

CO₂ SEQUESTRATION: OPPORTUNITIES AND CHALLENGES

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Abstract

Carbon management and sequestration offers an opportunity for reducing greenhouse gas emissions that can complement the current strategies of improving energy efficiency and increasing the use of non-fossil energy resources. Furthermore, this approach will enable us to continue to enjoy the benefits of fossil fuels while protecting our climate. When most people think of sequestering carbon, they think of planting trees. However, the focus of this paper is the capture of CO₂ from large stationary sources and then reusing it or sequestering it in geologic formations or the deep ocean.

The two biggest challenges for carbon sequestration from large stationary sources are reducing costs associated with CO₂ separation and capture and developing sinks that are safe, effective, and economical. In this paper, we present results of a detailed analysis of costs associated with today's technology for CO₂ separation and capture followed by a discussion of opportunities to lower costs in the future. Then, we review the challenges involved in developing secure storage reservoirs.

I. INTRODUCTION

Fossil fuels currently supply over 85% of the world's energy needs and will remain in abundant supply well into the 21st century. They have been a major contributor to the high standard of living enjoyed by the industrialized world. We have learned how to extract energy from fossil fuels in environmentally friendly ways, controlling the emissions of NO_x, SO₂, unburned hydrocarbons, and particulates. Even with these added pollution controls, the cost of fossil energy generated power keeps falling. Despite this good news about fossil energy, its future is clouded because of the environmental and economic threat posed by possible climate change, commonly referred to as the "greenhouse effect". The major anthropogenic greenhouse gas is carbon dioxide (CO₂) and the major source of anthropogenic CO₂ is combustion of fossil fuels. However, if we can develop technology to capture and sequester the fossil fuel CO₂ in a cost-

effective and environmentally sound manner, we will be able to enjoy the benefits of fossil fuel use throughout the next century.

The idea of capturing CO₂ from the flue gas of power plants did not start with concern about the greenhouse effect. Rather, it gained attention as a possible economic source of CO₂, especially for use in enhanced oil recovery (EOR) operations where CO₂ is injected into oil reservoirs to increase the mobility of the oil and, therefore, the productivity of the reservoir. Several commercial CO₂ capture plants were constructed in the late 1970s and early 1980s in the US (Arnold *et al.*, 1982; Hopson, 1985; Kaplan, 1982; Pauley *et al.*, 1984). The North American Chemical Plant in Trona, CA, which uses this process to produce CO₂ for carbonation of brine, started operation in 1978 and is still operating today. However, when the price of oil dropped in the mid-1980s, the recovered CO₂ was too expensive for EOR operations and all of the other CO₂ capture plants were closed. Several more CO₂ capture plants were subsequently built (Barchas and Davis, 1992; Sander and Mariz, 1992) to take advantage of some of the economic incentives in the Public Utility Regulatory Policies Act (PURPA) of 1978 for “qualifying facilities” and to provide CO₂ for sale commercially.

In addition to power plants, there are a number of large CO₂-emitting industrial sources that could also be considered for application of capture and sequestration technologies. In natural gas operations, CO₂ is generated as a by-product. In general, gas fields may contain up to 20% (by volume) CO₂, most of which must be removed to produce pipeline quality gas. Therefore, sequestration of CO₂ from natural gas operations is a logical first step in applying CO₂ capture technology. In the future, similar opportunities for CO₂ sequestration may exist in the production of hydrogen-rich fuels (e.g., hydrogen or methanol) from carbon-rich feedstocks (e.g., natural gas, coal, or biomass). Specifically, such fuels could be used in low-temperature fuel cells for transport or for combined heat and power. Relatively pure CO₂ would result as a byproduct (Socolow 1997).

The first commercial CO₂ capture and sequestration facility started-up in September 1996, when Statoil of Norway began storing CO₂ from the Sleipner West gas field into a sandstone aquifer 1000 m beneath the North Sea. The CO₂ is injected from a floating rig at a rate of 20,000 tonnes/week (corresponding to the rate of CO₂ produced from a 140 MW_e coal fired power plant). The economic incentive for this project is the Norwegian carbon tax of \$50 per tonne CO₂. Costs of the operation are approximately \$15/tonne of CO₂ avoided (Olav Kaarstad, Statoil, personal communication). An international research effort is being organized to monitor and document this effort so the experience can be built on by future endeavors.

To date, all commercial plants to capture CO₂ from power plant flue gas use processes based on chemical absorption with a monoethanolamine (MEA) solvent. MEA was developed over 60 years ago as a general, non-selective solvent to remove acid gases, such as CO₂ and H₂S, from natural gas streams. The process was modified to incorporate inhibitors to resist solvent degradation and equipment corrosion when applied to CO₂ capture from flue gas. Also, the solvent strength was kept relatively low, resulting in large equipment sizes and high regeneration energy requirements (Leci, 1997). Therefore, CO₂ capture processes have required significant amounts of energy, which reduces the power plant’s net power output. For example, the output of a 500 MW_e (net) coal-fired power plant may be reduced to 400 MW_e (net) after CO₂ capture.

This imposes an “energy penalty” of 20% (i.e., (500-400)/500). The energy penalty has a major effect on the overall costs. Table 1 shows typical energy penalties associated with CO₂ capture - both as the technology exists today and as it is projected to evolve in the next 10-20 years.

