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## **The Outlook for Power Plant CO<sub>2</sub> Capture**

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### **Abstract**

There is growing international interest in carbon capture and sequestration (CCS) technology to reduce carbon dioxide emissions linked to global climate change. CCS is especially attractive for electric power plants burning coal and other fossil fuels, which are a major source of global CO<sub>2</sub> emissions. This paper describes the performance and cost of CO<sub>2</sub> capture technologies for large-scale electric power plants including pulverized coal (PC), natural gas combined cycle (NGCC), and integrated gasification combined cycle (IGCC) plants. Different types of capture technologies, including pre-combustion, post-combustion, and oxyfuel combustion capture systems are discussed, along with the outlook for new or improved technology. Future cost for power plants with CO<sub>2</sub> capture are estimated using both a “bottom-up” approach based on engineering analysis and a “top-down” approach based on historical experience curves. The limitations of such projections are discussed along with needs for future research, development and demonstration of CCS technology. The most urgent need at this time is financing for several full-scale demonstrations of CCS at coal-based power plants.

### **INTRODUCTION**

On first hearing, the idea may sound a bit far-fetched. To avoid emitting billions of tons of carbon dioxide (CO<sub>2</sub>) to the atmosphere—the major greenhouse gas associated with global warming—engineers propose to equip coal-burning power stations with chemical plants that strip CO<sub>2</sub> from the flue gases before they go up the chimney. The concentrated CO<sub>2</sub> would then be compressed to a liquid and piped to a storage site where it would be injected deep underground. There it would be trapped by impermeable layers of rock and very slowly, over centuries, transform into solid carbonate minerals. This method of sequestering CO<sub>2</sub> would not come cheap—if applied to an existing power plant today, the cost of generating electricity would nearly double. Surely, one would think, there must be an easier way to reduce power plant CO<sub>2</sub> emissions.

Such was the general view when the idea of carbon capture and sequestration (CCS) was first proposed as a greenhouse gas mitigation strategy three decades ago (Marchetti 1977). But over the past decade things have changed. Scientists, engineers and policy analysts have been taking a closer look at CCS and finding that it could indeed make sense both technically and economically—making it a potentially important player in mitigating global climate change.

#### ***Why the interest in CCS?***

Current worldwide interest in CO<sub>2</sub> capture and sequestration (or storage) stems principally from three factors. First is the growing evidence that large reductions in

global CO<sub>2</sub> emissions are needed to avoid serious climate change impacts—as much as an 85% reduction in projected emissions by the middle of this century (IPCC 2007). And because power plants are a major contributor to greenhouse gas emissions (mostly from coal-burning plants), these \ reductions cannot be achieved unless power plant emissions also are greatly reduced.

Second is the recognition that large emission reductions cannot be achieved easily or quickly solely by using less electricity or replacing fossil fuels with renewable energy sources such as wind and solar that emit no CO<sub>2</sub>. While alternative energy sources are vital elements of any greenhouse gas reduction strategy, technical, economic and societal factors limit the speed and extent to which they can be implemented. The reality today is that the world relies on fossil fuels for over 85% of its energy use, much of that for electric power generation based on the combustion of coal. Changing that picture dramatically will take time. CCS thus offers a way to get large reductions in CO<sub>2</sub> emissions from fossil fuel use until cleaner more sustainable technologies can be widely deployed.

Finally, energy-economic models show that adding CCS to the suite of other greenhouse gas reduction measures significantly lowers the cost of mitigating climate change when deep reductions in emissions are required (IPCC 2005). In its most recent assessment, the Intergovernmental Panel on Climate Change (IPCC) affirmed CCS to be a major component of a cost-effective portfolio of technologies needed to mitigate climate change (IPCC 2007).

## **OPTIONS FOR CO<sub>2</sub> CAPTURE**

A variety of technologies are commercially available and in widespread use for separating (capturing) CO<sub>2</sub> from industrial gas streams, typically as a purification step in the manufacture of commercial products. Common applications include the separation of CO<sub>2</sub> in natural gas treatment and in the production of hydrogen, ammonia and ethanol. In most cases, the captured CO<sub>2</sub> stream is simply vented to the atmosphere. CO<sub>2</sub> also has been captured from a small portion of the flue gas at power plants burning coal and natural gas, and then sold as an industrial commodity to nearby food processing plants. Globally, however, only a small amount of CO<sub>2</sub> is utilized for industrial products, and nearly all of it is soon emitted to the atmosphere (think about the fizzy drinks you buy). To date, however, there has been no application of CO<sub>2</sub> capture at a large fossil fuel power plant (e.g., at a scale of hundreds of megawatts), although designs of such systems have been widely studied and proposed.

