of efficiency losses. Therefore, few companies are likely to install such technology until they are required to, either by regulation or by a carbon price. Regulated industries may find their regulators reluctant to accept the risks and cost of installing technology that is not required.

The Department of Energy (DOE) has invested millions of dollars since 1997 in carbon capture technology research and development (R&D), and the question remains whether it has been too much, too little, or about the right amount. In addition to appropriating funds each year for the DOE program, Congress supported R&D investment through provisions for loan guarantees and tax credits. Congress also authorized a significant expansion of carbon capture and sequestration (CCS) spending at DOE in the Energy Independence and Security Act of 2007. Funding for carbon capture technology may increase substantially as a result of enactment of the American Recovery and Reinvestment Act of 2009.

Legislation introduced in the 111th and 110th Congresses invokes the symbolism of the Manhattan project of the 1940s and the Apollo program of the 1960s to frame proposals for large-scale energy policy initiatives that include developing CCS technology. However, commercialization of technology and integration of technology into the private market were not goals of either the Manhattan project or Apollo program.

Finally, it should be noted that the status quo for coal with respect to climate change legislation isn't necessarily the same as "business as usual." The financial markets and regulatory authorities appear to be hedging their bets on the outcomes of any federal legislation with respect to greenhouse gas reductions, and becoming increasingly unwilling to accept the risk of a coal-fired power plant with or without carbon capture capacity. The lack of a regulatory scheme presents numerous risks to any research and development effort designed to develop carbon capture technology. Ultimately, it also presents a risk to the future of coal.

Chapter 2 - Coal, like most materials found in nature, contains trace quantities of the naturally occurring primordial radionuclides, i.e. of ^{40}K and of ^{238}U, ^{232}Th and their decay products. Therefore, the combustion of coal results in the released into the environment of some natural radioactivity and in the re-distribution from underground into the biosphere, that is from deep in the earth to locations where it can modify ambient radiation fields and population radiation exposures. The annual world production of coal, including brown coal and lignites, was about $3.7\text{x}10^{12}$ kg in 1979, $3.1\text{x}10^{12}$ kg in 1985, the main producers being China, the republics of the former Soviet Union and the United States. A large fraction of the coal extracted from the earth is burned in electric power stations, i.e. in coal-fired power plants; about $3\text{x}10^{9}$ kg of coal is required to produce 1 GW a of electrical energy. The average concentrations of ^{40}K, $^{238\text{U}}$ and ^{232}Th in coal was estimated to be 50, 20, 20, Bq kg^{-1}, respectively, based on the analysis of coal samples from 15 countries, and noted that the concentrations varied by more than two orders of magnitude.

The amounts of natural radionuclides discharged into the atmosphere from a coal-fired power plant depend on a number of factors, such as the concentration of radionuclides in coal, the ash content of the coal, the temperature of combustion, the partitioning between bottom ash and fly ash and the efficiency of the emission control device. Large quantities of coal ash, fly ash and bottom ash combined, are produced each year throughout the world. It was estimated that about 280 million tones of coal ash are produced annually in coal-fired power plants. Coal ash is used in a variety of applications, the largest of which is the manufacture of cement and concrete. It is also used as a road stabilizer, as road fill, in asphalt mix and as fertilizer. About 5 % of the total ash production from coal-fired power plants is used for the constructions of dwellings; this represents an annual usage of 14 million tones. From the radiological point of view, the use of coal ash in building materials, which may affect indoor doses from external irradiation and the inhalation of radon decay products, is the most significant.

The resulting normalized collective effective doses were 6 and 0.5 man-Sv (GW a)$^{-1}$ for typical old and modern coal-fired power plants, respectively. In China, because of higher-than-average concentrations of natural radionuclides in coal, relatively low filter efficiencies (90 %) and high population densities around the plants, the normalized collective effective doses arising from atmospheric release of radioactive materials from plants there is approximately 50m man-Sv (GW a)$^{-1}$.

Assuming that , worldwide, 1/3 of the electrical energy produced by coal-fired power plants is from modern plants, 1/3 is from old plants and 1/3 is from plants with characteristics similar to those in China, the average normalized collective effective dose is 20 man-Sv (GW a)$^{-1}$. About 70 % of the effective dose resulting from atmospheric releases of natural radionuclides from old plants is due to the inhalation of long-lived radionuclides as the cloud passes. The remainder of the effective dose is due to the external irradiation from radionuclides deposited onto the ground and to the ingestion of foodstuffs contaminated by radionuclides deposited onto the ground.

Chapter 3 - Significant coal reserves are reported in many countries including USA, China, Australia and India and it is often suggested that the use of this coal could play an important role in global energy security until the end of the century and beyond. But at the same time, concerns over the potential for dangerous climate change to be caused by carbon dioxide (CO_2) emissions from many human activities, including power generation using coal, has led to global efforts to identify technologies that can reduce CO_2 emissions. For coal-fired power plants, it is likely that successful development and deployment of carbon capture and storage (CCS) technologies will be the only way that their continued operation will be allowed, in order to avoid unacceptable environmental impacts. This chapter reviews the key carbon capture technologies closest to commercial deployment at coal-fired power plants. It identifies similarities and differences between options that should be taken into account when investment decisions are made, with a particular focus on operating characteristics. It is very likely that regulation, including on acceptable CO_2 emissions, will play a critical role in determining the landscape for power plant investment, so a discussion of some key regulatory issues in determining if, when and where CCS is introduced is also included.

Chapter 4 - The Clean Air Act Amendments of 1990 and the accompanying Acid Rain Program has been a successful marketable permit-based policy experiment designed to reduce sulfur dioxide emissions from U.S. electric plants. However, as a non-uniformly mixed pollutant, the distribution of the benefits from SO_2 reductions depends on the location of the emission source. In this study, we simulate pollution concentration patterns resulting from emissions at participating plants then couple these patterns with underlying population data to estimate the marginal and total health benefits of emission reductions at each location. Results indicate that a one ton reduction in emissions generates, on average, $2,500 in health benefits in the U.S. and Canada. However, the marginal benefits vary substantially depending on the location of the plant. We also find that approximately $6 billion per year in health benefits were generated during the first phase of the program with one third of these benefits attributable to abatement at only two locations.

Chapter 5 - Huge quantities of carbon are actively exchanged between the atmosphere and other storage pools, including the oceans, vegetation, and soils on the land surface. The exchange, or flux, of carbon among the atmosphere, oceans, and land surface is called the global carbon cycle. Comparatively, human activities contribute a relatively small amount of carbon, primarily as carbon dioxide (CO_2), to the global carbon cycle. Despite the addition of a relatively small amount of carbon to the atmosphere, compared to natural fluxes from the oceans and land surface, the human perturbation to the carbon cycle is increasingly recognized as a main factor driving climate change over the past 50 years.

If humans add only a small amount of CO_2 to the atmosphere each year, why is that contribution important to global climate change? The answer is that the oceans, vegetation, and soils do not take up carbon released from human activities quickly enough to prevent CO_2 concentrations in the atmosphere from increasing. Humans tap the huge pool of fossil carbon for energy, and affect the global carbon cycle by transferring fossil carbon — which took millions of years to accumulate underground — into the atmosphere over a relatively short time span. As a result, the atmosphere contains approximately 35% more CO_2 today than prior to the beginning of the industrial revolution (380 ppm vs 280 ppm). As the CO_2 concentration grows it increases the degree to which the atmosphere traps incoming radiation from the sun (*radiative forcing*), warming the planet.

The increase in atmospheric CO_2 concentration is mitigated to some extent by two huge reservoirs for carbon — the global oceans and the land surface — which currently take up more carbon than they release. They are net *sinks* for carbon. If the oceans, vegetation, and soils did not act as sinks, then the concentration of CO_2 in the atmosphere would increase even more rapidly. A key issue to consider is whether these two sinks will continue to store carbon at the same rate over the next few decades, or whether their behavior will change. Currently, most of the total global carbon sink is referred to as the *unmanaged*, or background, carbon cycle. Very little carbon is removed from the atmosphere and stored, or sequestered, by deliberate action.

Congress is considering legislative strategies to reduce U.S. emissions of CO_2 and/or increase the uptake of CO_2 from the atmosphere. Congress may also opt to consider how land management practices, such as afforestation, conservation tillage, and other techniques, might increase the net flux of carbon from the atmosphere to the land surface. How the ocean sink could be managed to store more carbon is unclear. Iron fertilization and deep ocean injection of CO_2 are in an experimental stage, and their promise for long-term enhancement of carbon uptake by the oceans is not well understood. Congress may consider incorporating what is known about the carbon cycle into its legislative strategies, and may also evaluate whether the global carbon cycle is sufficiently well understood so that the consequences of longterm policies aimed at mitigating global climate change are fully appreciated.

Chapter 6 - At least one recent report and numerous news articles suggest that carbon dioxide (CO_2) emissions are rising more rapidly than expected. This contention is often made by comparing recent emissions estimates with the greenhouse gas (GHG) scenarios published by the Intergovernmental Panel on Climate Change (IPCC) in 2000. While CO_2 emissions associated with human activities continue to rise — and may be worthy of alarm because of their influence on climate change — any short-term comparisons between actual emissions and IPCC scenarios miss the mark. First, the IPCC scenarios explicitly are not predictions. Second, the IPCC scenarios are meant to represent different possible GHG trajectories over many decades, and represent smooth emissions paths averaged over at least 10 years. Just as the actual weather over a few years is not necessarily representative of long-term climate, variability of emissions over one or several years is not necessarily representative of long-term trends. Nonetheless, monitoring of CO_2 emissions and concentrations, and analysis of the factors driving changes, is important to designing and evaluating policies to address climate change.

Chapter 7 - Key scientific assessments have underscored the urgency of reducing emissions of carbon dioxide (CO_2) to address climate change. Many have cited carbon capture and storage (CCS) as an essential technology because it has the potential to greatly reduce CO_2 emissions from power plants while allowing for projected increases in electricity demand. CCS involves capturing CO_2 from a power plant's emissions, transporting it to an underground storage location, and then injecting it into a geologic formation for long-term storage.

As requested, GAO examined (1) key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of CCS technology and (2) actions the Department of Energy (DOE), Environmental Protection Agency (EPA), and other agencies are taking to overcome barriers to commercial-scale deployment of CCS technology. Among other things, GAO examined key studies and contacted officials from pertinent agencies, companies, and environmental groups, as well as research and other organizations

Among GAO's recommendations are that (1) DOE continue to place greater emphasis on CO_2 capture at existing power plants and (2) EPA examine how its statutory authorities can be used to address potential CCS barriers. DOE neither explicitly agreed nor disagreed with the first recommendation. EPA expressed general agreement with the second recommendation.

In: Carbon Capture and Storage Including… ISBN: 978-1-60741-196-3
Editor: T. P. Carington, pp. 1-34

Chapter 1

CAPTURING CO_2 FROM COAL-FIRED POWER PLANTS: CHALLENGES FOR A COMPREHENSIVE STRATEGY[*]

***Larry Parker*[†]*, Peter Folger*[‡] *and Deborah D. Stine*[#]**

SUMMARY

Any comprehensive approach to substantially reduce greenhouse gases must address the world's dependency on coal for a quarter of its energy demand, including almost half of its electricity demand. To maintain coal in the world's energy mix in a carbon-constrained future would require development of a technology to capture and store its carbon dioxide emissions. This situation suggests to some that any greenhouse gas reduction program be delayed until such carbon capture technology has been demonstrated. However, technological innovation and the demands of a carbon control regime are interlinked; a technology policy is no substitute for environmental policy and must be developed in concert with it.

Much of the debate about developing and commercializing carbon capture technology has focused on the role of research, development, and deployment (technology-push mechanisms). However, for technology to be fully commercialized, it must also meet a market demand-a demand created either through a price mechanism or a regulatory requirement (demand-pull mechanisms). Any conceivable carbon capture technology for coal-fired powerplants will increase the cost of electricity generation from affected plants because of efficiency losses. Therefore, few companies are likely to install such technology until they are required to, either by regulation or by a carbon price. Regulated industries may find their regulators reluctant to accept the risks and cost of installing technology that is not required.

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[*] This is an edited, reformatted and augmented edition of a Congressional Research Service publication, Report RL34621, dated February 13, 2009.

[†] Corresponding author: lparker@crs.loc.gov, 7-7238

[‡] pfolger@crs.loc.gov, 7-1517

[#] dstine@crs.loc.gov, 7-8431

The Department of Energy (DOE) has invested millions of dollars since 1997 in carbon capture technology research and development (R&D), and the question remains whether it has been too much, too little, or about the right amount. In addition to appropriating funds each year for the DOE program, Congress supported R&D investment through provisions for loan guarantees and tax credits. Congress also authorized a significant expansion of carbon capture and sequestration (CCS) spending at DOE in the Energy Independence and Security Act of 2007. Funding for carbon capture technology may increase substantially as a result of enactment of the American Recovery and Reinvestment Act of 2009.

Legislation introduced in the 111th and 110th Congresses invokes the symbolism of the Manhattan project of the 1940s and the Apollo program of the 1960s to frame proposals for large-scale energy policy initiatives that include developing CCS technology. However, commercialization of technology and integration of technology into the private market were not goals of either the Manhattan project or Apollo program.

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INTRODUCTION: COAL AND GREENHOUSE GAS EMISSIONS

The world meets 25% of its primary energy demand with coal, a number projected to increase steadily over the next 25 years. Overall, coal is responsible for about 20% of global greenhouse gas emissions.[1] With respect to carbon dioxide (CO2), the most prevalent greenhouse gas, coal combustion was responsible for 41% of the world's CO_2 emissions in 2005 (11 billion metrictons).[2]

Coal is particularly important for electricity supply. In 2005, coal was responsible for about 46% of the world's power generation, including 50% of the electricity generated in the United States, 89% of the electricity generated in China, and 81% of the electricity generated in India.3 Coal-fired power generation is estimated to increase 2.3% annually through 2030, with resulting CO_2 emissions estimated to increase from 7.9 billion metric tons per year to 13.9 billion metric tons per year. For example, during 2006, it is estimated that China added over 90 gigawatts (GW) of new coal-fired generating capacity, potentially adding an additional 500 million metric tons of CO_2 to the atmosphere annually.[4]

Developing a means to control coal-derived greenhouse gas emissions is an imperative if serious reductions in worldwide emissions are to occur in the foreseeable future. Developing technology to accomplish this task in an environmentally, economically, and operationally acceptable manner has been an ongoing interest of the federal government and energy companies for a decade, but no commercial device to capture and store these emissions is currently available for large-scale coal-fired power plants.

Table 1. Expected Costs of CCS Technology Elements

CCS Element	\$/Metric Ton of CO_2
Capture	\$40-\$80
Storage	\$3-\$8
Monitoring and Verification	\$0.2-\$1.0

Source: S. Julio Friedmann, Carbon Capture and Sequestration As a Major Greenhouse Gas Abatement Option (November 2007), p. 11.

Note**:** Capture and storage costs are very site-specific. These estimates reflect the magnitude of difference between capture and storage costs; actual site-specific costs could vary substantially from these estimates. Estimates do not include any transportation costs.

Arguably the most economic and technologically challenging part of the carbon capture and sequestration (CCS) equation is capturing the carbon and preparing it for transport and storage.[5] Depending on site-specific conditions, the capture component of a CCS system can be the dominant cost-variable, and the component that could be improved most dramatically by further technological advancement. As indicated in Table 1, capture costs could be 5-10 times the cost of storage. Breakthrough technologies that substantially reduce the cost of capturing CO_2 from existing or new power plants, for example by 50% or more, would immediately reshape the economics of CCS. Moreover, technological breakthroughs would change the economics of CCS irrespective of a regulatory framework that emerges and governs how CO_2 is transported away from the power plant and sequestered underground.

In contrast, the cost of transporting CO_2 and sequestering it underground is likely less dependent on technological breakthroughs than on other factors, such as:

- the costs of construction materials and labor (in the case of pipelines for CO_2 transport);
- the degree of geologic characterization required to permit sequestration;
- the requirements for measuring, monitoring, and verifying permanent CO_2 storage;
- the costs of acquiring surface and subsurface rights to store CO_2;
- costs of insurance and long-term liability; and
- other variables driving the cost of transportation and sequestration.6

That is not to say that the transportation and storage components of CCS are independent of cost and timing. Depending on the degree of public acceptance of a large-scale CCS enterprise, the transportation and sequestration costs could be very large, and it may take years to reach agreement on the regulatory framework that would guide long-term CO_2 sequestration. But the variables driving cost and timing for the transportation and storage of CO_2 are less amenable to technological solution.

This chapter examines the current effort to develop technology that would capture CO_2. First, the paper outlines the current status of carbon capture technology. Second, the paper examines the role of government in developing that technology, both in terms of creating a market for carbon capture technology and encouraging development of the technology. Finally, the paper concludes with a discussion of implications of capture technology for climate change legislation.

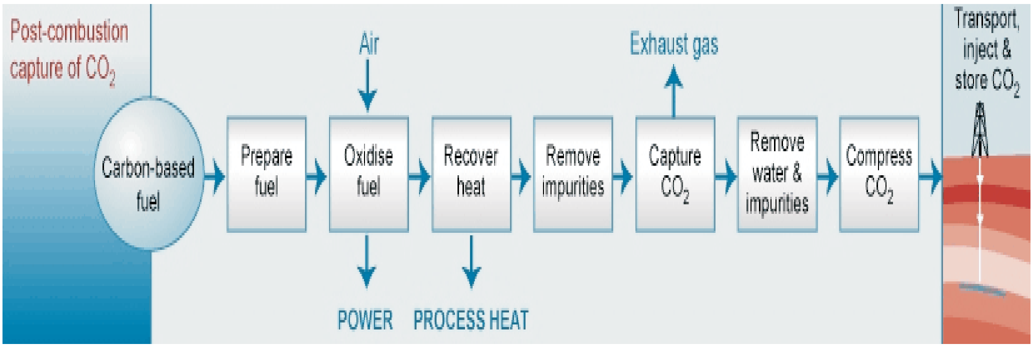


Figure 1. Simplified Illustration of Post-Combustion CO2 Capture

Source: Scottish Centre for Carbon Storage. Figure available at [http://www.geos.ed.ac.uk/sccs/capture/postcombustion.html].

BACKGROUND: WHAT IS CARBON CAPTURE TECHNOLOGY AND WHAT IS ITS STATUS?

Major reductions in coal-fired CO_2 emissions would require either precombustion, combustion modification, or post-combustion devices to capture the CO_2. Because there is currently over 300 GW of coal-fired electric generating capacity in the United States and about 600 GW in China, a retrofittable postcombustion capture device could have a substantial market, depending on the specifics of any climate change program. The following discussion provides a brief summary of technology under development that may be available in the near-term. It is not an exhaustive survey of the technological initiatives currently underway in this area, but illustrative of the range of activity. Funding for current government research and development activities to improve these technologies and move them to commercialization are discussed later.

Post-Combustion CO_2 Capture

Post-combustion CO_2 capture involves treating the burner exhaust gases immediately before they enter the stack. The advantage of this approach is that it would allow retrofit at existing facilities that can accommodate the necessary capturing hardware and ancillary equipment. In this sense, it is like retrofitting postcombustion sulfur dioxide (SO_2), nitrogen oxides (NOx), or particulate control on an existing facility. A simplified illustration of this process is provided in Figure 1.

Post-combustion processes capture the CO_2 from the exhaust gas through the use of distillation, membranes, or absorption (physical or chemical). The most widely-used capture technology is the chemical absorption process using amines (typically monoethanolamine (MEA)) available for industrial applications. Pilotplant research on using ammonia (also an amine) as the chemical solvent is currently underway with demonstration plants announced. These approaches to carbon capture are discussed below. Numerous other solvent-based post-combustion processes are in the bench-scale stage.[7]

Monoethanolamine (MEA)

The MEA CO_2 carbon capture process is the most proven and tested capture process available. The basic design (common to most solvent-based processes) involves passing the exhaust gases through an absorber where the MEA interacts with the CO_2 and absorbs it. The now CO_2-rich MEA is then pumped to a stripper (also called a regenerator) which uses steam to separate the CO_2 from the MEA. Water is removed from the resulting CO_2, which is compressed while the regenerated MEA is purged of any contaminants (such as ammonium sulfate) and recirculated back to the absorber. The process can be optimized to remove 90-95% of the CO_2 from the flue gas.[8]

Although proven on an industrial scale, it has not been applied to the typically larger volumes of flue gas streams created by coal-fired powerplants. The technology has three main drawbacks that would make current use on a coal-fired powerplant quite costly. First is the need to divert steam away from its primary use — generating electricity — to be used instead for stripping CO_2 from MEA. A second related problem is the energy required to compress the CO_2 after it's captured — needed for transport through pipelines — which lowers overall powerplant efficiency and increases generating costs. A recent study by the Massachusetts Institute of Technology (MIT) estimated the efficiency losses from the installation of MEA from 25%-28% for new construction and 36%-42% for retrofit on an existing plant.[9] This loss of efficiency comes in addition to the necessary capital and operations and maintenance cost of the equipment and reagents. For new construction, the increase in electricity generating cost on a levelized basis would be 60%-70%, depending on the boiler technology.[10] In the case of retrofit plants where the capital costs were fully amortized, the MEA capture process would increase generating costs on a levelized basis by about 220%-250%.[11]

A third drawback is degradation of the amine through either overheating (over 205 degrees Fahrenheit [F]) in the absorber or through oxidation from oxygen introduced in the wash water, chemical slurry, or flue gas that reacts with the MEA. For example, residual SO_2 in the flue gas will react with the MEA to form ammonium sulfate that must be purged from the system.[12] This could be a serious problem for existing plants that do not have highly efficient flue gas desulfurization (FGD) or selective catalytic reduction (SCR) devices (or none), requiring either upgrading of existing FGD and SCR equipment, or installation of them in addition to the MEA process.

Chilled ammonia (alstom)

An approach to mitigating the oxidation problem identified above is to use an ammonia-based solvent rather than MEA. Ammonia is an amine that absorbs CO_2 at a slower rate than MEA. In a chilled ammonia process, the flue gas temperature is reduced from about 130 degrees F to about 35-60 degrees F. This lower temperature has two benefits: (1) it condenses the residual water in the flue gas, which minimizes the volume of flue gas entering the absorber; and (2) it causes pollutants in the flue gas, such as SO_2, to drop out, reducing the need for substantial upgrading of upstream control devices.[13] Using a slurry of ammonium carbonate and ammonium bicarbonate, the solvent absorbs more than 90% of the CO_2 in the flue gas. The resulting CO_2-rich ammonia is regenerated and the CO_2 is stripped from the ammonia mixture under pressure (300 pounds per square inch [psi] compared with 15 psi using MEA), reducing the energy necessary to compress the CO_2 for transportation (generally around 1,500 psi).14

The chilled ammonia process is a proprietary process, owned by Alstom. In collaboration with American Electric Power (AEP) and RWE AG (the largest electricity producer in Germany), Alstom has announced plans to demonstrate the technology on a 20 megawatt (MW) slipstream[15] at AEP's Mountaineer plant in West Virginia, and to inject the captured CO_2 into deep saline formations on site.[16] Once commercial viability is demonstrated at Mountaineer, AEP plans to install the technology at its 450 MW Northeastern Station in Oologah, OK, early in the next decade. The captured gas is to be used for Enhanced Oil Recovery (EOR). The target is for full commercialization in 2015.

Ammonia (powerspan)

A second ammonia-based, regenerative process for CO_2 capture from existing coal-fired facilities does not involve chilling the flue gas before it enters the absorber. Using higher flue gas temperatures increases the CO_2 absorption rate in the absorber and, therefore, the CO_2 removal. However, the higher flue gas temperatures also mean that upgrades to existing FGD devices would be necessary.[17]

This process is being developed by Powerspan.[18] Called $ECO_{2,}$ two commercial demonstrations designed for 90% CO_2 capture have been announced with projected operations to begin in 2011 and 2012. The first will use a 120 MW slipstream from Basin Electric's Antelope Valley Station in North Dakota. The second will be sited at NRG's W.A. Parish plant in Texas and use a 125 MW slipstream. The captured CO_2 is to be sold or used for EOR.

Pre-Combustion CO_2 Capture

Currently, a requirement for the pre-combustion capture of CO_2 is the use of Integrated Gasification Combined-cycle (IGCC) technology to generate electricity.[19] There are currently four commercial IGCC plants worldwide (two in the United States) each with a capacity of about 250 MW. The technology has yet to make a major breakthrough in the U.S. market because its potential superior environmental performance is currently not required under the Clean Air Act, and, thus, as discussed above for carbon capture technology, its higher costs can not be justified (see the Virginia State Corporation Commission decision, discussed below).

Carbon capture in an IGCC facility would happen before combustion, under pressure using a physical solvent (e.g., Selexol and Rectisol processes), or a chemical solvent (e.g., methyl diethanolaimine (MDEA)). A simplified illustration of this process is provided in **Figure 2**. Basically, the IGCC unit pumps oxygen and a coal slurry into a gasifier to create a syngas consisting of carbon monoxide and hydrogen. The syngas is cleaned of conventional pollutants (SO_2, particulates) and sent to a shift reactor which uses steam and a catalyst to produce CO_2 and hydrogen. Because the gases are under substantial pressure with a high CO_2 content, a physical solvent can separate out the CO_2. The advantage of a physical solvent is that the CO_2 can be freed and the solvent regenerated by reducing the pressure — a process that is substantially less energy-intensive than having to heat the gas as in an MEA stripper.

From the capture process, the CO_2 is further compressed for transportation or storage, and the hydrogen is directed through gas and steam cycles to produce electricity. MIT estimates the efficiency loss from incorporating capture technology on an IGCC facility is about 19% (from 38.4% efficiency to 31.2%).[20] This loss of efficiency comes in addition to the necessary capital and operations and maintenance cost of the equipment and reagents. For new construction, the estimated increase in electricity generating cost on a levelized basis generally ranges from 22%-25%, with American Electric Power estimating the cost increase at 41%.[21]

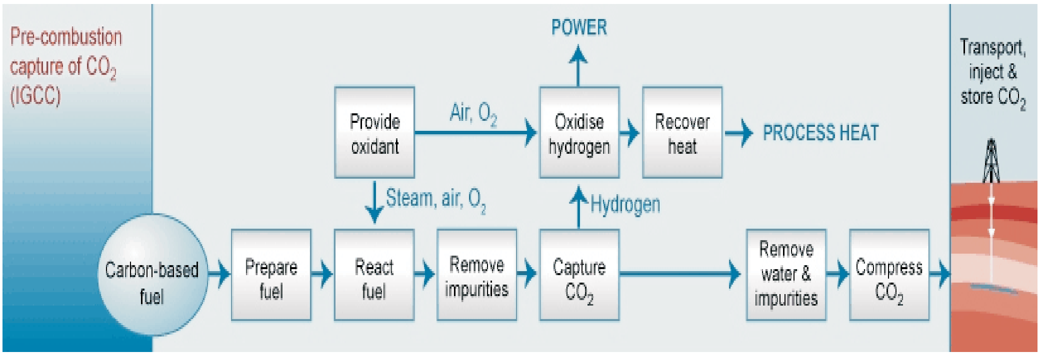


Figure 2. Simplified Illustration of Pre-Combustion CO2 Capture

Source: Emerging Energy Research (EER), "Global IGCC Power Markets and Strategies: 2007-2030" (December 2007). See [http://www.emerging-energy.com/].

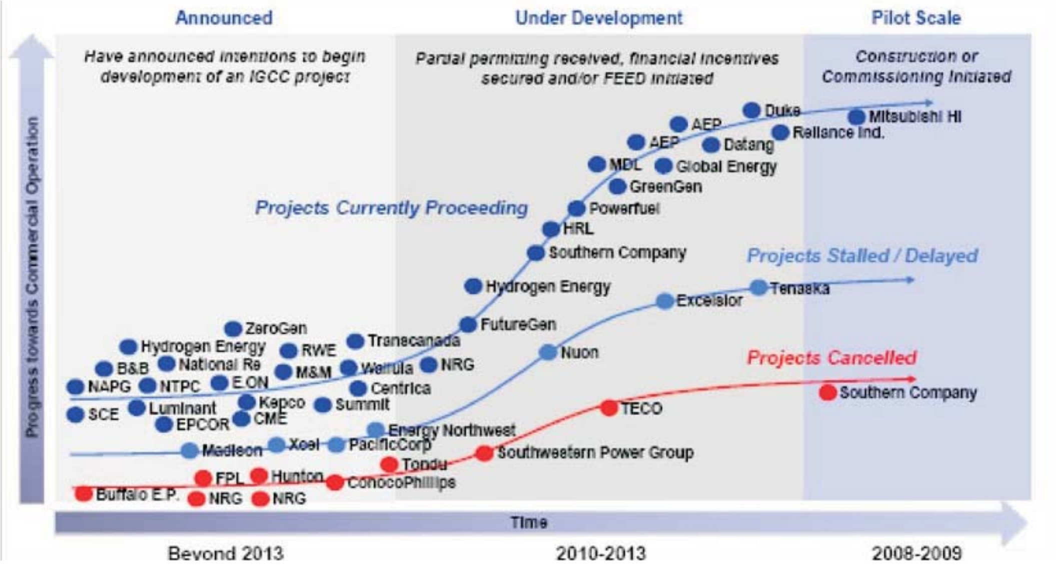


Figure 3. Status of Global IGCC Projects

Source: Scottish Centre for Carbon Storage. Figure available at [http://www.geos.ed.ac.uk/sccs/capture/oxyfuel.html].

There is a lot of activity surrounding the further commercialization of IGCC technology and in the demonstration of carbon capture methods on that technology. As illustrated in **Figure 3**, numerous projects are currently in the development pipeline. Whether development will be delayed by DOE's decision to restructure the FutureGen initiative (as discussed later, see box) is unclear.[22]

Combustion CO_2 Capture

Attempts to address CO_2 during the combustion stage of generation focus on increasing the CO_2 concentration of the flue gas exiting the boiler. The more concentrated the CO_2 is when it exits the boiler, the less energy (and cost) is required later to prepare it for transport or storage. The most developed approach involves combusting the coal with nearly pure oxygen (>95%) instead of air, resulting in a flue gas consisting mainly of highly concentrated CO_2 and water vapor. Using existing technology, the oxygen would be provided by an air-separation unit — an energy intensive process that would be the primary source of reduced efficiency. The details of this "oxy-fuel" process are still being refined, but generally, from the boiler the exhaust gas is cleaned of conventional pollutants (SO_2, NOx, and particulates) and some of the gases recycled to the boiler to control the higher temperature resulting from coal combustion with pure oxygen. The rest of the gas stream is sent for further purification and compression in preparation for transport and/or storage.[23] Depending on site-specific conditions, oxy-fuel could be retrofitted onto existing boilers. A simplified illustration of this process is provided in Figure 4.

The largest oxy-fuel demonstration projects under development are the Vattenfall Project in Germany and the Callide Oxyfuel Project in Queensland, Australia. The Vattenfall project is a 30MW pilot plant being constructed at Schewarze Pumpe and scheduled to begin operation soon. The captured CO_2 will be put in geological storage once siting and permitting processes are completed.[24] The Callide Project is being sponsored by CS Energy, who, with six partners, is retrofitting a 30 MW boiler at its Callide-A power station with an oxy-fuel process. Operation of the oxy-fuel process is scheduled for 2010, with transport and geological storage of the CO_2 planned for 2011.[25]

Numerous other bench- and pilot-plant scale initiatives are underway with specific work being conducted on improving the efficiency of the air-separation process. MIT estimates the efficiency losses from the installation of oxy-fuel at 23% for new construction and 31%-40% for retrofit on an existing plant (depending on boiler technology).[26] This loss of efficiency comes in addition to the necessary capital and operations and maintenance cost of the equipment and reagents. For new construction, the increase in electricity generating cost on a levelized basis would be about 46%. In the case of retrofit plants where the capital costs are fully amortized, the oxy-fuel capture process would increase generating costs on a levelized basis by about 170%-206%.[27]

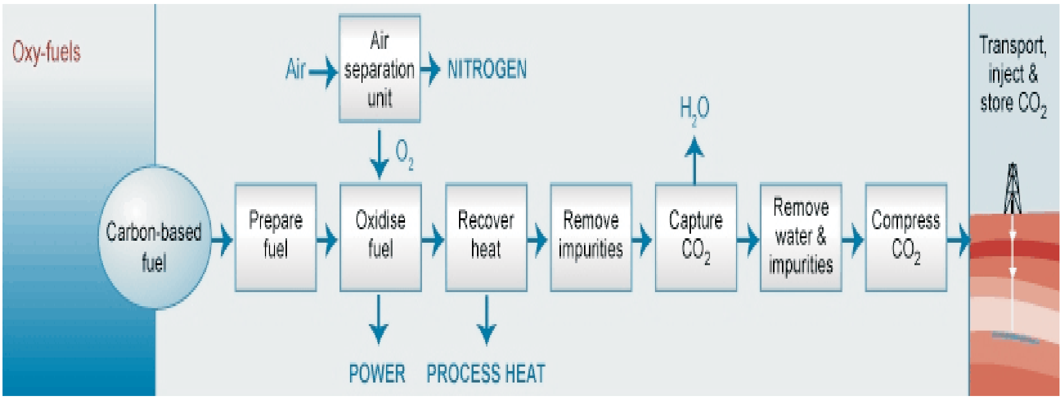


Figure 4. Simplified Illustration of Oxy-fuels CO_2 Capture

Source: Scottish Centre for Carbon Storage. Figure available at [http://www.geos.ed.ac.uk/sccs/capture/oxyfuel.html].

DOE-Supported Technology Development

As summarized in Table 2, CO_2 capture technology is currently estimated to significantly increase the costs of electric generation from coal-fired power plants. planning to capture about 90% of CO_2 from 15 MW(e) of the plant's output (equivalent to about 100,000 metric tons of CO_2 per year) beginning in 2010. Research is ongoing to improve the economics and operation of carbon capture technology. DOE's National Energy Technology Laboratory (NETL) is supporting a variety of carbon capture technology research and development (R&D) projects for pre-combustion, oxy-combustion, and post-combustion applications. A detailed description of all the NETL projects, and of carbon capture technology R&D efforts in the private sector, is beyond the scope of this chapter. However, funding from DOE (described later) is supporting approximately two dozen carbon capture research projects that range from bench-scale to pilot-scale testing.[28] The types of research explored in the NETL-supported projects include the use of membranes, physical solvents, oxy-combustion, chemical sorbents, and combinations of chemical and physical solvents. According to the NETL, these technologies will be ready for slipstream tests by 2014 and for large-scale field testing by 2018.[29] Projects pursued by the private sector may be ready for pilot-scale testing by 2010 and possibly sooner.[30]

ROLES FOR GOVERNMENT

Generally, studies that indicate that emerging, less carbon-intensive new technologies are both available and cost-effective incorporate a price mechanism (such as a carbon tax) that provides the necessary long-term price signal to direct research, development, demonstration, and deployment efforts (called "demand-pull" or "market-pull" mechanisms).[31] Developing such a price signal involves variables such as the magnitude and nature of the market signal, and its timing, direction, and duration. In addition, studies indicate combining a sustained price signal with public support for research and development efforts is the most effective long-term strategy for encouraging development of new technology (called “technology-push” mechanisms).[32] As stated by Richard D. Morgenstern: “The key to a long term research and development strategy is both a rising carbon price, and some form of government supported research program to compensate for market imperfections.”[33]

The various roles the government could take in encouraging development of environmental technologies are illustrated in Figure 5. The federal role in the innovation process is a complex one, reflecting the complexity of the innovation process itself. The inventive activity reflected by government and private research and development efforts overlap with demand pull mechanisms to promote or require adoption of technology, shaping the efforts. Likewise, these initiatives are facilitated by the government as a forum for feedback gained through both developed and demonstration efforts and practical application. The process is interlinked, overlapping, and dynamic, rather than linear. Attempting to implement one role in a vacuum can result in mis-directed funding or mis-timing of results.

Table 2. MIT Estimates of Additional Costs of Selected Carbon Capture Technology
(percent increase in electric generating costs on levelized basis)

	New Construction	Retrofit[a]
Post-combustion (MEA)	60%-70%	220%-250%
Pre-combustion (IGCC)	22%-25%	not applicable
Combustion (Oxy-fuel)	46%	170%-206%

Source: Massachusetts Institute of Technology, The Future of Coal: An Interdisciplinary MIT Study (2007), pp.27, 30, 36, 149. See text for discussion of technologies.

a. Assumes capital costs have been fully amortized.

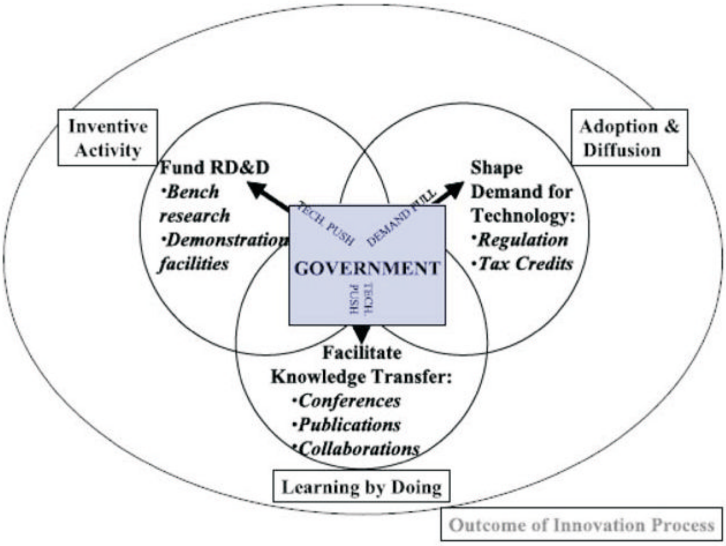


Figure 5. The Federal Role in R&D

Source: Margaret R. Taylor, Edward S. Rubin and David A Hounshell, “Control of SO_2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.,” *Technological Forecasting & Social Change* (July 2005), p. 699.

This section discusses these different roles with respect to encouraging development of carbon capture technology, including (1) the need for a demand-pull mechanism and possible options; (2) current technology-push efforts at the U.S. Department of Energy (DOE) and the questions they raise; and (3) comparison of current energy research and development efforts with past mission-oriented efforts.

THE NEED FOR A DEMAND-PULL MECHANISM

> Economists note that the driving force behind the development of new and improved technologies is the profit motive.... However, market forces will provide insufficient incentives to develop climate-friendly technologies if the market prices of energy inputs do not fully reflect their social cost (inclusive of environmental consequences).... Even if energy prices reflect all production costs, without an explicit greenhouse gas policy firms have no incentive to reduce their greenhouse gas emissions per se beyond the motivation to economize on energy costs. For example, a utility would happily find a way to generate the same amount of electricity with less fuel, but without a policy that makes carbon dioxide emissions costly, it would not care specifically about the carbon content of its fuel mix in choosing between, say, coal and natural gas. For firms to have the desire to innovate cheaper and better ways to reduce emissions (and not merely inputs), they must bear additional financial costs for emissions.[34]

Much of the focus of debate on developing carbon capture technology has been on research, development, and demonstration (RD&D) needs. However, for technology to be fully commercialized, it must meet a market demand — a demand created either through a price mechanism or a regulatory requirement. As suggested by the previous discussion, any carbon capture technology for coal-fired powerplants will increase the cost of electricity generation from affected plants with no increase in efficiency. Therefore, widespread commercialization of such technology is unlikely until it is required, either by regulation or by a carbon price. Indeed, regulated industries may find their regulators reluctant to accept the risks and cost of installing technology that is not required by legislation. This sentiment was reflected in a recent decision by the Virginia State Corporation Commission in denying an application by Appalachian Power Company (APCo) for a rate adjustment to construct an IGCC facility:

> The Company asserted that the value of this project is directly related to (1) potential future legal requirements for carbon capture and sequestration; and (2) the proposed IGCC Plant's potential ability to comply cost effectively with any such requirements. Both of these factors, however, are unknown at this time and do not overcome the other infirmities in the Application. The legal necessity of, and the capability of, cost-effective carbon capture and sequestration in this particular IGCC Plant, at this time, has not been sufficiently established to render APCo's Application reasonable or prudent under the Virginia Statute we must follow.[35]

At the same time there is reluctance to invest in technology that is not required, the unresolved nature of greenhouse gas regulation is affecting investment in any coal-fired generation.[36] The risk involved in investing in coal-fired generation absent anticipated greenhouse gas regulations is outlined in “The Carbon Principles” announced by three Wall Street banks — Citi, JP Morgan Chase, and Morgan Stanley — in February 2008. As stated in their paper:

> The absence of comprehensive federal action on climate change creates unknown financial risks for those building and financing new fossil fuel generation resources. The Financial Institutions that have signed the Principles recognize that federal CO_2 control legislation is being considered and is likely to be adopted during the service life of many new power plants. It is prudent to take concrete actions today that help developers, investors and financiers to identify, analyze, reduce and mitigate climate risks.[37]

Similarly, lack of a regulatory scheme presents numerous risks to any RD&D effort designed to develop carbon capture technology. Unlike a mission-oriented research effort, like the Manhattan Project to develop an atomic bomb, where the ultimate goal is victory and the cost virtually irrelevant, research efforts focused on developing a commercial device need to know what the market wants in a product and how much the product is worth. At the current time, the market value of a carbon capture device is zero in much of the country because there is no market for carbon emissions or regulations requiring their reduction.[38] All estimates of value are hypothetical — dependent on a reduction program or regulatory regime that doesn’t exist. With no market or regulatory signals determining appropriate performance standards and cost-effectiveness criteria, investment in carbon capture technology is a risky business that could easily result in the development of a “white elephant” or “gold-plated” technology that doesn’t meet market demand.

While the “threat” of a carbon regime is stimulating RD&D efforts and influencing decisions about future energy (particularly electricity) supply, the current spread of greenhouse gas control regimes being proposed doesn’t provide much guidance in suggesting appropriate performance and cost-effectiveness benchmarks for a solution with respect to coal-fired generation. For example, isolating just one variable in the future price of carbon under a cap-and-trade program — tonnage reduction requirement — the future value of carbon reductions can vary substantially.[39] As illustrated by Figure 6, three possible reduction targets in 2050 — maintaining current 2008 levels (287 billion metric tons [bmt]), reducing emissions to 50% of 1990 levels (203 bmt), and reducing emissions to 20% of 1990 levels (167 bmt) — result in substantially different price tracks for CO2.[40] Without a firm idea of the tonnage goal and reduction schedule, any deployment or commercialization strategy would be a high-risk venture, as suggested by the previously noted Virginia State Corporation Commission conclusion.

APPROACHES TO A DEMAND-PULL MECHANISM

There are two basic approaches to a demand-pull mechanism: (1) a regulatory requirement, and (2) a price signal via a market-based CO_2 reduction program. These approaches are not mutually exclusive and can serve different goals. For example, a regulation focused on new construction (such as the New Source Performance Standard under Section 111 of the Clean Air Act [41]) could be used to phase in deployment of carbon capture technology and prevent more coal-fired facilities from being constructed without carbon capture (or ensure they would be at least "ready" for carbon capture later). At the same time, a carbon tax or cap-and-trade program could be initiated to begin sending a market signal to companies that further controls will be necessary in the future if they decide to continue operating coal-fired facilities.

Creating Demand through a Regulatory Requirement: An Example from the SO_2 New Source Performance Standards

> It is an understatement to say that the new source performance standards promulgated by the EPA were technology-forcing. Electric utilities went from having no scrubbers on their generating units to incorporating very complex chemical processes. Chemical plants and refineries had scrubbing systems that were a few feet in diameter, but not the 30- to 40-foot diameters required by the utility industry. Utilities had dealt with hot flue gases, but not with saturated flue gases that contained all sorts of contaminants. Industry, and the US EPA, has always looked upon new source performance standards as technology-forcing, because they force the development of new technologies in order to satisfy emissions requirements.[42]

The most direct method to encourage adoption of carbon capture technology would be to mandate it. Mandating a performance standard on coal-fired powerplants is not a new idea; indeed, Section 111 of the Clean Air Act requires the Environmental Protection Agency (EPA) to develop New Source Performance Standards (NSPS) for any new and modified powerplant (and other stationary sources) that in the Administrator's judgment "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public heath or welfare." NSPS can be issued for pollutants for which there is no National Ambient Air Quality Standard (NAAQS), like carbon dioxide.[43] In addition, NSPS is the floor for other stationary source standards such as Best Available Control Technology (BACT) determinations for Prevention of Significant Deterioration (PSD) areas and Lowest Achievable Emission Rate (LAER) determinations for non-attainment areas.[44]

The process of forcing the development of emission controls on coal-fired powerplants is illustrated by the 1971 and 1978 SO_2 NSPS for coal-fired electric generating plants. The Clean Air Act states that NSPS should reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reductions and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[45] In promulgating its first utility SO_2 NSPS in 1971, EPA determined that a 1.2 pound of SO_2 per million Btu of heat input performance standard met the criteria of Sec. 111 — a standard that required, on average, a 70% reduction in new powerplant emissions, and could be met by low-sulfur coal that was available in both the eastern and western parts of the United States, or by the use of emerging flue gas desulfurization (FGD) devices.[46]

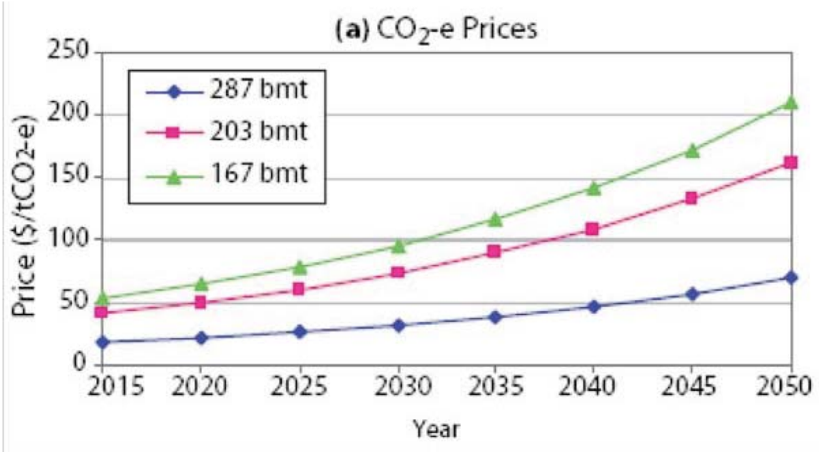


Figure 6. CO_2 Price Projections

Source: Segey Paltsev, et al., *Assessment of U.S. Capand- Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report 146 (April 2007), p. 16. For details on the analysis presented here, consult the report. Available at [http://mit.edu/globalchange].

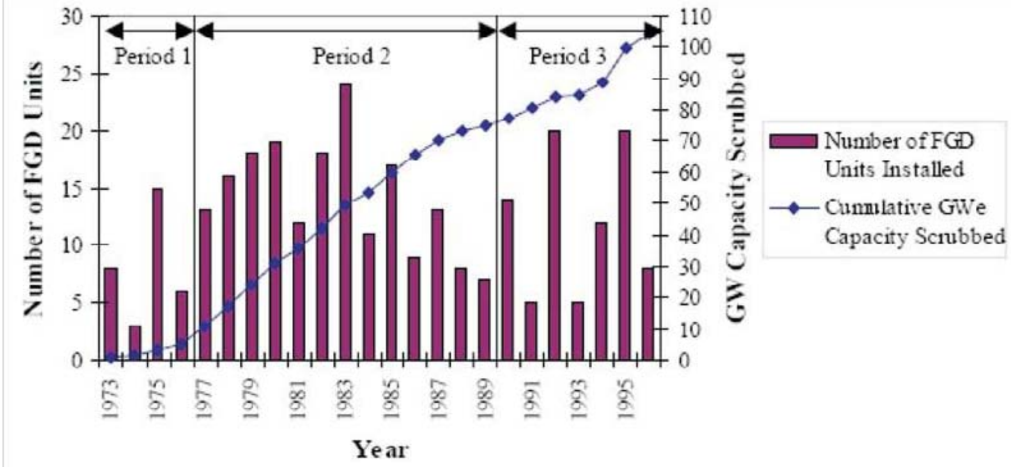


Figure 7. Number of FGD Units and Cumulative GW Capacity of FGD Units: 1973-1996

Source: Adapted by Taylor from Soud (1994). See Margaret R. Taylor, op. cit., 74.
Note: Numbers are archival through June 1994, then projected for 1994-96.

At the time the 1971 Utility SO_2 NSPS was promulgated, there was only one FGD vendor (Combustion Engineering) and only three commercial FGD units in operation — one of which would be retired by the end of the year.[47] This number would increase rapidly, not only because of the NSPS, but also because of the promulgation of the SO_2 NAAQS, the 1973 Supreme Court decision preventing significant deterioration of pristine areas,[48] and state requirements for stringent SO_2 controls, which opened up a market for retrofits of existing coal-fired facilities in addition to the NSPS focus on new facilities. Indeed, most of the growth in FGD installations during the early and mid-1970s was in retrofits — Taylor estimates that between 1973 and 1976, 72% of the FGD market was in retrofits.[49] By 1977, there were 14 vendors offering full-scale commercial FGD installation.[50]

However, despite this growth, only 10% of the new coal-fired facilities constructed between 1973 and 1976 had FGD installations. In addition, the early performance of these devices was not brilliant.[51] In 1974, American Electric Power (AEP) spearheaded an ad campaign to have EPA reject FGD devices as "too unreliable, too impractical for electric utility use" in favor of tall stacks, supplementary controls, and low-sulfur western coal.[52] This effort was ultimately unsuccessful as the Congress chose to modify the NSPS requirements for coal-fired electric generators in 1977 by adding a "percentage reduction" requirement. As promulgated in 1979, the revised SO_2 NSPS retained the 1971 performance standard but added a requirement for a 70%-90% reduction in emissions, depending on the sulfur content of the coal.[53] At the time, this requirement could be met only through use of an FGD device. The effect of the "scrubber requirement" is clear from the data provided in Figure 7. Based on their analysis of FGD development, Taylor, Rubin, and Hounshell state the importance of demand-pull instruments:

> Results indicate that: regulation and the anticipation of regulation stimulate invention; technology-push instruments appear to be less effective at prompting invention than demand-pull instruments; and regulatory stringency focuses inventive activity along certain technology pathways.[54]

That government policy could force the development of a technology through creating a market should not suggest that the government was limited to that role, or that the process was smooth or seamless. On the latter point, Shattuck, et al., summarize the early years of FGD development as follows:

> The Standards of Performance for New Sources are technology-forcing, and for the utility industry they forced the development of a technology that had never been installed on facilities the size of utility plants. That technology had to be developed, and a number of installations completed in a short period of time. The US EPA continued to force technology through the promulgation of successive regulations. The development of the equipment was not an easy process. What may have appeared to be the simple application of an equipment item from one industry to another often turned out to be fraught with unforeseen challenges.[55]

The example indicates that technology-forcing regulations can be effective in pulling technology into the market — even when there remains some operational difficulties for that technology. The difference for carbon capture technology is that for long-term widespread development, a new infrastructure of pipelines and storage sites may be necessary in addition to effective carbon capture technology. In the short-term, suitable alternatives, such as enhanced oil recovery needs and in-situ geologic storage, may be available to support early commercialization projects without the need for an integrated transport and storage system. Likewise, with economics more favorable for new facilities than for retrofits, concentrating on using new construction to introduce carbon capture technology might be one path to widespread commercialization. As an entry point to carbon capture deployment, a regulatory approach such as NSPS may represent a first step, as suggested by the SO_2 NSPS example above.

Creating Demand through a Price Signal: Carbon Taxes, Allowance Pricing and Auctions

Much of the current discussion of developing a market-pull mechanism for new carbon capture technology has focused on creating a price for carbon emissions. The literature suggests that this is an important component for developing new technology, perhaps more important even than research and development. As stated by the Congressional Budget Office (CBO):

> Analyses that consider the costs and benefits of both carbon pricing and R&D all come to the same qualitative conclusion: near-term pricing of carbon emissions is an element of a cost-effective policy approach. That result holds even though studies make different assumptions about the availability of alternative energy technologies, the amount of crowding out caused by federal subsidies, and the form of the policy target (maximizing net benefits versus minimizing the cost of reaching a target).[56]

Two basic approaches can be employed in the case of a market-based greenhouse gas control program: a carbon tax and a cap-and-trade program. The carbon tax would create a long-term price signal to stimulate innovation and development of new technology. This price signal could be strengthened if the carbon tax were escalated over the long run — either by a statutorily determined percentage or by an index (such as the producer price index). A carbon tax's basic approach to controlling greenhouse gas emissions is to supply the marketplace with a stable, consistent price signal — a signal that would also inform innovators as to the cost performance targets they should seek in developing alternative technologies. Designed appropriately, there would be little danger of the price spikes or market volatility that can occur in the early stages of a tradeable permit program.[57]

A cap-and-trade program creates a price signal for new technology through a market price for carbon permits (called allowances) — an allowance is a limited authorization to emit one metric ton of carbon dioxide equivalent (CO_2e). In a capand- trade system, these allowances are issued by the government and either allocated or auctioned to affected companies who may use them to comply with the cap, sell them to other companies on the market, or bank them for future use or sale. The resulting market transactions result in an allowance price. This price on carbon emissions, however, can be both uncertain and volatile.[58] In addition, a low allowance price may be insufficient to encourage technology development and refinement. For example, the 1990 acid rain control program effectively ended the development of FGD for retrofit purposes by setting an emission cap that resulted in low allowance prices and that could be met through the use of low-sulfur coal. Noting that only 10% of phase 1 facilities chose FGD to comply with its requirements, Taylor, et al., state:

> The 1990 CAAA, however, although initially predicted to increase demand for FGD systems, eroded the market potential for both dry and wet FGD system applications at existing power plants when the SO_2 allowance trading market returned low-sulfur coal to its importance in SO_2 control.... As a result, research in dry FGD technology declined significantly. In this case, the flexibility provided by the 1990 acid rain regulations discouraged inventive activity in technologies that might have had broader markets under the traditional command-and-control regimes in place prior to 1990.[59] [footnotes from original text omitted]

A cap-and-trade program need not have such a result. For example, to more effectively promote carbon capture technology, the price signal under a greenhouse gas reduction program could be strengthened by requiring the periodic auctioning of a substantial portion of available allowances rather than giving them away at no cost. The SO_2 program allocated virtually all of its allowance at no cost to affected companies. Auctioning a substantial portion of available allowances could create a powerful price signal and provide incentives for deploying new technology if structured properly.[60] The program could create a price floor to facilitate investment in new technology via a reserve price in the allowance auction process. In addition, the stability of that price signal could be strengthened by choosing to auction allowances on a frequent basis, ensuring availability of allowances close to the time of expected demand and making any potential short-squeezing of the secondary market more difficult.[61]

One positive aspect of the acid rain cap-and-trade experience for encouraging deployment of technology was the effectiveness of "bonus" allowances and deadline extensions as incentives to install FGD. Specifically, about 3.5 million of the allowances were earmarked for Phase 1 powerplants choosing to install 90% control technology (such as FGD). Such units were allowed to delay Phase 1 compliance from 1995 to 1997 and receive two allowances for each ton of SO_2 reduced below a 1.2 lb. per mmBtu level during 1997-1999. The 3.5 million allowance reserve was fully subscribed, and was a major factor in what FGD was installed during Phase 1 of the program. This experience may bode well for proposed CCS "bonus allowance" provisions in several greenhouse gas reduction schemes currently introduced in the Congress.

