Economic Evaluation of Leading Technology Options for Sequestration of Carbon Dioxide

by

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Abstract

The greatest contribution to greenhouse gas emissions is the burning of fossil fuels, which releases nearly six billion tons of carbon per year into the atmosphere. These fuels will continue to be used well into the 21st century, although there is a urgent need to manage a sustainable economic development. Since power plants are the largest point sources of CO_2 emissions, capturing the carbon dioxide at power plants and sequestering it has been suggested. This approach would be complementary to the current strategies that aim at reducing greenhouse gas emissions by improving the energy efficiency and by increasing the use of non-fossil energy resources. However, a major barrier to CO_2 capture and sequestration is its cost.

This thesis presents the results of a detailed analysis of costs associated with today's technology for CO_2 separation and capture at three types of power plants: Integrated Gasification Combined Cycles (IGCC), coal-fired simple cycles (Pulverized Coal, PC), and natural gas-fired combined cycles (Natural Gas Combined Cycles, NGCC). The analysis is based on studies from the literature that are reviewed and adjusted to a common economic basis. A composite cost model is then developed, and a sensitivity analysis performed to identify the cost-drivers of the capture. Finally, the economics at the three types of power plants are predicted for a 10-year horizon, and the competitiveness of CO_2 separation technologies under a specific policy scenario are discussed.

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1 Introduction

In 1998, human activities in the United States resulted in carbon dioxide emissions totaling about 5,480 million metric tons[1] (EIA, 1999). Nearly all of these anthropogenic emissions (98%) resulted from energy production and use, primarily the combustion of fossil fuels. Hence, significant reductions in carbon dioxide emissions can be accomplished only through changes in the energy economy. This chapter will present how energy can be more efficiently produced, distributed and used. It will begin by discussing the three approaches to reducing carbon dioxide emissions and will then elaborate on each of them. Carbon sequestration will be introduced as part of the portfolio of technology options to reduce carbon dioxide emissions.

1.1 Approaches to Reducing Carbon Dioxide Emissions

The Kaya equation, popularized by Professor Yoichi Kaya from the University of Tokyo, provides a good context to discuss approaches to reducing carbon dioxide emissions. This equation expresses carbon dioxide emissions as follows:

$$Net(CO_2) = \left[P \times \left(\frac{GDP}{P} \right) \times \left(\frac{E}{GDP} \right) \times \left(\frac{CO_2}{E} \right) \right] - S \qquad (1.1)$$

---

[1] In the policy debates, the quantity of carbon emitted is a common metric; however, to compare different mitigation options, it is more common to use the quantity of carbon dioxide emitted, which is 3.67 times the quantity of carbon emitted.

where:

$Net(CO_2)$ = net carbon dioxide emissions

P = population

GDP/P = per capita Gross Domestic Product (aggregate measure of the standard of living)

E/GDP = energy consumption per unit of GDP (aggregate measure of the energy intensity of the economy)

CO_2/E = amount of CO_2 emitted per unit of energy consumed (aggregate measure of the carbon intensity)

S = induced sequestration of carbon dioxide

Continued growth implies that the population, P, and the standard of living, GDP/P, continue to rise. Therefore, one or more of the remaining three terms in the Kaya equation must change for the economy to grow while carbon emissions decrease. These remaining terms are:

- The energy intensity of the economy;
- The carbon intensity;
- The amount of carbon removed through induced sequestration.

These three terms embody distinct technology routes to reducing greenhouse gases (GHG) emissions. By increasing the efficiency of primary energy conversion and end use, fewer units of primary fossil energy are required to provide the same energy service. By substituting lower-carbon or carbon-free energy sources to the current energy sources, the carbon intensity of the energy economy can be reduced. Finally, carbon sequestration can be developed to reduce CO_2 emissions while at the same time enabling the continued use of fossil fuels. It represents a third, complementary approach to efficiency improvements and evolution toward low-carbon fuels.

1.2 Improving Energy Efficiency

Improvements in the efficiency of using energy can take place at any stage of the fuel cycle from production to end-use. Improvements in energy efficiency can produce direct environmental benefits in a number of ways, not only reducing GHG emissions but also delaying the need to develop new fuel resources.

Recent Evolution of Energy Efficiency

Following the energy price spikes in the 1970s and early 1980s, energy intensity went through a 2.8% annual decline in the US from the mid-1970s until the mid-1980s. In the next decade, energy intensity decreased only by 0.6% annually, as energy prices dropped and then remained stable.

1.2.1 Electric Power Generation Sector

Table 1.1 shows the efficiencies of different types of power plants. Today, simple cycle plants account for most of the global electricity generation. However, more efficient technologies are needed to have a major impact on emissions. Amongst them are high-efficiency fossil fuel-based technologies that increase power generation cycle efficiency by combining two or more advanced energy conversion cycles. As capital stock is retired as it breaks down or begins to operate inefficiently, these advanced energy conversion cycles will become the technology of choice.

Technology	Simple Cycle Plant, Fueled by Coal	Advanced Natural Gas-Fired Combined Cycle
Efficiency	33%	58%

Table 1.1: Power Plants Efficiencies (Mobil, 1999)

1.2.2 End-Use Sectors

As shown in Figure 1.1, fossil fuels are used in all energy sectors.

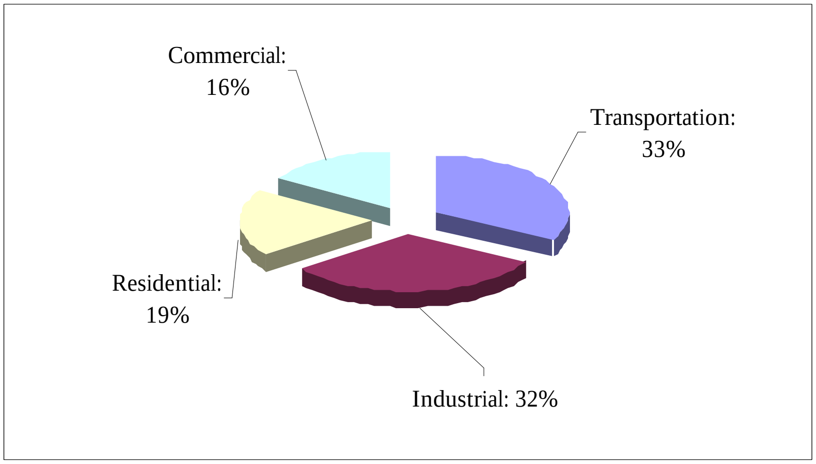

Figure 1.1: US Anthropogenic CO Sources, 1998 (IEA, 1999)

Electric utility emissions are distributed across sectors.

In 1998, the 3 major end-use sectors (transportation, industry, and residential and commercial buildings) emitted approximately equivalent levels of carbon in the US.

However, the sources of this carbon vary widely. For instance, 80% of the carbon emissions attributable to the energy used in buildings comes from electricity, whereas 99% of the energy used for transportation comes directly from consumption of petroleum products.

Each sector has its own unique set of CO_2 reduction opportunities. The energy consumed per vehicle-mile traveled, the energy required per unit of industrial output, and the energy used per square foot of home or office space can all be reduced. Technology that increases energy efficiency is the key to reducing the amount of energy consumed per unit of economic output, or energy intensity of our economy.

1.3 Lowering Carbon Intensity

Fossil energy dominates the world's energy supplies and is likely to do so for the foreseeable future. As shown in Figure 1.2, fossil energy provided 87% of the US energy in 1998.

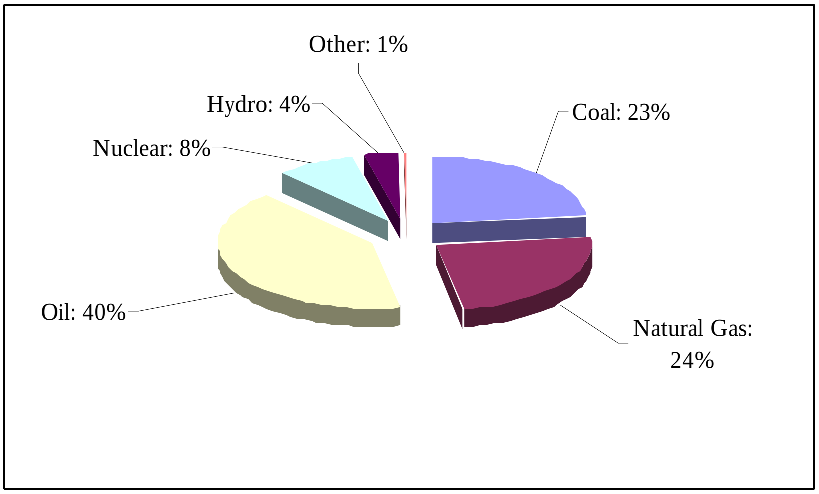

Figure 1.2: US Energy Consumption by Sources, 1998 (EIA, November 1999)

In 1998, coal supplied 51% of electricity, while natural gas made only a small contribution to US electricity needs (15%). This is shown in Figure 1.3.

Recent Evolution of Carbon Intensity

Throughout the 1980s, carbon intensity remained largely unchanged. In the late 1980s, two trends affected the carbon output of electricity generators and thereby the carbon intensity of the entire economy: independent power producers began to take an increasing share of the electricity market (their generation mix is mainly gas-fired, a low-carbon intensive fuel) and electric utilities began to rely less on petroleum while increasing the operating capability of their nuclear power facilities. Between 1991 and 1995, the carbon intensity fell. However, after 1995, the trend was reversed as petroleum and coal generation began to grow again.

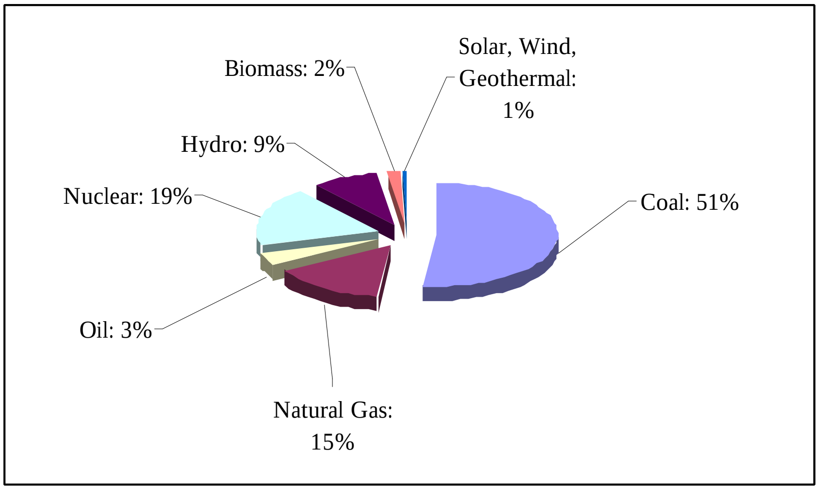

Figure 1.3: US Net Power Generation by Sources, 1998 (EIA, November 1999)

Clean energy technologies can decrease the amount of carbon produced per unit of energy, i.e. the carbon intensity. To lower the carbon intensity of the energy economy, changes in fuel mix are needed.

1.3.1 Low-Carbon Fuels Power Generation

Because of the desire to reduce CO_2 emissions per unit of energy produced, fossil fuels containing a low carbon to hydrogen ratio need to be developed. Therefore, any major clean fossil fuel-based energy plan must center on enhanced production of natural gas. It is predicted that the contribution of natural gas to US electricity needs will rise to 20% by 2015 (DOE, 1997). Moreover, advanced technologies that rely on the commercialization of other low-carbon fuels (synthesis gas, hydrogen) for fuel cells and gas turbines must be supported.

1.3.2 Nuclear Energy

Electricity generation using nuclear power results in very small emissions of GHG, so nuclear power is an important tool in reducing CO_2 emissions. Today, in the US, nuclear power plants generate nearly 20% of the US electrical capacity. This nuclear generating capacity has avoided so far the emissions of about 500 million metric tons of carbon dioxide per year compared with generating this electrical capacity by burning fossil fuels (DOE, 1997). However, public acceptance of nuclear power is poor in the United States, and it is forecasted that the US nuclear power generation capacity will be diminishing in the future.

1.3.3 Renewable Energy

The energy from sunlight, wind, rivers and oceans, the hot interior of the earth (geothermal energy), and biomass (agricultural and industrial wastes, municipal solid waste, and energy crops) can be used to produce electricity, fuels, and heat. All regions of the United States have these renewable resources. They currently account for about 12% of the electricity produced in the United States (see Figure 1.3) and have avoided so far the emissions of about 300 million metric tons of carbon dioxide per year compared with generating this electrical capacity by burning fossil fuels (DOE, 1997). However, the renewable "installed capacity" is mostly from hydropower and traditional biomass sources (agricultural and industrial wastes); solar, wind, and geothermal technologies are cost-effective today only in small and niche markets.

Renewable technologies are well along a path of decreasing cost, making their expanded commercialization prospects realistic for early in the next century. Consequently, renewable energy pathways hold significant potential for reducing GHG emissions in the next century by displacing fossil fuel-generated electricity or petroleum transportation fuels.

1.4 Sequestering Carbon

Carbon sequestration is another technological route to reducing carbon emissions. It can be defined as the capture and secure storage of carbon that would otherwise be emitted to or remain in the atmosphere. One approach is to remove carbon from the atmosphere. Carbon dioxide can be captured and sequestered by enhancing the ability of terrestrial or ocean ecosystems to absorb it naturally and store it in a stable form. A second approach is to keep carbon emissions produced by human activities from reaching the atmosphere by capturing them at the source and diverting them to secure storage. For example, CO_2 could be separated from power plant flue gases, from effluents of industrial processes (e.g. oil refineries and iron, steel, and cement production plants), or during production of decarbonized fuels (such as hydrogen produced from natural gas or coal). The captured CO_2 could be concentrated into a liquid or gas stream that could be transported and injected into the deep ocean or underground geological formations such as oil and gas reservoirs, coal seams, and deep aquifers. Other processes that are biological or chemical may convert captured CO_2 directly into stable products.

The Intergovernmental Panel on Climate Change has forecasted that, under "business as usual" conditions, global emissions of carbon dioxide could more than triple over the coming century, from 7.4 billion tons of carbon per year in 1997 to approximately 26 billion tons per year by 2100. The panel also warned that concentrations of carbon dioxide in the earth's atmosphere could double by the middle of the 21st century and continue to build up even faster in later years, potentially creating a variety of serious environmental consequences. It is clear that the eventual path to stabilization of atmospheric CO_2 concentrations would require the use of a portfolio of GHG reduction technologies that aim at improving energy efficiency, lowering carbon intensity and sequestering carbon.

