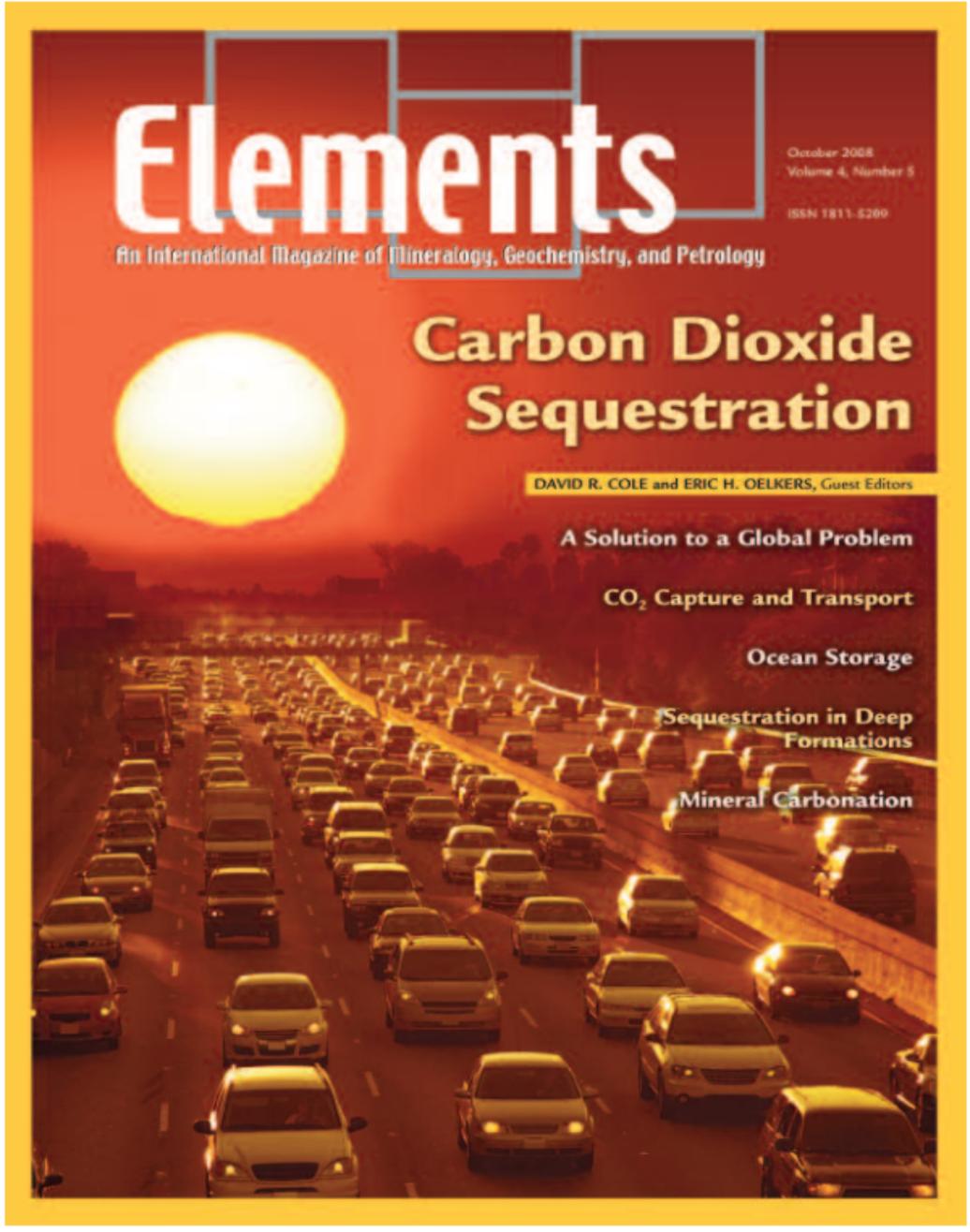


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Carbon Dioxide Sequestration

DAVID R. COLE and ERIC H. OELKERS, Guest Editors

A Solution to a Global Problem

CO₂ Capture and Transport

Ocean Storage

Sequestration in Deep
Formations

Mineral Carbonation

CO₂ Capture and Transport



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International interest in CO₂ capture and storage (CCS), as a method of reducing carbon dioxide emissions linked to global climate change, has been growing in recent years. CCS is particularly attractive for large industrial facilities, especially electric power plants, which contribute a large share of global CO₂ emissions from combustion of coal and other fossil fuels. This paper describes the current status of technologies to capture CO₂ and transport it to a storage site. The performance and cost of capture technologies are discussed, along with related environmental issues and the outlook for improved, lower-cost strategies. The key need now is financing of full-scale demonstrations of CCS at the various types of large coal-based power plants.

