Factors that Affect the Design and Implementation of Clean Coal Technologies in Indiana

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Final Report
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Introduction

The interests of the people of Indiana are intimately linked with coal. The state is a major coal producer with large reserves. About 95 percent of electricity produced in this state comes from coal, which is a major reason average state electricity prices are among the nation's lowest [1]. The state's steel industry, which out produces all other states, consumes large quantities of coke derived from coal [2].

Future use of coal in both Indiana and the United States as a whole has the powerful attraction of relatively low cost and high domestic availability. However, currently prevailing technologies make coal a major contributor to air pollution and the risk of global climate change, which has severely limited interest in expanding its use and posed serious financial and other risks to proposed new ventures.

The solution may lie in Clean Coal Technologies (CCT) -- emerging methods for using coal with substantially reduced emissions. The CCT term itself raises considerable controversy because traditional Pulverized Coal (PC) plants are not usually considered clean coal technology, yet their emissions can be substantially reduced at the cost of adding various flue gas cleanup processes and other enhancements. This project will strike a balance by placing special emphasis on Integrated Gasification Combined Cycle (IGCC) technology, which has the promise for near-zero emissions, while also including Supercritical and other pulverized coal enhancements that may be useful in many contexts.

This final report is the last of two to be submitted under the Purdue Energy Research Modeling Groups (PEMRG) scoping study on "Factors that Affect the Design and Implementation of Clean Coal Technologies in Indiana." The study is funded by the Center for Coal Technology Research (CCTR) for the period from March 1 through January 31, 2006.

Working with a variety of expert advisors, Purdue University is leading this investigation of how emerging CCT solutions can be shaped and encouraged within Indiana to best serve the needs of the people of the state. Emphasis is on how CCT technologies could be integrated into new and repowered electricity plants serving the state in order to minimize cost and investment risk from technology and emerging environmental standards, while increasing the environmentally responsible use of Indiana's coal. Other products and byproducts produced along with electricity are also discussed briefly, including fertilizer, CTL (coal to liquids) fuels (e.g., diesel, ethanol), and coal combustion residues.

Project Tasks 1 and 2, which are the topic of the Interim Report, collect in a single source all the relevant considerations in assessing CCT in Indiana. One dimension is properties of the available CCT technologies for both new and repowered electricity plants. Among those are maturity of the technologies, preferred fuels, estimated costs, suitability for scaling and retrofit, pollution removal, reliability/availability, chemical and CTL fuel production, and external R&D funding. The other dimension is the Indiana environment for CCT. Concerns include the available categories of state coal resources, the utility and environmental regulatory climate, possible CO_2 regulation in the future, the available human infrastructure for CCT research and implementation, projected electricity demand growth, the existing power gas and transportation grids, and the legacy boiler population.

The final report summarizes studies on how those technologies and state environmental issues relate and interact to encourage or discourage Indiana use of the various CCT technologies, including their consequences on the use of Indiana coals. Some plausible scenarios for the role of CCT in power generation across the state over the next 10-20 years have been developed and used with other results to inform and focus the analysis required in the two main products of the Final Report: a Public/Private Action Plan to proceed on agreed findings, and a CCTR Research Plan for investigating vital issues for CCT in Indiana about which too little is now known.

Greenhouse gas (GHG) emission regulation, especially carbon dioxide control has explicitly considered in the scenarios because it is a principal consideration that is assessing the appeal of CCT, and because there have been continuing CO_2 proposals in a variety of parts of the United States. For example the California Governor's Executive Order on CO_2 emission control was issued in June 2005 [5], and the agreement on CO_2 emission control was signed by nine Northeastern states [6]. In both cases, CO_2 is frozen initially followed by a reduction. In November, 2005, Senators Lugar and Biden issued a joint initiative stating the intent of the U.S. Senate Foreign Relations Committee to seek "fair and effective" international agreements on controlling green house gasses (available at the websites of Senators Lugar and Biden).

It should be emphasized that the team neither promotes CO_2 regulation, nor advocates a "go-alone" CO_2 policy in Indiana. Rather, the team tries to evaluate the impact of potential CO_2 regulation on the State of Indiana in terms of electricity prices and other consequences including for Indiana coals, and to find the least cost strategies for the state should there be a CO_2 regulation.

A few preliminary scenarios are designed: The table below details the twelve scenarios investigated, including the identifier used for each. They consist of all combinations of four technologies and three CO_2 capture assumptions.