Table 1. Typical Energy Penalties Associated with CO₂ Capture

Power Plant Type	Today	Future
Conventional Coal (PC)	27 - 37% (Herzog and Drake, 1993)	15% (Mimura <i>et al.</i> , 1997)
Gas (NGCC)	15 - 24% (Herzog and Drake, 1993)	10 - 11% (Mimura <i>et al.</i> , 1997)
Advanced Coal (IGCC)	13 - 17% (Herzog and Drake, 1993)	9% (Herzog and Drake, 1993)

II. CO₂ CAPTURE

Methodology for Analysis of Economic Studies

We have conducted a comparison of published studies from the past several years that analyzed the economics of capturing CO₂ from fossil fuel-fired power plants. These studies fall into three categories:

- Advanced Coal based on Integrated Gasification Combined Cycle (IGCC) power plants. In these plants, the coal is gasified to produce syngas (hydrogen plus carbon monoxide). The syngas is cleaned and shifted (carbon monoxide reacts with steam to form hydrogen and CO₂), followed by the removal of CO₂ with a physical absorption process (e.g., Selexol or Rectisol). The hydrogen rich gas left behind is used to fuel a combined cycle power plant.
- Conventional Coal based on Pulverized Coal (PC) power plants. In these plants, steam is raised in a boiler to drive a steam turbine. The CO₂ is removed from the flue gas with an MEA scrubbing process.
- Natural Gas is based on Natural Gas Combined Cycle (NGCC) power plants. In these plants, the natural gas drives a gas turbine. Steam to drive a steam turbine is produced by recovering heat from the gas turbine exhaust, as well as some additional natural gas firing. The CO₂ is removed from the flue gases with an MEA scrubbing process.

All studies were made using commercially available technology and include the cost of compressing the captured CO₂ to about 2000 psia for pipeline transportation. The studies analyzed in our work are listed below.

IGCC Studies:

Argonne National Laboratory (Doctor *et al.*, 1996; Doctor *et al.*, 1997)
Politecnico di Milano, Italy (Chiesa *et al.*, 1998)
SFA Pacific (Simbeck, 1998)
University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Condorelli *et al.*, 1991; Booras and Smelser, 1991)

PC Studies:

University Of Utrecht, Netherlands (Hendriks, 1994)
EPRI (Smelser *et al.*, 1991; Booras and Smelser, 1991)
SFA Pacific (Simbeck, 1998)

NGCC Studies:

SFA Pacific (Simbeck, 1998)
Norwegian Institute of Technology (Bolland and Saether, 1992)

We analyzed two cases from each study, a power plant with no capture (reference plant) and the same plant with CO₂ capture. Where necessary, we adjusted the fuel feed rates so that they were the same for both cases of a study. This means that the net power output for the capture plant will be less than the reference plant due to the energy requirements of the capture process (see Figure 1). It is also important to point out the difference between the amount of CO₂ captured and the amount avoided. In the example from Figure 1, we capture 242 tonnes CO₂/hr (0.769 kg/kWh), but avoid only 184 tonnes CO₂/hr (0.586 kg/kWh). The difference is caused by the need for energy in the capture process, which produces additional CO₂. This additional CO₂ must be subtracted from the CO₂ captured to obtain the CO₂ avoided.

From each study, we extracted the following data for both the reference and capture cases:

- Cost of electricity (¢/kWh) broken down into capital, fuel, and operation and maintenance (O&M)
- Capital cost (\$/kW)
- Net power output (MW)
- CO₂ emitted (kg/kWh)
- Heat rate (Btu/kWh) defined on a low heating value (LHV) basis (note that the thermal efficiency is simply 3412 Btu/kWh divided by the heat rate)

In addition, we extracted the following data so that we could put each of the studies on a common economic basis:

- the annual capacity factor (defined as operating hours per year divided by 8760, where 8760 is the total number of hours in a year).
- the cost of fuel in \$ per million Btu based on fuel LHV.
- the capital charge rate. The capital charge rate can be roughly correlated to the cost of capital and is used to annualize the capital investment of the plant. Specifically, the

capital component of the cost of electricity (\$/kWh) equals the capital charge rate (fraction/yr) times the capital cost (\$/kW) divided by the hours per year of operation.

We adjusted each study to the following economic basis:

- Capital charge rate of 15%/yr
- Annual capacity factor of 0.75 (6570 hrs/yr)
- Fuel costs for gas of \$2.93 per million Btus based on LHV
- Fuel cost for coal of \$1.24 per million Btus based on LHV

The studies all reported their results in U.S. dollars, but used different year dollars in their calculations. It should be noted that, despite inflation, electricity production costs have been falling. We decided not to adjust for different year dollars since the precision that might be gained in converting these estimates to the same year dollars is small relative to the uncertainty inherent in and across these cost estimates.

The key results calculated were the energy penalty and the cost of capture. The capture costs can be represented in many ways, but we have found the most useful representations to be the mitigation cost (\$/tonne CO₂ avoided) and the incremental cost of electricity (¢/kWh). Both of these metrics have their strengths and weaknesses.

The mitigation cost is a useful way to compare different mitigation strategies. This becomes important if we move toward a trading system, as it gives us a way to compare projects based on very different technologies. For example, using this metric, we can compare the cost of a sequestration project directly to the cost of an energy efficiency project or a renewable energy project. As a cautionary note, the mitigation cost is very sensitive to the basis chosen (see Figure 6 and accompanying discussion).

The incremental cost is important because it is a direct measure of the effect of CO₂ mitigation on electricity prices. This becomes extremely important for developers of new power projects considering the use of sequestration. Because this number is not normalized by the amount of CO₂ mitigated, it may be misleading. Specifically, this cost is the product of the unit cost of mitigation times the quantity mitigated. Therefore, two different strategies may yield similar incremental cost of sequestration, but one may sequester a large quantity at a small unit cost, while the other may sequester only a small amount at a large unit cost.