KEYWORDS: CO₂ capture, CO₂ transport, carbon sequestration costs, postcombustion capture, precombustion capture, oxycombustion capture

INTRODUCTION

Recent reports illustrate the growing international interest in carbon capture and storage (CCS) as a potentially important climate-change mitigation strategy (IPCC 2007; Macfarlane 2007; Schrag 2007). Commercial technologies are available for separating CO₂ from industrial gas streams, a process typically employed as a purification step in manufacturing. For example, CO₂ is routinely captured during natural gas treatment and in the production of hydrogen, ammonia, and ethanol. In most cases, the CO₂ stream is simply vented to the atmosphere. CO₂ is also captured from the flue-gas stream at some power plants burning coal or natural gas and then sold as a commodity to nearby food-processing plants. Globally, however, only a small amount of CO₂ is used for industrial products and nearly all is soon emitted into the atmosphere (think about the fizzy drinks you buy). To date, however, there has been no attempt to capture CO₂ at a large fossil fuel power plant (e.g. at a scale of hundreds of megawatts), although designs of such systems have been studied and proposed. TABLE 1 lists definitions and abbreviations

CO₂ capture and storage is best suited for facilities with large CO₂ emissions. The three biggest CCS projects to date remove 1–3 million metric tons of CO₂ per year from treatment or manufacture of natural gas (IPCC 2005). Other sources, including refineries, chemical plants, cement plants, and steel mills, are potential candidates. However, power plants should be the principal target because they account for roughly 80% of global CO₂ emissions from large stationary facilities.

Most CO₂ is formed by combustion, so capture technologies are commonly classified as pre- or postcombustion systems, depending on whether carbon is removed before or after a fuel is burned. In a third approach, called oxyfuel or oxycombustion—a process still under development—CO₂ isolation is easier. In all cases, the aim is to produce a concentrated CO₂ stream that can be transported to a sequestration site. To facilitate transport and storage, captured CO₂ is first compressed to a dense “supercritical” state in

which it behaves as a liquid, making it easier and cheaper to transport. The resulting high pressures, typically 11–14 MPa, are also required to inject CO₂ deep underground for geological sequestration (Benson and Cole 2008 this issue). Compression occurs inside the plant gate and is thus commonly included as part of the capture system.

CO₂ CAPTURE TECHNIQUES

Postcombustion Capture

In these systems CO₂ is separated from the flue gas produced when coal or other fuel is burned in air. Combustion-based systems provide most electricity today. In a modern pulverized coal (PC) power plant, the heat released by combustion generates steam, which drives a turbine generator (FIG. 1). Hot combustion gases exiting the boiler consist mainly of nitrogen (from air) and smaller concentrations of water vapor and CO₂. Other constituents, formed from impurities in coal, include sulfur dioxide, nitrogen oxides, and particulate matter (fly ash). These are pollutants that must be removed to meet environmental standards. Subsequently, CO₂ can be removed.

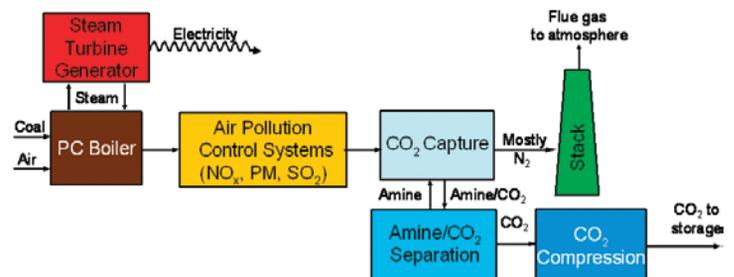


FIGURE 1 Schematic of a pulverized coal-fired (PC) power plant with postcombustion CO₂ capture using an amine system. Other major air pollutants (nitrogen oxides, particulate matter [PM], and sulfur dioxide) are removed from the flue gas prior to CO₂ capture.

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Because the flue gas is at atmospheric pressure and the concentration of CO₂ is fairly low (typically 12–15% by volume for coal plants), the most effective method to remove CO₂ is by chemical reaction with a liquid solvent. The most common solvents are a family of organic compounds known as amines, one of which is monoethanolamine (MEA) (Rao and Rubin 2002). In a vessel called an absorber, the flue gas is “scrubbed” with an amine solution, typically capturing 85–90% of the CO₂. The CO₂-laden solvent is then pumped to a second vessel, called a regenerator, where heat releases the CO₂ as a gas. The resulting concentrated CO₂ gas stream is then compressed into a supercritical fluid for transport to the sequestration site, while the solvent is recycled (Fig. 2A).