Carbon sequestration technology is the only option that can provide long-term greenhouse gases mitigation and still allow for continued use of the abundant fossil energy resources and large existing fossil infrastructure. Hence, it is an option that must be explored fully.

Chapter two will focus on pathways to store CO_2 in stable and environmentally benign manners. Chapter three will address the availability of separation and capture technologies at point sources of CO_2. The following two chapters will then present the separation approaches analyzed, and the economic analyses performed. Chapter six will propose a composite cost model, and chapter seven will analyze the results obtained. The cost-drivers of CO_2 separation will be identified and the economics of the capture in 2012 predicted in chapter eight. Finally, chapter nine will identify the most cost-efficient strategies to reduce CO_2 emissions while maintaining the same overall generation capacity.

2 Carbon Dioxide Sinks

This chapter discusses the reduction of net carbon emissions by increasing the absorption of CO_2 from the atmosphere and the necessary storage options for CO_2 captured directly at emissions sources. Technological options, ranging from chemical or biological stimulation of the absorption of CO_2 from the atmosphere, to storage of CO_2 in geologic formations or in the ocean are presented. Capturing CO_2 at point sources involve technologies that will be explored in chapter three.

2.1 Carbon Cycle

Understanding the fluxes and reservoirs of carbon is tied to the successful implementation of carbon sequestration options. Human activities during the first half of the 1990s have contributed to annual emissions of approximately 7.4 billion tons of carbon (GtC) into the atmosphere. Most of these emissions were from fossil fuel combustion, around 6 GtC, and the rest from changing land-use patterns. The net result of these CO_2 emissions is shown in Figure 2.1. During the first part of the 1990s, there was an annual net emissions increment to the atmosphere of 3.5 GtC. Storage of carbon in terrestrial systems due to photosynthesis and plant growth was 1.7 GtC per year. Oceans took up another 2.2 GtC per year.

Carbon fluxes between the atmosphere and ocean/terrestrial reservoirs are quite large, while net carbon exchange is over an order of magnitude smaller. For example, terrestrial ecosystems photosynthetically fixed 61.7 GtC per year, offset by 60 GtC per year due to plant/soil respiration. Similarly, the net ocean uptake of 2.2 GtC per year is the difference of ocean/atmosphere fluxes exceeding 90 GtC per year. Hence, developing the ability to alter these gross annual carbon exchanges of the global carbon cycle by a small percentage through carbon sequestration technologies would increase net storage of carbon in the major reservoirs and lessen atmospheric carbon concentrations.

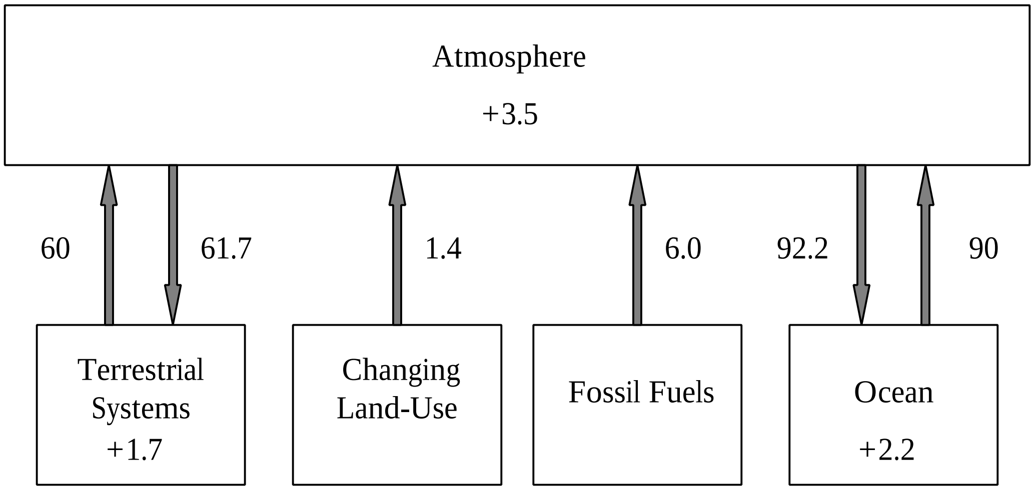

Figure 2.1: Global Carbon Cycle, Early 1990s (DOE, 1999)

All numbers in GtC/yr; 1 GtC = 3.7 $GtCO_2$

2.2 Enhancing Natural Sinks

Small increases in the absorption of CO_2 as a manipulation of the global carbon cycle could have a very significant effect on net GHG emissions.

2.2.1 Terrestrial Sequestration

Terrestrial ecosystems, which are made up of vegetation and soils containing microbial and invertebrate communities, sequester CO_2 directly from the atmosphere. The terrestrial ecosystem is essentially a huge natural biological scrubber for CO_2 from all fossil fuel emissions sources, such as automobiles, power plants, and industrial facilities. Computer models indicate that terrestrial ecosystems - forests, soils, farm crops, pastures, tundras, and wetlands - have a net carbon accumulation of about one-fourth (1.7 GtC) of the 7.4 GtC emitted annually into the atmosphere by fossil fuel combustion and land-use changes.

There are two fundamental approaches to sequestering carbon in terrestrial ecosystems: protection of ecosystems that store carbon so that sequestration can be maintained or increased and manipulation of ecosystems to increase carbon sequestration beyond current conditions. The potential for terrestrial ecosystems to remove and sequester more carbon from the atmosphere could be increased by improving agricultural cultivation practices to reduce oxidation of soil carbon, by enhancing soil texture to trap more carbon, and by protecting wetlands. The terrestrial biosphere is a large and accessible reservoir for sequestering CO_2 that is already present in the atmosphere.

2.2.2 Ocean Sequestration

On a time scale of 1000 years, about 85% of today's anthropogenic emissions of CO_2 will be transferred to the ocean. Ocean sequestration strategies attempt to speed up this process to reduce both peak atmospheric CO_2 concentrations and their rate of increase. Two concepts have been proposed for enhancing oceanic uptake of atmospheric CO_2: iron enrichment and nitrogen enrichment, both targeted at stimulating the growth of phytoplankton. Carbon dioxide dissolved in the oceans is removed by the growth of phytoplankton and ultimately replaced by CO_2 drawn from the atmosphere. The general understanding of these enrichment approaches is in its infancy. Key questions include what percent of increased uptake is really sequestered, and what the ecological and biological impacts are.

2.3 Storing Carbon

CO_2 can be stored in geological formations or in the ocean.

2.3.1 Geological Storage

Geologic formations are likely to provide the first large-scale opportunity for concentrated sequestration of CO_2. Developers of technologies for sequestration of CO_2 in geologic formations can draw from related experience gained over nearly a century of oil and gas production, groundwater resource management, and, more recently, natural gas storage. In some cases, sequestration may even be accompanied by economic benefits such as enhanced oil recovery (EOR), enhanced methane production from coal beds, and enhanced natural gas production from gas fields.

Three principal types of geologic formations are widespread and have the potential to sequester large amounts of CO_2:

- Active and depleted oil and gas reservoirs;
- Coal-bed methane formations;
- Deep aquifers.

One or more of these formations is located within 500 km of each of the fossil fuel-burning power plants in the United States. Table 2.1 compares the attractiveness of these different geological storage options.

The first and most viable option for CO_2 sequestration is to build upon the enormous experience of the oil and gas industry in enhanced oil recovery. Currently, about 80% of commercially used CO_2 is for EOR purposes. In the long term, the volume of CO_2 sequestered as part of EOR projects may not be comparatively large, but valuable operational experience can be gained that will benefit geologic sequestration in other types of formations, such as active and depleted gas reservoirs.

Storage Option	Relative Capacity	Relative Cost	Storage Integrity	Technical Feasibility
Active Oil Wells	Small	Very Low	Good	High
Depleted Oil and Gas Wells	Moderate	Low	Good	High
Coal Beds	Unknown	Low	Unknown	Unknown
Deep Aquifers	Large	Unknown	Unknown	Unknown

Table 2.1: Comparison of Geological Storage Options (Herzog et al., 1997)

The next option, coal formations, can provide an opportunity to simultaneously sequester CO_2 and increase the production of natural gas. Methane production from deep coal beds can be enhanced by injecting CO_2 into coal formations, where the adsorption of CO_2 causes the desorption of methane. This process has the potential to sequester large volumes of CO_2 while improving the efficiency and profitability of these commercial natural gas operations.

The last storage option consists of aqueous formations, which are large-volume formations available practically anywhere. One key issue distinguish sequestration in oil and gas reservoirs from CO_2 sequestration in aquifers: oil and gas reservoirs occur by virtue of the presence of a structural trap, likely to retain CO_2; identification of such effective traps may be more difficult in aqueous formations and may require new approaches for establishing the integrity and extent of a caprock.

2.3.2 Ocean Storage

Because the oceans already contain the estimated equivalent of 40,000 billion tons of carbon (GtC), it is not unreasonable to consider, as possible options for carbon sequestration, the enhancement of CO_2 fixation through ocean fertilization (explained previously), and the direct injection into the ocean of a relatively pure CO_2 stream generated at a power plant.

The direct injection of CO_2 into the ocean requires starting with a fairly concentrated stream of CO_2 and delivering it to locations in the ocean where it will be effectively sequestered for hundreds of years, if not longer. One limitation of this approach is that it is best suited to large, stationary CO_2 sources with access to deep-sea sequestration sites. Such sources may account for about 15 to 20% of world anthropogenic CO_2 emissions.

There are many technical options for sequestration by direct injection of CO_2:

- Liquid CO_2 injected at a depth of about 1,000 meters from a pipe towed by a moving ship and forming a rising droplet plume;
- Liquid CO_2 injected at a depth of about 1,000 meters from a manifold lying on the ocean bottom and forming a rising droplet plume;
- Liquid CO_2 introduced to a sea floor depression forming a stable "deep lake" at a depth of about 4,000 meters.

Table 2.2 compares the attractiveness of these different options.

Sequestration effectiveness will depend on the exact depth and location of the injection. In general, the deeper the CO_2 is injected, the more effectively it is sequestered; but injecting deeper requires more advanced technologies. The most significant environmental impact is expected to be associated with lowered pH as a result of the reaction of CO_2 with seawater. Non-swimming marine organisms residing at depths of about 1,000 meters or greater are the most likely to be affected adversely by acidic seawater. The magnitude of the impact will depend on both the level of pH change and the duration of exposure.

Technical Option	Development Required	Cost	Environmental Impact	Leakage to Atmosphere
Towed Pipe	Medium	Medium	Low	Medium
Droplet Plume	Low	Low	Medium	Medium
CO_2 Lake	High	High	Low	Low

Table 2.2: Comparison of Ocean Storage Options (Herzog et al., 1997)

Ultimately, both scientific understanding and public acceptability will determine whether ocean sequestration of carbon is a viable option.

2.4 Utilizing Carbon

Recycling the carbon captured can be at a first glance an alternative to the previously exposed storage options. CO_2 can be used commercially or converted into benign materials.

The captured carbon can have a commercial value, for example as a feedstock from which to make chemicals. Nevertheless, CO_2 is a very stable molecule and considerable energy is required to transform it into products. Hence, processes aiming at recycling CO_2 generally require a large energy input, thereby emitting more CO_2 if the energy comes from fossil fuels. Other possible uses of captured CO_2 are for EOR and fuels production. The potential for EOR is limited; however, advanced biological technologies that would enable direct use of CO_2 to grow algae and crops and make biofuels may offer the potential to sequester large amounts of anthropogenic carbon.

The other approach does not generate viable products but environmentally benign and thermodynamically stable waste forms, like carbonate minerals, that can be returned to the environment. However, this approach faces significant challenges, because large amounts of alkaline rocks and makeup hydrochloric acid - several times the weights of the CO_2 sequestered - must be transported and handled.

3 Carbon Dioxide Capture

3.1 Appropriate Carbon Dioxide Sources for Capture

This chapter addresses the separation and capture of anthropogenic CO_2 only. Sources that appear to lend themselves best to separation and capture technologies include large-point sources of CO_2 such as conventional pulverized-coal steam power plants, natural gas-fired combined cycle plants, and advanced power generation systems, including integrated coal gasification combined cycles, hydrogen turbines, and fuel cells. In addition to power plants, numerous other significant industrial sources of CO_2 are being considered for application of capture and sequestration technologies: oil refineries, iron and steel plants, and cement, lime and natural gas production sites. Natural gas reserves may contain significant amounts of CO_2 (20% or more by volume), most of which must be removed to produce pipeline-quality gas. In such cases, capture of CO_2 is necessary, but the captured CO_2 is usually vented to the atmosphere. However, sequestration of the relatively pure CO_2 stream obtained has been implemented at the Sleipner West project in Norway, and is considered for the proposed Natuna project in Indonesia and the proposed Gorgon project in Australia.

Dispersed sources of CO_2 emissions, particularly residential buildings and mobile spark ignition and diesel engines, are especially challenging sources for applying cost-effective separation and capture methods. Two scenarios that illustrate potential opportunities are:

- The introduction of fuel cells for vehicular propulsion and power generation, which may develop the need for central H_2 production facilities and enhance the opportunity for CO_2 sequestration;

- The increased use of electric vehicles, since separation and capture of CO_2 at the central power stations that produce the electricity for recharging electric vehicle batteries would indirectly reduce CO_2 emissions from the transportation sector.

Natural gas produced from the Sleipner West field in the North Sea contains nearly 10% by volume of CO_2. To meet the sales specification of only 2.5% CO_2, most of the CO_2 must be removed from the natural gas before delivery. Statoil uses an amine solvent to absorb the excess CO_2. The separated CO_2 is injected into an aquifer 1,000 meters under the North Sea. Approximately one million tons of CO_2 are captured and sequestered annually.

3.2 Capture Technologies

The goal of CO_2 separation and capture is to isolate carbon from its many sources in a form suitable for transport and sequestration. In general, a relatively pure, high pressure stream of carbon dioxide must be produced. The process of producing this CO_2 stream (referred to as separation and capture) encompasses all operations that take place at the source, including compression. For ease of transport, carbon dioxide is generally compressed to the order of 100 atmospheres. This improves the economics of transporting CO_2 any distance. Also, sink capacity is better utilized by injecting pure CO_2. High levels of purity are possible, but at significant costs.

The options currently identifiable for CO_2 separation and capture presented below are: physical and chemical absorption, adsorption, low-temperature distillation and gas-separation membranes. Currently, several CO_2 separation and capture plants use one or more of these methods to produce CO_2 for commercial markets.