The incremental cost may be broken down into two components, the capture cost and the derating cost. The capture cost is defined as the increase in electricity costs due to the additional capital and O&M required for CO₂ capture. It is normalized with the net power output of the reference plant. The derating cost is the increase in the cost of electricity due to the energy requirement of the capture process that results in a derating of the net power output for a given fuel input. With our definition, note that costs associated with both the reference plant and the capture process are derated.

In addition to the above studies, we included very recent data from the Coal Utilization Research Council (CURC, 1998) for all three types of plants. This data was limited to the reference plants.

Results of Analysis of Economic Studies

The results of our data extraction and calculations are shown in Figures 2-4.

Figure 5 plots the cost of electricity versus CO₂ emissions for each of the analyzed studies. In terms of emissions, the plants cluster into three groups: reference coal plants at about 0.75 kg CO₂ per kWh, reference natural gas plants at about 0.35 kg CO₂ per kWh, and the capture plants at about 0.1 kg CO₂ per kWh. If we ignore the EPRI results (this is the oldest study and was based on very conservative assumptions), we can make the following observations about costs:

- NGCC reference plants are 3-4 ¢/kWh
- Coal reference plants are 4-5 ¢/kWh, with PC plants slightly less expensive than IGCC plants
- NGCC capture plants are 5-6 ¢/kWh
- IGCC capture plants are 6-7 ¢/kWh
- PC capture plants are 7-8 ¢/kWh

Today, PC plants are slightly less expensive than IGCC plants. However, if CO₂ emissions are regulated and carbon sequestration becomes necessary, IGCC plants will become more economical. Also, with current technology, coal is at a competitive disadvantage compared to natural gas for both reference and capture plants.

We can make the following observations on the incremental cost of electricity (once again, ignoring the EPRI studies):

- For IGCC plants, the range is 1.1 to 1.7 ¢/kWh
- For NGCC plants, the range is 1.9 to 2.1 ¢/kWh
- For PC plants, the range is 2.3 to 3.1 ¢/kWh

This suggests that if CO₂ emissions from power plants were regulated, IGCC plants could be most efficient in meeting the goals through a sequestration pathway. This would require the reference IGCC plant to become more competitive with the NGCC reference plant.

In order to understand how to derive the mitigation cost, Figure 6 plots a subset of points from Figure 5. Specifically, the points plotted are from the SFA Pacific IGCC capture plant and all three CURC reference plants. The slope of the line connecting the 2 IGCC points is the cost of mitigation in \$/tonne of CO₂ avoided. Furthermore, by extending this line to the y-axis, we can read the cost of electricity that a zero emission technology (e.g., renewables) must beat to be competitive with the sequestration option. For this example, the cost is 64.8 mills/kWh.

It was noted earlier that the mitigation cost depends on the basis chosen. In the above example, the basis was an IGCC plant with no capture and the result was \$26/tonne CO₂ avoided. One can argue that PC plants are the standard coal plant today, so that should be the basis. This yields a mitigation cost of \$29/tonne CO₂ avoided. If one took as the basis an NGCC plant (this is the most popular plant being built today), the mitigation cost would be \$107/tonne CO₂ avoided.

Figure 7 plots the mitigation cost for each of the studies analyzed versus the energy penalty. In each instance, the basis of the mitigation cost was chosen to be the corresponding reference plant from each study. To find the total mitigation cost, the sequestration cost (i.e., the cost of transporting and injecting the CO₂ into the ground or ocean) must be added to the numbers shown in Figure 7. Preliminary estimates are that an additional \$5-10 per tonne CO₂ avoided will be needed.

Lowering the Cost of Capture

The results presented above represent technology that is commercial today, but that has not been optimized for CO₂ capture and sequestration. One should not judge the viability of CO₂ capture power plants based on today's relatively expensive technology. There is great potential for technological improvements that can significantly lower costs. Improving the thermal efficiency of the reference plants, reducing the energy penalty for CO₂ capture (see Table 1), or improved separation technologies can significantly reduce costs. Even larger costs reductions are possible in the future with new innovative technologies. For example, it may be possible to develop new types of power plants and power cycles.

The paper documents only a first step in our analysis of capture costs. We plan to develop a model based on the results presented above to conduct sensitivity studies. Some variables we will study include: reference plant heat rates, energy penalty and derating costs, capital costs of the capture plant, and fuel costs.

III. CO₂ SEQUESTRATION

Once the CO₂ is separated and captured, the next challenge is what to do with the large quantities of CO₂. Commercial use of the CO₂ would improve the economics of sequestration, but large-scale applications are limited. Most chemical processes that use CO₂ require relatively small amounts, with totals on the order of millions of tons, not the billions of tons produced from fossil fuels. However, geological formations and the deep ocean have the potential to store the large quantities produced by fossil fuel combustion (see Table 2).

Sequestration in Geological Formations

Geological sinks for CO₂ include deep saline formations, depleted oil and gas reservoirs, and unmineable coal seams. These formations are widely dispersed around the world and together can hold hundreds to thousands of GtC. In addition, the technology to inject CO₂ into the ground is well established. Injection of CO₂ into geological formations for enhanced oil recovery (EOR) is a mature technology. In 1998, a total of about 60 million m³/day (about 43 million metric tons per year) of CO₂ was injected at 67 commercial EOR projects. As mentioned in the Introduction of this paper, geological sequestration solely for reasons related to climate change is currently being demonstrated in the North Sea in Norway.