- Three popular CCTs are considered: Circulating Atmospheric Fluidized-Bed Combustion (AFBC), Supercritical PC (or Ultra SCPC) and IGCC in variants with and without a backup gasifier.
- Each of these technologies is run without CO_2 capture, with CO_2 capture on new baseload capacity after 2010, and with CO_2 capture on 150% of new baseload capacity after 2010 to simulate repowering.
- The Pulverized Coal scenario without CO_2 capture (bold) serves as a base case.

	No CO_2	CO_2 Recovery on New Baseload Required	CO_2 Recovery on 150% of New Baseload Required
Super Critical Pulverized Coal	**PC no CO_2**	PC CO_2	PC CO_2+50
IGCC with No Backup	IGnobk no CO_2	IGnobk CO2	IGnobk CO2+50
IGCC with Backup	IGbk no CO_2	IGbk CO_2	IGbk CO_2+50
Atmospheric Fluidize Bed Combustions	FB no CO_2	FB CO_2	FB CO_2+50

Results and conclusions of both the scenario analysis and the recommended action plans can be found in parts 3 and 4 of the report. The major results are summarized as follows: (1) When CO_2 capture is not required, SCPC may be the preferred technology for new baseload capacity, with an average electricity price around \$0.048/kWh by 2023 (2003 \$). If however capture is required and SCPC is again used, the price is about \$0.0528/kWh (see Table 3.05), with a percentage price change of about 11%. However, when IGCC is used instead SCPC for the new baseload capacity with CO_2 capture, the percentage change in price is about 9%, indicating that IGCC may be the preferred technology for CO_2 capture. (2) When 150% of new SCPC capacity is assumed with CO_2 capture, the state average price becomes \$0.0563/kWh by 2023, and the percentage change is about 18%. If IGCCs are used for coping with CO_2 capture for the 150% new baseload capacity, compared against the base case of SCPC without CO_2, the percentage price increase is 16% by 2023, which shows that price increase in 2023 is about 2% less with IGCCs than with SCPCs. (3) When IGCC is used for new baseload capacity, starting from 2011, CO_2 releases are reduced a bit for the first few years and then flattened out until 2023. This is because IGCC power plants have lower heat rates than the SCPC counterparts and consume less coal in power production (see Figure 3.03). Notice that the price changes reflect only generation capacity expansion with CO_2 capture, CO_2 transportation, storage, and monitoring, as well as the possible transmission line additions for power, have not been considered. Further studies are needed for quantifying CO_2 sequestration costs for the state.

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Dimension One:
Clean Coal Technology Options

1.01 Clean Coal Technology Overview

This section gives a general description of some of the competing technologies that may shape the future of coal utilization. Although traditional pulverized coal plants are generally not considered clean coal technologies, it is discussed in this section because of its historical value and, when proper post-combustion clean up is used on a pulverized coal plant, they may be considered clean. The clean coal technologies that will be discussed include flue gas recycling, supercritical pulverized coal (SCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). Although the list is not exhaustive it represents the technologies that are most likely to take the lead in forging a successful charge to the coal utilization of tomorrow.

A. Pulverized Coal

A simplified diagram of a pulverized coal power plant is shown in Figure 1.01a. Pulverized coal power plants have been around for many decades and have become the backbone of the electrical power industry in the United States. In a pulverized coal power 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 which 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 (the Rankine cycle) starts over again. Many different types of coal may be used in a pulverized coal system, but the complexity and price increases substantially for systems designed to burn multiple types of coal [1].

Historically, pulverized coal power plants have been justifiably maligned for poor environmental performance. Coal used in a pulverized coal plant must be cleaned of most of the sulfur compounds and ash before being burned in a boiler. Even then, they produce substantial amounts of sulfur dioxides and nitrous oxides, the principle culprits of acid rain. With increasing legislation on such emissions, pulverized coal power plants have been forced to use low sulfur, low heating value coals from the Powder River Basin in order to meet governmental regulations, or use costly post combustion technologies to reduce emissions.

Post combustion gas clean-up in pulverized coal 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 (ESP's) or bag filters, SO_2 is controlled by the addition of a flue gas desulpherizer (FGD) or spray dry scrubber, and NOx emissions can be reduced through the use of selective catalytic reduction (SCR). For plants with low residual value low cost options such as selective non-catalytic reduction (SNCR) may be used.

With CO_2 legislation looming on the distant horizon many have speculated that the cost of pulverized coal plants will be too large with the addition of CO_2 capture equipment (amine scrubbers). There are other technologies that may be added to pulverized coal technologies that can make them quite cost competitive for CO_2 capture (e.g., oxygen firing). 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 which would be required to be cleaned. Since the CO_2 concentration is low and the tail gas volume is huge, it would be costly to capture CO_2 from such tail gas.