3.2.1 Physical and Chemical Absorption

Absorption systems represent the most common capture technology. The flue gas is scrubbed in an absorption tower to collect the CO_2; the solvent is then regenerated and the CO_2 released by heat addition and/or pressure reduction. Absorption systems are typically available as three basic types, physical, chemical and hybrid.

Physical absorption processes are governed by Henry's law, which means that they are temperature and pressure dependent with absorption occurring at high partial pressures of CO_2 and low temperatures. Typical solvents are Selexol (dimethylether of polyethylene glycol) and Rectisol (cold methanol).

Chemical absorption is preferred for low to moderate CO_2 partial pressures. Because CO_2 is an acid gas, chemical absorption of CO_2 from gaseous streams such as flue gases depends on acid-base neutralization reactions using basic solvents. The CO_2 reacts with chemical solvents to form a weakly bonded intermediate compound, which is then broken down by the application of heat, regenerating the original solvent and producing a CO_2 stream. Figure 3.1 shows the process flow diagram of a typical chemical absorption system. The most common solvents commercially used for neutralizing CO_2 are alkanolamines such as monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA). Flue gases are typically at atmospheric pressure. The partial pressure of CO_2 being low, alkanolamines are the best chemical solvents to enable good CO_2 recovery levels; however, use of these solvents must be balanced against the high energy penalty of regenerating them using steam-stripping. Moreover, flue gases typically contain contaminants such as SO_x,

NO_x, O_2, hydrocarbons, and particulates. The presence of these impurities can reduce the absorption capacity of amines as well as create operational difficulties such as corrosion and foaming in the absorber. To avoid these problems, the contaminants are often reduced to acceptable levels through the use of suitable pretreatment techniques. Some commercial processes handle these difficulties through pretreatment and/or the use of chemical inhibitors in the absorption process.

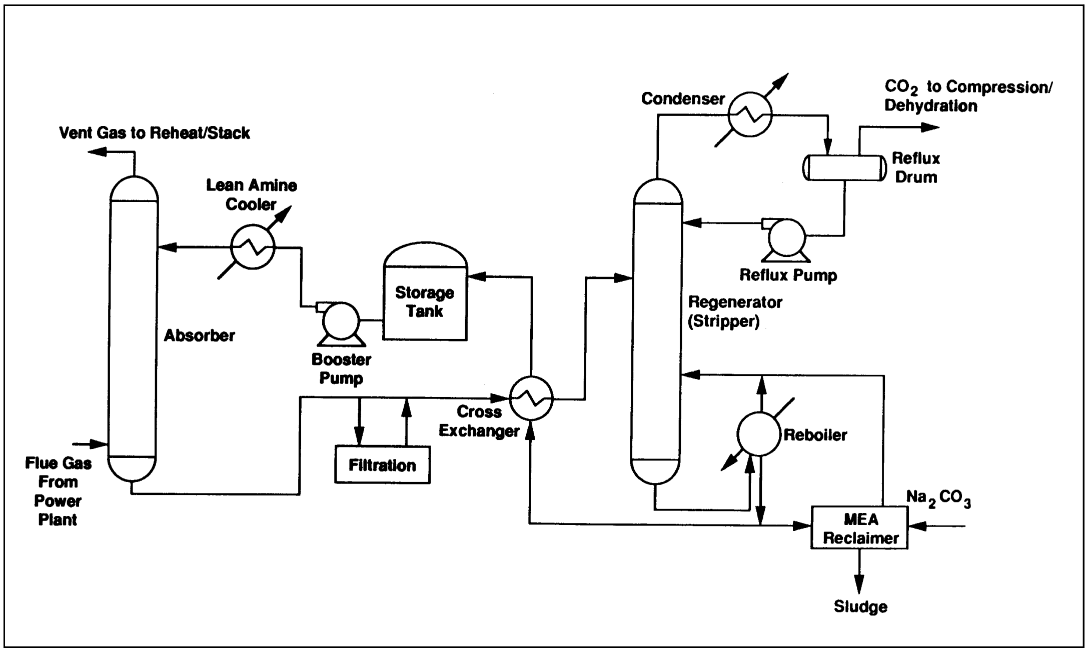

Figure 3.1: Process Flow Diagram of a Typical Chemical Absorption System

Hybrid solvents combine the best characteristics of both the physical and chemical solvents and are usually composed of a number of complementary solvents. Hybrid solvents have out-performed existing solvents. The tendency has been to develop tailor-made solvents using complementary solvents where the proportions are varied to suit the application. Typical solvents are A-MDEA, Purisol, Sulfinol, and UCARSOL.

3.2.2 Adsorption

Selective separation of CO_2 may be achieved by the adsorption of the gas on high-surface-area solids. Adsorption methods employ a physical attraction between the gas and "active sites" on the solid. There are several adsorption methods used commercially in the process industries that may be applicable for removing CO_2 from power plant flue gases. However, these processes are somewhat energy-intensive and expensive. Moreover, physical adsorbents suffer from low selectivity and low capacity, and they are limited to operation at low temperatures.

3.2.3 Low-Temperature Distillation

Low-temperature distillation is widely used commercially for the liquefaction and purification of CO_2 from high-purity sources. It could enable direct production of liquid CO_2 that could be stored or sequestered at high pressure via liquid pumping.

Carbon dioxide can be physically separated from other gases by condensing the CO_2 at cryogenic temperatures. If CO_2 is the only condensable gas in the mixture, its partial pressure in the gas phase is reduced to its vapor pressure at the cryogenic temperature, and the mole fraction in the gas phase will be its partial pressure divided by the total pressure (ignoring deviations from ideal gas behavior). The minimum CO_2 mole fraction in the gas phase is achieved by lowering the temperature and raising the total pressure as much as practical, but, in most situations it is not practical to reduce the temperature below the freezing point of CO_2 (-56.6°C).

Distillation generally has good economies of scale and can produce a relatively pure product. It is most cost effective when the feed gas is available at high pressure. The major disadvantages of this process are the amount of energy required to provide the refrigeration and the necessary removal of components that have freezing points above normal operating temperatures to avoid freezing and eventual blockage of process equipment.

Most CO_2 emissions being considered for CO_2 capture are produced in combustion processes. The associated streams contain water and other trace combustion by-products such as NO_x and SO_x, several of which must be removed before the stream is introduced into the low-temperature process. Moreover, these by-products are usually generated near atmospheric pressure. These attributes, coupled with the energy intensity of low-temperature refrigeration, tend to make distillation less economical than other routes.

3.2.4 Membrane Systems

Two membrane operations, which appear to have potential, are gas separation and gas absorption:

- Gas separation membranes. They are of many different types, and are in a development stage for CO_2 capture and sequestration. They rely on a difference in physical or chemical interaction between components present in a gas mixture with the membrane material, causing one component to permeate faster through the membrane than the other ones. The gas component dissolves into the membrane material and diffuses through it to the other side. Membranes can be made with a wide range of materials, and pore size and material can be changed to improve selectivity and permeance (the volume of gas transported through a membrane per unit of surface area per unit of time per unit of differential pressure). With all the design parameters available, it is likely that membranes can be made that will be useful for separating CO_2 from almost any other gas if appropriate operating conditions can be achieved. However, for multiple gas mixtures, several membranes with different characteristics are required to separate and capture high-purity CO_2. This leads to increased recompression costs and increased capital costs. Consequently, considerable R&D is required to realize the potential of membranes for separation and capture of CO_2, particularly at higher temperatures and pressures.

- Gas absorption membranes. Absorption processes based on membranes are on the verge of commercial introduction. These membranes are used as contacting devices between a gas flow and a liquid flow. The separation is caused by the presence of an absorption liquid on one side of the membrane, which selectively removes certain components from a gas stream on the other side of the membrane. In contrast with gas separation membranes, it is not essential that the membrane has any selectivity at all. It is merely intended to provide a contacting area without mixing gas and absorption liquid flow. The selectivity of the process is derived from the absorption liquid. It can be expected that removal of flue gas components, like SO_2 or CO_2, will be achieved through the use of such porous, hydrophobic membranes in combination with suitable absorption liquids (e.g. amine solutions).

Adsorption using molecular sieves, cryogenic processes, and membrane processes are only cost effective if the CO_2 exists at a high pressure in the effluent stream. For flue gas from power plants, typically at atmospheric pressure, physical and chemical absorption represent the most attractive technology. Hence, this thesis will study the economics of CO_2 capture by physical and chemical absorption at power plants.

4 Assessment of Capture Technologies: Scope and Method

This chapter defines the carbon separation technologies reviewed in this thesis. The economic analysis framework is then described. In the next chapter, the economics of the capture will be investigated by reviewing different studies from the literature and applying the framework discussed below.

4.1 Approaches to Carbon Separation Technologies

Today, natural gas and coal-fired simple cycle power plants account for most of the global electricity generation. Natural Gas Combined Cycles (NGCC) are a relatively new technology, in which a combustion turbine is added to a regular steam turbine. These conventional power generation technologies burn the fuel in air, so carbon dioxide can be captured from the flue gas (Approach 1). If the power plant was fed by oxygen instead of air, there would be no nitrogen in the flue gas, and CO_2 capture would be greatly simplified (Approach 2). However, combustion with oxygen yields temperatures too large for today's materials, so some flue gas should be recycled to moderate the temperature.

The third approach consists of decarbonizing the fuel before combustion. Coal can be gasified to form synthesis gas (syngas), a gas consisting mainly of H_2 and CO. Syngas can also be formed by steam reforming of natural gas. By adding steam to the synthesis gas under correct temperature and pressure conditions, carbon monoxide and steam are shifted to carbon dioxide and hydrogen. The carbon dioxide can then be separated from the shifted syngas (Approach 3).

The different approaches to carbon separation are summarized in Table 4.1.

Approach/ Fuel	Coal	Gas
1. Flue Gas	**Flue gas clean-up followed by CO_2 separation process** **Steam turbine**	**Flue gas clean-up followed by CO_2 separation process** **Combined Cycle**
2. Oxygen	Oxygen plus recycled flue gas in place of air Steam turbine	Oxygen plus recycled flue gas in place of air Combined cycle
3. Synthesis Gas	**Gasification followed by shift and capture** **Combined cycle**	Steam reforming followed by shift and capture Combined cycle

Table 4.1: Approaches to CO_2 Separation

In bold, approaches to CO_2 separation analyzed in this thesis.

As mentioned earlier, power generation mainly relies on the burning of fossil fuels in air, so the flue gas approach will be studied for both coal-fired simple cycle power plants (Pulverized Coal, PC), and natural gas-fired combined cycles (Natural Gas Combined Cycles, NGCC). But, first, an emerging technology, the separation of CO_2 in an Integrated Gasification Combined Cycle (IGCC), will be explored. The other approaches to CO_2 separation will not be analyzed in this thesis.

4.2 Economic Analysis Framework

4.2.1 Unadjusted Economic Analyses

For IGCC, PC, and NGCC power plants, several economic studies documented in the literature were reviewed. For each study, two cases were analyzed: the reference plant (no capture), and the capture plant, which includes carbon dioxide separation and compression up to 100 atmospheres. The economic analyses presented in this thesis do not include costs incurred by CO_2 transportation and storage[1]. Note that the different studies that have been reviewed all deal with new plants, not retrofit plants.

The following data is extracted from each study, for both the reference and capture plants:

- Cost of electricity (COE), in ¢/kWh, divided into:
    - COE due to capital investment (COE_{CAP}), in mills/kWh (one mill is equal to 0.1 ¢);
    - COE due to fuel cost (COE_{FUEL}), in mills/kWh;
    - COE due to operation and maintenance ($COE_{O\&M}$), in mills/kWh;
- Capital cost (C), in $/kW;
- Net power output (W), in MW;
- Quantity of CO_2 emitted (E), in kg/kWh;
- Heat rate (HR), in Btu/kWh, defined on the lower heating value (LHV) basis.

The three variables that characterize the performance of a particular capture process can then be calculated:

- The incremental electricity cost (? COE), in ¢/kWh, which represents the difference between the electricity cost of the capture plant and the electricity cost of the reference plant. It is a direct measure of the effect of CO_2 capture on electricity prices.
- The energy penalty (EP), in %, which measures the reduction in net power output of the capture plant compared to the reference plant for equal fuel inputs.

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[1] Typically, to account for the transportation and injection of the CO_2 once it leaves the power plant, an additional $5-15 per ton of CO_2 avoided should be added. However, if the CO_2 is going to be utilized for commercial purposes, a credit can be taken, improving the economics greatly.

- The mitigation cost (MC), expressed in \$ per ton of CO_2 avoided. This is a useful way to compare directly different mitigation strategies. However, the cost of mitigation varies depending on the reference plant chosen for the base case. When the studies are analyzed individually, the mitigation cost is calculated by comparing a capture plant to its associated reference plant (e.g. capture IGCC vs. reference IGCC), for self-consistency.

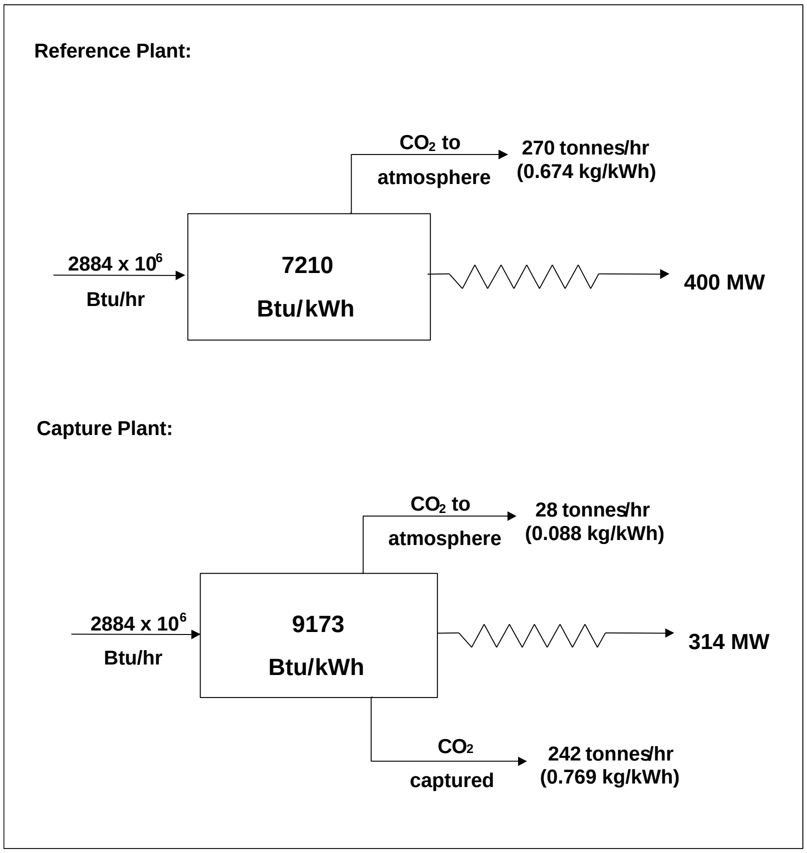

Figure 4.1: Difference Between CO_2 Avoided and CO_2 Captured [1]

Numbers are based on the IGCC SFA Pacific study (Simbeck, 1998), analyzed in chapter five.