Table 2. Order of magnitude estimates for the worldwide capacity of the various sinks. Note that the worldwide total anthropogenic carbon emissions are about 7 GtC per year.

Sequestration Option	Worldwide capacity in GtC
Ocean	1000s
Deep Saline Formations	100s to 1000s
Oil and Gas Reservoirs	100s
Unmineable Coal Seams	10s to 100s
Terrestrial Biosphere	10s to 100s
Utilization	0.1 per year

Oil and gas reservoirs appear to be a promising geologic storage option because these reservoirs have already demonstrated their ability to contain pressurized fluids for long periods of time. Currently abandoned oil and gas reservoirs in the US could hold about 3 billion tonnes of CO₂, while the ultimate reserves of oil and gas would hold roughly 100 billion tonnes of CO₂ (Winter and Bergman, 1996). If CO₂ is injected into active oil reservoirs, the added benefit of EOR could offset some of the sequestration costs.

Deep (>800 m) saline formations that are hydraulically separated from shallower aquifers and surface water supplies may be the best long-term geologic storage option because their potential storage capacity is large (1000s of GtC) and they are widely distributed. Because there has been less interest in them compared to oil and gas formations, the properties of deep saline formations are not as well known, which leads to technical uncertainty. It is believed that the formation should be located under a relatively impermeable cap, yet there should be high permeability, as well as porosity, below the cap to allow the CO₂ to be distributed efficiently. Effects of gravity segregation and fingering may limit the effective storage, and fractures and open peripheries can allow leakage (Lindeberg, 1997). Experience can be gleaned from the disposal of industrial wastes as the US currently uses over 400 wells to inject about 75 million cubic meters of industrial waste (some hazardous; some non-hazardous) into deep aquifers each year (Bergman and Winter, 1996).

Sequestration in saline formations or in oil and gas reservoirs is achieved by a combination of three mechanisms: displacement of the *in-situ* fluids by the CO₂, dissolution of the CO₂ into the fluids, and chemical reaction of the CO₂ with minerals present in the formation to form stable, solid compounds like carbonates. Displacement dominates initially, but dissolution and reaction become more important over time scales of decades and centuries.

Abandoned and uneconomic coal seams are another potential storage site. CO₂ diffuses through the pore structure of the coal, where it physically adsorbed to the coal. This process is similar to the way in which activated carbon removes impurities from air or water. CO₂ can also be used to enhance the recovery of coal bed methane (Gunter *et al.*, 1997). Estimated US coal bed methane resources are large -- ranging from 275 to 649 trillion cubic feet, with current

production coming mainly from the San Juan Basin in SW Colorado and the Black Warrior basin in Alabama (Dawson, 1995). Although still in the development stage, the process has been tested in pilot scale field studies conducted by Amoco and Meridian in the San Juan Basin.

Several steps need to be implemented to further the development of geologic sequestration of CO₂. The main issues are uncertainties in the volumes available for storage, the long-term integrity of the storage, and the costs associated with CO₂ transport to the sequestration site and the storage operation itself. Storage integrity is important not only to prevent the unintended return of CO₂ to the atmosphere, but also for concerns about public safety and the potential liability should there be a release. However, much experience resides in the oil and gas industry to prevent accidental releases.

Sequestration in the Deep Ocean

The ocean represents the largest potential sink for anthropogenic CO₂. It already contains an estimated 40,000 GtC (billion tonnes of carbon) compared with only 750 GtC in the atmosphere and 2,200 GtC in the terrestrial biosphere (IPCC, 1996). As a result, the amount of carbon that would cause a doubling of the atmospheric concentration would change the ocean concentration by less than 2%.

Worldwide anthropogenic emissions of carbon to the atmosphere are about 7 GtC. The ocean-atmosphere flux is about 90 GtC per year, with a net ocean uptake of 2 ± 0.8 GtC (IPCC, 1996). On a time-scale of a thousand years, over 90% of today's anthropogenic emissions of CO₂ will be transferred to the ocean. Discharging CO₂ directly to the ocean would accelerate this ongoing, but slow, natural process and would reduce both peak atmospheric CO₂ concentrations and their rate of increase.

In order to better understand the opportunities and challenges involved in direct injection of CO₂ into the ocean, a simplified view of the ocean and the properties of CO₂ are presented here. The exact temperature and density profiles in the ocean vary with season and location. In general, the vertical profile of the oceans are characterized by three strata: an upper mixed layer about 100 m deep, a thermocline region extending to about a depth of 1000 m, and a deep region. The upper mixed layer features near-constant density and temperature profiles over the depth and gaseous concentration levels in equilibrium with the atmosphere. The thermocline is stably stratified by large temperature and density gradients that inhibit vertical mixing. The deep ocean has near-constant temperatures in the range of 2-5°C. Pressure at any depth can be approximated by assuming a 1 bar pressure rise for every 10 m of depth.

At typical pressures and temperatures that exist in the ocean, pure CO₂ would be a gas above approximately 500 m and a liquid below that depth. In seawater, the liquid would be positively buoyant (i.e., it will rise) down to about 3000 m, but negatively buoyant (i.e., it will sink) below that depth. At about 3700 m, the liquid becomes negatively buoyant compared to seawater saturated with CO₂. In seawater-CO₂ systems, CO₂ hydrate (CO₂•nH₂O, 6<n<8) can form below about 500 m depth depending on the relative compositions. CO₂ hydrate is a solid with a density about 10% greater than that of seawater.

