Clean Coal Technologies

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Introduction

This report examines a number of technologies that can be used to generate electricity from coal in an environmentally sensitive manner. The outline of the report is:

- Section 1 – An overview of several coal combustion technologies for electricity generation.
- Section 2 – An overview of capital cost and efficiency estimates of the coal technologies.
- Section 3 – Considerations as to the fuel used by the coal technologies.
- Section 4 – An overview of methods to concentrate carbon dioxide or capture it from exhaust gas.

While the State Utility Forecasting Group (SUFG) would like to thank the Indiana Utility Regulatory Commission and the Center for Coal Technology Research for their support on this report, the SUFG is solely responsible for its content.

1 Generation of Electricity from Coal

This section gives a general description of various technologies that may shape the future of coal utilization. Although traditional pulverized coal plants are generally not considered clean coal technologies, they are discussed in this section because of their historical value and because they may be considered clean when combined with certain advanced technologies. The coal technologies that will be discussed include supercritical pulverized coal, circulating fluidized bed, and integrated gasification combined cycle. Although the list is not exhaustive it represents a number of feasible options for future coal utilization.

1.1 Pulverized Coal

A simplified diagram of a pulverized coal (PC) power plant is shown in Figure 1. PC plants have been in operation for many decades and have become the backbone of the electrical power industry in the United States. In a PC plant, finely ground coal is fed into a boiler with air where it is combusted, releasing the coal's chemical energy in the form of heat. The heat is used to produce steam from the water running through tubes in the boiler walls. The high temperature, high pressure steam is then passed through a steam turbine that is connected to a generator to produce electricity. After the steam passes through the turbine, it is cooled and condensed back to liquid before it runs back into the tubes of the boiler walls where the cycle starts over. Many different types of coal may be used in a PC system, but the complexity and cost increases for systems designed to burn multiple types of coal [1].

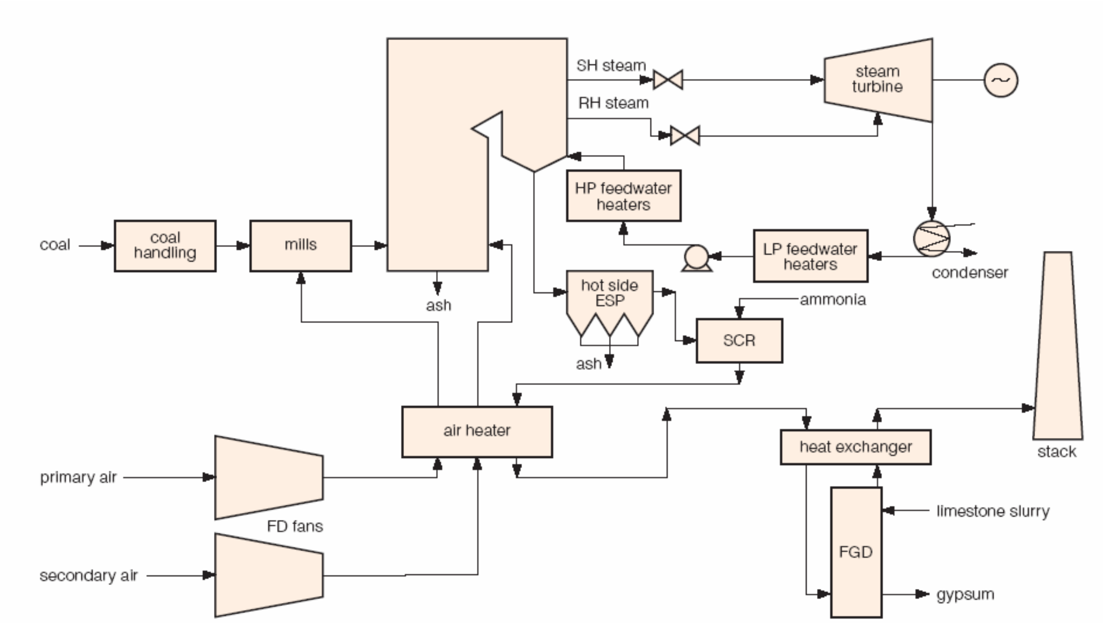

Figure 1. Pulverized Coal Power Plant [2]

Historically, PC plants have been characterized by poor environmental performance, producing substantial amounts of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), major components of acid rain and smog, respectively. With increasing regulation of such emissions, some PC plants have switched to low sulfur, low heating value coals from the Powder River Basin, while others have added costly post-combustion technologies to reduce emissions.