With equal reference and capture plants fuel inputs, the power output of the capture plant will always be less than the power output of the reference plant, because of the energy requirements for separating and compressing the carbon dioxide. The need for energy in the capture process generates additional carbon dioxide and introduces a difference between the amount of CO_2 avoided and the amount of CO_2 captured. This is illustrated in Figures 4.1 and 4.2: 0.769 kg/kWh is the quantity of CO_2 captured, while 0.674 – 0.088 = 0.586 kg/kWh is the quantity of CO_2 avoided.

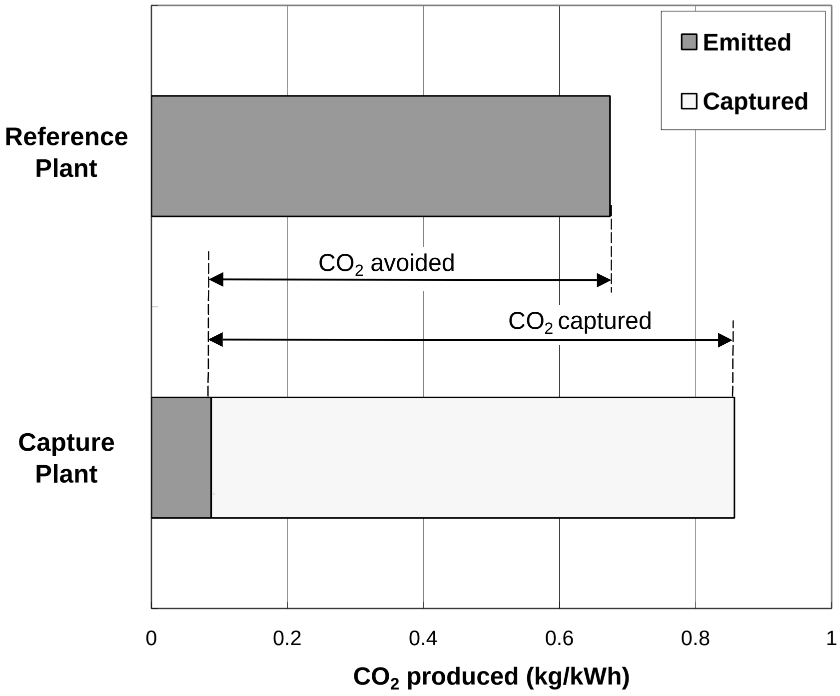

Figure 4.2: Difference Between CO_2 Avoided and CO_2 Captured [2]

Numbers are taken from Figure 4.1.

4.2.2 Adjustments to a Common Economic Basis

The variables characterizing the performance of a particular capture process depend on the following three parameters:

- The capacity factor, or number of operating hours per year (f);
- The capital charge rate (r), in % per year. It is used to annualize the capital investment of the plant and can be roughly correlated to the cost of capital. Specifically, the capital component of the cost of electricity equals the capital charge rate times the capital cost divided by the number of operating hours per year:

$$COE_{CAP} = \frac{1000 \times r \times C}{f} \tag{4.1}$$

- The fuel cost (FC), in \$ per million BTU, defined on the lower heating value (LHV) basis.

Yearly Operating Hours	6570 hrs/yr
Capital Charge Rate	15%/yr
Coal Price (LHV)	$1.24/MMBtu
Natural Gas Price (LHV)	$2.93/MMBtu

Table 4.2: Common Economic Basis for the Studies

The individual studies reviewed may use different values for each of these three parameters. Consequently, the results that can be obtained differ from each other not only because of technological variations amongst the processes, but also because of the economic assumptions. To better compare the technologies evaluated by each study and the attractiveness of the capture at different types of power plants, the original studies are adjusted to a common economic basis, which is described in Table 4.2. Appendix A shows how to adjust the different variables.

Note that the original $COE_{O\&M}$ is broken down into a fixed cost (65%) and a variable cost (35%). This assumption relies on the EPRI studies analyzed, which estimate the fixed portion of operation and maintenance costs to be 65% of the total O&M costs.

The adjustments affect the incremental electricity cost and, consequently, the mitigation cost. However, the energy penalty is not affected by these adjustments.

5 Individual Economic Analyses

5.1 Integrated Gasification Combined Cycles (IGCC)

Integrated Gasification Combined Cycles represent an emerging technology. Coal is first converted in a gasifier, generally oxygen-blown, into synthesis gas. The syngas is then used to drive a gas turbine generator. Finally, waste heat is recovered to drive a steam turbine generator for additional power generation.

IGCC offers the opportunity to decarbonize the fuel before combustion. This is done by shifting the syngas to CO_2 and H_2 and by removing the CO_2 at this point. Because the syngas is under pressure, it is possible to use physical solvents which need less energy for regeneration than chemical solvents. Desorption of CO_2 is followed by compression and drying.

The following studies are reviewed:

- Argonne National Laboratory (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);
- IEA (Stork Engineering Consultancy, 1999).

All of these studies consider oxygen-blown gasification, and absorption by a physical solvent called Selexol. The Argonne study points out that a reference plant is more economical if gasification is air-blown rather than oxygen-blown, but it demonstrates that it is more economical to use oxygen-blown rather than air-blown gasification for the capture.

Table 5.1 shows how the economics of the capture processes at IGCC plants compare across the different studies reviewed. The studies are then adjusted to a common economic basis, as defined in the previous chapter. Table 5.2 shows how the economics of the capture processes at IGCC plants compare across the different adjusted studies.

The average incremental electricity cost at an IGCC capture plant after adjustments is 1.72 ¢/kWh and the average mitigation cost 27 $/ton of CO_2 avoided. The energy penalty varies from 6.4% up to 21.4%.

Data Description/ Study	Argonne	Milan	SFA Pacific	Utrecht	EPRI	IEA
Reference Plant						
coe: CAPITAL, mills/kWh	33.7	38.3	29.7	15.0	33.4	27.2
coe: FUEL, mills/kWh	14.9	14.0	7.4	16.5	12.2	11.7
coe: O&M, mills/kWh	9.7	5.7	7.9	6.7	11.4	8.9
Capital Cost, $/kW	1332	1536	1300	1265	1600	1471
Net Power Output, MW	413.5	404.1	400.0	600.0	431.6	408.0
CO_2 Emitted, kg/kWh	0.790	0.709	0.674	0.760	0.868	0.710
Thermal Efficiency (LHV), %	38.2	43.7	47.3	43.6	36.8	46.3
Heat Rate (LHV), Btu/kWh	8938	7817	7210	7826	9280	7369
Cost of Electricity, ¢/kWh	5.83	5.80	4.50	3.82	5.70	4.78
Capture Plant						
coe: CAPITAL, mills/kWh	42.7	47.7	40.3	21.3	44.9	41.1
coe: FUEL, mills/kWh	16.3	16.4	9.4	19.8	15.2	14.2
coe: O&M, mills/kWh	11.7	7.0	10.8	9.7	20.5	13.8
Capital Cost, $/kW	1687	1913	1767	1799	2152	2204
Net Power Output, MW	377.5	345.6	314.4	500.0	347.4	382.0
CO_2 Emitted, kg/kWh	0.176	0.071	0.088	0.040	0.105	0.134
Thermal Efficiency (LHV), %	34.8	37.3	37.2	36.3	29.6	38.2
Heat Rate (LHV), Btu/kWh	9791	9140	9173	9399	11528	8932
Cost of Electricity, ¢/kWh	7.06	7.10	6.06	5.08	8.06	6.91
Comparison						
Incremental coe, ¢/kWh	1.23	1.31	1.56	1.27	2.36	2.13
Energy Penalty, %	8.7	14.5	21.4	16.7	19.5	6.4
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	20	20	27	18	31	37
Basis						
Yearly Operating Hours, hrs/yr	5694	7000	6570	6000	5694	8000
Capital Charge Rate, %/yr	14.4	17.4	15.0	7.1	11.9	14.8
Fuel Cost (LHV), $/MMBtu	1.66	1.79	1.03	2.11	1.32	1.58

Table 5.1: Performance of IGCC Capture Plants, Studies Not Adjusted

Data Description/ Study	Argonne	Milan	SFA Pacific	Utrecht	EPRI	IEA
Reference Plant						
coe: CAPITAL, mills/kWh	30.4	35.1	29.7	28.9	36.5	33.6
coe: FUEL, mills/kWh	11.1	9.7	8.9	9.7	11.5	9.1
coe: O&M, mills/kWh	9.3	5.8	7.9	6.5	10.4	9.6
Capital Cost, $/kW	1332	1536	1300	1265	1600	1471
Net Power Output, MW	413.5	404.1	400.0	600.0	431.6	408.0
CO_2 Emitted, kg/kWh	0.790	0.709	0.674	0.760	0.868	0.710
Thermal Efficiency (LHV), %	38.2	43.7	47.3	43.6	36.8	46.3
Heat Rate (LHV), Btu/kWh	8938	7817	7210	7826	9280	7369
Cost of Electricity, ¢/kWh	5.08	5.06	4.65	4.50	5.85	5.23
Capture Plant						
coe: CAPITAL, mills/kWh	38.5	43.7	40.3	41.1	49.1	50.3
coe: FUEL, mills/kWh	12.1	11.3	11.3	11.7	14.3	11.1
coe: O&M, mills/kWh	11.2	7.2	7.2	9.4	18.8	14.9
Capital Cost, $/kW	1687	1913	1767	1799	2152	2204
Net Power Output, MW	377.5	345.6	314.4	500.0	347.4	382.0
CO_2 Emitted, kg/kWh	0.176	0.071	0.088	0.040	0.105	0.134
Thermal Efficiency (LHV), %	34.8	37.3	37.2	36.3	29.6	38.2
Heat Rate (LHV), Btu/kWh	9791	9140	9173	9399	11528	8932
Cost of Electricity, ¢/kWh	6.18	6.22	6.25	6.21	8.23	7.63
Comparison						
Incremental coe, ¢/kWh	1.10	1.16	1.59	1.71	2.38	2.39
Energy Penalty, %	8.7	14.5	21.4	16.7	19.5	6.4
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	18	18	27	24	31	42

Table 5.2: Performance of IGCC Capture Plants, Studies Adjusted

5.2 Pulverized Coal Power Cycles (PC)

Pulverized Coal power cycles represent the most commonly available technology for power generation. Pulverized coal is combusted with air in a coal-fired boiler to produce high-pressure steam, generally at sub-critical conditions, that is used for power generation in a steam turbine. The flue gas exiting the boiler is passed through an heat exchanger to heat up the air going into the boiler, a desulfurization unit to remove SO_2, and, finally, a stack. The capture plant has an amine absorption CO_2 removal unit that follows the desulfurization unit.

The following studies are reviewed:

- University of Utrecht, Netherlands (Hendriks, 1994);
- EPRI (Smelser et al., 1991; Booras and Smelser, 1991);
- SFA Pacific (Simbeck, 1998);
- IEA (Stork Engineering Consultancy, 1999).

The IEA study is based on a PC plant for which the steam cycle is super-critical.

Table 5.3 shows how the economics of the capture processes at PC plants compare across the different studies reviewed. The studies are then adjusted to a common economic basis, as defined in chapter four. Table 5.4 shows how the economics of the capture processes at PC plants compare across the different adjusted studies.

The average incremental electricity cost at a PC capture plant after adjustments is 3.48 ¢/kWh and the average mitigation cost 52 $/ton of CO_2 avoided. The energy penalty varies from 15.9% up to 34.1%.

Data Description/ Study	Utrecht	EPRI	SFA Pacific	IEA
Reference Plant				
coe: CAPITAL, mills/kWh	13.6	22.5	29.7	18.9
coe: FUEL, mills/kWh	17.5	12.4	7.9	11.9
coe: O&M, mills/kWh	6.1	11.0	7.9	6.7
Capital Cost, $/kW	1150	1129	1300	1022
Net Power Output, MW	600	513.3	400	501
CO_2 Emitted, kg/kWh	0.800	0.909	0.717	0.722
Thermal Efficiency (LHV), %	41.0	36.1	44.4	45.6
Heat Rate (LHV), Btu/kWh	8322	9440	7680	7482
Cost of Electricity, ¢/kWh	3.73	4.60	4.55	3.74
Capture Plant				
coe: CAPITAL, mills/kWh	24.5	49.6	46.2	34.7
coe: FUEL, mills/kWh	22.8	18.9	9.4	16.4
coe: O&M, mills/kWh	13.3	31.9	12.3	12.4
Capital Cost, $/kW	2073	2484	2022	1856
Net Power Output, MW	462	338.1	336.5	362
CO_2 Emitted, kg/kWh	0.100	0.138	0.128	0.148
Thermal Efficiency (LHV), %	31.5	23.8	37.4	33.0
Heat Rate (LHV), Btu/kWh	10832	14331	9130	10339
Cost of Electricity, ¢/kWh	6.07	10.04	6.79	6.35
Comparison				
Incremental coe, ¢/kWh	2.34	5.44	2.24	2.61
Energy Penalty, %	23.0	34.1	15.9	27.7
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	33	71	38	45
Basis				
Yearly Operating Hours, hrs/yr	6000	5694	6570	8000
Capital Charge Rate, %/yr	7.1	11.4	15.0	14.8
Fuel Cost (LHV), $/MMBtu	2.11	1.32	1.03	1.58

Table 5.3: Performance of PC Capture Plants, Studies Not Adjusted

Data Description/ Study	Utrecht	EPRI	SFA Pacific	IEA
Reference Plant				
coe: CAPITAL, mills/kWh	26.3	25.8	29.7	23.3
coe: FUEL, mills/kWh	10.3	11.7	9.5	9.3
coe: O&M, mills/kWh	5.9	10.3	7.9	7.2
Capital Cost, $/kW	1150	1129	1300	1022
Net Power Output, MW	600	513.3	400.0	501
CO_2 Emitted, kg/kWh	0.800	0.909	0.717	0.722
Thermal Efficiency (LHV), %	41.0	36.1	44.4	45.6
Heat Rate (LHV), Btu/kWh	8322	9440	7680	7482
Cost of Electricity, ¢/kWh	4.25	4.78	4.71	3.98
Capture Plant				
coe: CAPITAL, mills/kWh	47.3	56.7	46.2	42.4
coe: FUEL, mills/kWh	13.4	17.8	11.3	12.8
coe: O&M, mills/kWh	12.9	29.9	12.3	13.4
Capital Cost, $/kW	2073	2484	2022	1856
Net Power Output, MW	462	338.1	336.5	362
CO_2 Emitted, kg/kWh	0.100	0.138	0.128	0.148
Thermal Efficiency (LHV), %	31.5	23.8	37.4	33.0
Heat Rate (LHV), Btu/kWh	10832	14331	9130	10339
Cost of Electricity, ¢/kWh	7.37	10.44	6.98	6.86
Comparison				
Incremental coe, ¢/kWh	3.12	5.66	2.27	2.88
Energy Penalty, %	23.0	34.1	15.9	27.7
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	45	73	39	50

Table 5.4: Performance of PC Capture Plants, Studies Adjusted

5.3 Natural Gas Combined Cycles (NGCC)

Natural Gas Combined Cycles represent an available technology that produces less carbon dioxide per energy output than IGCC and PC power plants; it also has the highest thermal efficiency of all the options. Natural gas is combusted in a gas turbine with air. To keep the turbine inlet temperature at a permissible level, a high overall excess air ratio in the gas turbine is needed. Waste heat is then recovered in a heat recovery steam generator to drive a steam turbine generator for additional power generation. The capture plant has an amine absorption CO_2 removal unit that follows the heat recovery step.