In the near-term, a consensus is developing that the best strategy is to discharge the CO₂ below the thermocline at depths of 1000 - 1500 m. The technology exists today to implement such a strategy. The injection can be achieved with minimal environmental impacts. The cost is low compared to most other ocean injection strategies and is much smaller than anticipated capture costs. The major question revolves around sequestration efficiency.

To implement the above strategy, two methods of injection have been proposed. One is to transport the liquid CO₂ from shore in a pipeline and discharge it from a manifold lying on the ocean bottom, forming a rising droplet plume about 100 m high (Liro *et al.*, 1992). Alternatively, the liquid CO₂ could be transported by tanker and then discharged from a pipe towed by the moving ship (Ozaki *et al.*, 1995). Although the means of delivery are different, the plumes resulting from these two options would be quite similar and, therefore, research on these two injection methods should be considered complementary.

Another approach to CO₂ ocean sequestration is to inject the CO₂ as deeply as possible in order to maximize the sequestration efficiency. In order to accomplish this, new technology would need to be developed, with unknown costs. One such idea is to inject the liquid CO₂ to a sea floor depression forming a "deep hydrate lake" at a depth of about 4000 m (Ohsumi, 1995).

In assessing strategies for implementing ocean sequestration of CO₂, several key research topics need to be addressed:

- **Sequestration efficiency**, which is very site-specific, refers to how long the CO₂ will remain in the ocean before ultimately equilibrating with the atmosphere. The use of ocean general circulation models are required to determine sequestration efficiencies.
- **Environmental impacts** must be viewed at two different scales. *On a global scale*, direct injection of CO₂ to the ocean can be considered environmentally beneficial compared to our present trajectory. *On a local scale*, the most significant environmental impact is derived from lowered pH as a result of the reaction of CO₂ with seawater (Magnesen and Wahl, 1993; Kollek, 1993; Auerbach *et al.*, 1997). Impacts would occur principally to non-swimming marine organisms (e.g., zooplankton, bacteria and benthos) residing at depths of about 1000 m or greater and their magnitude will depend on both the level of pH change and the duration of exposure (Auerbach *et al.*, 1997). However, available data suggest that impacts associated with pH change can be completely avoided if the injection is properly designed to disperse the CO₂ as it dissolves (Caulfield *et al.*, 1997).
- **Engineering analysis**, in terms of what technology exists and what must be developed, is an important consideration. Led in part by the oil industry, great strides have been made in undersea off-shore technology.

IV. CONCLUDING REMARKS

Carbon management and sequestration presents an opportunity for us to address climate change concerns while still enjoying the benefits of fossil fuels. However, there are several challenges that must be met.

One challenge is to reduce the cost of sequestration associated with separation and capture of CO₂ from power plants. Of the three types of power plants studied, advanced coal plants like IGCC had the lowest incremental cost of electricity for CO₂ capture. This suggests that coal could compete with natural gas in a greenhouse gas constrained world.

Another challenge is to verify the feasibility of the various geologic and ocean reservoirs for CO₂ storage. This includes understanding the long-term fate of the CO₂ and addressing environmental and safety concerns.

Finally, carbon sequestration should be viewed as part of an overall strategy that includes improved efficiency and non-carbon energy sources. For us to be able to address climate change issues at a reasonable cost, we will need as many mitigation options as possible.

V. ACKNOWLEDGMENT

This work was conducted with support from the U.S. Department of Energy. Specific offices and program managers are: BER program, Office of Science (John Houghton), Office of Fossil Energy (Bob Kane), and Federal Energy Technology Center (Perry Bergman).