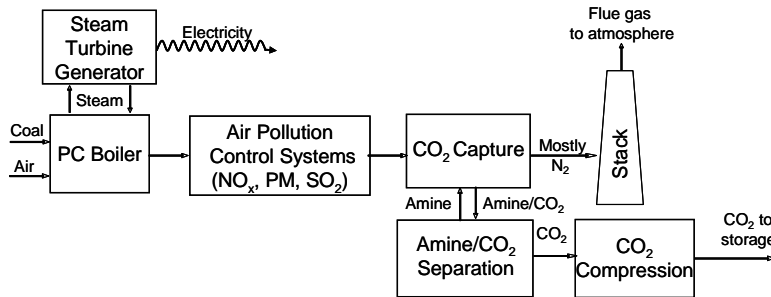
As a climate change mitigation strategy, CO<sub>2</sub> capture and storage is best suited for facilities with large CO<sub>2</sub> emissions. The four biggest CCS projects to date—each sequestering 1–3 million metric tons CO<sub>2</sub>/yr —capture CO<sub>2</sub> from industrial processes that produce or manufacture natural gas. Other industrial sources, including refineries, chemical plants, cement plants and steel mills, also are potential candidates for CCS. However, power plants are the principal target because they account for roughly 80% of global CO<sub>2</sub> emissions from large stationary facilities.

Most CO<sub>2</sub> is formed via combustion, so capture technologies are commonly classified as pre-combustion or post-combustion systems, depending on whether carbon is removed before or after a fuel is burned. A third approach, called oxyfuel or oxy-combustion, does not require a CO<sub>2</sub> capture device. This concept is still under development. In all cases, the aim of CO<sub>2</sub> capture is to produce a concentrated CO<sub>2</sub>

stream that can be transported to a sequestration site. To facilitate transport and storage, captured CO<sub>2</sub> is first compressed to a dense “supercritical” state, where it behaves as a liquid, making it easier and much less costly to transport than in gaseous form. High pressures, typically 11–14 MPa, also are required to inject CO<sub>2</sub> deep underground for geological sequestration (Benson and Cole, 2008). The CO<sub>2</sub> compression step is commonly included as part of the capture system since it occurs inside the plant gate.

**Post-combustion Capture**

In these systems CO<sub>2</sub> 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 CO<sub>2</sub>. 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, CO<sub>2</sub> can be removed.



**Fig. 1.** Schematic of a pulverized coal–fired (PC) power plant with post-combustion CO<sub>2</sub> capture using an amine system. Other major air pollutants [nitrogen oxides, particulate matter (PM) and sulfur dioxide] are removed

Because the flue gas is at atmospheric pressure and the concentration of CO<sub>2</sub> is fairly low (typically 12–15% by volume for coal plants), the most effective method to remove CO<sub>2</sub> 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). In a vessel called an absorber, the flue gas is “scrubbed” with an amine solution, typically capturing 85–90% of the CO<sub>2</sub>. The CO<sub>2</sub>-laden solvent is then pumped to a second vessel, called a regenerator, where heat releases the CO<sub>2</sub> as a gas. The resulting concentrated CO<sub>2</sub> gas stream is then compressed into a supercritical fluid for transport to the sequestration site, while the solvent is recycled (FIG. 2A).



**Fig. 2a.** An amine-based post-combustion CO<sub>2</sub> capture system treating a portion of the flue gas (~40 MW equivalent) from a coal-fired power plant in Oklahoma, USA. (Photo courtesy of U.S. Department of Energy)

Post-combustion capture also can 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 CO<sub>2</sub> 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 CO<sub>2</sub>, a common impurity (FIG. 2B).