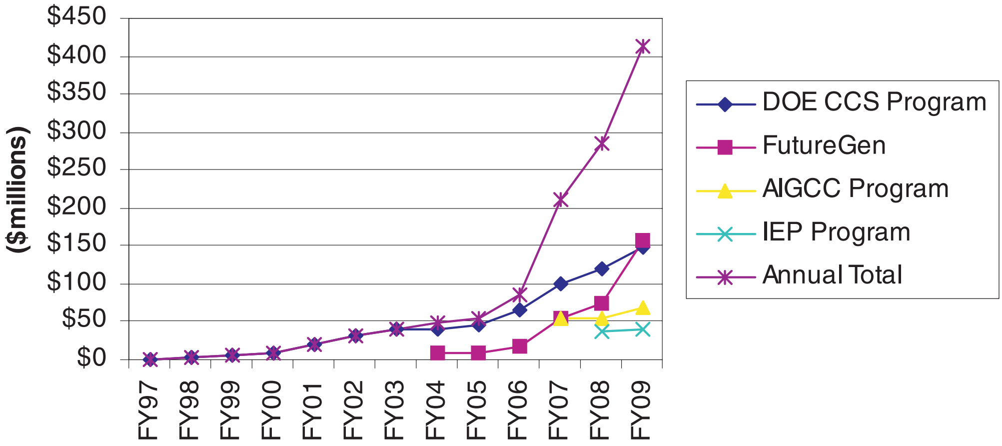


Figure 8. Spending on CCS at DOE Since FY1997

Source: Personal communication, Timothy E. Fout, General Engineer, DOE National Energy Technology Laboratory, Morgantown, WV (July 16, 2008); and U.S. Department of Energy, *FY2009 Congressional Budget Request*, Volume 7, DOE/CF-030 (Washington, D.C., February 2008).

Note: Funding for FutureGen shown is the appropriated amounts. AIGCC means Advanced Integrated Gasification Combined Cycle, and IEP means Innovations for Existing Plants; both are programs under DOE's Office of Fossil Energy. Funding for FY2009 are the requested amounts.

CURRENT TECHNOLOGY-PUSH MECHANISMS: DOE INVESTMENT IN CCS R&D

The Department of Energy (DOE) is currently engaged in a variety of activities to push development and demonstration of carbon capture technologies. These activities include direct spending on research and development, and providing loan guarantees and tax credits to promote carbon capture projects. These technologypush incentives, and the issues they raise, are discussed below.

Direct Spending on R&D

The federal government has recognized the potential need for carbon capture technology — as part of broader efforts to address greenhouse-gas induced climate change — since at least 1997 when the DOE spent approximately $1 million for the entire CCS program.[62] DOE spending on the CCS program has increased over the 11-year period to its highest amount in FY2008 of $118.9 million.[63] If DOE spending for FutureGen (discussed further below) is included, together with carboncapture technology investments through the Innovations for Existing Plants (IEP) and the Advanced Integrated Gasification Combined Cycle (AIGCC) programs (also within the DOE Office of Fossil Energy), then CCS spending at DOE could equal nearly $283 million in FY2008.[64] If the Administration's budget request for FY2009 were fully funded, then overall spending for CCS R&D could equal $414 million, a 46% increase over FY2008 spending levels. Figure 8 shows the trajectory of overall DOE spending on CCS, under this accounting, since FY1997. From FY1997 to FY2007, a total of nearly $500 million has been allocated to CCS at DOE.

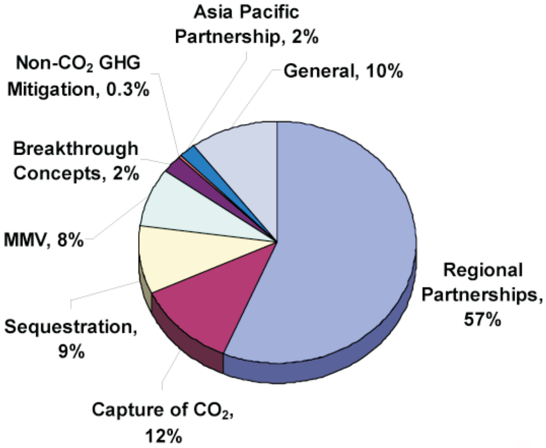


Figure 9. Spending on CCS by Category in FY2008

Source: Personal communication, Timothy E. Fout, General Engineer, DOE National Energy Technology Laboratory, Morgantown, WV (July 16, 2008).

Note: Total expected spending for CCS in FY2008 shown on this chart equals $118.91 million. Also, MMV as shown on the chart stands for measurement, monitoring, and verification.

According to DOE, the CCS line item in its Fossil Energy budget allocated approximately 12% of the FY2008 budget to carbon capture technology specifically, or approximately \$14.3 million. Nearly \$68 million, or 57% of the FY2008 CCS budget, was allocated to the regional partnerships,[65] which are primarily pursuing projects to store CO_2 underground, not to develop capture technologies. The remaining third of the FY2008 budget was allocated to other aspects of CCS, such as technologies for monitoring, mitigating, and verifying the long-term storage of CO_2, other aspects of sequestration, breakthrough concepts (which includes capture technologies), and others. (See Figure 9 for the breakdown of the DOE CCS program spending in FY2008.) Of the \$283 million in total funding for CCS in FY2008 (by one estimation, which includes IEP and AIGCC funding (Figure 8)), less than half is likely allocated for developing carbon capture technology.

Carbon capture and sequestration in the american recovery and reinvestment act of 2009 (ARRA)

Funding for carbon capture technology may increase substantially as a result of enactment of ARRA, the economic stimulus package (conference report to accompany H.R. 1).[66] In the compromise legislation considered in conference on February 11, 2009, the conferees agreed to provide \$3.4 billion through FY2010 for fossil energy research and development. Of that amount, \$1.52 billion would be made available for a competitive solicitation for industrial carbon capture and energy efficiency improvement projects, according to the explanatory statement accompanying the legislation. This provision likely refers to a program for large-scale demonstration projects that capture CO_2 from a range of industrial sources. A small portion of the \$1.52 billion would be allocated for developing innovative concepts for reusing CO_2, according to the explanatory statement. Of the remaining \$1.88 billion, \$1 billion would be available for fossil energy research and development programs. The explanatory statement does not specify which program or programs would receive funding, however, or how the \$1 billion would be allocated. Of the remaining \$880 million, the conferees agreed to allocate \$800 million to the DOE Clean Coal Power Initiative Round III solicitations, which specifically target coal-based systems that capture and sequester, or reuse, CO_2 emissions. Last, \$50 million would be allocated for site characterization activities in geologic formations (for the storage component of CCS activities), \$20 million for geologic sequestration training and research, and \$10 million for unspecified program activities.

If the bulk of the \$3.4 billion agreed to by conferees for fossil energy research and development is used for CCS activities, it would represent a substantial infusion of funding compared to current spending levels. It would also be a large and rapid increase in funding over what DOE spent on CCS *cumulatively* over 11 years since 1997. Moreover, the bulk of DOE's CCS program would shift to the capture component of CCS, unless funding for the storage component increases commensurately in annual appropriations. The large and rapid increase in funding, compared to the magnitude and pace of previous CCS spending, may raise questions about the efficacy of a "crash" CCS program as part of a long-term strategy to reduce CO_2 emissions. This issue is discussed further below.

Loan Guarantees and Tax Credits

Appropriations represent one mechanism for funding carbon capture technology RD&D; others include loan guarantees and tax credits, both of which are available under current law. Loan guarantee incentives that could be applied to CCS are authorized under Title XVII of the Energy Policy Act of 2005 (EPAct2005, P.L. 109- 58). Title XVII of EPAct2005 (42 U.S.C. 16511-16514) authorizes the Secretary of Energy to make loan guarantees for projects that, among other purposes, avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases. The Consolidated Appropriations Act for FY2008 (P.L. 110-161) provides loan guarantees authorized by EPAct2005 for coal-based power generation and industrial gasification activities that incorporate CCS, as well as for advanced coal gasification. The explanatory statement66 directs allocation of $6 billion in loan guarantees for retrofitted and new facilities that incorporate CCS or other beneficial uses of carbon.[67]

Title XIII of EPAct2005 provides for tax credits that can be used for Integrated Gasification Combined Cycle (IGCC) projects and for projects that use other advanced coal-based generation technologies (ACBGT). For these types of projects, the aggregate credits available total up to $1.3 billion: $800 million for IGCC projects, and $500 million for ACBGT projects. Qualifying projects under Title XIII of EPAct2005 are not limited to technologies that employ carbon capture technologies; however, the Secretary of the Treasury is directed to give high priority to projects that include greenhouse gas capture capability. Under the same title of EPAct2005, certain projects employing gasification technology [68] would be eligible to receive up to $650 million in tax credits, and these projects would also receive high priority from the Secretary of the Treasury if they include greenhouse gas capture technology.

ENCOURAGING TECHNOLOGY DEVELOPMENT IN THE ABSENCE OF A MARKET: ISSUES FOR CURRENT CARBON CAPTURE RD&D POLICY

Each of the funding mechanisms described above — appropriations, loan guarantees, and tax credits — are examples of government "pushing" carbon capture technologies (the upper left arrow in Figure 5) via direct spending and through private sector incentives. Thus far, however, these activities are taking place in a vacuum with respect to a carbon market or a regulatory structure. Lacking a price signal or regulatory mandate, it is difficult to assess whether a government-push approach is sufficient for long-term technology development.[69] Some studies appear to discount the necessity of a price signal or regulatory mandate, at least initially, and place a higher priority on the successful demonstration of large-scale technological, economic, and environmental performance of technologies that comprise all of the components of an integrated CCS system: capture, transportation, and storage.[70] So far, however, the only federally sponsored, fully integrated, large-scale CCS demonstration project — called FutureGen (see box) — failed in its original conception, which may have been due, in part, to the lack of a perceived market.

DOE announced it was restructuring the FutureGen program because of its rising costs, which are difficult to assess against the project's "benefits" without a monetary value attached to those benefits (i.e., the value of carbon extracted from the fuel and permanently sequestered). A carbon market would at least provide some way of comparing costs against benefits. One could argue that the benefits of CCS accrue to the amelioration of future costs of environmental degradation caused by greenhouse gas-induced global warming. Although it may be possible to identify overall environmental benefits to removing CO_2 that would otherwise be released to the atmosphere, assigning a monetary value to those benefits to compare against costs is extremely difficult.

Trying to Pick a Winner: FutureGen

On February 27, 2003, President Bush proposed a 10-year, $1 billion project to build a coal-fired power plant that integrates carbon sequestration and hydrogen production while generating 275 megawatts of electricity, enough to power about 150,000 average U.S. homes. As originally conceived, the plant would have been a coalgasification facility and produced between 1 and 2 million metric tons of CO_2 annually. On January 30, 2008, DOE announced that it was "restructuring" the FutureGen program away from a single, state-of-the-art "living laboratory" of integrated R&D technologies — a single plant — to instead pursue a new strategy of providing funding for the addition of CCS technology to multiple commercial-scale Integrated Gasification Combined Cycle (IGCC) power plants.[71] In the restructured program, DOE would support up to two or three demonstration projects, each of at least 300 MW,[72] and that would sequester at least 1 million metric tons of CO_2 per year. In its budget justification for FY2009, DOE cited "new market realities" for its decision, namely rising material and labor costs for new power plants and the need to demonstrate commercial viability of IGCC plants with CCS.[73] A policy question that emerged following the DOE's decision to scrap the original FutureGen concept was whether such a concept can be viable without a longterm price signal for carbon. FutureGen supporters have indicated that the rise in FutureGen's projected costs were consistent with the rise in global energy infrastructure projects due to inflation, implying that rising costs are not unique to FutureGen.[74] Nevertheless, the reasons given by DOE in its decision to cancel the original concept are *prima facie* evidence that lack of a price signal for carbon in the face of known and rising costs for plant construction created too much uncertainty for the agency to continue the project. It is unclear whether a long-term price signal would have supported the FutureGen concept anyway, given the project's other uncertainties, such as its choice of a capture technology and disagreements over the private cost-share agreement.[75]

What Should the Federal Government Spend on CCS Technology Development?

As discussed above, several studies underscore the value of a long-term price or regulatory signal to shape technological development and, presumably, to help determine a level of federal investment needed to encourage commercialization of an environmental technology such as carbon capture. As stated by Fischer:

> With respect to R&D for specific applications (such as particular manufacturing technologies or electricity generation), governments are notoriously bad at picking

> winners... [e.g., the breeder reactor]. The selection of these projects is best left to private markets while the government ensures those markets face the socially correct price signals.[76]

Despite the lack of regulatory incentives or price signals, DOE has invested millions of dollars since 1997 into capture technology R&D, and the question remains whether it has been too much, too little, or about the right amount. In addition to appropriating funds each year for the DOE program, Congress signaled its support for RD&D investment for CCS through provisions for tax credits available for carbon capture technology projects in EPAct2005, and through loan guarantees authorized in the Consolidated Appropriations Act for FY2008 (P.L. 110- 161). Congress also authorized a significant expansion of CCS spending at DOE in the Energy Independence and Security Act of 2007 (EISA, P.L. 110-140), which would authorize appropriations for a total of \$2.2 billion from FY2008 through FY2013. Although EISA places an increased emphasis on large-scale underground injection and storage experiments, the legislation authorizes \$200 million per year for projects that demonstrate technologies for the large-scale capture of CO_2 from a range of industrial sources. The American Recovery and Reinvestment Act of 2009 could greatly enlarge the amount of federal spending on CCS over the next several years.

Legislation in the 110th and 111th Congresses

Legislation has also been introduced in the 110th Congress that would authorize specific amounts of spending for CCS and capture technology development. Notably, the Carbon Capture and Storage Early Deployment Act (H.R. 6258), if enacted, would authorize distribution utilities[77] to collect an assessment on fossil-fuel based electricity delivered to retail customers. The assessment would total approximately \$1 billion annually, and would be issued by a corporation — established by referendum among the distribution utilities — as grants or contracts to private, academic, or government entities to accelerate commercial demonstration or availability of CO_2 capture and storage technologies and methods. This legislation contains elements that resemble, in many respects, recommendations offered in the MIT report.[78] Hearings were held, but the measure was not reported out of committee.

Other bills introduced in the 110th Congress include incentives such as tax credits, debt financing, and regulations to promote CO_2 capture technology development. For example, S. 3132, the Accelerating Carbon Capture and Sequestration Act of 2008, provides a tax credit of \$20 per metric ton of CO_2 captured and stored.[79] S. 3233, the 21st Century Energy Technology Deployment Act, would establish a corporation that could issue debt instruments (such as bonds) for financing technology development. A priority cited in S. 3233 is the deployment of commercial-scale CO_2 capture and storage technology that could capture 10 million short tons of CO_2 per year by 2015. A bill aimed at increasing the U.S. production of oil and natural gas while minimizing CO_2 emissions, S. 2973, the American Energy Production Act of 2008, would require the promulgation of regulations for clean, coal-derived fuels. Facilities that process or refine such fuels would be required to capture 100% of the CO_2 that would otherwise be released at the facility. None of the bills were enacted into law.

One bill introduced in the 111th Congress, the New Manhattan Project for Energy Independence (H.R. 513), calls for a system of grants and prizes for RD&D on the scale of the original Manhattan project, with a goal of attaining energy independence for the nation. Other legislation introduced invokes the symbolism of the Apollo program of the 1960s to frame proposals for large-scale energy policy initiatives that include developing CCS technology.[80] The relevance and utility of large-scale government projects, such as the Apollo program, or the Manhattan project, to developing carbon capture technology are explored in the following sections.

Should the Federal Government Embark on a “Crash” Research and Development Program?

Some policymakers have proposed that the United States invest in energy research, development, and demonstration activities at the same level of commitment as it invested in the past during the Manhattan project and the Apollo program.[81] As analogues to the development of technologies to reduce CO_2 emissions and thwart long-term climate change, the Manhattan project and Apollo program are imperfect at best. They both had short-term goals, their success or failure was easily measured, and perhaps most importantly, they did not depend on the successful commercialization of technology and its adoption by the private sector. Nevertheless, both projects provide a funding history for comparison against CO_2 capture technology cost projections, and as examples of large government-led projects initiated to achieve a national goal. The Manhattan project and Apollo program are discussed briefly below.

The federal government’s efforts to promote energy technology development in response to the energy crisis of the 1970s and early 1980s may be a richer analogy to CO_2 capture technology development than either the Manhattan project or Apollo program. After the first oil crisis in 1973, and with the second oil crisis in the late 1970s, the national priority was to reduce dependence on foreign supplies of energy, particularly crude oil, through a combination of new domestic supplies (e.g., oil shale), energy efficiency technologies, and alternative energy supplies such as solar, among others. The success of these efforts was to have been determined, in part, by the commercialization of energy technologies and alternative energy supplies and their incorporation into American society over the long-term. Similarly, many analysts see the development of CCS technology as a necessary step needed over the next several decades or half-century to help alleviate human-induced climate change, which is itself viewed as a global problem for at least the next century or longer. As discussed more fully later, the outcome of the federal government’s efforts to promote energy technologies in the 1970s and 1980s may be instructive to current approaches to develop CCS technology.

The Manhattan Project and Apollo Program

The Manhattan project took place from 1942 to 1946.[82] In July 1945, a bomb was successfully tested in New Mexico, and used against Japan at two locations in August 1945. In 1946, the civilian Atomic Energy Commission was established to manage the nation’s future atomic activities, and the Manhattan project officially ended. According to one estimate, the Manhattan project cost \$2.2 billion from 1942-1946 (\$21 billion in 2007 dollars), greater than the original cost and time estimate of approximately \$148 million for 1942 to 1944.[83]

The Apollo program encompassed 17 missions including six lunar landings that took place from FY1960 to FY1973.[84] Although preliminary discussions regarding the Apollo program began in 1960, Congress did not decide to fund it until 1961 after the Soviets became the first country to send a human into space. The peak cost for the Apollo program occurred in FY1966 when NASA's total budget was $4.5 billion and its funding for Apollo was $3.0 billion.[85] According to NASA, the total cost of the Apollo program for FY1960-FY1973 was $19.4 billion ($95.7 billion in 2007 dollars).[86] The first lunar landing took place in July 1969. The last occurred in December 1972. Figure 10 shows the funding history for both the Manhattan project and Apollo program.

DOE-Supported Energy Technology Development

The Department of Energy has its origins in the Manhattan project,[87] and became a cabinet-level department in 1977,[88] partly in response to the first oil crisis of 1973, caused in part by the Arab oil embargo. Another oil crisis (the "second" oil crisis) took place from 1978-1981 as a result of political revolution in Iran. Funding for DOE energy R&D rose in the 1970s in concert with high oil prices and resultant Carter Administration priorities on conservation and development of alternative energy supplies. Crude oil prices fell during the 1980s and the Reagan Administration eliminated many energy R&D programs that began during the oil crisis years. Figure 10 shows the rise and fall of funding for DOE energy technology programs from 1974 to 2008.

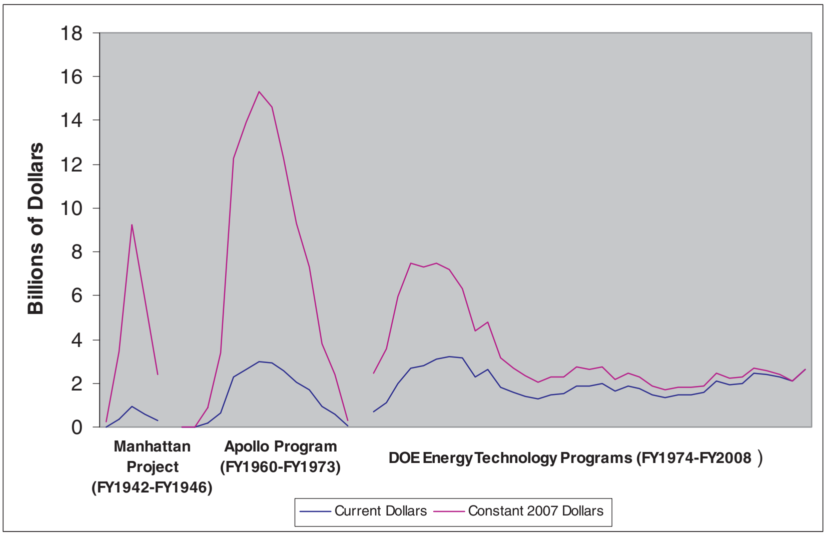
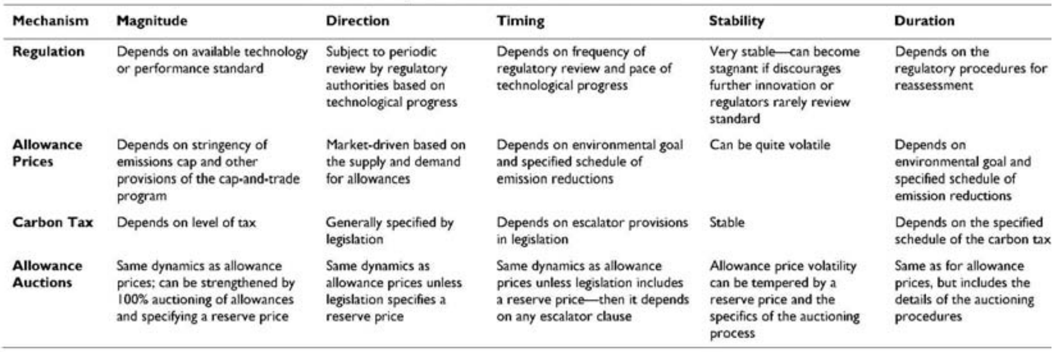


Figure 10. Annual Funding for the Manhattan Project, Apollo Program, and DOE Energy Technology Programs

Source: Congressional Research Service. Manhattan Project data: Richard G. Hewlett and Oscar E. Anderson, Jr., A *History of the United States Atomic Energy Commission: The New World, 1939/1946, Volume I*. Apollo program data: Richard Orloff, *Apollo By The Numbers: A Statistical Reference*, NASA SP-2000-4029, 2004 web update. DOE data: CRS Report RS22858, *Renewable Energy R&D Funding History: A Comparison with Funding for Nuclear Energy, Fossil Energy, and Energy Efficiency R&D*, by Fred Sissine.

Table 3. Comparison of Various Demand-Pull Mechanisms



Mechanism	Magnitude	Direction	Timing	Stability	Duration
Regulation	Depends on available technology or performance standard	Subject to periodic review by regulatory authorities based on technological progress	Depends on frequency of regulatory review and pace of technological progress	Very stable—can become stagnant if discourages further innovation or regulators rarely review standard	Depends on the regulatory procedures for reassessment
Allowance Prices	Depends on stringency of emissions cap and other provisions of the cap-and-trade program	Market-driven based on the supply and demand for allowances	Depends on environmental goal and specified schedule of emission reductions	Can be quite volatile	Depends on environmental goal and specified schedule of emission reductions
Carbon Tax	Depends on level of tax	Generally specified by legislation	Depends on escalator provisions in legislation	Stable	Depends on the specified schedule of the carbon tax
Allowance Auctions	Same dynamics as allowance prices; can be strengthened by 100% auctioning of allowances and specifying a reserve price	Same dynamics as allowance prices unless legislation specifies a reserve price	Same dynamics as allowance prices unless legislation includes a reserve price—then it depends on any escalator clause	Allowance price volatility can be tempered by a reserve price and the specifics of the auctioning process	Same as for allowance prices, but includes the details of the auctioning procedures

Source: Congressional Research Service.

Comparisons to CO_2 Capture R&D at DOE

Current DOE spending on CCS technology development (discussed above) is far below levels of funding for the Manhattan project and Apollo program and for the energy technology R&D programs at their peak spending in the late 1970s and early 1980s. The development of CO_2 capture technology is, of course, only one component of all federal spending on global climate change mitigation. However, the total annual federal expenditures on climate change, including basic research, are still far less than the Manhattan project and Apollo program, although similar to DOE energy technology development programs during their peak spending period.[89] For comparison, the FY2008 budget and FY2009 budget request for DOE's energy technology R&D is approximately \$3 billion per year. (See Figure 10.)

Even if spending on CO_2 capture technology were increased dramatically to Manhattan project or Apollo program levels, it is not clear whether the goal of developing a commercially deployable technology would be realized. As mentioned above, commercialization of technology and integration of technology into the private market were not goals of either the Manhattan project or Apollo program. For the Manhattan project, it did not matter what the cost was, in one sense, if a consequence of failing to build a nuclear weapon was to lose the war. For CO_2 capture, the *primary* goal is to develop a technology that would be widely deployed and thus effective at removing a substantial amount of CO_2 over the next half century or more, which necessarily requires its commercialization and widespread use throughout the utility sector.

The Possibility of Failure: The Synthetic Fuels Corporation

A careful study of one of the federal projects initiated in response to the energy crisis of the 1970s and early 1980s — the Synthetic Fuels Corporation (SFC) — may provide a valuable comparison to current thinking about the federal role in CO_2 capture technology development:

> The government's attempt to develop a synthetic fuels industry in the late 1970s and early 1980s is a case study of unsuccessful federal involvement in technology development. In 1980, Congress established the Synthetic Fuels Corporation (SFC), a quasi-independent corporation, to develop large-scale projects in coal and shale liquefaction and gasification. Most of the projects centered on basic and conceptual work that would contribute to demonstration programs in later stages, although funds were expended on several prototype and full-scale demonstration experiments. Formed in response to the 1970s energy crisis, the SFC was intended to support projects that industry was unable to support because of technical, environmental, or financial uncertainties. Federal loans, loan guarantees, price guarantees, and other financial incentives totaling $20 billion were authorized to spur industry action. Although SFC was designed to continue operating until at least 1992, the collapse in energy prices, environmental concerns, lack of support from the Reagan Administration, and administrative problems ended the synthetic fuels program in 1986.[90] [citations from original text omitted]

One of the primary reasons commonly cited for the failure of the SFC was the collapse of crude oil prices during the 1980s, although other factors contributed.[91] Without a stable and predictable price for the commodity that the SFC was attempting to produce in specific, mandated quantities, the structure of the SFC was unable to cope with market changes:

> The failure of the federal government's effort to create a synthetic fuels industry yields valuable lessons about the role of government in technology innovation. The synthetic fuels program was established without sufficient flexibility to meet changes in market conditions, such as the price of fuel. Public unwillingness to endure the environmental costs of some of the large-scale projects was an added complication. An emphasis on production targets was an added complication. An emphasis on production targets reduced research and program flexibility. Rapid turnover among SFC's high-level officials slowed administrative actions. The synthetic fuels program did demonstrate, however, that large-scale synthetic energy projects could be build and operated within specified technical parameters.[92] [citations from original text omitted]

It may be argued that the demise of DOE's FutureGen program (as originally conceived, see box above) was partly attributable to the project's inflexibility in dealing with changing market conditions, in this case the rise in materials and construction costs and the doubling of FutureGen's original price estimate. However, the analogy between FutureGen and the SFC is limited. Although the SFC failed in part because of collapsing oil prices (the costs of the SFC program could be measured against the benefits of producing oil), for FutureGen the value of CO_2 *avoided* (i.e. the benefit provided by the technology) was not even calculable for comparison to the costs of building the plant, because there is no real global price for CO_2.

The market conditions that contributed to the downfall of the SFC, however, could be very different from the market conditions that would arise following the creation of a price for CO_2 emissions. The stability and predictability of the price signal would depend on the mechanism: carbon tax, allowance pricing, or auctions. A mechanism that allowed for a long-term price signal for carbon would likely benefit CO_2 capture technology R&D programs.

IMPLICATIONS FOR CLIMATE CHANGE LEGISLATION

Any comprehensive approach to reducing greenhouse gases substantially must address the world's dependency on coal for a quarter of its energy demand, including almost half of its electricity demand. To maintain coal as a key component in the world's energy mix in a carbon-constrained future would require developing a technology to capture and store its CO_2 emissions. This situation suggests to some that any greenhouse gas reduction program be delayed until such carbon capture technology has been demonstrated. However, technological innovation and the demands of a carbon control regime are interlinked; therefore, a technology policy is no substitute for environmental policy and must be developed in concert with it.[93]

This linkage raises issues for legislators attempting to craft greenhouse gas reduction legislation. For the demand-pull side of the equation, the issue revolves around how to create the appropriate market for emerging carbon capture technologies. Table 3 compares four different "price" signals across five different criteria that influence their effectiveness in promoting technology:

- **Magnitude**: What size of price signal or stringency of the regulation is imposed initially?
- **Direction**: What influences the direction (up or down) of the price signal or stringency of the regulation over time?
- **Timing**: How quickly is the price or regulation imposed and strengthened?
- **Stability**: How stable is the price or regulation over time?
- **Duration**: How long is the price or regulation imposed on affected companies?

In general, the criteria suggest that regulation is the surest method of forcing the development of technology — price is not necessarily a direct consideration in decision-making. However, regulation is also the most limiting; technologies more or less stringent than the standard would have a limited domestic market (although foreign opportunities may be available), and development could be frozen if the standards are not reviewed and strengthened periodically. In contrast, allowance prices would provide the most equivocal signal, particularly if they are allocated free to participants. Experience has shown allowance prices to be subject to volatility with swings both up and down. The experience with the SO_2 cap-and-trade program suggests the incentive can be improved with "bonus" allowances; however, the eligibility criteria used could be perceived as the government attempting to pick a winner.

In contrast, carbon taxes and allowance auctions (particularly 100% auctions with a reserve price) provide strong market-based price signals. A carbon tax is the most stable price signal, providing a clear and transparent signal of the value of any method of greenhouse gas reductions. Substantial auctioning of allowances also places a price on carbon emissions, a price that can be strengthened by incorporating a reserve price into the structure of the auction.

However, each of these signals ultimately depends on the environmental goal envisioned and the specifics of the control program: (1) the stringency of the reduction requirement; (2) the timing of desired reductions; (3) the techniques allowed to achieve compliance. The interplay of these factors informs the technology community about the urgency of the need for carbon capture technology; the price signal informs the community what cost-performance parameters are appropriate for the emerging carbon market. The nature of that price signal (regulatory, market, stability) informs the community of the confidence it can have that it is not wasting capital on a "white elephant" or on a project that the market does not want or need.

The issues for technology-push mechanisms are broader, and include not only the specifics of any reduction program and resulting price signal, but also international considerations and the interplay between carbon capture technology, storage, and the potential need for CO_2 transport. Groups as diverse as The Pew Center, the Electric Power Research Institute, DOE, and MIT have suggested "roadmaps" and other schemes for preparing carbon capture technology for a pending greenhouse gas reduction program.[94] Generally, all of these approaches agree on the need for demonstration-size (200-300 MW) projects to sort out technical performance and cost effectiveness, and identify potential environmental and safety concerns. The Energy Independence and Security Act of 2007 (P.L. 110-140) reflected Congress' desire for more integrated demonstration projects, and DOE's restructured approach to FutureGen purportedly provides incentives for integrating capture technology on IGCC plants of 300 MW or greater.

Finally, it should be noted that the status quo for coal with respect to climate change legislation isn't necessarily the same as "business as usual." The financial markets and regulatory authorities appear to be hedging their bets on the outcomes of any federal legislation with respect to greenhouse gas reductions, and are becoming increasingly unwilling to accept the risk of a coal-fired power plant with or without carbon capture capacity. This sort of limbo for coal-fired powerplants is reinforced by the MIT study, which makes a strong case against subsidizing new construction (allowed for IGCC under the EPAct2005) without carbon capture because of the unattractive costs of retrofits:

> *Coal plants will not be cheap to retrofit for CO_2 capture.* Our analysis confirms that the costs to retrofit an air-driven SCPC [supercritical pulverized coal] plant for significant CO2 capture, say 90%, will be greater than the costs to retrofit an IGCC plant. However, ... the modifications needed to retrofit an IGCC plant for appreciable CCS are extensive and not a matter of simply adding a single simple and inexpensive process step to an existing IGCC plant.... Consequently, IGCC plants without CCS that receive assistance under the 2005 Energy Act will be more costly to retrofit and less likely to do so.
>
> *The concept of a "capture ready" IGCC or pulverized coal plant is as yet unproven and unlikely to be fruitful.* The Energy Act envisions "capture ready" to apply to gasification technology. [citation omitted] Retrofitting IGCC plants, or for that matter pulverized coal plants, to incorporate CCS technology involves substantial additional investments and a significant penalty to the efficiency and net electricity output of the plant. As a result, we are unconvinced that such financial assistance to conventional IGCC plants without CCS is wise.93 [*emphasis in original*]

As noted earlier, lack of a regulatory scheme (or carbon price) presents numerous risks to any research and development effort designed to develop carbon capture technology. Ultimately, it also presents a risk to the future of coal.

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[4] Pew Center on Global Climate Change, *Coal and Climate Change Facts* 2008, available at [http://www.pewclimate.org/global-warming-basics/coalfacts.cfm]. Capacity factor derived by CRS from data presented, assuming plants would operate in baseload mode with 70% capacity factors.

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[9] Massachusetts Institute of Technology, *The Future of Coal: An Interdisciplinary MIT Study* (2007), p. 147. Hereafter referred to as MIT, *The Future of Coal.*

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[12] Ryan M. Dailey & Donald S. Shattuck, "An Introduction to CO_2 Capture and Sequestration Technology, *Utility Engineering*" (May 2008), p. 4.

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[28] Steve Blankinship, "The Evolution of Carbon Capture Technology, Part 2," *Power Engineering* (May 2008), pp. 62-63.

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[31] For example, see Interlaboratory Working Group, *Scenarios for a Clean Energy Future*, ORNL/CON-476 (November 2000).

[32] For example, see *CERA Advisory Service, Design Issues for Market-based Greenhouse Gas Reduction Strategies; Special Report* (February 2006), p. 59; Congressional Budget Office, *Evaluating the Role of Prices and R&D in Reducing Carbon Dioxide Emissions* (September 2006).

[33] Richard D. Morgenstern, *Climate Policy Instruments: The Case for the Safety Valve* (Council on Foreign Relations, September 20-21, 2004), p. 9.

[34] Carolyn Fischer, *Climate change Policy Choices and Technical Innovation*, Resources for the Future Issue Brief #20 (June 2000), p. 2.

[35] State Corporation Commission, *Application of Appalachian Power Company*, Case No. PUE-2007-00068 (Richmond, April 14, 2008), p. 16.

[36] As stated by DOE: "Regulatory uncertainty for GHG legislation is a key issue impacting technology selection and reliability of economic forecasts. Returns on investment for conventional plants, including supercritical, can be severely compromised by the need to subsequently address CO_2 mitigation. Higher capital costs incurred for IGCC may make such new plants less competitive unless their advantage in CO_2 mitigation is assured." DOE National Energy Technology Laboratory, *Tracking New Coal-fired Power Plants* (June 30, 2008), p. 14.

[37] Citi, Morgan Chase, and Morgan Stanley, *The Carbon Principles: Fossil Fuel Generation Financing Enhanced Environmental Diligence Process* (February 2008), p. 1.

[38] Exceptions to this would include areas where the carbon dioxide could be used for EOR, or where a state or region has enacted greenhouse gas controls, such as California and several northeastern states.

[39] For a fuller discussion of the uncertainties involved in estimating the cost of cap-and-trade programs, see CRS Report RL34489, *Global Climate Change: Costs and Benefits of S. 2191 (S. 3036),* by Larry Parker and Brent Yacobucci.

[40] Segey Paltsev, et al., *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change, Report 146 (April 2007), p. 16.

[41] The Clean Air Act, Section 111 (42 U.S.C. 7411).

[42] Donald Shattuck, et al., *A History of Flue Gas Desulfurization (FGD) — The Early Years*, UE Technical Paper (June 2007), p. 3.

[43] For a fuller discussion of EPA authority to regulate greenhouse gases under the Clean Air Act, see Robert J. Meyer, Principal Deputy Assistant Administrator, Office of Air and Radiation, EPA Testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representation (April 10, 2008).

[44] For a discussion of the structure of the Clean Air Act, see CRS Report RL30853: *Clean Air Act: A Summary of the Act and Its Major Requirements*, by James E. McCarthy, Claudia Copeland, Larry Parker, and Linda-Jo Schierow.

[45] 42 U.S.C. 7411, Clean Air Act, Sec. 111(a)(1)

[46] 40 CFR 60.40-46, Subpart D — Standards of Performance for Fossil-Fuel-Fired Steam Generator for Which Construction is Commenced After August 17, 1971.

[47] Margaret R. Taylor, *The Influence of Government Actions on Innovative Activities in the Development of Environmental Technologies to Control Sulfur Dioxide Emissions from Stationary Sources,* Thesis, Carnegie Institute of Technology (January 2001), p. 37, 40.

[48] Fri v. Sierra Club, 412 US 541 (l973). This decision resulted in EPA issuing “prevention of significant deterioration” regulations in 1974; regulations what were mostly codified in the 1977 Clean Air Amendment (Part C).

[49] Taylor, ibid., p. 37.

[50] Taylor, ibid., p. 39.

[51] For a discussion of challenges arising from the early development of FGD, see Donald Shattuck, et al., *A History of Flue Gas Desulfurization (FGD) — The Early Years*, UE Technical Paper (June 2007).

[52] Examples include full-page ads in the Washington Post entitled “Requiem for Scrubbers,” “Scrubbers, Described, Examined and Rejected,” and “Amen.” For an example, see Washington Post, p. A32 (October 25, 1974).

[53] 40 CFR 60.40Da-52Da, Subpart Da — Standards of Performance for Electric Utility Stream Generating Units for Which Construction is Commenced After September 18, 1978.

[54] Margaret R. Taylor, Edward S. Rubin, & David A. Hounshell, “Control of SO_2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.,” *Technological Forecasting & Social Change* (July 2005), p. 697.

[55] Shattuck, et. al., p. 15.

[56] Congressional Budget Office, *Evaluating the Roles of Prices and R&D in Reducing Carbon Dioxide Emissions* (September 2006), p. 17.

[57] In addition, some of the revenue generated by the tax could be used to fund research, development, demonstration, and deployment of new technology to encourage the long-term transition to a less-carbon-intensive economy.

[58] For a fuller discussion, see CRS Report RL33799, *Climate Change: Design Approaches for a Greenhouse Gas Reduction Program*, by Larry Parker.

[59] Margaret R. Taylor, Edward S. Rubin, and David A. Hounshell, "Effect of Government Actions on Technological Innovation for SO_2 Control," *Environmental Science & Technology* (October 15, 2003), p. 4531. In a more recent article, the authors state: "Finally, the case provides little evidence for the claim that cap-and-trade instruments induce innovation more effectively than other instruments." Margaret R. Taylor, Edward S. Rubin, and David A. Hounshell, "Control of SO_2 Emissions from Power Plants: A Case of Induced Technological Innovation in the U.S.," *Technological Forecasting & Social Change* (July 2005), p. 697-8.

[60] Like a carbon tax, the revenues received could be at least partly directed toward research, development, and demonstration programs.

[61] Karsten Neuhoff, *Auctions for CO_2 Allowances — A Straw Man Proposal*, University of Cambridge Electricity Policy Research Group (May 2007), pp. 3-6. A short-squeeze is a situation where the price of a stock or commodity rises and investors who sold short (believing the price was going to fall) rush to buy it to cover their short position and cut their losses.

[62] Personal communication, Timothy E. Fout, General Engineer, DOE National Energy Technology Laboratory, Morgantown, WV (July 16, 2008).

[63] CCS research and development program line item in the DOE budget (part of the Office of Fossil Energy), U.S. Department of Energy, *FY2009 Congressional Budget Request*, Volume 7, DOE/CF-030 (Washington, DC, February 2008).

[64] Ibid.

[65] Beginning in 2003, DOE created seven regional carbon sequestration partnerships to identify opportunities for carbon sequestration field tests in the United States and Canada.

[66] The conference report and accompanying explanatory statement are available on the House Committee on Rules website, at http://www.rules.house.gov/.

[67] The explanatory statement was published with the Committee Print of the House Committee on Appropriations, Consolidated Appropriations Act, 2008, H.R. 2764/Public Law P.L. 110-161. The Committee Print, which was published in January 2008, is available at [http://www.gpoaccess.gov/congress/house/appropriations/ 08con-appro.html].

[68] Under Title XIII of EPAct2005, gasification technology means any process which converts a solid or liquid product from coal, petroleum residue, biomass, or other materials, which are recovered for their energy or feedstock value, into a synthesis gas (composed primarily of carbon monoxide and hydrogen) for direct use in the production of energy or for subsequent conversion to another product.

[69] See quote by Morgenstern above. In that analysis, government-supported research is needed to compensate for market imperfections. In the current situation, there is no market, and thus its imperfections are moot.

[70] MIT, *The Future of Coal*, p. xi.

[71] See [http://www.fossil.energy.gov/news/techlines/2008/08003-DOE_Announces _ Restructured_FutureG.html].

[72] See [http://www.fossil.energy.gov/news/techlines/2008/08013-DOE_Takes_Next_ Steps_With_Restruct.html].

[73] DOE FY2009 Budget Request, p. 16.

[74] FutureGen Alliance press release (April 15, 2008), at [http://www. futuregenalliance. org/news/releases/pr_04-15-08.stm].

[75] See, for example, Michael T. Burr, “Death of a Turkey, DOE’s Move to ‘Restructure’ FutureGen Clears the Way for a More Rational R&D,” Public Utilities Fortnightly (March 2008); and David Goldston, “Demonstrably Wrong,” Nature, Vol. 453, No. 16 (April 30, 2008), p. 16.

[76] Carolyn Fischer, *Climate Change Policy Choices and Technical Innovation*, Resources for the Future Climate Issue Brief #20 (June 2000), p. 9

[77] A distribution utility is defined in the legislation as an electric utility that has a legal, regulatory, or contractual obligation to deliver electricity directly to retail customers.

[78] MIT, *The Future of Coal*, p. 102.

[79] S. 3132 would also provide a $10 per metric ton credit for CO_2 captured and used as a tertiary injectant in an enhanced oil and natural gas recovery project.

[80] For example, H.R. 2809, the New Apollo Energy Act of 2007; and H.R. 6385, the Apollo Energy Independence Act of 2008.

[81] For more information on this topic, see CRS Report RL34645, The Manhattan Project, the Apollo Program, and Federal Energy Technology R&D Programs: A Comparative Analysis, by Deborah D. Stine.

[82] U.S. Department of Energy, Office of History and Heritage Resources, “The Manhattan Project: An Interactive History,” webpage at [http://www.cfo.doe.gov/me70/ manhattan/1939-1942.htm]. F.G. Gosling, *The Manhattan Project: Making the Atomic Bomb*, January 1999 edition (Oak Ridge, TN: Department of Energy).

[83] Richard G. Hewlett & Oscar E. Anderson, Jr., A *History of the United States Atomic Energy Commission: The New World, 1939/1946 ,Volume I,* (University Park, PA: The Pennsylvania State University Press, 1962). Appendix 2 provides the annual Manhattan project expenditures. These costs were adjusted to 2007 dollars using the price index for gross domestic product (GDP), available from the Bureau of Economic Affairs, National Income and Product Accounts Table webpage, Table 1.1.4., at [http://www.bea.gov/bea/dn/nipaweb/].

[84] There is some difference of opinion regarding what activities comprise the Apollo program, and thus when it begins and ends. Some include the first studies for Apollo, Skylab, and the use of Apollo spacecraft in the Apollo-Soyuz Test Project. This analysis is based on that provided by the National Aeronautics and Space Administration (NASA), which includes the first studies of Apollo, but not Skylab or Soyuz activities, in a 2004 web update by Richard Orloff of its publication entitled *Apollo By The Numbers: A Statistical Reference*, NASA SP-2000-4029, at [http://history.nasa.gov/SP-4029/Apollo_00_ Welcome.htm].

[85] The funding data is available at [http://history.nasa.gov/SP-4214/app2.html#1965]. It is based on information in NASA, *The Apollo Spacecraft - A Chronology*, NASA Special Publication-4009, at [http://www.hq.nasa.gov/office/pao/History/SP-4009/contents.

htm].This data is from Volume 4, Appendix 7 at [http://www. hq.nasa.gov/ office/pao/History/ SP-4009/v4app7.htm].

[86] Richard Orloff, *Apollo By The Numbers: A Statistical Reference*, NASA SP-2000-4029, 2004 web update, at [http://history.nasa.gov/SP-4029/Apollo_00_Welcome.htm]. The funding data is available at [http://history.nasa.gov/SP-4029/Apollo_18-16_Apollo_ Program_Budget_Appropriations.htm]. It is based on information in NASA, *The Apollo Spacecraft - A Chronology*, NASA Special Publication-4009, at [http://www.hq. nasa.gov/ office/pao/History/SP-4009/contents.htm].

[87] Department of Energy, "Origins & Evolution of the Department of Energy," webpage at [http://www.doe.gov/about/origins.htm].

[88] The Department of Energy Organization Act of 1977 (P.L. 95-91).

[89] CRS estimates that budget authority for federal climate change programs was $5.44 billion in FY2007. See CRS Report RL33817, *Climate Change: Federal Funding and Tax Incentives*, by Jane A. Leggett.

[90] The National Academy of Sciences, "The Government Role in Civilian Technology: Building a New Alliance" (National Academy Press, Washington, DC, 1992), pp. 58-59.

[91] For a variety of reasons, Canada's experience with producing synthetic fuels, specifically oil sands development, has differed from the U.S. experience. For more information, see CRS Report RL34258, *North American Oil Sands: History of Development, Prospects for the Future*, by Marc Humphries. [90] Ibid., p. 59.

[92] Ibid., p. 59.

[93] Carolyn Fischer, *Climate Change Policy Choices and Technical Innovation*, Resources for the Future Climate Issue Brief #20 (June 2000), p. 9.

[94] For example, see Pew Center on Global Climate Change, *Coal and Climate Change Facts*, (2008), available at [http://www.pewclimate.org/global-warming-basics/ coalfacts.cfm]; Coal Utilization Research Council and Electric Power Research Institute technology roadmap at [http://www.coal.org/roadmap/]; DOE Energy, National Energy Technology Laboratory, *Carbon Sequestration Technology Roadmap and Program Plan 2007* available at [http://www.netl.doe.gov/technologies/ carbon_seq/refshelf/ project%20portfolio/ 2007/2007Roadmap.pdf; and, MIT, *The Future of Coal*, pp. xi-xv.

[95] MIT, *The Future of Coal*, pp. 98-99.

In: Carbon Capture and Storage Including… ISBN: 978-1-60741-196-3
Editor: T. P. Carington, pp. 35-55

Chapter 2

ESCAPING RADIOACTIVITY FROM COAL-FIRED POWER PLANTS

Constantin Papastefanou
Aristotle University of Thessaloniki, Atomic & Nuclear Physics
Laboratory Thessaloniki 54124, Greece

ABSTRACT

Coal, like most materials found in nature, contains trace quantities of the naturally occurring primordial radionuclides, i.e. of ^{40}K and of ^{238}U, ^{232}Th and their decay products. Therefore, the combustion of coal results in the released into the environment of some natural radioactivity and in the re-distribution from underground into the biosphere, that is from deep in the earth to locations where it can modify ambient radiation fields and population radiation exposures. The annual world production of coal, including brown coal and lignites, was about 3.7×10^{12} kg in 1979, 3.1×10^{12} kg in 1985, the main producers being China, the republics of the former Soviet Union and the United States. A large fraction of the coal extracted from the earth is burned in electric power stations, i.e. in coal-fired power plants; about 3×10^{9} kg of coal is required to produce 1 GW a of electrical energy. The average concentrations of ^{40}K, ^{238U} and ^{232}Th in coal was estimated to be 50, 20, 20, Bq kg^{-1}, respectively, based on the analysis of coal samples from 15 countries, and noted that the concentrations varied by more than two orders of magnitude.

The amounts of natural radionuclides discharged into the atmosphere from a coal-fired power plant depend on a number of factors, such as the concentration of radionuclides in coal, the ash content of the coal, the temperature of combustion, the partitioning between bottom ash and fly ash and the efficiency of the emission control device. Large quantities of coal ash, fly ash and bottom ash combined, are produced each year throughout the world. It was estimated that about 280 million tones of coal ash are produced annually in coal-fired power plants. Coal ash is used in a variety of applications, the largest of which is the manufacture of cement and concrete. It is also used as a road stabilizer, as road fill, in asphalt mix and as fertilizer. About 5 % of the total ash production from coal-fired power plants is used for the constructions of dwellings; this represents an annual usage of 14 million tones. From the radiological point of view, the use of coal ash in building materials, which may affect indoor doses

from external irradiation and the inhalation of radon decay products, is the most significant.

The resulting normalized collective effective doses were 6 and 0.5 man-Sv $(GW\ a)^{-1}$ for typical old and modern coal-fired power plants, respectively. In China, because of higher-than-average concentrations of natural radionuclides in coal, relatively low filter efficiencies (90 %) and high population densities around the plants, the normalized collective effective doses arising from atmospheric release of radioactive materials from plants there is approximately 50m man-Sv $(GW\ a)^{-1}$.

Assuming that , worldwide, 1/3 of the electrical energy produced by coal-fired power plants is from modern plants, 1/3 is from old plants and 1/3 is from plants with characteristics similar to those in China, the average normalized collective effective dose is 20 man-Sv $(GW\ a)^{-1}$. About 70 % of the effective dose resulting from atmospheric releases of natural radionuclides from old plants is due to the inhalation of long-lived radionuclides as the cloud passes. The remainder of the effective dose is due to the external irradiation from radionuclides deposited onto the ground and to the ingestion of foodstuffs contaminated by radionuclides deposited onto the ground.

1. INTRODUCTION

The energy crisis caused by the reduction of fuel oil availability and the consequent continuous increase of the oil fuel prices in the nowadays has led (until the discovery and application of new energy forms) and therefore contributes to the increased worldwide use of coal. However, some parameters must be considered with extensive coal use, since there are coals which showed high concentrations of radioactive nuclides, particularly of the uranium series (Eisenbud and Petrow,1964; Jaworowski et al., 1971; Kirchner et al., 1974). Barber and Giorgio (1977) mentioned a coal sample, from Illinois, USA, in which the ^{226}Ra content reached up to 1.48 kBq kg^{-1} (40 pCi g^{-1}). Measurements for lignites (a kind of brown coal) burned by Greek coal-fired power plants (CPP) resulted in about 110 to 260 Bq kg^{-1} (3 to 7 pci g^{-1}) for ^{226}Ra, while there are other Greek lignites originated from Kotili of Xanthi, Northertn Greece, in which ^{226}Ra reached up to 2.59 kBq kg^{-1} (70 pCi y^{-1})(Papastefanou and Charalambous, 1979; 1980).

Eisenbud and Petrow (1964) estimated that the radioactivity discharged into the atmosphere as ^{226}Ra from the stack of one CPP is of the order of 74 MBq y^{-1} (20 mCi y^{-1}). Papastefanou and Charalambous (1979) showed that the radioactivity discharged into the atmosphere as ^{226}Ra from the stack of a Greek CPP in particulate form is of the order of 740 MBq y^{-1}(200 mCi y^{-1}), i.e. one order of magnitude higher. However, regarding the specific activity of lignite, the amount of lignite burning, the quantity of ash produced and their specific activities, then it is deduced by a simple calculation that the radioactivity escaping as ^{226}Ra from the stack of a CPP would be at least two orders of magnitude higher than that mentioned elsewhere (Papastefanou and Charalambous, 1980). Of course, the total escaping radioactivity due to all elements in the chain of the uranium series will be much higher.

Emissions from coal-fired power plants in gaseous and particulate form containing radioisotopes and discharged into the environment are causing radiation exposures to the population living around coal-fired power plants (McBride et al., 1978). Collective doses to the population arise primarily through inhalation of radioactivity during the passage of the cloud containing fly ash emitted from the stacks and through the ingestion of foodstuffs contaminated by deposition on crops and pastures (main pathways) (Papastefanou,1996)

Fly ash is a waste product, by-product from coal-fired power plants. In several countries, fly ash is used as a component of building materials (Venuat, 1975; Voyatzakis et al., 1976; Sipitanos et al., 1977). Use of fly ash is advantageous from economical and resource points of view and it has the advantages associated with using a waste product which may be regarded as a possible environmental pollutant. Fly ash may contain enhanced levels of the natural radionuclides in the uranium and thorium series, and by using the fly ash in building materials, the radiation levels in houses may thus be technologically enhanced. Fly ash may be used as the major component of building blocks or just as a small fraction of the final building material (Papastefanou and Charalambous, 1980; Stranden, 1983).

In the present work an attempt was made to evaluate the escaping radioactivity as ^{226}Ra from a coal-fired power plant, CPP and the arising hazards (radiological impact) in regard with the occurrence of natural radioactivity in the coals and fly ashes.

2. RADIOACTIVITY OF COALS AND FLY ASHES

Coal samples (N=53) from open and closed (galleries) coal mines and fly ash samples (N=36) from electrostatic precipitator (ESP) from coal-fired power plants in Greece were obtained for the measurement of the natural radioactivity. The coal samples were collected from the loading bands which feed the furnace (oven) after pulverization had taken place in the mills. Fly ash samples were obtained from three points along the flowing line of a coal-fired power plant before the exit through the loading bands on the way to the fly ash repositories (Figure 1) as well as from the fly ash deposits (repositories). All samples of coals and fly ashes were homogenized , packaged to preclude radon emanation (Manolopoulou, 1990), and then measured for determining the specific activities of the naturally occurring radionuclides by the emitted gamma-radiation on a low-background high-purity Ge detector of coaxial type linked to an appropriate data-acquisition system including PC MCA card facilities. The detector resolution was1.9 keV for the 1.33 MeV of ^{60}Co gamma-ray peak, efficiency 42 % and the uncertainty of the measurements was known to an accuracy of better than 5 % for the plastic can geometry with diameter of 6 cm and 12 % for the geometry of a standard Marinelli beaker of 1-litre in volume. A planar type Ge detector was also used for the low energy gamma rays, lower than 300 keV, with a resolution of 700 eV for the 122 keV of ^{57}Co photopeak and an active area of 2000 mm^2. The data collection time was 200,000 s. Instrumental neutron activation analysis (INAA) and delayed neutron techniques were also applied in order to confirm the ^{238}U and ^{232}Th data.

Plots of typical gamma-ray spectra of a fly ash sample obtained by planar and coaxial type Ge detectors are shown in Figs 2a and 2b, respectively. The gamma-ray peaks of the natural radionuclides are clearly evident. Tables 1 and 2 present the activity concentrations in Bq kg^{-1} of ^{238}U, ^{226}Ra (from ^{214}Pb and ^{214}Bi), ^{210}Pb, ^{232}Th (from ^{228}Ra, ^{228}Ac and ^{208}Tl) and ^{40}K of coals and fly ashes, respectively. Radioactive equilibrium does not exist in the coals between ^{238}U and ^{226}Ra (^{238}U:^{226}Ra=1.7±0.4), whereas it does exist between ^{226}Ra and ^{210}Pb (^{226}Ra:^{210}Pb=1.0±0.2). Coles et al. (1978) reported that secular equilibrium does exist between all the nuclides of the uranium series chain in the coals but not in the fly ashes. The isotopic ratio ^{235}U:^{238}U is fairly in good agreement with the natural one, 7x10^{-3}. There is very approximately enhancement of radioactivity concentrations from coal to fly ashes by a factor of 3.

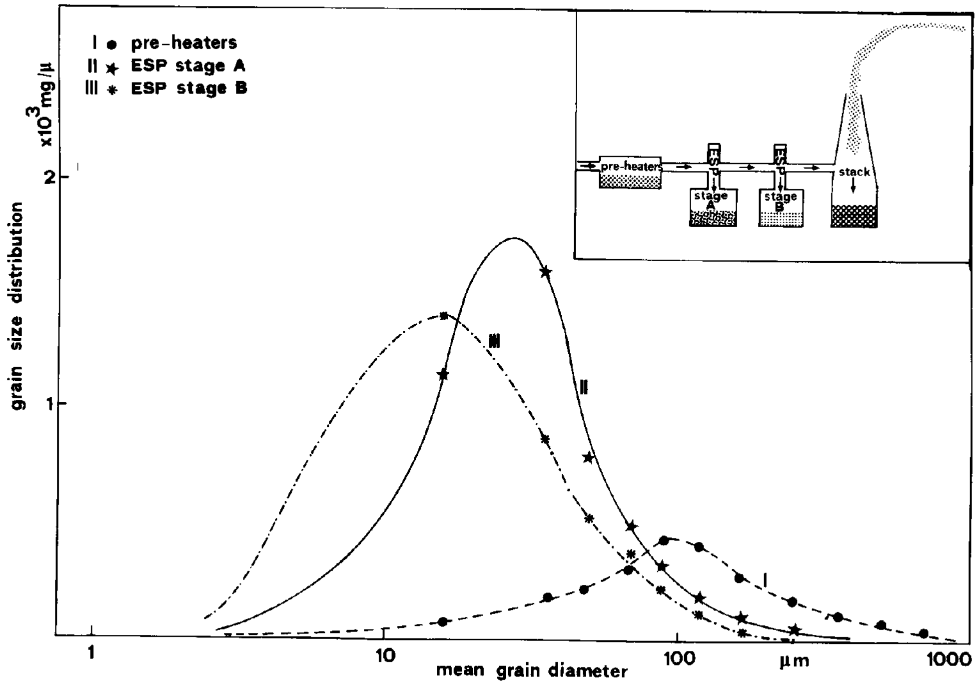

Figure 1. Grain size distribution of fly ash particles vs mean grain diameter, in μm, after sampling in various stages of fly ash flowing line of the stack in a unit of a coal-fired power plant at Kardia Ptolemais, Northern Greece.