The following studies are reviewed:

- SFA Pacific (Simbeck, 1998);
- Trondheim (Bolland and Saether, 1992);
- IEA (Stork Engineering Consultancy, 1999);
- Politecnico di Milano, Italy (Chiesa et Consonni, 1999).

The study from Politecnico di Milano and the IEA report from the Stork Engineering Consultancy compare the conventional combined cycles (which have a CO_2 chemical absorption ahead of the stack) with similar combined cycles for which part of the exhaust gases is recycled to the gas turbine compressor. This recycle reduces the flow rate of exhaust gases to be treated and increases the CO_2 concentration; hence, capital investments and steam consumption in the stripper can be lowered. According to the Milan and IEA studies, the scheme with recycling is slightly more advantageous to the economics of the capture than the base scheme; the incremental cost of electricity is claimed to be reduced by about 10% and 15%, respectively. Nevertheless, to avoid technical variations between the four NGCC power plants studied, these combined cycles with flue gas recycling were not further investigated; they illustrate, however, that innovation in power generation can contribute to improve the economics of CO_2 capture.

Table 5.5 shows how the economics of the capture processes at NGCC plants compare across the different studies reviewed. The studies are then adjusted to a common economic basis, as defined in chapter four. Table 5.6 shows how the economics of the capture processes at NGCC plants compare across the different adjusted studies.

The average incremental electricity cost at a NGCC capture plant after adjustments is 1.59 ¢/kWh and the average mitigation cost 51 $/ton of CO_2 avoided. The energy penalty varies from 9.8% up to 16.1%.

Data Description/ Study	SFA Pacific	Trondheim	IEA	Milan
Reference Plant				
coe: CAPITAL, mills/kWh	11.1	9.2	6.8	11.8
coe: FUEL, mills/kWh	18.9	19.2	12.8	22.3
coe: O&M, mills/kWh	3.0	2.6	2.1	2.1
Capital Cost, $/kW	485	754	414	531
Net Power Output, MW	400	721.2	790	373.2
CO_2 Emitted, kg/kWh	0.330	0.400	0.370	0.374
Thermal Efficiency (LHV), %	60.0	52.2	56.2	53.3
Heat Rate (LHV), Btu/kWh	5688	6536	6071	6400
Cost of Electricity, ¢/kWh	3.30	3.10	2.16	3.62
Capture Plant				
coe: CAPITAL, mills/kWh	25.9	16.1	12.9	18.6
coe: FUEL, mills/kWh	21.4	22.5	15.3	24.7
coe: O&M, mills/kWh	6.9	5.0	4.2	3.6
Capital Cost, $/kW	1135	1317	786	807
Net Power Output, MW	353.7	615.3	663	336.6
CO_2 Emitted, kg/kWh	0.056	0.046	0.061	0.037
Thermal Efficiency (LHV), %	53.0	44.5	47.2	48.1
Heat Rate (LHV), Btu/kWh	6433	7667	7229	7097
Cost of Electricity, ¢/kWh	5.42	4.36	3.23	4.68
Comparison				
Incremental coe, ¢/kWh	2.12	1.26	1.07	1.07
Energy Penalty, %	11.6	14.7	16.1	9.8
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	77	36	35	32
Basis				
Yearly Operating Hours, hrs/yr	6570	7008	8000	7000
Capital Charge Rate, %/yr	15	8.6	13.1	15.5
Fuel Cost (LHV), $/MMBtu	3.33	2.93	2.11	3.48

Table 5.5: Performance of NGCC Capture Plants, Studies Not Adjusted

Data Description/ Study	SFA Pacific	Trondheim	IEA	Milan
Reference Plant				
coe: CAPITAL, mills/kWh	11.1	17.2	9.5	12.1
coe: FUEL, mills/kWh	16.7	19.2	17.8	18.8
coe: O&M, mills/kWh	3.0	2.7	2.2	2.2
Capital Cost, $/kW	485	754	414	531
Net Power Output, MW	400.0	721.2	790.0	373.2
CO_2 Emitted, kg/kWh	0.330	0.400	0.370	0.374
Thermal Efficiency (LHV), %	60.0	52.2	56.2	53.3
Heat Rate (LHV), Btu/kWh	5688	6536	6071	6400
Cost of Electricity, ¢/kWh	3.07	3.91	2.94	3.30
Capture Plant				
coe: CAPITAL, mills/kWh	25.9	30.1	17.9	18.4
coe: FUEL, mills/kWh	18.8	22.5	21.2	20.8
coe: O&M, mills/kWh	6.9	5.2	4.5	3.6
Capital Cost, $/kW	1135	1317	786	807
Net Power Output, MW	353.7	615.3	663.0	336.6
CO_2 Emitted, kg/kWh	0.056	0.046	0.061	0.037
Thermal Efficiency (LHV), %	53.0	44.5	47.2	48.1
Heat Rate (LHV), Btu/kWh	6433	7667	7229	7097
Cost of Electricity, ¢/kWh	5.17	5.77	4.36	4.29
Comparison				
Incremental coe, ¢/kWh	2.10	1.86	1.42	0.98
Energy Penalty, %	11.6	14.7	16.1	9.8
Mitigation Cost, Capture vs. Ref., $/ton of CO_2 avoided	77	53	46	29

Table 5.6: Performance of NGCC Capture Plants, Studies Adjusted

6 Composite Cost Model of CO_2 Capture

The incremental cost of electricity, energy penalty and mitigation cost calculated for each type of power plant in chapter five were simply averaged across different studies. Another approach is to use the raw data from the individual studies and to synthesize them into a composite cost model. The resulting cost model should have predictive power (e.g. what happens to the incremental cost of electricity if the heat rate is reduced by 5% at an IGCC plant?) and should permit the identification of cost-drivers.

6.1 Cost Model Structure

The cost model developed uses six independent inputs. Three inputs characterize the reference plant:

- Capital cost (C), in $/kW;
- Cost of electricity due to operation and maintenance ($COE_{O\&M}$), in mills/kWh;
- Heat rate (HR), in Btu/kWh, defined on the lower heating value (LHV) basis.

These three inputs are straightforward to obtain from each individual study reviewed in chapter five. Note that:

1. The quantity of CO_2 emitted (E), in kg/kWh, and the heat rate are correlated for a given type of power plant (IGCC, PC or NGCC), as shown in Figure 6.1, where each data point represents a study. Hence, the quantity of CO_2 emitted can be obtained if the heat rate of the power plant is known. Table 6.1 gives the quantity of CO_2 emitted per input Btu at IGCC, PC and NGCC power plants. These three coefficients were determined by fitting straight lines crossing the origin to the data points given by the individual studies and shown in Figure 6.1. Table 6.1 also gives the R^2 values, which are indicators of how

well the equations resulting from the regression analysis explain the relationship amongst the variables. They can range from 0 to 1, 1 indicating a perfect correlation. The R^2 obtained show that the regression equations are meaningful.

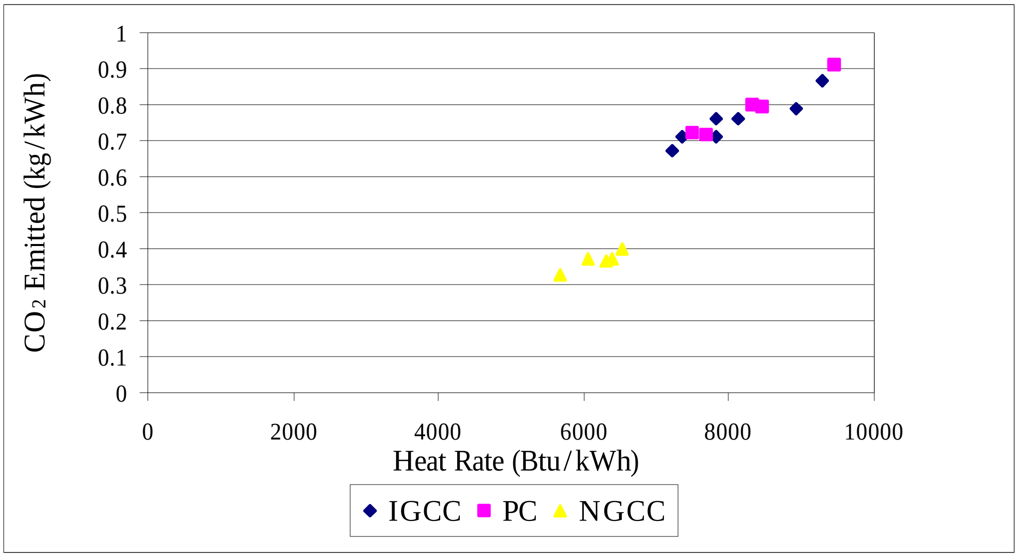

Figure 6.1: CO_2 Emissions and Heat Rates, Graphic Evidence of Correlation

This figure includes three data points from the Coal Utilization Research Council, described in greater details in Appendix B.

Power Plant Type	IGCC	PC	NGCC
Quantity of CO_2 emitted (kg/MMBtu)	93.1	95.3	59.4
R^2	0.849	0.977	0.840

Table 6.1: CO_2 Emissions and Heat Rates, Numerical Evidence of Correlation

2. The data analyzed in the different studies show no correlation between heat rate and capital cost. Therefore, it is assumed that gains in heat rate do not induce capital cost reductions. The supporting graph is shown in Appendix C.
3. The cost model developed does not break down the cost of electricity due to operation and maintenance into a fixed cost and a variable cost. This approximation is justified in chapter eight.

The other three inputs characterize the capture plant:

- Incremental capital cost (ΔC), in \$/kg of CO_2 processed per hour;
- Incremental cost of electricity due to operation and maintenance ($\Delta COE_{O\&M}$), in mills/kg of CO_2 processed;
- Energy requirements of the capture process (ER), in kWh/kg of CO_2 processed.

These last three inputs are not as straightforward to obtain from each individual study reviewed in chapter five as the three inputs characterizing the reference plant; some calculations are required. Keeping the notation introduced in chapter four, the incremental capital cost is given by the following equation:

$$\Delta C = \frac{C_{cap} \times W_{cap} - C_{ref} \times W_{ref}}{W_{ref} \times E_{ref}} \tag{6.1}$$

The numerator gives the increase in capital cost, in \$, and the denominator the quantity of CO_2 emitted, in kg per hour. This equation can be simplified to become:

$$\Delta C = \frac{C_{cap} \times \frac{W_{cap}}{W_{ref}} - C_{ref}}{E_{ref}} \tag{6.2}$$

Similarly, the incremental cost of electricity due to operation and maintenance is given by:

$$\Delta C = \frac{(COE_{O\&M})_{cap} \times \frac{W_{cap}}{W_{ref}} - (COE_{O\&M})_{ref}}{E_{ref}} \tag{6.3}$$

The energy required by the capture process (ER), and the capture efficiency (η_{cap}), are defined as follows:

$$ER = \frac{W_{ref} - W_{cap}}{W_{ref} \times E_{ref}} \tag{6.4}$$

$$\eta_{cap} = \frac{W_{ref} \times E_{ref} - W_{cap} \times E_{cap}}{W_{ref} \times E_{ref}} \tag{6.5}$$

The capture efficiency is usually about 90% in the studies reviewed, as shown in Appendix D. However, to compare the different types of capture plants on a similar basis, the capture efficiency should be kept constant. Consequently, the capture efficiency is set as a constant whose value is 90% in the cost model developed.

The symmetry of the cost model inputs is shown in Table 6.2. The generation costs are normalized by the reference power plant output, while the capture costs are normalized by the quantity of CO_2 processed (which is directly related to the quantity and type of fuel burnt at the plant). These six parameters can be reasonably viewed as independent of each other, and will form the basis of the sensitivity analyses performed in chapter eight.

	Reference Plant	Capture Plant
Capital Costs	\$/kW	\$/(kg of CO_2 processed per hour)
O&M Costs	mills/kWh	mills/kg of CO_2 processed
Energy Requirements	Btu/kWh	kWh/kg of CO_2 processed

Table 6.2: Symmetry of the Cost Model Inputs

Appendix E shows the structure of the cost model and how to derive the incremental cost of electricity, energy penalty, and mitigation cost.

6.2 Inputs Determination

For each type of power plant, there are different sets of inputs, one set being given by each individual study:

- For IGCC power plants, there are six studies (see Table 5.1 or 5.2);
- For PC power plants, four (see Table 5.3 or 5.4);
- For NGCC power plants, four (see Table 5.5 or 5.6).

In addition, data from the Coal Utilization Research Council (CURC) is used to add a reference plant to each set of input.

These inputs from the individual studies (see Appendix F) are averaged for each type of power plant to obtain the composite cost model inputs shown in Table 6.3.