B. Flue Gas Recycling

Flue gas recycling (Figure 1.01b) 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 easier capture of CO_2 and reduces the level of all emissions per unit energy generated.

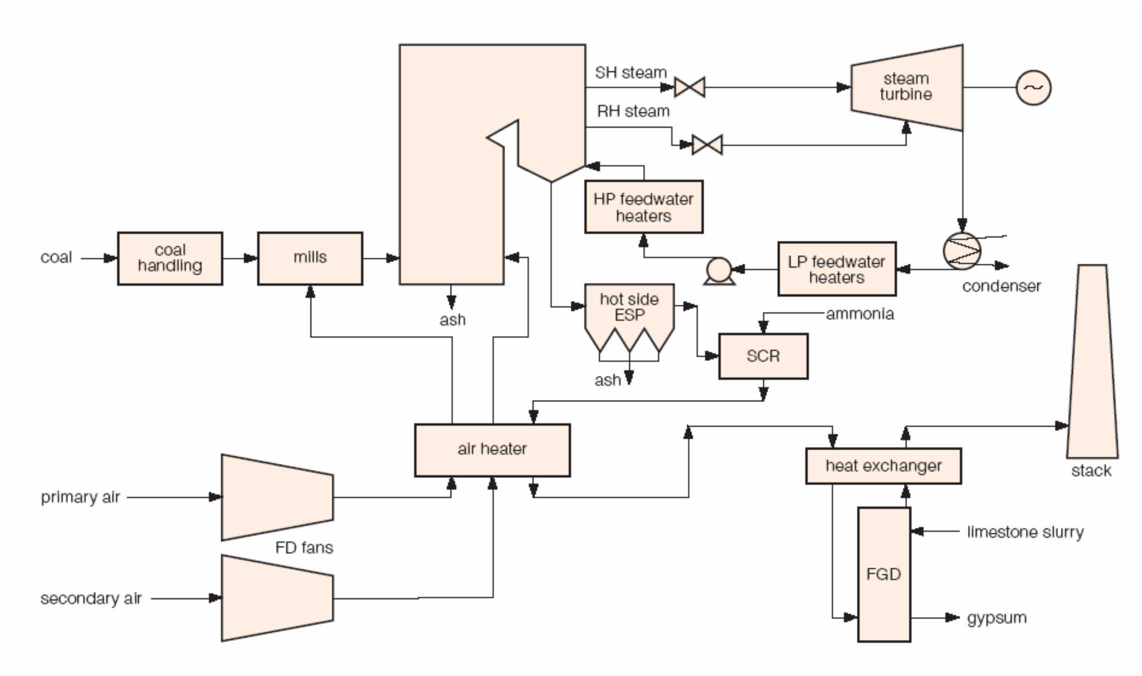

Figure 1.01a. Pulverized Coal Power Plant [2]