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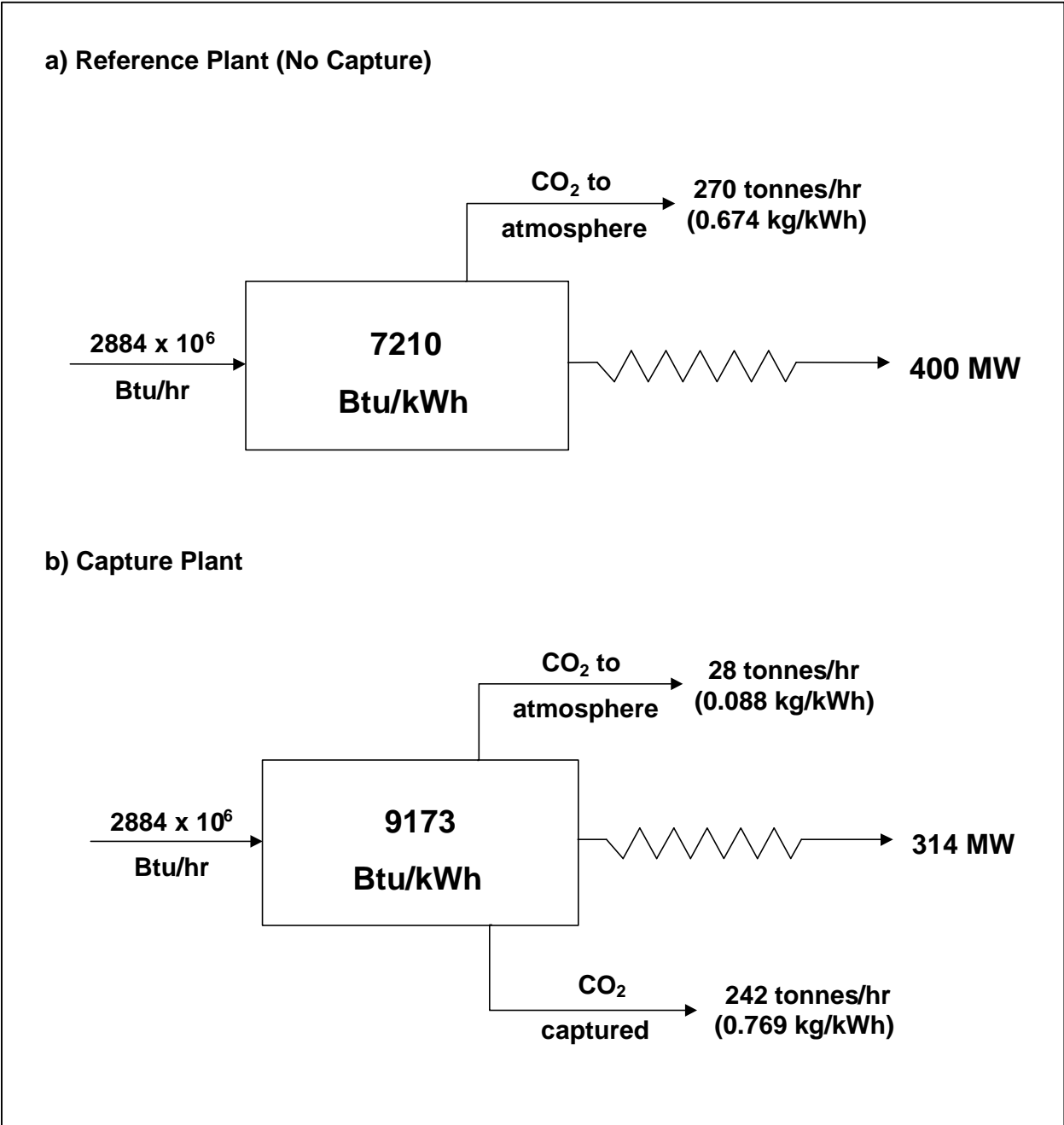


Figure 1. Example based on SFA Pacific IGCC Study (Simbeck, 1998). We adjusted the capture plant to have the same energy input as the reference plant. The energy penalty is 21.5% [(400-314)/400]. While we capture 242 tonnes of CO₂/hr, we only avoid 184 tonnes/hr. This is calculated by comparing the 0.088 kg/kWh emitted from the capture plant to the 0.674 kg/kWh emitted by the reference plant. We multiply the difference by 314 MW to obtain the 184 tonnes of CO₂/hr avoided.

Study:	Argonne	Milan	SFA Pacific	Utrecht	EPRI	CURC
Cycle:	IGCC	IGCC	IGCC	IGCC	IGCC	IGCC

Data Description	Units	Value	Value	Value	Value	Value	Value
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Reference Plant

coe: CAPITAL	mill / kWh	30.4	35.1	29.7	28.9	36.5	29.7
coe: FUEL	mill / kWh	11.0	9.2	8.9	9.7	11.5	10.1
coe: O&M	mill / kWh	9.3	7.1	7.9	6.5	10.4	6.1
Capital Cost	\$/kW	1332	1536	1300	1265	1600	1300
Net Power Output	MW	413.5	404.1	400.0	600.0	431.6	
CO ₂ emitted	kg/kWh	0.790	0.709	0.674	0.760	0.868	0.740
Thermal Efficiency (LHV)		38.4%	46.0%	47.3%	43.6%	36.8%	42.0%
Heat Rate (LHV)	Btu/kWh	8888	7425	7210	7826	9280	8124
Cost of Electricity	¢/kWh	5.07	5.13	4.65	4.50	5.85	4.58

CO₂ Capture Plant

coe: CAPITAL	mill / kWh	38.5	43.7	40.3	41.1	49.1
coe: FUEL	mill / kWh	12.1	10.8	11.4	11.7	14.3
coe: O&M	mill / kWh	11.2	8.7	10.8	9.4	18.8
Capital Cost	\$/kW	1687	1913	1767	1799	2152
Net Power Output	MW	377.5	345.6	314.4	500.0	347.4
CO ₂ emitted	kg/kWh	0.176	0.071	0.088	0.040	0.105
Thermal Efficiency (LHV)		35.0%	39.3%	37.2%	36.3%	29.6%
Heat Rate (LHV)	Btu/kWh	9735	8684	9173	9399	11528
Cost of Electricity	¢/kWh	6.18	6.32	6.25	6.21	8.23

Comparison

Capture Cost	¢/kWh	0.57	0.27	0.26	0.67	0.77
Derating Cost	¢/kWh	0.54	0.91	1.34	1.04	1.60
Incremental coe	¢/kWh	1.10	1.18	1.59	1.71	2.38
Energy Penalty		8.7%	14.5%	21.4%	16.7%	19.5%
\$/tonne CO ₂ avoided	\$/tonne	\$18	\$19	\$27	\$24	\$31

Basis

Capital Charge Rate		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Yearly Operating Hrs	hrs/yr	6570	6570	6570	6570	6570	6570
Fuel Cost, LHV	\$/MMBtu	1.24	1.24	1.24	1.24	1.24	1.24

Figure 2. Results of data analysis for IGCC plants. Note that the studies have been adjusted to a common economic basis.