Post combustion gas clean-up in PC plants can require large capital investments. Different equipment is needed to remove harmful pollutants before the gas is released into the environment. Particulate matter must be removed by electrostatic precipitators (ESPs) or bag filters, SO_2 is controlled by the addition of a flue gas desulfurization (FGD) unit or spray dry scrubber, and NO_x emissions can be reduced through the use of selective catalytic reduction (SCR). For older and smaller plants, low cost, low removal efficiency options such as selective non-catalytic reduction (SNCR) and low NO_x burners are often used, since the relatively small amount of electrical energy produced by the facility is not sufficient to justify a larger capital expense.

With potential carbon dioxide (CO_2) legislation, many have speculated that the PC plants will be uneconomic with the addition of CO_2 capture equipment (such as amine scrubbers). There are other technologies that may be added to PC plants that might make them cost competitive for CO_2 capture (e.g., flue gas recycling). The major problem with CO_2 capture in combustion PC plants is that at atmospheric pressure the CO_2 is only about 20-25 percent of the combustion products that would be required to be cleaned. Since the CO_2 concentration is low and the exhaust gas volume is large, it would be costly to capture CO_2.

1.2 Supercritical Pulverized Coal

Although pulverized coal plants have been around for some time, there have been considerable recent advances in materials and technologies. Supercritical pulverized coal (SCPC) plants are essentially the same as conventional pulverized coal plants, but they can operate at much higher temperatures and pressures by using the advanced materials and technologies. Operating at higher temperatures makes it possible to have higher efficiencies. Since less coal is used to produce a given amount of electrical energy, SCPC plants generally have lower emissions of most pollutants than PC units. The diagram for a basic SCPC plant is the same as that of a subcritical pulverized coal plant (Figure 1). Since the supercritical technology is essentially the same as for traditional pulverized coal technologies, it faces many of the same issues associated with post-combustion gas cleanup.

1.3 Circulating Fluidized Bed

In a circulating fluidized bed (CFB), crushed coal and limestone or dolomite (for SO_2 capture) are fed into a bed of ash and coal particles, then made highly mobile by a high velocity stream of preheated air (see Figure 2). The air is fed into the combustor at two levels to control combustion and minimize NO_x formation. The combustion chamber is lined with water to produce steam. Particles and combustion products travel up through the combustor and on to a cyclone where the solids are separated from the gases and sent back to the combustor for further oxidation. Hot gases are passed through heat exchangers to produce more steam to drive a steam turbine.

CFB technology is generally used with low heat content coals. Since the thermodynamic cycle is the same as for pulverized coal plants, efficiencies are in the same range as the pulverized coal plants. As with the pulverized coal plants, this configuration may be pressurized to increase efficiency, but the gains come at increased capital and operating costs.

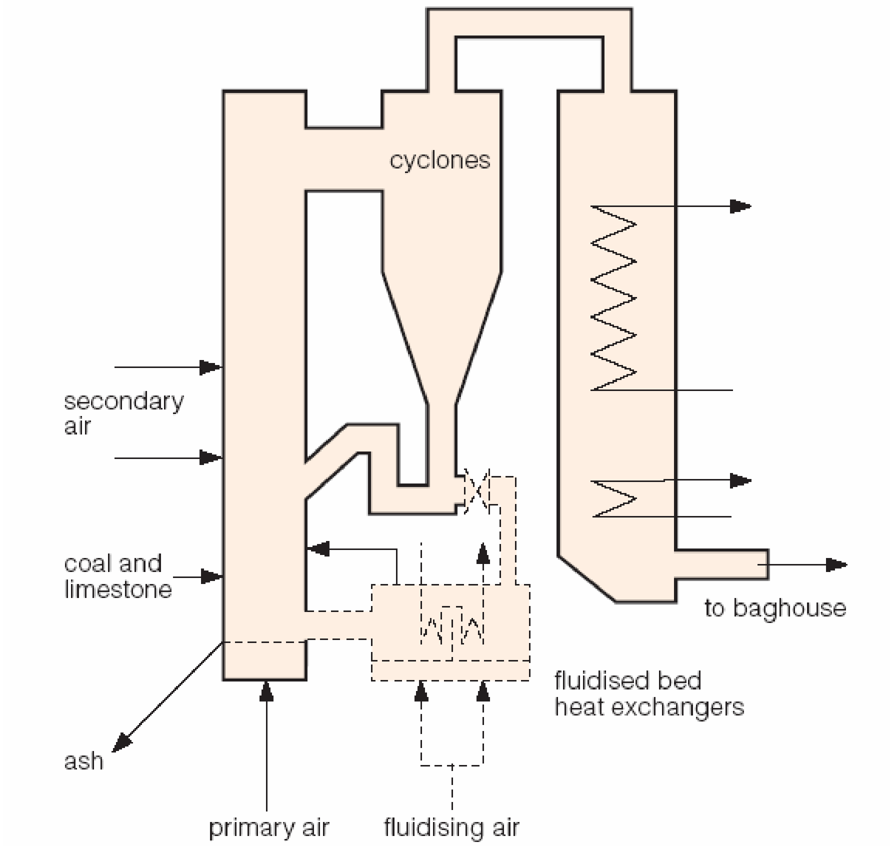

Figure 2. Diagram of a Circulating Fluidized Bed Combustor [4]

1.4 Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC) generation differs considerably from the combustion technologies described previously. A block diagram of the system is shown in Figure 3. In this type of configuration the carbon in the coal chemically reacts with steam at high temperatures to produce a combustible gas, which is primarily a mixture of hydrogen (H_2) and carbon monoxide (CO). Methane (CH_4) may also be present.