Postcombustion capture can also be applied to natural gas combined cycle (NGCC) power plants, which have come into broad use over the past decade. In this type of plant, clean natural gas is combusted with compressed air to produce a high-temperature gas stream that drives a turbine. The hot exhaust from the turbine is then used to produce steam, which powers a second turbine, generating more electricity (hence the term “combined cycle”). Although the CO₂ in NGCC flue gas is even more dilute than in coal plants (about 3–5% by volume), high removal efficiencies are still achieved with amine capture. Amine capture technology is also widely used to purify industrial gas streams, as in the processing of raw natural gas to remove CO₂, a common impurity (Fig. 2B).

Precombustion Capture

To decrease CO₂ emissions, fuel-bound carbon can first be converted to a form amenable to capture. This is accomplished by reacting coal with steam and oxygen at high temperature and pressure, a process called coal gasification. By restricting the amount of oxygen, the coal is only partially oxidized, providing the heat needed to operate the gasifier. The reaction products are mainly carbon monoxide and hydrogen (a mixture commonly known as synthesis gas, or syngas). Sulfur compounds (mainly hydrogen sulfide, H₂S) and other impurities are removed using conventional gas-cleaning technology. The clean syngas can be burned to generate electricity in a combined cycle power plant similar to the NGCC plant described above. This approach is known as integrated gasification combined cycle, or IGCC.

To capture CO₂ from syngas, two additional process units are added (Fig. 3). A “shift reactor” converts the carbon monoxide (CO) to CO₂ through reaction with steam (H₂O). Then, the H₂-CO₂ mixture is separated into streams of CO₂ and H₂. The CO₂ is compressed for transport, while the H₂ serves as a carbon-free fuel that is combusted to generate electricity.

Although initial fuel-conversion steps are more elaborate and costly than postcombustion systems, the high pressures of modern gasifiers and the high concentration of CO₂ produced by the shift reactor (up to 60% by volume) make CO₂ separation easier. Thus, instead of chemical reactions to capture CO₂, commercial processes such as Selexol use

TABLE 1 DEFINITIONS OF SELECTED TERMS AND ABBREVIATIONS

| Term or abbreviation | Definition |
|-----------------------|---|
| Carbon capture | Removal or separation of CO ₂ (or other carbon compound) from a gas stream, typically through a chemical or physical process |
| Storage/sequestration | A method or repository that prevents CO ₂ from entering the atmosphere. These two terms are often used interchangeably, though “storage” generally applies to CO ₂ captured from an industrial process, while sequestration is the more general (and rigorous) term, which also includes CO ₂ removed from the atmosphere by trees and soils. |
| CCS | Carbon (or carbon dioxide) capture and storage (or sequestration). This is the most widely used abbreviation for capture and sequestration of industrial CO ₂ . |
| EOR | Enhanced oil recovery – a major use for CO ₂ as an industrial commodity. CO ₂ increases mobility, thus increasing production. |
| ETS | Emissions trading system – a term commonly applied to the European Union’s cap-and-trade policy for CO ₂ emissions |
| IGCC | Integrated gasification combined cycle – a power generation technology typically fueled by coal or petroleum coke, which is converted to a gaseous fuel that is burned to generate electricity |
| NGCC | Natural gas combined cycle – a power generation system fueled by natural gas, which is burned to generate electricity using both a gas turbine (Brayton cycle) and a steam turbine (Rankine cycle) |
| PC | Pulverized coal – this term refers to the prevailing technology for coal-fired power plants, in which coal is crushed to a fine powder, then injected into a furnace (boiler) where it is combusted to generate steam, which drives a turbine to generate electricity. |
| SCPC | Supercritical pulverized coal – this term refers to a pulverized coal power plant in which steam is heated to a temperature and pressure above the thermodynamic “critical point,” enabling higher plant efficiencies than with conventional “subcritical” units, which operate at lower pressures and temperatures. The term “ultrasupercritical” (USC) designates a supercritical plant with even higher steam temperature and pressure than conventional SCPC units. |