The activity concentrations of natural radionuclides measured in coals varied over two orders of magnitude and ranged from 2 to 435 Bq kg^{-1} for ^{238}U, from 6.5 to 420 Bq kg^{-1} for ^{232}Th, and from 6 to 759 Bq kg^{-1} for ^{40}K. The natural radionuclide concentrations in soil, however, varied from 16 to 110 Bq kg^{-1} (average 35 Bq kg^{-1}) for ^{238}U, from 17 to 60 Bq kg^{-1} (average 35 Bq kg^{-1}) for ^{226}Ra, from 11 to 64 Bq kg^{-1} (average 30 Bq kg^{-1}) for ^{232}Th and from 140 to 850 Bq kg^{-1} (average 400 Bq kg^{-1}) for ^{40}K (UNSCEAR, 2000). The natural radionuclide concentrations measured in fly ashes produced and retained or escaped from coal-fired power plants are significantly higher than the corresponding concentrations in coals and soil (earth's crust). They ranged from 44.4 to 950 Bq kg^{-1} for ^{238}U, from 54.2 to 866 Bq kg^{-1} for ^{226}Ra, from 43.5 to 428 Bq kg^{-1} for ^{210}Pb, from 47.5 to 133.2 Bq kg^{-1} for ^{232}Th, from 27 to 138 Bq kg^{-1} for ^{228}Ra and from 56 to 1547 Bq kg^{-1} for ^{40}K.

The higher concentrations of radionuclides in coals were observed to those originated from coal mines in Greece (this work; Papastefanou and Charalambous, 1979), and in Poland (Tomczynska et al., 1980), while in fly ashes to those originated from coal-fired power plants operating in Greece (this work; Papastefanou and Charalambous, 1979), in Poland (Tomczynska et al., 1980; Bem et al., 2002) and in India (Mishra et al., 1984).

Table 3 shows the average composition of coals and fly ashes. It is seen that the carbon content of coals is about 20 % and the ashes about 13 %. Barber and Giorgio (1977) classifying the coals into three categories reported that the percentage of ash in coal after ashing varied from 2 to 9 % for bituminous coals, 6 % for lignite and 11 % for subbituminous coals.

Table 1. Activity concentrations of natural radionuclides in coals (in Bq kg^{-1}).

Source	^{238}U	^{226}Ra	^{210}Pb	^{232}Th	^{228}Ra	^{40}K	Reference
Lignites	243 (117–399)	266 (44–236)	134 (59–205)	–	18 (9–14)	108 (59–227)	This work
Brown coal	385 (298 435)	167 (118–255)	–	–	–	–	Papastefanou and Charalambous, 1979
Coke	323	144	–	–	–	–	Papastefanou and Charalambous, 1979
Anthracite	13.9	-	–	21.8	–	–	McBride et al., 1978
Bituminous	23.6	–	–	20.2	–	–	McBride et al., 1978
Subbituminous	16.2	–	-	13.3	–	–	McBride et al., 1978
Lignite	31.1	-	–	25.5	–	–	McBride et al., 1978
Coal	(8.9–31.5)	(7.8–23.7)	(9.6–25.1)	(6.3–20.7)	(6.3–20.4)	(27.0 51.8)	Coles et al., 1978
Coal	37.9 (1.85–141)	–	..	30.0 (9.4–107)	-	294 (37.0–759)	Tomczynska et al., 1980
Coal	–	30.3 (14.8–81.4)	–	36.6 (25.9–48.1)	–	94.7 (7.4–199.8)	Mishra et al., 1984
Coal	12.4 (6.0–16.2)	–	–	13.3 (6.5–19.4)	–	72.2 (40.3–179.8)	Nakaoka et al., 1984
Coal	12.4±0.3		–	7.5±0.3	–	26.4±0.6	Tracy and Prantl, 1985
Coal	25 (9–47)	21 (19 24)	28 (20–33)	24 (17–29)	34 (11–69)	75 (23–140)	Fardy et al., 1989
Anthracite	26 (22–30)	–	-	22 (19–30)	-	300 (216–451)	Alvarez and Garzon, 1989
Soft coal	31 (16–40)		–	23 (14–31)	–	295 (50–398)	Alvarez and Garzon, 1989
Brown lignite	16 (7–47)	–	–	18 (8–54)	–	24 (6 73)	Alvarez and Garzon, 1989
Black lignite	86		–	16	–	249	Alvarez and Garzon, 1989
Coal	-	46 (34–88)	–	56 (39–120)	–	–	Hayumbu et al., 1995
Coal	416±6(^{236}Th)	309±6	99±2(^{214}Pb)	-	123±3(^{228}Ac)	106±5	Font et al., 1993
Coal	23.5 (12.7–38.9)	18.1 (10.4 28.4)	22.3 (13.3–34.5)	14.3 (8.5–20.1)	–	129.9 (43.9–152.5)	Bem et al., 2002

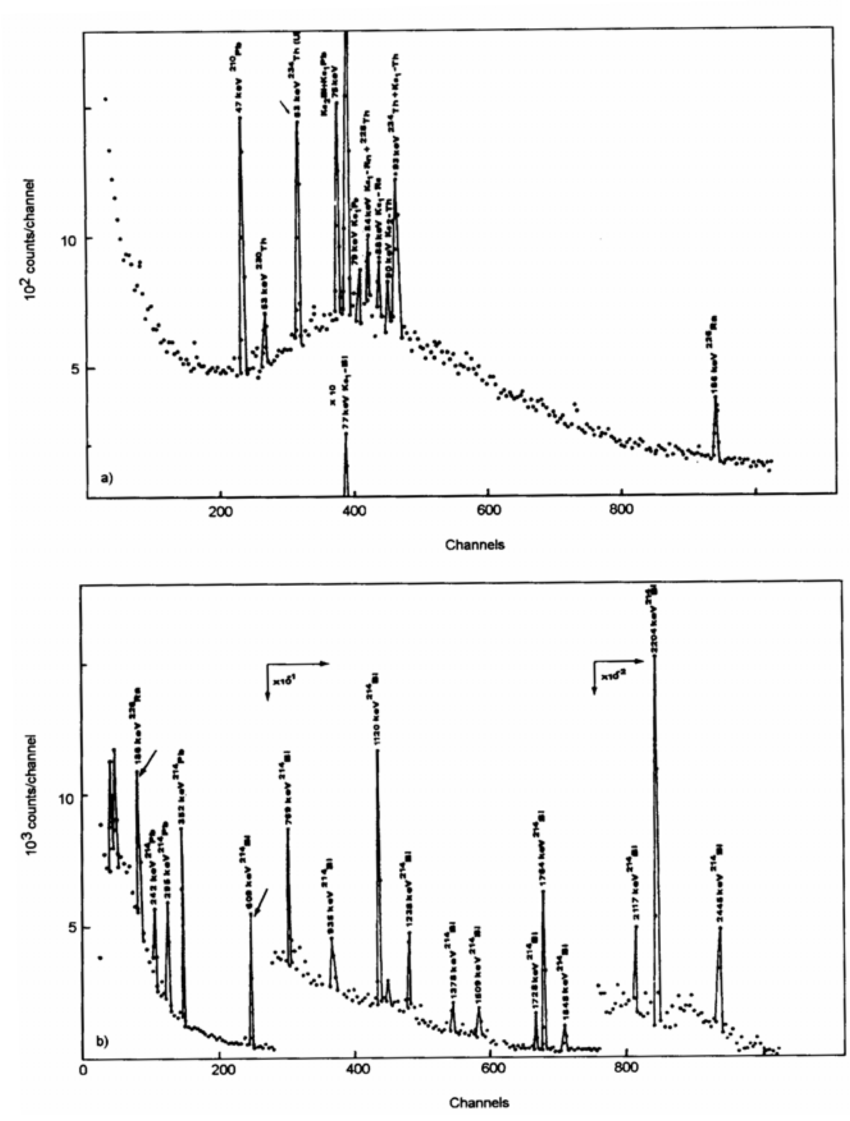

Figure 2. Gamma-ray spectrum of a fly ash sample obtained by a planar Ge detector (a) and by coaxial Ge detector (b).

Table 2. Activity concentrations of natural radionuclides in fly ashes (in Bq kg^{-1})

^{238}U	^{226}Ra	^{210}Pb	^{232}Th	^{228}Ra	^{40}K	Reference
356 (263–950)	366 (142–605)	275 (133–428)	–	50 (27–68)	297 (204–382)	This work
574 (460–870)	343 (211–422)	–	–	–	–	Papastefanou and Charambous, 1979
(70–130)	(85–107)	(52–81)	(63–89)	(63–89)	(233–300)	Coles et al., 1978
96.7 (44.4–169)	–	–	73.9 (33.3–126)	–	728 (185–1547)	Tomczynska et al., 1980
–	453.3 (70.3–866)	–	132 (107.3–207.2)	–	267.5 (56–348)	Mishra et al., 1984
117.5 (105.5–123.6)	–	–	126.8 (114.0–133.2)		687.0 (617.9–721.5)	Nakaoka et al., 1984
92±3	–	–	58±2	–	204±4	Tracy and Prantl, 1985
89 (76–114)	79 (59–110)	98 (60–150)	91 (57–130)	89 (57–138)	364 (170–615)	Fardy et al., 1989
344±2(^{234}Th)	246±2	95±1(^{214}Pb)	–	106±1(^{228}Ac)	107±2	Font et al., 1993
–	96 (77–120)	–	111 (90–126)	–	–	Hayumbu et al., 1995
134.2 (94.0–184.6)	94.1 (54.2–119.3)	147.6 (43.5–264.3)	74.7 (47.5–91.5)	–	646.9 (448.5–758.0)	Bem et al., 2002

Table 3. Average composition of coals and fly ashes

Coals, %		Fly ashes, %	
Humidity	56.50	SiO_2	30.70
Ashes	12.80	Fe_2O_3	5.58
C	19.94	Al_2O_3	14.56
H_2	1.40	TiO_2	0.22
S	0.53	CaO	34.67
N_2	0.38	MgO	3.47
O_2	8.45	SO_3	8.47
		Na_2O	0.53
		K_2O	0.88

Uranium and its decay product radionuclides in coals are associated with the organic material of coals (coal matrix), e.g. the humic acids (Calvo, 1974). Thorium and its decay product radionuclides as well as potassium are associated with inorganic materials (ash matrix). The concentrations of ^{226}Ra, a decay product of ^{238}U in coals are increased when the concentrations of ^{40}K are decreased, whereas the concentrations of ^{228}Ra, a decay product of ^{232}Th, are increased with increasing concentrations of ^{40}K. The different behavior between the two isotopes of radium, ^{226}Ra and ^{228}Ra, in coals is probably due to the fact that ^{226}Ra has higher mobility in the coal matrix than ^{228}Ra which is associated (as parent of ^{232}Th) with the aluminosilicates. Radium-226 and its precursor ^{238}U has a bimodal behavior either in the volatile form of uranium or in the silicate form of coffinite (Coles et al., 1978).

Thorium and potassium belong to the elements of Group I according to the classification of Coles et al. (1979), which shows little or no enrichment on the smaller fly ash particles. Group I includes lithophilic elements which are associated with aluminosilicate minerals and are assumed to have been homogenously incorporated into aluminosilicate-dominated fly ash matrix.

Lead belongs to the elements of Group II, where the enrichment factor (EF) increases with decreasing particle size. Group II includes chalcophylic elements

Which are associated with sulphide minerals and are mostly volatilized during the combustion process and later condense onto the smaller fly ash particles which have larger specific surface areas, i.e. a high surface to mass ratio and thus, will have greater concentrations of these elements.

Uranium belongs to the elements if Group III which shows a behavior intermediate to that of elements of Group I and Group II. The elements of Group III have higher enrichment factors, on smaller fly ash particles, which did not increase as dramatically as those of the Group II elements. The behavior of radium has not been adequately studied by many investigators because of its small (about zero in ppm) concentration (1 Bq ^{226}Ra per kg of sample is equivalent to $2.7x10^{-8}$ ppm) in coals and fly ashes. Kaakinen et al., (1975) stated that the general behavior of ^{226}Ra fits that of Group I (non-enriched elements) better than Group II (enriched elements). Coles et al. (1978) and Papastefanou and Charalambous (1984), however, observed an enrichment of ^{226}Ra as well as of ^{238}U on smaller fly ash particles in the activity size distribution. Uranium-238 and ^{210}Pb are enriched on smaller fly ash particles (Group II), while ^{40}K was decreased on smaller fly ash particles (Group I) as expected. The two isotopes of radium, ^{226}Ra and ^{228}Ra are also decreased on smaller fly ash particles but the rate of decrease of ^{226}Ra is weaker than the corresponding rate of decrease of ^{228}Ra as well as of ^{40}K. Radium-228 as a decay product of ^{232}Th behaves similarly with its parent ^{232}Th as well as ^{40}K (Group I). Radium-226 has rather an intermediate behavior between Group I and Group II as the ^{238}U and all its decay product radionuclides. A part of ^{238}U which is associated with silicates or which is mineralized as coffinite [$U(SiO_4)_{1-x}(OH)_{4x}$] in the coal (coal matrix) remains with the bottom ash, whereas the ^{238}U which is associated with the uraninite (UO_2) in the coal matrix forms volatile compounds such as UO_3, and ^{226}Ra also forms volatile compounds such as $Ra(OH)_2$ and later condenses out on the finer fly ash particles (fly ash matrix) (Coles et al., 1978).

The apparent enrichment of some radionuclides in fly ash particles can be characterized by the enrichment factor, EF defined as the ratio of the concentration of the radionuclide X and of ^{40}K in the sample of fly ash divided by the corresponding ratio in the input coal (Coles et al., 1978 ; Coles et al., 1979):

$$\mathrm{EF} = \frac{[\mathrm{X}]_{\text{fly ash}} / [^{40}\mathrm{K}]_{\text{fly ash}}}{[\mathrm{X}]_{\text{coal}} / [^{40}\mathrm{K}]_{\text{coal}}} \tag{2.1}$$

This effectively normalizes the apparent enrichment resulting from loss of carbon during the combustion process. Potassium-40 is used as a reference in this normalization because its activity concentration remains more or less constant in all types of fly ash in a given coal-fired power plant and thus is assumed to be a tracer for the aluminosilicate-dominated fly ash matrix (Coles et al., 1978).

Corbett (1983) reported the enhancement factor, which is associated with each element in a given fraction of fly ash, namely:

$$\mathrm{EF} = \frac{\text{Concentration of element in the fly ash}}{\text{Concentration of element in coal}} \times \text{Fly ash fraction of coal} \tag{2.2}$$

The enhancement factor is unity for an element that is distributed uniformly throughout the fly ash. Greater values of EF indicate enhancement in the fraction of fly ash being studied, whereas smaller values of EF indicate depletion.

Table 4 presents EF values for fly ash samples from different coal-fired power plants which may or may not use ^{40}K as a reference. The enrichment factors ranged from 0.60 to 0.94 for ^{238}U, from 0.69 to 1.7 for ^{226}Ra, from 0.48 to 1.00 for ^{210}Pb, from 0.89 to 1.4 for ^{232}Th, from 0.86 to 1.7 for ^{228}Ra and from 0.95 to 1.10 for ^{40}K. As a general rule, the values of the enrichment factors increase with the temperature of combustion and decrease with the particle size, at least for sizes above 1 μm (Coles et al., 1978).

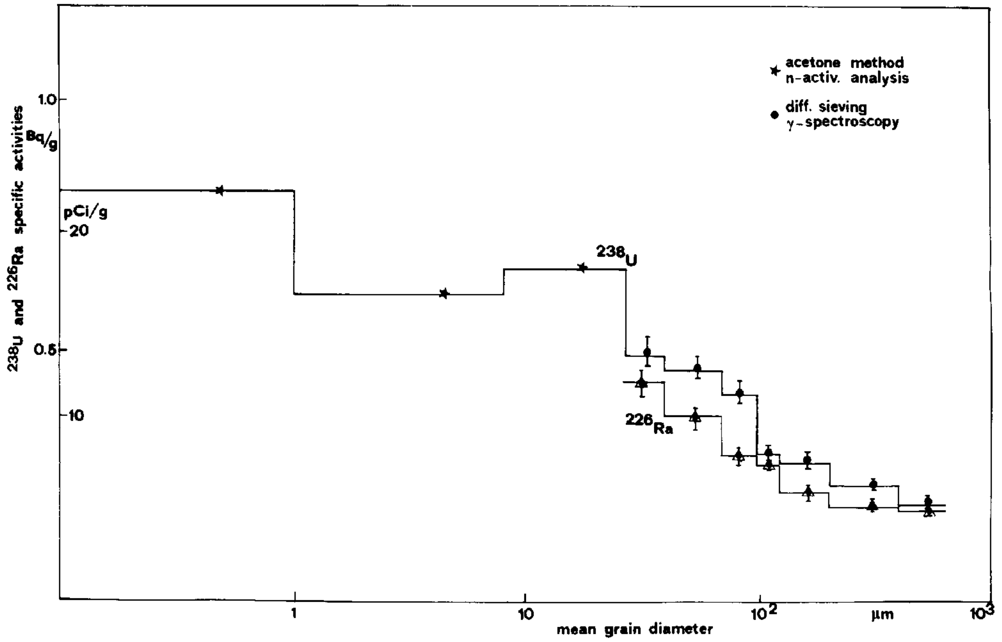

Figure 3. Uranium-238 and ^{226}Ra specific activities of fly ash size-fractionated particles vs mean grain diameter.

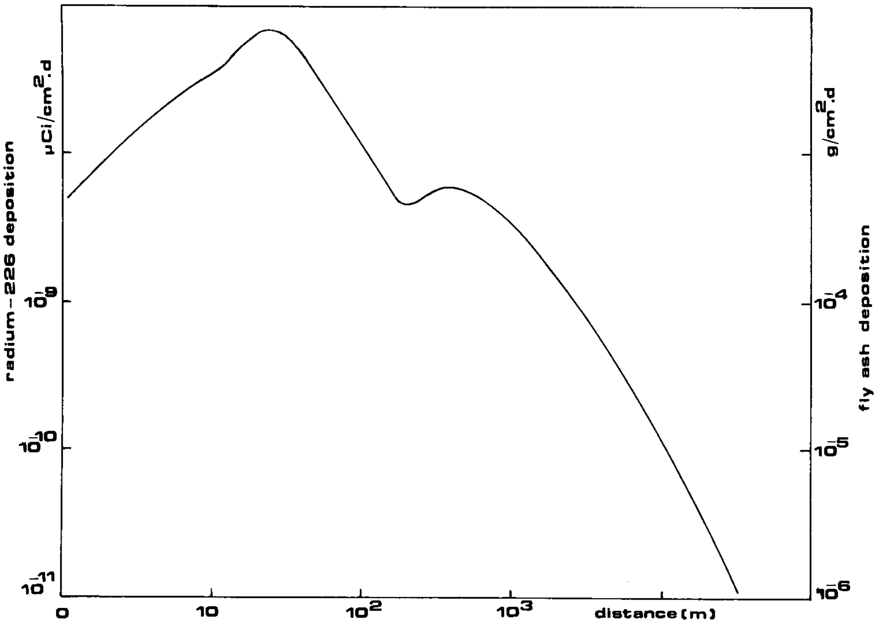

Figure 4. Deposition of fly ash and ^{226}Ra activity depositing in one direction (blowing wind) as a function of the distance downwind from the stack (1 μCi = 3.7x10^4 Bq).

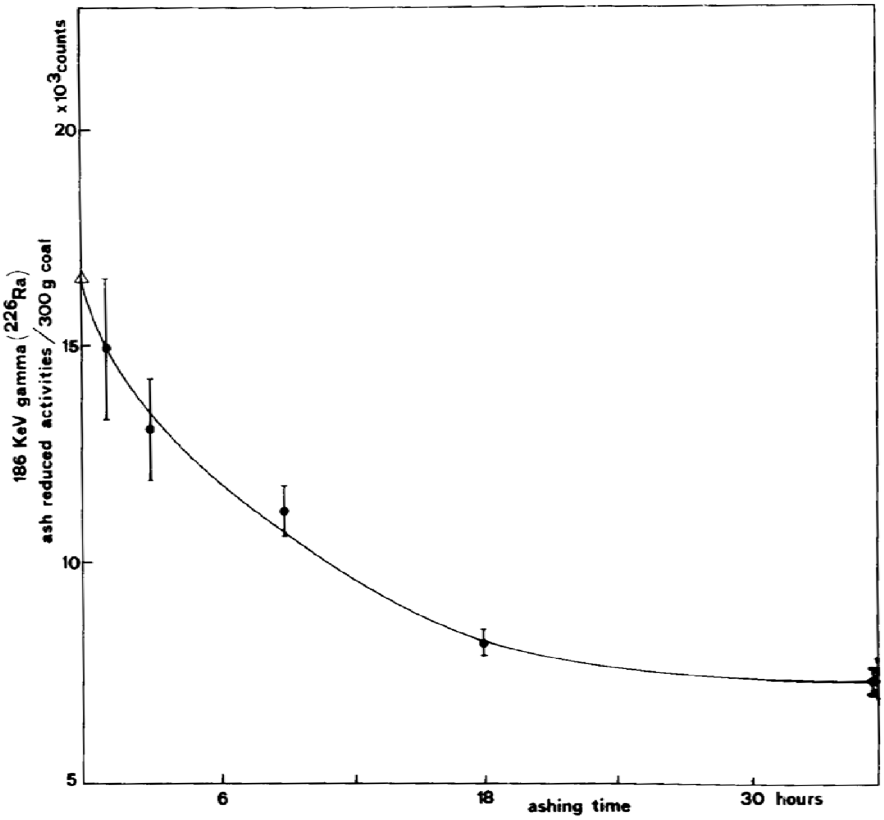

Figure 5. The remaining ^{226}Ra activity in bottom ash of 186-keV γ-line, in the mild coal ashing as a function of the time of ashing at 700°C.

Table 4. Enrichment factors of natural radionuclides in fly ashes relative to input coals

Particle size, μm	^{238}U	^{226}Ra	^{210}Pb	^{232}Th	^{228}Ra	^{40}K	Reference
	0.71 (0.60–0.76)	0.87 (0.76–0.97)	0.68 (0.62–0.75)	–	1.00 (0.95–1.03)	–	This work
	0.69 (0.66–0.72)	0.86 (0.69–1.07)	0.66 (0.57–0.72)	–	1.00 (0.86–1.11)	0.98 (0.95–1.10)	This work
	–	1.7	1.1	1.4	1.7	–	KLEIN et al., 1975
	(0.71–0.94)	(1.0–2.0)	(0.48–0.74)	(0.89–0.96)	(0.90–0.98)	–	COLES et al., 1978
18.5	1.3	1.1	1.3	1.0	1.0	–	COLES et al., 1978
6.0	1.6	1.4	3.0	1.1	1.2	–	COLES et al., 1978
3.7	2.3	1.6	4.1	1.1	1.4	–	COLES et al., 1978
2.4	2.8	1.9	5.0	1.2	1.6	–	COLES et al., 1978

[1] According to COLES et al., 1978.

[2] According to CORBETT, 1983.

Table 5. Uranium-238 and ^{226}Ra in fly ash samples obtained from the flowing line in a unit of a coal-fired power plant at Kardia Ptolemais, Northern Greece

Sampling location	^{238}U (Bq kg^{-1})	^{226}Ra (Bq kg^{-1})
Preheaters	340.4	192.4
ESP stage A	481.0	336.7
ESP stage B	640.1	499.5

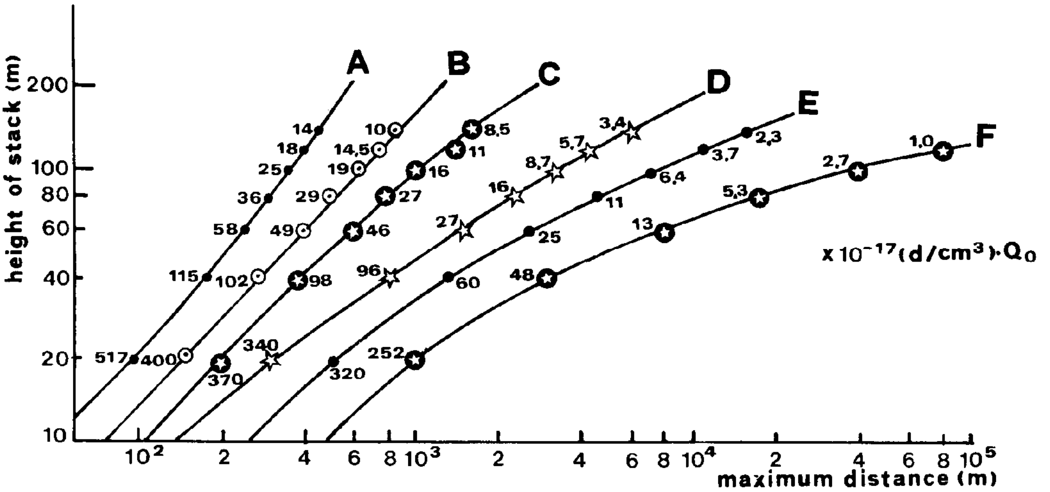

Figure 6. Typical curves for various Pasquill atmospheric stability conditions, from A to F. The numbers in the curves show the maximum concentration of ^{226}Ra in air, in μCi cm^{-3} (1 μCi cm^{-3} = 3.7x10^{10} Bq m^{-3}) at several distances downwind from the stack, as a function of the height of the stack. Q_o is the radioactive release in μCi d^{-1} (1 μCi = 3.7x10^{4} Bq).

Table 6. Uranium-238 and ^{226}Ra of the material deposited in different layers on the heating pipes of a unit of a coal-fired power plant of LIPTOL Ptolemais, Northern Greece

Sample	^{238}U (Bq kg^{-1})	^{226}Ra (Bq kg^{-1})
Initial layer (inner)	873.2	451.4
Final layer (outer)	599.4	355.2

3. PARTICULATE DISPERSION OF FLY ASH

Fly ash escapes from the stacks of coal-fired power plants in a percentage of 3 or 1 % of the total fly ash, in the better cases. Attempts were made to determine the mass distribution and from it the radioactivity of size-fractionated fly ash particles.

(i) Fly-ash samples were obtained from three points along the flowing line of a coal-fired power plant unit at Kardia Ptolemais, Northern Greece, as is pointed out in the flow diagram in Figure1. Thirty grams of each sample were measured by gamma-ray spectrometry for ^{238}U and ^{226}Ra concentrations. The results are presented in Table 5. Samples obtained from the second stage, Stage B of the electrostatic precipitator (ESP) are more radioactive than other samples obtained from the first points, preheater and stage A, of the flowing line. This means that the fly ash which is ejected from the stack should be considerably more radioactive than that presented in Table 5. In explaining this effect, the particle-size distribution of each sample had to be examined.

(ii) Fly-ash samples obtained from the preheater and the ESP stages A and B along the flowing line (Figure 1) were separated in fractions of standard sieve ranges, of mean diameters between δ and δ+Δδ of the particle size. For large diameters, differential sieving was used. Sieves of the following mean diameters, in μm, were used: 28, 40, 63, 80, 100, 140, 200, 315, 400, 630 and 800. For the fine particles, δ<28 μm, centrifugal sedimentation in acetone was applied (acetone method). The fly-ash fraction of the particles δ<28 μm was separated in three parts as follows: (a) 28-8 μm, (b) 8-1 μm and (c) <1 μm. The results are summarized and illustrated in Figure 1. The size distribution of the second-stage of ESP samples, stage B, increases in the finer part of the fly ash particles, δ<32 μm. It was concluded, as one would expect, that finer particles, e,g. less than δ = 20 μm, move farther into the atmosphere by flowing with the gases.

(iii) Thirty grams of fly ash per range of distribution function of sampling from the second stage of ESP samples, stage B, from the experiment (ii), were counted by a gamma-ray spectrometer for the determination of ^{238}U- and ^{226}Ra-content. Fractions of the finer fly-ash, δ<28 μm, were measured for ^{238}U-content by the instrumental neutron activation analysis (INAA), because of the small quantities available. The ^{226}Ra-content was measured only for grains with diameter up to 28 μm. The results of the activity of particles fractionated according to size are shown in Figure 3.

It is seen that the uranium and radium content increases as the grain diameter decreases. This may be due to the larger specific surface area of the finer particles (Coles et al. 1978). In fact, since the finer particles are cooled faster than the large ones, the vapors containing radioactive nuclides should condense more on them.

Moreover, the specific gravity of the finer particles was found to be higher than that of the gross particles. It is concluded that the fine particles, δ<20 μm, which are discharged out of the stack into the atmosphere, will present the higher uranium and radium contents. It must be noted that this part of the finer grains is in the respirable fraction, that is 10 μm in size, and it is associated with the health risk of inhalation for its higher radioactive content.

It must also be noted that radioactive equilibrium does not exist in the coals (lignites). Also, the ratio of ^{238}U/^{226}Ra in coals (lignites) is not the same in fly ash (Papastefanou and Charalambous, 1979; 1980).

The grains of the escaping fly ash leave the stack with an initial velocity, which is not of interest, and they are dispersed by the wind at several distances from the stack. In fact, the grains have terminal velocities of settling under gravity governed by the Stocks settling law (δ>1.1 μm), whilst they are removed simultaneously horizontally by the wind with a mean speed, u.

The horizontal distance, x, in which the grains of mean diameter, δ, with fall on the ground surface from the height, h, of the stack, is given by the formula

$$x = 18 \cdot \frac{\eta_\alpha}{\left(\rho_g - \rho_\alpha\right) \cdot g} \cdot \frac{h}{\delta^2} \cdot u \tag{3.1}$$

where

$\eta_\alpha = 182.7 \times 10^{-6}$ g cm^{-1} s^{-1}, the air viscosity at 18°C (Weast,1974),
$\rho_g = 2.47$ g cm^{-3}, the grain density,
$\rho_\alpha = 0.001293$ g cm^{-3}, the air density, STP, and
$g = 981$ cm s^{-2}, the gravity acceleration

It was found that $\rho_g = 2.34$ g cm^{-3} for $\delta > 45$ μm and $\rho_g = 2.67$ g cm^{-3} for $\delta < 45$ μm. After substitution of the rates of constant, equation (3.1) becomes

$$x = 1.36x10^4 \cdot \frac{h}{\delta^2} \cdot u \tag{3.2}$$

where x and h in meters, u in m s^{-1} and δ in μm. For a stack 120 m in height and wind speed of 1 m s^{-1} (typical value), the equation (3.2) becomes

$$x = 1.63x10^6 \cdot \frac{1}{\delta^2} \tag{3.3}$$

The formula (3.1) shows that the grains will be deposited at a distance from the stack which is inversely proportional to the square of their mean diameter, δ.

The next step is to find the distribution function, F, of the quantity of fly ash deposited onto the ground surface around the stack. This will be a combination of the distribution function of the particle size of fly ash and the equation (3.3). As distribution function of the escaping fly ash is considered the corresponding in curve III of Figure 1. The collection point of this fly ash, ESP samples stage B, curve III, was closest to the point at which the fly ash is escaping. Evidently, the general form of the distribution function, F, will be

$$F = F[h,u.(x,\delta)] \tag{3.4}$$

To find the arithmetic value of F, some assumptions have to be made first against the wind. For the case of equal distribution in the direction of the blowing wind (2π geometry), the function F, in general form, can be written

$$F = \mathrm{const} \cdot h \cdot u \cdot \frac{1}{f\left(\delta^2\right)} \cdot \frac{1}{2\pi x \Delta x} \tag{3.5}$$

If M is the mass of the total escaping fly ash per day, then the quantity of fly ash deposited per day in the unit of area of the annular region limited between x and x + Δx will be given by the equation

$$P_x = \mathrm{const.}\ F.M \tag{3.6}$$

where P_x, in g cm^{-2} d^{-1}.

If Q is the total radioactivity escaping by the fly ash per day, then the radioactivity depositing per day in the unit of area of the annular region limited between x and x + Δx, will be given by the equation

$$R_x = \mathrm{const.}\ F.Q \tag{3.7}$$

where R_x, in Bq cm^{-2} d^{-1}.

For the case of the wind blowing with a mean speed of 1 m s^{-1}, P_x and R_x, were found by arithmetic analysis. The results are summarized and illustrated in Figure 4. The height of the stack was taken to be equal to 120 m.

As a consequence of the distribution function of Figure1, curve III, the integrand of F shows a maximum at a region of about 400 m downwind from the stack (Figure 4). As the wind speed increases, this maximum is removed to major distances, Integrating of equations (3.6) and (3.7) in the limits of the peak, e.g. from 200 m up to 1100 m for this case, gives results that indicate the fly ash and its radioactivity deposited into the annular region is about 50 % of the total stack release. These are expressed, respectively, by the relationships

$$M_P = \int_0^{2\pi} d\varphi \int_{x_1}^{x_2} P_x \, dx$$

and

$$Q_R = \int_0^{2\pi} d\varphi \int_{x_1}^{x_2} R_x dx \tag{3.8}$$

On the site of maximum, the P_x and R_x have the values $P_{max} = 6x10^{-4}$ g cm^{-2} d^{-1} and $R_{max} = 2.29x10^{-4}$ Bq cm^{-2} d^{-2}, for ^{226}Ra. It was considered that from a coal-fired power plant unit escape M = 40 tons of fly ash per day and the corresponding ^{226}Ra activity Q = 18.5 MBq per day. At the distances where the maximum is achieved the height of the layer of fly ash on the ground surface could reach up to 7 mm y^{-1}.

The hypotheses used in the case of the wind for the above calculations are strong. At any site there is always a prevailing wind direction. In that case, the concentration of fly ash and radioactivity deposited will obviously be increased by a percentage which depends on the direction of the prevailing wind. Also, it should be a removal of the position of maximum, away from the stack, according to the wind strength. However, a wind speed of 1 m s^{-1} is a most probable annual mean value as given by

Meteorologists (Laboratory of Meteorology, 1979). In fact, a comparison of the values of fly ash deposited, as it is estimated by the above calculations and given by experimental data of ash collection (Vakalis, 1979), which are about the same, leads to accept that the hypotheses used were realistic.

4. RADIOACTIVITY ESCAPING FROM COAL-FIRED POWER PLANTS AS FINE PARTICLES

In the determination of specific activities of ^{226}Ra and ^{238}U in the coals (lignites) and fly ash of coal-fired power plants it was found that no balance exists throughout the range of their activities. In fact, if the coal-fired power plant of Kardia Ptolemais, Northern Greece is taken as a model, it burns about $7x10^6$ tons of coal per year with a 12.8 % ash content. Using data for the coals, the fly ash retained in the electrostatic precipitators, the liquid ash, and the escaping fly ash in a percentage of 2 %, it was found a difference as high as 1.55 TBq y^{-1} (42 Ci y^{-1}) for ^{226}Ra, i.e. the escaping ^{226}Ra-activity from the coal-fired power plant, in any form is about 1.55 TBq y^{-1}. This number must be compared with the 7.4 GBq y^{-1} (18.5 MBq d^{-1}) of

^{226}Ra which escapes as gross particulate dispersion. This means that the most important fraction, 99 %, of escaping radioactivity is ejected in the finest particulate form or, in gaseous form (vapor phase).

For this purpose, two types of experiments of mild ashing of coal were made in the laboratory:

In the first experiment , the coal was pulverized (3 mm in diameter) and homogenized. Samples of 300 g of coal ore were burned mildly each time (without high air currents) in an electrical oven at several temperatures and time durations. The volatile hot materials (vapors) flow with the gases out into the atmosphere. The specific activity of residues of ashing at various stages of ashing was measured by a gamma-ray spectrometer. The loss of radioactivity in this experiment was evidently due to the flying volatile materials which escape in the vapor phase. The results of the mild ashing experiment are presented in Figure5. This figure shows the total ^{226}Ra-activity of an initial mass (300 g) of coal of Serres coal mine, Northern Greece which is one of the most radioactive (Papastefanou and Charalambous, 1980). It was observed that a fraction of 60 %, at least, of radioactivity was ejected in gaseous form (vapor phase). The curve of Figure5 concerns the 186-keV γ-line of ^{226}Ra on which much attention was focused and referred to the ashing temperature of 700^{o}C. The 63-keV γ-line of ^{238}U shows a similar behavior. It must be noted that burning in the electrical oven, even at 700^{o}C, is very mild as compared with the combustion in coal-fired power plants. This means, that large amounts of radioactivity will escape in gaseous form.

The second experiment was carried out as follows: Coal ashing was achieved in a quartz tubing flask (bulb of 500 mL). Also, 300 g of coal each time was ashed by burning at 500^{o}C in the presence of oxygen bubbles. The upper walls of the tube were cooled continuously. Thus, the volatile materials precipitated down into the flask. The gases, such as CO_2 and SO_2, passed through barium chloride (carrier) and alcalic solutions in order to form radium, carbonic or sulfuric precipitates. The ash and the sediments produced were counted for their radioactivity by known methods. The measurements showed that the whole uranium and radium content of coal remained in the bottom ash of the flask. The volatile materials were condensed by cooling and returned to the flask and mixed with bottom ash. Thus, the radioactivity of the bottom ash contained the precipitated radioactive nuclides of the vapor phase. Volatile species could probably contain uranium as UO_3, oxidized uraninite, or in silicate form (coffinite) and radium as $Ra(OH)_2$ volatile species or with uraninite fraction. These elements preferentially condense out on the finer fly-ash particles (Coles et al., 1978).

Another experiment was performed with the same purpose. The volatile materials during the combustion process in a unit of a coal-fired power plant may rise and may come into contact with the heating pipes in the heater, condense and be deposited on them. After a long operating time, a thick (solid) layer was formed. That layer which surrounds the pipes acts as thermal insulation. Thus, the volatile materials in the vapor phase settle onto the pipes less than at the start of operation.

Samples of the material of such layers were collected from a unit of a coal-fired power plant of Ptolemais (LIPTOL), Nothern Greece, and separated into two parts, the initial and the final. The initial layer was formed at the starting time of operation of the unit of coal-fired power plant and the final layer at the shutdown time which takes place for normal service (solid layer cleaning of heating pipes etc) and control.

The samples were measured for their uranium and radium content. The results are given in Table 6. The uranium and radium specific activities were higher in the initial layer sample than the final one in excess of a factor of 1.5 or 1.25 for ^{238}U and ^{226}Ra, respectively. Also, the uranium specific activity was higher than that of radium in the initial layer sample by a factor of 2 and in the final layer by a factor of 1.7. This means that the volatile materials contain more uranium than radium because the volatility of the uranium species is higher than that of radium (Coles et al., 1978).

Thus, it is expected that more uranium than radium to be dispersed with the gases which are discharged from the stack into the atmosphere by a factor of 2 or higher.

5. HAZARDS FROM THE RADIOACTIVITY ESCAPING FROM THE STACKS OF COAL-FIRED POWER PLANTS

5.1. Hazards from the Escaping Fly Ash

Because of the characteristic distribution of the particle sizes of fly ash (Figure 1, curve III), it was shown that the particulate dispersion will always show a maximum for each wind speed. For the conditions mentioned in section 3 (wind speed 1 m s^{-1} and 2π geometry), it was shown that the maximum deposition could take place at about 400 m downwind from the stack. Considering the amount of deposition in the unit area, and in the unit of time, it is easily could be found the concentration of fly ash in the unit of volume of air in the locality of deposition.

In the case considered , a fly-ash particle concentration of about 220 μg m^{-3} was found. This means an equivalent radioactive concentration of ^{226}Ra of about 85.1 μBq m^{-3}. This fly ash consists of grains with mean diameter of about 15 μm. This specific radioactive concentration must be compared with the maximum permissible concentration (MPC)$_a$ of ^{226}Ra in air, which is 111 mBq m^{-3} for non-occupational exposures from radioactive concentrations which may be averaged over a period not greater than one year (CFR 1978). The value of radioactive concentration found is three orders of magnitude lower than the MPC and must be considered extremely negligible. Radium-226 was only considered, in this section, against ^{238}U, because of its high radiotoxicity (nefro-toxic element). The above estimations were made considering 2π geometry,that means on one hand non-preferable wind directions and on the other an annual basis.

It could be regarded that concentration maxima mean that the wind blows in a definite direction. For example, let a wind have a ± 7.5^{o} deviation in its direction. Let also an equal distribution to the segment be considered.By a simple ratio (5/360), it is found that ^{226}Ra concentration is 25 times higher, that is about 2.22 mBq m^{-3}. This is also 50 times lower than the maximum permissible concentration, (MPC)$_a$ of ^{226}Ra in air.

5.2. Hazards from the Atmospheric Dispersion of Fly Ash

It was showed that the highest amount of radioactivity from the stack of a coal-fired power plant must escape in gaseous or fine partition. Its dispersion can be calculated by the diffusion theory of Fick's law. The problem is similar with that of the common smoke dispersion and has been studied by Pasquill (1962).

The maximum concentration, χ_{max}, in Bq m^{-3}, of a radioactive element in air at a distance, x, in m, from the stack in the direction of the blowing wind, as it results from the theory, will be a function of the amount of radioactivity, Q_o, in Bq y^{-1}, which escapes in the unit of time from the stack of a coal-fired power plant, of the height of stack, h, in m, of the wind speed, u, in m s^{-1}, and of the Pasquill atmospheric stability conditions. The maximum concentration, χ_{max} at distance x, for which $h^2 = 2\sigma_z^2$, is given by the formula (Lamarsh, 1975)

$$\chi_{\max} = \text{const}\frac{Q_0}{u \cdot (\sigma_y \cdot \sigma_z)_{\max}} \tag{5.1}$$

where σ_y and σ_z are the coefficients of horizontal and vertical dispersion for various Pasquill atmospheric stability conditions, in m, and the constant is 3.16×10^{-8} for the above units.

In Figure 6, typical curves for ^{226}Ra concentration in air due to atmospheric dispersion, are presented. The number of the curves show the maximum concentration, χ_{max} of ^{226} Ra, in Bq m^{-3}, at several distances downwind from the stack of a coal-fired power plant, at the level of its base, in the main direction of the local wind blown, as a function of the height of the stack Qo is the radioactive release of ^{226}Ra , in Bq y^{-1}. Each curve corresponds to one Pasquill atmospheric stability condition, from A (extremely unstable) to F (moderately stable). In a case of a radioactive release, Q_o = 1.55 TBq y^{-1} of ^{226}Ra, of one unit of a coal-fired power plant using 2×10^4 tons of coal per day, it is found that the maximum concentration, χ_{max} of ^{226}Ra in air is estimated to be 0.74 Bq m^{-3} for the Pasquill condition A, that is extremely unstable, and considered as the worst one and the most extreme. The above value is too much higher than that estimated in the section 5.1 and is about one order of magnitude higher than the maximum permissible concentration of ^{226}Ra in air. The above consideration presupposed a single and stable wind direction. This hypothesis is non-realistic and therefore, the maximum concentration of ^{226}Ra in air will be lower than the one estimated. However, other toxic radionuclides, such as ^{238}U and ^{210}Pb escape from the stack of a coal-fired power plant, which makes the hazard even greater.

Under the mean stable Pasquill condition F (moderately stable), the whole-body man dose exposure was calculated at the distance x = 400 m downwind from a stack 120 m, in height, where the maximum deposition could take place, and u = 1 m s^{-1}. Using the philosophy of calculations as given by Cohen et al., (1978), it was found that for a radioactive release Q_o = 1.55 TBq y^{-1} for ^{226}Ra, the whole-body man dose exposure is about 0.005 man-Sv. This is an order of magnitude higher than the average annual effective dose of the population for individual members of the public, which will not exceed 0.5 mSv y^{-1}, i.e. the 1 % of 0.05 man-Sv, which is the permissible whole-body man dose exposure (ICRP, 1977).

5.3. Hazards from Wall Radioactivity in Dwellings due to the Fly Ash

In the case that fly ashes are used as substitute of cement in concrete, then the hazards arisen from direct irradiation to its radioactivity can be estimated as follows:

The cement in concrete is about 30 % and the proposed substitution is between 20 and 40 % (Voyatzakis et al., 1976; Sipitanos et al., 1977) Let assume 30 % fly ash in the cement. Since 1 m^3 of concrete contains about 300 kg of cement, it was found that its activity concentration will be: $P_i = 0.09\ A_i$, where A_i is the activity concentration (number of γ-photons per cm^3, emitted in 4π geometry, per unit time of the particular i-th γ-line) of the ash.

The problem set is to estimate the dose from a given energy γ-line at a distance z from a concrete wall containing fly ash. Firstly, it is calculated the γ-photons flux at the surface of the wall. This problem has been solved in several manuals, e.g. in Price et al. (1957). Next, using the flux of γ-photons so found, it is calculated the dose from well-known relations or curves.

At a distance of 1 m across a wall of infinite area and of infinite depth, it was estimated that about 600 gammas of 0.609 MeV per cm^2 and hour. This gives a dose of about $2x10^{-6}$ mGy h^{-1} (2 nGy h^{-1}) or about 0.02 mSv per year. Assuming that a person stays for 24 hours a day in a room made by concrete of this type, it was found that he should receive from the 0.609 Mev gammas an annual dose less than 0.1 mSv per year. By considering all the important gammas of the uranium-radium series in secular equilibrium with the 0.609 MeV gammas and which should be emitted from the doped concrete, it was calculated an annual dose of the order of 1 mSv. The assumption made in the above estimation was strong, i.e. 24 h permanent living in the room. So, the 1 mSv must be considered as an overestimate.

In practice, if the hazards from the use of fly ash in concrete should arise only from wall radiation, it might be considered as a tolerable risk. This risk, however, should be combined with the hazards from radon diffusing from the wall.

5.4. Hazards from Diffusion of Radon through Concrete

If fly ash should be used in concrete, the radon gas will diffuse out of it. It was calculated the hazards from the radon concentration in concrete in the following manner:
Culot et al. (1976) studied the effective diffusion coefficient of radon in concrete. Applying a linear diffusion theory to diffusion of radon across a concrete wall, they found results indicating that the relaxation distance of radon in a concrete wall is of the order of 10 cm with an associated effective diffusion coefficient k_e of the order of $2x10^{-5}$ cm^2 s^{-1}. This value is in good agreement with the value of k_e given by Schweite et al. (1968).

Using the philosophy of Culot et al. (1976), it was found that in a room of dimension 10x10x14 m^3, then the concentration of radon in the air indoors will be about 37 Bq m^{-3}. For the above estimation it was used a concrete porosity of 5 % and a wall thickness of 20 cm. The concrete composition was taken as in 5.3. The estimated indoor radon concentration is about two orders of magnitude lower than that of the maximum permissible concentration of radon in air, $(MPC)_a$, which is about $3.7x10^3$ Bq m^{-3}.

In spite of the fact that the hazard from radon diffused through concrete can be considered as a tolerable risk, it may be better, however, to avoid this doped concrete for construction of dwellings or buildings for habitation, in general. It is possible to use such a concrete for foundations, bridges and other big concrete constructions of open air. It must be noted that the estimations for radon diffusion were made for concrete which has a porosity of 5 %, while it is well known that concrete can have porosities of up to 25 %. The radon concentration in indoor air will then be an order of magnitude higher than that given above.

6. CONCLUSIONS

If the coal burning in one coal-fired power plant contains ^{226}Ra with a concentration higher than 370 Bq kg^{-1} (10 pCi g^{-1}), then the radioactivity escaping from the stack as fly ash and as fine dispersion could result in a ^{226}Ra concentration in air near the ground comparable with or higher than the maximum permissible concentration of radium in air, $(MPC)_a$.

It is expected that the coal use for electric power generation will be increased from year to year in respect with the restrictions of the use of nuclear energy for this purpose. Several estimation, i.e. by Bertine and Golberg (1971), Kleint et al. (1975) and Ondov et al. (1977) , were made on the atmospheric releases of various potentially toxic elements from large coal-fired power plants. In them, the release of radioactive elements must be also added. All of them must be taken seriously into consideration in the design of the new and/or modern coal-fired power plants, since, as the present work demonstrates, they could result in the concentrations of radionuclides in air close to, or even greater than, the maximum permissible concentration of them in air, $(MPC)_a$.

The major component of the risk is due to the releases in fine particles. While for the fly ash the risks are eliminated when either the height of the stack is increased or better electrostatic filters are used, for the fine particles the risks are eliminated only when the height of the stack is increased. For example, if instead of a stack of 120 m in height, is considered a stack of 170 m in height (Figure 6), the ^{226}Ra concentration is reduced by a factor of 2.

As is known, the coal-fired power plants discharge relatively larger quantities of of radioactive pollutants into the atmosphere than the nuclear power plants, of comparable size, during their normal operation (Eisenbud and Petrow, 1964; Aurand, 1978; Kolb, 1978) .

Finally, it is suggested that the type of coal to be burned in a coal-fired power plant must be chosen carefully and must be monitored for radioactivity before the combustion. If for reasons of economy a coal containing radioactivity must be burned, then the ^{226}Ra concentration should not exceed the rate of 370 Bq kg^{-1} (10 pCi g^{-1}).

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In: Carbon Capture and Storage Including… ISBN: 978-1-60741-196-3
Editor: T. P. Carington, pp. 57-79

Chapter 3

INTRODUCING CCS: POTENTIAL CHANGES IN COAL-FIRED POWER PLANT DESIGN, OPERATION AND REGULATION IN A CARBON CONSTRAINED FUTURE

Hannah Chalmers[1,2*], Jon Gibbins[1], Mathieu Lucquiaud[1] and Matt Leach[2]
[1]Energy Technology for Sustainable Development Group, Mechanical Engineering Department, Imperial College, London, SW7 2AZ, UK
[2]Centre for Environmental Strategy, University of Surrey, Guildford, GU2 7XH, UK

ABSTRACT

Significant coal reserves are reported in many countries including USA, China, Australia and India and it is often suggested that the use of this coal could play an important role in global energy security until the end of the century and beyond. But at the same time, concerns over the potential for dangerous climate change to be caused by carbon dioxide (CO_2) emissions from many human activities, including power generation using coal, has led to global efforts to identify technologies that can reduce CO_2 emissions. For coal-fired power plants, it is likely that successful development and deployment of carbon capture and storage (CCS) technologies will be the only way that their continued operation will be allowed, in order to avoid unacceptable environmental impacts. This chapter reviews the key carbon capture technologies closest to commercial deployment at coal-fired power plants. It identifies similarities and differences between options that should be taken into account when investment decisions are made, with a particular focus on operating characteristics. It is very likely that regulation, including on acceptable CO_2 emissions, will play a critical role in determining the landscape for power plant investment, so a discussion of some key regulatory issues in determining if, when and where CCS is introduced is also included.

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[*] Corresponding author: hannah.chalmers02@imperial.ac.uk; +44(0)7888 801020

1. INTRODUCTION

There is growing concern over the risk that dangerous climate change could be caused by anthropogenic emissions of greenhouse gases, including carbon dioxide (CO_2). The Fourth Assessment Report (AR4) of the Intergovernmental Panel on Climate Change (IPCC, 2007; IPCC 2008a; IPCC 2008b) considers a range of different stabilisation scenarios, which are categorised as different classes. Policies aiming at limiting atmospheric GHG concentrations to twice pre-industrial levels fall into the category of Class III stabilisation at 535-590 ppm CO_2-eq. The median value of cumulative emissions for models that have considered stabilisation within this range is around 2250 Gt CO_2 from 2000-2100 (IPCC, 2008a).

It has been suggested, however, that global average temperature rises of more than 2°C are the “threshold beyond which irreversible and possibly catastrophic changes become far more likely” (EUROPA, 2008). If this temperature increase is to be avoided then it is likely that deeper cuts in future cumulative emissions of CO_2 would be required. For example, IPCC Class I cases are for stabilisation at 445-490 ppm CO_2-eq, which would significantly improve the likelihood of avoiding global temperature rises that could be unacceptably high. Models meeting this requirement reported in AR4 have a median cumulative CO_2 emissions of around 1250Gt CO_2 from 2000-2100 (i.e. 1000Gt CO_2 lower than the median value for Class III). To put this in context, the IPCC report notes that:

> “The cumulative emissions range [in the 56 scenarios considered by the study] represents a huge increase compared to the historical experience. Cumulative global emissions were about 1100 GtCO_2 from the 1860s to today, a very small fraction indeed of future expected emissions across the scenarios.” (IPCC, 2008a)

This implies that it will be necessary to ensure that much of the CO_2 that could be produced by accessible fossil fuel reserves is not emitted to the atmosphere. Although some argue that the most effective way to limit fossil CO_2 emissions is to keep the fuels themselves in the ground, a number of countries currently view the use of fossil fuels as an important contributor to providing reliable and affordable energy supplies. This includes a number of nations that have both relatively large indigenous coal reserves and power to affect the outcome of international negotiations on global action to mitigate the risk of dangerous climate change such as USA, China, Russia and India. A number of influential studies and organisations have, therefore, suggested that it will be necessary to deploy carbon capture and storage (CCS) to reconcile likely continued use of fossil fuel use with climate change concerns, at least in the short to medium-term future (e.g. Box 1).

Table 1 (from Chalmers et al, 2009) summarises a classification for projects which is based on residual emissions potential for different approaches to using fossil fuels with CCS. Projects that use CCS at coal-fired power plants should normally be class 2 or class 3B projects, depending on whether biomass is co-combusted or co-gasified with coal. Thus, they should have the potential to make a significant contribution to mitigating the risk of dangerous climate change by converting the energy in the coal to a carbon-free energy vector (electricity and, possibly, co-products such as hydrogen or heat). It should be noted that there can be potential for co-products derived from syngas ($CO+H_2$) at integrated gasification combined cycle (IGCC) plants to contain carbon. This would be a class 1 application of CCS which would be less beneficial for reducing the risk of dangerous climate change and is not discussed in detail in this chapter.

Box 1 Some international perspectives on the role of CCS

International Energy Agency World Energy Outlook 2007: China and India Insights (IEA 2007)

“Clean coal technology, notably CCS, is one of the most promising routes for mitigating emissions in the longer term – especially in China, India and the United States, where coal use is growing fastest. CCS could reconcile continued coal burning with the need to cut emissions in the longer term – if the technology can be demonstrated at large scale and if adequate incentives are put in place.”

International Energy Agency Energy Technology perspectives (IEA, 2008)

“CO_2 capture and storage for power generation and industry is the most important single new technology for CO_2 savings in both ACT Map and BLUE Map scenarios in which it accounts for 14% and 19% of total CO_2 savings respectively.”

G8 Hokkaido Toyako Summit Leaders Declaration (G8 leaders, 2008)

“We strongly support the launching of 20 large-scale CCS demonstration projects globally by 2010, taking into account various national circumstances, with a view to beginning broad deployment of CCS by 2020.”

The most developed CO_2 capture technologies for use at coal-fired power plants are, however, ready for commercial-scale demonstration and a number of projects have been proposed. For example, the European Technology Platform for Zero Emission Fossil Fuel Power Plants, which includes a wide range of CCS stakeholders including industry, non-governmental organisations and academics, has proposed a demonstration programme for Europe (ZEP, 2007). This would include “10-12 full-scale, integrated demonstration projects covering a wide variety of CCS technologies, Europe-wide”, with plants operating by 2015 to facilitate commercial deployment of CCS by 2020.