The gas may be cleaned up pre-combustion and used in a gas turbine to drive a generator, thereby producing electricity. The diagram in Figure 3 shows a fuel cell being used in addition to the gas turbine, which is an uncommon but technically feasible design. The post-combustion gases exiting the turbine are still at a high temperature and may be used to produce steam, which in turn can be used to produce more electricity. The use of both a combustion turbine and a steam turbine is referred to as a combined cycle process and is more efficient than a simple steam cycle.

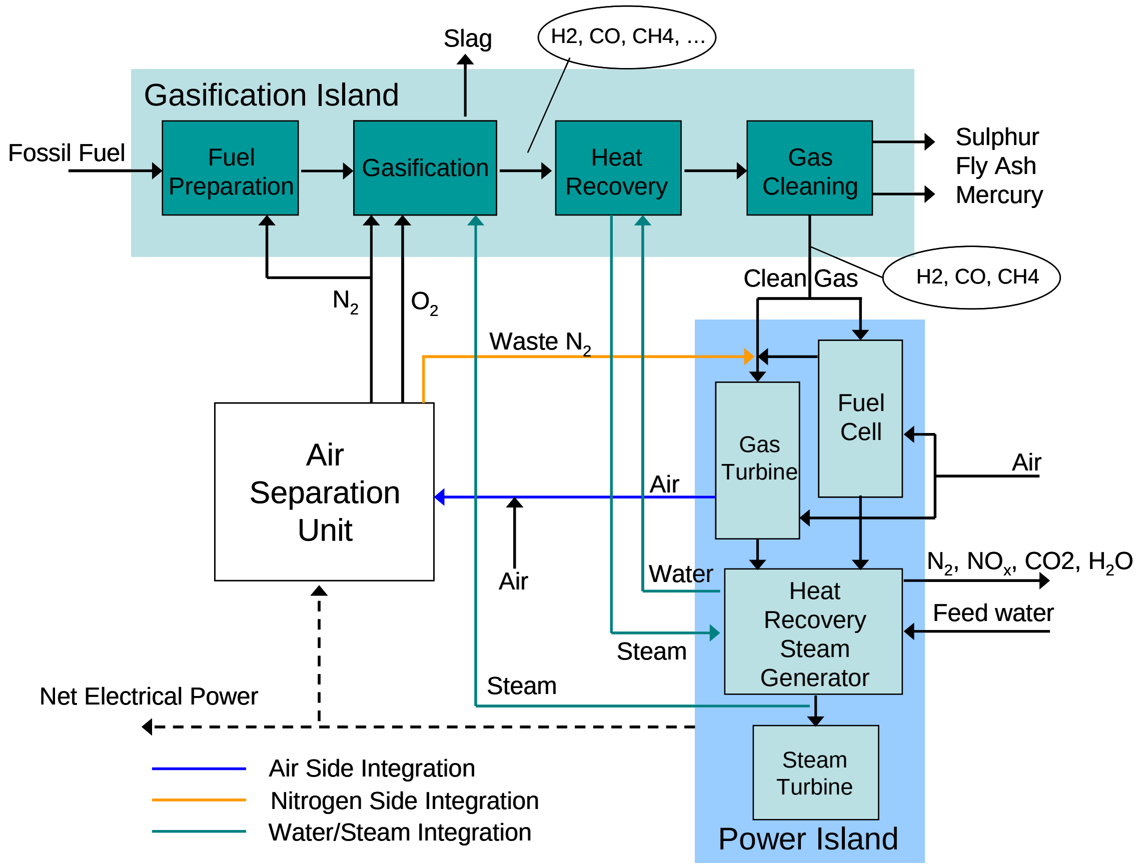

Figure 3. Block Diagram of an IGCC Power Plant

The ability to clean gases pre-combustion is an important aspect of IGCC systems. This allows for NO_x and SO_2 controls that are less expensive than post-combustion controls. Also, since the CO_2 is relatively concentrated in the exhaust stream, it is much simpler and less costly to capture CO_2.