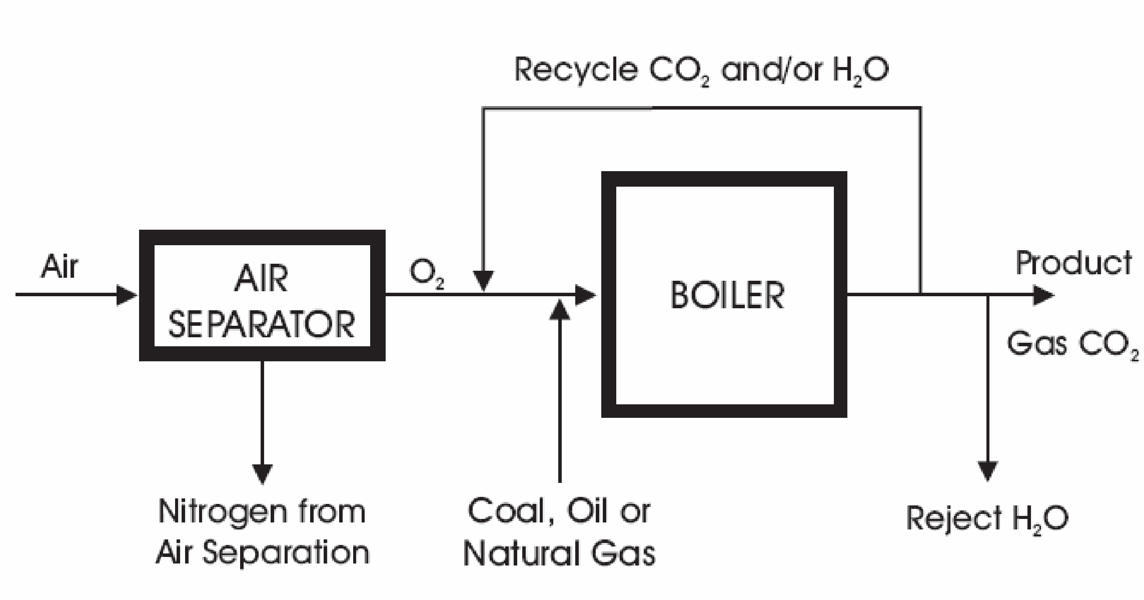

Figure 1.01b. Basic concept of flue gas recycling in an oxygen combustion plant [3]

C. Supercritical Pulverized Coal

Although pulverized coal plants have been around for some time, there have been some recent advances in materials and technologies to the point where some considerable improvements have been made. Supercritical pulverized coal plants are essentially the same as pulverized coal plants, but they operate at much higher temperatures and pressures. This makes it possible to have higher efficiencies and lower emissions per unit of energy produced. The diagram for a basic supercritical pulverized coal plant is the same as that of a subcritical pulverized coal plant and is given in Figure 1.01a. Substantial improvements in emissions are limited due to the fact that supercritical technology is essentially the same as subcritical pulverized coal.

D. Circulating Fluidized Bed

In a circulating fluidized bed (1.01c), crushed coal, and limestone or dolomite (for SO_2 capture) are fed into a bed of ash and coal particles and made highly mobile by a relatively high velocity stream of preheated air. The air is normally fed into the combustor at two levels to control combustion and minimize NOx 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 for low quality 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 an increased capital and operating cost.

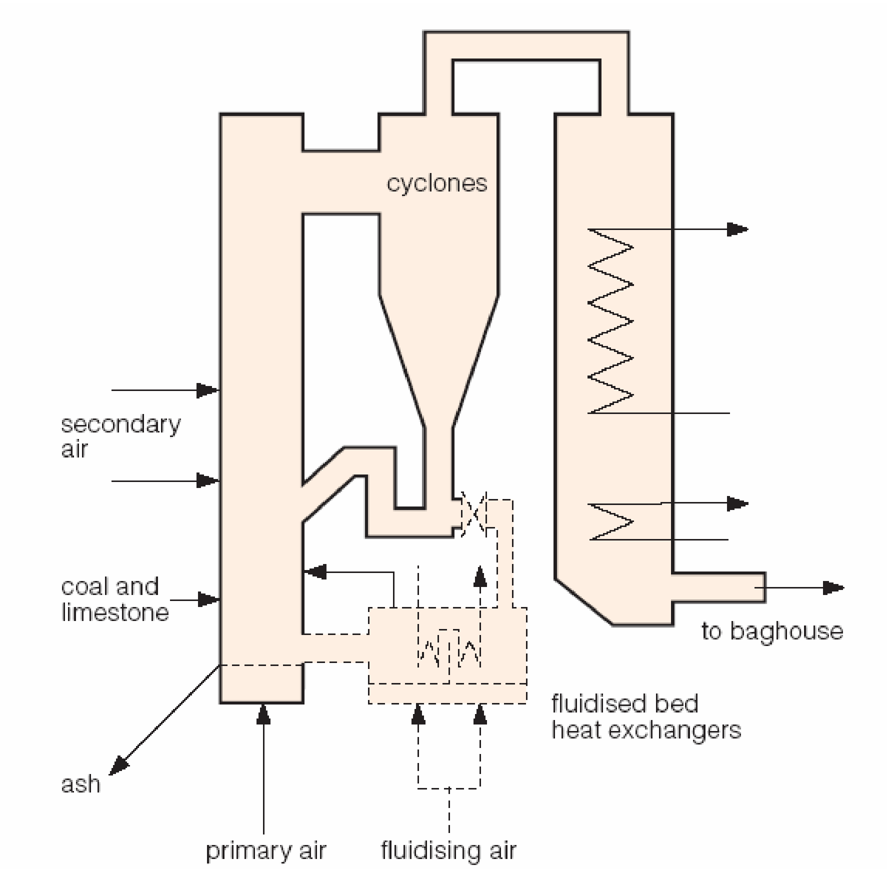

Figure 1.01c. Diagram of a circulating fluidized bed combustor. Taken from [4]