Study: Cycle:		Utrecht PC	EPRI PC	SFA Pacific PC	CURC PC
Data Description	Units	Value	Value	Value	Value
Reference Plant					
coe: CAPITAL	mill / kWh	26.3	25.8	29.7	26.3
coe: FUEL	mill / kWh	10.3	11.7	9.5	10.5
coe: O&M	mill / kWh	5.9	10.3	7.9	5.8
Capital Cost	\$/kW	1150	1129	1300	1150
Net Power Output	MW	600	513.3	400.0	
CO ₂ emitted	kg/kWh	0.800	0.909	0.717	0.771
Thermal Efficiency (LHV)		41.0%	36.1%	44.4%	40.3%
Heat Rate (LHV)	Btu/kWh	8322	9440	7680	8462
Cost of Electricity	¢/kWh	4.25	4.78	4.71	4.25
CO₂ Capture Plant					
coe: CAPITAL	mill / kWh	47.3	56.7	46.2	
coe: FUEL	mill / kWh	13.4	17.8	11.3	
coe: O&M	mill / kWh	12.9	29.9	12.3	
Capital Cost	\$/kW	2073	2484	2022	
Net Power Output	MW	462	338.1	336.5	
CO ₂ emitted	kg/kWh	0.100	0.138	0.128	
Thermal Efficiency (LHV)		31.5%	23.8%	37.4%	
Heat Rate (LHV)	Btu/kWh	10832	14331	9130	
Cost of Electricity	¢/kWh	7.37	10.44	6.98	
Comparison					
Capture Cost	¢/kWh	1.42	2.10	1.16	
Derating Cost	¢/kWh	1.69	3.56	1.11	
Incremental coe	¢/kWh	3.12	5.66	2.27	
Energy Penalty		23.0%	34.1%	15.9%	
\$/tonne CO ₂ avoided	\$/tonne	\$45	\$73	\$39	
Basis					
Capital Charge Rate		15.0%	15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570	6570
Fuel (Coal) Cost, LHV	\$/MMBtu	1.24	1.24	1.24	1.24

Figure 3. Results of data analysis for PC plants. Note that the studies have been adjusted to a common economic basis.

Study: Cycle:		SFA Pacific NGCC	Trondheim NGCC	CURC NGCC
Data Description	Units	Value	Value	Value
Reference Plant				
coe: CAPITAL	mill / kWh	11.1	17.2	12.0
coe: FUEL	mill / kWh	16.7	19.2	18.5
coe: O&M	mill / kWh	3.0	2.7	2.4
Capital Cost	\$/kW	485	754	525
Net Power Output	MW	400.0	721.2	
CO ₂ emitted	kg/kWh	0.330	0.400	0.366
Thermal Efficiency (LHV)		60.0%	52.2%	54.1%
Heat Rate (LHV)	Btu/kWh	5688	6536	6308
Cost of Electricity	¢/kWh	3.07	3.91	3.28
CO₂ Capture Plant				
coe: CAPITAL	mill / kWh	25.9	30.1	
coe: FUEL	mill / kWh	18.8	22.5	
coe: O&M	mill / kWh	6.9	5.2	
Capital Cost	\$/kW	1135	1317	
Net Power Output	MW	353.7	615.3	
CO ₂ emitted	kg/kWh	0.056	0.046	
Thermal Efficiency (LHV)		53.0%	44.5%	
Heat Rate (LHV)	Btu/kWh	6433	7667	
Cost of Electricity	¢/kWh	5.17	5.77	
Comparison				
Capture Cost	¢/kWh	1.50	1.02	
Derating Cost	¢/kWh	0.60	0.85	
Incremental coe	¢/kWh	2.10	1.86	
Energy Penalty		11.6%	14.7%	
\$/tonne CO ₂ avoided	\$/tonne	\$77	\$53	
Basis				
Capital Charge Rate		15.0%	15.0%	15.0%
Yearly Operating Hours	hrs/yr	6570	6570	6570
Fuel (NG) Cost, LHV	\$/MMBtu	2.93	2.93	2.93

Figure 4. Results of data analysis for NGCC plants. Note that the studies have been adjusted to a common economic basis.

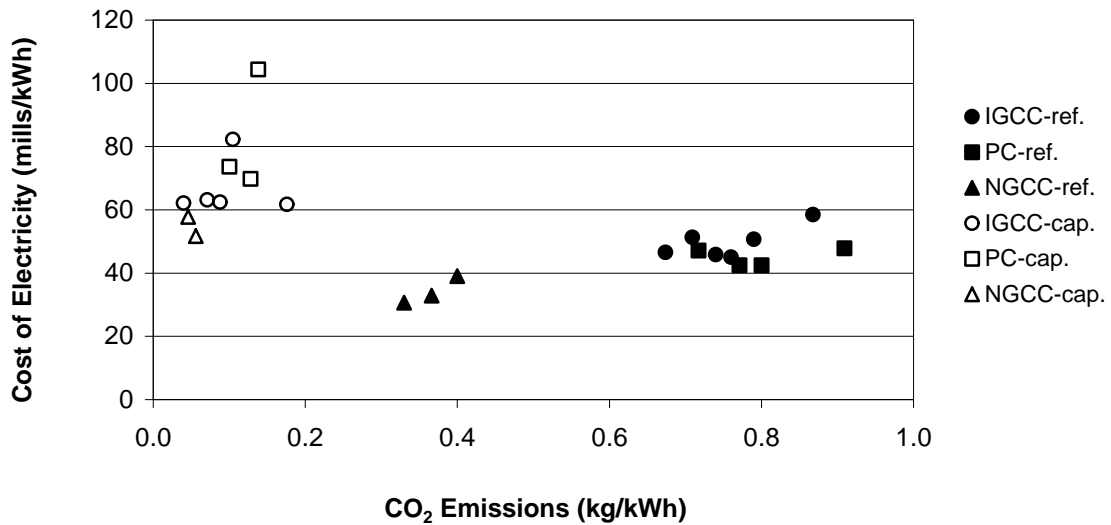


Figure 5. Cost of Electricity versus CO₂ Emissions for the 13 reference plants and the 10 capture plants analyzed.