1.4.1 IGCC Experience

The first IGCC power plant in the world was tested in Germany in the 1970s [5]. The first IGCC power plant in the United States was in operation in Southern California in the 1980s [5]. Today, there are at least five IGCC plants in operation or development with power as sole output or co-product in the United States [6, 7]. Of the five, the Wabash River Repowering Project, located in western Indiana, is the first modern IGCC plant and has been in commercial operation intermittently since 1995. As with many technological innovations, there have been a number of start-up issues with IGCC. As the technology has matured, many of these issues have been resolved.

There are many IGCC power plants around the world, with more in the planning, pre-development or construction stages. In addition, IGCC has been considered for co-production of chemicals (e.g., ammonia based fertilizers), clean diesel fuels, and many other products [6].

Opinions are mixed on the reliability and maturity level of IGCC technology. Some think that IGCC power plant technology is relatively mature, while others consider it to be unproven. While significant experience has been gained with the chemical processes of gasification, system reliability is still relatively lower than conventional coal-based power plants.

1.4.2 Retrofit of Existing Facilities to IGCC

In some instances, it may be economically attractive to retrofit an existing generator as an IGCC facility. This may be especially true in the cases of older, less efficient pulverized coal units or of natural gas-fired combined cycle units.

Older pulverized coal units are likely to face substantial repair costs due to the accumulated wear on the existing equipment. Furthermore, replacement of existing equipment may trigger the New Source Review requirements of the Federal Clean Air Act Amendments of 1990, thereby requiring additional pollution control expenses. Also, older units tend to be smaller, which makes the cost of pollution control devices higher on a per unit output basis. In such cases, retrofit to IGCC may be economically feasible, provided some of the common facilities (coal handling; electrical transformers and transmission lines; and steam plant equipment) are in sufficiently good condition so as to be usable. Additionally, there would have to be adequate physical space available to add the additional equipment.

In the case of natural gas combined cycle units, it is not the age of the equipment that is the issue in moving toward IGCC; rather it is the price of natural gas. The recent price of natural gas has made it difficult for natural gas-fired generators to operate profitably, even with the high efficiencies gained using combined cycle technology. If an existing natural gas combined cycle facility has sufficient room on site to construct a gasifier and if it has reasonable access to coal supplies, it may be economically attractive to retrofit to IGCC.

2 Estimated Costs and Efficiencies

This section provides an overview of the capital costs and heat rates[1] of the various clean coal technologies covered in this report. It should be noted that capital costs can be very sensitive to specific location due to a number of factors, such as greenfield/brownfield status, land values, availability of cooling water, and availability of electricity transmission. Additionally, capital costs can vary considerably with time due to the volatility of the costs of construction inputs, such as steel, concrete, and labor.

2.1 Capital Costs

Table 1 shows a range of capital costs for PC, CFB, IGCC, and SCPC as taken from recent reports by the National Energy Technology Laboratory (NETL) [8] and the National Regulatory Research Institute (NRRI) [9]. The NETL numbers are based on more recent information and are generally higher. NETL did not provide cost estimates for CFB; one may safely assume that the upper range for CFB is higher than the NRRI numbers shown. Recent increases in the price of steel and concrete, along with higher engineering and labor costs, have caused costs estimates to rise considerably from these levels. It is uncertain whether the cost increases will continue or if costs will level off or even decrease in the future.

Table 1. Capital Cost Estimates for Coal Technologies [9]

Technology	*Capital Cost ($/kW)*	
	Without CO_2 Capture	*With CO_2 Capture*
PC [8, 9]	1235 – 1548	2270 – 2893
SCPC [8]	1574	2868
CFB [9]	1327 – 1490	Not available
IGCC [8, 9]	1431 – 1999	1920 – 2688

The cost estimates involve many factors and assumptions such as the cost of capital, tax rate, depreciation scheme, and so forth. These varying assumptions can result in a number of different estimates. In the past few years, material and construction costs have increased dramatically, largely due to an increase in international demand and a shortage of labor for plant construction. Figure 4 shows the cost escalation in the chemical industry which relies on the same types of construction inputs [10]. As the figure shows, estimated plant costs have increased significantly since 2003. Compared with earlier cost estimates, the most recent estimates are about 50-100 percent higher than those prior to 2006.

[1] Heat rate is a measure of the thermal efficiency of a generating unit. It is computed by dividing the total Btu content of the fuel burned by the resulting net kilowatthour generation.