This chapter will review the carbon capture and storage (CCS) options that are closest to commercial deployment at coal-fired power stations. CO_2 capture technology design and operation for coal-fired power plants is introduced first in sections 2 and 3 respectively. Issues for incentivising and regulating the introduction of CCS are highlighted and some immediate actions to prepare the global fleet for retrofit of CCS, probably from around 2020, are then identified in section 4.

2. CO_2 Capture Technology Design for Coal-Fired Power Plants

A number of different options exist for each of the three stages required for a complete CCS chain: capture, transport and storage. Figure 1 illustrates three processes that can be used to capture CO_2 at a power plant before it is transported to safe geological storage (or use). Although some individual techno-economic studies have concluded that one approach is likely to most cost effective for the site and assumptions considered, the literature as a whole suggests that similar costs, in terms of c/kWh of low-carbon electricity produced, can be expected for each approach. Identification of any clear ‘winners’ is therefore impossible, particularly given current uncertainties about actual costs for real projects and the unpredictable scope for learning and innovation as part of the initial tranches of commercial-scale deployment. Due to the volumes and distances involved it is expected that CO_2 will normally be transported by pipeline or ship. Typical storage locations include deep saline aquifers and depleted oil and gas fields. The 2005 Intergovernmental Panel on Climate Change special report on CCS (IPCC, 2005) provides a comprehensive review on all the stages of CCS, addressing both technical and economic aspects of the process.

Table 1. Classes of CCS: definitions and examples (from Chalmers et al, 2009)

	Definition and impact on CO_2 emissions	Typical Example
Class 1	Projects that produce gaseous and liquid fuels that contain carbon. When these products are used they will produce CO_2 that often cannot viably be captured (e.g. when used in transport and buildings). Thus, although these projects will reduce CO_2 emissions compared to production of the same fuels from high-emission sources without CCS, they do not stop the emission of amounts of CO_2 to the atmosphere that could still be significant in the context of dangerous climate change.	Coal-to-liquids plants producing synthetic fuels (approx 50% of carbon in coal is captured)
Class 2	Projects that produce carbon-free energy (normally electricity, hydrogen and/or heat). These projects should lead to significant CO_2 emissions reductions since the majority of CO_2 in the fossil fuel used can be captured. It is likely that there will still be some net fossil CO_2 emission to atmosphere from the project though (unless it includes biomass co-utilisation, as in Class 3B CCS below), particularly when analysis is carried out on a lifecycle basis.	Power plant producing electricity using coal (>90% of carbon incoal is captured)
Class 3	Class 3B: As above, but with fossil fuel replaced, partially or wholly, by biomass. Currently, it is expected that economies of scale will favour CO_2 capture for co-combustion or co-gasification of the biomass with fossil fuel rather than from smaller biomass-only plants. When biomass grows, it removes CO_2 from the atmosphere. If CO_2 emitted when the biomass is burned or gasified is captured, the net CO_2 emission for the biomass lifecycle can be negative, depending on a number of factors including how the biomass is grown and transported. This can offset the emissions associated with a Class 2 project and may allow for the whole project to remove CO_2 from the atmosphere on a lifecycle basis.	Co-firing biomass in a power plant fitted with CO_2 capture (>90% of carbon in biomass is captured and removed from the air)
	Class 3A: Direct capture of CO_2 from the air. This could be a valuable additional option, particularly since the location for the capture plant does not need to take into account many of the constraints that other classes must consider for locating the CO_2 producing facility. Typical Class 3A approaches are, however, expected to be more expensive than capturing fossil CO_2 emissions from stationary sources, at least in the short to medium term.	Zeman and Lackner, 2004; Keith et. al., 2006

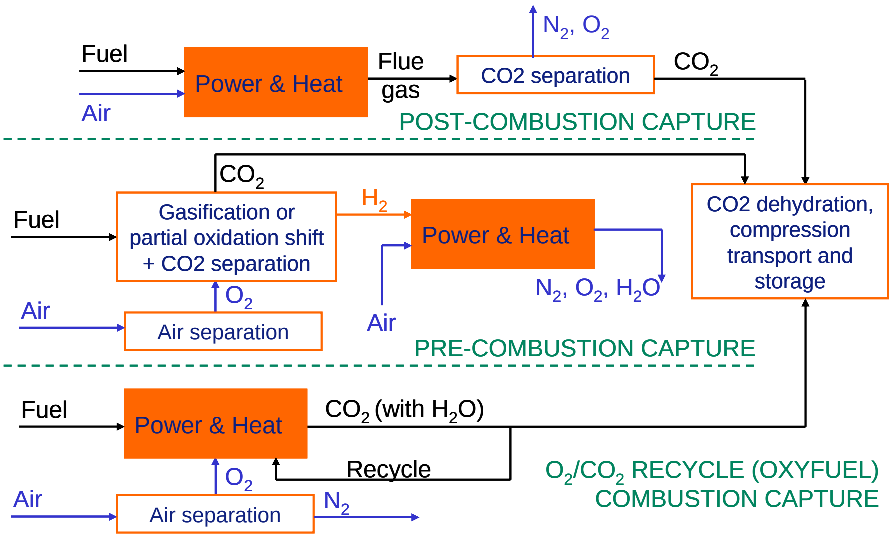

Figure 1. Schematics of CO_2 capture technologies closest to commercial deployment, after Jordal et. al. (2004)

Post combustion capture, which is shown in the top third of Figure 1, involves relatively few changes to a conventional pulverised coal-fired power plant when it is added as a last stage of emissions cleaning. For pulverised coal-fired power plants, flue gas leaving the boiler will be treated to remove conventional pollutants (particulates, NOx and SOx) to levels exceeding normal environmental targets to meet the requirements of most, if not all, CO_2 capture processes that are currently closest to commercial deployment. The CO_2 is then separated from other flue gases in a two-stage process. First, the CO_2 is removed from the flue gas by a slightly alkaline solvent (often based on an amine such as MEA or ammonia). This is a reversible reaction and in the second stage the solvent is heated to release the CO_2. The 'regenerated' solvent is then recycled back to the flue gas 'scrubber' and the produced CO_2 is dried and compressed before it is transported to safe storage (or use).

All forms of CO_2 capture have significant energy requirements. For post-combustion capture the main energy inputs are for solvent regeneration and subsequent CO_2 compression. It has been shown that the most efficient way to provide the heat required for solvent regeneration is to abstract some steam before the low pressure turbines in the power plant steam cycle (e.g. Gibbins et. al. 2004a; 2004b). Thus, part of the CO_2 capture energy requirement is typically observed as power that is not generated because this steam is diverted away from the power generation cycle. Researchers are currently exploring a number of approaches to reduce the cost and energy requirements of post-combustion capture processes including identifying or developing solvents with lower energy requirements for regeneration and improved process design, including novel integration approaches that make optimum use of heat that would otherwise be wasted (e.g. IEA Greenhouse Gas R&D Programme, 2008a).

Oxyfuel combustion, illustrated in the bottom third of Figure 1, also uses a pulverised fuel boiler when coal is the fuel. A significant change here, however, is that the fuel burns in an oxygen/CO_2 mixture rather than in air. Different O_2 concentrations have been used in different studies; typically values in excess of the 21% O_2 in air (e.g. 30% O_2 in CO_2) are required to compensate for the higher heat capacity of the CO_2. In all cases, some use of recycled CO_2 to moderate flame temperatures is, however, required given material constraints. Much of the work to improve oxyfuel processes is focussed on improved understanding of the combustion process using both experimental and theoretical approaches (e.g. IEA Greenhouse Gas R&D Programme, 2008b).

The air separation process for oxyfuel combustion accounts for around 60% of the energy penalty associated with this CO_2 capture process (IEA Greenhouse Gas R&D Programme, 2005). The majority of the rest of the energy penalty for CO_2 capture at power plants using oxyfuel combustion processes is associated with the CO_2 purification and compression process. Unlike the other forms of CO_2 capture closest to commercial deployment, oxyfuel processes do not require a solvent-based process to remove CO_2 from other waste gases since CO_2 is the major combustion product from this process. Instead, other gases are removed from the CO_2 during compression, typically using a distillation process. There is ongoing work to reduce the costs and energy penalties associated with both oxygen production and CO_2 purification/compression (e.g. White et. al., 2006).

The third option for CO_2 capture for power generation from coal uses pre-combustion capture at an IGCC plant. Although there has been very limited use of IGCC for power generation in the past, the process is potentially well-suited to CO_2 capture since it is possible to obtain a gas stream with a relatively high CO_2 concentration (although not as high as oxyfuel combustion) and at relatively high pressure, with an associated reduction in the energy required for CO_2 separation and compression. CO_2 capture is possible before combustion since coal is gasified to produce a syngas mixture of carbon monoxide and hydrogen. If CO_2 capture is not used then this syngas can be used directly for power generation in a combined cycle. If CO_2 capture is to be used then the syngas is normally ‘shifted’ so that the carbon monoxide is converted to CO_2 plus additional hydrogen. This shift process loses some of the energy available in the syngas so represents a further energy penalty associated with CO_2 capture at IGCC power plants.

Other contributors to the energy penalty at IGCC plants include the need to reduce combustion temperatures in the gas turbine due to differences in the heat transfer properties of flue gases from hydrogen combustion (rather than syngas) and the energy required for a solvent-based process to separate CO_2 from hydrogen between the shift process and the combined cycle power generation. Typically, a physical solvent with pressure swing regeneration will be used and this has a lower energy penalty than the chemical solvent process needed for post-combustion capture. There is also ongoing work to improve IGCC costs and performance. It seems likely that work on plant integration could be particularly important since there is a need for improved understanding of the trade-offs between improving efficiency through tighter integration between different parts of the plant and the potential to improve operability, which could often require reduced obligatory integration (e.g. IEA Greenhouse Gas R&D Programme, 2007a). Achieving levels of IGCC plant availability comparable to those for modern pulverised coal plant (~90%) is also a critical factor for IGCC economics.

Although there are versions of the technology options illustrated in Figure 1 available for commercial-scale demonstration it is expected that some significant improvements could occur in coming years and decades. As already discussed, researchers are investigating the potential for significant, but often incremental improvements, to current ‘standard’ technologies. There are also a number of novel technologies under development that are less closely related to the options that are most likely to be deployed initially. For example, Figueroa et al (2008) introduce a range of CO_2 capture technologies that have been developed with funding from the US Department of Energy. This includes current state-of-the-art and “innovative concepts” such as ionic liquids and enzyme-based systems.

3. POWER PLANT OPERATION WITH CCS

Before considering the CCS technology details, it is useful to review what the electricity system requires power plants to do and, hence, what can be valuable to power plant operators. For example, Kirschen and Strbac (2004) review the fundamentals of power system economics and a review of some key considerations for economic analysis of power plants with CCS is included in Chalmers et. al. (2007a). In particular, a number of factors that vary depending on the power plant site chosen are identified and are summarised in Box 2. The need to identify appropriate techniques for economic analysis of investments and potential policy measures is also highlighted and this is discussed further in the next section which addresses regulation and incentivisation of CCS.

Box 2 Some factors to consider in CCS investment decisions from Chalmers et. al. (2007a)

Factors that can make it impossible to use a particular technology

- Water availability
- Availability of raw materials for any required pollution control measures
- Planning (and other) regulations
- Lack of infrastructure (and not able to build it)
- Access to viable route to transport CO2 to safe geological storage
- Space to fit CO2 capture equipment
- Availability of additional raw materials for CO2 capture

Additional cost factors that can change which technology is favoured at a particular site

- Labour availability/cost
- Cost of commodities and components (for construction and operation)
- Financial factors, including tax regime and interest rates
- Ambient conditions, particularly temperatures
- Policy factors, including support mechanisms

Additional factors that can affect plant revenue expectations

- Price variations in electricity selling price and by-product selling/disposal price.*
- Local, national and international policy and regulation
- Electricity market structure
- Electricity network physical structure
- Construction time
- Portfolio diversity within an individual company

*Also, similar uncertainty for variation in power generation cost associated with commodity price variations.

Although some plants will operate at maximum possible output most of the time (so are called baseload plants), this is not the case for all plants. Since it is difficult to store electricity, some plants will need to change their output to match changes in consumer demand. Also, to ensure the security and quality of electricity supply, a number of 'ancillary services' are required by electricity network operators. Fossil-fired power plants are often used to provide some of these services (Burdon, 1998; OXERA, 2003). Thus, in addition to considering income from electricity sales at coal-fired power plants, it is often necessary to identify potential revenues from ancillary service provision too. Although ancillary services are required in all electricity networks, the specific level of provision that must be paid for by the network operator will vary depending on a number of factors including the 'natural' flexibility of generating plants that are best suited to local conditions.

Ancillary services are required for two distinct groups of purposes, responding to 'normal' changes in operation (e.g. changes in demand at different times of day) and 'contingencies' when there are unexpected changes in supply or demand. Since ancillary services for both purposes are required over similar timescales they may be provided by similar plants. It is useful, however, to maintain a conceptual distinction between them since the capacity requirements are different[1]. Some plants providing ancillary services will be required to choose between providing energy (i.e. electricity) to the network and providing ancillary services and this can lead to a complex co-optimisation problem if the most economic use of all plants in the network is to be determined.

When 'plant flexibility' is discussed it is important to define what kind of flexibility is being considered. For example, it is often useful to draw a distinction between managerial flexibility and operating flexibility. Managerial flexibility generally refers to choices that must be made by plant designers and investors when an investment decision is made (e.g. deciding whether CO_2 capture should be fitted at all and, if so, which technology should be used). Operating flexibility refers to short-run decisions made by a plant manager who must decide how it is best to operate a plant that has been built. This would include deciding whether the plant should be operated at all and, if so, whether it is best to provide energy or ancillary services.

This chapter is going to focus on some modes of flexible operation that seem most likely to be attractive to plant managers for each of the technologies closest to commercial deployment. For post-combustion capture and oxyfuel plants the discussion will mostly focus on characteristics that can be related to successful provision of traditional ancillary services. Variations to plant design that could be considered when managerial decisions are made to improve the range of options for flexible operation available to the plant manager are highlighted. We expect that IGCC plants will be less well suited to providing most ancillary services. Thus, we focus our discussion on other options for flexible operation, including by exploiting the potential value of products that are not sold into the electricity network.

Although the detailed discussion of physical potential for operating flexibility in this chapter is limited to CO_2 capture technologies, it is important to note that power plant operation could be constrained by other factors including regulatory decisions and the

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[1] Requirements to respond to 'normal' changes in operation are based on typical observed variability of demand in the network. In many circumstances, requirements will be lower during the night and the day. Contingency reserves are based on the largest possible failure(s) in the system and will tend to roughly constant.

requirements of the transport and storage system. Further work is required to develop a better understanding of likely limiting factors for flexible operation of whole CCS systems and operating approaches to optimise system operation and performance. For example, Race et al. (2007) reviewed particular challenges for offshore CO_2 transport given limited experience. They identified a number of issues that are the subject of ongoing work, and relevant to onshore pipelines too, including understanding the impact of impurities on CO_2 behaviour and transient flow characterisation, including from variable sources within a network. Policy and regulation is discussed in the next section.

3.1 Flexibility of Plants with Post-Combustion Capture

A review of the state of knowledge on flexible operation of power plants with post-combustion capture is reported in Chalmers et al. (2007b). The importance of different modes of flexible operation and some key conclusions are reported in Table 2. A number of ways to operate post-combustion plant flexibly are noted: part load operation, bypassing the capture unit and solvent storage. These are all discussed in more detail in Lucquiaud et al. (2007) and Chalmers and Gibbins (2007). Part load operation refers to an operating mode where power plant output is deliberately reduced so that it is able to rapidly increase output later typically because the plant operator is providing ancillary services. This incurs costs due to decreased plant efficiency. The part load behaviour of post-combustion capture systems and the transient behaviour of the unit as CO_2 throughput increases or decreases is not yet fully understood. The ability to rapidly reduce the volume of CO_2 captured and, instead, emit CO_2 directly to the atmosphere for a limited period could also provide a rapid increase in power plant output. One notable feature of this approach is that the ancillary service can now be provided to the network operator without any need for part load operation of the power plant.

Particularly if choosing to bypass the CO_2 capture plant is not economically or politically viable then it may be worth investing in solvent storage tanks within the post-combustion capture unit. Plants operating with solvent storage would still remove CO_2 from the power plant flue gases when the power is produced so that CO_2 emissions are kept low. The difference for a plant operating with solvent storage would be that the solvent loaded with CO_2 could then be stored and the energy intensive process that is used to release CO_2 from the solvent and compress it for transport to safe storage undertaken later. During this period of additional regeneration there will be an additional plant efficiency penalty, compared to only regenerating solvent needed to capture CO_2 produced at the time. Although this has associated costs and lost output, solvent storage may be economically favourable since the plant operator can have additional capacity available to sell when electricity prices are high and this may be more valuable than the lost revenue later during stored solvent regeneration (which is likely to occur at a time when electricity selling prices are lower)[2].

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[2] Although this description is focussed on an electricity system where a competitive market is in operation to set a real-time price for electricity, similar principles also apply in regulated markets. Within regulated markets, electric utility revenues are set in advance so the utility should then aim to minimise the cost of meeting demand (which it is normally obliged to serve). In this case, the value is expressed as solvent storage minimising the use of high operating cost plants.

Table 2. Current state of knowledge of technical impact of post-combustion capture based on Chalmers et al., (2007b)

Technical measure of plant flexibility	Definition and example occasion(s) when this can be important	Summary of current knowledge
Start-up/shutdown time	Time taken for plant to start-up or shutdown. Affects ability to provide ancillary services when the plant would not normally operate.	Not yet clear what the impact will be. Depends on ability to bypass the CO_2 capture system (including compression), if necessary.
Ramp rate when changing loads	Rate (MW/min) that plant output can be changed. Affects ability of plant to make money by offering to operate at reduced output, but be able to ramp up quickly.	Not yet clear what the impact will be. Potential for improvements compared to coal-fired plants without capture if steam can be diverted from the capture plant to/from the steam cycle quickly.
Part load efficiency	Plant efficiency at reduced output. Likely to be lower than for full load operation and affects cost to supply some ancillary services.	Not yet clear what the impact will be. See Chalmers and Gibbins (2007) and Lucquiaud and Gibbins (2009) for an outline of key issues and modelling challenges.
Grid rated capacity and maximum output	Grid rated capacity is the plant output (MW) that the network operator uses for the plant. For plants without capture this would be very similar to maximum possible output, but this may not be the case for plants with capture.	Reduced plant efficiency due to energy penalty will maximum output when CO_2 capture is operating. We expect that bypassing CO_2 capture or storing solvent could allow maximum output to be close to the grid rated capacity of an equivalent plant without capture.
Minimum stable generation	Lowest possible plant output while maintaining stable output. Typically ~30% of maximum output for pulverised coal plants. Can affect overnight plant mix when demand is low.	Minimum stable generation in MW will be reduced due to reduced plant efficiency. Also lower minimum stable generation when additional solvent is regenerated following a period of solvent storage*.
Variety of fuels	Many coal-fired plants can co-fire some biomass and will also accept a variety of coals. Important to have access to many sources for security and economics.	Expected to have same flexibility as current pulverised coal-fired power plant. Also, note that biomass combustion could result in negative CO_2 emissions overall.

* In systems with high penetration of plants that have limited ability to provide ancillary services but are often preferred for energy/electricity provision (e.g. intermittent renewables and nuclear) this can be valuable since it allows more space on the network for other plants to be used, but with sufficient flexible plants still operating to provide the ancillary services the network needs.

Table 3. Some potential changes to power plant flexibility for oxyfuel based on Chalmers et al., 2007

Flexibility Consideration or Option	Description for oxyfuel	Comparison with post-combustion capture
Start-up/shutdown time of ASU/ compression equipment	As with post-combustion capture, further work is required here. However, in this case the ASU is an integral part of the power plant operations so may have a direct impact on plant start-up time. Liquid oxygen storage (see below) could be able to minimise/remove ASU constraints.	Not clear since further work is required to improve both systems. If post-combustion capture plant can be bypassed during start-up/shutdown and the ASU start-up time is a constraint for oxyfuel plants then there may be some significant differences here.
Ramp rate of CO_2 capture/ compression equipment when changing load	As with post-combustion capture, further work is required here. Early work suggests that liquid oxygen storage may be important to minimise potential constraints. Also, note that the oxyfuel compression train is more complex since it also includes separation of impurities, which may lead to differences in characteristics when compared to post-combustion capture schemes.	Not clear since further work is required to improve understanding of both systems. The key features which are likely to be relevant here are the use of liquid oxygen storage for oxyfuel and the potential to rapidly divert steam from capture plant to steam cycle (or vice versa) with post-combustion capture.
Part load operation of CO_2 capture/ compression equipment	As with post-combustion capture, further work is required here. For electrically-driven processes, would expect to see part-load efficiencies which are lower than full-load efficiencies, but may be able to avoid this at sites with multiple units since the number of operating capture systems components can be varied with flow, rather than varying the flow through individual components.	Not clear since further work is required to improve understanding of both systems. Also, might depend on trade-off with other factors as in the example in the main text about different operating strategies for multiple ASUs (potential trade-off between efficiency and ramp rates).
Bypassing CO2 capture	If the plant is appropriately designed (so that flue gas can be vented to atmosphere without being passed through the CO2 compression/inerts removal plant) this could be technically possible. Additional pollution control measures may also be required, but might represent a significant expenditure if only.	Post-combustion capture plant is expected to offer a better option for bypassing CO2 capture to provide additional capacity. In post-combustion capture the majority of the energy penalty is avoided, whereas with oxyfuel capture less than half of the energy penalty is avoided unless the ASU is also

Table 3. (Continued)

Flexibility Consideration or Option	Description for oxyfuel	Comparison with post-combustion capture

Bypassing CO_2 capture	required when CO_2 capture is bypassed.	bypassed.
Storing liquid oxygen to avoid later ASU use	As noted above, use of liquid oxygen storage may be crucial for maintaining plant start-up/shutdown times and ramp rates. Also, when stored liquid oxygen is used, this will increase plant efficiency and when it is generated plant efficiency would decrease.	Storing/using liquid oxygen at an oxyfuel plant could have a similar operating profile to amine storage/regeneration at a post-combustion plant. However, a smaller swing in capacity is expected for oxyfuel plants since the CO_2 compression/inerts removal plant penalty is independent of ASU operation.
Fuel flexibility	Further work is required to improve understanding of oxyfuel combustion processes using burner-scale test rigs. Some experiments are now underway, but detailed conclusions are not yet available.	Since further work is required on oxyfuel combustion, this is not yet clear. It seems likely that oxyfuel and plants with post-combustion could have similar levels of flexibility.

3.2. Flexibility of Plants with Oxyfuel Capture

The key considerations for plants with oxyfuel capture are similar to plants with post-combustion capture in some respects. For example, variable flows associated with off-design and part load operation are also important for determining part-load performance. Flow recirculation at some loads is likely to be required in both the CO_2 compression/inerts removal system and the cryogenic air separation units (ASUs) that are used to supply oxygen for combustion in the designs that are closest to commercial deployment.

Bypassing CO_2 capture to increase available power for export would be less effective for oxyfuel plants since around half of the energy penalty is associated with O_2 generation using an ASU. Thus, liquid oxygen storage[3] or air-firing would be required in addition to stopping CO_2 compression/inerts removal to allow increases in power plant output similar to those obtained by completely stopping CO_2 capture with post combustion capture and associated CO_2 compression. Bypassing CO_2 capture and/or avoiding ASU operation should lead to additional net power being available to export to the grid without any capital expenditure to increase capacity in the steam turbine island (compared to full CO_2 capture operation) unless steam-driven auxiliaries are chosen. Since net power production is increased, however, some additional capacity in switchgear etc may be required to allow this potential increased net output to be sold into the grid (as with post combustion capture). Table 3 summarises some potential impacts of oxyfuel capture on power plant flexibility and, where possible, provides a comparison with the post-combustion capture impacts identified in Table 2.

It should also be noted that maximising performance in one area of plant flexibility might reduce performance in another area. (Again, this is also the case for flexible operation of post-combustion capture plants.) For example, depending on unit size, it is likely that at least two

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[3] Storing liquid oxygen is common practice for current ASUs. It is likely that this storage capacity could also be used to improve start-up times and contribute to other modes of flexible operation as outlined in Table 3.

ASU's will be required for an oxyfuel boiler given current constraints in ASU sizes. These units will not operate at optimum efficiency below a certain load so if an oxyfuel plant was running below 50% load, it is likely that plant efficiency would be improved by turning off one ASU and running the other ASU at close to full load. However, if the power plant is then required to increase output to some value above 50%, the electricity output ramp rate could be poor depending on the start-up time before additional oxygen is available from the second ASU. One option to avoid this problem could be to keep both ASU's running below 50% load, even though this could reduce plant efficiency at low loads. The use of liquid oxygen storage to improve start-up times for ASU's should also be considered.

3.3. Flexibility of IGCC Plants with CO_2 Capture

Generally, it appears likely that the most attractive options for flexible operation of IGCC plants with CO_2 capture will be different to those that are most valuable for pulverised coal-fired power plants with CO_2 capture. Many of the options discussed above for pulverised coal-fired power plants consider operating the boiler and/or the capture plant at part load with the operator aiming to provide ancillary services that require relatively rapid changes in electricity output. It is likely that IGCC plants will be less well suited to providing this type of flexibility to the electricity network. For example, since the energy penalty associated with CO_2 capture process itself is relatively small there is likely to be less potential to observe significant benefits by flexible operation of the CO_2 capture system. Also, it is difficult to integrate IGCC processes so that they operate at or close to optimum efficiency both with and without capture.

There may, however, be some modes identified for pulverised coal-fired plants that are also valuable for IGCC plants. Liquid oxygen storage could have some value for some IGCC plants but is likely to be more lucrative for oxyfuel plants since oxyfuel plants generally have O_2 requirements that are significantly higher than typical IGCC designs. Perhaps most importantly, fuel flexibility tends to attract more attention for plants with gasifiers than for pulverised coal-fired plants. Depending on the design of the feed system it should be possible to co-gasify a very wide range of fuels (and wastes). This could be particularly valuable where it allows Class 3B (see Table 1 – Class 3B schemes are those where net negative emissions are possible because biomass fuel is used). For example, working group III of the Intergovernmental Panel on Climate Change reported in AR4 that:

> "An increasing body of literature assesses the attainability of very low targets of below 450 ppmv CO_2… The attainability of such low targets is shown to depend on: 1) using a wide range of different reduction options; and 2) the technology 'readiness' of advanced technologies, in particular the combination of bio-energy, carbon capture and geologic storage (BECCS)… [A few studies have found that] such negative emissions technologies might be essential for achieving very stringent targets." (IPCC, 2008a)

Another approach to flexible operation that could be particularly valuable for IGCC plant operators is to consider selling products that are not electricity or ancillary services. For pulverised coal-fired plants this option is limited to a few by-products that can sometimes have niche markets. The situation could be very different for IGCC plant operators since it is possible to switch some or all of the useful output of the power plant to hydrogen sales[4]. This co-production option has recently been studied in some detail by the IEA Greenhouse Gas R&D programme (2007a). Once produced, hydrogen could have a number of uses potentially including fuelling zero-carbon local heating networks and part load operation of other gas turbine power plants that are providing ancillary services[5].

Of course, if the production of hydrogen can be separated from when it is used then this introduces the option for interim storage, if efficient hydrogen storage options are developed. This could be used to provide similar services to solvent or LOx storage, previously discussed for post-combustion and oxyfuel plants respectively. Newcomer and Apt (2007) have completed work on the potential value of syngas storage at IGCC plants for a similar purpose, thus avoiding the need for hydrogen storage technology to become available. They considered IGCC with and without CCS and found that for the US Midwest case they studied:

> "Adding a second turbine to use the stored syngas to generate electricity at peak hours and implementing 12 hours of above ground high pressure syngas storage significantly increases the ROI [return on investment] and net present value. Storage lowers the carbon price at which IGCC enters the US generation mix by approximately 25%."

4. PREPARING FOR WIDESPREAD DEPLOYMENT OF CCS: REGULATIONS, INCENTIVES AND CAPTURE-READY

One important characteristic of all CO_2 capture options is that they consume energy and require additional capital expenditure when compared to similar plants that do not abate their CO_2 emissions. This implies that widespread, commercial deployment of CCS as an option to mitigate global CO_2 emissions will require an external driver, for example a regulatory requirement to use CCS and/or incentive mechanisms for low carbon technologies.

Although a number of commercial-scale demonstrations involving CO_2 capture at power plants have been proposed the financing of many of these projects has not been secured at the time of writing. Gibbins and Chalmers (2008) have also suggested that it could be advantageous for two tranches of commercial-scale demonstration and initial deployment to be undertaken before widespread commercial roll-out. This implies that a significant number of coal-fired power plants could be built globally before these initial commercial deployment projects are completed. There are concerns that these unabated plants (and, also, existing plants that may have decades of operation ahead of them) could cause 'lock in' to future CO_2

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[4] It may also be possible to generate other products using the syngas before the CO is shifted to CO_2+H_2. These products would, however, significantly reduce the CO_2 emissions reduction potential of the IGCC plant since they contain carbon that can produce CO_2 that will not be captured and stored (depending on the application the product is used in). As discussed in the introduction to this chapter, we are not discussing 'class 1' CCS applications in this chapter.

[5] This alternative use of H_2 to produce power would displace natural gas use at that combined cycle plant. This can occur overnight when the gas turbine plant is part-loaded since the de-rating associated with using H_2 is not so important since maximum rated output is not required.

emissions. It is, therefore, important that new plants that are constructed without CO_2 capture are designed to be suitable for retrofit. This section begins with a discussion of regulations and incentives for CCS deployment and then outlines measures that can be taken to ensure that plants are 'capture ready'.

4.1. Regulations and Incentives for CCS Deployment

A broad range of issues are raised when regulations and incentives for CCS are discussed. This includes the importance of establishing operating codes so that project developers can establish what permits will be required and which authorities will regulate their activities. Different approaches are likely to be taken in different jurisdictions, but it can also be expected that some common practices will be adopted internationally partly due to sharing best practice (e.g. through various technical networks established by the IEA Greenhouse Gas R&D Programme – see IEA Greenhouse Gas R&D Programme, 2008c for further details) and the relevance of some international conventions to CO_2 storage activities.

At the time of writing, some developed countries are in the process of developing legislation for CCS projects but there are still some significant uncertainties that need to be resolved. One initial focus for developing the legal framework for CO_2 storage for many countries was amendment of international treaties to protect the marine environment to allow sub-seabed storage of CO_2 in geological formations. Amendments to two major treaties have been agreed (OSPAR Commission; International Maritime Organisation, 2007). More local permitting and operating arrangements are now under development. For example, in January 2008 a draft directive for geological storage of CO_2 was published by the European Commission (Commission of the European Communities, 2008a) leading to a final directive being agreed in 2009 (Commission of the European Communities, 2009). In the USA, the Environmental Protection Agency has developed guidance on CO_2 storage activities as part of its remit to protect underground sources of drinking water (EPA, 2008).

As well as establishing a regulatory framework to ensure that CCS projects are undertaken safely, it is also possible that CCS projects could be required as a result of future regulations introduced to reduce CO_2 emissions in response to concerns about global greenhouse gas emissions. A broad range of regulatory options could be used by policy-makers. For example, a mandatory requirement for CCS to be deployed at combustion plants or sectoral emissions standards which effectively require the use of CCS for fossil-fired plants to be used within the energy mix could be introduced. A mandatory requirement for CCS from 2020 has already been discussed in Europe but it was decided that CCS technology is not mature enough for it to be a reasonable policy approach yet (Commission of the European Communities, 2008b). At the time of writing, emission standards are being considered or introduced in some jurisdictions, including California and Japan.

CO_2 cap-and-trade schemes[6] are also often cited as a useful approach to encourage deployment of 'low carbon' technologies, including CCS. For example, the European

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[6] In 'cap-and-trade' schemes a limit to absolute emissions, i.e. cap, is set for a range of activities. Some activities will be able to implement emissions reductions more easily and cheaply than others. Operators of activities that

Commission suggests that CCS should “stand on its own feet in an Emission Trading Scheme (ETS) -driven system” from around 2020 (Commission of the European Communities, 2008c). It is important to note, however, that initial projects are unlikely to be supported by trading schemes alone. There are a number of reasons for this, including that it is unlikely that CO_2 prices expected for the early stages (up to 2020, at least) of trading schemes will be high enough to cover the full cost of initial CCS schemes that could be deployed during this period. Also, commercial investors will require reassurance that expenditure on CO_2 emissions reductions is the best option when considering the whole economic life of the plant. This is not provided by current trading schemes due to their time horizons which are significantly shorter than the economic life of a typical coal-fired power plant.

Since it is expected that neither a mandatory requirement for CCS or cap-and-trade scheme will be suitable for incentivising initial commercial-scale deployment of CCS, a number of alternative approaches are being explored by interested Governments and other stakeholders. Some of these are regulatory ‘sticks’ such as emissions performance standards that could be used to force some initial deployment of CCS, but many are also exploring incentivising ‘carrots’. For example, Climate Change Capital (2007) work commissioned by the European Technology Platform for Zero Emission Fossil Fuel Power Plants explores a number of different options for incentivising early CCS projects and concludes that the best approach would be to give a fixed number of additional EU Emissions Trading Scheme allowances to projects storing CO_2 to provide additional support for these projects. This approach could, however, lead to project developers receiving significantly higher revenues than are required to cover the costs of CCS if CO_2 prices increase over time.

It can be argued that this potential for high profits may be beneficial since the promise of potential high returns can encourage risky investments (echoing a typical oil/gas company approach). For utility investors, however, it may be more appropriate to identify an incentive mechanism that is lower risk and provides a closer match to the supplementary payment that is actually required over the project lifetime. Potential mechanisms include a ‘contract for differences’ or a scheme based on the sale of real options proposed by Kemp and Swierzbinski (2007). In fact, a number of different approaches could be taken to incentivise CCS projects and it seems possible that different support mechanisms will be most appropriate for different tranches of deployment of commercial-scale demonstration before full roll-out (Gibbins and Chalmers, 2008).

As Governments, commercial organisations and others have started to consider how CCS development and deployment might progress, another area that has emerged as being potentially important for developing a cost-effective CCS system is transport infrastructure planning. Initial studies are suggesting that it may be best to use a co-ordinated approach with hubs that connect CO_2 emissions gathered from a particular area to large trunk pipelines that form a network that connects CO_2 sources to storage sites (Poyry Energy Consulting, 2007; Element Energy Ltd et. al., 2007). For this to occur in reality, it seems likely that Government intervention will be necessary. For example, IEA Energy Technology Perspectives 2008 discusses CCS deployment, more generally, and explains that:

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would find it relatively expensive to reduce their emissions can pay for cheaper emissions reduction elsewhere, so there is trading.

> “CCS deployment at the scale of 1.8Gt by 2030 will be challenging, as it requires fast-tracking the RD&D phases, the validation of the technology options, and the development of large-scale regional transport infrastructures. As the curve flattens in 2040, the 2050 targets are achievable, the main issue is in the phase-in of large-scale deployment. Achieving 5 Gt of storage a year would present a formidable challenge in terms of investment and infrastructure. To achieve this, it would be necessary to inject 1.8 Gt per annum worldwide by 2030. This is equivalent to 1800 Sleipner[7] CO_2 projects. A major international collaboration effort would be required to meet this challenge.” (IEA, 2008)

Finally, as noted previously, regulations and incentive mechanisms could have a significant influence on which plants are built and how they are operated. For example, some of the modes of flexible operation that could be used by power plant operators that are identified in the previous section could, perhaps inadvertently, be ruled out depending on how legislation is implemented. For example, if an emissions performance standard is applied as a requirement for plants to achieve an annual average CO_2 emission then some bypass of the CO_2 capture could be possible. If it is required that plants meet the same standard on a hour-by-hour basis, through unconsidered extension of regulatory practices for local air pollutants such as SOx to CO_2, then it is likely that bypassing the CO_2 capture unit would not be possible. Depending on the economic value of being able to operate flexibly, if regulators choose to limit which modes of flexible operation can be used then an associated change in required levels of incentivisation to encourage CCS deployment can be expected.

4.2. Capture Ready Design and Retrofitting CO_2 Capture to Existing Plants

As well as establishing a regulation and incentive framework for CCS projects, there has been ongoing discussion around how it is best to begin preparations for CCS deployment before sufficient drivers are in place for global commercial roll-out. The previous section discussed a number of important actions, including initial development of a CO_2 transport infrastructure. Another important area to consider is retrofit of CO_2 capture to existing facilities, with some focus on making current new-build plants ‘carbon capture ready’ (CCR). This section will review some important issues in CCR design and regulation. It will also briefly discuss the potential to retrofit CO_2 capture technology at existing pulverised coal-fired power plants.

At the time of writing, regulatory requirements for CCR deployment are just emerging, although mostly on an individual project basis. Legislation currently under discussion could also encourage power plant designers and operators to ensure that all plants are built with CCR designs. In Europe, Aa draft directive published on geological storage of CCS published by the European Commission (Commission of the European Communities, 2008a) that CCR should be made mandatory for all new large combustion plants above 300MWe. When the

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[7] Sleipner is one of the earliest large-scale demonstrations of CO_2 storage to implemented globally. Around 1Mt of CO_2 each year are separated from natural gas produced at the field and reinjected into a saline aquifer under the North Sea in the same area. But note that Sleipner uses a single injection well to inject all the CO_2 available. Purpose-built CO_2 injection platforms receiving CO_2 piped from onshore might support ten such wells with directional drilling, so leading to a much more manageable 180 offshore injection hubs.

related directive (Comission of the European Communities, 2009) was agreed, a CCR study became mandatory according to Article 33, but it not mandatory to change the location of a site if CCR requirements cannot be met. The Government of South Africa has also indicated that it intends to make CCR mandatory within the climate policy framework that it plans to adopt by the end of 2010, after the conclusion of the current round of international negotiations on action to mitigate the risk of dangerous climate change (South African Government Information, 2008).

Although a number of studies have reviewed the technical requirements for CCR power plants (e.g. IEA Greenhouse Gas R&D Programme, 2007b; Lucquiaud and Gibbins, 2008) there is still some uncertainty over what regulatory requirements will be associated with CR deployment in different jurisdictions. A UK Government consultation on how the European directive noted above should be implemented provides a useful overview of many of the most important issues (BERR, 2008). Some key issues include how much detail should be required in feasibility studies undertaken as part of CCR permitting activities and which organisations should be the competent authorities advising Government when assessing applications for plants that are applying for planning consents that include CCR status.

It is important to note that most, if not all, of the essential actions to make power plants CCR, at least for post combustion capture, can be undertaken at little or no cost. For example, a study undertaken by Mott MacDonald (2008) indicates that an additional capital expenditure for CCR would be around 1% of a non-CCR plant. It is these relatively low costs, combined with potentially significant negative consequences (both environmental and economic) that could be incurred if CO_2 capture retrofits are difficult or impossible that has driven European policy-makers, at least, to consider a mandatory requirement for CCR. Other authors have also developed other approaches for financing CCR plants which are driven by a commercial response to develop options to respond to potential future regulation of global CO_2 emissions. For example, Liang et. al. (2008) discuss and explore a mechanism using real options to fund CCR implementation in China.

CCR considerations for new-build power plants are likely to focus on appropriate space on-site for constructing the capture unit and in critical access locations. For power plants that are capture ready for post combustion capture to be added another important consideration is designing the steam cycle to handle variable steam flows. This is discussed further in Lucquiaud and Gibbins (2009). For plants that are capture ready for oxyfuel, different technology specific requirements must be considered and many of the preparations required would need to be implemented by the boiler manufacturer. Much of the early literature on capture ready in the USA focussed solely on IGCC as a capture ready option. It seems unlikely, however, that IGCC would be the best choice for a capture ready plant since it is difficult, due to the integration requirements, to obtain performance and costs that are close to state-of-the-art both before and after capture is added. This sub-optimal performance is unlikely to be acceptable to many electric utilities.

Of course, as well as designing new-build plants to be CCR, it is important to consider whether existing plants that have been built without any consideration of CCS could be suitable for later retrofit of CO_2 capture. A study of retrofit to existing plants in the UK has demonstrated that it can be technically feasible to retrofit existing plants (Panesar et. al., 2006), although significant challenges with identifying space for equipment, integrating CO_2 capture with the power plant and determining an appropriate route to CO_2 storage can occur. Where it is technically feasible to retrofit capture, it can be expected that the retrofit will be more expensive than a retrofit of similar technology to a CCR power plant in many cases. It should be noted, however, that retrofit to existing plants could be an economically attractive option when compared to constructing a new-build plant in some locations since CCS retrofits require significantly less capital expenditure since the base power plant is already built.

Viable economic lifetimes for retrofit projects are also likely to be shorter. This may be an attractive feature to avoid excessive technology lock-in in a period of rapid improvement that is expected during initial commerscial-scale deployment and initial rollout of CCS. Once a power plant retrofitted with CO_2 capture has completed perhaps 10-15 years of operation it should be possible to repower the site with a mature coal-based capture plant, reusing the CO_2 compressors and pipeline as well as the conventional coal supply, grid connections and cooling water supplies that make existing sites attractive. Thus retrofitting many existing plants rather than accelerated replacement with new, but relatively unproven, technologies may be an effective route to achieve a changeover in national power plant fleet operations from unabated to full CCS operation.

5. CONCLUSION

Amidst growing concerns about the potential for dangerous climate change, CCS has been identified as a potentially important technology to mitigate CO_2 emissions from fossil fuel use, including at coal-fired power plants. This chapter has introduced the technologies closest to commercial deployment and discussed how plants fitted with CO_2 capture could be operated. There are some significant differences between technologies for CO_2 capture but in all cases various modes of operating flexibility can be identified. Investors and designers should determine which modes are most likely to be valuable for the power plant they are developing since this may affect which plant design is most appropriate for their situation.

Since all CO_2 capture options have energy penalties associated with their use and also require additional capital expenditure, it is necessary for a legal requirement and/or sufficient incentive to support CCS project development to be made available for commercial projects, except in some limited niche applications (e.g. enhanced oil recovery, EOR) where a significant revenue can be obtained by selling the CO_2 produced. Successful, rapid deployment of CCS will require a stable regulatory framework so that project developers can have reasonable certainty in the permitting regime they will need to act within. Additional actions that could help to accelerate CCS deployment include the development of a CO_2 transport infrastructure so that individual project developers only need to consider how to connect to a local gathering hub (or distributing hub for a CO_2 storage activity). Regulations could affect what level of support is required. For example, if operating flexibility is constrained by legislation then increased incentivisation may be required for the same amount of CCS deployment.

Finally, since CCS technologies are yet to be proven in commercial-scale, integrated projects involving power plants it is important to consider what action can be taken to prepare for potentially rapid global rollout from around 2020. As well as establishing the regulatory framework above, designing new plants to be ‘capture ready’ has been identified as a potentially important option. Most, if not all, changes to plant design to facilitate later retrofit of pulverised coal-fired power plants with post combustion capture are achievable at low or no cost. CCR plants could, however, be critical to avoid 'lock-in' to a potentially significant number of coal-fired plants that are likely to be constructed before CCS becomes a standard, commercial option. Although retrofits at existing plants that have already been built without any consideration for potential future use of CCS could be more difficult and, in some cases impossible, it is also expected that this could be an attractive approach in some locations.

ACKNOWLEDGEMENTS

This chapter is a revised and extended version of a paper initially presented at 'Sustainable Energy UK: Meeting the Science and Engineering Challenge' held in May 2008 in Oxford, UK. The authors gratefully acknowledge conversations from colleagues that have helped to develop many of the ideas included in this chapter and financial support for Ms Chalmers from the UK Energy Research Centre.

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In: Carbon Capture and Storage Including…
Editor: T. P. Carington, pp. 81-100
ISBN: 978-1-60741-196-3

Chapter 4

SPATIAL IMPACTS OF TRADABLE PERMIT MARKETS: THE CASE OF SULFUR DIOXIDE EMISSIONS

Jon P. Rezek[1] and Meghan Millea[1*]

[1]Dept. of Finance & Economics College of Business & Industry Box 9580
Mississippi State, MS 39762-9580

ABSTRACT

The Clean Air Act Amendments of 1990 and the accompanying Acid Rain Program has been a successful marketable permit-based policy experiment designed to reduce sulfur dioxide emissions from U.S. electric plants. However, as a non-uniformly mixed pollutant, the distribution of the benefits from SO_2 reductions depends on the location of the emission source. In this study, we simulate pollution concentration patterns resulting from emissions at participating plants then couple these patterns with underlying population data to estimate the marginal and total health benefits of emission reductions at each location. Results indicate that a one ton reduction in emissions generates, on average, $2,500 in health benefits in the U.S. and Canada. However, the marginal benefits vary substantially depending on the location of the plant. We also find that approximately $6 billion per year in health benefits were generated during the first phase of the program with one third of these benefits attributable to abatement at only two locations.

I. INTRODUCTION

Title IV of the Clean Air Act Amendments of 1990 (CAAA) and the accompanying Acid Rain Program initiated a dramatic shift in the orientation of environmental policy in the United States. The program represented the first regulatory attempt to control aggregate sulfur

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[*] Corresponding author: Telephone: (662) 325-1970 Fax: (662) 325-1977 e-mail: jrezek@cobilan. msstate.edu

dioxide (SO_2) emissions from electric utilities at the national level, standing in marked contrast to the technology standards or the limits on emission rates embodied in previous legislation. However, the Acid Rain Program is most notable for its large-scale use of emission allowances as a market based pollution reduction mechanism. The program was successful in its first phase of operation (1995-1999), accomplishing larger overall SO_2 emission reductions than anticipated at a lower than expected cost of compliance.[1] Contemporaneous evidence also suggests that both wet and dry deposition of sulfur declined significantly during Phase I of the program (GAO, 2000 and EPA, 2002).

The program operates as a tradable permit or cap-and-trade system in which an annual quantity of allowances is distributed to each participating unit based on historic emissions and fuel-use patterns.[2] These allowances are then freely tradable between units or between units and third parties.[3] Emissions are monitored continuously by the Environmental Protection Agency (EPA) and at year's end each affected unit must hold a number of allowances of current or any previous year's vintage equaling or exceeding its actual annual SO_2 discharge. Under such a system, low marginal abatement cost plants have the incentive to reduce emissions and sell excess allowances, with the difference between their marginal abatement cost and the market price representing the cost-savings to the firm. The system also offers the opportunity for high marginal abatement cost plants to purchase allowances at prices below what they would otherwise pay for abatement, similarly reducing their compliance costs. Montgomery (1972) shows that under straightforward assumptions, such a system minimizes the cost of reaching a given aggregate emission target.

The SO_2 program expanded in 2000 to include all electric plants with more than 25 megawatts of generating capacity. It was replicated for nitrogen oxides (NO_X) and mercury under the EPA's Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule, respectively. As the tradable allowance model expands in these new directions, it is appropriate to review the general applicability and potential pitfalls of such a system. While these programs utilize similar approaches to emission reduction, Carlin (2002) notes that, "the nature of the pollutant and the environmental problem greatly influence the viability of any abatement approach or strategy, which in turn influences the efficiency of resource allocation." Thus, when evaluating program efficiency, the dispersive properties of the pollutant and the local atmospheric conditions should be considered. The regulated emissions, SO_2, NO_X and mercury, are, to varying degrees, non-uniformly mixed pollutants with their impacts depending on the source of origin, prevailing wind and atmospheric patterns, the sensitivity of the underlying population and environment and other local or regional variables.

In this study, we focus on the regional impacts of SO_2 emissions for three major reasons. First, the Acid Rain Program represents the first major policy experiment using tradable allowances and has served as a model for subsequent emission reduction programs. Second, SO_2 emanates primarily from fixed point-sources offering an opportunity to track and

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[1] See Joskow *et al.* (1998), Burtraw *et al.* (1998), and Hansurgens (1998) for reviews of various aspects of the program. Ellerman *et al.* (2000) also provides an in-depth overview of the Acid Rain Program.

[2] For more on emission trading see, Baumol and Oates (1988) and Tietenberg (1985).

[3] "Participating unit" or "affected unit" refers to an individual boiler within an electric plant.

quantify the significant, individual impacts of specific emitters.[4] Finally, there has been substantial concern among state and local policymakers regarding the nationwide scope of the SO_2 allowance market. Legislatures in several states, including New York and North Carolina, have extensively debated the issue of trans-boundary SO_2 pollution.

In 2000, New York passed the Air Pollution Mitigation law which assessed penalties to New York electric utilities selling permits to upwind Midwestern power plants. The law was subsequently challenged by Clean Air Markets Group who argued that, in limiting trade, the law violated the interstate commerce clause of the U.S. Constitution. While regional limitations were considered by both Congress and the EPA, they were not included in the final Acid Rain Program. Both the U.S. District Court and the Second Circuit Court of Appeals ruled in favor of Clean Air Markets Group.[5]

Section 126 of the Clean Air Act addresses interstate transport of SO_2 and NO_x. Under this "good neighbor" clause no state is allowed to significantly contribute to another state's inability to meet National Ambient Air Quality Standards (NAAQS). In 2004, North Carolina petitioned the EPA for relief from SO_2 and NO_x emissions from twelve upwind states, but the EPA denied the petition citing that its Federal Implementation Plans (FIPs) for the CAIR would address the state's concerns.[6] In July, 2008, the U.S. Court of Appeals for the District of Columbia Circuit ruled in favor of North Carolina, vacating the CAIR in its entirety citing "more than several fatal flaws in the rule." Such recent focus on interstate transport of SO_2 and NO_X emissions underscores the importance of the regional implications of these federal programs.

While the purpose of the allowance system is to harness the power of the market to achieve pollution reduction at minimum cost, these examples serve as a reminder that it is also important for policies to make some accommodation for the physical reality that emission damages vary according to source location. For instance, Montgomery (1972) first detailed how a system of tradable ambient pollution licenses could be used to maintain minimum environmental standards at a series of monitoring stations. Such a system generates a separate market for licenses specific to each receptor station. Freeman (1984) showed that a set of Pigouvian taxes corresponding to the marginal damages inflicted by each source could also be established to maintain minimum environmental standards at the local level. A more simplified system was described by Atkinson and Tietenberg (1982) in which polluters are grouped into geographic zones based on the location, damage or dispersion of their pollutants. Intra-zonal trading is permitted but not inter-zonal trading thus reducing potential transboundary effects. Policies that deal appropriately with the complexity associated with non-uniformly distributed pollutants, however, have potentially higher compliance or implementation costs and thus are less viable than the unconstrained market-based approach.

Despite the controversy surrounding transboundary pollution, post-implementation GAO (2000) and EPA (2002) evidence indicates that local areas of significantly increased pollution

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[4] In 2000, power plants contributed 63 percent of SO_2 emissions, but only 22 percent of NO_X emissions, 33 percent of anthropogenic mercury, and 39 percent of anthropogenic CO_2 emissions produced in the U.S. (Natural Resource Defense Council, 2002).

[5] Clean Air Markets Group v. Pataki, 338 F.3d. 82 (2d Cir. 2003)

[6] In April, 2008, the EPA withdrew FIPs for several states that had received approval for their state implementation plans (SIPs) for the CAIR including, Alabama, Arkansas, Florida, Georgia, Illinois, Iowa, Kentucky, and Louisiana.

concentration (hot spots) have not materialized as a result of the tradable allowance system; however, recent policies of the EPA that focus on northern and eastern states, such as the CAIR, suggest that these states are more likely to struggle to reach acceptable concentrations under the NAAQS than states further west. While this study does not focus directly on hot spots it deals with a closely related issue – heterogeneity of marginal damages across plants. If marginal damages are equal across plants then an allowance transfer will have definite distributional consequences but no net effect on society. However, if there is substantial heterogeneity in marginal damages across plants there is an increased likelihood that a given allowance trade will have a significant *net* impact on social welfare. Certain trades may result in a post-trade emission distribution that affects a larger population base or a more sensitive environment than the pre-trade emission distribution thus decreasing net social welfare. The converse is also possible if the new distribution affects a smaller population base or less sensitive ecosystem. Our findings suggest that most potential trades generate negligible net social costs but that regulation of trades based on unit-specific marginal damages may improve social welfare by discouraging certain trades in which allowances flow from low damage emitters to high damage emitters.

Consistent with the operation of the national allowance market, several program evaluations have been conducted at the aggregate level including the EPA's analyses of the potential impacts of CAA, the Clear Skies Act, and CAIR, as well as the Burtraw et. al. (1998) examination of the Acid Rain Program.[7] This study, however, focuses on the plant-specific impacts of the program, replicating, on the micro level, the methodology established in the EPA's 1995 pre-program assessment. We estimate the impacts of emissions from each of the original 110 Phase I plants individually, limiting our analysis to the health effects because they represent a significant portion of the overall benefits (Burtraw et. al., 1998).

In the first stage of the process we model emission dispersions using atmospheric simulation software to combine physical plant characteristics and meteorological data. The resulting simulated pollution concentration patterns for each of the plants are matched with underlying population densities using Arcview geographic information systems (GIS) software. We then incorporate established epidemiological concentration-response relationships to calculate the marginal health benefits from emission reductions at each location. By analyzing the pattern of emissions during the Phase I period against an historic baseline, we are further able to calculate the total health benefits attributable to emission reductions at each plant under consideration. This procedure allows us to identify precisely which plants are generating the observed health (and environmental) improvements. Finally, we examine the magnitude and dispersion of marginal health benefits across plants to estimate the net social consequences of the observed pattern of emission reductions.

II. DAMAGE FUNCTION METHODOLOGY

This study takes a damage function approach to evaluating and quantifying the health benefits associated with reduced SO_2 emissions from the Phase I electric plants during the

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[7] Multi-Pollutant Analyses and Technical Support Documents can be found at http://www.epa.gov/airmarkets/progsregs/cair/multi.html.

1995-2000 period. These 110 plants provide a manageable subset of point-sources, allowing us to calculate the health impacts of the Acid Rain Program at the plant level. The timeframe under consideration allows us to compare our results to the macro-level analysis performed in the EPA's pre-implementation evaluation (EPA, 1995).

Determining Health Consequences

Several assumptions must be made to operationalize the damage function approach in this context. While these assumptions may be relatively restrictive, they are implicit in the EPA study we use as our benchmark and thus required for consistency with that standard. Most importantly, however, they allow our approach to be empirically tractable.

Assumption 1: There exists a set of linear and continuous damage functions that depict the relationships between changes in the pollution concentration in a region and changes in the observed number of cases of various medical conditions.

Mathematically, the damage function can be written as:

$$\Delta Q_{ij} = R_{ij} \cdot N_j \cdot \Delta S_j \tag{1}$$

where,

Q_{ij} = cases of condition *i* in region *j*
R_{ij} = concentration-response coefficient for condition *i* in region *j*
N_j = affected population in region *j*
S_j = pollution concentration in region *j*.

The number of cases caused by an increase in pollution concentration is dependent on the magnitude of the pollution, the population affected, and the concentration-response relationship, which differs across conditions.[8] For instance, increases in sulfate concentrations in a given area will lead to increases in the number of reported cases of asthma, bronchitis, upper respiratory infections, and other illnesses.

Assumption 2: The Concentration-Response Coefficients are Constant across All Geographic Regions

$$R_{i1} = R_{i2} = \ldots = R_{im} \text{ for all conditions i.} \tag{2}$$

Assumption 2 implies that changes in pollution concentrations affect people in different locations in the same way. Epidemiological studies are not available for a complete set of regions; therefore we apply this simplifying assumption to generalize the concentration-response estimates across the population. In reality, population responses to the pollutant may vary due to demographic and environmental attributes not considered here.

Assumption 3: Health Conditions are Independent of one Another

$$\Delta Q_{1j} \neq f(\Delta Q_{2j}, \ldots, \Delta Q_{mj}) \text{ for all conditions i.} \tag{3}$$

Independence of health conditions implies that increased incidence of one medical condition does not generate increases in the prevalence of other conditions. For example, an increase in the number of asthma sufferers does not cause an increase in the incidence of bronchitis.