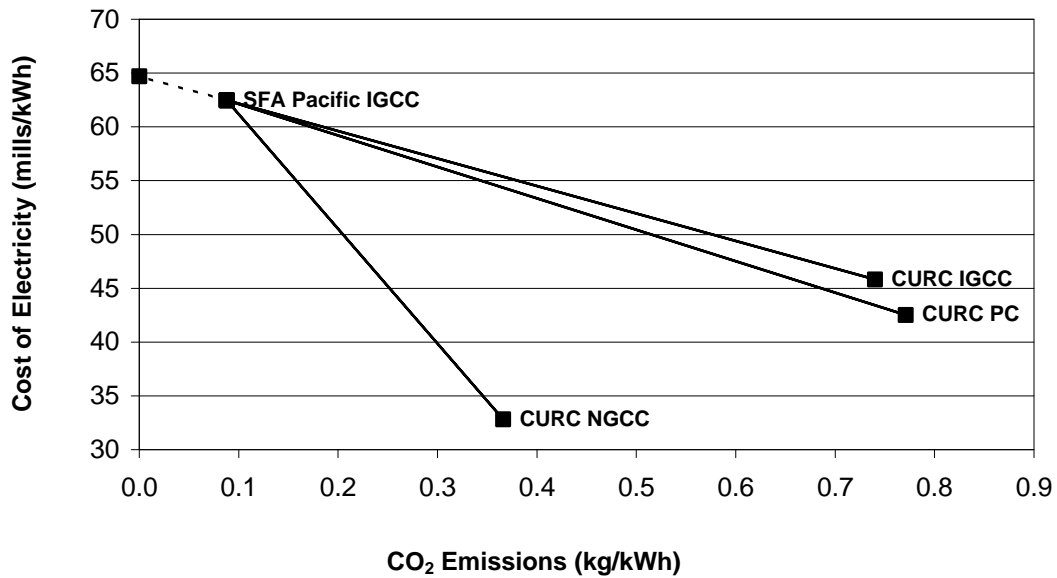


Figure 6. Calculation of Mitigation Costs. Mitigation cost is simply the slope of the connecting line. All reference plants are based on the CURC data. The cost of mitigation varies depending on the reference plant chosen for the base case: IGCC (\$26/tonne CO₂ avoided), PC (\$29/tonne CO₂ avoided) and NGCC (\$107/tonne CO₂ avoided). Target cost of electricity for a zero emission technology is y-intercept of each line (e.g., 64.80 mills/kWh for IGCC base.)

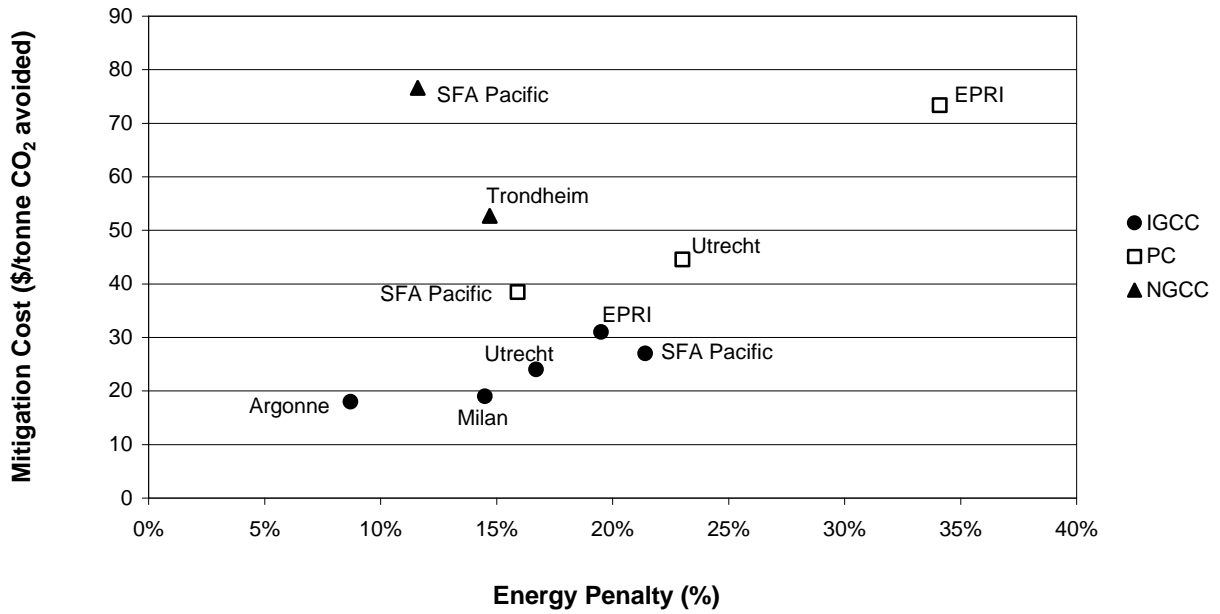


Figure 7. Summary of mitigation costs for the 10 studies analyzed, plotted against the energy penalty. Note that the basis of the mitigation cost is the corresponding reference plant from each individual study.