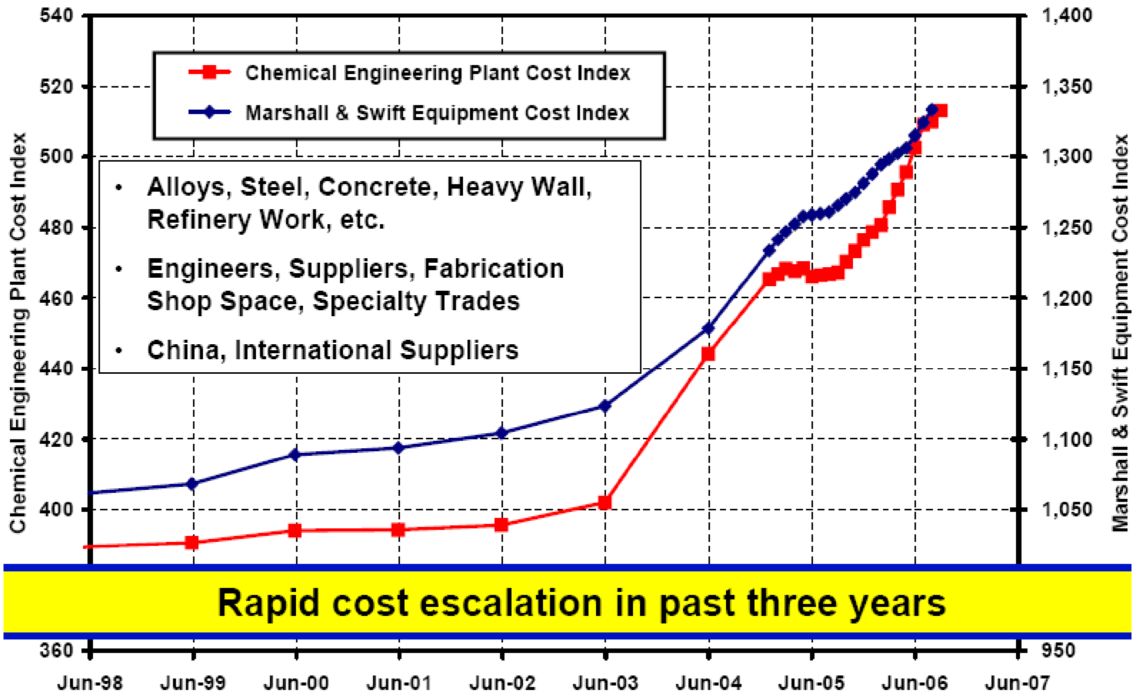

Figure 4. Cost Escalation Indices [10].

2.2 Heat Rates

In general, IGCC and SCPC units are more efficient than PC and FBC; thus, they have lower heat rates. A typical PC or FBC unit might have a heat rate in the 9,500 to 10,000 Btu/kWh range. For more recent technologies, heat rates of 8,700 Btu/kWh for both IGCC and SCPC have been reported [11]. A heat rate of 7,369 Btu/kWh has been reported for the more efficient ultra-supercritical pulverized coal technology[2] [12].

Since all of the proposed carbon capture techniques use a substantial amount of energy (see Section 4), they will significantly increase the heat rate for any unit which employs them. Under such a carbon capture scenario, the IGCC technology would most likely suffer the least amount of efficiency loss due to its relatively higher CO_2 concentration.

[2] Ultra-supercritical pulverized coal units are similar to SCPC units, except they operate at even higher pressures and temperatures. Thus they are more efficient.

3 Fuel Considerations

When considering which clean coal technology to use for any application, it is important to take into account the characteristics of the coal that will be used in the technology. The quality of fuel that is used will have a direct effect on the operating cost as well as the capital cost. Moisture content, ash fusion temperature and content, sulfur content, and heating value of the coal all have significant influences on plant design. This section discusses some of the fuel considerations for different clean coal technologies.

3.1 Pulverized Coal, SCPC, and CFB

The coal properties mentioned above all directly affect a boiler's design. They affect both the heat rate (and hence, the operating costs) of the plant and the size (and hence, the capital costs) of the plant. For example, a low ash softening temperature requires a lower exit gas temperature. This requires a larger heat transfer area in the boiler and increases the size of the boiler [13]. Sub-bituminous coals and lignites generally have low softening temperatures. Also, coals with high ash content will reduce boiler efficiency because extra energy is expended in heating up the ash to the operating temperature of the boiler, reducing the energy available to create steam.

Moisture content in the fuel also decreases the efficiency of the plant for the same reason that ash does. It also affects the combustion reaction to some extent which may result in an additional reduction in the efficiency of the boiler.

Sulfur content in a fuel has a significant impact on boiler design and operation. In a combustion process the sulfur reacts with oxygen to form SO_2 and sulfur trioxide (SO_3). If the downstream temperature of the gas is low enough, the SO_3 forms a sulfuric acid with detrimental effects on the plant equipment. Therefore, the sulfur in the coal affects the minimum allowable gas exit temperature and directly affects the efficiency of the plant since some of the heat energy must leave the plant with the flue gas instead of being transferred to steam [13].

Coal rank or heating value is also critical in the operation of a power plant. For example, in pulverized coal power plants that have switched to low sulfur Powder River Basin coals in order to meet emissions regulations, the plants have been de-rated slightly due to the use of a lower rank coal.