Quantifying Health Impacts

The total health benefit associated with a reduction in pollution concentration is the product of the cost of the condition and the change in the number of cases, aggregated over all affected regions and health consequences generated. These benefits are given as:

$$B = -\sum_{j=1}^{m} \sum_{i=1}^{n} P_{ij} \Delta Q_{ij} \tag{4}$$

where,

B = total health benefits
P_{ij} = cost of condition *i* in region *j*
Q_{ij} = cases of condition *i* in region *j*.

Two additional assumptions are required to calculate the aggregated monetary value of a given pollution concentration change as shown in equation 4.

Assumption 4:The real cost of condition i is spatially homogeneous.

$$P_{i1} = P_{i2} = \ldots = P_{im} \text{ for all conditions i.} \tag{5}$$

The economic cost of a given medical condition is measured here as the consumer's willingness to pay (WTP) to avoid the illness. On average, the cost of a specific health condition is assumed to be the same across locations. Again, since a full set of regional avoidance cost estimates are not available, a representative estimate must be used. In reality, however, avoidance costs are likely to vary according to local demographic or environmental factors.

Assumption 5: The cost of condition i is independent of the presence of other medical problems also generated by ambient pollution concentrations.

$$P_{ij} \neq f(Q_{1j}, Q_{2j}, \ldots, Q_{nj}). \tag{6}$$

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[8] In other applications damage functions are often modeled to be log-linear or to include a threshold concentration level below which health effect are assumed to be negligible.

Assumption 5 implies that an individual's WTP to avoid a given health condition, such as bronchitis, is independent of whether they are experiencing another health condition - asthma symptoms, for example. The assumption simplifies the analysis in the event that an individual acquires multiple conditions, altering their WTP to avoid each.

The unique contribution of this study centers on the spatial analysis at the individual plant level. Our model incorporates existing emission data, and peer-reviewed medical literature with specialized atmospheric and GIS software to calculate estimated marginal and total benefits of emission reductions for each plant. In particular, we rely on the vast existing epidemiological and valuation literature to provide estimates of R_i and P_i, respectively, while contributing the spatial modeling to the process. Given the novelty of this approach we rely heavily on the methodology and the literature surveyed in the EPA's pre-implementation assessment of the Acid Rain Program (EPA, 1995) to establish a baseline for comparison. Using this study as a baseline allows a comparison of pre-implementation expectations with estimated post-implementation health outcomes.

III. IMPLEMENTATION OF THE DAMAGE FUNCTION APPROACH

The damage function methodology employs four specific steps. First plant-specific emissions are mapped into regional ambient pollution concentrations. Second, these concentrations are translated into human exposure based on population distribution. Third, the health effects of this exposure pattern are determined. And finally, the economic value of these health effects is computed. In this study, we repeat each step of the damage function approach monthly for the complete panel of 110 electric utility plants designated as Phase I by the CAAA. The estimated health benefits associated with a one ton reduction in SO_2 emissions from each plant is calculated as the mean of twelve monthly results.[9]

Pollution Concentrations

First, we simulate the specific pollution dispersion pattern that applies to the plant on the day sampled. The dispersion patterns are generated using the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT4) software package, which is designed to map potential pollution concentration and deposition based on meteorological and atmospheric conditions.[10] We generate one simulation per plant per month using Nested Grid Mapping (NGM) weather data prepared for the National Climatic Data Center by the National Oceanic and Atmospheric Administration's Air Resources Laboratory. We run each simulation at the middle of each month using NGM weather data for 1996, which is the most recent complete year available and is appropriate for analyzing the first phase of the program that ran from 1995 to 2000. The NGM data include information from across North America on elements

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[9] General prevailing weather patterns were not available; therefore, we simulated emissions for each plant each month. While more frequent simulations may offer marginal improvement on our monthly proxy of prevailing patterns, it would also impose substantial computational costs.

[10] For further information on the HYSPLIT program visit www.arl.noaa.gov.

such as wind speed and direction, temperature, and pressure. Each plant's latitude, longitude and stack height are entered as geographic inputs into the simulation model.[11] To generate a "marginal" effect we specify the release of one ton of emission and evaluate the results after a 24-hour run time.[12, 13]

Each simulation produces a GIS shape-file such as the one displayed in Figure 1 below. The figure shows the simulated dispersion and concentration patterns of the Jack Watson plant for January 15th, 1996. Emissions released from this plant travel in a north-westerly direction, affecting portions of Mississippi, Alabama and Georgia. The small black area, near the plant's location on the Gulf coast, represents the area of heaviest concentration. The dark band, stretching north through the state of Alabama, and the lighter band, consuming most of eastern Georgia each receive lighter doses. The largest band in the figure receives only modest concentrations of sulfate.

Human Exposure

The dispersion pattern for each simulation is then overlaid on population data to estimate human exposure in each band. We integrate the pollution concentrations and population densities using the Arcview GIS software package by overlaying the dispersion data generated by HYSPLIT with spatial population data from the 2000 U.S. Census and the 1996 Canadian Census. We use Arcview to calculate the population present in each of the concentration bands generated by HYSPLIT. A greater pollution concentration over heavily populated areas translates into a larger potential health benefit from abatement. Referring to the example shown in Figure 1, major population centers affected include: Tuscaloosa and Birmingham, AL (band 2), and Atlanta and Macon, GA (band 3).

Health Impacts

Next, a link between the simulated exposure patterns generated in the first two steps and their likely health consequences must be established. The medical literature estimating the relationship between ambient sulfate and its health effects is substantial. We will concentrate on the epidemiological approach as it presents advantages over clinical, laboratory or toxicological studies in this context (EPA, 1995). Epidemiological studies involve the statistical estimation of concentration-response coefficients, which relate changes in pollution concentrations observed at monitoring stations to the frequency of various illnesses or health effects in surrounding areas.

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[11] Plant zip codes come from FERC Form 1. The codes are used as input in the Tiger software package to retrieve five digit latitude-longitude coordinates. Stack heights are collected from Form EIA-767. For plants with multiple stacks, we use the average stack height in the simulation model.

[12] The plume has largely dissipated by this time; altering run time beyond 24 hours does not alter results significantly.

[13] While the HYSPLIT program does have an additional chemistry module that simulates atmospheric chemical reactions, advisors from NOAA determined this module would not be applicable for this study.

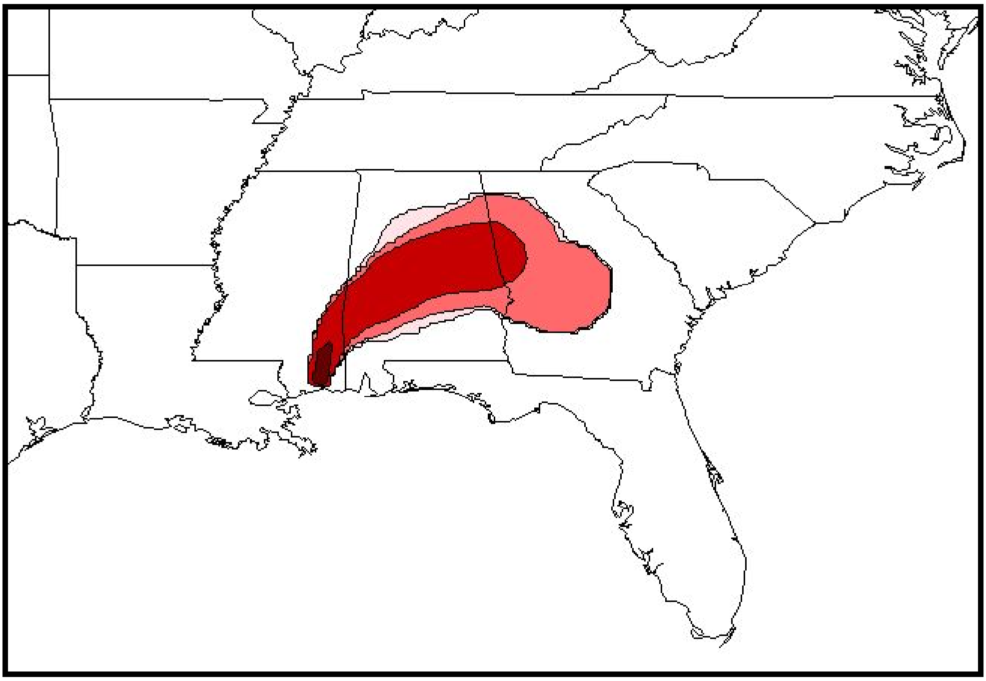

Figure 1. An Example Dispersion and Concentration Pattern for Plant 2049 on January 15, 1996

Concentration Bands:
Band 1: 2.87×10^{-1} µg
Band 2: 2.87×10^{-3} µg
Band 3: 2.87×10^{-5} µg
Band 4: 2.87×10^{-7} µg

In this study we calculate the effects of increased sulfate concentrations on seven different health consequences: premature mortality, bronchitis, respiratory hospital admittances (RHA), cardiac hospital admittances (CHA), reduced-activity days (RAD), asthma, and acute lower respiratory symptoms (LRS). Since the individual concentration-response relationships are not the focus of this study we use the existing coefficients gathered as part of the EPA's pre-program health effects assessment (EPA, 1995) to complete our analysis. The concentration-response coefficients for each of the illnesses, given as R_{ij} in equation (1), are listed in Table 1.[14] Due to the uncertainty arising from the variance in the results of the epidemiological studies we include high, central and low coefficient estimates.[15] Referring to equation (1), the product of the concentration-response coefficient, the affected population and the change in sulfate concentration gives us the estimated health effects of a marginal reduction in SO_2 emissions.

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[14] The concentration-response coefficients listed in Table 1 are for changes in annual sulfate concentration, to calculate the daily C-R coefficient we divide by 365.

Table 1. Annual Concentration-Response Coefficients Used to Calculate Health Effects

Case	Concentration-response coefficient		
	High	Central	Low
Mortality[16]	11.2×10^{-5}	4.0×10^{-5}	0.8×10^{-5}
Bronchitis[17]	2.0×10^{-4}	1.1×10^{-4}	0.5×10^{-4}
RHA[18]	1.8×10^{-5}	1.6×10^{-5}	1.3×10^{-5}
CHA[19]	1.7×10^{-5}	1.3×10^{-5}	1.0×10^{-5}
RAD[20]	14.6×10^{-2}	9.3×10^{-2}	4.7×10^{-2}
Asthma[21]	9.9×10^{-1}	6.7×10^{-1}	3.3×10^{-1}
LRS[22]	23.0×10^{-2}	16.4×10^{-2}	6.6×10^{-2}

Source: EPA (1995)

Table 2. Estimated Monetary Values Associated with Per Case Consequences of Sulfate Concentrations

	Monetary Value of Case (1994$)		
Case	High	Central	Low
Mortality[23]	$7,100,000	$3,500,000	$2,000,000
Bronchitis[24]	$380,000	$240,000	$140,000
RHA[25]	$21,000	$14,000	$7,000
CHA[26]	$21,000	$14,000	$7,000
RAD[27]	$90	$60	$30
Asthma[28]	$58	$36	$13
LRS[29]	$17	$11	$6

Source: EPA (1995)

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[15] This is also the procedure followed in EPA (1995) and serves as a sensitivity analysis. See Chapter 4 of the report for a more complete description of the procedures used to generate high, central and low estimates.

[16] EPA (1995) provides a complete and authoritative review of the literature used to quantify these health effects. For a more complete explanation of how these values were estimated see EPA (1995), Chapter 5.

[17] All figures are calculated assuming both central C-R coefficients and monetary values for each condition. Figures are reported in 1994 dollars.

[18] The central estimate is calculated using the central C-R coefficient from Table 1 and the central monetary value from Table 2. The high scenario is generated using the high C-R coefficient and the high valuation while the low scenario is calculated similarly. Only central estimates are reported here, but the high and low estimates are available for each plant upon request of the authors.

[19] The Burtraw et. al. study attributes 94 percent of the health benefits to reduced mortality, while our results suggest that 71 percent of health benefits are derived from reduced mortality. Total health (mortality and morbidity combined) are of similar magnitude.

[20] See Pope *et al.* (1995), Dockery *et al.* (1993), Ozkaynak and Thurston (1987), Evans *et al.* (1984), Chappie and Lave (1982) and Plagiannakos and Parker (1988)

[21] Abbey *et al.* (1995)

[22] Burnett *et al.* (1995)

[23] Burnett *et al.* (1995)

[24] Ostro *et al.* (1987) and Ostro and Rothschild (1989)

[25] Ostro *et al.* (1991)

[26] Ostro *et al.* (1993)

[27] EPA (1995) Value of statistical life estimate. See chapter 5 of EPA (1995) for a more complete review of this literature.

[28] Viscusi et al. (1991) and Krupnick and Cropper (1992). Willingness-to-pay estimate.

Economic Valuation

Finally, to compute the economic value of the estimated health effects we must quantify the value of each of the seven conditions. Once again, following the EPA baseline, we rely on published contingent valuation studies which use survey-based methods to assess the value individuals, on average, place on the elimination or reduction of the effects of these cases. In the absence of such stated preference studies, cost-of-illness studies are used. The results of these studies are summarized in Table 2 which is derived from the EPA's pre-implementation assessment. We again choose to include high, central and low estimates both to be consistent with previous work done at the aggregate level and to provide a sensitivity analysis.[30] By multiplying the change in the number of cases by the value per case we calculate the estimated benefits generated per condition. Summing over all seven studied conditions yields the estimated overall value of the emission reduction.

In our Jack Watson example, a one ton reduction in emissions results in benefits of \$1,390 (in \$1994) from the reduction in the probability of premature mortality; \$437 from the reduction in chronic bronchitis cases; \$4 and \$3 from the reduction in RHA and CHA respectively; \$92 from decreased reduced activity days; \$399 from the reduction in asthma symptoms; and \$30 from the reduction in acute lower respiratory symptoms.[31] Thus a one ton decrease in emissions from plant 2049 on January 15th, 1996 yields \$2,355 in health benefits to the population in the affected areas.

IV. RESULTS

Marginal Benefits

The mean marginal health benefit (MHB) of emission abatement at each of the 110 Phase I electric utilities under the central specifications are detailed in Table 3. The mean MHB for the entire sample was \$2,502 using the central estimate, \$8,744 under the high scenario and \$558 using the low scenario.[32] The standard deviation of MHB was \$643 for the central estimate; while this does not constitute exceptional dispersion, the range of the benefits across plants was fairly substantial. Using central estimates, a unit reduction in SO_2 emissions from the most sensitive location, the Eagle Valley Generating Station in Indiana generates \$4,518 in health improvements, on average, for each ton of SO_2 abated. This is nearly seven times the benefit of a reduction at the least sensitive location, the B L England plant in New Jersey, where the MHB averages \$633 per ton. These results are broadly consistent with existing literature which quantifies the health benefits of SO_2 emissions. Average health benefits were estimated to be approximately \$2,800 in 1997 by the baseline EPA study. Burtaw et. al. (1998) estimates that average health benefits will be in the range of \$2,100 to \$3,800 per ton when the program is fully implemented in 2010.[33]

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[29] Graves (1994) and EPA (1995). Adjusted cost-of-illness estimate

[30] Graves (1994) and EPA (1995). Adjusted cost-of-illness estimate

[31] Loehman et al. (1979) and EPA (1995). Adjusted cost-of-illness estimate and willingness-to-pay estimate

[32] Rowe and Chestnut (1986). Willingness-to-pay estimate.

[33] Loehman et al. (1979) and Tolley et al. (1986). Willingness-to-pay estimate.

Table 3. Central Estimates of Marginal Health Benefits at 110 Phase I Plants (Average, 1995-1999)

Plant Code (ORISPL)	Marginal Health Benefits ($)	Plant Code (ORISPL)	Marginal Health Benefit	Plant Code (ORISPL)	Marginal Health Benefit
26	$3,333	1356	$2,891	2857	$1,326
47	$2,533	1357	$2,654	2861	$2,524
641	$3,481	1374	$2,935	2864	$3,258
645	$1,868	1378	$3,070	2866	$2,888
703	$2,415	1379	$2,651	2872	$3,133
708	$2,546	1381	$2,922	2876	$3,641
710	$3,203	1382	$3,049	3113	$2,559
728	$3,240	1384	$3,045	3118	$2,841
861	$2,062	1552	$1,340	3131	$1,760
862	$2,247	1571	$1,684	3140	$2,778
864	$2,091	1573	$2,117	3148	$2,247
876	$2,550	1710	$2,247	3152	$2,821
887	$2,594	1912	$2,593	3178	$2,199
889	$2,912	2049	$2,954	3179	$2,160
892	$2,420	2076	$2,136	3393	$2,327
897	$3,160	2080	$1,985	3399	$2,282
983	$2,764	2094	$2,820	3403	$2,681
984	$2,807	2103	$3,161	3406	$2,060
988	$2,916	2107	$3,219	3942	$2,232
990	$3,827	2161	$3,072	3943	$2,084
991	$4,529	2167	$2,298	3944	$2,619
994	$2,904	2168	$1,704	3947	$2,454
995	$2,332	2364	$2,172	3948	$3,799
997	$1,753	2378	$634	3954	$2,222
1001	$2,956	2516	$1,336	4039	$1,612
1008	$2,775	2517	$1,176	4041	$1,498
1010	$3,051	2527	$2,172	4050	$1,362
1012	$3,098	2535	$2,411	4054	$2,382
1043	$2,744	2554	$2,068	4072	$1,428
1048	$2,589	2828	$2,575	4143	$2,434
1073	$2,751	2830	$2,683	6041	$2,872
1081	$2,298	2832	$2,961	6052	$2,881
1083	$2,200	2835	$1,599	6113	$2,871
1091	$2,565	2836	$1,508	6705	$2,671
1104	$2,183	2837	$1,518	8102	$3,826
1295	$2,338	2840	$3,599	8226	$3,131
1355	$2,364	2843	$3,541	Avg.	$2,534

All figures in 1994 dollars.

The map in Figure 2 indicates the marginal health benefits at each plant location. Plants with the lowest MHB (< $2,250) are labeled (L), plants with the highest MHB (> $2,750) are labeled (H) and those in the middle range are labeled (•). Emission reductions in the plants represented by (H) have the largest health impact while emission reductions in plants represented by (L) have the least effect. An emission exchange in which a (H) plant reduces its emissions and sells allowances to an (L) plant has a net positive effect on public health. On the other hand, if a (H) plant purchases from an (L) plant, net health conditions deteriorate. The wide dispersion of the MHB across sources implies that gains in social welfare may be accomplished by discouraging trades which generate excessive social losses.

Geographically, the most harmful plants are generally located in a band stretching from the Ohio-Pennsylvania-West Virginia border southwest toward the Indiana-Kentucky-Illinois border. On the other hand, the least harmful plants are generally located either east of the Pennsylvania-Ohio border or west of the Indiana-Illinois border. One major factor driving these results is the location of the plants relative to bodies of water. A portion of the plumes of the plants in Wisconsin, northern Indiana, and northern Ohio as well as those in New York, New Jersey and Maryland are dispersed over bodies of water, uninhabited by human population, thereby generating no health effects in this model. This is generally consistent with the view that the plants along the Ohio River are disproportionately harmful compared to plants in other regions. Conversely, abatement activities in these regions generate disproportionate health improvements accruing to both local populations and those downwind.

Total Benefits

Estimation of the total health effects of SO_2 reduction at the plant level is tractable due to our use of a linear damage function in equation (1). Such a linear function renders the marginal health benefit unaffected by the level of emission; marginal health benefits are therefore equal to the average health benefits. To find the plant-level total health benefits relative to a benchmark year we multiply the change in emissions at each plant by its estimated marginal health benefits listed in Table 3. In this study, we designate two baseline years, 1980 and 1994, calculating the total health benefits arising from emission changes relative to each base case. We chose 1980 to allow for comparison with previous work completed at the aggregate level by the EPA (1995) and we selected 1994, the final year of the previous regulatory regime, in order to gauge the effect of the Acid Rain Program apart from other systemic changes occurring during the 1980's and early 1990's. However, due to other regional programs, low prices for low-sulfur coal, general technological change in the industry and other factors, these benefits cannot be attributed solely to the Acid Rain Program. The total health benefits attributable to each of the 110 plants over the first phase of the CAAA program (1995 to 1999) using 1980 as the base year are listed in Table 4; the total health benefits using 1994 as the base year are listed in Table 5.

Table 4. Central Estimates of Total Health Benefits from 110 Phase I Plants (1995-1999), 1980 Baseline

Plant Code (ORISPL)	Total Health Benefits ($ in Millions)	Plant Code (ORISPL)	Total Health Benefits	Plant Code (ORISPL)	Total Health Benefits
26	$1,482	1356	$460,966,817	2857	$86,152,933
47	$656,466,967	1357	-$134,177,725	2861	$58,995,460
641	$661,948,056	1374	$556,201,000	2864	$636,988,238
645	$547,837,156	1378	$2,597,933,947	2866	$107,662,560
703	$1,278,169,571	1379	$816,297,264	2872	$1,578,909,981
708	$308,977,686	1381	$339,961,312	2876	$1,756,093,386
710	$106,864,180	1382	$650,138,255	3113	$100,832,044
728	$1,291,500,689	1384	$24,299,198	3118	$2,680,474,562
861	$1,170,445,441	1552	-$105,329,662	3131	$78,034,613
862	$69,784,243	1571	$25,078,532	3140	$718,099,838
864	$272,836,985	1573	$215,309,873	3148	$426,451,876
876	$2,059,764,468	1710	$243,164,291	3152	-$69,481,010
887	$1,000,831,213	1912	$165,678,230	3178	$34,107,579
889	-$45,429,002	2049	$232,591,464	3179	$277,610,967
892	-$11,251,900	2076	$633,371,088	3393	$589,985,531
897	$341,560,126	2080	$1,550,976,822	3399	$3,955,391,481
983	$2,895,093,098	2094	$292,994,893	3403	$535,832,992
984	$1,023,259,315	2103	$2,592,341,086	3406	$205,961,632
988	$655,484,564	2107	$750,198,856	3942	$138,895,101
990	$221,678,051	2161	$188,448,089	3943	$173,916,578
991	$196,557,252	2167	$2,152,689,008	3944	$2,777,396,967
994	$636,806,807	2168	$1,032,578,211	3947	$452,534,822
995	$531,333,969	2364	$189,749,657	3948	$2,234,627,271
997	$556,025,276	2378	$73,262,224	3954	-$124,665,405
1001	$438,790,874	2516	$415,580,182	4039	$374,053,477
1008	$154,693,225	2517	$116,704,064	4041	$107,742,449
1010	$258,699,606	2527	$136,531,527	4050	$260,282,730
1012	$893,699,066	2535	$271,360,105	4054	$265,580,463
1043	$489,688,865	2554	-$34,225,317	4072	$254,749,121
1048	$328,274,982	2828	-$187,322,026	4143	$75,443,992
1073	$75,833,709	2830	$256,913,737	6041	-$371,406,949
1081	$101,416,700	2832	$380,127,208	6052	$2,095,846,720
1083	$130,710,919	2835	$198,339,547	6113	$2,112,594,429
1091	-$15,477,327	2836	$460,445,894	6705	-$969,112,698
1104	$170,576,737	2837	$302,766,009	8102	$6,376,460,869
1295	$202,350,061	2840	$652,840,482	8226	$9,820,994
1355	$203,512,848	2843	$132,754,553	Total	$69,992,459,665

All figures in 1994 dollars. Figures represent the total health benefits generated from 1995-1999 versus the 1980 baseline.

According to the 1995 EPA report, the health benefits were predicted to escalate throughout the program from $1.4 billion in 1995 to $19.7 billion in 1999 as plants gradually curtailed their emissions. The sum over the 5-year period was approximately $53 billion relative to the 1980 baseline. Our results, also using 1980 as the base case, indicate health benefits totaled approximately $70 billion during Phase I with the gains occurring immediately and ranging only from $13.5 to $14.6 billion per year over the five year period (see Table 4). This is consistent with the general consensus that the program achieved larger emission reductions faster than anticipated, and indicates that the benefits were relatively large from program's genesis and did not escalate throughout as the EPA study predicted. Despite the temporal differences, the magnitude of the health benefits in our study mirrors the implicit 5-year predictions of the EPA's pre-implementation assessment.

The total health benefits attributable to each plant during Phase I of the Acid Rain Program relative to the 1994 base case are given in Table 5. Our estimates indicate that changes in emission patterns generated $30.2 billion in health benefits from 1995 to 1999 – approximately $6 billion annually. These figures may understate the true benefits of the program as many plants began installing flue gas desulfurization and other scrubbing technologies prior to 1995 in anticipation of the increased regulatory stringency. On the other hand, they may overstate the benefits of the program since regional programs, lower prices for clean coal and other factors are surely responsible for some of the emission reductions occurring post-1994.

Perhaps the most interesting result of this analysis is that emission reductions from only ten plants account for around 82 percent of the overall health benefits during the Phase I years. Even more specifically, emission reductions from the General J M Gavin plant in Ohio accounted for over $1.3 billion in health improvements per year in the eastern U.S. and Canada. Similarly, reductions in emissions at West Virginia's Harrison plant (3944) generated over $650 million per year in health improvements. Abatement at these two plants together generated approximately one third of the health improvements over Phase I of the Acid Rain Program. This evidence suggests that the health benefits associated with SO_2 reductions are perhaps more concentrated than previously thought, as a substantial portion of these beneficial effects can be attributed to massive emission changes at only a few facilities.

Emission Trading

A tradable permit-based policy allows high-abatement-cost plants the flexibility to increase their emission rates as they purchase allowances in the market to meet the programs requirements. Alternatively, low-abatement-cost plants can capture gains from trade by reducing emissions and selling the surplus. Forty-eight plants were net buyers of allowances during Phase I; they are identified geographically by (B) in Figure 3. Sixty plants were net sellers, shown as (S) in the figure. Comparison of Figures 2 and 3 yields a high degree of correspondence between high benefit plants and purchasing plants. Many plants labeled (H) in the Ohio Valley are also labeled (B) plants in the subsequent figure. Such a correspondence would indicate that a net health burden was created by the trade pattern that emerged as allowances flowed to plants that had the potential to generate large social costs.

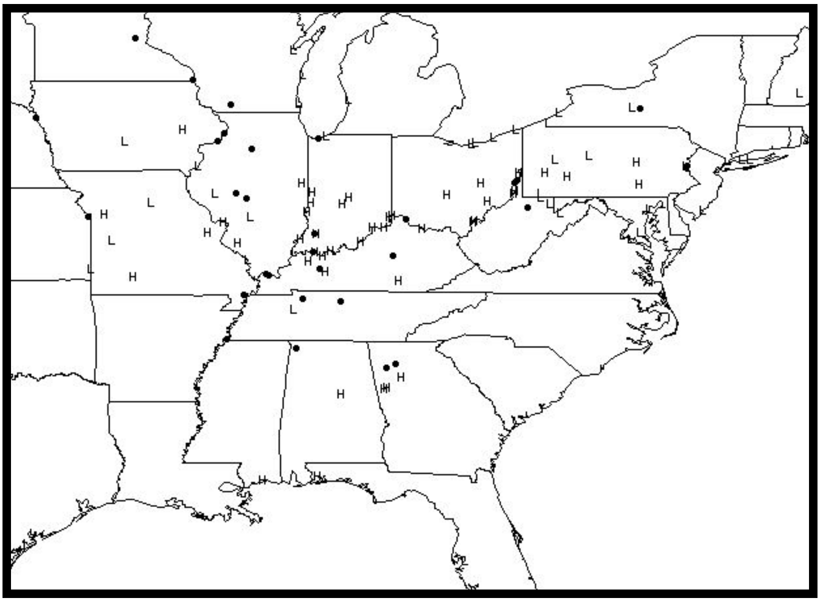

Figure 2. Marginal Health Effects at 110 Plants Designated Phase I by the Clean Air Act Amendments of 1990

H = plant with marginal health benefits exceeding $2,750
L = plant with marginal health benefits below $2,250
● = plant with marginal health benefits between $2,250 and $2,750.

Table 5. Central Estimates of Total Health Benefits from 110 Phase I Plants (1995-1999), 1994 Baseline

Plant Code (ORISPL)	Total Health Benefits	Plant Code (ORISPL)	Total Health Benefits	Plant Code (ORISPL)	Total Health Benefits
26	$695,014,696	1356	-$59,777,635	2857	-$111,810
47	$91,167,067	1357	-$103,125,132	2861	$107,409,085
641	$318,796,300	1374	$760,501,624	2864	$311,792,101
645	$565,594,137	1378	-$842,326,683	2866	$154,574,319
703	$571,286,093	1379	-$550,477,474	2872	$845,851,570
708	-$120,383,235	1381	$123,541,759	2876	$2,239,302,367
710	-$20,266,579	1382	$440,662,735	3113	-$22,066,780
728	-$132,849,920	1384	$52,737,474	3118	$2,246,254,330
861	$337,674,242	1552	$19,704,251	3131	-$80,497,282
862	-$77,776,212	1571	-$30,604,947	3140	$153,639,943
864	-$7,068,038	1573	-$51,187,738	3148	-$124,447,380
876	$1,629,107,992	1710	-$267,094,734	3152	-$328,043,147
887	$534,521,984	1912	-$34,245,397	3178	-$47,173,201
889	-$459,767,264	2049	$30,402,887	3179	$200,849,955
892	-$197,508,775	2076	-$4,206,377	3393	$615,411,959

Table 5. (Continued)

Plant Code (ORISPL)	Total Health Benefits	Plant Code (ORISPL)	Total Health Benefits	Plant Code (ORISPL)	Total Health Benefits
897	$74,807,134	2080	$28,933,045	3399	$2,908,625,640
983	$2,319,083,590	2094	-$93,053,126	3403	$297,912,969
984	$0	2103	$1,151,903,479	3406	$137,759,483
988	-$148,561,105	2107	$121,548,960	3942	-$38,305,763
990	$250,402,591	2161	-$46,973,783	3943	$56,073,305
991	-$188,198,163	2167	$1,405,368,627	3944	$3,296,301,569
994	$292,749,289	2168	$67,476,346	3947	$336,475,239
995	$39,025,707	2364	$68,925,075	3948	$462,716,067
997	$3,387,724	2378	$45,325,710	3954	$357,008,604
1001	$392,224,158	2516	-$395,009	4039	$0
1008	$181,836,379	2517	$14,419,175	4041	-$117,229,027
1010	-$154,820,110	2527	-$233,262	4050	$9,763,737
1012	$560,167,528	2535	$205,618,902	4054	-$46,706,684
1043	$350,213,814	2554	-$262,649,211	4072	-$22,974,609
1048	$136,300,854	2828	$31,165,537	4143	$34,328,309
1073	-$7,522,711	2830	-$397,923,077	6041	-$208,163,584
1081	$132,921,348	2832	-$196,983,275	6052	$1,041,382,498
1083	$0	2835	$7,539,412	6113	$111,170,896
1091	-$257,223,978	2836	-$99,218,462	6705	-$570,737,136
1104	$26,431,532	2837	$126,040,158	8102	$6,655,058,618
1295	-$19,546,536	2840	-$570,754,011	8226	$159,319,912
1355	$179,061,345	2843	$237,135,703	Total	$30,350,530,474

All figures in 1994 dollars. Figures represent the total health benefits generated from 1995-1999 versus the 1994 baseline.

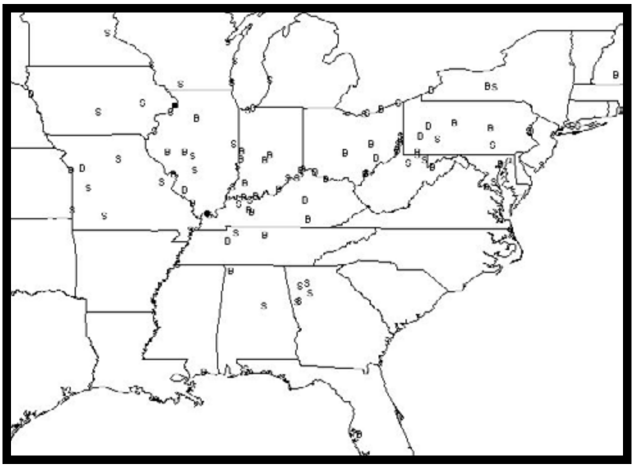

Figure 3. Trading Patterns at 110 Plants Designated Phase I by the Clean Air Act Amendments of 1990

B = plant purchasing permits on net during Phase I.
S = plant selling permits on net during Phase I.
● = plant not participating in the market during Phase I.

While data is not available on individual trades, we are able to show the general health consequences of trading by examining the MHB of net buyers and sellers, on average. We compute the weighted-average MHB of selling plants to be \$2,664 and the weighted-average MHB of purchasing plants to be \$2,702. These averages do not take environmental justice or distributional effects into account, however, they do indicate that, on average, each transfer generated approximately \$38 in net health costs. While this trading pattern is less than desirable the net costs it generates are relatively small given the magnitude of the marginal effects in general.

V. CONCLUSION

This study analyzes the health benefits of emission reductions from electric utility plants affected by Phase I of the EPA's Acid Rain Program. Using source-specific deposition simulations and population mapping, we estimate the marginal health benefits of SO_2 emission reductions for each plant. These measures weight SO_2 emissions that affect highly populated areas more heavily than emissions in sparsely populated areas thus accounting for the variation in effects across plants. Our central estimate of the average marginal health benefit is approximately \$2,500 over all 110 plants. Eighty-two percent of the health benefits of the program can be attributed to SO_2 emission reductions at only ten plants; nearly one third of the overall health benefits are the result of emission reductions at only two locations. Total health benefits of emission reductions in the U.S. and Canada approached \$6 billion per year for a total of approximately \$30 billion over the five-year span of Phase I.

Under the EPA's program, emission allowances are freely tradable, allowing for the possibility that plants affecting densely populated areas may increase their emission rates thereby generating net social costs to society. For social optimality, policies designed to reduce non-uniformly mixed pollutants need to account for impact differences across point-sources. The large range of marginal health benefits (\$4,518 to \$633) indicates that social gains may be achieved by restricting certain detrimental trades. However, the low variance of these benefits implies that the majority of potential trades have only small net health impacts.

Future research should focus on extending the measures of marginal social damage to consider environmental costs of SO_2 emissions, as well as extending the population component to include characteristics about the vulnerability of the underlying population. This vain of research is also important for other non-uniformly mixed pollutants, especially in light of the recent Clean Air Interstate Rule that extends the tradable allowance program to NO_X, the Clean Air Mercury Rule, and the proposed Federal Implementation Plan to regulate interstate transport of SO_2 and NO_X. Examination of distributional and environmental justice concerns also remains a fruitful offshoot using the methodology demonstrated here.

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In: Carbon Capture and Storage Including… ISBN: 978-1-60741-196-3
Editor: T. P. Carington, pp. 101-113

Chapter 5

THE CARBON CYCLE: IMPLICATIONS FOR CLIMATE CHANGE AND CONGRESS[*]

Peter Folger

SUMMARY

Huge quantities of carbon are actively exchanged between the atmosphere and other storage pools, including the oceans, vegetation, and soils on the land surface. The exchange, or flux, of carbon among the atmosphere, oceans, and land surface is called the global carbon cycle. Comparatively, human activities contribute a relatively small amount of carbon, primarily as carbon dioxide (CO_2), to the global carbon cycle. Despite the addition of a relatively small amount of carbon to the atmosphere, compared to natural fluxes from the oceans and land surface, the human perturbation to the carbon cycle is increasingly recognized as a main factor driving climate change over the past 50 years.

If humans add only a small amount of CO_2 to the atmosphere each year, why is that contribution important to global climate change? The answer is that the oceans, vegetation, and soils do not take up carbon released from human activities quickly enough to prevent CO_2 concentrations in the atmosphere from increasing. Humans tap the huge pool of fossil carbon for energy, and affect the global carbon cycle by transferring fossil carbon — which took millions of years to accumulate underground — into the atmosphere over a relatively short time span. As a result, the atmosphere contains approximately 35% more CO_2 today than prior to the beginning of the industrial revolution (380 ppm vs 280 ppm). As the CO_2 concentration grows it increases the degree to which the atmosphere traps incoming radiation from the sun (*radiative forcing*), warming the planet.

The increase in atmospheric CO_2 concentration is mitigated to some extent by two huge reservoirs for carbon — the global oceans and the land surface — which currently take up more carbon than they release. They are net *sinks* for carbon. If the oceans, vegetation, and

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[*] This is an edited, reformatted and augmented edition of a Congressional Research Service publication, Report RL34059, updated March 13, 2008.

soils did not act as sinks, then the concentration of CO_2 in the atmosphere would increase even more rapidly. A key issue to consider is whether these two sinks will continue to store carbon at the same rate over the next few decades, or whether their behavior will change. Currently, most of the total global carbon sink is referred to as the *unmanaged*, or background, carbon cycle. Very little carbon is removed from the atmosphere and stored, or sequestered, by deliberate action.

Congress is considering legislative strategies to reduce U.S. emissions of CO_2 and/or increase the uptake of CO_2 from the atmosphere. Congress may also opt to consider how land management practices, such as afforestation, conservation tillage, and other techniques, might increase the net flux of carbon from the atmosphere to the land surface. How the ocean sink could be managed to store more carbon is unclear. Iron fertilization and deep ocean injection of CO_2 are in an experimental stage, and their promise for long-term enhancement of carbon uptake by the oceans is not well understood. Congress may consider incorporating what is known about the carbon cycle into its legislative strategies, and may also evaluate whether the global carbon cycle is sufficiently well understood so that the consequences of longterm policies aimed at mitigating global climate change are fully appreciated.

INTRODUCTION

Congress is considering several legislative strategies that would reduce U.S. emissions of greenhouse gases — primarily carbon dioxide (CO_2) — and/or increase uptake and storage of CO2 from the atmosphere. Both approaches are viewed by many observers as critical to forestalling global climate change caused, in part, by the buildup of greenhouse gases in the atmosphere from human activities. Others point out that the human contribution of carbon to the atmosphere is a small fraction of the total quantity of carbon that cycles naturally back and forth each year between the atmosphere and two huge carbon reservoirs: the global oceans and the planet's land surface. A question raised is whether the human fraction of the global carbon cycle — the exchange, or flux, of carbon between the atmosphere, oceans, and land surface — is large enough to induce climate change and global warming.

Despite the addition of a relatively small amount of carbon to the atmosphere, compared to natural fluxes from the oceans and land surface, the human perturbation to the carbon cycle is increasingly recognized as a main factor driving climate change over the past 50 years. For most of human history, the global carbon cycle has been roughly in balance, and the concentration of CO_2 in the atmosphere has been fairly constant at approximately 280 parts per million (ppm). Human activities, namely the burning of fossil fuels, deforestation, and other land use activities, have significantly altered the carbon cycle. As a result, atmospheric concentrations of CO_2 have risen by over 35% since the industrial revolution, and are now greater than 380 parts per million (ppm).[1]

An understanding of the global carbon cycle has shifted from being of mainly academic interest to being also of policy interest. Policy makers are grappling with, for example, how to design a cap-and-trade system that accurately accounts for carbon sequestration by components of the land surface sink, such as forests. Yet how much CO_2 forests are capable of taking up in the future is largely a scientific question. More broadly, a cap-and-trade system that limits emissions, and is designed to keep atmospheric CO_2 below a specific concentration, would depend inherently on continued uptake of carbon by the oceans and land surface. How those two carbon reservoirs will behave in the future — how much CO_2 they will take up or release and at what rate — are also topics of active scientific inquiry.[2]

Thus the scientific understanding of the carbon cycle is integral to many aspects of the current congressional debate over how to mitigate climate change. This chapter puts the human contribution of carbon to the atmosphere into the larger context of the global carbon cycle. The report focuses almost entirely on $CO_{2,}$ which alone is responsible for over half of the change in Earth's radiation balance.3 Moreover, according to the Intergovernmental Panel on Climate Change (IPCC), CO_2 is the most important greenhouse gas released to the atmosphere from human activities.[4]Methane, black carbon, and organic carbon pollution are also part of the carbon cycle and have roles in human-induced climate change (e.g., methane accounts for about an additional 20% of the change in the Earth's radiation balance).

CARBON STORAGE, SOURCES AND SINKS

The atmosphere, oceans, vegetation, and soils on the land surface all store carbon. (See Figure 1a.) Geological reservoirs also store carbon in the form of fossil fuels; for example, oil, gas, and coal.[5] Of these reservoirs (or pools), dissolved inorganic carbon in the ocean is the largest, followed in size by fossil carbon in geological reservoirs, and by the total amount of carbon contained in soils. (See Figure 1a and Table 1.) The atmosphere itself contains nearly 800 billion metric tons of carbon (800 GtC),[6] which is more carbon than all of the Earth's living vegetation contains.[7] Carbon contained in the oceans, vegetation, and soils on the land surface is linked to the atmosphere through natural processes such as photosynthesis and respiration. In contrast, carbon in fossil fuels is linked to the atmosphere through the extraction and combustion of fossil fuels. The atmosphere has a fairly uniform concentration of $CO_{2,}$ although it shows minor variations by season (about 1%) — due to photosynthesis and respiration — and by latitude.[8] Carbon dioxide released from fossil fuel combustion mixes readily into the atmospheric carbon pool, where it undergoes exchanges with the ocean and land surface carbon pools. Thus, *where* fossil fuels are burned makes relatively little difference to the concentration of CO_2 in the atmosphere; emissions in any one region affect the concentration of CO_2 everywhere else in the atmosphere.[9]

The oceans, vegetation, and soils truly *exchange* carbon with the atmosphere constantly on daily and seasonal time cycles (Figure 1b). In contrast, carbon from fossil fuels is *not* exchanged with the atmosphere, but is transferred in a one-way direction from geologic storage, at least within the time scale of human history.[10] Some of the CO_2 currently in the atmosphere may become fossil fuel someday, after it is captured by vegetation, buried under heat and pressure, and converted into coal, for example, but the process takes millions of years. How much of the fossil fuel carbon ends up in the atmosphere, instead of the oceans, vegetation, and soils, and over what time scale, is driving much of the debate over what type of action to take to ameliorate global warming.

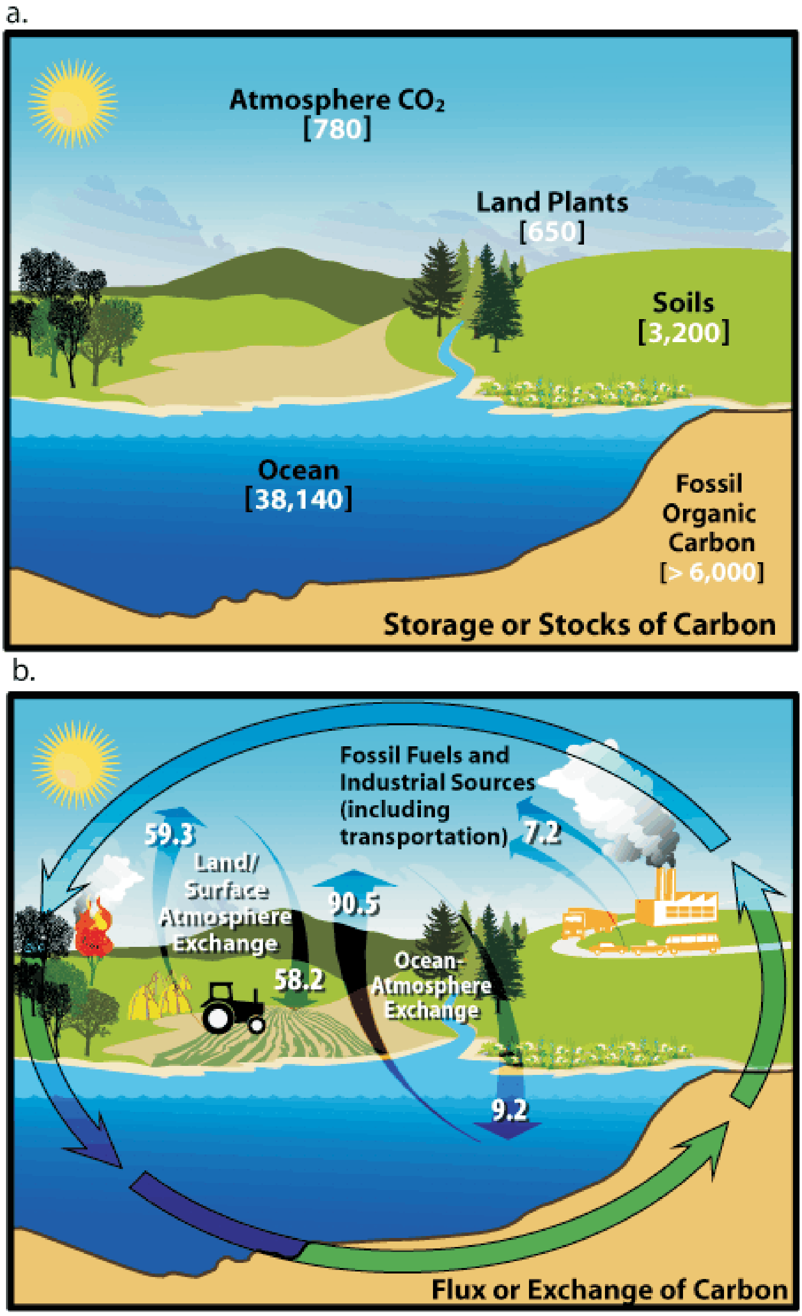

Figure 1. (a) Storage or Pools (GtC) and (b) Annual Flux or Exchange of Carbon (GtC per year)

Note: Figure prepared by CRS.

Sources: SOCCR; 2007 IPCC Working Group I Report, Table 7.1; and Christopher L. Sabine et al., “Current Status and Past Trends of the Global Carbon Cycle,” in C. B. Field and M. R. Raupach, eds., *The Global Carbon Cycle: Integrating Humans, Climate, and the Natural World* (Washington, DC: Island Press, 2004), pp. 17-44.

Table 1. Carbon Stocks in the Atmosphere, Ocean, and Land Surface, and Annual Carbon Fluxes

Storage pool	GtC	Annual flux (GtC/yr) *From* the atmosphere	Annual flux (GtC/yr) *To* the atmosphere	Net to the atmosphere (GtC/yr)
Atmosphere	780			
Ocean	38,140	92.2	90.5	-1.7[b]
Land Surface[a] (soils plus vegetation)	3,850	59.3	58.2	-1.1[c]
Fossil Carbon (coal, gas oil, other)	>6,000	—	7.2	+7.2

How much carbon is stored in each pool — especially the atmospheric pool — is important in global warming because as more CO_2 is added to the atmosphere, its heat-trapping capacity becomes greater.[11] Each storage pool — oceans, soils, and vegetation — is considered a *sink* for carbon because each pool takes up carbon from the atmosphere. Conversely, each storage pool is also a *source* of carbon for the atmosphere, because of the constant exchange or *flux* between the atmosphere and the storage pools. For example, vegetation in the northern hemisphere is a sink for atmospheric carbon during the spring and summer months due to the process of photosynthesis. In the fall and winter it is a source for atmospheric carbon because the process of respiration returns carbon to the atmosphere from the vegetation pool.

The pool of fossil carbon is only a source, not a sink, except over geologic time scales, as described above. How much carbon is transferred between the atmosphere and the sources and sinks is a topic of scientific scrutiny because the mechanisms are still not understood completely. Whether a storage pool will be a net sink or a net source for carbon in the future depends very much on the balance of mechanisms that drives its behavior, and how those mechanisms may change.[12]

CARBON FLUX, OR EXCHANGE, WITH THE ATMOSPHERE

Carbon actively exchanges (*fluxes*) between the atmosphere and the other storage pools, or stocks, of carbon. Over 90 GtC is exchanged each year between the atmosphere and the oceans, and close to 60 GtC is exchanged between the atmosphere and the land surface annually. (See Table 1.)[13] Human activities — primarily land-use change and fossil fuel combustion — contribute slightly less than 9 GtC to the atmosphere each year.[14] If the human contribution of CO_2 is removed from the global carbon cycle, then the average *net flux* — the amount of CO_2 released to the atmosphere versus the amount taken up by the oceans, soils, and vegetation — is close to zero. Most scientists conclude that for 10,000 years prior to 1750, the net flux was less than 0.1 GtC per year when averaged over decades.[15] That small value for net flux is reflected by the relatively stable concentration of CO_2 in the atmosphere — between 260 and 280 ppm — for the 10,000 years prior to 1750.[16]

Currently the atmospheric concentration of CO_2 is approximately 100 ppm higher than it was before 1750 because human activities are adding carbon to the atmosphere faster than the oceans, land vegetation, and soils remove it. The relatively rapid addition of CO_2 to the atmosphere has tipped the balance so that the oceans and the land surface take up more CO_2 per year on average than they release, yet atmospheric concentrations of CO_2 continue to rise. (See Table 1.) Why is that occurring?

The short answer is timing; CO_2 from fossil fuel combustion and land use changes is being released to the atmosphere faster than the oceans, vegetation, and soil can take it up, so CO_2 is accumulating in the atmosphere. About 45% of the CO_2 released from fossil fuel combustion and land use activities during the 1990s has remained in the atmosphere, while the remainder has been taken up by the oceans, vegetation, or soils on the land surface.17 Carbon dioxide is nonreactive18 in the atmosphere and has a relatively long residence time, although eventually most of it will return to the ocean and land sinks. About 50% of a single pulse of CO_2 will be removed within 30 years, a further 30% removed in within a few centuries, and the remaining 20% may persist in the atmosphere for thousands of years.19 If CO_2 emissions continue or grow, however, atmospheric concentrations of CO_2 will likely also continue to increase, with serious implications for future climate change.

As the CO_2 concentration grows it increases *radiative forcing* (the degree to which the atmosphere traps incoming radiation from the sun), warming the planet. At present, the oceans and land surface are acting as sinks for CO_2 emitted from fossil fuel combustion and deforestation, but as they accumulate more carbon the capacity of the sinks — and the rate at which they accumulate carbon — may change. It is also likely that climate change itself (e.g., higher temperatures, a more intense hydrologic cycle) may alter the balance between sources and sinks, due to changes in the complicated feedback mechanisms between the atmosphere, oceans, and land surface.[20] How carbon sinks will behave in the future is a prominent question for both scientists and policy makers.

Land Surface-Atmosphere Flux

Most estimates of the carbon cycle indicate that the land surface (vegetation plus soils) accumulates more carbon per year than it emits to the atmosphere.[21] (See Figure 1b and Table 1.) The land surface thus acts as a net sink for CO_2 at present. Some policy makers advocate strategies for increasing the amount of CO_2 taken up and stored, or *sequestered*, by soils and plants, typically through land use changes, such as agricultural or forestry practices.[22] How effective those strategies are likely to be depends, in part, on how the carbon cycle behaves in the future, particularly the land-atmosphere flux. How the land-atmosphere flux may change, and how land use practices will change in the future is not clear.

The land use change component has the largest uncertainty of any component in the overall carbon cycle.[23] Most scientists agree, however, that in the past two decades *tropical deforestation* has been responsible for the largest share of CO_2 released to the atmosphere from land use changes.[24] Tropical deforestation and other land use changes released approximately 1.6 GtC per year to the atmosphere in the 1990s, and may be contributing similar amounts of carbon to the atmosphere today.[25] Even though deforestation releases more carbon than is captured by forest regrowth within some regions, net forest regrowth in other regions takes up sufficient carbon so the land surface acts as a global net *sink* of approximately 1 GtC per year. By some estimates, even tropical lands, despite widespread deforestation, may be carbon-neutral or even net carbon sinks; tropical systems take up substantial carbon to offset what is lost through deforestation and fire.[26]

What used to be known as “the missing sink” component in the overall global carbon cycle is now understood to be that part of the terrestrial ecosystem responsible for the net uptake of carbon from the atmosphere to the land surface (especially highlatitude, or boreal, forests).[27] Scientists now prefer the term “residual land sink” to “missing sink” as it portrays the residual — or left over — part of the global carbon cycle calculation once the other components are accounted for (fossil fuel emissions, land-use emissions, atmospheric increase, and ocean uptake).[28] Precisely which mechanisms are responsible for the residual land sink is a topic of scientific inquiry. One mechanism postulated for many years has been the fertilizing effect of increased atmospheric CO_2 concentrations on plant growth. Most models predict enhanced growth and carbon sequestration by plants in response to rising CO_2 levels; however, results of experiments have been mixed. Many experiments show enhanced growth from increased CO_2 concentrations — at least initially — but nutrient and water availability and other limitations to growth are common. Long-term observations of biomass change and growth rates suggest that fertilization effects are too small to account for the residual land sink, at least in the United States.[29]

In North America, particularly the United States, the land-atmosphere flux is strongly tilted towards the land, with approximately 0.5 GtC per year accumulating in terrestrial sinks.[30] That amount constitutes a large fraction — possibly 40% — of the global terrestrial carbon sink.[31] According to some estimates, approximately half of the North American terrestrial carbon sink stems from regrowth of forests on abandoned U.S. farmland.[32] Woody encroachment — the increase in woody biomass occurring mainly on former grazing lands — is thought to be another potentially large terrestrial sink, possibly accounting for more than 20% of the net North American sink (although the actual number is highly uncertain).[33] Wood products (e.g., furniture, house frames, etc.), wetlands, and other smaller, poorly understood carbon sinks are responsible for accumulating the remaining carbon in North America.

Most of the North American terrestrial carbon sink, such as the forest regrowth component, is sometimes referred to as the *unmanaged*, or background, carbon cycle. Very little carbon is sequestered by deliberate action.[34] The future behavior of the unmanaged terrestrial carbon sink is another consideration for lawmakers. Whether the United States will continue its trajectory as a major terrestrial carbon sink is highly uncertain, and little evidence suggests that the terrestrial ecosystem sinks will increase in the future; some current sinks may even become *sources* for carbon.[35]

Policy makers may also need to evaluate how management practices, such as afforestation, conservation tillage, and other techniques, would increase the net flux of carbon from the atmosphere to the land surface.[36] How forests, rangelands, and croplands are managed in the future for carbon sequestration may become an important factor in the overall land-atmosphere flux.

Ocean-Atmosphere Flux

Similar to the land surface, the oceans today accumulate more carbon than they emit to the atmosphere each year, acting as a net sink for about 1.7 GtC per year. (See Figure 1b and Table 1.) If the land surface and oceans were not acting as net sinks, the CO_2 concentration in the atmosphere would be increasing at a faster rate than observed. More than the land surface, the oceans have a huge capacity to store carbon. Ultimately, the oceans could store more than 90% of all the carbon released to the atmosphere by human activities, but the process takes thousands of years.[37] Policy makers may be more concerned about CO_2 accumulating in the oceans now, its impact on ocean chemistry and marine life (e.g., ocean acidification), and its behavior as a net sink over the next few decades.

Carbon dioxide enters the oceans by dissolving into seawater at the ocean surface, at a rate controlled by the difference in CO_2 concentration between the atmosphere and the sea surface.[38] Because the surface waters [39] of the ocean have a relatively small volume — and thus a limited capacity to store CO_2 — how much CO_2 is stored in the oceans over the time scale of decades depends on ocean mixing and the transport of CO_2 from the surface to intermediate and deep waters. Mixing between surface waters and deeper portions of the ocean is a sluggish process; for example, the oldest ocean water in the world — found in the North Pacific — has not flowed to the ocean surface for about 1,000 years.[40] Thus the slow rate of ocean mixing, and slow transport of CO_2 from the surface to the ocean depths, is of possible concern to policymakers because it influences the effectiveness of the ocean sink for CO_2, and because CO_2 added to the surface waters of the ocean increases its acidity.