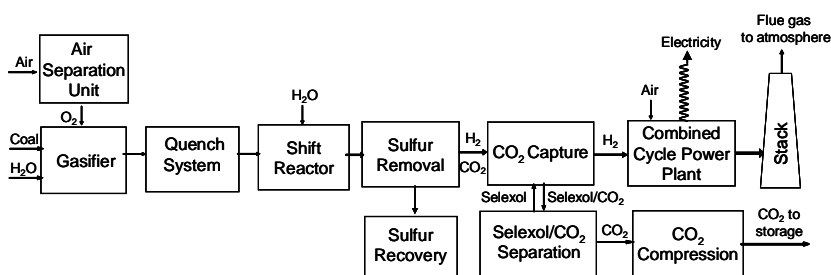


**Fig. 2b.** An amine-based CO<sub>2</sub> capture system used to purify natural gas at BP's In Salah plant in Algeria. Approximately 1 Mt/y of CO<sub>2</sub> is captured and transported by pipeline to a geological sequestration site. (Photo courtesy of IEA Greenhouse Gas Programme)

### Pre-combustion Capture

To decrease CO<sub>2</sub> 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, H<sub>2</sub>S) 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 CO<sub>2</sub> from syngas, two additional process units are added (FIG. 3). A “shift reactor” converts the carbon monoxide (CO) to CO<sub>2</sub> through reaction with steam (H<sub>2</sub>O). Then, the H<sub>2</sub>–CO<sub>2</sub> mixture is separated into streams of CO<sub>2</sub> and H<sub>2</sub>. The CO<sub>2</sub> is compressed for transport, while the H<sub>2</sub> serves as a carbon-free fuel that is combusted to generate electricity.



**Fig. 3.** Schematic of an integrated gasification combined cycle (IGCC) power plant with pre-combustion CO<sub>2</sub> capture using a water-gas shift reactor and a Selexol CO<sub>2</sub> separation system

Although initial fuel-conversion steps are more elaborate and costly than post-combustion systems, the high pressures of modern gasifiers and the high concentration

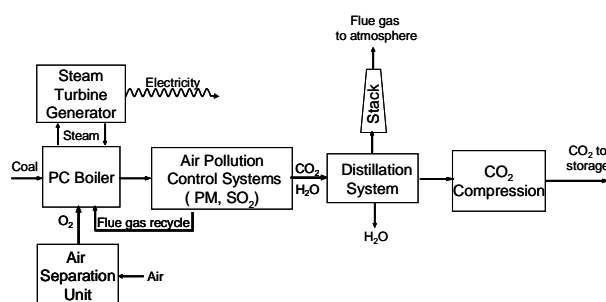
of CO<sub>2</sub> produced by the shift reactor (up to 60% by volume) make CO<sub>2</sub> separation easier. Thus, instead of chemical reactions to capture CO<sub>2</sub>, commercial processes such as Selexol use sorbents (such as glycol) to physically adsorb CO<sub>2</sub>, then release it in a second vessel when the pressure is quickly reduced. This technology for pre-combustion capture is favored in a variety of processes, mainly in the petroleum and petrochemical industries (FIG. 4).



**Fig. 4.** A pre-combustion CO<sub>2</sub> capture system used to produce synthetic natural gas (syngas) from coal at the Dakota Gasification Plant in North Dakota. About 3 Mt/y captured CO<sub>2</sub> 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 US Department of Energy)

### Oxy-combustion Capture

Oxy-combustion (or 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 CO<sub>2</sub>, with low concentrations of pollutants such as sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). The water vapor is easily removed by cooling and compressing, leaving nearly pure CO<sub>2</sub> that can be sent directly to sequestration. Oxy-combustion avoids the need for a post-combustion capture device, but most designs require additional processing to remove conventional air pollutants to comply with environmental requirements or CO<sub>2</sub> 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, oxy-combustion also requires roughly 70% of the inert flue gas to be recycled back to the boiler to maintain normal operating temperatures.



**Fig. 5.** Schematic of a coal-fired power plant using oxy-combustion. Approximately 70% of the CO<sub>2</sub>-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.

As a CO<sub>2</sub> capture method, oxy-combustion 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 CO<sub>2</sub> 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 CO<sub>2</sub> capture.

## THE ENERGY PENALTY AND ITS IMPLICATIONS

Current CO<sub>2</sub> capture systems require large amounts of energy to operate. This decreases net efficiency and contributes significantly to CO<sub>2</sub> capture costs. Post-combustion capture systems use the most energy, requiring nearly twice that of pre-combustion systems (TABLE 1).

**Table 1.** 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) (+ post-combustion)	33	23	40%
New supercritical (SCPC) (+ post-combustion)	40	31	30%
New supercritical (SCPC) (+ oxy-combustion)	40	32	25%
Coal gasification (IGCC) (+ pre-combustion)	40	34	19%
New natural gas (NGCC) (+ post-combustion)	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

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<sub>x</sub> and SO<sub>2</sub> emissions. 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 CO<sub>2</sub> 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 CO<sub>2</sub> 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.