Combustion type coal plants are constrained in the type of fuel they may use. The design parameters (boiler geometry, flue gas temperature, etc.) are usually optimized for a particular type of coal or other type of fuel. Any change in the type of fuel used usually results in a drop in operating efficiency and changes in emissions.

3.2 IGCC

The design and operation of an IGCC system is also dependent on many of the fuel properties mentioned previously but to a lesser extent. Fuel selection is governed by the plant performance decreasing and capital cost increasing as fuel quality decreases (see Figure 5). As in other coal technologies, ash content in an IGCC plant will reduce efficiency because energy is expended to heat the ash up with no benefit in plant production. However, IGCC technology is less concerned with the exit temperature of the product gases from the perspective of the ash fusion temperature (gas exit temperature is important in an IGCC plant for other reasons).

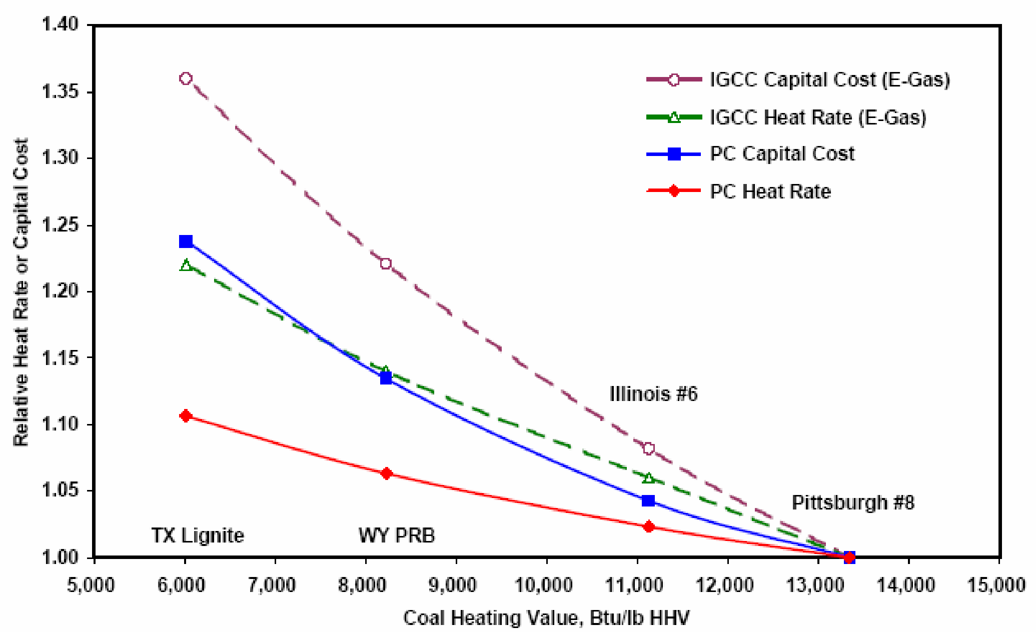

Figure 5. Effect of Coal Quality on Heat Rate and Capital Cost [13]

Moisture in an IGCC plant is also a critical component of efficiency. As the moisture of a fuel increases, the achievable slurry concentration of the feed decreases, which reduces the efficiency of the gasifier. An IGCC plant also requires more energy to evaporate the chemically bound moisture content of a fuel, which further reduces efficiency.

Sulfur content of a fuel in an IGCC plant is less critical because the gas clean-up process produces either elemental sulfur or sulfuric acid. These products are removed from the pre-combustion gases much more easily than the sulfur products from the post-combustion process in boilers, so the capital cost of doing so is much less, and the sulfur by-products of an IGCC plant may be sold to offset costs.

In general the IGCC plant is much less constrained on what type of fuels may be used in the plant by the design of the plant. While it is still true that the operating characteristics of the plant will change based on the fuel, the operating characteristics may actually improve rather than worsen. Thus, IGCC technology is much more flexible in the type of fuel that it may use. This has been demonstrated particularly in the Wabash IGCC plant which switched from using bituminous coal to using petroleum coke with a slight improvement in plant performance and much better operating costs. According to the Wabash IGCC operating team, only a minor operating condition adjustment is needed for switching from bituminous coal to petroleum coke.

4 CO_2 Concentration and Capture

CO_2 can be concentrated and captured using different technologies that will have varying effects on cost and unit efficiency. This section briefly describes some technologies that might play a major role in future power plants. These are: flue gas recycling, chemical solvents, and physical solvents.

4.1 Flue Gas Recycling

Flue gas recycling (Figure 6) is a process in which the CO_2 in the post-combustion products is concentrated (possibly at high pressures) by recycling the flue gas back into the oxygen stream from an air separation plant. Typical concentrations of CO_2 in the product stream are as high as 80-85 percent, which facilitates the capture of CO_2 and reduces the level of all emissions per unit of energy generated.