In addition to the vertical mixing of the ocean, large-scale circulation of the oceans around the globe is a critical component for determining the effectiveness of the ocean sink.[41] Surface waters carrying anthropogenic CO_2 descend into the ocean depths primarily in the North Atlantic and the Southern Oceans, part of the so-called oceanic "conveyor belt."[42] Some model simulations suggest that the Southern Ocean around Antarctica accounts for nearly half of the net air-sea flux of anthropogenic carbon.[43] From that region, a large portion of dissolved CO_2 is transported north towards the subtropics. Despite its importance as a CO_2 sink, the Southern Ocean is poorly understood, and at least one study suggests that its capacity for absorbing carbon may be weakening.[44]

As CO_2 is added to the surface of the ocean from the atmosphere, it increases the acidity of the sea surface waters, with possible impacts to the biological production of organisms, such as corals. Corals, and calcifying phytoplankton and zooplankton, are susceptible to increased acidity as their ability to make shells in the water column is inhibited or possibly reversed, leading to dissolution.[45] Some reports indicate that sea surface pH has dropped by 0.1 pH units since the beginning of the industrial revolution.[46] One report suggests that pH levels could drop by 0.5 pH units by 2100, and suggests further that the magnitude of ocean acidification can be predicted with a high level of confidence.[47] The same report states, however, that research on the impacts of high concentrations of CO_2 on marine organisms is in its infancy.

The oceans appear to be a larger net sink for carbon than the land surface at present. As with the land surface, however, a consideration for policy makers is the future behavior of the ocean sink, particularly the Southern Ocean, given its importance to the net ocean-atmosphere CO_2 flux. In contrast to the terrestrial carbon sink, where management practices such as afforestation and conservation tillage may increase the amount of carbon uptake, it is unclear how the ocean carbon sink can be *managed* in a similar fashion. Some proposed techniques for increasing ocean sequestration of carbon, such as iron fertilization48 and deep ocean injection of CO_2, are in an experimental phase and have unknown long-term environmental consequences.[49]

POLICY IMPLICATIONS

Huge amounts of carbon are exchanged among the atmosphere, the land surface, and the oceans each year. Although humans are responsible for only a small fraction of the total exchange, that small amount affects the global system by adding a significant net flux of CO_2 to the atmosphere. Before the industrial revolution — and the large-scale combustion of fossil fuels, land-clearing and deforestation activities — the average *net* flux of CO_2 to the atmosphere hovered around zero for nearly 10,000 years. Because of the human contribution to the net flux, the amount of CO_2 in the atmosphere is now nearly 100 ppm (35%) higher today than it has been for the past 650,000 years.[50]

Congress is exploring legislative strategies that would alter the human component of the global carbon cycle. Strategies that limit emissions from fossil fuel combustion would reduce the current one-way transfer of fossil carbon to the atmosphere; what took millions of years to accumulate geologically is being released in only a few hundred years. Capturing CO_2 before it is released to the atmosphere and injecting it back into geological reservoirs — carbon capture and sequestration — is one possible strategy to “short circuit” the geologic process and return the carbon underground over a much shorter time scale. CO_2 injection into the subsurface has been used for decades to enhance recovery of oil. However, largescale geologic sequestration of CO_2 for *storage* is currently in a pilot testing stage.

Less than half of the total amount of CO_2 released from burning fossil fuels over the past 250 years remains in the atmosphere, because two huge sinks for carbon — the global oceans and the land surface — take up more carbon than they release at present. Congress is exploring if and how management practices, such as afforestation, conservation tillage, and other techniques, might increase the net flux of carbon from the atmosphere to land surface. How the ocean sink could be managed to store more carbon is unclear. Iron fertilization and deep ocean injection of CO_2 are in an experimental stage, and their promise for long-term enhancement of carbon uptake by the oceans is not well understood.

Also of possible concern to Congress is how the ocean and land surface sinks will behave over the coming decades and longer, and whether they will continue to take up more carbon than they release. For example, carbon emissions may be capped so as to keep atmospheric CO_2 concentrations below a prescribed level at some future date, but changes in the magnitude, or even the direction, of the ocean or land-surface sinks may affect whether those target concentrations can be achieved. Congress may wish to incorporate what is known about the carbon cycle into its legislative strategies. Congress may also wish to evaluate whether the global carbon cycle is sufficiently well understood that the consequences of long-term policies aimed at mitigating global climate change are fully appreciated.

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[1] World Data Centre for Greenhouse Gases (WDCGG), *WMO Greenhouse Gas Bulletin: The State of Greenhouse Gases in the Atmosphere Using Global Observations through 2005* (Geneva, Switzerland: 2006); at [http://gaw.kishou.go.jp/wdcgg.html].

[2] In addition to its climate warming effect, the buildup of CO_2 in the atmosphere is also changing the chemistry of the ocean's surface waters, a phenomenon known as ocean acidification, which could harm aquatic life.

[3] See The First State of the Carbon Cycle Report (SOCCR): The North American Carbon Budget and Implications for the Global Carbon Cycle, U.S. Science Program Synthesis and Assessment Product 2.2, ed. Anthony W. King, Lisa Dilling, Gregory P. Zimmerman, David M. Fairman, Richard A. Houghton, Gregg Marland, Adam Z. Rose, and Thomas J. Wilbanks (November 2007), p. 2, at [http://cdiac.ornl.gov/SOCCR/final.html], hereafter referred to as SOCCR. Also see the Intergovernmental Panel on Climate Change, "Working Group I Contribution to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change," Climate Change 2007: the Physical Science Basis (2007), at [http://ipcc-wg1. ucar.edu/wg1/wg1-report.html], hereafter referred to as 2007 IPCC Working Group I Report.

[4] 2007 IPCC Working Group I Report (Summary for Policymakers).

[5] Carbon in the Earth's crust is mainly in the form of carbonates, and is linked to the atmosphere by natural processes, such as erosion and weathering, and by metamorphism over geologic time scales. In contrast, the key source of fossil carbon for the purposes of this chapter are fossil fuels, which are now linked to the atmosphere almost entirely via human activities.

[6] One metric ton of carbon is equivalent to 3.67 metric tons of CO_2. A metric ton (or tonne) is 2,204.6 pounds. One billion metric tons of carbon is one gigatonne, or GtC.

[7] William H. Schlesinger, *Biogeochemistry: an Analysis of Global Change*, 2nd Ed. (San Diego, CA: Academic Press, 1997), p. 360. Hereafter referred to as Schlesinger, 1997.

[8] Schlesinger, 1997, p. 56. Larger fluctuations by season occur in the northern hemisphere.

[9] Concentrations of CO_2 are slightly higher in the northern hemisphere compared to the southern hemisphere, by several parts per million, because most of the emissions of CO2 from human activities are in the north.

[10] An exception to this is the concept of carbon capture and sequestration, whereby the geologic time scale cycle of carbon storage is "short circuited" by capturing CO_2 at its source — a fossil-fueled electricity generating plant for example — and injecting it underground into geologic reservoirs.

[11] See CRS Report RL33849, *Climate Change: Science and Policy Implications*, by Jane A. Leggett, for an explanation of the heat-trapping properties, or *radiative forcing*, of CO_2 and other greenhouse gases.

[12] Jorge L. Sarmiento and Nicolas Gruber, “Sinks for Anthropogenic Carbon,” *Physics Today* (August 2002): pp. 30-36.

[13] These massive exchanges of CO_2 between the atmosphere, oceans, and land surface result mostly from natural processes, such as photosynthesis, respiration, decay, and gas exchange between the ocean surface and the lower atmosphere.

[14] About 80% of human-related CO_2 emissions results from fossil fuel combustion, and 20% from land use change (primarily deforestation). Fossil fuel burning and industrial activities release approximately 7.2 GtC per year, land use change releases about 1.6 GtC per year (2007 IPCC Working Group I Report, pp. 501, 514-515).

[15] 2007 IPCC Working Group I Report, p. 514.

[16] Ice core data indicate that CO_2 concentrations ranged between 180 and 300 ppm over the past 650,000 years, and between 275 and 285 ppm from AD 1000 to AD 1750 (2007 IPCC Working Group I Report, p. 137 and p. 435). See also E.T. Sundquist and K. Visser, “The Geologic History of the Carbon Cycle,” in Heinrich D. Holland and Karl K. Turekian (eds.), *Treatise on Geochemistry* (Amsterdam, Netherlands: Elsevier Ltd., 2004), p. 443.

[17] 2007 IPCC Working Group I Report, pp. 514-515.

[18] That is, it does not react with other chemicals in the atmosphere. This contrasts with other greenhouse gases, such as methane (CH_4), which reacts with the hydroxl ion (OH^-) to produce water and a methyl group (CH_3); and nitrous oxide (N_2O), which is decomposed to nitric oxide (NO) in the atmosphere by its reaction with ultraviolet light.

[19] 2007 IPCC Working Group I Report, p. 515.

[20] See CRS Report RL33849, *Climate Change: Science and Policy Implications*, by Jane A. Leggett, for more information on climate feedback mechanisms.

[21] 2007 IPCC Working Group I Report, p. 515.

[22] For more information on sequestration in the agricultural and forestry sectors, see CRS Report RL31432, *Carbon Sequestration in Forests*, by Ross W. Gorte, and CRS Report RL33898, *Climate Change: The Role of the U.S. Agriculture Sector*, by Renee Johnson.

[23] 2007 IPCC Working Group I Report, p.518.

[24] 2007 IPCC Working Group I Report, p. 517.

[25] 2007 IPCC Working Group I Report, Table 7.1.

[26] 2007 IPCC Working Group I Report, p. 522. However, SOCCR (p. 5) notes that rates of forest clearing in the tropics, including Mexico, exceed rates of recovery and concludes that tropical regions dominated by rainforests or other forest types *are* a net source of carbon to the atmosphere.

[27] However, a recent study indicates that the northern latitude forests take up less carbon than previously estimated, and tropical forests take up more. See Britton B. Stephens, et al., “Weak northern and strong tropical land carbon uptake from vertical profiles of atmospheric CO_2,” *Science*, Vol. 316 (June 22, 2007): pp. 1732-1735.

[28] SOCCR, p. 25.

[29] Sarmiento and Gruber, p. 31.

[30] SOCCR, p. 29. This includes fluxes to and from land vegetation and soils, and excludes emissions from fossil fuel combustion, cement manufacturing, and other industrial processes.

[31] SOCCR, p. 32. However, SOCCR reports that the magnitude of the global terrestrial carbon sink is highly uncertain.

[32] SOCCR, p. VII.

[33] SOCCR, Table 3.1; 2007 IPCC Working Group I Report, p. 527.

[34] SOCCR, p. 27.

[35] SOCCR, p. 27. Sinks may convert to sources, for example, if melting permafrost under warming conditions releases large amounts of methane currently trapped in frozen tundra; or increased wildfires from increased drought releases large amounts of CO_2. See Christopher B. Field, et al., "Feedbacks of terrestrial ecosystems to climate change," *Annual Review of Environment and Resources*, vol. 32 (July 5, 2007): pp. 7.1-7.29.

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[37] CO_2 forms carbonic acid when dissolved in water. Over time, the solid calcium carbonate ($CaCO_3$) on the seafloor will react with, or *neutralize,* much of the carbonic acid that entered the oceans as CO_2 from the atmosphere. See David Archer, et al., "Dynamics of fossil fuel CO_2 neutralization by marine $CaCO_3$," *Global Biogeochemical Cycles*, vol. 12, no. 2 (June 1998): pp. 259-276.

[38] SOCCR, p. 26. In addition to the relative difference in CO_2 concentration between atmosphere and ocean, the rate of CO_2 dissolution also depends on factors such as wave action, wind, and turbulence.

[39] The surface waters or surface layer of the ocean is commonly characterized as the top layer of the ocean that is well mixed by waves, tides, and weather events, and is separated from the deep ocean by a difference in density. The depth of the surface layer varies, but probably averages 100-200 meters deep. See [http://www.windows.ucar.edu/tour/link=/ earth/Water/ocean_currents.html].

[40] Sarmiento and Gruber, p. 31

[41] SOCCR, p. 26.

[42] Sarmiento and Gruber, p. 31.

[43] Sarmiento and Gruber, p. 31.

[44] Corinne Le Quere et al., "Saturation of the Southern Ocean CO_2 sink due to recent climate change," *Science,* vol. 316 (June 22, 2007): pp. 1735-1737.

[45] 2007 IPCC Working Group I Report, p. 529.

[46] 2007 IPCC Working Group I Report, p. 529. pH is a measure of the concentration of hydrogen ions in solution. A lower pH means an increase in acidity, or a higher concentration of hydrogen ions. A change of one pH unit is a factor of 10 different than the next higher or lower unit. For example, a pH of 4.0 is 10 times the acidity than a pH of 5.0.

[47] Ken Caldeira, et al., "Ocean acidification due to increasing atmospheric carbon dioxide," *The Royal Society,* Policy Document 12/05 (June 2005), 60 pages; at [http://www.royalsoc. ac.uk/].

[48] The deliberate introduction of iron into the surface ocean to stimulate marine phytoplankton growth, which would increase carbon sequestration from the atmosphere via photosynthesis. The Southern Ocean, in particular, is deficient in iron as a nutrient such that the introduction of iron could stimulate phytoplankton growth. Several

experiments have been conducted or are underway to further explore this process, for example, Stephane Blain, et al., "Effect of natural iron fertilization on carbon sequestration in the Southern Ocean," *Nature*, vol. 446, no. 7139 (April 26, 2007): pp. 1070-1074.

[49] For more information about injection of CO_2 into the deep oceans, see CRS Report RL33801, *Carbon Capture and Sequestration (CCS)*, by Peter Folger.

[50] Urs Siegenthaler et al., "Stable carbon cycle — climate relationship during the Late Pleistocene," *Science*, vol. 310 (Nov. 25, 2005): pp. 1313-1317.

In: Carbon Capture and Storage Including… ISBN: 978-1-60741-196-3
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Chapter 6

ARE CARBON DIOXIDE EMISSIONS RISING MORE RAPIDLY THAN EXPECTED?[*]

Jane A. Leggett and Jeffrey Logan

SUMMARY

At least one recent report and numerous news articles suggest that carbon dioxide (CO_2) emissions are rising more rapidly than expected. This contention is often made by comparing recent emissions estimates with the greenhouse gas (GHG) scenarios published by the Intergovernmental Panel on Climate Change (IPCC) in 2000. While CO_2 emissions associated with human activities continue to rise — and may be worthy of alarm because of their influence on climate change — any short-term comparisons between actual emissions and IPCC scenarios miss the mark. First, the IPCC scenarios explicitly are not predictions. Second, the IPCC scenarios are meant to represent different possible GHG trajectories over many decades, and represent smooth emissions paths averaged over at least 10 years. Just as the actual weather over a few years is not necessarily representative of long-term climate, variability of emissions over one or several years is not necessarily representative of long-term trends. Nonetheless, monitoring of CO_2 emissions and concentrations, and analysis of the factors driving changes, is important to designing and evaluating policies to address climate change.

RISING CARBON DIOXIDE EMISSIONS

At least one recent report and numerous news articles suggest that emissions of carbon dioxide (CO_2) — the leading greenhouse gas (GHG)[1] — are rising more rapidly than expected.[2] Global CO_2 emissions associated with fossil fuel combustion in 2007 were

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[*] This is an edited, reformatted and augmented edition of a Congressional Research Service publication, Report RS22970, dated October 17, 2008.

approximately 8.1 billion metric tons of carbon, compared to estimates of 6.5 billion tons in 2000.[3] Three sources of global emissions estimates are provided in **Figure 1**. The estimates are all similar, but have some degree of uncertainty due to inconsistencies in the quality of energy data provided and estimations made by the compilers.

There has been a notable increase in the rate of growth of CO_2 emissions this decade. Data from the Energy Information Administration (EIA) indicate that global CO_2 emissions rose at an annual rate of 1.5% during the 1980s, 0.9% during the 1990s,[4] and 3.2% during the first five years of this decade. Emissions increases in 2003 and 2004 were particularly pronounced. As noted later, increased coal consumption, especially in developing countries, is one of the main drivers behind the recent surge in emissions.[5]

When CO_2 emissions accumulate in the atmosphere faster than the rate at which they are removed from the atmosphere by "sinks," atmospheric concentrations rise. Scientists have concluded that the increased concentration of greenhouse gases (GHG) over the past century, due to human activities, is likely responsible for most of the global warming observed since the 1970s, and could lead to climate changes over the next century that would be unprecedented in the course of human civilization. The potential impacts of such climate change, including the possibility of non-linear or abrupt effects, cause alarm among many scientists and citizens. Reports that CO_2 emissions may be rising more rapidly than expected often conclude, therefore, that the climate system may be changing sooner than expected.

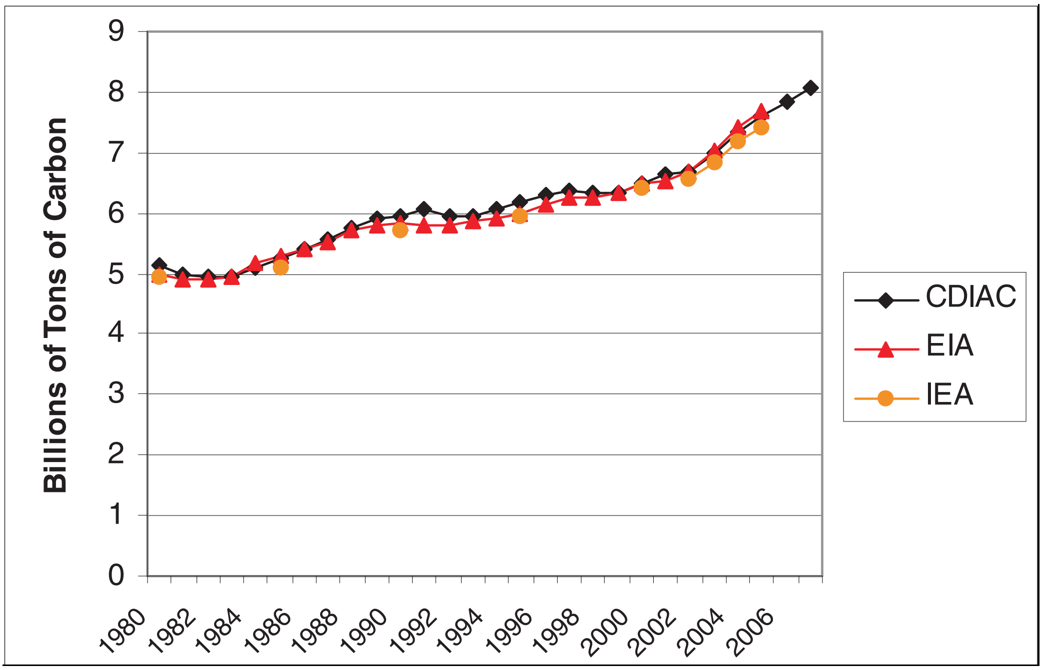
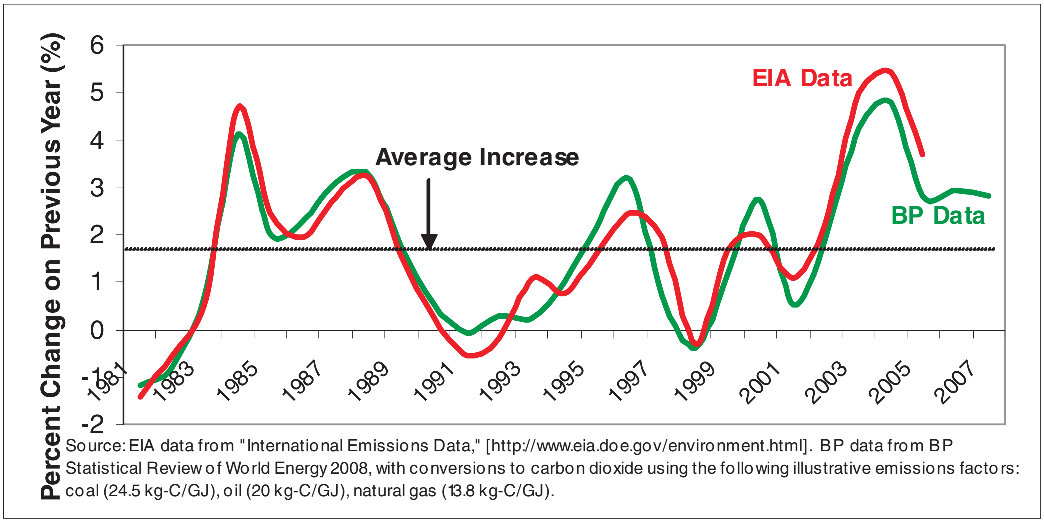


Figure 1. Global Carbon Emissions from Fossil Fuel Combustion

Source: CDIAC, Carbon Dioxide Informamation Analysis Center [http://cdiac.ornl.gov/]; EIA, Energy Information Administration [http://www.eia.doe.gov/emeu/international/carbondioxide.html]; IEA, International Energy Agency, *CO2 Emissions from Fossil Fuel Combustion 2007*



Source: EIA data from "International Emissions Data," [http://www.eia.doe.gov/environment.html]. BP data from BP Statistical Review of World Energy 2008, with conversions to carbon dioxide using the following illustrative emissions factors: coal (24.5 kg-C/GJ), oil (20 kg-C/GJ), natural gas (13.8 kg-C/GJ).

Figure 2. Estimated Annual Change in Energy-Related Global CO2 Emissions

Source: EIA data from "International Emissions Data," [http://www.eia.doe.gov/environment.html]. BP data from BP Statistical Review of World Energy 2008, with conversions to carbon dioxide using the following illustrative emissions factors: coal (24.5 kg-C/GJ), o il (20 kg-C/GJ), natural gas (13.8 kg-C/GJ).

COMPARING CO$_2$ EMISSIONS WITH ESTABLISHED SCENARIOS

Carbon dioxide emissions have been rising, almost continuously, since the beginning of the Industrial Revolution at least 120 years ago. One press report contended that “[t]he rise in global carbon dioxide emissions last year outpaced international researchers’ most dire projections”[6] — a statement drawn by comparing annual emissions for the year 2007 (or even a multi-year average from 2000 to 2007) with the GHG scenarios published by the Intergovernmental Panel on Climate Change (IPCC) in 2000.[7] While CO$_2$ emissions associated with human activities continue to rise — and may be worthy of alarm because of their influence on climate change — a comparison of one or a few years’ emissions with the IPCC emissions scenarios misses the mark.

First, the IPCC scenarios are not predictions. The IPCC’s *Special Report on Emission Scenarios*[8] (SRES), which produced the CO$_2$ emissions estimates cited above, stated “[s]cenarios are alternative images of how the future might unfold and are an appropriate tool with which to analyze how driving forces may influence future emission outcomes and to assess the associated uncertainties. The possibility that any single emissions path will occur as described in the scenarios is highly uncertain.” While observed increases in CO$_2$ emissions merit attention and concern, comparing annual or short-term multi-year emissions with the IPCC GHG scenarios reflects misunderstanding or mischaracterization of the IPCC scenarios (and the models that produce them).

Second, the IPCC exercises are intended to produce scenarios (not predictions) over multiple decades and to provide only long-term averages. The “time steps” of model outputs from the six models that produced the "illustrative scenarios" typically is 5 to 10 years, represented by the reporting of outcomes for 2000, 2010, 2020, etc. Even with these long periods between model outputs, the scenarios are meant to provide conceptual results over multi-decadal periods, not predictions for a year or a particular decade. As the SRES report states, "[t]he modeling tools that have been used to develop these scenarios that focus on the century time scale are less suitable for analysis of near term (a decade or less) developments."[9] In addition, the assumptions and parameters used in modeling will change over time, creating value in updating the scenarios periodically.

Normal inter-annual and inter-decadal variability of actual energy use and resulting CO_2 emissions would be expected to produce yearly emission values that fall both above and below multi-year averages. For example, although recent economic growth in China and India may have been higher than projected in the first part of this decade, those rates may drop below the projected level (perhaps substantially) due to the current and expected economic adjustments. Figure 2 provides estimates of recent annual changes in energyrelated global CO_2 emissions. The average annual rate of increase between 1981 and 2005 was about 1.8%, but clear cyclical patterns are evident. In 1981, global emissions declined by 1.4%. In 2004, they rose by 5.5%.

Economies routinely experience cycles of faster and slower growth; the GHG emissions associated with these cycles normally fluctuates as well (if policies controlling emissions remain constant). China, whose emissions have contributed substantially to recent global CO_2 increases, is also likely to experience periodic increases and slowdowns in emissions. After a recent period of very strong growth, Chinese officials now expect a period of slower emissions growth over the next few years.[10]

Comparisons with the IPCC Scenarios

Returning to the question of whether recent carbon dioxide emission trends are higher than IPCC forecasts, Figure 3 shows recent CO_2 emissions (including from cement production) compared to IPCC scenarios. The figure displays the six official IPCC "illustrative scenarios," represented by solid lines. It also displays six "averaged" IPCC scenarios represented by dashed lines that were introduced by the Global Carbon Project (GCP), whose "Carbon Budget 2007" report was cited in the media.[11] The dashed lines are the numerical averages of all model results for each of the IPCC scenario storylines.[12] The IPCC did not calculate or publish such averaged results; rather, the IPCC illustrative scenarios were chosen as best representing each of the scenario storylines.[13] The SRES illustrative scenarios intentionally did not use all the models' results because of certain models' limitations and other reasons.

The GCP averaged all models' results for each scenario rather than using the IPCC's "most representative" model results when saying that "[t]his makes current trends in emissions higher than the worst case IPCC-SRES scenario."[14] The GCP statement is true only when comparing emissions with its averaged model results, not those published by the IPCC. Recent emissions are below the A1B illustrative scenario and the top of the range IPCC found in published research literature.

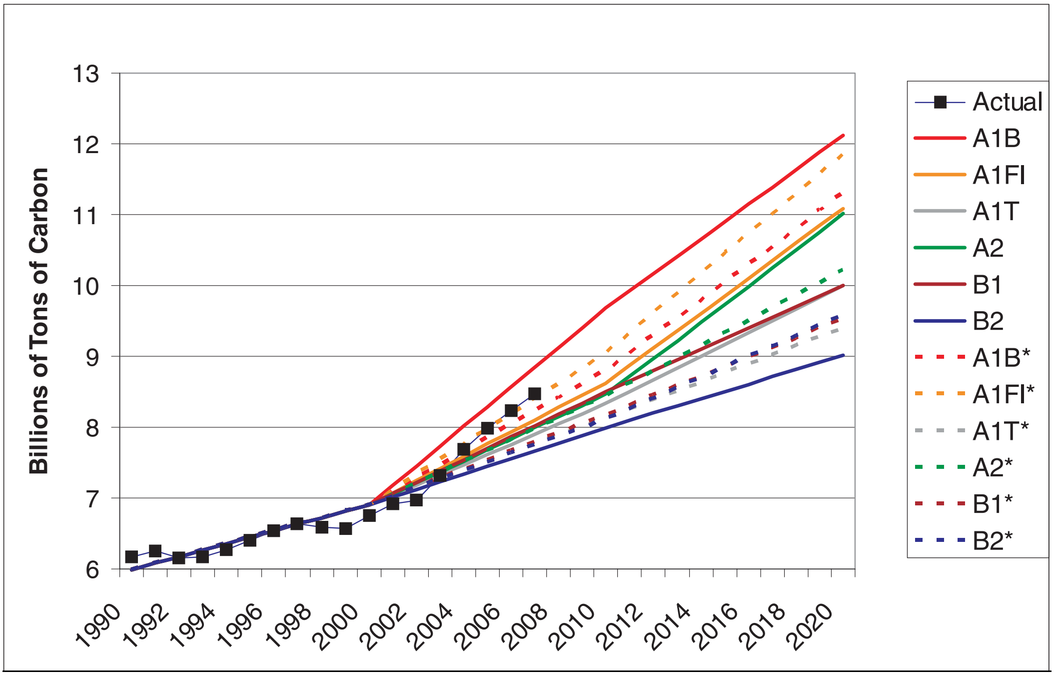


Figure 3. Comparison of Actual Carbon Emissions with SRES Illustrative and Average* Scenarios

Note: * and dashed lines represent averaged scenarios used by the Global Carbon Project. Solid lines are IPCC illustrative scenarios. Source: Observed emissions from Carbon Dioxide Information and Analysis Center, "Latest Published Global Estimates," and "2006-2007 Global and National Estimates by Extrapolation," [http://cdiac.ornl.gov/trends/emis/meth_reg.html]. SRES scenario data from [http://www.ipcc.ch/ipccreports/sres/emission/index.htm].

Moreover, comparing recent emissions with the IPCC scenarios is not, in itself, adequate to understand future global GHG trajectories. Although the SRES A1B scenario has the highest GHG emissions in the near term of all the IPCC illustrative scenarios, its assumptions result in emissions beyond 2050 that are far below some other scenarios (like A1F, which has lower near-term emissions). Understanding the factors driving emissions in the short- and long-run is more revealing than comparing current emissions with scenarios.

Monitoring Emissions Trends

Watchfulness over annual CO2 and other GHG emissions is a vital element of addressing climate change and evaluating the effectiveness of actions to mitigate it, and it is important to use appropriate data in monitoring progress. Evaluating recent trends may help to discern which future GHG emission paths are most likely and why.[15] For example, recent population growth has been lower than many of the SRES scenarios, while the use of some low-emission technologies (e.g. low emissions vehicles, wind power, etc.) has been faster than in many of the scenarios. The combined effects of such differences, however, require complex analysis.

Both the Environmental Protection Agency (EPA) and the Energy Information Administration (EIA), in cooperation with additional federal agencies, track CO_2 and other GHG emissions and evaluate the factors that influence inter-annual variability and longer-term trends. Several international entities provide similar services, including the International Energy Agency, the World Bank, and BP (formerly British Petroleum). The EPA and EIA also analyze how changes in the factors driving GHG emissions may affect understanding of future climate trajectories. Some analysts believe, however, that the EPA and EIA do not have adequate funding to analyze sufficiently how policies may influence emissions and climate trajectories.

In sum, the past few years of exceptionally high growth may not provide a good basis for setting expectations for emissions rates in the coming few years or in the long run. Other changes, including the rate of growth in the global economy, emission control policies and regulations, and the specific technologies drawing investment, may provide greater insights into future GHG trajectories. Monitoring these factors, and how they may be determining future emissions and climate paths, remains important as input to policymaking to address climate change.

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[3] Carbon dioxide emissions presented in figures are measured in metric tons of carbon. Carbon measurements can be converted to carbon dioxide units after multiplying by 3.67, the ratio of the molecular weights of carbon dioxide to carbon.

[4] The GHG emissions of the 1990s were strongly influenced by the collapse of the former Soviet Union and Eastern European economies, as well as by restructuring of the energy systems in the United Kingdom.

[5] International Energy Agency, "CO_2 Emissions from Fuel Combustion," 2007. p. xix.

[6] Eilperin, J. sop. cit.

[7] The International Panel on Climate Change is a panel established by national governments that assesses scientific research and publishes consensus findings for use by national policy-makers and the public. The IPCC published *Special Report on Emissions Scenarios* in 2000. For more information, see [http://www.ipcc.ch/].

[8] Nakicenovic, Nebojsa, et al. 2000. *Special Report on Emissions Scenarios*. Published for the Intergovernmental Panel on Climate Change by Cambridge University Press.

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[11] J. Eilperin, op. cit.

[12] More information on the A1, A2, B1, and B2 scenarios is available in the IPCC's *Special Report on Emissions Scenarios* at [http://www.ipcc.ch/ipccreports/sres/ emission/index.htm]. The IPCC report notes 40 individual simulations in the A1, A2, B1, and B2 family of scenarios: 17 model runs used in the A1 scenario, six in the A2 scenario, nine in B1, and eight in B2.

[13] However, some of the six models used to analyze the storylines were better able than others to represent certain storylines; some models could not produce results consistent with certain storyline assumptions. This is one reason that all the model results for a scenario were not averaged, but the "most representative" was selected for publication.

[14] [http://www.globalcarbonproject.org/carbontrends/index.htm]

[15] For more discussion of factors that drive long-term GHG trends, see CRS Report RL33970, *Greenhouse Gas Emission Drivers: Population, Economic Development and Growth, and Energy Use*, by John Blodgett and Larry Parker.

In: Carbon Capture and Storage Including…
Editor: T. P. Carington, pp. 123-172

ISBN: 978-1-60741-196-3

Chapter 7

CLIMATE CHANGE: FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION*

United States Government Accountability Office

WHY GAO DID THIS STUDY

Key scientific assessments have underscored the urgency of reducing emissions of carbon dioxide (CO_2) to address climate change. Many have cited carbon capture and storage (CCS) as an essential technology because it has the potential to greatly reduce CO_2 emissions from power plants while allowing for projected increases in electricity demand. CCS involves capturing CO_2 from a power plant's emissions, transporting it to an underground storage location, and then injecting it into a geologic formation for long-term storage.

As requested, GAO examined (1) key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of CCS technology and (2) actions the Department of Energy (DOE), Environmental Protection Agency (EPA), and other agencies are taking to overcome barriers to commercial-scale deployment of CCS technology. Among other things, GAO examined key studies and contacted officials from pertinent agencies, companies, and environmental groups, as well as research and other organizations.

WHAT GAO RECOMMENDS

Among GAO's recommendations are that (1) DOE continue to place greater emphasis on CO_2 capture at existing power plants and (2) EPA examine how its statutory authorities can be used to address potential CCS barriers. DOE neither explicitly agreed nor disagreed with

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* Excerpted from GAO Report GAO-08-1080, dated September 2008.

the first recommendation. EPA expressed general agreement with the second recommendation.

WHAT GAO FOUND

Nationally-recognized studies and GAO's contacts with a diverse group of industry representatives, nongovernmental organizations, and academic researchers show that key barriers to CCS deployment include (1) underdeveloped and costly CO_2 capture technology and (2) regulatory and legal uncertainties over CO_2 capture, injection, and storage. Key technological barriers include a lack of experience in capturing significant amounts of CO_2 from commercial-scale power plants and the significant cost of retrofitting existing plants that are the single largest source of CO_2 emissions in the United States. Regulatory and legal uncertainties include questions about liability concerning CO_2 leakage and ownership of CO_2 once injected. According to the National Academy of Sciences and other knowledgeable authorities, another barrier is the absence of a national strategy to control CO_2 emissions (emissions trading plan, CO_2 emissions tax, or other mandatory control of CO_2 emissions), without which the electric utility industry has little incentive to capture and store its CO_2 emissions. Moreover, according to key agency officials, the absence of a national strategy to control CO_2 emissions has also deterred their agencies from resolving other important practical issues, such as how sequestered CO_2 will be transported from power plants to appropriate storage locations and how stored CO_2 would be treated in a future CO2 emissions trading plan.

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- *DOE's* research strategy has, until recently, devoted relatively few resources to lowering the cost of CO_2 capture from existing coal-fired power plants, focusing instead on innovative technologies applicable to new plants. In recent years, however, the agency has begun to place greater emphasis on CCS technologies applicable to existing facilities.

- *EPA* issued in July 2008 a proposed rule to guide the permitting of large volume, or commercial-scale, CO_2 injections. It addressed at least some of the key issues under the Safe Drinking Water Act but left other issues related to EPA's implementation of its air, hazardous waste and substance statutes unresolved.
- *Other agencies*, such as Interior and Transportation, have jurisdiction over a number of interdisciplinary issues that could delay CCS deployment if unaddressed, but which have thus far received little attention. These include, among others, a legal and regulatory regime for a national CO_2 pipeline infrastructure and a plan for addressing CO_2 emissions reductions from CCS in a future emissions trading plan. In addition, unless the effects of CCS deployment are clearly explained, public opposition could delay future CCS projects.

ABBREVIATIONS

AoR	Area of Review
BLM	Bureau of Land Management
CCS	carbon capture and storage
CCTP	Climate Change Technology Program
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CO_2	carbon dioxide
DOE	Department of Energy
EPA	Environmental Protection Agency
ETS	Emissions Trading Scheme
EU	European Union
FERC	Federal Energy Regulatory Commission
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
MIT	Massachusetts Institute of Technology
NSR	New Source Review
PHMSA	Pipeline and Hazardous Materials Safety Administration
RCRA	Resource Conservation and Recovery Act
SDWA	Safe Drinking Water Act
SO_2	sulfur dioxide
STB	Surface Transportation Board
UIC	Underground Injection Control
UNFCCC	United Nations Framework Convention on Climate Change
USGS U.S.	Geological Survey

September 30, 2008

The Honorable Edward Markey
Chairman
Select Committee on Energy Independence and Global Warming
House of Representatives

Dear Mr. Chairman:

Key scientific assessments have underscored the urgency of reducing emissions of carbon dioxide (CO_2), the most significant greenhouse gas, to help mitigate the negative effects of climate change. Given the United States' heavy reliance on coal-burning power plants that emit significant quantities of CO_2, many have cited carbon capture and storage (CCS) as an essential technology because it can greatly reduce CO_2 emissions from these facilities, while allowing for projected increases in electric power demand.[1] CCS is a process of separating CO_2 from other gases produced in fuel combustion and other industrial processes, transporting the CO_2 via pipeline to an underground storage location, and injecting and storing it long-term in underground geologic formations.

While other climate mitigation options exist—such as energy efficiency improvements, a switch to less carbon-intensive fuels, nuclear power, and renewable energy sources—CCS is considered by many to be a crucial component of any U.S. approach or strategy for addressing the climate change problem, particularly given the United States' current reliance on coal for almost half of its electricity production. Moreover, there is a large potential role for CCS in rapidly developing countries, such as China and India, which will be relying increasingly on coal to meet their energy needs. In fact, as of 2007, Chinese CO_2 emissions likely exceeded those of the United States, according to the International Energy Agency (IEA).[2]

The IEA projects continued growth in CO_2 emissions from China and other developing economies.

At present, there are few commercial-scale CCS projects in operation. While recent assessments by the IEA and the Intergovernmental Panel on Climate Change (IPCC) have indicated that CCS could be a key contributor to controlling greenhouse gas emissions worldwide,[3] a number of barriers may preclude its widespread use. Therefore, many organizations, including the IEA, emphasize that it will be critical to overcome these barriers and demonstrate the feasibility of this technology. In this context, this chapter examines (1) the key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of CCS technology and (2) the actions federal agencies are taking to overcome barriers to or facilitate the commercial-scale deployment of CCS technology.

To examine barriers to CCS, we conducted a literature review and synthesized CCS-related information contained in a number of key reports, including those by the IPCC, the National Academy of Sciences, and by various federal agencies. We also contacted a nonprobability sample of electric power companies, major oil and gas companies, CO_2 pipeline owners, environmental organizations, and researchers at think tanks and universities to determine their perspectives on key barriers to CCS deployment at commercial scale. We selected major U.S. energy producing companies, as well as organizations and researchers that participate actively in ongoing dialogues on CCS. We also selected a number of smaller companies and organizations to ensure that we obtained a broader range of perspectives on key issues.[4] We used a semistructured interview guide to (1) obtain information from individual stakeholders on key barriers to CCS deployment at commercial scale and (2) facilitate an aggregate analysis of stakeholder perspectives on key barriers to CCS.

To examine federal actions to address CCS barriers, we obtained and analyzed information from the Environmental Protection Agency (EPA), the Department of Energy (DOE), and other federal agencies regarding their CCS-related activities. We collected 12 years of budget information from DOE's Coal Program and followed up on recommendations contained in two recent EPA and DOE advisory committee reports. We also attended two EPA Underground Injection Control program workshops and followed up with EPA officials on stakeholder concerns expressed at these meetings. Using the methodology described for our first objective, we obtained the perspectives of industry stakeholders, environmental organizations, and researchers at think tanks and universities on federal agency actions to overcome barriers to, or to facilitate deployment of, commercial-scale CCS in the United States. We conducted this performance audit from October 2007 to September 2008 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

RESULTS IN BRIEF

Nationally-recognized studies and our contacts with a diverse group of industry representatives, nongovernmental organizations, and academic researchers show that key barriers to CCS deployment include (1) underdeveloped and costly CO_2 capture technology and (2) regulatory and legal uncertainties over CO_2 capture, injection, and storage. Among the key technological barriers are a lack of experience in capturing significant amounts of CO_2 from power plants and the significant cost of capturing CO_2, particularly from existing coal-fired power plants, which are the single largest source of CO_2 emissions in the United States. Compounding these technological issues are regulatory and legal uncertainties, including uncertainty regarding liability for CO_2 leakage and ownership of CO_2 once injected. According to the IPCC, the National Academy of Sciences, and other knowledgeable authorities, another barrier is the absence of a national strategy to control CO_2 emissions (emissions trading plan, CO_2 emissions tax, or other mandatory control of CO_2 emissions), without which the electric utility industry has little incentive to capture and store its CO_2 emissions. Moreover, according to key agency officials, the absence of a national strategy has also deterred their agencies from addressing other important practical issues, such as resolving how stored CO_2 would be treated in a future CO_2 emissions trading plan.

Federal agencies have begun to address some CCS barriers but have yet to comprehensively address the full range of issues that would require resolution for commercial-scale CCS deployment:

- *Key technological barriers*. DOE has achieved limited results in lowering the cost of CO_2 capture from existing coal-fired power plants. A major reason is that the agency has focused on "Integrated Gasification Combined Cycle" (IGCC) technology, a promising technology for new coal-fired power plants, but one that is less useful when applied to existing coal power plants. The agency has only recently begun to shift toward an approach that also emphasizes CCS technologies applicable to existing power plants.
- *Key legal and regulatory barriers*. The EPA issued a proposed rule in July 2008 concerning underground injection of CO_2 for geologic sequestration. Because of the large injection volumes associated with geologic sequestration, this proposed rule would apply to commercial-scale injections. The proposed rule was issued under the agency's Safe Drinking Water Act (SDWA) authority. However, some issues that fall outside of this authority are still unresolved. These include whether and how the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and the Resource Conservation and Recovery Act (RCRA) apply to injected CO_2. Also unresolved are issues concerning how the Clean Air Act's requirements will apply to existing power plants that install CCS.
- *Other considerations*. Even if the DOE- and EPA-related issues are resolved, there are a number of issues, many of which cross the jurisdictions of multiple agencies, that could delay CCS deployment if not addressed in a timely fashion. These include whether the federal government could be held liable if CO_2 stored below public lands leaked onto adjoining nonfederal property. In addition, a number of federal agencies (such as the Federal Energy Regulatory Commission, the Surface Transportation Board, Department of Transportation, DOE, and EPA) will need to work together to examine how CO_2 pipeline infrastructure might be regulated to accommodate commercial-scale CCS. Others will need to devise a plan for how CO_2 emissions reductions from CCS will be treated in a future emissions trading scheme.

We are making a number of recommendations to agencies with major CCS-related responsibilities to address key barriers to CCS deployment. To better ensure that DOE's research and development efforts address CCS at both new coal-fired power plants and existing plants, we are recommending that DOE continue its recent practice of placing a greater emphasis on technologies that can reduce CO_2 emissions from existing coal-fired power plants. In commenting on a draft of this chapter, DOE's September 9, 2008, letter neither explicitly agreed nor disagreed with this recommendation but included a number of comments that recognized a need for increased funding for CO_2 emissions control technologies for existing coal-fired power plants.

To enhance EPA's ability to address barriers that may be affecting CCS deployment, we are recommending that EPA more comprehensively examine barriers to CCS development beyond those relevant to the SDWA, by addressing issues under RCRA, CERCLA, and other statutes within the agency's jurisdiction. EPA's September 12, 2008, letter responded that providing regulatory certainty on issues related to geological storage of CO_2 was a high priority for the agency and agreed with the intent of the recommendation—to provide clarity on how statutes within the agency's jurisdiction may apply. The agency noted that it had made an initial effort to identify and discuss these issues in the preamble of its July 2008 proposed rulemaking and had requested comments on many of the SDWA topics—including some of those identified in our report. It said it expected further progress on the SDWA topics after receiving input from stakeholders during the comment period (which extends through November 24, 2008).

Finally, we are recommending that an interagency task force (or similar mechanism) be established to develop a comprehensive strategy that guides cognizant federal agencies in resolving remaining issues that, if not addressed proactively, could impede commercial-scale CCS deployment. DOE maintained that a coordinating body—the DOE-led Climate Change Technology Program (CCTP)—already addresses these kinds of issues. However, the CCTP's scope focuses on technology; it does not address legal and institutional issues, such as the resolution of CO_2 pipeline regulation and infrastructure, among others. In addition, officials from cognizant offices within the Departments of the Interior and Transportation told us they have not yet been invited to participate in CCTP discussions. Moreover, we continue to believe that a more centralized task force with a broader mission, perhaps authorized by the Executive Office of the President, would be a preferable alternative.

DOE's and EPA's comments are addressed at the end of this letter and reproduced in appendixes II and III, respectively (along with our responses to each of their main points). The agencies also provided technical comments separately, which have been incorporated in our final report, as appropriate. In addition, we sought and received clarification and verification on specific issues from the Department of the Interior's Bureau of Land Management and U.S. Geological Survey; the Department of Transportation's Pipeline and Hazardous Materials Safety Administration; the Federal Energy Regulatory Commission; and the Surface Transportation Board, and have incorporated their input in finalizing the report.

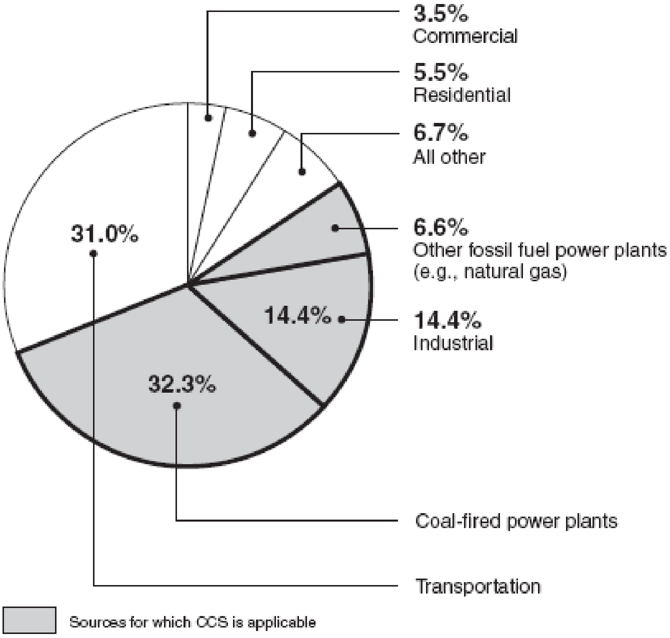
BACKGROUND

There is growing concern about climate change and the impact it will have on people and the ecosystems on which they depend. According to the National Academy of Sciences, global temperatures have already risen 1.4 degrees Fahrenheit since the start of the 20th century—with much of this warming occurring in the last 30 years alone—and temperatures will likely rise at least another 2 degrees Fahrenheit, and potentially more than 11 degrees, over the next 100 years. This warming will cause significant changes in sea level, ecosystems, and ice cover, among other impacts. In the Arctic region, temperatures have increased almost twice as much as the global average, and the landscape is changing rapidly. Most scientists agree that the warming in recent decades has been caused primarily by human activities that have increased the amount of greenhouse gases in the atmosphere. Greenhouse gases, such as CO_2, have increased markedly since the Industrial Revolution, mostly from the burning of fossil fuels for energy, industrial processes, and transportation. According to the National Academy of Sciences, CO_2 levels are at their highest in at least 650,000 years and continue to rise.

In 1992, the first major multilateral treaty on global warming, the United Nations Framework Convention on Climate Change (UNFCCC), was finalized. One hundred ninety-two countries, including the United States, have ratified this treaty and agreed to its objective to "achieve…stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." The UNFCCC required signatory states to publish greenhouse gas emission levels; formulate a national response to climate change; and develop and distribute technologies to control, reduce, or prevent greenhouse gas emissions. However, its mitigation provisions focused on voluntary efforts by signatory states. Under the Kyoto Protocol to the UNFCCC, 37 industrialized countries have agreed to reduce or limit their greenhouse gas emissions by an average of 5 percent below 1990 levels between 2008 and 2012. Also, in 2005, the European Union (EU) began implementing its Emissions Trading Scheme (ETS), a program that limits CO_2 emissions in each member state and is intended to help states achieve their commitments under the Kyoto Protocol. Many countries with significant greenhouse gas emissions, including the United States, China, and India, have not committed to binding limits on emissions through the Kyoto Protocol or other mechanisms as of the date of this chapter. Despite the UNFCCC's ratification, global annual fossil fuel-related CO_2 emissions increased from an average of approximately 23.5 billion metric tons of CO_2 per year in the 1990's to approximately 26.4 billion metric tons of CO_2 per year from 2000 to 2005.[5]

A complicating factor in addressing this increase in temperature is the heavy reliance by the United States and other countries on coal-fired power plants for electric power generation. Coal accounts for about half of electricity generation in the United States. Moreover, according to the IEA, coal is used to produce more than half of several other nations' electricity, including South Africa, Poland, China, Australia, and India.

Coal-fired power plants are one of the largest sources of CO_2 emissions. In the United States, coal-fired power plants account for approximately one-third of total CO_2 emissions. Figure 1 shows total U.S. CO_2 emissions, what portions are from each sector of the economy, and sources where CCS could more readily be used.[6]



Source: GAO analysis of data from the Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006 (April 2008).

Figure 1. Contribution of Coal-Fired Power Plants and Other Sources to Total U.S. CO_2 Emissions.

To complicate matters further, increased energy demands are projected for the future, both in the United States and worldwide. The IEA projects that if governments around the world proceed with current policies, the world's energy needs would be over 50 percent higher in 2030 than today.[7] For the United States, an assessment by DOE's Energy Information Administration indicates that electricity sales will increase 29 percent by 2030, if current policies continue. Moreover, the IEA anticipates that the two largest developing countries—China and India—will drive increased demand for coal to meet growing electricity demand. The IEA notes that China and India's heavy reliance on coal has already contributed significantly to recent increases in global CO_2 emissions, with China likely overtaking the United States as the largest CO_2 emitter in 2007.

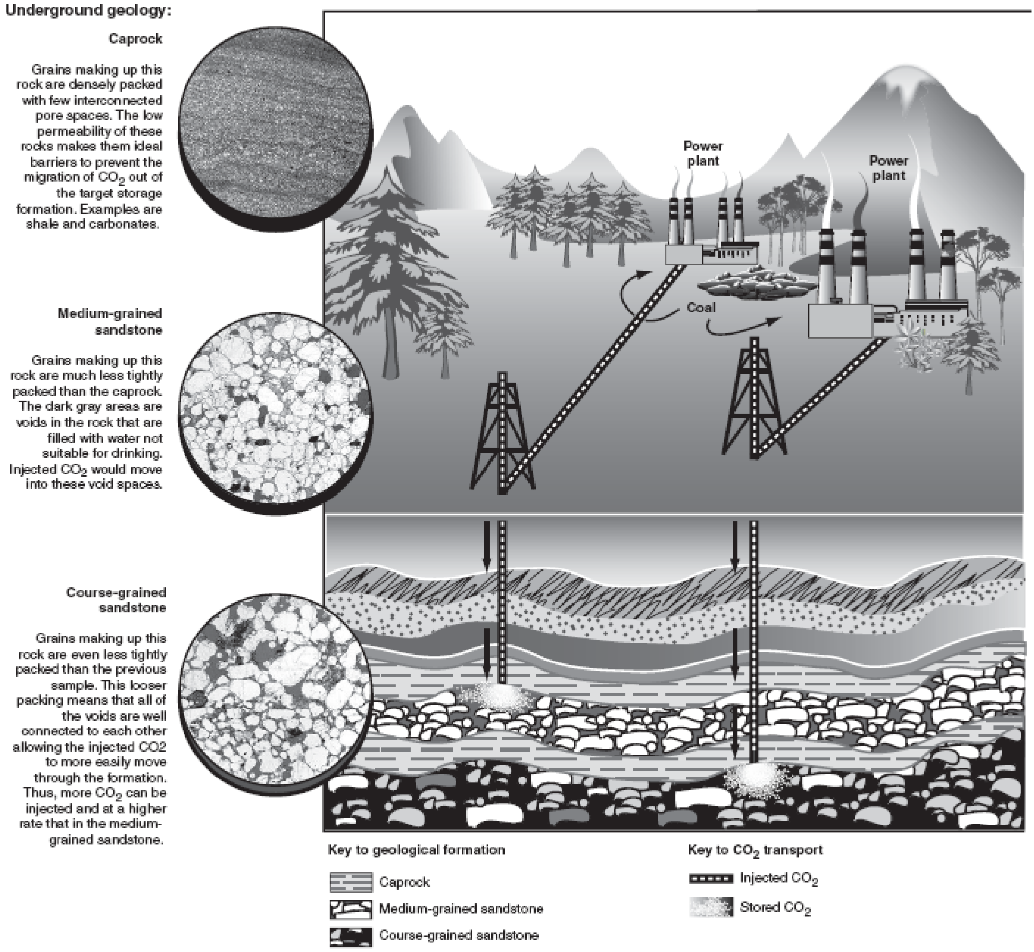
In order to prevent this dramatic increase in coal-based energy production from emitting significant amounts of CO_2 to the atmosphere, many are suggesting CCS as a unique tool that allows for continued coal use, while mitigating its associated effect on the climate. The IEA identifies CCS and other clean coal technologies as one of the most promising routes for mitigating emissions and notes that "CCS could reconcile continued coal burning with the need to cut emissions in the longer term." Similarly, the IPCC notes that CCS would help preserve existing energy infrastructure, thereby restraining the cost of emissions reductions. Looking ahead, the IEA projects that CCS could contribute to 21 percent of avoided emissions to stabilize atmospheric CO_2 concentrations at 450 parts per million, a level which is projected to limit the average increase in global temperature to 2.4 degrees Celsius (4.3 degrees Fahrenheit).

The EU is also beginning to highlight the importance of CCS in addressing climate change. In 2008, the EU proposed legislation, known as a proposed directive, on the geological storage of CO_2 that would support the EU policy of limiting global average temperature increases to less than 2 degrees Celsius (3.6 degrees Fahrenheit). Specifically, in 2007, the European Council urged EU member states and the European Commission to develop the necessary technical, economic, and regulatory framework to remove existing legal barriers to CCS so that the technology can be applied to new fossil fuel power plants by 2020, if possible. The following year, the European Commission proposed legislation that would create a legal framework for capture, transport, and geological storage of CO_2 within member states' territories.

CCS is comprised of multiple processes, including CO_2 capture and compression; transport of the CO_2 to a storage location; injection and storage in geologic formations; and monitoring to verify that the CO_2 is staying in place. A successful CCS system must integrate all of them. The first step in CCS is identifying and verifying a suitable location for CO_2 storage. Next, CO_2 would be captured at power plants and other large industrial sources. The goal of CO_2 capture is to produce a concentrated stream of nearly pure CO_2 at high pressure so that it can be transported via pipeline to a storage site. Regardless of the capture approach used, additional energy, often referred to as the energy penalty, is required for capture and compression. Three major approaches to capturing or separating CO_2 from industrial sources have been identified—pre-combustion capture, post-combustion capture, and oxyfuel combustion capture.[8]

After CO_2 capture and compression, the compressed gas, now in a supercritical state,[9] would likely be transported via pipeline to a storage site, unless a storage site was available at the capture facility. Once at a storage site, the CO_2 would likely be injected well below the surface, at depths of over 800 meters, or about 2,600 feet, into geologic formations thought to be conducive for long-term sequestration (that is, hundreds to thousands of years) from the atmosphere. When injected, the CO_2 is sequestered by a combination of physical and geochemical trapping processes.

Physical trapping occurs because the relatively buoyant CO_2 reaches a layer of rock that inhibits further upward migration. Geochemical trapping occurs when the CO_2 reacts chemically with minerals in the geologic formation that result in the precipitation of solid minerals. Geologic formations, such as depleted oil and gas reservoirs and saline formations, are thought to be particularly favorable for CO_2 storage. These formations tend to have high porosity, or an abundance of pores for CO_2 to fill in, and an impermeable barrier, known as a solid caprock, to keep the buoyant CO_2 from migrating to the surface. Figure 2 depicts CO_2 capture, transport, and storage in geologic formations and highlights the characteristics of caprock and the underlying rock that are favorable for CO_2 storage. DOE and IEA estimates indicate that the United States has appropriate geology that could potentially store over 3 trillion tons of CO_2—enough to store 1,000 years of CO_2 emissions from nearly 1,000 coal-fired power plants.