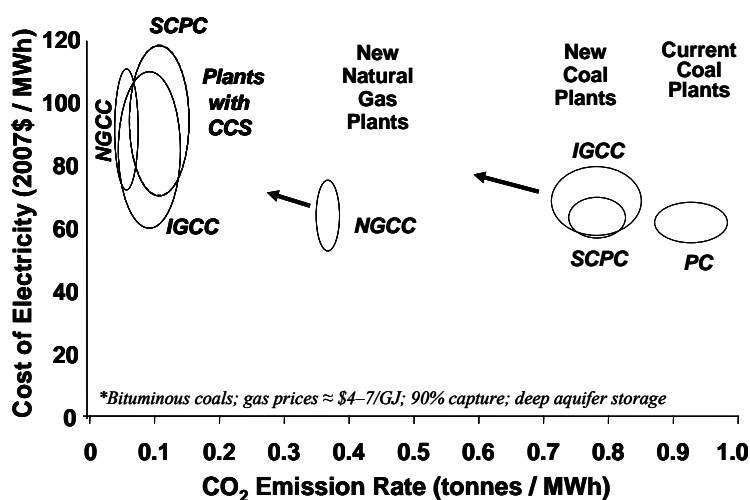
## THE COST OF CO<sub>2</sub> CAPTURE

TABLE 2 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 CO<sub>2</sub> is separated as part of normal operations, such as during hydrogen production, where the added cost is simply for CO<sub>2</sub> compression.

**Table 2.** Estimated costs of CO<sub>2</sub> capture, transport, and geological storage (2007 US\$/t CO<sub>2</sub>). Ranges reflect differences in the technical and economic parameters affecting the cost of each component. (Source: IPCC 2005 data, adjusted to 2007 cost basis)

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

FIGURE 6 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 CO<sub>2</sub> emission rate (t CO<sub>2</sub>/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 CO<sub>2</sub> capture and electricity generation. No single set of assumptions applies to all situations or all parts of the world, so estimated costs vary. Broader range would appear if other factors were considered, such as subcritical boilers or non-bituminous coals.



**Fig. 6.** Cost of electricity generation (2007 US\$/MWh) as a function of the CO<sub>2</sub> emission rate (t CO<sub>2</sub>/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. (2007); IPCC (2005), adjusted to 2007 cost basis.



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 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 CO<sub>2</sub> capture step (including compression) accounts for 80–90% of this cost, while the remaining 10–20% is due to 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.

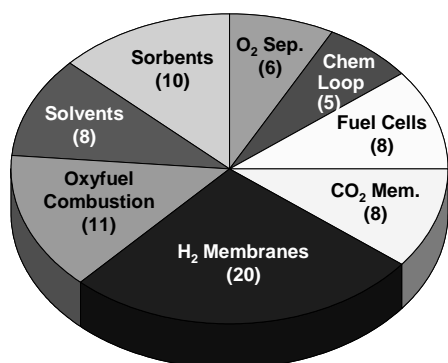
FIGURE 6 can also be used to calculate the cost per ton of CO<sub>2</sub> avoided when a plant is built with CCS instead of without. For a new supercritical (SCPC) coal plant with deep aquifer storage, this is currently about \$60–80/t CO<sub>2</sub>, which is the magnitude of the “carbon price” needed to make CCS cost-effective. For IGCC plants with and without capture, the CCS cost is smaller, about \$30–50/t CO<sub>2</sub>. All costs are decreased when CO<sub>2</sub> can be sold for EOR with storage. The cost of CO<sub>2</sub> 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 CO<sub>2</sub> 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 CO<sub>2</sub> avoided is roughly \$40–60/t CO<sub>2</sub>.

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 CO<sub>2</sub> 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 CO<sub>2</sub> 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 TECHNOLOGY**

Research and development (R&D) programs are underway worldwide to produce CO<sub>2</sub> capture technologies with lower cost and energy requirements (IEAGHG 2008). For example, the European CASTOR project aims at lower post-combustion capture costs by developing advanced amines and other solvents. In the US, the Department of Energy (USDOE) has a major R&D program supporting a variety of approaches to CO<sub>2</sub>