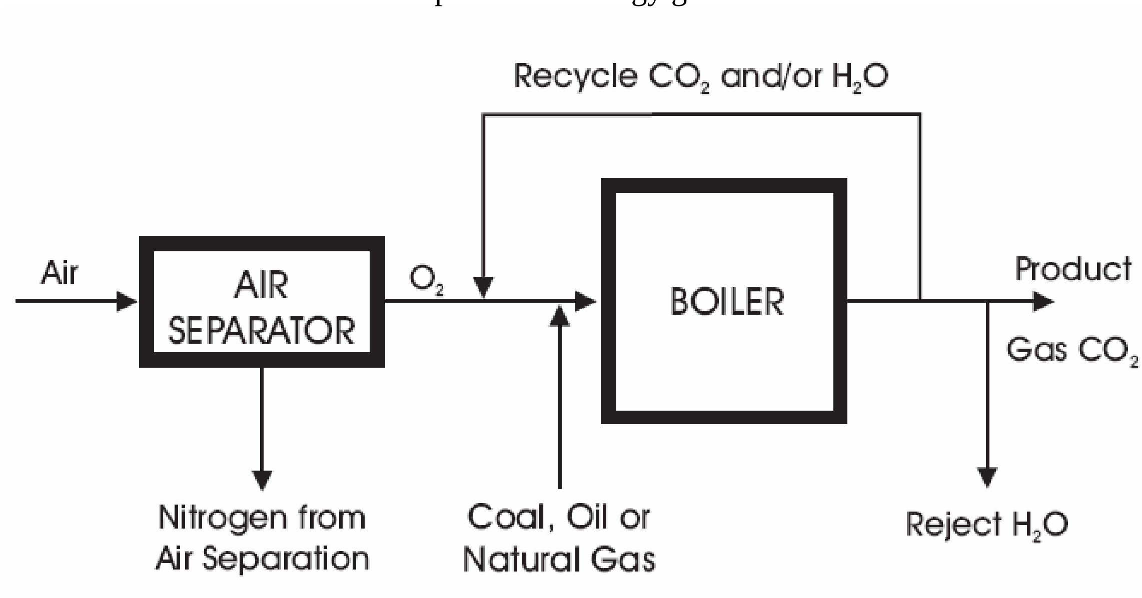

Figure 6. Basic Concept of Flue Gas Recycling in an Oxygen Combustion Plant [3]

4.2 Chemical Solvents

Chemical solvents show promise for use in both PC and IGCC power plants. The majority of chemical solvents are organic based [15]. Chemical solvents are broken down into three categories: primary, secondary, and tertiary. Figure 7 shows a diagram of a chemical based, or amine, process that captures CO_2 from a PC plant with a natural gas unit to compensate for lost power due to CO_2 capture. The flue gas is routed through an absorption column where the amine reacts with the CO_2 thus absorbing it. The CO_2 rich solvent is then taken to the regeneration column where the CO_2 is given off and the amine is reused in the absorption column. Table 2 shows a comparison of the oxygen blown system with a chemical/based system in 2001 dollars.