Cycle		IGCC	PC	NGCC
Input	Units			
Capital Cost, C	\$/kW	1401	1150	542
O&M, $COE_{O\&M}$	mills/kWh	7.9	7.4	2.5
Heat Rate (LHV), HR	Btu/kWh	8081	8277	6201
Incremental Capital Cost, ΔC	\$/(kg/h)	305	529	921
Incremental O&M, $\Delta COE_{O\&M}$	mills/kg	2.65	5.56	5.20
Energy Requirements, ER	kWh/kg	0.194	0.317	0.354

Table 6.3: Cost Model, Inputs

It can be seen that NGCC power plants have the highest incremental capital cost and the highest energy requirements for the capture (0.354 kWh/kg of CO_2 processed), due to the low content of CO_2 in the flue gas (about 3%). Post-combustion decarbonization at PC plants is somewhat less energy intensive than at NGCC plants - 0.317 kWh/kg of CO_2 processed, because of the higher content of CO_2 in the flue gas (about 13%). Finally, the carbon dioxide is in a concentrated flow under a fairly high pressure at IGCC plants, so these plants have the lowest energy requirements (0.194 kWh/kg of CO_2 processed).

6.3 Costs Obtained

Table 6.4 reports the costs obtained for each type of power generation. The economic basis used remains the same as the one described in Table 4.2, so Table 6.4 can be compared with the results obtained in chapter five. As expected, the direct averaging method and the cost model approach give extremely similar incremental cost of electricity, energy penalty, and mitigation cost for each type of power generation.

Cycle		IGCC	PC	NGCC
Data Description	Units			
Basis				
Yearly Operating Hours	hrs/yr	6570	6570	6570
Capital Charge Rate	%/yr	15	15	15
Fuel Cost (LHV)	$/MMBtu	1.24	1.24	2.93
Capture Efficiency	%	90	90	90
Reference Plant				
CO_2 Emitted	kg/kWh	0.752	0.789	0.368
coe: CAPITAL	mills/kWh	32.0	26.3	12.4
coe: FUEL	mills/kWh	10.0	10.3	18.2
coe: O&M	mills/kWh	7.9	7.4	2.5
Cost of Electricity	¢/kWh	4.99	4.39	3.30
Thermal Efficiency (LHV)	%	42.2	41.2	55.0
Capture Plant				
Relative Power Output	%	85.4	75.0	87.0
Heat Rate (LHV)	Btu/kWh	9462	11037	7131
Capital Cost	$/kW	1909	2090	1013
CO_2 Emitted	kg/kWh	0.088	0.105	0.042
coe: CAPITAL	mills/kWh	43.6	47.7	23.1
coe: FUEL	mills/kWh	11.7	13.7	20.9
coe: O&M	mills/kWh	11.6	15.7	5.1
Cost of Electricity	¢/kWh	6.69	7.71	4.91
Thermal Efficiency (LHV)	%	36.1	30.9	47.8
Comparison				
Incremental coe	¢/kWh	1.70	3.32	1.61
Energy Penalty	%	14.6	25.0	13.0
Mitigation Cost, Capture vs. Ref.	$/ton of CO_2 avoided	26	49	49

Table 6.4: Performance of Capture Plants, From Cost Model

7 Current Economics: Conclusions

7.1 Electricity Cost

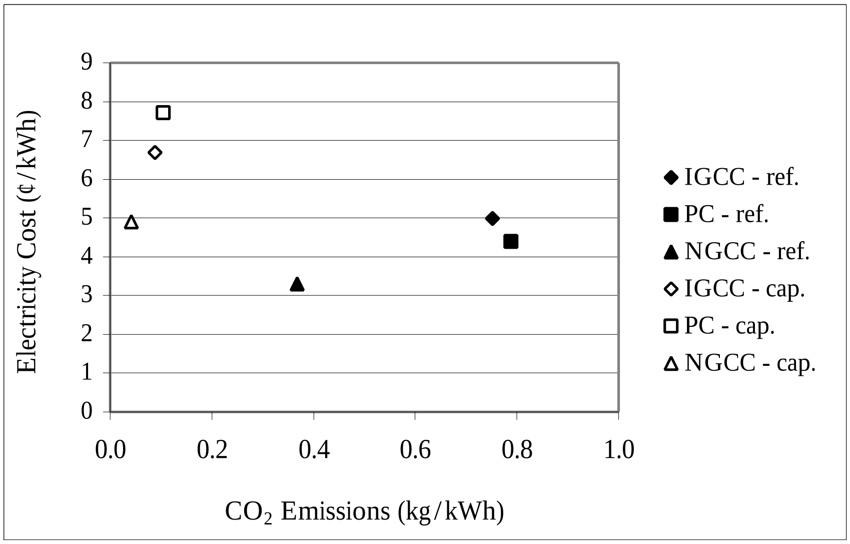

Figure 7.1: Electricity Cost vs. Carbon Dioxide Emissions

The plants are those described in Table 6.4.

Figure 7.1 shows the electricity cost versus CO$_2$ emissions for each type of power generation, without and with CO$_2$ capture. In terms of emissions, there are three groups of power plants: reference coal plants (at about 0.75 kg/kWh), reference natural gas plants (at about 0.35 kg/kWh), and capture plants (at about 0.10 kg/kWh).

Figure 7.2 shows the cost of electricity at reference and capture plants for each type of power generation. Today, reference PC plants are slightly less expensive than reference IGCC plants. However, IGCC plants will become more economical than PC plants if carbon sequestration becomes necessary. IGCC plants produce carbon dioxide in a concentrated flow at a high pressure, so less capital intensive capture equipment is required at IGCC plants than at PC plants.

Finally, it can be concluded from Figure 7.2 that natural gas is always more competitive than coal for both reference and capture plants, assuming today's fuel prices remain constant.

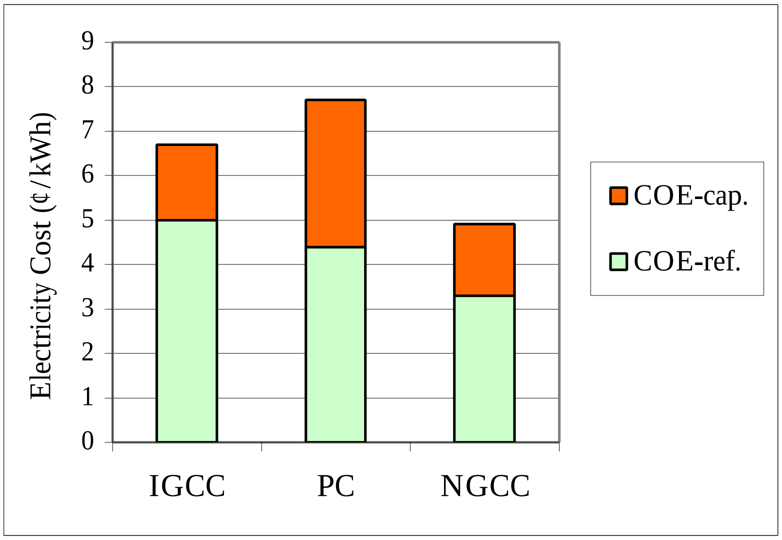

Figure 7.2: Electricity Cost at Reference and Capture Plants

7.2 Mitigation Cost

The mitigation cost is given by the following equation:

$$MC = \frac{COE_{cap} - COE_{ref}}{E_{ref} - E_{cap}} \tag{7.1}$$

The cost of mitigation varies depending on the reference plant chosen for the base case. In chapter five, the studies were analyzed individually, and the mitigation cost was calculated by comparing a capture plant to its reference plant (e.g. capture IGCC vs. reference IGCC), for self-consistency.

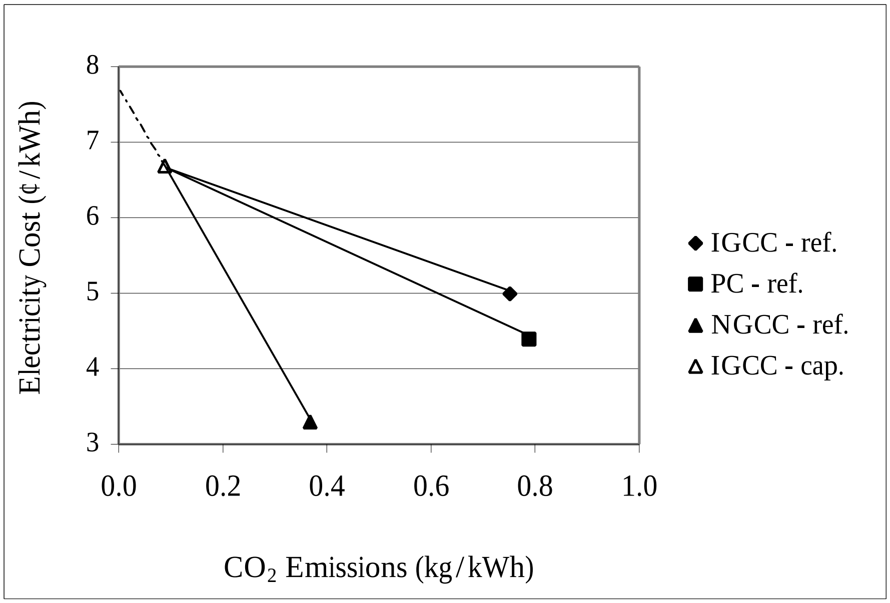

Figure 7.3: Different Mitigation Costs

However, the mitigation cost can be calculated by comparing a capture plant to any reference plant (e.g. capture IGCC vs. reference IGCC, PC or NGCC). Figure 7.3 shows the cost of electricity and CO_2 emissions of the three reference plants and the cost of electricity and CO_2 emissions of an IGCC capture plant. The mitigation cost is simply the slope of the connecting lines. The cost of mitigation varies depending on the reference plant chosen for the base case: IGCC ($26 per ton of CO_2 avoided), PC ($33 per ton of CO_2 avoided), and NGCC ($121 per ton of CO_2 avoided). Furthermore, the y-intercept of each line gives the cost of electricity that a zero emission technology must beat to be competitive with the IGCC sequestration option (7.76 cents per kWh based on a NGCC reference plant).

It can be argued that NGCC plants are the most popular plants being built today, so they should be the basis; this would yield a mitigation cost of $121 per ton of CO_2 avoided at a capture IGCC plant, $168 per ton of CO_2 avoided at a capture PC plant and only $49 per ton of CO_2 avoided at a capture NGCC plant. These different mitigation costs are reported in Figure 7.4.

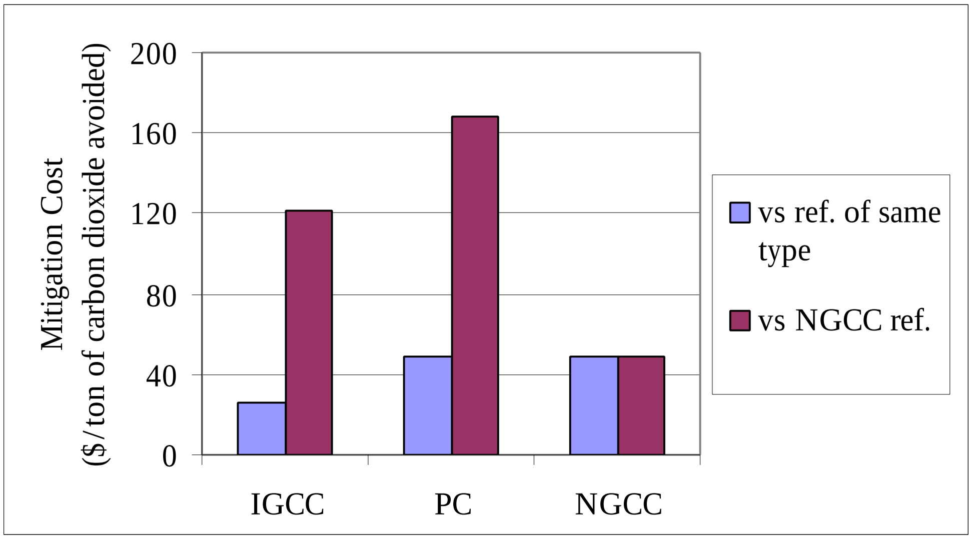

Figure 7.4: Mitigation Costs Using Different Reference Plants

8 Identification of Cost-Drivers and Future Economics

8.1 Identification of Cost-Drivers

The six inputs of the cost model are treated as independent variables. Consequently, a sensitivity analysis (i.e. the inputs are decreased by 10% one by one for each type of power plant) can be performed to identify the key inputs affecting the economics of the capture.

To assess the overall competitiveness of sequestration technologies, it is the change in absolute cost of electricity at the capture plant that must be evaluated. To quantify specific improvements in the capture process, it is the change in incremental cost of electricity and mitigation cost that must be established. Figure 8.1, 8.2 and 8.3 show the change in absolute cost of electricity, incremental cost of electricity and mitigation cost at IGCC, PC, and NGCC power plants for a 10% decrease in each input. A 10% decrease in heat rate is equivalent to an 11.1% increase in efficiency.

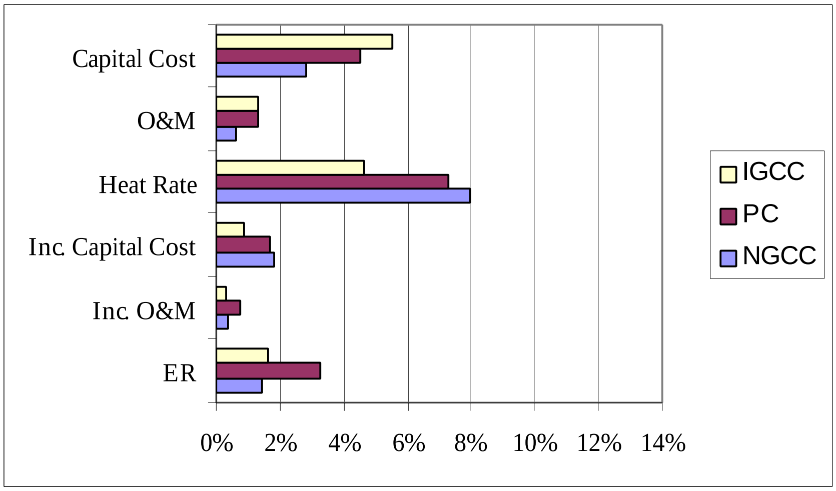

Figure 8.1: Absolute Cost of Electricity Sensitivity to the Cost Model Inputs

% Decrease in Absolute Cost of Electricity for a 10% Decrease in Each of the Six Inputs. The reference plants used are those described in Table 6.6.