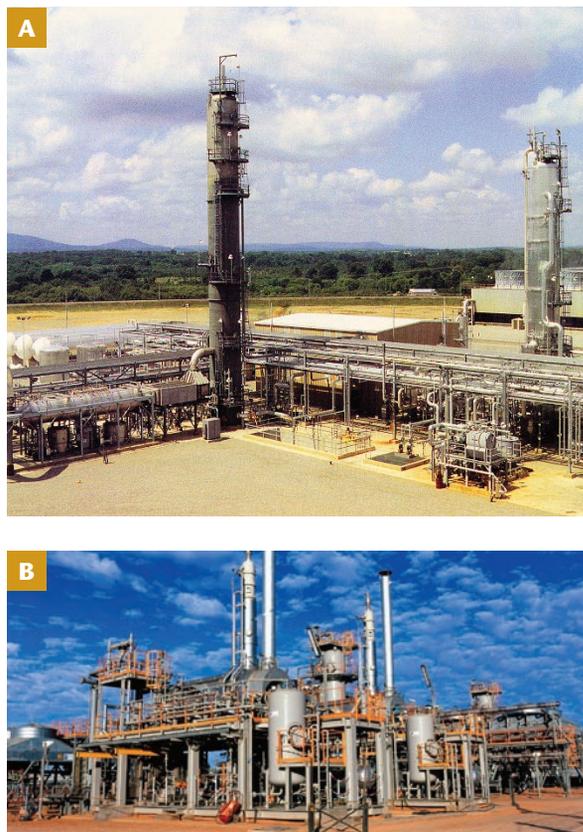


FIGURE 2 (A) An amine-based postcombustion CO₂ capture system treating a portion of the flue gas (~40 MW equivalent) from a coal-fired power plant in Oklahoma, USA. (B) An amine-based CO₂ capture system used to purify natural gas at BP’s In Salah plant in Algeria. Approximately 1 Mt/y of CO₂ is captured and transported by pipeline to a geological sequestration site. PHOTOS COURTESY OF U.S. DEPARTMENT OF ENERGY (A) AND IEA GREENHOUSE GAS PROGRAMME (B)

sorbents (e.g. glycol) to physically adsorb CO₂, then release it in a second vessel when the pressure is quickly reduced. This technology for precombustion capture is favored in a variety of processes, mainly in the petroleum and petrochemical industries (Fig. 4).

Oxycombustion Capture

Oxyfuel systems are similar to conventional combustion systems, except that oxygen is used rather than air to avoid nitrogen in the flue-gas stream. After the particulate matter (fly ash) is removed, the gas consists mainly of water vapor and CO₂, with low concentrations of pollutants such as sulfur dioxide (SO₂) and nitrogen oxides (NO_x). The water vapor is easily removed by cooling and compressing, leaving nearly pure CO₂ that can be sent directly to sequestration. Oxycombustion avoids the need for a postcombustion capture device, but most designs require additional processing to remove conventional air pollutants to comply with environmental requirements or CO₂ purity specifications. The system also requires an air-separation unit to generate the relatively pure (95–99%) oxygen needed for combustion (Fig. 5) and must be sealed against air leakage. Approximately three times more oxygen is needed for oxyfuel systems than for IGCC plants, which adds considerably to the cost. Because combustion temperatures in oxygen are much higher than in air, oxycombustion also requires roughly 70% of the inert flue gas to be recycled back to the boiler to maintain normal operating temperatures.

As a CO₂ capture method, oxycombustion has been studied theoretically and in small-scale test facilities. A major demonstration project (10 MW electrical equivalent) began in September 2008 at a pilot plant in Germany (Vattenfall 2008). Although, in principle, oxyfuel systems can capture all of the CO₂ produced, the need for additional gas treatment and distillation decreases the capture efficiency to about 90% in most current designs (IEA GHG 2005). For all approaches, higher removal efficiencies are possible, but more costly. Thus, engineers seek to optimize design to achieve the most cost-effective CO₂ capture.

OPTIONS FOR CO₂ TRANSPORT

Except in cases where an industrial plant is located directly above a suitable geological formation, captured CO₂ must be transported from the point of capture to a sequestration site. In the US, pipelines are the most common method for transporting CO₂. Many were built in the early 1970s in the western United States to transport CO₂, extracted mainly from natural geological sources, to depleted oil wells in western Texas for enhanced oil recovery (EOR). Today in the US, increasing numbers of EOR projects rely on a network of >4500 km of pipeline to carry >40 million metric tons of CO₂ per year from natural and industrial sources. The newest pipeline, operational since 2004, transports 3Mt CO₂/y from a coal gasification plant in North Dakota to the Weyburn and Midale oil fields, 320 km north in southern Saskatchewan (Fig. 6). This US-Canadian venture is the largest CCS project. The other two (each ~1 Mt CO₂/y) are the Statoil gas production facility at Sleipner, Norway, an offshore drilling platform where CO₂ is injected into a saline aquifer beneath the North Sea, and the BP gas treatment plant at In Salah, Algeria, where captured CO₂ is transported by pipeline to a nearby injection site at Krechba.