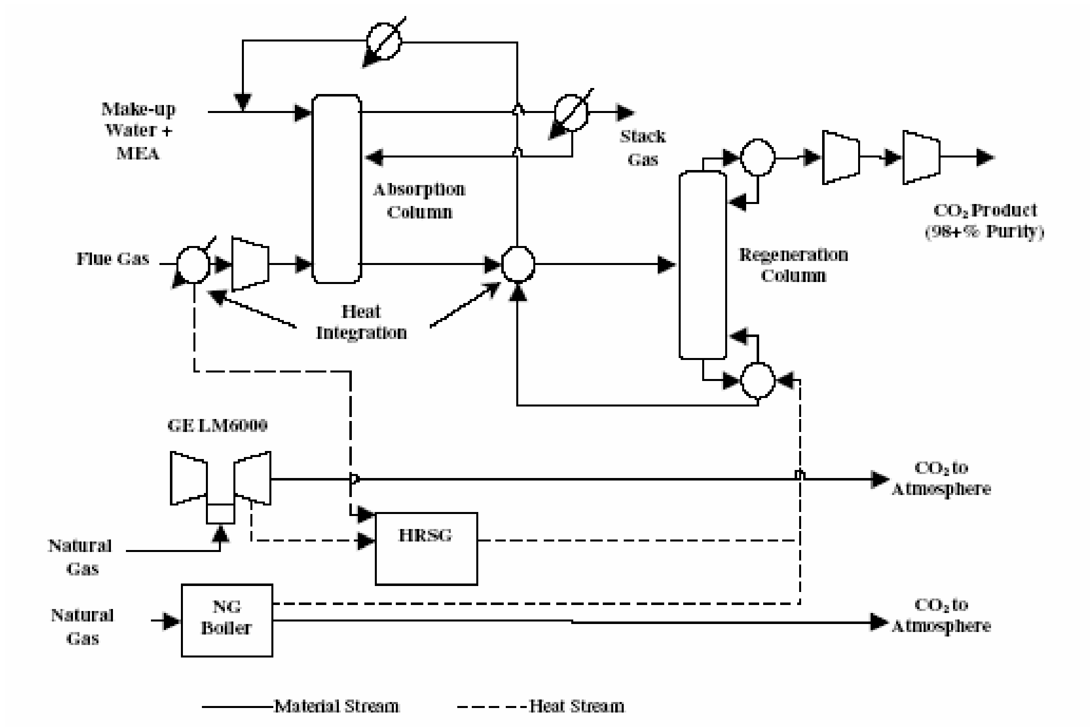

Figure 7. Chemical Based CO_2 Capture [15]

Table 2. Comparison of Costs for a Chemical Based System and an Oxygen-blown System [15]

Comparison of annual costs for O_2/CO_2 and amine scrubbing

	Amine	O_2/CO_2
Capital cost	$294,249,975	$316,292,097
Amortised capital cost ($/year)	$27,775,116	$29,855,736
O&M (4% of capital cost)	$11,769,999	$12,651,684
Cooling water ($0.01/m^3)	$2,869,812	$947,641
Scrubber chemicals (from Fluor study)	$7,000,000	–
MEA make-up ($1.55/ton CO_2 produced)	$6,606,720	–
Operating subtotal ($/year)	$28,246,531	$13,599,325
GT fuel (MMBtu/year)	2,821,824	8,193,997
NB boiler fuel (85% efficiency) (MMBtu/year)	9,742,923	–
ASU NG (MMBtu/year)	–	50,541
Total NG (MMBtu/year)	12,564,747	8,244,538
Annual NG cost ($4.00/MMBtu)	$50,258,989	$32,978,153
Total annual cost	$106,280,636	$76,433,214
Original CO_2 emissions (ton/year)	2,960,000	2,960,000
CO_2 avoided from coal plant (ton/year)	2,664,000	2,664,000
CO_2 emissions from natural gas (ton/year)	740,315	466,701
NET CO_2 avoided (ton/year)	1,923,685	2,197,299
% CO_2 avoided	65%	74%
Capture cost ($/ton CO_2)	$55	$34
Capture cost (¢/kW h)	¢3.3	¢2.4

4.3 Physical Solvents

Unlike chemical solvents, physical solvents are capable of absorbing CO_2 without undergoing a chemical reaction. Physical solvents show great promise in capturing CO_2 from IGCC, because they are ideally suited for high vapor pressure [16]. The basic types of physical solvents are Rectisol, Selexol, Fluor, and NMP-Purisol. The unit creates three separate flows; one of the treated syngas, one of CO_2, and one of hydrogen sulfide gas (H_2S). In regards to IGCCs, the Selexol process is less expensive than Rectisol, but is less efficient, while both technologies are more expensive and more efficient than amine [17]. Table 3 shows a comparison of the Selexol and Rectisol processes. The numbers are based on a chemical plant with a feed rate of 2,593 metric tons per day and Chevron-Texaco Quench Gasifier.

Table 3. Sample Cost Estimates for CO_2 Capture [17]

	Selexol	Rectisol	Selexol	Rectisol
Operating Cost ($ x 1000)	No CO_2 Production		With CO_2 Production	
Annual Fixed Operating Costs	19,430	19,900	19,512	20,174
Annual Utilities & Feed Costs	51,480	52,830	54,785	57,289
Annual Catalyst & Chemical Costs	1,500	1,530	1,840	1,830
Total Annual Operating Costs	72,410	74,260	76,137	79,292
Incremental Annual Fixed Op. Costs	Base	470	82	744
Incremental Annual Utilities & Feed Costs	Base	1,350	3,305	5,809
Incremental Annual Cat. & Chem. Costs	Base	30	340	330
Incremental Total Operating Costs	Base	1,850	3,727	6,882

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List of Acronyms

CFB – Circulating Fluidized Bed
CH_4 – Methane
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
ESPs – Electrostatic Precipitators
FGD – Flue Gas Desulfurization
H_2 - Hydrogen
H_2S – Hydrogen Sulfide Gas
IGCC – Integrated Gasification Combined Cycle
NETL – National Energy Technology Laboratory
NO_x – Nitrogen Oxides
NRRI – National Regulatory Research Institute
PC – Pulverized Coal
SCPC – Supercritical Pulverized Coal
SCR – Selective Catalytic Reduction
SO_2 – Sulfur Dioxide
SO_3 – Sulfur Trioxide
SUFG – State Utility Forecasting Group
SNCR – Selective Non-Catalytic Reduction