Underground geology:

Caprock

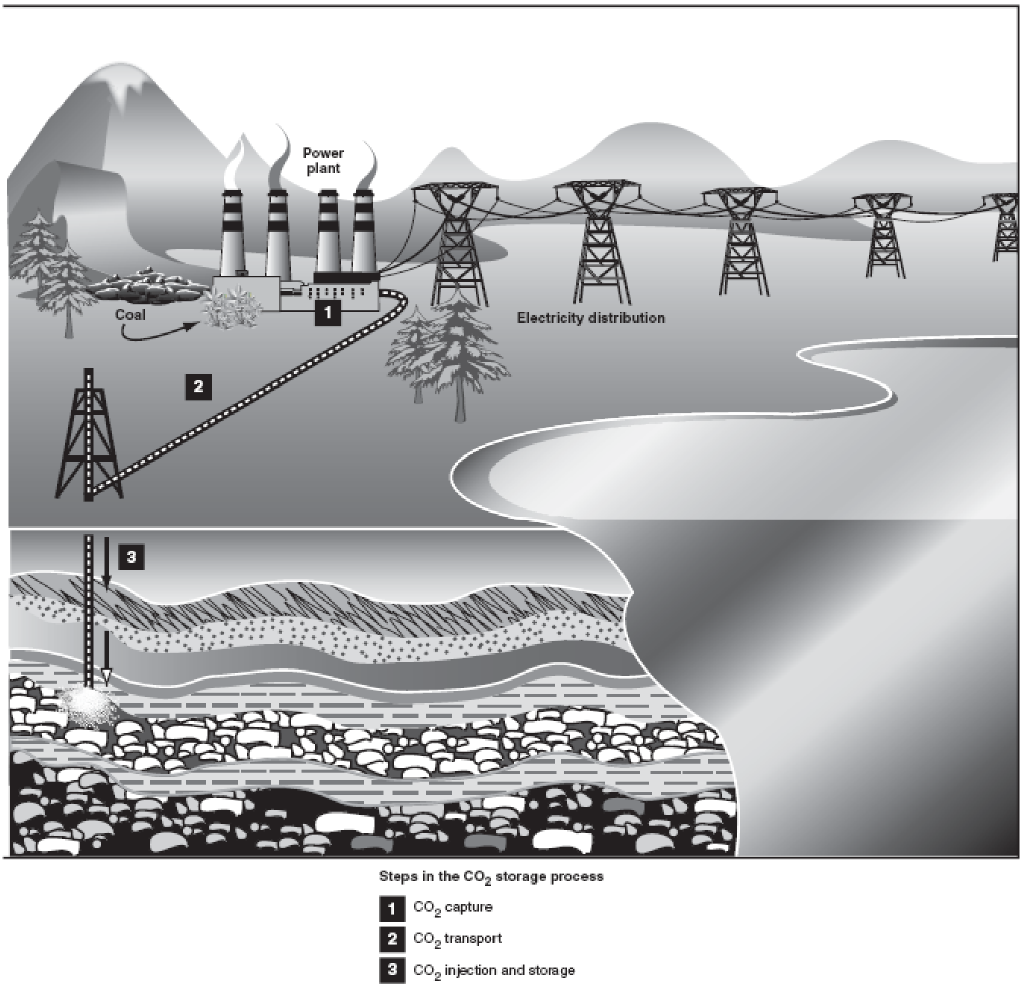
Grains making up this rock are densely packed with few interconnected pore spaces. The low permeability of these rocks makes them ideal barriers to prevent the migration of CO_2 out of the target storage formation. Examples are shale and carbonates.

Medium-grained sandstone

Grains making up this rock are much less tightly packed than the caprock. The dark gray areas are voids in the rock that are filled with water not suitable for drinking. Injected CO_2 would move into these void spaces.

Course-grained sandstone

Grains making up this rock are even less tightly packed than the previous sample. This looser packing means that all of the voids are well connected to each other allowing the injected CO2 to more easily move through the formation. Thus, more CO_2 can be injected and at a higher rate that in the medium-grained sandstone.



Source: GAO analysis of IPCC and Joint Global Change Research Institute, Battelle Pacific Northwest Division data.

Figure 2. CO_2 Capture, Transport, and Storage in Geologic Formations.

Multiple federal agencies have programs and other responsibilities that will affect CCS deployment, but the key ones are administered primarily by DOE and EPA:

- DOE is the lead federal agency for supporting the development of clean coal technology, including CCS technology. The agency established the Carbon Sequestration program in 1997 to ascertain the technical viability of CCS. The core research and development in the program involves laboratory and pilot-scale research in areas that include CO_2 capture and storage. The demonstration and deployment element of the program is designed to show the viability of CCS technologies at a scale large enough to overcome real and perceived infrastructure challenges. In order to do so, DOE established a network of seven Regional Carbon Sequestration Partnerships to develop the technology, infrastructure, and regulations necessary to implement CO_2 storage in different regions of the nation. Other DOE programs are also developing technologies related to coal-fueled power generation with CO_2 capture; including (1) the Advanced Integrated Gasification Combined Cycle (IGCC) program to support development of gasification technology to enable CO_2 capture; (2) the restructured FutureGen program to demonstrate IGCC or other advanced coal technology, as well as CO_2 capture; (3) the Innovations for Existing Plants program, which has recently focused more attention on developing technology to facilitate CO_2 capture at existing coal-fired power plants; and (4) the Clean Coal Power Initiative, which is supporting advanced coal-based technologies that capture and sequester CO_2 emissions.

- EPA has authority under the SDWA to regulate underground injections of various substances, including nonhazardous and hazardous wastes into injection wells. Injection wells have a range of uses that traditionally include waste disposal, enhancing oil production, and mining. The SDWA requires EPA to develop minimum federal requirements for injection practices that protect public health by preventing injection wells from endangering underground sources of drinking water. There are five different well types: Class I (injections of hazardous wastes, industrial nonhazardous wastes, municipal wastewater); Class II (injections associated with enhanced oil and gas production); Class III (injections associated with mineral extraction); Class IV (now mostly banned,[10] but formerly, to inject hazardous or radioactive waste above or into an underground source of drinking water); and Class V (wells not included in other classes, including wells used in experimental technologies, such as pilot CO_2 storage).[11] EPA has given 33 states primacy, or primary enforcement responsibility, to administer the Underground Injection Control (UIC) program, and 7 states have partial responsibility for administering the UIC program.[12]
- The prospect of widespread, nationwide use of CCS would also require the involvement of other agencies with varied responsibilities. The Department of the Interior's Bureau of Land Management, for example, would have broad jurisdiction over CO_2 injected on public lands. Whether the Federal Energy Regulatory Commission or the Surface Transportation Board would have regulatory responsibilities for pipelines transporting captured CO_2 is an issue that needs to be resolved. The CCTP, authorized by the Energy Policy Act of 2005, is tasked with assisting the interagency coordination of climate change technology research, development, demonstration, and deployment. Because the CCTP coordinates interagency discussion of climate change technology issues, it will likely also be involved in any ongoing interagency dialogue on CCS deployment.

BARRIERS TO CCS DEPLOYMENT INCLUDE THE HIGH COST OF CURRENT TECHNOLOGIES, REGULATORY UNCERTAINTY, AND THE LACK OF A NATIONAL STRATEGY TO CONTROL CO_2 EMISSIONS

Nationally-recognized studies and our contacts with a diverse group of industry representatives, nongovernmental organizations, and academic researchers show that key barriers to CCS deployment include (1) the high cost of, and lack of experience with, CO_2

capture technologies and (2) regulatory uncertainties concerning CO_2 capture, injection, and storage. Among the technological barriers impeding CCS deployment at coal-burning power plants are the significant cost of retrofitting existing coal-fired power plants and lack of commercial-scale demonstrations. Compounding these technological issues are uncertainties over regulatory and legal issues, including legal uncertainty regarding liability for CO_2 leakage and ownership of CO_2 once injected. According to the IPCC, the National Academy of Sciences, and other knowledgeable authorities, another barrier is the absence of a national strategy to control CO_2 emissions (emissions trading plan, CO_2 emissions tax, or other mandatory control of CO_2 emissions), without which the electric utility industry has little incentive to capture and store its CO_2 emissions. Moreover, according to key agency officials, the absence of a national strategy to control CO_2 emissions has also deterred their agencies from resolving other important practical issues, such as how stored CO_2 would be treated in a future CO_2 emissions trading plan.

CO_2 CAPTURE MUST OVERCOME SIGNIFICANT TECHNOLOGICAL HURDLES TO BE A COST-EFFECTIVE TECHNOLOGY FOR COAL-FIRED POWER PLANTS

Capturing CO_2 from large electric power plants, particularly coal-fired power plants, entails a number of technological challenges that affect its cost of deployment, and hence its appeal to industry. Among these challenges are (1) the absence of any commercial-scale demonstration of the technology at a power plant; (2) certain limitations of coal gasification technology for capturing CO_2 emissions at new power plants; and (3) the high cost of retrofitting CCS to existing pulverized coal-fired power plants that will, for the next several decades, account for a significant share of U.S. CO_2 emissions.

CCS Has Yet to Be Demonstrated on a Commercial Scale at a Power Plant

To date, there have been several small-scale tests of CO_2 capture at power plants in the United States and other countries, but these demonstration projects have typically removed CO_2 from only a small fraction of the power plant's overall output. Large-scale demonstrations of CO_2 capture at a power plant have been identified as an important step in improving capture technology, as well as securing industry support for CCS. Hence, the DOE Carbon Sequestration Program's program plan notes that the testing of CCS technologies at a larger scale is important to identify and eliminate technical and economic barriers to commercialization of CCS technology. With the need to accelerate the testing of innovative technologies in mind, two key international organizations—the IEA and the Carbon Sequestration Leadership Forum—recommend that a minimum of 20 full-scale CCS demonstration projects be implemented worldwide by 2020.

In a similar vein, a DOE advisory committee, the National Coal Council, noted that larger-scale demonstrations will be necessary to secure industry support. It noted, in particular, that "deployment will require successful pilot-scale testing and operation at a demonstration scale of 50 to 100 megawatts before companies will have confidence in their cost and performance for large scale systems."[13] Similar opinions were offered by several of the stakeholders we interviewed, who told us they thought it would be helpful for testing to focus more on actual demonstrations, rather than laboratory testing. For example, two electric power company officials told us they thought testing on a larger scale was important because the reliability of power plants with carbon management has not been adequately considered.

Despite the importance of gaining this kind of experience with CO_2 capture, CO_2 capture has not been demonstrated on a large scale at a power plant in the United States or in any other country. The IPCC's Special Report on CCS observed that "there have been no applications [of carbon capture] at large-scale power plants of several hundred megawatts" and emphasized the significance of this omission by cautioning that large-scale power plants are the major source of current and projected CO_2 emissions.

It should be noted that some progress has been made in testing CCS at other types of industrial facilities. Specifically, four industrial facilities have received attention as major demonstrations of CO_2 capture and storage technology. These facilities presently capture and store anthropogenic CO_2 on a large scale.[14] Three of these projects involve separation of CO_2 from natural gas: the Sleipner and Snohvit projects, located off the coast of Norway, and the In Salah project in Algeria. The fourth project captures CO_2 at a facility in North Dakota, where coal is gasified to make methane. The captured CO_2 is then injected at an oil field in Weyburn, Canada for the purposes of enhanced oil recovery and to permanently store almost all of the injected CO_2.

CO_2 capture has also been demonstrated at other industrial facilities, including plants that purify natural gas and produce chemical products (ammonia, alcohols, and synthetic liquid fuels). For example, one existing industrial application of CO_2 capture is to remove CO_2 from natural gas—a process called natural gas sweetening—to prevent pipeline corrosion and increase the heating value of the gas. However, much of the CO_2 captured at these facilities is currently vented to the atmosphere because there is no requirement or incentive to store it.[15]

Nonetheless, according to the IPCC and other knowledgeable authorities, key differences may inhibit the transferability of CO_2 capture at these facilities to coal-fired power plants:

- *Lower* CO_2 *concentrations at coal-fired power plants.* A study by researchers at the Massachusetts Institute of Technology (MIT) indicated that industrial processes, such as natural gas processing and ammonia production, produce highly concentrated streams of CO_2 as a byproduct, facilitating CO_2 capture.[16] By contrast, CO_2 is relatively diffuse in the exhaust, or flue gas, produced by coal power plants—about 13 to 15 percent by volume—making CO_2 capture substantially more energy intensive.
- *Challenges in adapting the* CO_2 *removal process to power plants.* The most commonly-used chemical method for removing CO_2 from natural gas may be challenging to adapt to capture at power plants. According to the IPCC Special Report on CCS, CO_2 is most commonly removed from natural gas using chemical solvents. However, DOE officials told us that one such commonly used solvent, monoethanolamine, is not designed to cost-effectively remove the dilute concentrations of CO_2 from the extremely large volumes of flue gas produced by pulverized coal power plants.

The IPCC report noted that applying CO_2 capture and sequestration only at these types of industrial facilities—and not at other facilities, such as coal-fired power plants—would contribute only marginally to addressing climate change. Specifically, it estimates that CO_2 capture, if widely used at natural gas sweetening facilities, would account for less than 1 percent of CO_2 emissions per year from large stationary sources.

Coal Gasification Technology Offers Promise in Capturing CO_2 at New Plants but Has Limitations That May Impede Its Widespread Use

DOE has pursued gasification technology—specifically IGCC technology—as a key technology for reducing the environmental impact of coal-based electricity generation, and which may be advantageous for CO_2 capture. The gasification process chemically decomposes the fuel before its combustion to provide a stream of CO_2 for separation and storage, as well as a stream of hydrogen for electricity production. It is advantageous in facilitating CO_2 capture because it provides a more concentrated stream of CO_2 at high pressure for separation and reduces the energy required for additional compression of the CO_2 for transport. DOE also indicates that IGCC plants may enable near-zero emissions of pollutants, including sulfur dioxide, nitrogen oxides, and particulate emissions, as well as increase fuel efficiency.

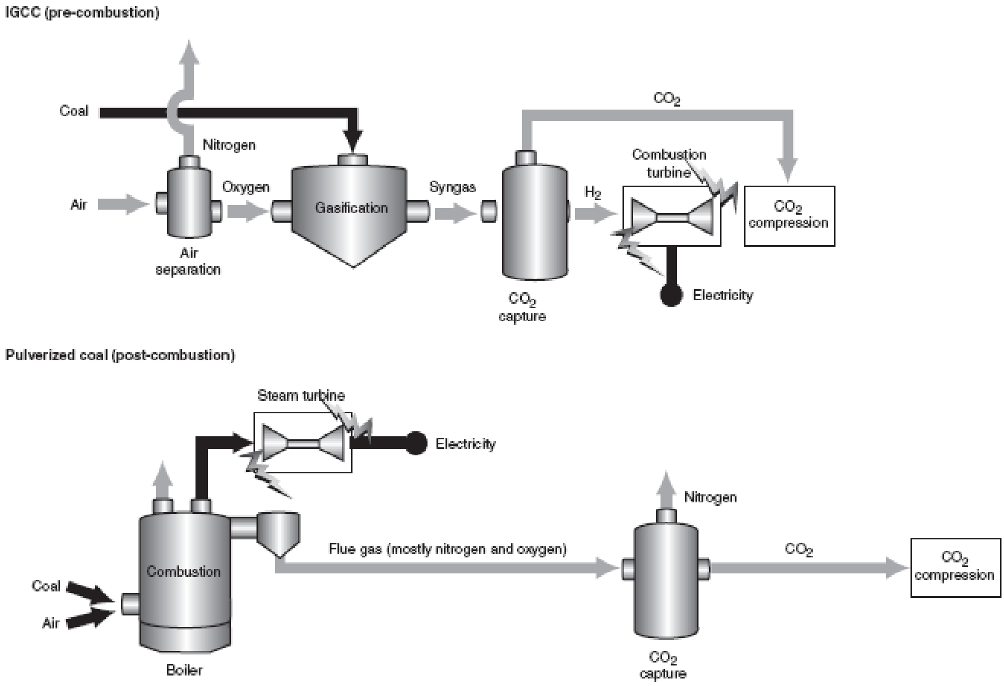
While capturing CO_2 at IGCC plants would impose additional costs, assessments by DOE and international organizations concluded that these costs would be lower than they would be for pulverized coal-fired power plants that remove the CO_2 after fuel combustion. For example, a 2007 DOE study concluded that IGCC plants—if built initially with the capability to capture CO_2 emissions—had a lower adverse impact on efficiency and cost of electricity production than equipping a new pulverized coal-fired power plant and, therefore, were a less expensive option for capturing CO_2 emissions.[17] DOE officials told us that, based on the agency's analysis, the cost of electricity production would increase by 35 percent for newly constructed IGCC plants with CO_2 capture, compared to a 77 percent increase for newly constructed pulverized coal power plants equipped with CO_2 capture.[18] Figure 3 illustrates several of the key differences between the two capture approaches.

Nonetheless, while IGCC plants using CCS technology have been planned in a number of countries, the outlook for IGCC power plants remains uncertain. Among the factors impeding deployment of the technology are the following:

- *Cost of constructing IGCC power plants*. Recent assessments indicate that it may be initially more expensive to build a new IGCC power plant than to build a pulverized coal power plant if CO_2 emissions are not captured. The IEA notes, in particular, that the investment cost for an IGCC plant is about 20 percent higher than for a pulverized coal combustion plant.[19] Moreover, the DOE *Cost and Performance Baseline for Fossil Energy Plants* report states that if the power plant does not capture CO_2 emissions, both the total cost of the plant as well as cost of electricity production would be more expensive at the IGCC power plants.[20] Furthermore, the IEA notes considerable uncertainty in IGCC costs because no coal-fired IGCC plants have recently been built.
- *Reliability concerns with IGCC plants*. Several stakeholders we interviewed expressed concern about the reliability of IGCC plants for electricity production. One electric power company official said that existing turbines for IGCC power plants are not reliable enough to provide base-load power for customers at high levels of CO_2 capture. Moreover, according to an MIT study, several IGCC power plants

experienced reliability challenges in the first few years of operation, although many of these early problems proved manageable and the reliability of the plants subsequently improved.[21] However, the National Coal Council identifies reliability as one continuing area of concern in which IGCC technology could be improved.[22]

- *Challenges in building new coal-fired power plants in the United States*. Using IGCC as an enabling technology for CCS is premised on building new coal-fired power plants. However, efforts to build new coal-fired power plants, regardless of the technology used, are facing increased regulatory scrutiny due to environmental concerns. A 2008 DOE report, *Tracking New Coal-Fired Power Plants*, states that significantly fewer new U.S. coal-fired power plants have been built than originally planned. Delays and cancellations have been attributed to regulatory uncertainty, including climate change concerns and escalating costs.



Source: GAO analysis of IPCC and DOE data.

Figure 3. Pre-combustion (i.e., IGCC) versus Post-combustion (i.e., pulverized coal) CO_2 Capture.

Capturing CO_2 from Existing Coal-fired Power Plants Requires Significant Amounts of Energy and Imposes High Costs

Key assessments indicate that post-combustion capture of CO_2, which would be used at pulverized coal power plants, faces significant technical challenges that greatly affect the cost and feasibility of its deployment using currently available technology.[23] This is significant because these pulverized coal facilities account for an overwhelming share of the world's coal-fired capacity.

In a pulverized coal plant, coal is burned with air in the boiler to produce steam. The steam then drives a turbine to generate electricity. Hence, CO_2 would have to be separated from the boiler exhaust, or flue gas, after combustion, rather than separating the carbon before combustion, as is the case in an IGCC plant. The need to separate CO_2 from the flue gas adds a number of technical challenges that can affect the cost and efficiency of CO_2 capture:

- *Treating large volumes of flue gas to remove* CO_2. As noted earlier, large volumes of flue gas must be treated to remove dilute concentrations of CO_2. DOE estimates that CO_2 accounts for only about 15 percent of the volume of the flue gas from a pulverized coal-fired power plant, compared to about 40 percent in an IGCC plant.
- *Removing impurities from the flue gas before* CO_2 *removal.* Trace impurities in the flue gas, such as particulate matter, sulfur dioxide, and nitrogen oxides, can reduce the effectiveness of certain CO_2 capture processes. The IPCC notes that it is important to reduce the acidic gas components, which would reduce the absorption capacity of the solvent used to remove CO_2. Additionally, IPCC notes that fly ash and soot present in the flue gas could be problematic, if not addressed.
- *Compressing the captured or separated* CO_2. Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure represents a large auxiliary power load on the overall plant system. The MIT study indicated that the energy required to compress the CO_2 is the second largest factor in reducing the efficiency of the power plant.[24]
- *Significant cost increases in retrofitting CCS to an existing plant.* An IPCC assessment of several studies concluded that retrofitting a CO_2 capture system to existing coal-fired power plants would increase the incremental cost of producing electricity from about 150 to 290 percent. Similarly, based on a study of a representative coal-fired plant in Ohio, DOE estimated that capturing 30 percent of a retrofitted plant's CO_2 emissions would increase its cost of electricity production by 2.3 cents per kilowatt-hour, while capturing 90 percent of the plant's CO_2 emissions would increase the cost of producing electricity by nearly 7 cents per kilowatt-hour.[25] For comparative purposes, the DOE's Energy Information Administration reports that the average retail price of electricity in the United States is 8.9 cents per kilowatt hour.

Regulatory and Legal Uncertainties also Complicate Capture, Injection, and Storage of CO_2

The IPCC, two federal advisory committee reports, and many stakeholders we contacted agreed that key regulatory and legal issues will need to be addressed if CCS is to be deployed at commercial scale. Among these issues are (1) confusion over the rules for injecting large volumes of CO_2, (2) long-term liability issues concerning CO_2 storage and potential leakage, (3) how property ownership patterns may affect CO_2 storage, and (4) how the Clean Air Act will apply to facilities that capture CO_2.

Confusion over Rules about Large-Volume Injections of CO_2

Electric utilities and oil and gas companies have underscored the need for guidance on how CCS projects that inject large volumes of CO_2 would be regulated under EPA's

Underground Injection Control (UIC) program, which is designed to protect underground sources of drinking water. As noted earlier, under the UIC program, EPA regulates underground injections of various substances, including nonhazardous and hazardous wastes into more than 800,000 injection wells. The SDWA requires EPA to develop minimum federal requirements for injection practices that protect public health by preventing injection wells from endangering underground sources of drinking water. However, the injection of CO_2 for long-term storage raises a new set of unique issues related to its relative buoyancy, its corrosiveness in the presence of water, and large volumes in which it would be injected.

Stakeholders suggested that the absence of regulations related to large-volume CO_2 injection and storage was creating considerable uncertainty for CCS projects. Recently, EPA proposed a regulation to address this uncertainty. Prior to this proposal, nearly half of the 20 stakeholders we interviewed said uncertainty regarding CO_2 injection and storage regulations was a large or very large barrier to CCS deployment. For example, one industry stakeholder said that he was uncertain about whether injecting CO_2 in large volumes was actually legal, since EPA's guidance to date only addresses pilot CCS projects. Other stakeholders have mentioned that without new EPA guidance on large volume CO_2 injections, they were uncertain about how stringent their well construction and monitoring needed to be. In addition, a diverse panel at EPA's 2007 UIC workshop on the issue noted that well spacing could be a significant issue that needed to be addressed, since the pressure effects caused by various CO_2 injections could intersect and have a major impact due to injection volumes, particularly with the size and potential number of CO_2 projects. Finally, according to a 2007 report by the American Public Power Association, the uncertainty associated with UIC permit requirements has complicated commercial scale planning for new coal-fired power plants because it has left utilities uncertain as to whether they could inject CO_2 locally or be required to pipe CO_2 over great distances.

In July 2008, EPA addressed some of these technical and regulatory issues in its proposed rule for underground injection of CO_2 for geologic sequestration. Preliminary stakeholder reaction to EPA's proposed rule, discussed later in this chapter, suggests that some CO_2 injection-related uncertainties may be headed for resolution through the EPA rulemaking but that others will be more challenging to resolve.

Long-Term Liability Concerns over CO_2 Storage and Possible Leakage

Beyond the immediate concerns over how to inject large volumes of CO_2, stakeholders expressed broader concerns over the long-term liability associated with its storage. They pointed specifically to a lack of clarity regarding who—the injector or the property owner—will ultimately be responsible for CO_2 injections and storage after the wells are capped. If stored CO_2 migrated beyond the area in which it was intended to be stored, there are two potential outcomes that generate concern:

- Stored CO_2 could migrate underground and endanger underground sources of drinking water, leading to liability under the SDWA for the party responsible. According to EPA, CO_2 migration into drinking water can cause the leaching of contaminants, such as arsenic, lead, and other compounds, into the water. CO_2 migration could also result in changes in regional groundwater flow and the movement of saltier fluids into drinking water, causing its quality to degrade. As the July 2008 proposed rule's preamble reiterates, under the SDWA, well operators remain responsible indefinitely for any migration that endangers underground sources of drinking water, and courts could impose civil penalties as high as $25,000 per day. Participants in EPA's 2007 UIC workshop raised the prospect of environmental and health concerns posed by CO_2 injections, including the mobilization of previously isolated metals, lower pH as a result of CO_2 interaction with water, and saltwater displacement.

- Stored CO_2 could also migrate beneath adjacent lands. If CO_2 was injected for geologic storage and it migrated underground into neighboring mineral deposits, for example, it could interfere with the adjacent mineral owners' abilities to extract those resources, and the injection well's operator could be held liable for nuisance, trespass, or another tort.

EPA's 2007 UIC workshop, attended by more than 200 stakeholders, revealed liability associated with unintended migration of injected CO_2 to be a critical concern. Similarly, 19 of the 20 stakeholders we interviewed told us that liability related to CO_2 storage was a large or very large barrier to deployment of CCS at commercial scale, with some noting that liability concerns have already negatively impacted companies' ability to initiate CCS projects. For example, two stakeholders reported that these concerns have already made it difficult to obtain insurance for CCS projects. They noted specifically that insurers have difficulty writing insurance policies because of the uncertainties associated with and limited data available for CCS, while another added that investors will not support projects like CCS if they expose them to unlimited and undefined long-term liabilities, especially when future revenue streams are uncertain.

Property Ownership Patterns May Also Affect CO_2 Storage

Setting aside any complications that could later arise from CO_2 leakage onto others' property, electric utilities and other stakeholders note that at the outset of a CCS project, it would be essential to identify and obtain the consent of all surface and mineral property rights owners. Such a determination is not always straightforward because ownership of surface land is often severed from ownership of minerals located below the land's surface and, in the same vein, ownership of saline reservoirs. In these circumstances of severed ownership, state law varies on who owns the geologic formation or potential storage site that would sequester the CO_2. In some states, the surface landowner owns the geological formation, but in others, the mineral rights owner owns the formation. Moreover, those geologic formations used for CO_2 storage that extend below surface lands could encompass the mineral rights of multiple owners.

Aside from the question of who owns the storage site, it is also not clear who would actually own the CO_2 once injected—the injector, the owner of the surface land, or the owner of the subsurface geologic formation—because few state laws or courts have yet to address the issue. Some state laws and courts, however, have recognized that injectors of natural gas retain ownership of that gas.

Multiple stakeholders told us that this issue will be a much larger one as CCS projects are scaled up to commercial scale and move beyond existing enhanced oil recovery projects that inject smaller volumes of CO_2 in order to extract additional oil from underground reservoirs. They noted that the CO_2 plume, or pressure front created by injecting the CO_2 underground, can cover tens to hundreds of square miles, affecting numerous property owners. According to one power company official, this property rights issue is different from liability-related issues, since it could prevent CO_2 from being injected into the ground in the first place. If they cannot get access rights to the formation, they cannot do a project.

Uncertainty Regarding How the Clean Air Act Will Apply to Power Plants with CCS

According to EPA air officials, the Clean Air Act's New Source Review (NSR) requirements apply to new power plants that are constructed with carbon capture technology and may apply to existing power plants that install the technology. NSR is triggered when a new facility is built, or when an existing facility makes a major modification, a physical or operational change that would result in a significant net increase in emissions. Under NSR, permitting authorities review the proposed facility or modification to establish emission limits and ensure the requisite pollution control technologies will be used before granting it a permit. Because of the additional energy required for carbon capture, EPA officials note that power plants implementing the technology might need to burn more coal to generate the same amount of electricity. If this increased coal usage resulted in a significant net increase of emissions of pollutants regulated under the act, such as ozone or sulfur oxide, NSR could be triggered.

Some note that the NSR requirements, and the additional costs and uncertainties associated with them, may discourage facilities such as power plants from adopting CCS technology. For example, a recent report from a federal advisory committee to the Secretary of Energy states that "for existing coal-fired facilities, a major question is whether the Clean Air Act, including the NSR requirements of the Act, would apply if CCS equipment is installed."[26] Multiple stakeholders we interviewed agreed that adding CCS equipment to an existing power plant could raise problems under NSR. One noted, in particular, that NSR challenges were manageable while CCS projects were at the demonstration scale but could pose greater problems when CCS is deployed at a larger scale.

The Absence of a National Strategy to Control CO_2 Emissions Gives Neither Industry Nor Government Agencies an Incentive to Invest in CCS

According to the IPCC, the National Academy of Sciences, and other knowledgeable authorities, another barrier is the absence of a national strategy to control CO_2 emissions (emissions trading plan, CO_2 emissions tax, or other mandatory control of CO_2 emissions), without which the electric utility industry has little incentive to capture and store its CO_2 emissions. Moreover, according to key agency officials, the absence of a national strategy to control CO_2 emissions has also deterred their agencies from resolving other important practical issues that will ultimately require resolution if CCS is to be deployed on a large scale. Such issues include lack of clarity regarding who owns injected CO_2 and how stored CO_2 will be addressed in a future emissions trading scheme.

Industry Has Little Incentive to Invest in CO_2 Control Technologies without a National Strategy to Control CO_2 Emissions

A wide range of academic, industry, and other knowledgeable authorities agree that CCS is unlikely to be used to any substantial extent without some kind of national strategy to control CO_2 emissions. The IPCC's 2005 report on CCS observed, for example, that "all models indicate that CCS systems are unlikely to be deployed on a large scale in the absence of an explicit policy that substantially limits greenhouse gas emissions to the atmosphere. With greenhouse gas emission limits imposed, many integrated assessments foresee the deployment of CCS systems on a large scale within a few decades from the start of any significant climate change mitigation regime." It stated further that "the stringency of future requirements for the control of greenhouse gas emissions and the expected costs of CCS systems will determine, to a large extent, the future deployment of CCS technologies relative to other greenhouse gas mitigation options."[27]

EPA's Clean Air Act Advisory Committee's Advanced Coal Technology Workgroup similarly reported that widespread commercial deployment of advanced clean coal technologies, including large-scale CCS, likely will not occur without legislation that establishes a significant long-term "market driver." The majority of stakeholders we interviewed agreed, characterizing the absence of a national strategy to control CO_2 emissions as a large or very large barrier to CCS deployment on a commercial scale, with many stating that without a price on emitting CO_2, there is no rationale for utilities or other facilities to control their emissions. Moreover, according to a leading researcher,[28] "in order for significant progress to be made in reducing greenhouse gas emissions, some form of mandatory emissions limits or tax on greenhouse gases will be required, just as in every other area of environmental regulation where substantial costs of emission reductions must be borne."

One indication as to how emitters might respond to a cost on CO_2 emissions was provided by a Norwegian petroleum company after Norway introduced a $40 per metric ton tax on offshore CO_2 emissions in 1991. The Statoil petroleum company's Sleipner project, a natural gas processing project located at a gas field 250 kilometers off the coast of Norway, had already been removing CO_2 from the natural gas to prepare it for sale on the open market. But with no financial incentive to do otherwise, Statoil had simply vented the CO_2 into the atmosphere. At least partly in response to the tax, however, the company, in 1996, began to capture approximately 3,000 metric tons of CO_2 per day from natural gas extraction and store it 800 meters under the North Sea's seabed in a geologic formation called a saline reservoir.

The United States' experience with other pollutants, notably sulfur dioxide (SO_2), also provides insights into the kind of market-based emissions control regime that could emerge if a national strategy to control CO_2 emissions was adopted. In Title IV of the Clean Air Act 1990 Amendments, Congress established a goal of reducing annual emissions of SO_2 by 10 million tons from 1980 emissions levels. Specifically, the law established overall emission limitations and allocated SO_2 emission allowances to individual electric utilities. The utilities are required to own enough allowances at the end of each year to cover their emissions. Under the law's allowance trading system, utilities can trade some or all their allowances in a way that allows them greater flexibility in achieving the required emission reductions at the lowest cost. In cases where utilities were able to reduce emissions below their required allowance, they were able to sell the extra allowances at the market price to other utilities. As with the SO_2 program, analyses by government and academic organizations generally indicate that CCS technology will be more extensively used as emission limits tighten.

An important lesson from the SO_2 program was that as vendors competed to meet utilities' emission reduction needs, they were prompted to seek the least expensive means of providing utilities with low-sulfur coal, "scrubbers," and other methods for reducing sulfur dioxide emissions.[29] As a result, the overall cost of reducing emissions decreased over time. More generally, a study commissioned by the IEA's Greenhouse Gas R&D Program emphasizes the decrease in costs of new technologies over time.[30] It suggests that for new coal emission control technologies, the initial higher plant costs incurred are gradually reduced through experience and from continued research and development.

The Absence of a National Strategy to Control CO_2 Emissions Has Constrained the Federal Government's Efforts to Plan For and Develop CCS Projects

The absence of a national strategy to control CO_2 emissions not only leaves the regulated community with little incentive to reduce their emissions, it also leaves regulators with little reason to devise the practical arrangements necessary to implement the reductions. For example, regulators have not addressed how utilities that capture and sequester CO_2 would be treated under a future emissions trading plan. The EU's early experience with CO_2 emissions trading illustrates the significance of including CCS in an emissions trading plan. EU officials told us when the Emissions Trading System (ETS) was conceived, the maturity of CCS as a technical reduction option for CO_2 was not clear. Therefore, CCS projects were not systematically included in the ETS.[31] However, EU officials noted that the situation has changed substantially since then. Indeed, a recent European Commission report indicates that not systematically including CCS in the ETS may be one barrier to its deployment.[32] Accordingly, the European Commission is now proposing legislation to explicitly include, after 2012, facilities involved in the capture, transportation, and storage of CO_2 in the ETS. These facilities would then earn allowances for nonemitted CO_2 and would have to surrender emissions allowances for any leakages of CO_2 that occur. Consequently, EU officials told us that the proposed directive, when enacted, would remove this barrier.

Likewise, cognizant agency officials responsible for U.S. programs have told us that they will not act on key CCS implementation issues prior to Congress establishing a national strategy to control CO_2 emissions. For example, as noted earlier, the officials told us that uncertainty regarding property rights ownership stems from ambiguity over who owns the injected CO_2, and it is similarly unclear what the government's potential liability might be for long-term storage of CO_2 on federal lands. Bureau of Land Management (BLM) officials said they are aware of the issue and of the BLM's jurisdiction in the matter but told us they are looking to Congress for a solution before they will take any specific actions to address it. These officials also noted that while they do have authority to permit CO_2 injections on federal lands that are solely for sequestration purposes, they are uncertain whether BLM has statutory authority to establish a funding mechanism for long-term management of sequestration sites on federal lands.

Other practical issues requiring resolution, which cross the jurisdictions of a range of federal agencies and of state and local governments, are discussed later in this chapter.

FEDERAL AGENCIES HAVE YET TO RESOLVE THE FULL RANGE OF ISSUES REQUIRING RESOLUTION FOR WIDESPREAD CCS DEPLOYMENT

While federal agencies have begun to address CCS barriers, they have yet to comprehensively address the full range of issues that would require resolution for widespread CCS deployment. DOE has achieved limited results in lowering the cost of CO_2 capture at existing power plants, and the agency's focus on gasification technology to date may not provide for the needed reductions in emissions because few facilities with this technology currently exist. However, DOE's focus has recently shifted to better balance the need for capture technology at both new and existing power plants. EPA has recently issued a proposed rule that clarifies significant regulatory uncertainties related to CO_2 injection and storage. However, critical questions remain about long-term liability for stored CO_2. Elsewhere in the federal government, agencies have not addressed a number of issues that could delay CCS deployment. Among them are how CO_2 pipeline infrastructure might be developed and how a future emissions trading plan would treat avoided CO_2 emissions due to CCS.

DOE Has Only Recently Prioritized Research to Help Control CO_2 Emissions from Existing Power Plants

DOE has identified IGCC technology as the key enabling technology for reducing CO_2 emissions from newly constructed coal-fired power plants and has helped to develop and demonstrate IGCC technology. However, key assessments by the National Academy of Sciences and international organizations have raised questions about how the agency's focus on IGCC technology may have affected the broader effort to substantially reduce CO_2 emissions from coal-based electricity generation because (1) as noted earlier, the outlook for widespread deployment of IGCC technology is questionable and (2) the agency's funding related to IGCC technology has substantially exceeded funding for technologies more applicable to reducing emissions from existing coal-fired power plants. DOE has recently started to focus greater attention on technologies more applicable to reducing emissions from existing power plants.

DOE Has Achieved Some Advances with IGCC Technology

Consistent with DOE's emphasis on IGCC, the agency cites a number of accomplishments in advancing the technology, such as its support for two operational IGCC power plants, in Florida and Indiana, that produce substantial amounts of electricity, while also demonstrating the production of high-pressure syngas amenable to CO_2 capture.[33] DOE also cites its contributions to the development of several IGCC-related technologies, which would advance pre-combustion CO_2 capture. Specifically, recent technological advances cited by the agency include successful fabrication and testing of a liquid membrane that is stable at high temperatures and that could be used for CO_2 capture in IGCC plants, as well as a new material with CO_2 separation potential for gas separation. Moreover, according to a published journal article with three DOE co-authors, advances in membranes may be significant in advancing CO_2 capture because membranes are less energy intensive, compared to other separation techniques.[34] Taken together, the National Academy of Sciences credits DOE's efforts in promoting IGCC technology, citing the agency's

efforts to develop "a close working relationship with the industry to move the technology through the commercial demonstration stage."[35]

Looking ahead, DOE hopes to make further investments, and progress, in demonstrating IGCC's feasibility to capture CO_2 through its FutureGen program, which aims to accelerate commercial deployment of IGCC or other advanced clean coal-based power generation technology with CCS. Moreover, under the restructured FutureGen program, DOE anticipates supporting demonstrations at more than one site.

DOE Funding Decisions Reflect Agency's Focus on IGCC

DOE's progress, however, has required both significant time and resources. As the National Academy of Sciences noted, the development of an integrated IGCC system has been an important component of DOE's Fossil Energy Research Development and Demonstration program for more than 20 years, and between 1978 and 2000, DOE invested \$2.3 billion in gasification technology.[36] Moreover, DOE budget data indicate that in more recent years, the agency has continued to provide substantial funding for IGCC technology. Several Fossil Energy programs provide substantial support for developing IGCC technology, including the IGCC program, the FutureGen program, and the advanced turbines program. Together, these programs account for a significant share of Fossil Energy's overall budget. The Carbon Sequestration program also provides some additional funding for CO_2 capture using IGCC technology.

Developing an exact estimate of DOE funding for IGCC technology is challenging because the individual DOE programs pursue multiple objectives and funding categories have changed over time. However, an examination of DOE's budget information suggests that its support from 1997 (the year the Carbon Sequestration program began) to present is likely on the order of hundreds of millions of dollars and probably in excess of \$500 million. A DOE official within Fossil Energy acknowledged to us that "the bulk of coal program capture funding relates to gasification, particularly IGCC," although DOE officials said they are now focusing more attention on existing pulverized coal power plants.

IGCC Technology's Potential for Reducing CO_2 Emissions Is Uncertain

The payoff for this investment, however, will depend heavily on the extent to which IGCC technology is used in newly constructed power plants—both in the United States and worldwide. In this regard, the National Academy of Sciences said in a recent assessment that the Carbon Sequestration program "is taking on a relatively high overall risk to create technologies for commercial demonstration by 2012 in that it relies heavily on the successful deployment of full-scale IGCC plants." The report added that there are only a few IGCC plants operating worldwide and advanced, commercial-scale IGCC units are only in the design phase and have no CO_2 sequestration.[37]

Moreover, as noted earlier, studies by the IEA, DOE, and the National Coal Council cite a number of compelling factors, such as the relative cost of IGCC plant construction and the limited operational experience worldwide with this relatively new technology, which may limit commercial deployment of IGCC technology. Several industry stakeholders we interviewed expressed concerns about using IGCC technology for electricity generation, including the cost of constructing IGCC plants and possible reliability concerns. For example, officials from one electric power company told us they thought high levels of CO_2 capture at IGCC plants would necessitate the use of a turbine, which has not yet been commercially demonstrated. Looking ahead, the IEA's 2007 *World Energy Outlook* notes that "for IGCC to establish itself in the market, further development to bring down costs and improve operational flexibility is necessary."

DOE Has Thus Far Achieved Limited Success in Reducing CO_2 Emissions from Existing Power Plants

Until recently, DOE budget decisions reflected a view that IGCC technology offered greater potential to capture CO_2 than technologies applicable to pulverized coal-fired power plants. As indicated earlier, DOE budget information we reviewed indicates substantial funding for IGCC technology, likely in the order of hundreds of millions of dollars. By comparison, DOE support for post-combustion CO_2 capture technology, most applicable for existing plants, appears more limited, likely on the order of tens of millions of dollars.

As noted earlier, DOE has cited a number of challenges that complicate efforts to capture CO_2 emissions from pulverized coal-fired power plants, including the large volumes of gas that must be treated; trace impurities in the exhaust gas (such as particulate matter, sulfur dioxide, and nitrogen oxides) that can degrade the effectiveness of certain capture processes; and the high amount of energy needed to compress CO_2 emissions. Among other things, a DOE study concluded that if CO_2 capture were added to a pulverized coal-fired power plant that started operations in 2010, its cost of electricity production would increase by approximately 80 percent.[38]

These technological realities, however, are at odds with another reality anticipated by a number of organizations: these facilities will account for the vast majority of coal capacity in the United States and around the world in the near term. Accordingly, in past years, the agency has undertaken some initiatives to advance technologies to capture CO_2 from these facilities and points to a number of accomplishments arising from these efforts. Among them, DOE researchers reported patenting a technique to capture CO_2 from a coal-fired power plant's exhaust using ammonia, a technique planned for two capture demonstrations at power plants in Ohio and North Dakota. DOE officials also point to several other projects related to post-combustion CO_2 capture, including development of ionic liquids with greater absorption capacity for CO_2 and development of sorbent technology for retrofitting existing pulverized coal plants. DOE officials also pointed to investments in two other challenging aspects of CO_2 capture. One involves research to address one of the largest cost drivers, the cost of regenerating the absorbent. DOE officials also pointed to work on technologies to improve the efficiency of compressing CO_2, a major cost factor in capturing CO_2 at these facilities.

Nonetheless, DOE's own analysis raises questions concerning the agency's progress in helping to reduce the cost of CO_2 capture at pulverized coal power plants. For post-combustion CO_2 capture, DOE officials indicated to us that the agency's current goal is to develop, by 2012, pilot-scale systems to capture 90 percent of CO_2 at no more than a 35 percent increase in the cost of electricity production. However, it is noteworthy that this goal is to develop pilot-scale systems only; commercial-scale units will not come online until the 2020 time frame.

An assessment report recently published by DOE indicates the size of the challenge DOE faces in reducing the cost of capture. The study indicated that CO_2 capture would increase the cost of electricity production by 77 percent at a pulverized coal power plant starting operation in 2010.[39] A DOE official within Fossil Energy acknowledged to us that owners of existing pulverized coal power plants, under a future emissions trading arrangement, might choose to purchase carbon allowances, rather than pay for an expensive retrofit, and that plant age and other economic considerations will make the determination of whether a retrofit or another action, such as purchasing allowances, will occur.

One contributing factor to DOE's limited progress in reducing CO_2 emissions from existing power plants is that it is a relatively lower priority for DOE. The National Academy of Sciences noted that the Carbon Sequestration program has focused on IGCC technology to achieve its goal of reducing the cost of carbon capture.[40] Our examination of DOE's budget in recent years supports this view:

- *The Carbon Sequestration program has provided limited capture funding*: DOE officials estimated the Carbon Sequestration program provided approximately $50 million in funding related to all types of CO_2 capture from fiscal year 2002 to fiscal year 2007. While DOE officials were able to provide limited information quantifying precisely how this funding was split between post-combustion and pre-combustion capture, they indicated that the majority of it went toward the development of post-combustion and oxy-combustion capture technologies. DOE officials suggest that, historically, 20 percent of the Carbon Sequestration program's budget has gone toward capture, which DOE officials said allowed capture technology development to continue as DOE evaluated geologic storage of CO_2. However, capture-related funding has generally received less funding in the Carbon Sequestration program's budget than other areas, such as the regional partnerships.
- *Post-combustion capture has not been supported by related programs*: Until recently, post-combustion CO_2 capture had not received large amounts of funding from other programs in Fossil Energy. Specifically, until fiscal year 2008, no other major Fossil Energy programs provided substantial funding related to post-combustion capture, in contrast to those programs' support for IGCC technology.

DOE Has Recently Focused More Attention on Existing Plants

Looking ahead, DOE officials told us that the agency is now focusing more attention on reducing CO_2 emissions from existing plants by shifting the focus of a related Fossil Energy program, the Innovations for Existing Plants program, so that it emphasizes the development of post-combustion capture of CO_2. Among the factors cited in this decision were (1) the large number of pulverized coal power plants in the United States; (2) congressional direction in the report accompanying the agency's fiscal year 2008 appropriation to focus more attention on this issue; and (3) the applicability of advances in this area to the large number of pulverized coal power plants under construction in China and India.

In February 2008, DOE announced that it was soliciting applications for projects "specifically focused on developing technologies for CO_2 capture and separation that can be retrofitted to existing pulverized coal (PC) power plants." In July 2008, the agency announced it was providing $36 million in funding for 15 projects to develop new and cost-effective capture technologies for existing power plants.

Other recent changes in DOE's funding decisions also appear to recognize the significance of reducing emissions from existing power plants:

- The Carbon Sequestration program's funding for post-combustion CO_2 capture (including oxyfuel combustion capture) increased from $10.1 million in fiscal year 2007 to $15.4 million in fiscal year 2008.
- The network of Regional Carbon Sequestration Partnerships appears to be placing more emphasis on demonstrations of CO_2 capture at coal power plants for an upcoming series of large-scale sequestration projects. Specifically, a DOE official identified three projects being planned to capture CO_2 from coal-fired power plants, including possibly capturing 500,000 tons of CO_2 from a coal-fired power plant in North Dakota.
- DOE indicated in an August 2008 announcement that the agency's Clean Coal Power Initiative program would support coal-based technologies to capture and sequester CO_2 emissions. For post-combustion CO_2 capture, the announcement indicated that advanced technologies are sought to reduce the cost and additional power load of CO_2 capture.

While it seems too early to evaluate the results of DOE's increased focus on post-combustion CO_2 capture, key organizations' assessments appear supportive of this shift. A 2008 National Coal Council report, for example, identifies retrofitting existing coal power plants with CCS as part of a larger approach to reducing emissions.[41] In the same vein, the IPCC notes that the strategic importance of post-combustion capture systems becomes evident when one considers the large amount of emissions from pulverized coal power plants.

EPA Has Begun to Address Regulatory Uncertainty Concerning CO_2 Injection and Storage, but Key Issues Remain Unresolved

As discussed earlier in this chapter, CCS stakeholders have stated that the absence of regulations governing large-volume CO_2 injection and storage had created considerable uncertainty about the projects and risks associated with CCS. In an effort to address many of these concerns, EPA issued a proposed a rule in July 2008 to address permitting and other requirements for injection of CO_2 for geologic sequestration. The proposed rule, issued under the agency's SDWA authority, clarifies a number of practical issues for prospective well owners and operators concerning CO_2 injection and identifies certain requirements governing their financial responsibilities, including for the period after the CO_2 is injected and the well is closed. However, as EPA officials note, the rulemaking was not intended to resolve many questions concerning how other environmental statutes may apply to captured and injected CO_2, including the Clean Air Act, CERLCA, and RCRA. A number of key issues, therefore, have yet to be addressed.

EPA Has Issued a Proposed Rule under the SDWA on Permitting Large-Volume CO_2 Injections

EPA's July 2008 proposed rule creates a new "Class VI" well type for injection of CO_2 for geologic sequestration. In doing so, it clarifies a number of issues relating to the more immediate, practical issues regarding CO_2 injection for geological storage. However, some notable ambiguities remain, particularly in the area of longer-term financial responsibility requirements. The following summarizes both the issues that have been addressed and those which may still need to be clarified. In the discussion below, we provide the preliminary views of the stakeholders we interviewed. It is important to note, however, that the proposed rule's 120-day comment period runs until November 24, 2008, during which time EPA will obtain a broader array of public advice and opinions on its proposed rule.

Site characterization, well construction, and monitoring requirements. The proposed rule specifies a number of requirements concerning the location of the CO_2 injection well, including (1) the criteria for characterizing the site of the geologic formation and (2) requirements for reviewing the wider geographic area surrounding the storage site prior to injection. Regarding site characterization, the well owner or operator must demonstrate that the well will be located in an area with a suitable geologic system, including a confining zone for the injected CO_2 that is free of faults or fractures, that would contain the CO_2. The proposed rule also specifies that injection of CO_2 above the lowermost formation containing an underground source of drinking water is prohibited. Regarding the wider geographic area surrounding the storage site that may be impacted by the injection, it requires well owners and operators to delineate an Area of Review (AoR) within which the owner or operator must identify all penetrations, such as wells, that may penetrate the confining zone and determine whether the wells have been plugged in a manner that prevents the movement of CO_2 or associated fluids that may endanger underground sources of drinking water.

The proposed rule also includes standards for well construction, operation, and monitoring. For example, although EPA does not specify which materials must be used, the proposed rule does require the use of materials that meet or exceed industry standards, that are compatible with injected CO_2, and that are designed for the life of the well. The proposed rule also contains an injection pressure limitation so that an injection does not create new fractures or cause movement of injected CO_2 that endangers underground sources of drinking water. It requires continuous monitoring of injection pressure, rate, and volume, and requires semiannual reporting of this data to EPA. The proposed rule also requires well owners and operators to submit, with their permit application, a testing and monitoring plan to verify that the CO_2 storage project is operating as permitted and is not endangering underground sources of drinking water.

The proposed rule also addresses stakeholder concerns about how current CO_2 injection wells operating as Class I industrial wells, Class II injection wells that use CO_2 for enhanced oil or natural gas extraction, and Class V experimental CO_2 injection wells would be regulated if they transition to use for long-term storage. It specifies that owners of these existing wells may apply for the new Class VI permit and that the UIC program director would have the discretion to grandfather the well's pre-existing construction requirements if the director determined that doing so would not endanger underground sources of drinking water. With this exception, the project would have to meet all other Class VI requirements in order to obtain a Class VI permit.

Financial Responsibility Requirements

EPA’s proposed rule specifies that well owners and operators must demonstrate and maintain financial responsibility for corrective action (that is, repairs or other actions necessary to assure that wells within the AoR do not serve as conduits for the movement of fluids into underground sources of drinking water), well plugging, post-injection site care for a period of 50 years following cessation of injections, site closure, and emergency and remedial response. The UIC program director can adjust the 50-year time period for post-injection site care depending on whether the project poses an endangerment to underground sources of drinking water. If the UIC program director chooses to lengthen the post-injection site care time period, the owner and operator must continue to demonstrate financial responsibility until the end of that period. Although the financial responsibility demonstration requirement ends when the post-injection site care time period does, the proposed rule’s preamble indicates that well operators remain responsible indefinitely for any endangerment of underground sources of drinking water.

In addition to clarifying well site care, the proposed rule also requires that well owners and operators periodically update their cost estimate for corrective action, well plugging, post-injection site care and site closure, and emergency and remedial response, and that they redemonstrate financial responsibility for these increased costs as the UIC program director deems necessary. It also requires well owners and operators to notify the UIC program director of any adverse financial conditions they encounter, such as bankruptcy.

While stakeholders acknowledge EPA’s progress in clarifying some key financial responsibility requirements, they cite several other concerns:

- Although EPA’s proposed rule establishes a post-injection site care period, it does not include a provision allowing well operators to be released from liability for endangerment of underground sources of drinking water during the hundreds of years that CO_2 will be stored in a geologic storage project. While it is beyond EPA’s authority to release injection well owners and operators from liability, a discussion of long-term liability is included in the proposed rule’s docket. Stakeholders told us that they were concerned by the unspecified period of time for which they may be liable for stored CO_2.
- The proposed rule only specifies a duty to demonstrate financial responsibility, stating that guidance will be developed at a later date describing the types of financial mechanisms that owners or operators can use. Currently, financial responsibility for other well classes is demonstrated through third-party instruments, such as a surety bond that establishes a trust fund, or self-insurance instruments, such as a corporate financial test. However, EPA’s existing financial responsibility requirements have been criticized as inadequate and the agency is currently reviewing its approach. EPA is evaluating whether to revise its financial responsibility guidance in light of these criticisms and is seeking public comments on various financial responsibility topics. Moreover, EPA officials told us that the Miscellaneous Receipts Statute limits the financial responsibility regulations because it prevents EPA from requiring a cash deposit or receiving money as a trustee.[42] The proposed rule’s preamble also notes that EPA does not have the statutory authority to transfer financial responsibility from the well owner or operator to a third party.

Finally, there is some question as to whether EPA will have sufficient resources to implement the expanded UIC program. EPA has not examined the level of resources that will be needed to administer the UIC program once commercial-scale deployment of CCS occurs. However, a 2007 report by DOE's Argonne National Laboratory did examine the issue and concluded that if CO_2 were stored in large enough volumes to have a meaningful impact on global warming, it is likely that thousands or tens of thousands of injection wells would need to be developed and permitted in the United States. The report noted that this would require that state and regional UIC programs expand their staff and capabilities. In this connection, it observed that the annual national budget for the UIC program—approximately $11 million—has remained static for many years, even as UIC agencies have been asked to take on additional responsibilities. It warned that failure to provide sufficient resources would likely create permitting backlogs, resulting in a bottleneck in the overall carbon sequestration effort.

Multiple stakeholders agreed that EPA needs additional resources for the UIC program, including permit writers. One industry representative expressed concern that it can take up to 2 years to obtain a permit for a well under EPA's UIC program, and that if CCS projects become more widespread, EPA will be responsible for permitting thousands of additional injection wells.

Key Legal and Regulatory Issues outside of the SDWA Have Been Largely Unaddressed

While EPA has addressed at least some of the legal and regulatory issues on how CO_2 injectors are to protect underground sources of drinking water, it has thus far not resolved a number of key environmental issues that fall under the jurisdiction of other statutes, including the Clean Air Act, RCRA, and CERCLA.

Clean Air Act. As noted earlier, the Clean Air Act's New Source Review (NSR) requirements could be triggered if an existing facility's installation of capture technology makes a major modification that significantly increases emission of regulated pollutants. EPA officials acknowledge concerns that NSR could cause delays and impose added costs to CCS projects. However, they said that an assessment of how NSR might impact the feasibility of CCS projects cannot be made globally because it depends on site-specific factors, such as geological and hydrological considerations, the CCS technology that will be used, how it will operate, and how that operation could affect the rest of the plant.

Laws governing hazardous wastes and substances. RCRA and CERCLA could pose similar complications for CCS projects. RCRA authorizes EPA to establish regulations governing the treatment, storage, and disposal of hazardous waste. A hazardous waste is generally defined as a solid waste that either (1) exhibits certain characteristics (ignitability, corrosivity, reactivity, or toxicity) or (2) has been listed as a hazardous waste by EPA. CERCLA established the Superfund program to clean up sites that have been contaminated by hazardous substances. CERCLA authorizes EPA to compel the parties statutorily responsible for the hazardous substances to bear the costs of cleaning up the contaminated site or to carry out cleanups itself and recover costs from the responsible parties. Hazardous substances are those which may present substantial danger to the public health, welfare, or environment when released and include all hazardous wastes subject to RCRA.