Other transport methods also have been considered. Compressed CO₂ can be transported in large tanker ships, similar to those used to transport liquefied natural or petroleum gas. This could become economical if CO₂ has to be moved large distances over water, as might occur with injection into the deep ocean (an option that remains controversial; Adams and Caldeira 2008 this issue). Other

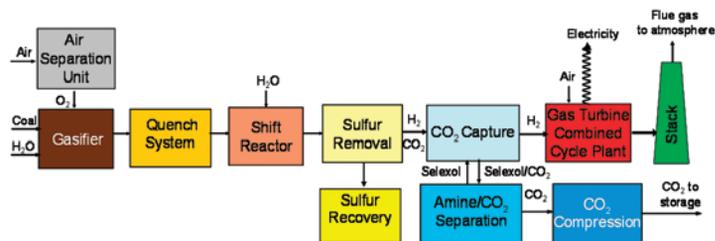


FIGURE 3 Schematic of an integrated gasification combined cycle (IGCC) power plant with precombustion CO₂ capture using a water–gas shift reactor and a Selexol CO₂ separation system



FIGURE 4 A precombustion CO₂ capture system used to produce synthetic natural gas (syngas) from coal at the Dakota Gasification Plant in North Dakota. About 3 Mt/y captured CO₂ is currently transported by pipeline to the Weyburn and Midale oil fields in Saskatchewan, Canada, where it is used for enhanced oil recovery and sequestered in depleted oil reservoirs. PHOTO COURTESY OF U.S. DEPARTMENT OF ENERGY

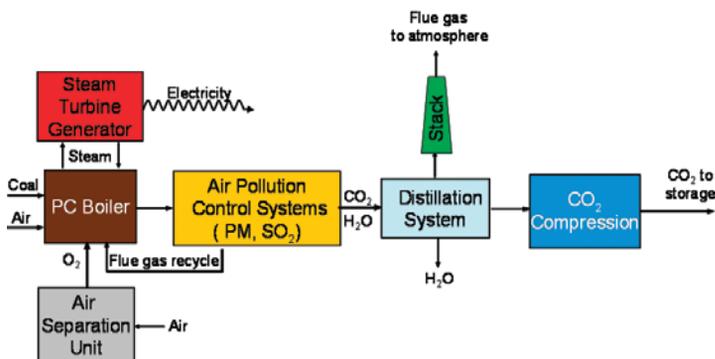


FIGURE 5 Schematic of a coal-fired power plant using oxycombustion. Approximately 70% of the CO₂-laden flue gas is recycled to the boiler to maintain normal operating temperatures. Depending on the purity of the oxygen from the air separation unit, small amounts of nitrogen and argon also enter the flue gas.



FIGURE 6 A portion of the pipeline delivering CO₂ to the Weyburn oil field in Saskatchewan, Canada. PHOTO COURTESY OF IEA GREENHOUSE GAS PROGRAMME

options include transport by truck or railroad in insulated tanks. Road and rail are used on a limited basis for small-scale shipments of industrial CO₂, but these options are not economical at the scale required for climate-change mitigation (IPCC 2005).

THE ENERGY PENALTY AND ITS IMPLICATIONS

Current CO₂ capture systems require large amounts of energy to operate. This decreases net efficiency and contributes significantly to CO₂ capture costs. Postcombustion capture systems use the most energy, requiring nearly twice that of precombustion systems (TABLE 2). Lower plant efficiency means more fuel is needed for electricity generation. For coal plants, this added fuel produces proportionally more solid waste and requires more chemicals, such as ammonia and limestone, to control NO_x and SO₂ emis-

sions. Plant water use also increases proportionally, with additional cooling water needed for amine capture systems. Because of efficiency loss, a capture system that removes 90% of the CO₂ within a plant actually reduces net emissions per kilowatt-hour (kWh) by a smaller amount, typically 85–88%.

In general, the more efficient the power plant, the smaller are the energy penalty impacts. For this reason, replacing or repowering an old, inefficient plant with a new, more efficient facility with CO₂ capture can still yield a net efficiency gain that decreases all plant emissions and resource consumption. Thus, the net impact of the energy penalty is best assessed in the context of strategies for reducing emissions across a fleet of plants, including existing facilities as well as planned new units. Innovations in power generation and carbon capture technologies are expected to further reduce future energy penalties and their impacts.

THE COST OF CO₂ CAPTURE SYSTEMS

TABLE 3 summarizes the cost of individual components of the CCS system. The broad ranges reflect different sets of assumptions used in various studies of hypothetical power plants in North America and Europe. The most costly component is capture, including compression. The lowest capture costs are for processes where CO₂ is separated as part of normal operations, such as during hydrogen production, where the added cost is simply for CO₂ compression.

FIGURE 7 depicts the cost of generating electricity with and without CCS, as reported in recent studies. The total electricity cost (\$/MWh) is shown as a function of the CO₂ emission rate (t CO₂/MWh) for new plants burning bituminous coal or natural gas. One sees a broad range of values. While variations in capture-system design contribute to this range, the dominant factors are differences in design, operation, and financing of the power plants to which capture technologies are applied. For example, higher plant efficiency, larger plant size, higher fuel quality, lower fuel cost, higher annual hours of operation, longer operating life, and lower cost of capital all reduce the costs, both of CO₂ capture and electricity generation. No single set of assumptions applies to all situations or all parts of the world, so estimated costs vary. An even broader range would appear if other factors were considered, such as subcritical boilers and nonbituminous coals.