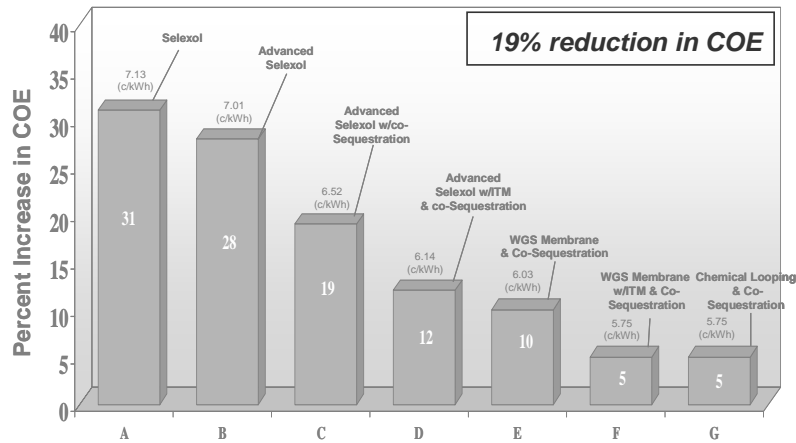
capture (FIG. 7) as well as a Regional Partnership Program that supports CCS data collection and field tests across the country (NETL 2009). US electric utility companies and equipment manufacturers are also testing a post-combustion process using chilled ammonia in the hope of greatly reducing the CCS energy penalty and with it the cost of capture. Researchers in Australia, Europe, Japan, and North America are seeking major improvements also in pre-combustion capture with membrane technologies for oxygen and hydrogen production and CO<sub>2</sub> separation. A number of national and international programs are also pursuing new process concepts such as chemical looping combustion.



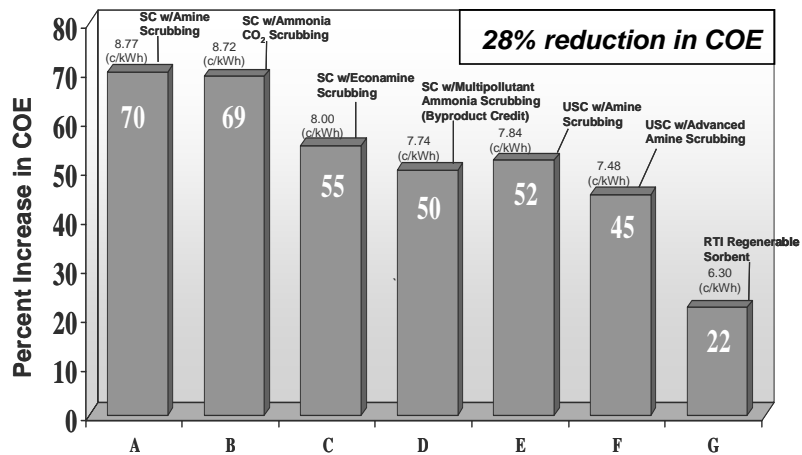
**Fig. 7.** Advanced approaches for CO<sub>2</sub> capture being pursued in the USDOE R&D program. Values in parenthesis are the number of projects in each category as of early 2007. Total funding for these projects was \$205 million (averaging approximately \$62 million per year). Largest areas of funding were hydrogen membranes and oxygen separation systems. (Source: data from NETL 2007)

Although future costs remain highly uncertain, technological innovations in capture systems, in conjunction with improvements in power plant design, are projected to yield sizeable reductions in the future cost of CO<sub>2</sub> capture. Two methods are used to estimate future costs. One is a “bottom-up” approach that employs engineering and economic analyses of proposed new process designs. FIGURE 8 shows examples of such projections by the USDOE for post-combustion and pre-combustion systems. These analyses estimate cost reductions of 20%–30% in the total (levelized) cost of electricity generation with CCS using advanced technologies.

Similar results are obtained from a “top-down” approach to cost estimation based on historical “experience curves.” This approach does not specify any details of future technology design; rather, it assumes that costs evolve in a manner consistent with past experience for similar technologies. A large body of literature shows that technologies typically become cheaper as they mature and are more widely adopted. The rate of cost reduction is commonly represented as a “learning rate” expressed as a function of cumulative production or installed capacity. In this analysis, the cost of different types of power plants with CO<sub>2</sub> capture was estimated using historical learning rates for seven different energy or environmental technologies (see, Rubin et al. 2007b for details). Key results are summarized in FIGURE 9 for four types of power plants. Coal gasification-based power plants (IGCC) show the largest potential for cost reductions since the major components of that system are not nearly as mature as the major components of combustion-based systems. Thus, unlike the bottom-up approach, the experience-based approach to cost estimation 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.