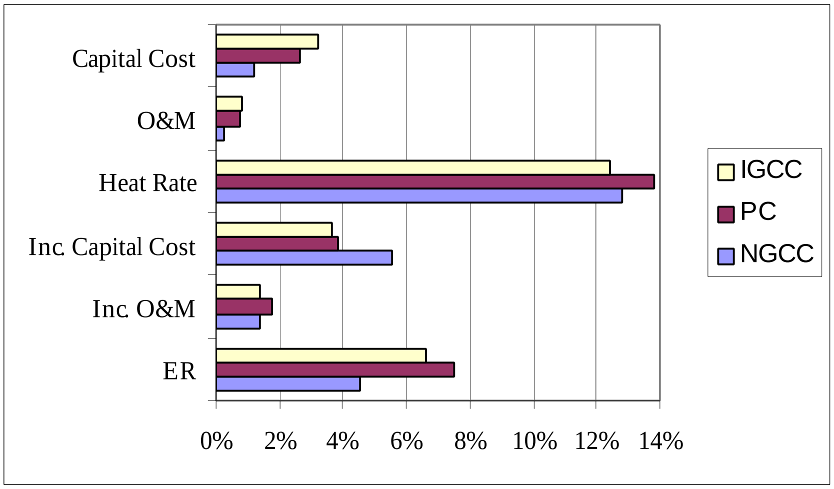

Figure 8.2: Incremental Cost of Electricity Sensitivity to the Cost Model Inputs

% Decrease in Incremental Cost of Electricity for a 10% Decrease in Each of the Six Inputs. The reference plants used are those described in Table 6.6.

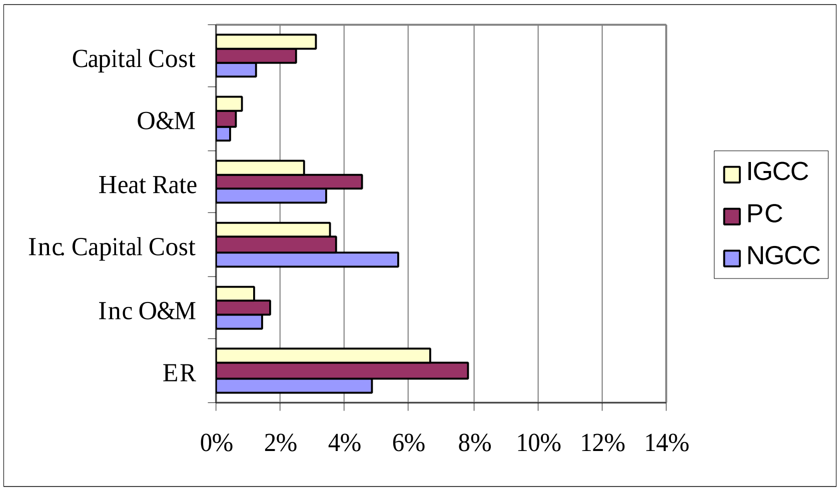

Figure 8.3: Mitigation Cost Sensitivity to the Cost Model Inputs

% Decrease in Mitigation Cost for a 10% Decrease in Each of the Six Inputs. The reference plants used are those described in Table 6.6.

Two conclusions can be drawn from Figures 8.1, 8.2 and 8.3:

- The changes in absolute cost of electricity and incremental cost of electricity are primarily sensitive to gains in heat rates, while the change in mitigation cost is primarily sensitive to reductions in energy requirements;
- The incremental cost of electricity and mitigation cost are equally sensitive to the cost model inputs, excluding one: the heat rate. For instance, for a 10% decrease in the heat rate of an IGCC plant, there is a relatively large decrease in the incremental cost of electricity (12.4%) and in the quantity of CO_2 to be sequestered (10%); however, there is only a small reduction in the mitigation cost (2.7%). This is because reductions in CO_2 emissions due to improved energy efficiency are not reflected in the mitigation cost.

Note that the absolute cost of electricity, incremental cost of electricity and mitigation cost appear to be least sensitive to the cost of electricity due to operation and maintenance - as hypothesized in chapter six, it is reasonable not to break down the cost of electricity due to operation and maintenance into a fixed cost and a variable cost.

It can be concluded that improving heat rates is extremely important for improving the economics of carbon sequestration. This supports a mitigation strategy that focuses on improved efficiency in the near-term, with sequestration becoming more important in the longer-term.

8.2 Future Economics

Technological improvements in power generation and capture technology can lower the capture costs. For instance, capital investment can be lowered and efficiency increased at the reference plant. Moreover, it is likely that improved solvents and system components will reduce the capital and energy costs for syngas or flue gas treatment to separate and capture CO_2. To reduce the energy requirements, research needs have been identified in CO_2 capture. They include means to concentrate the CO_2, which will facilitate existing capture processes, and improvements in chemical absorption.

The capture costs in 2012 can be predicted by using the cost model proposed in chapter six. The 2012 capital costs (C), costs of operation and maintenance ($COE_{O\&M}$), and heat rates (HR) are taken from CURC. Reductions in capital cost and gains in heat rate are significant at IGCC plants (above 10%), but limited at PC and NGCC plants (under 10%), which are more mature. The energy requirements (ER) are obtained by using the energy penalties (EP) given by Herzog and Drake (Herzog and Drake, 1993) at IGCC power plants, and by Mimura et al. (Mimura et al., 1997) at PC and NGCC power plants. Equation (8.1) links energy requirements and energy penalties:

$$ER = \frac{EP}{E} \tag{8.1}$$

The highest reductions in energy requirements for the capture processes are predicted to be at IGCC and PC plants (above 30%). Finally, it is assumed that the incremental capital cost, and the incremental cost of electricity due to operation and maintenance will be lowered by 10% from their 2000 level. Table 8.1 gathers the economic performance of CO_2 capture at IGCC, PC and NGCC power plants today and in 2012. Although the capture costs are expected to decrease more at IGCC and PC plants than at NGCC plants, Figure 8.4 shows that the economics are still more favorable at NGCC plants.

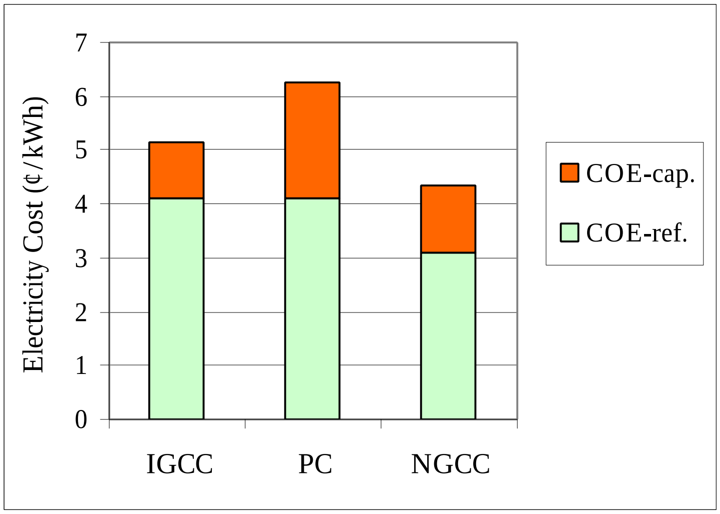

Figure 8.4: Electricity Cost at Reference and Capture Plants in 2012

Cycle	IGCC	IGCC	PC	PC	NGCC	NGCC
Data Description	2000	2012	2000	2012	2000	2012
Input						
Capital Cost, \$/kW	1401	1145	1150	1095	542	525
O&M, mills/kWh	7.9	6.1	7.4	6.1	2.5	2.4
Heat Rate (LHV), Btu/kWh	8081	7137	8277	8042	6201	5677
Incremental Capital Cost, \$/(kg/h)	305	275	529	476	921	829
Incremental O&M, mills/kg	2.65	2.39	5.56	5.00	5.20	4.68
Energy Requirements, kWh/kg	0.194	0.135	0.317	0.196	0.354	0.297
Basis						
Yearly Operating Hours, hrs/yr	6570	6570	6570	6570	6570	6570
Capital Charge Rate, %/yr	15	15	15	15	15	15
Fuel Cost (LHV), \$/MMBtu	1.24	1.24	1.24	1.24	1.24	2.93
Capture Efficiency, %	90	90	90	90	90	90
Reference Plant						
CO_2 Emitted, kg/kWh	0.752	0.664	0.789	0.766	0.368	0.337
coe: CAPITAL, mills/kWh	32.0	26.1	26.3	25.0	12.4	12.0
coe: FUEL, mills/kWh	10.0	8.8	10.3	10.0	18.2	16.6
coe: O&M, mills/kWh	7.9	6.1	7.4	6.1	2.5	2.4
Cost of Electricity, ¢/kWh	4.99	4.10	4.39	4.10	3.30	3.10
Thermal Efficiency (LHV), %	42.2	47.8	41.2	42.4	55.0	60.1
Capture Plant						
Relative Power Output, %	85.4	91.0	75.0	85.0	87.0	90.0
Heat Rate (LHV), Btu/kWh	9462	7843	11037	9461	7131	6308
Capital Cost, \$/kW	1909	1459	2090	1718	1013	894
CO_2 Emitted, kg/kWh	0.088	0.073	0.105	0.090	0.042	0.037
coe: CAPITAL, mills/kWh	43.6	33.3	47.7	39.2	23.1	20.4
coe: FUEL, mills/kWh	11.7	9.7	13.7	11.7	20.9	18.5
coe: O&M, mills/kWh	11.6	8.4	15.7	11.6	5.1	4.4
Cost of Electricity, ¢/kWh	6.69	5.14	7.71	6.26	4.91	4.33
Thermal Efficiency (LHV), %	36.1	43.5	30.9	36.1	47.8	54.1
Comparison						
Incremental coe, ¢/kWh	1.70	1.04	3.32	2.16	1.61	1.23
Energy Penalty, %	14.6	9.0	25.0	15.0	13.0	10.0
Mitigation Cost, Capture vs. Ref., \$/ton of CO_2 avoided	26	18	49	32	49	41

Table 8.1: Performance of Capture Plants, in 2000 and 2012, From Cost Model

9 Climate Change Policy and Carbon Sequestration

Specific policy options aimed at reducing CO_2 emissions to the atmosphere are required before CO_2 capture and sequestration technologies can compete with other technological options in the marketplace. Consequently, the potential use of carbon sequestration depends on the outcome of the climate change debate. In this chapter, the policy debate about climate change and its challenges are briefly discussed, pertinent policy formulation alternatives are reviewed, and a scenario under which carbon dioxide emissions must be lowered while maintaining the same overall system capacity is analyzed by using the results established in the previous chapters.

9.1 The Challenges of Global Climate Change

Climate change presents the decision maker with a set of formidable complications: a considerable number of remaining uncertainties, the potential for irreversible damages or costs, a very long planning horizon, long time lags between emissions and effects, wide regional variations in causes and effects, the irreducibly global scope of the problem, and the need to consider multiple greenhouse gases and aerosols. Another complication arises from the fact that effective protection of the climate system requires global cooperation.

The family of analytical techniques for examining economic environmental policies and decisions includes traditional project level cost-benefit analysis, cost-effectiveness analysis, multicriteria analysis, and decision analysis. In principle, this group of techniques can contribute to improving policy decisions concerning the desirable extent of actions to mitigate global climate change, the timing of such actions, and the methods to be employed. However, these analytical techniques do not resolve questions involving equity - for example, determining who should bear the costs. Moreover, practical application of traditional cost-benefit analysis to the problem of climate change is difficult, because of the global nature of the problem and variations in monetary estimates of the costs of mitigation options and potential physical damages due to climate change. To the extent that some impacts and measures cannot be valued in monetary terms, economists prefer the use of techniques such as multicriteria analysis over the traditional cost-benefit approach, permitting some quantitative expression of the trade-offs to be made.

Despite their many imperfections, these techniques provide a valuable framework for identifying essential questions that policymakers must face when dealing with climate change, namely:

- By how much should emissions of greenhouse gases be reduced?
- When should emissions be reduced?
- How should emissions be reduced?

This last question is particularly relevant to the possible implementation of a carbon sequestration strategy. Hence, the different policy formulations aiming at reducing carbon dioxide emissions should be understood.

9.2 Policy Formulation Alternatives

There are two primary categories of policy mechanisms, that can be classified as direct regulation or incentive-based regulation.

Direct regulation includes command-and-control and standards. Command-and-control regulation can take the form of limits, quotas, or bans on particular activities. Amongst these might be fuel use, technology use, or environmental emissions. The second set of direct mechanisms, standards, could detail technological specifications that must be met by power plants. For instance, regulations could specify the use of CO_2 capture and storage technologies. Direct regulation is relatively easy to implement and enforce if correctly designed, but its primary disadvantage is economic inefficiency. It is unlikely that direct regulations will be promoted in the future - they are not acceptable to those being regulated, and are contrary to the current trends for the deregulation of utilities initiated by the Energy Policy Act (EPACT) of 1992.

The second broad category, incentive-based regulations, are based on free market principles and can take many forms: subsidies (for removal of CO_2 from the flue gas), tradable permits, and taxes (on the production or purchase of coal, on CO_2 emissions, on the price of electricity itself…). At both the international and national levels, the economic literature indicates that these instruments that provide economic incentives are likely to be more cost-effective than direct regulations. Subsidies that can contribute to the commercial applications of carbon sequestration technologies at the turnover of existing capital stocks can be promoted, such as investment and production tax credits. Under a tradable permit system, each utility is permitted to emit a certain level of pollution. If it can self reduce pollution below those levels, it can sell its extra permits to the companies that find it cheaper to buy these permits than achieving emissions reductions. This allows for economically efficient emissions reduction, since emissions are reduced by those most capable of doing so. A tradable quota system has the disadvantage of making the marginal cost of emissions uncertain, while a carbon tax (and related instruments) has the disadvantage of leaving the level of emissions uncertain.

In 1997, the General Agreement on Climate Change (GACC) was signed at Kyoto. It contains a set of economic instruments, called Kyoto Mechanisms. International Emissions

Trading, which will come into operation before 2008, is one of these instruments that will create a market price for carbon in the countries in compliance with the GACC. These instruments will certainly increase the competitiveness of carbon sequestration technologies.

9.3 CO_2 Sequestration and Costs of Emissions Under a Constraint on CO_2 Emissions

9.3.1 Problem Definition

Consider a generation system composed solely of Integrated Gasification Combined Cycles, Pulverized Coal power cycles, and Natural Gas Combined Cycles (none of them sequestering carbon dioxide), for which CO_2 emissions must be reduced while maintaining the same overall capacity.

Different independent power producers are pooled together in this system; if one of them has to cut its emissions, it can decide to change its fuel mix or to buy carbon dioxide emissions permits, whichever is cheaper. If this power producer buys emissions permits, the fuel mix of another power producer has to be changed. This mechanism allows for economically efficient emissions reductions.