Over the past several years, construction costs for power plants and other industrial facilities have escalated dramatically (CEPCI 2008). So too has the price of fuel, especially natural gas, making NGCC plants uneconomical in most

TABLE 2 REPRESENTATIVE VALUES OF CURRENT POWER PLANT EFFICIENCIES AND CCS ENERGY PENALTIES

SOURCES: IPCC (2005); EIA (2007)

| Power plant type (and capture system type) | Net plant efficiency (%) without CCS* | Net plant efficiency (%) with CCS* | Energy penalty: Added fuel input (%) per net kWh output |
|--|---------------------------------------|------------------------------------|---|
| Existing subcritical (PC) (+ postcombustion) | 33 | 23 | 40% |
| New supercritical (SCPC) (+ postcombustion) | 40 | 31 | 30% |
| New supercritical (SCPC) (+ oxycombustion) | 40 | 32 | 25% |
| Coal gasification (IGCC) (+ precombustion) | 40 | 34 | 19% |
| New natural gas (NGCC) (+ postcombustion) | 50 | 43 | 16% |

* All efficiency values are based on the higher heating value (HHV) of fuel, not the lower heating value (LHV) used in Europe and elsewhere, which yields greater efficiencies by omitting the fuel energy needed to evaporate water produced in combustion. For each plant type, there is a range of efficiency values around those shown here. See Rubin et al. (2007a) for details

TABLE 3 ESTIMATED COSTS OF CO₂ CAPTURE, TRANSPORT, AND GEOLOGICAL STORAGE (2007 US\$/T CO₂)

SOURCE: IPCC (2005) DATA ADJUSTED TO 2007 COST BASIS

| CCS system component | Cost range (US\$) |
|---|--|
| Capture: Fossil fuel power plants | \$20–95/t CO ₂ net captured |
| Capture: Hydrogen and ammonia production or gas-processing plant | \$5–70/t CO ₂ net captured |
| Capture: Other industrial sources | \$30–145/t CO ₂ net captured |
| Transport: Pipeline | \$1–10/t CO ₂ transported |
| Storage: Deep geological formation | \$0.5–10/t CO ₂ net injected |

Ranges reflect differences in the technical and economic parameters affecting the cost of each component.

locations where coal is also available at much lower cost. Uncertainty about future cost escalations further clouds the “true” cost of plants, with or without CCS. On a relative basis, however, CCS is estimated to increase the cost of generating electricity by approximately 60–80% at new coal combustion plants and by about 30–50% at new coal gasification plants. On an absolute basis, the increased cost of generation translates to roughly \$40–70/MWh for PC plants and \$30–50/MWh for IGCC plants using bituminous coal. The CO₂ capture step (including compression) accounts for 80–90% of this cost, while the remaining 10–20% results from transport and storage. Note, however, that consumers would see much smaller increases in their electricity bills because generation accounts for only about half the total cost of electricity supply, and only a gradually increasing fraction of all generators might employ CCS at any time in response to future climate policies.

FIGURE 7 can also be used to calculate the cost per ton of CO₂ avoided when a plant is built with CCS instead of without. For a new supercritical (SCPC) coal plant with deep aquifer storage, this is currently about \$60–80/t CO₂, which is the magnitude of the “carbon price” needed to make CCS cost-effective. For IGCC plants with and without capture, the CCS cost is smaller, about \$30–50/t CO₂. All costs are decreased when CO₂ can be sold for EOR with storage. The cost of CO₂ avoided depends on the type of “reference plant” used to compare with the CCS plant. For example, without capture, a SCPC plant today is about 15–20% cheaper than a similarly sized IGCC plant, making it preferred. But with CO₂ capture, an IGCC plant gasifying bituminous coal is expected to be the lower-cost system. Thus, it is useful to compare a SCPC reference plant without capture to an IGCC plant with CCS. In this case the cost of CO₂ avoided is roughly \$40–60/t CO₂.

The relative cost of SCPC and IGCC plants can change significantly with coal type, operating hours, cost of capital, and many other factors (Rubin et al. 2007a). Experience with IGCC power plants is still quite limited, and neither SCPC nor IGCC plants with CCS have been built and operated at full scale. Thus, neither the absolute nor relative costs of these systems can yet be stated with confidence. For existing power plants, the feasibility and cost of retrofitting a CO₂ capture system depends especially on site-specific factors such as plant size, age, efficiency, and space to accommodate a capture unit. For many existing plants, the most cost-effective strategy is to combine CO₂ capture with a major plant upgrade (repowering) in which an existing unit is replaced by a high-efficiency unit or a gasification combined cycle system (Chen et al. 2003; Simbeck 2008). In such cases, the cost approaches that of a new plant.