E. Integrated Gasification Combined Cycle Systems

This type of coal plant differs drastically from the combustion technologies mentioned above. A block diagram of the system is shown in Figure 1.01d. In this type of configuration the coal is chemically reacted with steam at high temperatures to produce a combustible gas. The main reactions occur at different extents and at different rates depending on temperature and pressure as well as location in the gasifier. In general the reactions are as follows:

$$C(s)+\frac{1}{2}O_2 \rightarrow CO;\ \Delta\text{H} = \text{-123.1 kJ/mol (rapid)} \tag{1}$$

$$C(s)+O_2 \rightarrow CO_2;\ \Delta\text{H} = \text{-405.9 kJ/mol (rapid)} \tag{2}$$

$$C(s)+H_2O(g) \rightarrow H_2+CO;\ \Delta\text{H} = \text{118.9 kJ/mol (medium)} \tag{3}$$

$$C(s)+2H_2O(g) \rightarrow 2H_2+CO_2;\ \Delta\text{H} = \text{78.0 kJ/mol (medium)} \tag{4}$$

$$C(s) + 2H_2 \rightarrow CH_4; \;\; \Delta\text{H} = \text{-87.4 kJ/mol (slow)} \tag{5}$$

$$C(s) + CO_2 \rightarrow 2CO; \;\; \Delta\text{H} = \text{78.3 kJ/mol (medium)} \tag{6}$$

$$CO + H_2O(g) \leftrightarrow H_2 + CO_2; \;\; \Delta\text{H} = \text{-40.9 kJ/mol (rapid)} \tag{7}$$

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O; \;\; \Delta\text{H} = \text{-206.3 kJ/mol (slow)} \tag{8}$$

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O; \;\; \Delta\text{H} = \text{-165.4 kJ/mol (slow)} \tag{9}$$

Reactions (1) and (2) represent a partial combustion of the coal as it enters a gasifier. This is necessary to provide enough heat to drive reactions (3), (4), and (6). There are some gasifiers which provide the heat for the gasification reactions indirectly, but they are rather complex and will not be considered in this report. Methane formation (reactions (5), (8), and (9)) varies with gasifier technology (discussed below) and is favored at lower temperatures and higher pressures.