9.3.2 Methodology Developed

Many strategies can satisfy a reduction in emissions while maintaining the same overall capacity. The basic idea is to shut down some existing capacity at a high CO_2 emitting power plant and to replace it at a lower CO_2 emitting power plant. The following strategies are studied:

- Shut down some existing capacity at a PC power plant and add capacity at an IGCC or NGCC reference plant or at a PC, IGCC or NGCC capture plant.
- Shut down some existing capacity at an IGCC power plant and add capacity at a NGCC reference plant or at a PC, IGCC or NGCC capture plant.
- Shut down some existing capacity at a NGCC power plant and add capacity at a PC, IGCC or NGCC capture plant.

Hence, twelve strategies ought to be considered. For each of these twelve strategies, the cost of CO_2 emissions avoided is established. It is given by the following formula:

$$Cost(Emissions) = \frac{COE_{low} - (COE_{O\&M} + COE_{FUEL})_{high}}{E_{high} - E_{low}} \qquad (9.1)$$

Note that the capital cost of the high CO_2 emitting power plant does not matter, since variable costs are the only costs that matter when making operating decisions.

9.3.3 Results Obtained

Table 6.4 provides the 2000 emissions and costs. If the prices of coal and gas do not change, the most economical strategy is to switch from PC and IGCC power plants to NGCC reference plants ($37 and $39 per ton of CO_2 avoided, respectively). The second most economical strategy is to switch from these same PC and IGCC power plants to NGCC capture plants ($42 and $44 per ton of CO_2 avoided, respectively). The other strategies are viable only if the market price of CO_2 is above $70/ton. If the gas prices rise about 100%, and the coal prices remain constant, the most economical strategies are to switch from IGCC and PC power plants to IGCC capture plants ($74 and $70 per ton of CO_2 avoided, respectively).

The same analysis was then performed for the 2012 emissions and costs obtained (see Table 8.1). The most economical strategies are to switch from PC and IGCC power plants to NGCC reference plants ($35 per ton of CO_2 avoided) and NGCC capture plants ($45 per ton of CO_2 avoided), respectively. Moreover, switching from PC plants to NGCC capture plants would cost only $37 per ton of CO_2 avoided. If the gas prices rise about 60% by 2012, and the coal prices remain constant, the most economical strategies are to switch from IGCC and PC power plants to IGCC capture plants ($62 and $51 per ton of CO_2 avoided, respectively).

This shows the economic potential for the introduction of capture technologies at NGCC power plants, and potentially at IGCC power plants if the price of natural gas increases.

9.3.4 Discussion

The most critical issues facing the electric power industry today are associated with deregulation and competition in the marketplace, both of which are leading to substantial challenges in the structure and organization of the industry. Independent power producers are no longer certain that they will be able to recover their capital investment in generating capacity because they can no longer pass the cost of excess capacity on to ratepayers. Consequently, many have been discouraged from investing in expensive new generating capacity. This is certainly an hurdle that a policy promoting carbon sequestration in the US would have to overcome.

Research on CO_2 sequestration is a very high-risk, long-term R&D that will not be undertaken by industry alone without strong incentives or regulations. The research conducted on SO_2 control options has contributed to the success of US policies aiming at controlling SO_2 emissions; by analogy, to be able to control CO_2 emissions in a cost-effective manner in the future, research on possible technological responses is needed today.

10 Conclusions

In this thesis, it was found that carbon dioxide capture increases the electricity cost from 5.0 to 6.7 ¢/kWh at IGCC plants, from 4.4 to 7.7 ¢/kWh at PC plants, and, finally, from 3.3 to 4.9 ¢/kWh at NGCC plants. The strongest opportunities for lowering the separation costs in the future were identified as gains in heat rates and reductions in the amount of energy required by the separation. New technologies like gasification show the most long-term promise, with incremental costs for CO_2 sequestration at IGCC power plants being potentially reduced to about 1 ¢/kWh in the next decade. Today, if CO_2 emissions had to be reduced while maintaining the same overall generation capacity, the most cost-efficient strategies would be to switch from IGCC and PC power plants to NGCC plants at costs below $40 per ton of CO_2 avoided, or, at a premium of $5 per ton of CO_2 avoided, to NGCC capture plants. Although these costs would have to be compared to the cost of alternative mitigation options, such as renewable energy, carbon capture and sequestration seems to be a competitive carbon mitigation option.

Future work will require the investigation of opportunities for innovative technologies including new types of power plants and power cycles that may bring even larger reductions in the costs of capturing and sequestering CO_2. Moreover, system-level analyses should be performed to minimize not only capture costs, but the associated transportation and injection costs.

There are numerous options for the separation and capture of CO_2, and many of these are commercially available. However, none has been applied at the scale required as part of a CO_2 emissions mitigation strategy. Many issues remain regarding the ability to separate and capture CO_2 from anthropogenic sources on the scale required, and to meet the cost, safety, and environmental requirements for CO_2 separation and capture.

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12 Appendices

12.1 Appendix A: Mechanics of the Adjustment

Data Description	Acronyms	Units	Calculations
Reference Plant			
coe: CAPITAL	COE_{CAP}	mills/kWh	$= \frac{1000 \times r \times C}{f}$
coe: FUEL	COE_{FUEL}	mills/kWh	$= \frac{HR \times FC}{1000}$
coe: O&M	$COE_{O\&M}$	mills/kWh	$= \frac{0.35 \times (COE_{O\&M})_{orig.} \times (f)_{orig.}}{f}$ $+ 0.65 \times (COE_{O\&M})_{orig.}$
Capital Cost	C	\$/kW	same as original
Net Power Output	W	MW	same as original
CO_2 Emitted	E	kg/kWh	same as original
Thermal Efficiency (LHV)	η	%	same as original
Heat Rate (LHV)	HR	Btu/kWh	same as original
Cost of Electricity	COE	¢/kWh	$= \frac{COE_{CAP} + COE_{FUEL} + COE_{O\&M}}{10}$
Capture Plant			
Same procedure as above			
Comparison			
Incremental coe	ΔCOE	¢/kWh	$= COE_{cap} - COE_{ref}$
Energy Penalty	EP	%	$= \frac{W_{ref} - W_{cap}}{W_{ref}}$
Mitigation Cost, Capture vs. Reference	MC	\$/ton of CO_2 avoided	$= \frac{COE_{cap} - COE_{ref}}{E_{ref} - E_{cap}} \times 10$

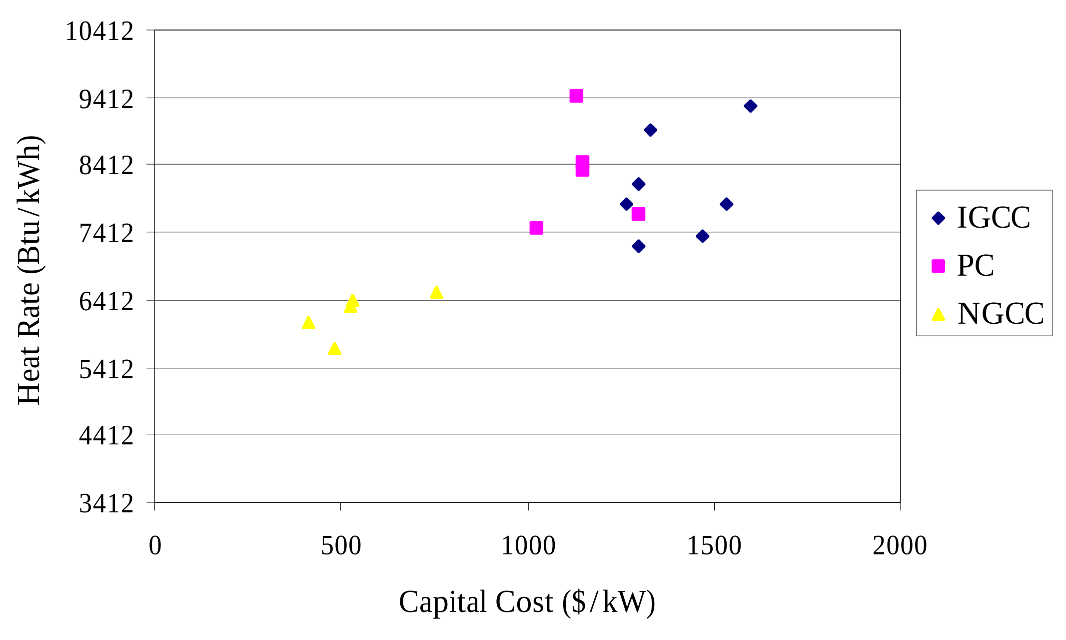
Ref.: Section 4.2.2

12.2 Appendix B: Adjusted CURC Studies

Data Description/ Cycle	IGCC	PC	NGCC
Reference Plant			
coe: CAPITAL, mills/kWh	29.7	26.3	12.0
coe: FUEL, mills/kWh	10.1	10.5	18.5
coe: O&M, mills/kWh	6.1	5.8	2.4
Capital Cost, $/kW	1300	1150	525
Net Power Output, MW			
CO_2 Emitted, kg/kWh	0.762	0.795	0.366
Thermal Efficiency (LHV), %	42.0	40.3	54.1
Heat Rate (LHV), Btu/kWh	8124	8462	6308
Cost of Electricity, ¢/kWh	4.58	4.25	3.28
Basis			
Yearly Operating Hours, hrs/yr	6570	6570	6570
Capital Charge Rate, %/yr	15.0	15.0	15.0
Fuel Cost (LHV), $/MMBtu	1.24	1.24	2.93

Ref.: Section 6.1

12.3 Appendix C: Heat Rates and Capital Costs



Ref.: Section 6.1

12.4 Appendix D: Capture Efficiencies Reported in the Literature

Cycle: IGCC

Study	Argonne	Milan	SFA Pacific	Utrecht	EPRI	IEA
Capture Efficiency	80%	91%	90%	96%	90%	82%

Cycle: PC

Study	Utrecht	EPRI	SFA Pacific	IEA
Capture Efficiency	90%	90%	85%	85%

Cycle: NGCC

Study	SFA Pacific	Trondheim	IEA	Milan
Capture Efficiency	85%	90%	86%	91%

Ref.: Section 6.1

12.5 Appendix E: Cost Model, Calculations

Data Description	Acronyms	Units	Calculations
Calculations, Reference Plant			
CO_2 Emitted	E	kg/kWh	$= a \times \mathbf{HR}$
coe: CAPITAL	COE_{CAP}	mills/kWh	$= \frac{1000 \times r \times \mathbf{C}}{f}$
coe: FUEL	COE_{FUEL}	mills/kWh	$= \frac{\mathbf{HR} \times FC}{1000}$
Cost of Electricity	COE	¢/kWh	$= \frac{COE_{CAP} + COE_{FUEL} + \mathbf{COE_{O\&M}}}{10}$
Calculations, Capture Plant			
Relative Power Output	RPO	%	$= 1 - E \times \mathbf{ER}$
Heat Rate (LHV)	HR_{cap}	Btu/kWh	$= \frac{\mathbf{HR}}{RPO}$
Capital Cost	C_{cap}	$/kW	$= \frac{\mathbf{C} + \mathrm{D}\mathbf{C} \times \mathrm{E}}{\mathrm{RPO}}$
CO_2 Emitted	E_{cap}	kg/kWh	$= \frac{E \times (1 - \boldsymbol{h}_{cap})}{RPO} \quad (= 0.1 \times \frac{E}{RPO})$
coe: CAPITAL	$(COE_{CAP})_{cap}$	mills/kWh	$= \frac{1000 \times r \times C_{cap}}{f}$
coe: FUEL	$(COE_{FUEL})_{cap}$	mills/kWh	$= \frac{HR_{cap} \times FC}{1000}$
coe: O&M	$(COE_{O\&M})_{cap}$	mills/kWh	$= \frac{\mathbf{COE_{O\&M}} + \mathrm{D}\mathbf{COE_{O\&M}} \times \mathrm{E}}{\mathrm{RPO}}$
Cost of Electricity	COE_{cap}	¢/kWh	$= 0.1 \times (COE_{CAP})_{cap}$ $+ 0.1 \times (COE_{FUEL})_{cap}$ $+ 0.1 \times (COE_{O\&M})_{cap}$
Calculations, Outputs			
Incremental coe	ΔCOE	¢/kWh	$= COE_{cap} - COE$
Energy Penalty	EP	%	$= 1 - RPO$
Mitigation Cost	MC	$/ton of CO_2 avoided	$= \frac{COE_{cap} - COE}{E - E_{cap}} \times 10$

Ref.: Section 6.1. a depends of the type of power plant. The cost model inputs are in bold.

12.6 *Appendix F: Cost Model, Inputs*

Cycle: IGCC

Study		Argonne	Milan	SFA Pacific	Utrecht	EPRI	IEA	CURC
Input	Units							
Capital Cost	$/kW	1332	1536	1300	1265	1600	1471	1300
O&M	mills/kWh	9.3	5.8	7.9	6.5	10.4	9.6	6.1
Heat Rate	Btu/kWh	8938	7817	7210	7826	9280	7369	8124
Inc. Cap. Cost	$/(kg/h)	263	141	132	308	152	835	
Inc. O&M	mills/kg	1.17	0.50	0.87	1.75	5.45	6.13	
Energy Req.	kWh/kg	0.107	0.204	0.318	0.219	0.225	0.090	

Cycle: PC

Cycle		Utrecht	EPRI	SFA Pacific	IEA	CURC
Input	Units					
Capital Cost	$/kW	1150	1129	1300	1022	1150
O&M	mills/kWh	5.9	10.3	7.9	7.2	5.8
Heat Rate	Btu/kWh	8322	9440	7680	7482	8462
Inc. Cap. Cost	$/(kg/h)	558	558	559	442	
Inc. O&M	mills/kg	5.04	10.33	3.41	3.44	
Energy Req.	kWh/kg	0.288	0.375	0.221	0.384	

Cycle: NGCC

Cycle		SFA Pacific	Trondheim	IEA	Milan	CURC
Input	Units					
Capital Cost	$/kW	485	754	414	531	525
O&M	mills/kWh	3.0	2.7	2.2	2.2	2.4
Heat Rate	Btu/kWh	5688	6536	6071	6400	6308
Inc. Cap. Cost	$/(kg/h)	1572	924	664	526	
Inc. O&M	mills/kg	9.40	4.34	4.26	2.80	
Energy Req.	kWh/kg	0.351	0.368	0.434	0.262	

Ref.: Section 6.2