Whether any given injected CO_2 stream is categorically a hazardous waste or hazardous substance has not been resolved by EPA. The preamble to EPA's proposed rule notes that pure CO_2 in and of itself is not listed as a hazardous substance under CERCLA. However, the rule's preamble cautions that injected CO_2 streams could contain hazardous constituents that would make these streams "hazardous."[43] It notes that since the chemical composition of individual injected CO_2 streams vary, no categorical determination can be made as to whether all injected CO_2 streams are hazardous wastes. Accordingly, the preamble says that it will be up to the well owners and operators to make this determination on the basis of their particular circumstances. EPA officials said that they lacked the information about the composition of CO_2 streams captured from coal-fired power plants necessary to determine whether those streams should categorically be listed as a hazardous waste under RCRA.

Thus, considerable uncertainties over how owners and operators of CCS projects would be treated under key environmental laws other than the SDWA remain unresolved. An EPA federal advisory committee working group had emphasized, in particular, that the EPA address the liability implications concerning CO_2 injection under RCRA and CERCLA.[44] However, the proposed rule is unclear as to whether the two laws even apply to injected CO_2, and it is therefore uncertain whether injectors will be subject to hazardous waste disposal requirements and liability for hazardous substance releases.

Other Key Issues that Should Be Proactively Addressed to Support a National CCS Framework

In addition to the technical and legal issues affecting CCS's prospects, key studies, federal advisory committees, and the stakeholders we interviewed also identified an array of other issues that would need to be resolved if the technology is to be deployed within a time frame scientists believe is needed to address climate change. Moreover, whereas many of the technical and regulatory issues discussed earlier fall within the domain of two agencies (DOE and EPA), these other issues cross the jurisdictions of the Departments of the Interior and Transportation, the Federal Energy Regulatory Commission, and other agencies in a manner that would require collaboration between agencies and, in many cases, coordination with state governments and other entities.

Property Rights and Liability Issues Related to CO_2 Injection on Both Federal and Nonfederal Lands

Under a national CCS program, CO_2 could be sequestered on both federal and nonfederal lands and would raise complex property rights issues needing resolution in both instances. In the case of federal lands, BLM, which manages the federal government's mineral resources, is required by the Energy Independence and Security Act of 2007[45] to report by December 2008 on a framework to manage geological carbon sequestration activities on public lands. According to BLM officials, the report will include a discussion of the unresolved property ownership and liability issues related to long-term CO_2 storage. They note that the report will also discuss the statutory authority BLM currently has and what it lacks, such as the authority to establish a funding mechanism for monitoring and mitigation efforts associated with sequestration sites. They cautioned, however, that the report will not recommend solutions to current uncertainties and explained that since injected CO_2 can move onto adjacent private or state lands, resolving them will require collaboration with private landowners and state agencies.

Nationwide CO_2 sequestration would also pose major challenges on nonfederal lands. EPA notes that states with primacy for the UIC program have typically addressed such challenges when they have arisen under that program. The agency acknowledged the additional complications that would arise as stored CO_2 crossed state boundaries, but noted that such cross-jurisdictional issues typically occur under the UIC program and that states have worked together to address them. Nonetheless, the significantly larger scale of a future CCS program could magnify the problems posed by these jurisdictional issues. EPA officials noted that they are hoping that the proposed rule's comment process will surface ideas to address these problems. However, EPA officials also note that the agency lacks authority to issue regulations resolving these issues.

Furthermore, while EPA's proposed rule reaffirms liability related to underground sources of drinking water, ambiguity remains regarding who—the injector or the property owner— is ultimately responsible for unanticipated releases of the injected CO_2 that have other effects. As discussed earlier, the released CO_2 could interfere with the adjacent mineral owners' abilities to extract those resources, and the injection well's operator could be held liable for nuisance, trespass, or another tort.

CO_2 Pipeline Regulation

Pipelines are the preferred method of transporting large amounts of CO_2. The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) administers safety regulations for CO_2 pipelines that affect interstate commerce and certifies states that have adopted regulations compatible with the minimum federal safety standards to regulate their intrastate pipelines. No federal agency has claimed jurisdiction over siting, rates, or terms of service for interstate CO_2 pipelines.[46] However, early assessments indicate that a nationwide CCS program could require a network of interstate CO_2 pipelines that would raise cross-jurisdictional issues and involve multiple regulatory authorities—all in the unprecedented context of a nationwide program to transport massive volumes of CO_2.

Neither the Federal Energy Regulatory Commission (FERC) or Surface Transportation Board (STB) currently regulate interstate CO_2 pipelines and have not developed any guidance for possible regulation because, according to agency officials, neither agency has statutory authority to do so. FERC has the statutory authority to regulate the siting, rates, and terms of service for interstate pipelines transporting natural gas, which is defined as "natural gas unmixed or any mixture of natural and artificial gas."[47] FERC has interpreted this statutory language to mean a gaseous mixture of hydrocarbons that is used as a fuel.[48] According to FERC officials, under this interpretation, CO_2 pipelines fall outside of the commission's jurisdiction.[49] According to the FERC Chairman's congressional testimony, he would not recommend that Congress preempt the states on CO_2 pipelines because state siting has not been a failure, unlike the situation that led to federal preemption of natural gas pipeline siting.[50] FERC officials noted that the commission could have a prospective role in regulation of CO_2 pipelines, which could be modeled on its natural gas transport and storage work, but that it would need statutory authority to take such a role.

The STB has statutory jurisdiction over pipelines that transport a commodity "other than water, gas, or oil."[51] STB's predecessor, the Interstate Commerce Commission, interpreted its organic statute as excluding all gas types (including CO_2), regardless of origin or source, from its jurisdiction.[52] Therefore, the commission concluded that it lacked jurisdiction over interstate CO_2 pipelines. STB staff told us that if a party sought reconsideration of the prior decision disclaiming jurisdiction over interstate CO_2 pipelines, the board would consider re-examining the commission's earlier decision.

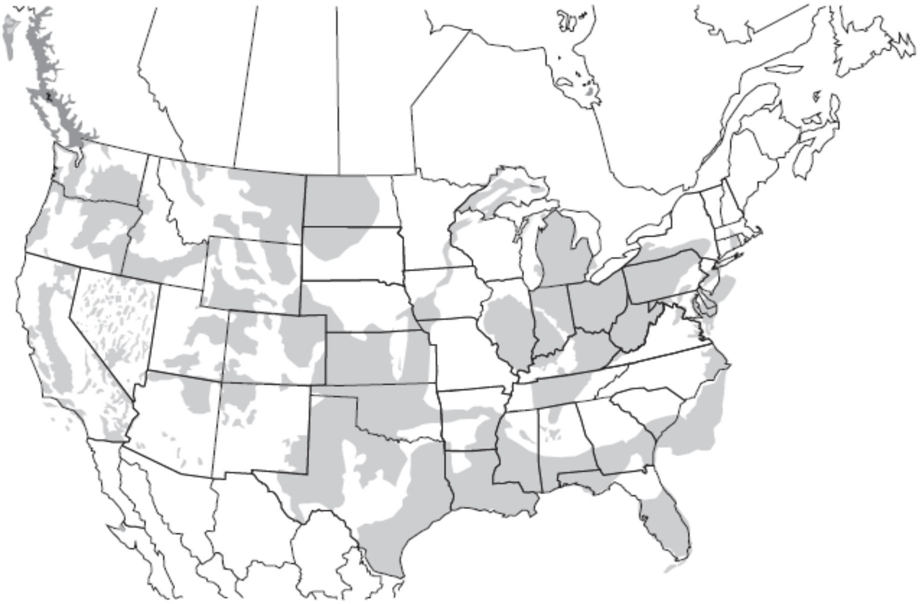
While neither FERC nor STB has developed guidance for the regulation of interstate CO_2 pipelines, the stakeholders we interviewed had differing views on whether federal regulation of CO_2 pipelines should be expanded. Several stakeholders thought it would be necessary for the federal government to take a more active role in siting issues and CO_2 pipeline rates. On the other hand, several other stakeholders expressed concern that expanding federal regulation could have unintended consequences. For example, one industry stakeholder told us that regulating pipeline rates could discourage investment in new pipelines.

Other factors may need to be considered for CO_2 pipelines that cross federal lands managed by BLM. According to stakeholders, one key question will be whether new CO_2 pipelines should operate as common carriers under federal law. As common carriers, pipelines' terms of service would need to be just, reasonable, and nondiscriminatory. Under the Federal Land Policy Management Act, BLM has the authority to grant rights-of-way for pipelines across federal lands but not to require them to operate as common carriers. In addition, BLM officials told us they are not assessing the rights-of-way on federal lands for CO_2 pipelines because their current statutory authority for rights-of-way is sufficient.

DOE's Southwestern and West Coast Regional Carbon Sequestration Partnerships are presently conducting a CO_2 pipeline study, in conjunction with MIT and Sandia National Laboratories, which may inform the discussion about future CO_2 pipelines. According to DOE officials, the report will be issued next year. The officials note that it is not clear whether the report will address all of the relevant issues, including regulatory jurisdiction and siting decisions.[53]

Detailed Assessment of Feasible CO_2 Storage Sites

In recent years, DOE has worked with state geologic survey offices and other partners to construct a national carbon sequestration geographic information system that provides information that can be used to evaluate the potential for CO_2 geologic sequestration across the United States. However, knowledgeable authorities agree that a more detailed evaluation of these sites' actual capacity is needed. As figure 4 shows, the geology of much of the United States may be well suited for CO_2 sequestration. However, a more detailed evaluation would determine whether these potential sites are actually appropriate for long-term CO_2 sequestration. For example, it is currently not known whether the caprock overlying these geologic formations is sufficient to contain stored CO_2.



Source: GAO analysis of DOE data.

Figure 4. Potential Geologic Storage in the United States.

The Energy Independence and Security Act of 2007[54] requires the U.S. Geological Survey (USGS) to develop a methodology for, and conduct an assessment of, the capacity for sequestration of CO_2 in the United States. USGS officials explained that their approach will be to explore geologic formations at the individual sedimentary basin level, and they will take storage integrity and injectivity into account. They plan to begin with oil and gas reservoirs because these are the most familiar geologic formations in terms of the integrity of the reservoirs and their ability to store CO_2. USGS officials will then assess saline formations, about which less data are available. According to USGS officials, the methodology should be completed by March of 2009, at which time it will be released for external technical review and public comment. Following any needed revisions to the methodology and receipt of funding, the USGS will proceed with the actual assessment.

Potential Public Opposition Arising from Health Concerns over CO_2 Storage and Transport

According to the preamble to EPA's proposed rule, improperly operated injection activities or ineffective long-term storage could result in release of injected CO_2 to the atmosphere, resulting in the potential to impact human health. EPA's summaries of stakeholder workshops indicate that public health concerns have been expressed about such issues. One concern is the risk that improperly operated injections could result in the release of CO_2, and that at very high concentrations and with prolonged exposure, CO_2 can lead to suffocation. Concerns have also been raised that improperly injected CO_2 could raise the pressure in a geologic formation and, if it became too high, could cause otherwise dormant faults to trigger seismic events, such as earthquakes. The IPCC has noted, however, that 99 percent of the CO_2 stored in appropriately selected and managed formations is very likely to be retained for over 100 years,[55] and EPA states in the preamble to its proposed rule that the risk of asphyxiation and other health effects from airborne exposure to CO_2 resulting from injection activities is minimal.

Thus far at least, there has been little public opposition to the CO_2 injections that have taken place in states such as Texas to enhance oil recovery. However, several notable studies explain that this lack of publicly-expressed concern may reflect more a lack of knowledge about CCS rather than confidence that the process is safe.[56] This is suggested in the IPCC's 2005 report on CCS which stated, for example, that there is insufficient public knowledge of climate change issues and of the various mitigation options and their potential impact. In another 2005 study, researchers surveyed 1,200 people, representing a general population sample of the United States, and found that that less than 4 percent of the respondents were familiar with the terms carbon dioxide capture and storage or carbon storage.

Some of the stakeholders we interviewed explained that public opposition could indeed grow when CCS extends beyond the relatively small projects used to enhance oil and gas recovery, to include much larger CO_2 sequestration projects located in more populated areas. One noted, in particular, that a lack of education about CCS's safety could potentially create confusion and fear when commercial-scale CCS is implemented.

Citing such concerns, a recent report by the National Academy of Sciences underscored the importance of public outreach, noting that while the success of DOE's carbon capture program depends heavily on its ability to reduce the cost of the technology, "the storage program cannot be successful if a significant fraction of the public views it as dangerous or unacceptable. Thus, the technologies must not only be safe and effective, they must be explainable to the public and the regulatory community in such a way as to instill confidence that they are in fact safe and effective."[57] The report went on to caution that "the federal government in general and the DOE in particular have not had a good track record in accomplishing this task in other programs." For its part, EPA received similar advice from its Clean Air Act Advisory Committee's Advanced Coal Technology Work Group. The Work Group's January 2008 report recommended that the agency immediately develop, in consultation with other agencies, a public outreach effort to explain carbon capture and sequestration.[58] A diverse group of panel members at EPA's 2007 UIC workshop made similar recommendations for public outreach and participation.

Accounting System for Measuring CO_2 Stored by CCS for Use in a CO_2 Emissions Trading Plan

According to a recent federal advisory committee report, an accounting system, or protocol, will be needed to quantify the CO_2 emissions from CCS. The accounting protocol could clarify uncertainty related to monitoring, reporting, quality assurance and control, and cross-border issues. Establishing this protocol would be a necessary step to integrate projects that prevent CO_2 from being emitted to the atmosphere into a future regulatory regime that addresses climate change. The advisory committee report also notes that the IPCC has released national

greenhouse gas inventory guidelines for CO_2 capture, transport, injection, and storage, and that a comprehensive CCS accounting protocol developed by EPA and other agencies would provide needed guidance for applying IPCC Guidelines in the United States.

The European Union's experience suggests that in planning for future CCS deployment, it is important to address such practical issues early in the process, particularly how to address reductions in emitted CO_2 achieved by CCS. Specifically, the European Commission proposes to revise the EU ETS to include CO_2 capture facilities, pipelines, and storage sites. A European Commission report acknowledges that resolution of this important practical matter is important to remove barriers to future CCS deployment.[59] Although EU member states can seek to include CCS projects in their national emissions cap by gaining approval from the European Commission on a case-by-case basis, proposed legislation would explicitly include, after 2012, facilities involved in the capture, transportation, and storage of CO_2 in the ETS. These facilities would then earn allowances for nonemitted CO_2 and would have to surrender emission allowances for any leakages of CO_2 that occur.

Thus far, EPA's Office of Air and Radiation has begun to develop a rule requiring mandatory reporting of greenhouse gas emissions from all sectors of the economy.[60] The agency is not, however, developing a protocol clarifying how emissions avoided as a result of a CCS project would be measured, nor how a future emissions trading plan would treat the avoided emissions. EPA officials explained that, given the pressure of other priorities, they would only develop such a protocol when mandated by Congress to do so. However, they noted that such an accounting system would be closely linked to the design of voluntary programs, future policies, and regulations to reduce greenhouse gas emissions.

CONCLUSIONS

Recent federal and international assessments indicate that the United States will need to rely on CCS as an essential mitigation option to achieve appreciable reductions in greenhouse gas emissions. Federal agencies whose action—or inaction—will greatly affect the prospects for timely CCS deployment have taken early steps that address some barriers to CCS, but have left critical gaps that impede our understanding of CCS's full potential for reducing CO_2 emissions and that could affect CCS deployment on a broader scale.

DOE has invested heavily in advancing CCS in IGCC plants, but knowledgeable authorities agree that these facilities will account for only a small percentage of power plants' CO_2 emissions in the next several decades to come. DOE has recently begun to shift its approach in a way that also emphasizes development of CCS technology for existing coal-fired power plants. Given the broad consensus that the technology used by these plants will dominate coal-fired power plant capacity for the next several decades—both in the United States and around the world—we believe the agency should continue this trend. EPA has begun to address some of the regulatory uncertainties under the SDWA that will need resolution for a national CCS program to move forward, but other key issues associated with other environmental statutes—such as RCRA, CERCLA, and the NSR provisions of the Clean Air Act—have not been addressed.

In addition to these key barriers, there is an array of other issues that would need to be resolved if the technology is to be deployed within a time frame scientists believe is needed to address climate change. Moreover, whereas many of the technical and regulatory issues discussed earlier fall within the domain of two key agencies (DOE and EPA), these other issues cross the jurisdictions of the Departments of the Interior and Transportation, FERC, and other agencies in a manner that would require collaboration between agencies and, in many cases, coordination with state governments and other entities. While the DOE-led CCTP coordinates climate change technology research, development, demonstration, and deployment among federal agencies, it has not been tasked with resolving the issues of CO_2 pipeline regulation and infrastructure and liability for stored CO_2, among other issues. Furthermore, officials from relevant offices within the Departments of the Interior and Transportation told us they have not yet been invited to participate in CCTP discussions.

RECOMMENDATIONS FOR EXECUTIVE ACTION

We recommend that the Secretary of Energy direct the Office of Fossil Energy to continue its recent budgetary practice of helping to ensure that greater emphasis is placed on supporting technologies that can reduce greenhouse gas emissions at existing coal-fired power plants.

We recommend that the Administrator of EPA more comprehensively examine barriers to CCS development by identifying key issues that fall outside the agency's SDWA authority. Specifically, we recommend that the Administrator direct the cognizant EPA offices to collectively examine their authorities and responsibilities under RCRA, CERCLA, and the Clean Air Act for the purposes of (1) obtaining the information necessary to make informed decisions about the regulation of (and potential liabilities associated with) the capture, injection, and storage of CO_2; (2) using this information to develop a comprehensive regulatory framework for capture, injection, and underground storage of CO_2; and (3) identifying any areas where additional statutory authority might be needed to address key regulatory and legal issues related to CO_2 capture, injection, and storage.

We recommend that the Executive Office of the President establish an interagency task force (or other mechanism as deemed appropriate) to examine the broad range of issues that, if not addressed proactively, could impede large-scale commercial CCS deployment and to develop a strategy for cognizant federal agencies to address these issues. Among the issues this task force should examine are: (1) identifying strategies for addressing regulatory and legal uncertainty that could impede the use of federal lands for the injection, storage, and transport of CO_2; (2) examining how any regulation of carbon emissions will address leakage of stored CO_2 into the atmosphere; (3) developing an accounting protocol to quantify the CO_2 emissions from capture, transport, injection, and storage of CO_2 in geologic formations; (4) examining CO_2 pipeline infrastructure issues in the context of developing a large-scale national CCS program; (5) developing a public outreach effort to explain CCS; (6) evaluating the efficacy of existing federal financial incentives authorized by the Energy Policy Act of 2005 and other relevant laws in furthering the deployment of CCS; and (7) examining the federal and state resources required to implement the EPA's expanded UIC program incorporating commercial-scale CCS.

AGENCY COMMENTS AND OUR EVALUATION

We provided a draft of this chapter to the Secretary of DOE and the EPA Administrator for review and comment. DOE's September 9, 2008, letter first "commend[s]… the comprehensiveness of this study, including the analysis of potential barriers to widespread commercialization of CCS and the potential need for involvement by multiple Federal agencies." The letter's subsequent comments are also consistent with the report's recommendations that (1) DOE continue to place greater emphasis on pursuing increased funding for CO_2 emissions control technologies for existing coal-fired power plants and (2) an interagency task force be established to examine critical CCS issues and develop a comprehensive CCS strategy. However, the agency expressed disagreement with our rationale for placing greater emphasis on CCS technologies applicable to these facilities and suggests a different approach for the interagency task force we recommended:

- *Placing greater emphasis on existing coal-fired power plants*. DOE says that while it agrees with the report's findings concerning the importance of pursuing CCS options for existing coal-fired power plants, these findings incorrectly imply "that DOE has focused too heavily on the IGCC option for new plants at the expense of retrofit opportunities." We are not second-guessing decisions DOE made in past decades. Rather, we are concerned about how the agency can best move forward in light of the new emphasis on substantially reducing CO_2 emissions and the scientific consensus that CCS will be needed to help reduce emissions.
- *Establishing an interagency CCS Task Force*. DOE maintained that a coordinating body—the DOE-led CCTP—already addresses these kinds of issues. However, the CCTP's scope focuses on technology; it does not address legal and institutional issues such as the resolution of CO_2 pipeline regulation and infrastructure or liability for stored CO_2, among others. In addition, officials from cognizant offices within the Departments of the Interior and Transportation told us they have not yet been invited to participate in CCTP discussions. Moreover, we continue to believe that a more centralized task force, with a broader scope than the technology-focused CCTP, may be a preferable alternative.

DOE's letter appears in appendix II, along with our responses to each of its main points. The agency separately provided technical comments, which were incorporated in our final report, as appropriate.

EPA's September 12, 2008, letter stated that providing regulatory certainty on issues related to geological storage of CO_2 was a high priority for the agency and agreed with the intent of our recommendation—to provide clarity on how the broader range of statutes within the agency's jurisdiction may apply. The agency noted that it had made an initial effort to identify and discuss these issues in the preamble of its July 2008 proposed rulemaking and had requested comments on many SDWA topics—including some of those identified in our report. It said it expected further progress on these SDWA topics after receiving input from stakeholders during the comment period (which extends through November 24, 2008). EPA did not respond to the recommendation that an interagency task force be established to examine critical CCS issues and to develop a comprehensive CCS strategy. The agency also offered several other comments and clarifications, which are presented in appendix III, along with our responses.

Sincerely yours,
John B. Stephenson Director, Natural Resources and Environment

APPENDIX I: OBJECTIVES, SCOPE, AND METHODOLOGY

We were asked to examine (1) the key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of carbon capture and storage (CCS) technology and (2) the actions federal agencies are taking to overcome barriers to or facilitate the commercial-scale deployment of CCS technology.

To determine the key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of CCS, we reviewed assessments by the Intergovernmental Panel on Climate Change, the National Academy of Sciences, federal agencies, nongovernmental organizations, and academic researchers. We also contacted a nonprobability sample of stakeholders from industry, including officials from electric power companies and oil and gas companies, as well as stakeholders from nongovernmental organizations and academic researchers. We selected major U.S. energy producing companies, as well as organizations and researchers that participate actively in ongoing dialogues on CCS. We also selected a number of smaller companies and organizations to ensure that we obtained a broader range of perspectives on key issues.[61] We used a semistructured interview guide to interview these stakeholders and facilitate analysis of what stakeholders identified as key economic, legal, regulatory, and technological barriers impeding commercial-scale deployment of CCS. To obtain federal agency officials' perspectives on key economic, legal, regulatory, and technological barriers, we conducted interviews with officials from the Department of Energy's (DOE) Office of Fossil Energy, the Environmental Protection Agency's (EPA) Office of Ground Water and Drinking Water and Office of Air and Radiation, as well as other agencies, primarily in the Department of the Interior and Department of Transportation.

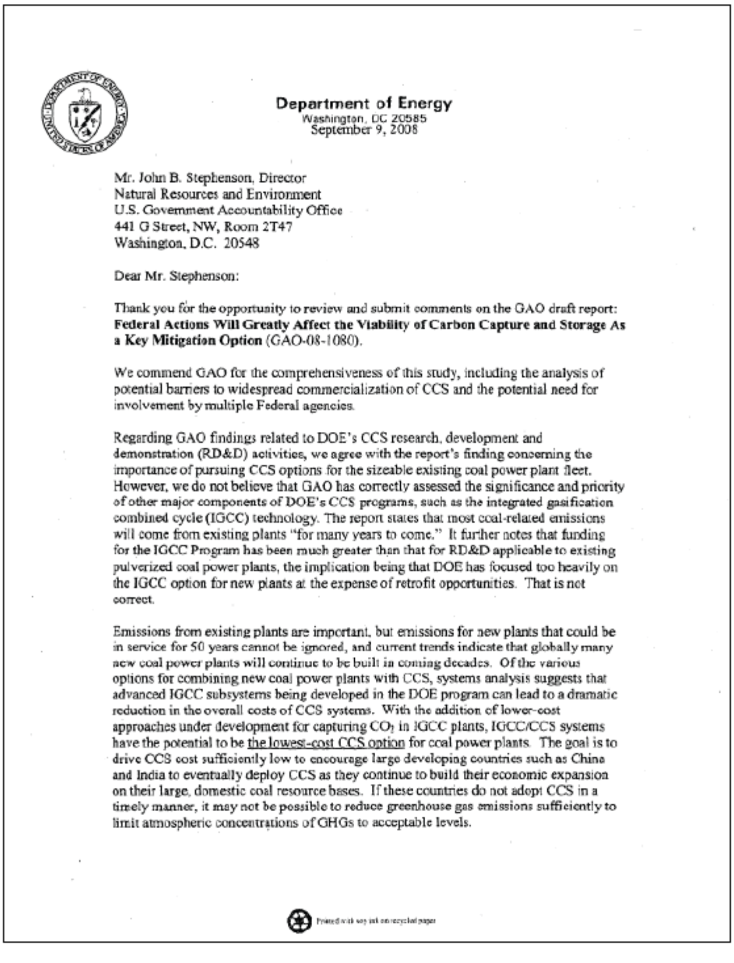
To examine the actions federal agencies are taking to overcome barriers to or facilitate the commercial-scale deployment of CCS technology, we conducted interviews with officials from the DOE's Office of Fossil Energy and the EPA's Office of Ground Water and Drinking Water and the Office of Air and Radiation to assess these agencies' efforts to overcome barriers to or facilitate the commercial-scale deployment of CCS. Moreover, we reviewed a report by the National Academy of Sciences assessing DOE's Fossil Energy research and development programs. We reviewed reports made by two federal advisory committees, the National Coal Council advising the Secretary of Energy and the Clean Air Act Advisory Committee advising the EPA Administrator, and asked agency officials how they were implementing recommendations contained in these reports. We obtained and analyzed 12 years of DOE budget information, from fiscal year 1997 through the present, to assess the funding DOE has provided for various CO_2 capture related technologies. We reviewed the proposed EPA rule for the underground injection of CO_2 for geologic sequestration under the Safe Drinking Water Act. To obtain perspectives from outside the government, using the methodology described above we contacted a nonprobability sample of stakeholders and used a semistructured interview guide to facilitate an aggregate analysis of stakeholders' assessments of the actions of federal agencies. To assess the extent to which other federal agencies are overcoming barriers to or facilitating the commercial-scale deployment of CCS technology, we also conducted interviews with officials from federal agencies in the Department of the Interior and Department of Transportation (DOT), including the U.S. Geological Survey, Bureau of Land Management, Surface Transportation Board, and DOT's

Pipeline and Hazardous Materials Safety Administration, as well as the Federal Energy Regulatory Commission. To assess the role of the Climate Change Technology Program (CCTP) in coordinating CCS-related activities across federal agencies, we interviewed a senior CCTP official and asked officials at several federal agencies about their involvement in CCTP activities. Finally, we attended two stakeholder workshops the EPA held concerning development of proposed regulations for the underground injection of CO_2 for geologic sequestration under the Safe Drinking Water Act.

We conducted this performance audit from October 2007 to September 2008 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

APPENDIX II: COMMENTS FROM THE DEPARTMENT OF ENERGY

Note: GAO comments supplementing those in the report text appear at the end of this appendix.



Department of Energy
Washington, DC 20585
September 9, 2008

Mr. John B. Stephenson, Director
Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, NW, Room 2T47
Washington, D.C. 20548

Dear Mr. Stephenson:

Thank you for the opportunity to review and submit comments on the GAO draft report: **Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage As a Key Mitigation Option** (GAO-08-1080).

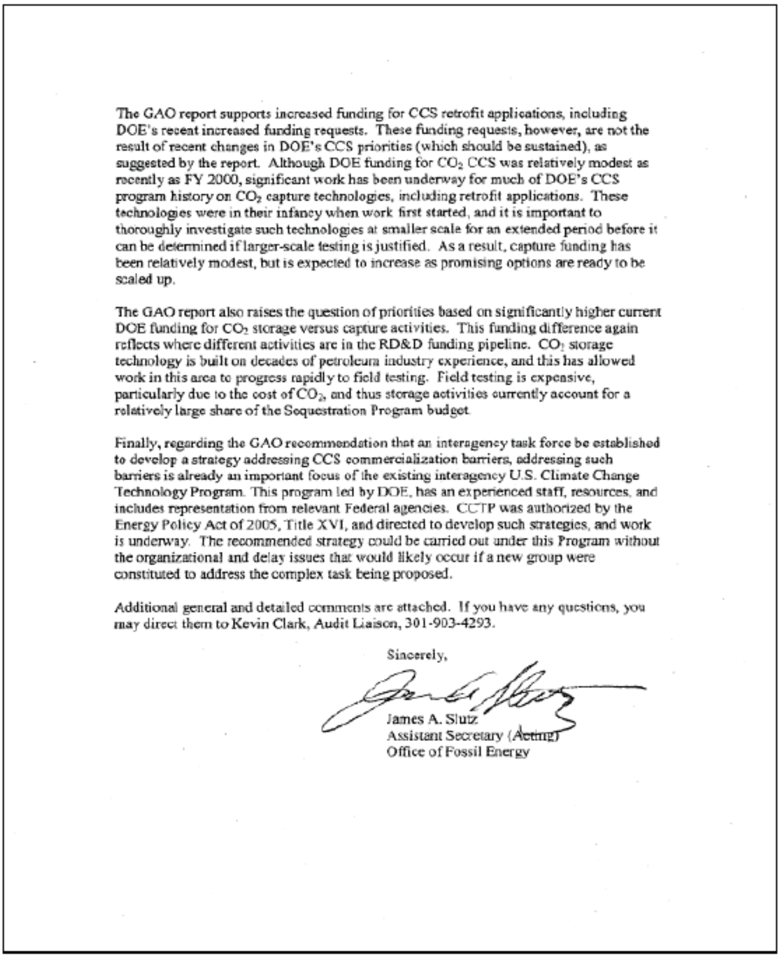
We commend GAO for the comprehensiveness of this study, including the analysis of potential barriers to widespread commercialization of CCS and the potential need for involvement by multiple Federal agencies.

See comment 1.

Regarding GAO findings related to DOE's CCS research, development and demonstration (RD&D) activities, we agree with the report's finding concerning the importance of pursuing CCS options for the sizeable existing coal power plant fleet. However, we do not believe that GAO has correctly assessed the significance and priority of other major components of DOE's CCS programs, such as the integrated gasification combined cycle (IGCC) technology. The report states that most coal-related emissions will come from existing plants "for many years to come." It further notes that funding for the IGCC Program has been much greater than that for RD&D applicable to existing pulverized coal power plants, the implication being that DOE has focused too heavily on the IGCC option for new plants at the expense of retrofit opportunities. That is not correct.

See comment 2.

Emissions from existing plants are important, but emissions for new plants that could be in service for 50 years cannot be ignored, and current trends indicate that globally many new coal power plants will continue to be built in coming decades. Of the various options for combining new coal power plants with CCS, systems analysis suggests that advanced IGCC subsystems being developed in the DOE program can lead to a dramatic reduction in the overall costs of CCS systems. With the addition of lower-cost approaches under development for capturing CO_2 in IGCC plants, IGCC/CCS systems have the potential to be the lowest-cost CCS option for coal power plants. The goal is to drive CCS cost sufficiently low to encourage large developing countries such as China and India to eventually deploy CCS as they continue to build their economic expansion on their large, domestic coal resource bases. If these countries do not adopt CCS in a timely manner, it may not be possible to reduce greenhouse gas emissions sufficiently to limit atmospheric concentrations of GHGs to acceptable levels.



See comment 3.

The GAO report supports increased funding for CCS retrofit applications, including DOE's recent increased funding requests. These funding requests, however, are not the result of recent changes in DOE's CCS priorities (which should be sustained), as suggested by the report. Although DOE funding for CO_2 CCS was relatively modest as recently as FY 2000, significant work has been underway for much of DOE's CCS program history on CO_2 capture technologies, including retrofit applications. These technologies were in their infancy when work first started, and it is important to thoroughly investigate such technologies at smaller scale for an extended period before it can be determined if larger-scale testing is justified. As a result, capture funding has been relatively modest, but is expected to increase as promising options are ready to be scaled up.

See comment 4.

The GAO report also raises the question of priorities based on significantly higher current DOE funding for CO_2 storage versus capture activities. This funding difference again reflects where different activities are in the RD&D funding pipeline. CO_2 storage technology is built on decades of petroleum industry experience, and this has allowed work in this area to progress rapidly to field testing. Field testing is expensive, particularly due to the cost of CO_2, and thus storage activities currently account for a relatively large share of the Sequestration Program budget.

See comment 5.

Finally, regarding the GAO recommendation that an interagency task force be established to develop a strategy addressing CCS commercialization barriers, addressing such barriers is already an important focus of the existing interagency U.S. Climate Change Technology Program. This program led by DOE, has an experienced staff, resources, and includes representation from relevant Federal agencies. CCTP was authorized by the Energy Policy Act of 2005, Title XVI, and directed to develop such strategies, and work is underway. The recommended strategy could be carried out under this Program without the organizational and delay issues that would likely occur if a new group were constituted to address the complex task being proposed.

Additional general and detailed comments are attached. If you have any questions, you may direct them to Kevin Clark, Audit Liaison, 301-903-4293.

Sincerely,

James A. Slutz
Assistant Secretary (Acting)
Office of Fossil Energy

The following are GAO's comments on the Department of Energy's letter dated September 9, 2008.

GAO COMMENTS

1. DOE says that while it agrees with the report's findings concerning the importance of pursuing CCS options for existing coal-fired power plants, these findings incorrectly imply "that DOE has focused too heavily on the IGCC option for new plants at the expense of retrofit opportunities." We are not second-guessing decisions DOE made in the decades before concerns about carbon dioxide (CO_2) emissions had taken on the prominence they have today. Rather, we are concerned about how the agency can best move forward in light of the new emphasis on CO_2 emissions and the scientific consensus that CCS will be needed to help deal with them.

2. DOE says that even though CO_2 emissions from existing plants are important, current global trends indicate that many new coal power plants will continue to be built in coming decades and that many would choose IGCC as the lowest-cost CCS option if it were

available. However, a DOE report, *Tracking New Coal-Fired Power Plants*, indicates that the new coal fired power plants currently being built and permitted in the United States are predominately using pulverized coal technologies, with a smaller number of plant operators opting for IGCC technology. Furthermore, DOE cites the importance of controlling CCS emissions in developing countries—in particular, China and India. However, the International Energy Agency states that "the expansion of coal-fired generation in China will continue to be based on pulverized coal" and observes that all of India's operating coal-fired power plants use a form of pulverized coal technology. That said, our report does not call for a radical shift in focus from IGCC to conventional technology, but rather a budgetary strategy that appropriately reflects a greater emphasis on developing capture technologies that could be applied to existing pulverized coal power plants. As our draft report noted, such a strategy has in fact already been reflected in recent DOE budgets.

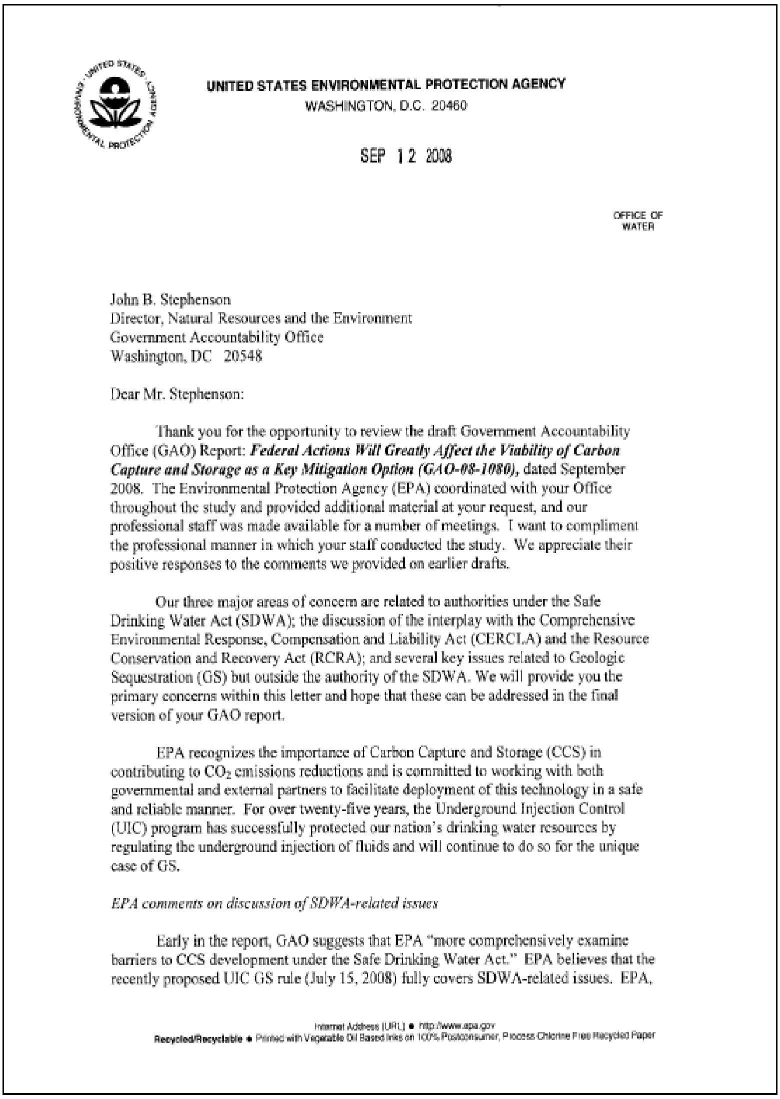
3. DOE acknowledges that it has recently increased requested funding for CCS technologies applicable to existing plants, but states that the increase does not necessarily reflect a higher priority. Rather, the increase reflects an evolution of the technology development process. Specifically, it is now moving from investigating such technologies from a less costly small scale to the point where costs rise as technology development is "scaled up." Recent statements by the agency, however, suggest that research applicable to existing coal-fired power plant technologies do warrant a higher priority. In particular, DOE's recent funding announcement for CCS technology development for existing pulverized coal power plants states that this funding opportunity is "driven by the fact that existing coal-fired power plants produce a sizeable portion of current CO_2 emissions from all fossil fuel-based sources, and that only about 6 GW of the existing coal-fired electricity generating fleet is projected to retire by 2030." Similarly, in our discussions with DOE fossil energy officials about their fiscal year 2008 budget priorities, they pointed to language in House Report 110-185, which recommended "a rigorous research program on the potential for retrofitting existing coal plants for CO_2 capture and sequestration."

4. DOE questions the report's observation that funding for CO_2 storage has been significantly higher than the resources devoted to CO_2 capture, noting that the higher funding level for storage-related activities reflects the fact that it has evolved to the point where advances in storage would now require expensive field-testing. We do not dispute the need to invest in the field-testing of storage activities. Rather, we note that timely CCS deployment will occur only if progress is made with both capture and storage and that considerably more progress is needed on the capture front. A comprehensive CO_2 storage capability will mean little if there is no CO_2 to store.

5. DOE maintains that a coordinating body—the DOE-led Climate Change Technology Program (CCTP)—already addresses CCS-related issues. However, the CCTP's scope focuses on technology; it does not address legal and institutional issues such as CO_2 pipeline regulation and infrastructure or liability for stored CO_2, among others. In addition, officials from cognizant offices within the Departments of the Interior and Transportation told us they have not yet been invited to participate in CCTP discussions. Moreover, we continue to believe that a more centralized task force, with a broader mission than the technology-focused CCTP, may be a preferable alternative.

APPENDIX III: COMMENTS FROM THE ENVIRONMENTAL PROTECTION AGENCY

Note: GAO comments supplementing those in the report text appear at the end of this appendix.



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

SEP 12 2008

OFFICE OF
WATER

John B. Stephenson
Director, Natural Resources and the Environment
Government Accountability Office
Washington, DC 20548

Dear Mr. Stephenson:

Thank you for the opportunity to review the draft Government Accountability Office (GAO) Report: ***Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage as a Key Mitigation Option (GAO-08-1080),*** dated September 2008. The Environmental Protection Agency (EPA) coordinated with your Office throughout the study and provided additional material at your request, and our professional staff was made available for a number of meetings. I want to compliment the professional manner in which your staff conducted the study. We appreciate their positive responses to the comments we provided on earlier drafts.

Our three major areas of concern are related to authorities under the Safe Drinking Water Act (SDWA); the discussion of the interplay with the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and the Resource Conservation and Recovery Act (RCRA); and several key issues related to Geologic Sequestration (GS) but outside the authority of the SDWA. We will provide you the primary concerns within this letter and hope that these can be addressed in the final version of your GAO report.

EPA recognizes the importance of Carbon Capture and Storage (CCS) in contributing to CO_2 emissions reductions and is committed to working with both governmental and external partners to facilitate deployment of this technology in a safe and reliable manner. For over twenty-five years, the Underground Injection Control (UIC) program has successfully protected our nation's drinking water resources by regulating the underground injection of fluids and will continue to do so for the unique case of GS.

EPA comments on discussion of SDWA-related issues

Early in the report, GAO suggests that EPA "more comprehensively examine barriers to CCS development under the Safe Drinking Water Act." EPA believes that the recently proposed UIC GS rule (July 15, 2008) fully covers SDWA-related issues. EPA,

See comment 1.

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working with partners at the Department of Energy (DOE) and several State regulatory agencies, proposed these new UIC regulations specifically for commercial-scale GS. The public comment period is currently ongoing for this proposed regulation and promulgation of the rule is anticipated in late 2010 or early 2011. The GAO report includes a preliminary discussion of the recently proposed UIC rule. We suggest that information related to this proposed rule should be placed as early in the report as possible. Although there may be misunderstandings among certain stakeholders regarding the regulatory framework for CO_2 injection, EPA has been clear that there is no regulatory impediment to seeking a permit for large-volume injection of CO_2 under the existing UIC program. In fact, depending on the nature of the injection activity, CO_2 injection could currently be permitted as a Class I, Class II or Class V UIC well. The purpose of the Class VI well category which is proposed in EPA's rule is to provide a more appropriate well classification for program implementation of this technology on a large scale.

See comment 2.

The draft report mentions 'ambiguity' regarding whether the operator of a GS site will remain liable indefinitely for potential problems posed by leakage of CO_2. EPA has been clear during discussions with stakeholders that, consistent with current UIC regulations under the SDWA applying to all injection wells, the owner/operator of a GS site will be held liable indefinitely for potential damages caused by leakage of CO_2. Some stakeholders may feel confused about this issue; GAO's report, however, should represent EPA's position, which is also reflected in the proposed rule.

See comment 3.

In addition, the report discusses government indemnification of the potential liability associated with GS sites. It is important to note that EPA does not have authority under the SDWA to release or indemnify injection well owners/operators from long-term liability. Thus, the report should clarify that it is currently beyond the Agency's authority to do this.

Finally, EPA has stated in the proposed Class VI regulation that owners and operators of GS sites must demonstrate financial responsibility for the operation and post-injection site care phases of the project. However, EPA acknowledges the need for additional information and plans to provide guidance on how additional financial responsibility can be demonstrated.

EPA comments on GAO discussion of CERCLA and RCRA

See comment 4.

The GAO report states that ambiguity exists regarding how CERCLA and RCRA regulations may apply to GS sites and states that the proposed EPA UIC-GS rule does not resolve, does not address and is 'unclear' regarding these issues. EPA would appreciate if, at the beginning of this discussion, GAO would note that EPA has discussed RCRA and CERCLA issues in the preamble to the proposed regulation. EPA is currently in the process of further evaluating how CERCLA and RCRA may apply to GS sites. However EPA's proposed rule is clear that if a CO_2 stream meets the definition of "hazardous waste" it may only be injected under the existing provisions for a Class I hazardous well, which by definition is subject to RCRA, and if it falls within certain categories of hazardous waste, it may not be injected unless EPA grants a RCRA exemption. Such hazardous waste streams would not be subject to the proposed Class VI permit. Finally releases of a hazardous substance beyond the scope of a federally-permitted release may be subject to CERCLA authorities.

EPA comments on GAO discussion of issues outside of SDWA authorities

See comment 5.

See comment 6.

The UIC proposed regulations include clarifications on the effect of permits on property rights. 40 CFR 144.35 (b) and (c) clearly state that the issuance of a permit does not convey any property rights of any sort, or any exclusive privilege, and the permit does not authorize any injury to the persons or property or invasion of other private rights, or any infringement of State or local law or regulations. While EPA's proposed rule includes a discussion of how regulations may impact these issues, EPA does not have the authority to propose federal regulations related to property rights. To be clear, EPA does not anticipate resolving issues outside the scope of the SDWA in the context of the regulatory action recently proposed under the UIC program.

EPA response to specific GAO recommendation

GAO recommends that EPA offices "collectively examine their authorities and responsibilities under RCRA, CERCLA, and the Clean Air Act…" Providing regulatory certainty on issues related to GS is a high priority for the Agency and EPA agrees that it is important to provide clarity on the various statutes that may apply. EPA made an initial effort to identify and discuss issues related to SDWA, RCRA and CERCLA in the preamble of its July 2008 proposal and specifically requested comments on various topics including some of those identified by GAO. We hope that the input we receive through the public comment process, in combination with our own efforts to work across EPA to assess implications of these various statutes on GS, will shed more light on these important issues.

We have a few additional comments on the draft final report which we are providing as an enclosure to this letter. Again, we appreciated the opportunity to coordinate with your staff on this project. Should you need additional information or have further questions, please let me know. You may also contact Cynthia C. Dougherty, Director of the Office of Ground Water and Drinking Water, at (202) 564-3750.

Sincerely,

Michael Shapiro

Benjamin H. Grumbles
Assistant Administrator

Enclosure

The following are GAO's comments on the Environmental Protection Agency's letter dated September 12, 2008.

GAO COMMENTS

1. EPA says that its recently-proposed UIC rule fully covers Safe Drinking Water Act (SDWA)-related issues. We have modified the report to more fully reflect the work that EPA is doing to examine SDWA-related barriers to CCS deployment. However, while we acknowledge that the proposed rule discusses and seeks comments on many issues, we continue to believe that it leaves many of these issues unresolved. While EPA's proposed rule prohibits the injection of CO_2 above the lowermost formation containing an underground source of drinking water, EPA is still exploring whether the UIC director should be given the authority to approve such an injection—an issue that can affect whether unmineable coal seams are used for CO_2 storage.

2. EPA suggests that the report should state EPA's position on whether the operator of an injection well will remain liable indefinitely for potential problems posed by leakage of CO_2. Pages 23 and 39 of the draft report did in fact state that well operators remain responsible indefinitely for any endangerment for underground sources of drinking water caused by such leakage. However, the draft report also addressed other unresolved liability issues of concern to stakeholders, which are unrelated to endangerment of underground sources of drinking water. We have added language to further emphasize these issues.

3. EPA says that it is important to note that the agency does not have authority under the SDWA to release injection well owners or operators from long-term liability. The draft report had already done so on page 39 and 40, where it explained that EPA does not have the statutory authority to release well owners or operators from liability or transfer financial responsibility from the well owner or operator to a third party. In response to EPA's comments, we have added language to the report to further clarify this point.

4. EPA suggests that GAO note in its final report that EPA had discussed RCRA and CERCLA issues in the preamble to its proposed rule. The draft report had, in fact, mentioned that EPA addressed RCRA and CERCLA issues in the preamble. For example, page 42 of the draft noted that the preamble explained that pure CO_2 in and of itself is not listed as a hazardous substance under CERCLA, and cautioned that injected CO_2 streams could contain hazardous constituents that would make these streams "hazardous." That said, we continue to believe that the preamble's limited treatment of these issues still leaves much to be resolved about the implications of the Resource Conservation and Recovery Act (RCRA) and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) for CO_2 sequestration. Specifically, EPA suggests that determinations about whether injected CO_2 is a hazardous waste or substance will be made on a case-by-case basis. Moreover, EPA says it is "currently in the process of further evaluating how CERCLA and RCRA may apply to [geologic sequestration] sites."

5. EPA notes that the proposed rule includes clarifications on the effect of permits on property rights. However, these effects were not among the property rights-related issues of greatest concern to the stakeholders we interviewed. As we stated in the report, these

stakeholders told us they were concerned about a lack of clarity regarding ownership of injected CO_2 and ownership of geologic formations.

6. Notwithstanding the permit-related property rights issues raised in comment 5 above, EPA explains that it does not have the authority to propose federal regulations related more broadly to property rights issues. We agree that EPA’s authority does not extend to many of these issues discussed in the report, which is why the report notes that the resolution of this and other issues will require the involvement of other federal agencies and, in some cases, states.

REFERENCES

[1] CCS can also be used to reduce the CO_2 emissions from industrial production of hydrogen, chemicals, substitute natural gas, and transportation fuels.

[2] The International Energy Agency (IEA) is an intergovernmental organization founded in 1974 that acts as energy policy advisor to 27 member countries. The IEA’s current work focuses on climate change policies, market reform, and energy technology collaboration and outreach.

[3] The Intergovernmental Panel on Climate Change (IPCC) is a scientific body set up by the World Meteorological Organization and by the United Nations Environment Programme. The IPCC was established to provide decision makers with an objective source of information about climate change.

[4] Results from nonprobability samples cannot be used to make inferences about a population. This is because, in a nonprobability sample, some elements of the population being studied have no chance or an unknown chance of being selected as part of the sample.

[5] The IPCC notes that these emissions include those from the production, distribution, and consumption of fossil fuels and as a by-product from cement production. The data from 2004 and 2005 are interim estimates.

[6] CCS is not considered suitable for reducing emissions from the transportation, residential, and commercial sectors because sources in these sectors tend to emit small quantities of CO_2.

[7] The IEA’s 2007 *World Energy Outlook* also assesses two alternative scenarios. These include a scenario in which world demand for energy and coal generally increases less than otherwise expected due to changes in government policies that address climate change concerns and a scenario in which world demand increases more than otherwise expected due to higher rates of economic growth in China and India.

[8] This chapter focuses primarily on pre- and post-combustion capture.

[9] When the temperature and pressure of CO_2 are increased, the CO_2 enters a fluid, or supercritical state.

[10] An exception is made for groundwater remediation at hazardous waste sites.

[11] Class V wells are typically shallow wells that place a variety of fluids directly below the land surface.

[12] EPA administers the UIC program in 10 states and for all Indian tribes.

[13] National Coal Council, Technologies to Reduce or Capture and Store Carbon Dioxide Emissions (June 2007).

[14] The IEA defines large scale as injecting over 0.5 Mt (500,000 metric tons) per year.

[15] The IPCC Special Report on CCS notes that some of the CO_2 captured from natural gas processing and ammonia production facilities is used for enhanced oil recovery, a process which may result in the sequestration of a substantial amount of the CO_2 from the atmosphere.

[16] Howard Herzog and Dan Golomb, "Carbon Capture and Storage from Fossil Fuel Use," *Encyclopedia of Energy*, 2004.

[17] Department of Energy, National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants—Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report (2007).

[18] DOE officials told us these estimates were based on Cost and Performance Baseline for Fossil Energy Power Plants—Volume 1.

[19] International Energy Agency, Energy Technology Perspectives 2008: Scenarios and Strategies to 2050 (Paris, 2008).

[20] DOE officials told us that the study was based on current technology and not on possible advanced technology being developed.

[21] MIT, The Future of Coal (2007).

[22] The National Coal Council, Technologies to Reduce or Capture and Store Carbon Dioxide Emissions.

[23] Nearly all existing coal-fired power plants are pulverized coal power plants.

[24] MIT, The Future of Coal.

[25] Department of Energy, National Energy Technology Laboratory, *Carbon Dioxide Capture from Existing Coal-Fired Power Plants* (2007).

[26] The National Coal Council, The Urgency of Sustainable Coal (Washington D.C., 2008).

[27] IPCC, IPCC Special Report on Carbon Dioxide Capture and Storage (2005).

[28] J.M. Antle, University Fellow, Resources for the Future, Is There a Role for Geologic and Terrestrial Carbon Sequestration in Greenhouse Gas Mitigation? (February 2008).

[29] GAO, Air Pollution: Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost, GAO/RCED-95-30 (Washington, D.C.: December 16, 1994) and Air Pollution: Overview and Issues on Emissions Allowance Trading Programs, GAO/RCED-97-183 (Washington, D.C.: July 9, 1997).

[30] Edward S. Rubin et al, "Use of Experience Curves to Estimate Future Cost of Power Plants with CO_2 Capture," *International Journal of Greenhouse Gas Control*, vol. 1, issue 2 (2007).

[31] EU member states can seek to include CCS projects in their national emission cap by gaining approval from the European Commission on a case-by-case basis.

[32] EU Commission Staff Working Document, accompanying document to the Proposal for a Directive of the European Parliament and of the Council on the Geologic Storage of Carbon Dioxide (January 23, 2008).

[33] Syngas is the gas produced by the gasification process, composed of hydrogen, carbon monoxide, and minor amounts of other constituents. While DOE considers the gas stream amenable to CO_2 recovery, CO_2 capture was not actually demonstrated in the projects.

[34] Jose D. Figueroa, Timothy Fout, Sean Plasynski, Howard McIlvried, and Rameshwar D. Srivastava, "Advances in CO_2 capture technology- The U.S. Department of Energy's Carbon Sequestration Program," *International Journal of Greenhouse Gas Control,* vol. 2 (2008).

[35] National Research Council, National Academy of Sciences, Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000 (Washington, D.C., 2001).

[36] National Academy of Sciences, Energy Research at DOE: Was It Worth It?

[37] National Research Council, National Academy of Sciences, Prospective Evaluation of Applied Energy Research and Development at DOE (Phase Two) (Washington, D.C., 2007).

[38] DOE, Cost and Performance Baseline for Fossil Energy Plants—Volume 1.

[39] DOE, Cost and Performance Baseline for Fossil Energy Power Plants—Volume 1.

[40] National Academy of Sciences, *Prospective Evaluation.*

[41] The National Coal Council, The Urgency of Sustainable Coal.

[42] 31 U.S.C. § 3302(b).

[43] The proposed rule's preamble notes that if a CO_2 stream contains hazardous waste as a constituent, it must be permitted as a Class I well. Class I wells are intended for hazardous materials.

[44] Clean Air Act Advisory Committee Advanced Coal Technology Work Group, Final Report of the Advanced Coal Technology Work Group (Jan. 29, 2008).

[45] Pub. L. No. 110-140 (2007).

[46] FERC has jurisdiction over interstate pipelines that transport oil or natural gas. STB has jurisdiction over interstate pipelines that transport a commodity other than water, gas, or oil.

[47] 15 U.S.C. § 717a(5).

[48] Cortez Pipeline Company, 7 F.E.R.C. ¶ 61,024 (1979).

[49] *Id.*

[50] Testimony of the Honorable Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission, before the Committee on Energy and Natural Resources, United States Senate, January 31, 2008.

[51] 49 U.S.C. § 15301.

[52] 45 Fed. Reg. 85,178 (Dec. 24, 1980); 46 Fed. Reg. 18,805 (Mar. 26, 1981).

[53] DOE officials note that several of the Regional Partnerships, including the Southwest, West Coast, Southeast, Midwest, and Plains CO_2 reduction partnerships, have completed or are working on pipeline studies for their individual regions.

[54] Pub. L. No. 110-140 (2007).

[55] IPCC, IPCC Special Report on Carbon Dioxide Capture and Storage.

[56] IPCC, IPCC Special Report on Carbon Dioxide Capture and Storage (2005); National Academy of Sciences, Prospective Evaluation; and Congressional Research Service, Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges (July 2008).

[57] National Academy of Sciences, *Prospective Evaluation.*

[58] Clean Air Act Advisory Committee Advanced Coal Technology Work Group, Final Report of the Advanced Coal Technology Work Group.

[59] EU Commission Staff Working Document, accompanying document to the Proposal for a Directive of the European Parliament and of the Council on the Geologic Storage of Carbon Dioxide, January 23, 2008.

[60] Specifically, EPA officials told us they are developing a proposal that would require “upstream” producers and “downstream” sources above appropriate thresholds to report their greenhouse gas emissions.

[61] Results from nonprobability samples cannot be used to make inferences about a population. This is because, in a nonprobability sample, some elements of the population being studied have no chance or an unknown chance of being selected as part of the sample.

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