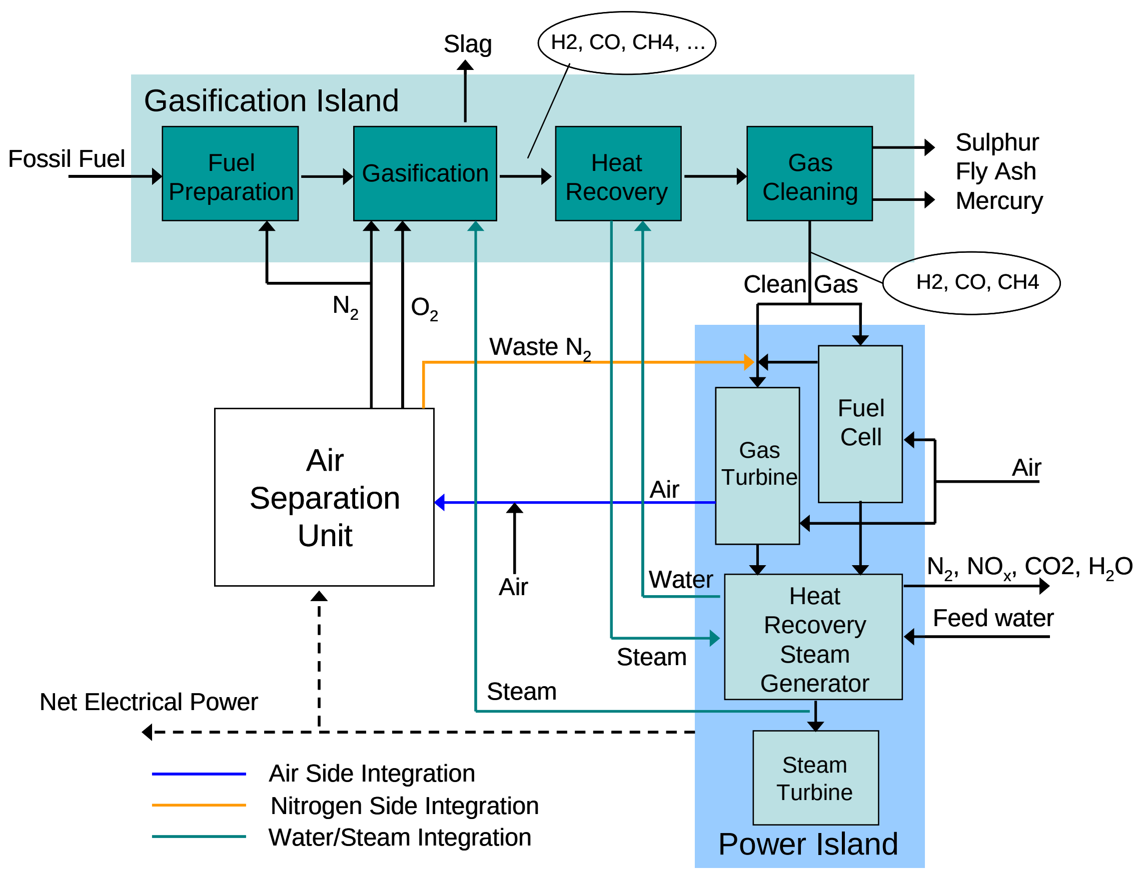

Figure 1.01d. Block diagram of an IGCC power plant.

Since a combustible gas is produced from the process instead of steam the thermodynamic cycle is completely different for the power generation portion of an

IGCC plant. The gas produced (mainly CO and H_2) may be cleaned up pre-combustion (similar to natural gas clean up) and combusted in a gas turbine (Brayton Cycle) to drive a generator and produce electricity. Also, since the post-combustion gases exiting the turbine are still at a high temperature, they may be used to produce steam for a Rankine cycle and produce more electricity. This is known as a combined cycle and the attainable thermodynamic efficiency is much greater than with a Rankine cycle on its own.

The fact that the gases may be cleaned pre-combustion is an important aspect of IGCC systems. This allows for NOx and SO_2 controls that are less expensive than post-combustion controls. Also, since the CO_2 is relatively concentrated it allows for a much simpler CO_2 separation.

There are three main types of gasifiers that are used in most IGCC plants. They are classified by the residence time of the coal in the gasifier. The first is known as a moving bed gasifier, the second is the fluidized bed gasifier, and the third is called an entrained flow gasifier.

F. Moving Bed

This type of gasifier is also known as a fixed bed gasifier. A picture of a common moving bed gasifier is shown in Figure 1.01e along with temperature profiles of the coal and product gases. In this type of a configuration the coal is fed into the gasifier through a lock hopper and sits in a pile at the bottom of the gasifier. Oxygen and steam are fed into the bottom of the gasifier and as they rise they form the gases according to reactions (1)-(9). Since the coal on the bottom is first to be oxidized and gasified it rises through the solids above it, heating them up and allowing new solids to take its place. The coal particles are generally larger and the residence time and reaction rate of the coal are generally long which limits the capacity of these types of gasifiers. Since the product gas cools as it warms the upper layer solids, this type of gasifier tends to produce more methane. The cooler product gases are also ideal for cold gas clean up which is simpler than a hot gas clean-up.

G. Fluidized Bed

In a fluidized bed (FB) gasifier the coal particle size is relatively fine and the air and steam are passed up through the coal bed with sufficient velocity to fluidize the solids bed. This increases solids gas contact and reaction rates occur at a more rapid rate than in a moving bed gasifier, decreasing residence time and increasing throughput. Since the high velocity gases will inevitably carry some solids with it, a cyclone arrangement must be used to separate the solids from the product gases and feed them back into the gasifier. This adds somewhat to the complexity of the system. Since the product gases are at a higher temperature, they must be cooled for cold gas clean-up which causes somewhat of an efficiency penalty. A representation of a fluidized bed gasifier is shown in Figure 1.01f along with temperature profiles of the gas and solids. A similar type of the FB gasifier is the KBR transport gasifier that was developed by the Kellog Brown and Root, Inc. (KBR), and has been in test operation in the Power Systems Development Facility jointly funded by DOE (Department of Energy), Southern Company, EPRI (Electric Power Research Institute), KBR, Siemens-Westinghouse and Peabody Holding Company. It is claimed that this type of gasifier is easy to maintain and may reduce O&M costs, even though the final test results are yet to be available [30].

H. Entrained Flow

In an entrained flow (EF) gasifier the coal particle diameter is very small. The solids are fed into the gasifier with a high velocity stream of air and/or steam. Residence time is very short and temperatures are quite high. As with the fluidized bed gasifier the gas must be cooled before clean-up at a significant efficiency penalty. This is usually done through a heat exchanger to produce more steam for the Rankine cycle. A picture of an entrained flow gasifier with accompanying temperature profiles is shown in Figure 1.01g.