Outlook for Lower-Cost Technologies

Research and development (R&D) programs are underway worldwide to produce CO₂ capture technologies with lower cost and energy requirements (IEA GHG 2008). For example, the European CASTOR project aims at lower postcombustion capture costs by developing advanced amines and other solvents. In the US, electric utilities and equipment manufacturers are testing a postcombustion process using chilled ammonia in the hope of greatly reducing the CCS energy penalty, and with it, the cost of capture. Researchers in Australia, Europe, Japan, and North America are seeking major improvements also in precombustion capture with membrane technologies for oxygen and hydrogen production and CO₂ separation. A number of national and international programs are also pursuing new process concepts such as chemical looping combustion.

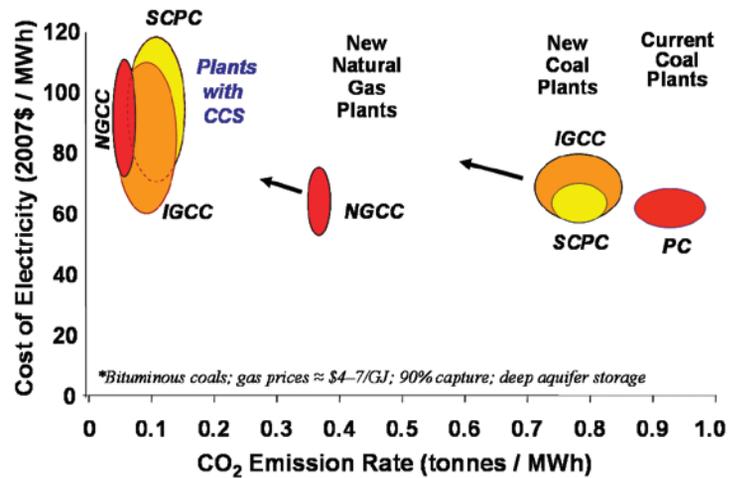


FIGURE 7 Cost of electricity generation (2007 US\$/MWh) as a function of the CO₂ emission rate (t CO₂/MWh) for new power plants burning bituminous coal or natural gas (PC = subcritical pulverized coal units; SCPC = supercritical pulverized coal; IGCC = integrated gasification combined cycle; NGCC = natural gas combined cycle). Ranges reflect differences in technical and economic parameters affecting plant cost. Figure based on data from NETL (2007); Holt (2007); MIT (2007); Rubin et al. (2007a); IPCC (2005), adjusted to 2007 cost

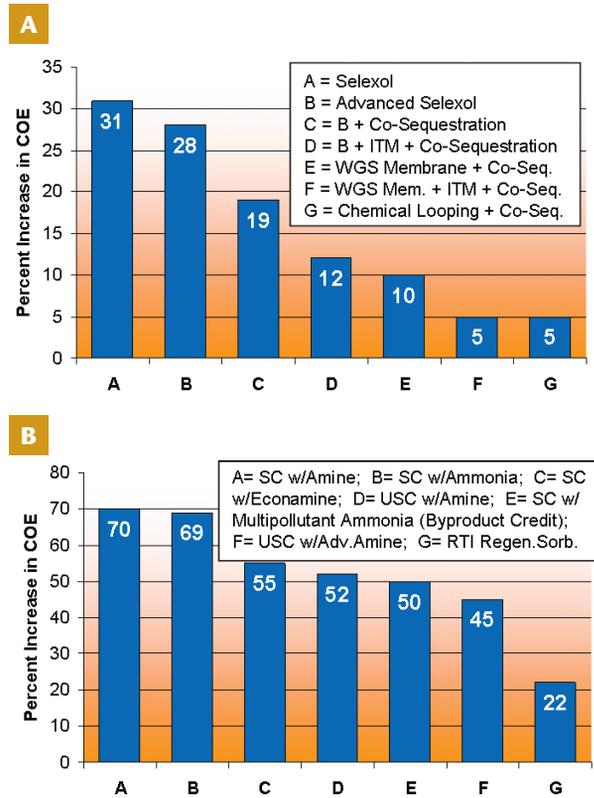


FIGURE 8 Projected increases in the cost of electricity (COE) for CO₂ capture and storage using current technology (bar A) and various advanced capture technologies for (A) an IGCC plant with precombustion capture (ITM = ion transport membrane; WGS = water gas shift) and (B) an SCPC plant with postcombustion capture (RTI = Research Triangle Institute). The height of each bar shows the percent increase in COE relative to a similar plant without CO₂ capture and storage. The absolute value of COE (in 2006 US cents/kWh) for the IGCC plant is projected to fall from 7.13 ¢/kWh currently to 5.75 ¢/kWh with advanced technology (bars F and G)—an overall COE reduction of 19%. For the PC plant, the COE falls from 8.77 ¢/kWh to 6.30 ¢/kWh—an overall reduction of 28%. A similar projection for a PC plant with oxycombustion (not shown in this figure) estimates that advanced technologies can reduce the total cost of electricity from 7.86 ¢/kWh (currently) to 6.35 ¢/kWh, a 19% reduction in COE. SOURCE: NETL (2006)