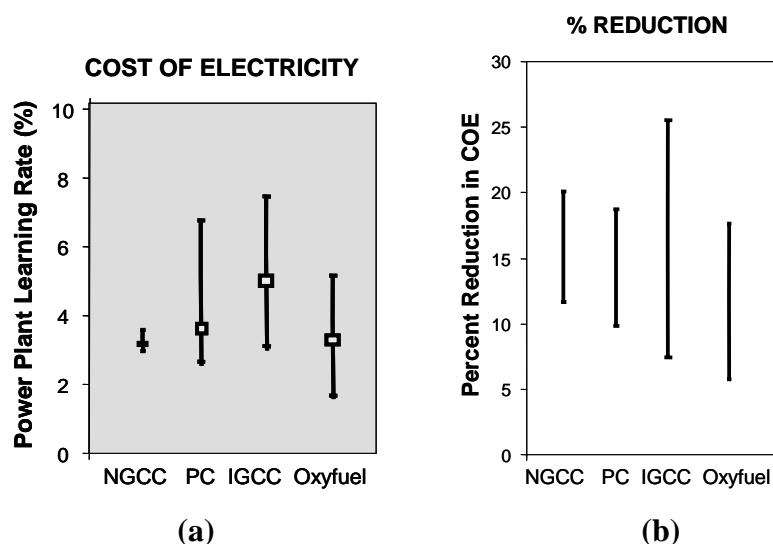


(a) IGCC Plant (Pre-combustion Capture)



(b) SCPC Plant (Post-combustion Capture)

**Fig. 8.** Projected increases in the cost of electricity (COE) for CO<sub>2</sub> capture and storage using current technology (column A) and various advanced capture technologies for, (a) an IGCC plant with pre-combustion capture (note: ITM= ion transport membrane; WGS= water gas shift) and (b) a SCPC plant with post-combustion capture (note: RTI= Research Triangle Institute). The height of each bar shows the percent increase in COE relative to a similar plant without CO<sub>2</sub> capture and storage. The absolute value of COE (in US cents/kWh) appears in small print at the top of each bar. For the IGCC plant, the total COE is projected to fall from 7.13 ¢/kWh currently to 5.75 ¢/kWh with advanced technology (columns 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 oxy-combustion (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)



**Fig. 9. (a)** Projected plant-level learning rates (percent reduction in cost of electricity generation for each doubling of installed capacity) after an assumed 100 GW of total installed capacity worldwide for each of four types of power plants with CO<sub>2</sub> capture. **(b)** The resulting overall percent reduction in cost of electricity (COE) generation after 100 GW of installed capacity. (Source: Rubin et al 2007b)

## CONCLUDING REMARKS

Although CO<sub>2</sub> capture and sequestration holds considerable promise, its acceptance will depend on the nature and pace of government policies to limit CO<sub>2</sub> emissions and/or to provide financial incentives for its use. At present, only the European Union (EU) has CO<sub>2</sub> 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 CO<sub>2</sub>. The price of a CO<sub>2</sub> allowance is established in a financial market called the European Union’s emissions trading system (ETS), the largest existing market for carbon reductions (Ellerman and Joskow 2008). At current ETS carbon prices, CO<sub>2</sub> 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 recently proposed in Congress fall far short of the carbon prices needed to stimulate use of CCS, although some proposals included financial incentives for its early adoption (Pena and Rubin 2008). More recent bills, such as the Waxman-Markey bill adopted by the US House of Representatives, would complement cap-and-trade with power plant performance standards that restrict CO<sub>2</sub> emissions to levels only achievable with CCS. Whatever the method, until there are sufficiently stringent limits on CO<sub>2</sub> 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 or requirements, 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 critically 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). To date, adequate financing (of roughly one billion

US dollars per project for a large coal-based power plant) has not yet been forthcoming. Government–industry partnerships in Asia, Europe, and North America are currently in various stages of planning and financing CCS projects (TABLE 3). Once adequate funding is in place, it will take several years to design and build each facility, followed by several years of operation to evaluate its reliability, safety, public acceptance, and performance in reducing CO<sub>2</sub> emissions. If all goes well, a viable CCS industry could be launched in approximately a decade.

**Table 3.** A few examples of planned and proposed CO<sub>2</sub> 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 <sub>2</sub>	Germany	Coal	450	Pre	2015
Monash Energy	Australia	Coal	60 k bpd	Pre	2016

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