The EF gasifiers have been used extensively in IGCC plants due to its large throughput. There are several versions of the EF gasifier in operation, including the E-Gas gasifier used in the Wabash River Repowering IGCC project and the GE-Quench gasifier. The existing EF gasifiers operate at a temperature range around 1,300 degrees centigrade and can be as high as 2,000 degrees in the combustion zone of the gasifier.

Recently, a new type of EF gasifier called the Rocketdyne gasifier has been under design and test by the Pratt & Whitney company [31]. The major design features are illustrated below in Figure 1.01h, which claims a 90 percent reduction in size, a 14.5 percent reduction in capital cost ($1297/kW vs. $1517/kW), and a 18.5 percent reduction in cost of electricity (COE) compared with current EF gasifiers. At the same time, the target design availability is 94 percent, considerably higher than existing IGCCs. The gasifier can operate at very high pressures (up to 1,500 psia) and very high temperatures (up to 5,000 degrees F). This type of gasifier may offer a great promise for IGCC in the future.

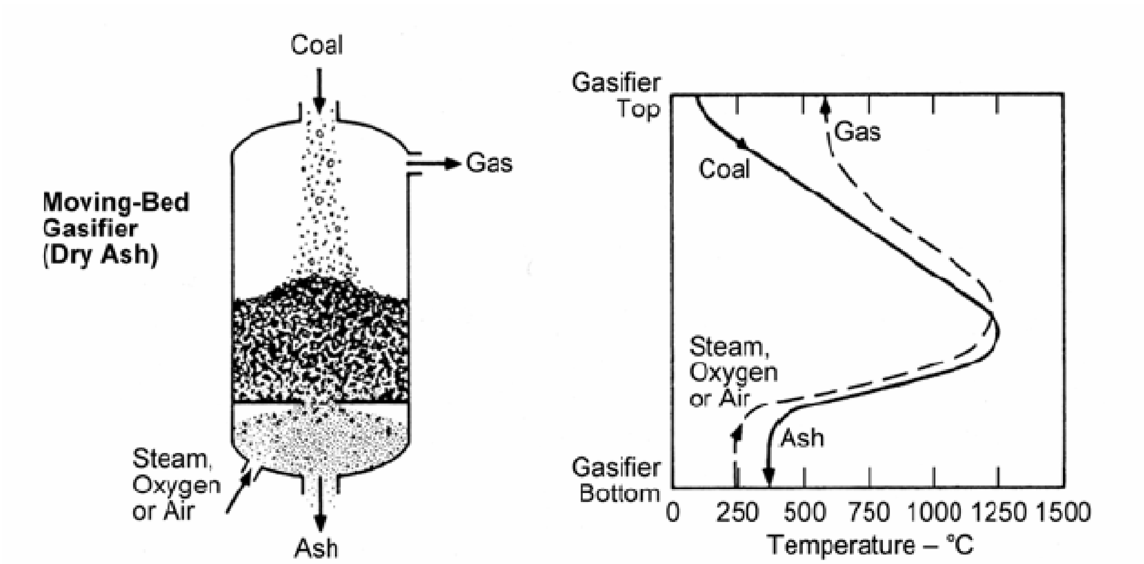

Figure 1.01e. Moving (Fixed) bed gasifier and temperature profiles [5]

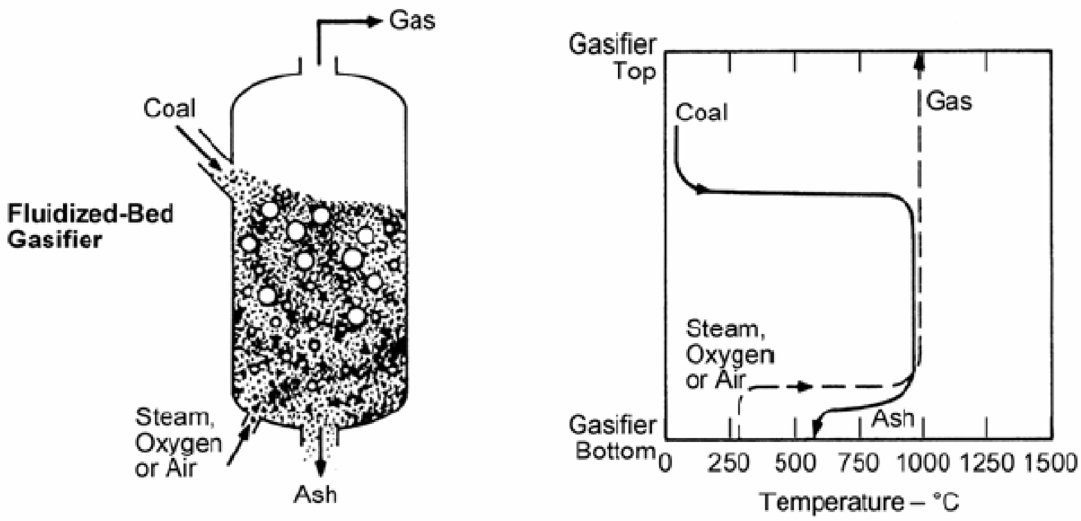

Figure 1.01f. Fluidized bed gasifier and temperature profiles [5].