Although future costs remain highly uncertain, sizeable reductions in CO₂ capture costs are foreseen over the next few decades. Combined with improvements in power plant design, engineering-economic analyses predict reductions of 20–30% for electricity generation with CCS (FIG. 8). Such estimates are consistent with projections from historical “learning curves,” which show technologies become cheaper with maturity (Rubin et al. 2007b). Experience also indicates that reducing cost requires not only sustained R&D but also deployment and adoption of technologies in the marketplace to facilitate learning-by-doing. Policies that promote CCS deployment are thus essential to achieve the cost reductions that are projected.

CONCLUDING REMARKS

Although CO₂ capture and storage holds considerable promise, its acceptance will depend on the nature and pace of government policies to limit CO₂ emissions and/or to provide financial incentives for its use. At present, only the European Union (EU) has CO₂ emission limits in the form of a “cap-and-trade” policy, which requires industrial sources either to reduce emissions or to buy “allowances” to emit CO₂. The price of a CO₂ allowance is established by the European Union in a financial market called the emissions trading system (ETS), the largest existing market for carbon reductions (Ellerman and Joskow 2008). At current ETS carbon prices, CO₂ capture and storage remains prohibitive relative to other measures for meeting emission limits. Although under considerable attention, unresolved legal, regulatory, and public-acceptance issues pose additional barriers to CCS deployment. New post-2012 EU emission limits are under negotiation.

In the US, most cap-and-trade policies proposed in Congress fall short of what is needed to motivate implementation of CCS, although a few proposals include financial incentives for its early adoption (Pena and Rubin 2008). Other proposals would establish power plant performance standards that restrict CO₂ emissions to levels only achievable with CCS. Whatever the method, until there are sufficiently stringent limits on CO₂ emissions, CCS will be used only at a small number of facilities that can exploit government incentives or other economic opportunities such as enhanced oil recovery.

In the absence of strong policy incentives, where do we go from here? There is broad agreement that progress on CCS requires several full-scale demonstrations at fossil fuel power plants, especially coal-based plants. Such projects are needed to establish the true costs and reliability of the various approaches in different settings and to resolve legal and regulatory issues of large-scale geological sequestration (Wilson et al. 2008). Government–industry partnerships in Asia, Europe, and North America are at various stages of planning and financing such projects (TABLE 4). Once funding is in place, it will take several years to design and build each facility, then several years of operation to evaluate its reliability, safety, public acceptance, and performance in reducing CO₂ emissions. If all goes well, a viable CCS industry could be launched in approximately a decade. ■

TABLE 4 A FEW EXAMPLES OF PLANNED AND PROPOSED CO₂ CAPTURE AND STORAGE PROJECTS (BEYOND 2008). Many would proceed in phases beginning with smaller units than shown here. As of mid-2008, approximately 65 projects have been announced worldwide. Several large projects also were cancelled in 2007–2008. SOURCE: MIT (2008)

| Project Name | Location | Feedstock | Size MW | Capture | Start-up |
|--------------------------|-----------|-----------|----------|---------|-----------|
| Callide-A Oxy Fuel | Australia | Coal | 30 | Oxy | 2009 |
| GreenGen | China | Coal | 250 | Pre | 2009 |
| Williston | USA | Coal | 450 | Post | 2009–2015 |
| Sargas Husnes | Norway | Coal | 400 | Post | 2011 |
| S&S Ferrybridge | UK | Coal | 500 | Post | 2011–2012 |
| Naturkraft Kårstø | Norway | Gas | 420 | Post | 2011–2012 |
| Fort Nelson | Canada | Gas | Process | Pre | 2011 |
| Zero Gen | Australia | Coal | 100 | Pre | 2012 |
| UAE Project | UAE | Gas | 420 | Pre | 2012 |
| Appalachian Power | USA | Coal | 629 | Pre | 2012 |
| UK CCS Project | UK | Coal | 300–400 | Post | 2014 |
| Statoil Mongstad | Norway | Gas | 630 | Post | 2014 |
| RWE Zero CO ₂ | Germany | Coal | 450 | Pre | 2015 |
| Monash Energy | Australia | Coal | 60 k bpd | Pre | 2016 |

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