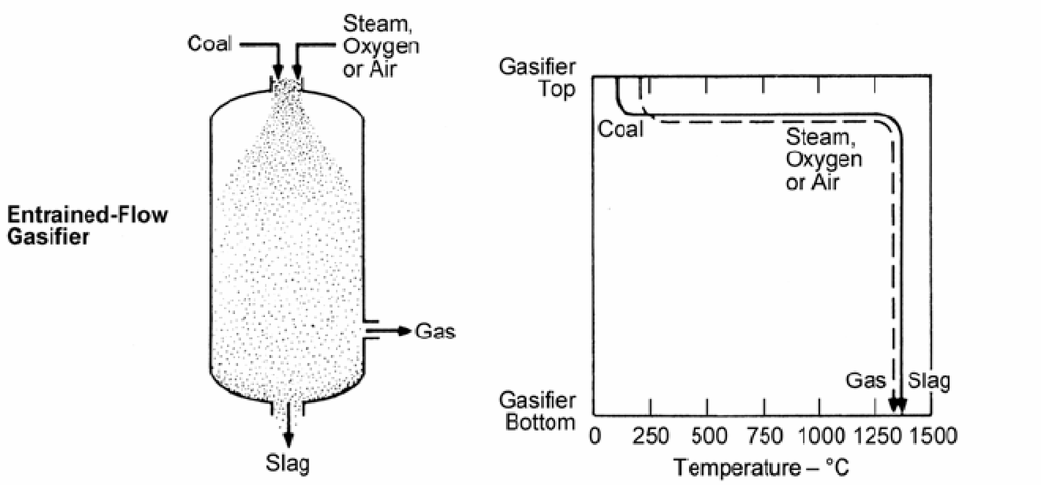

Figure 1.01g. Entrained flow gasifier and temperature profiles [5]

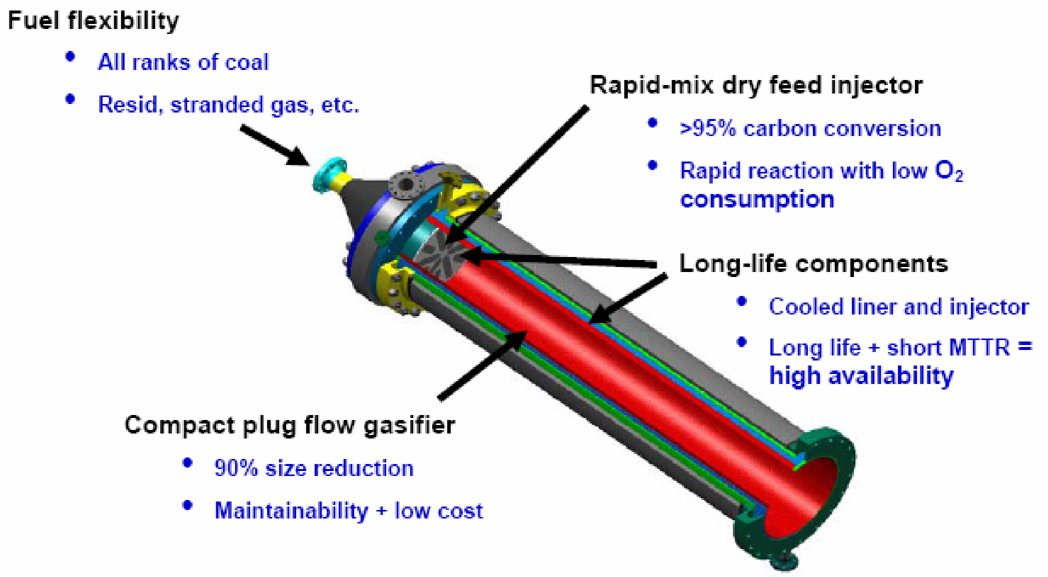

Figure 101h. The design feature of the Rocketdyne gasifier (MTTR = Mean time to repair. Source: [31])

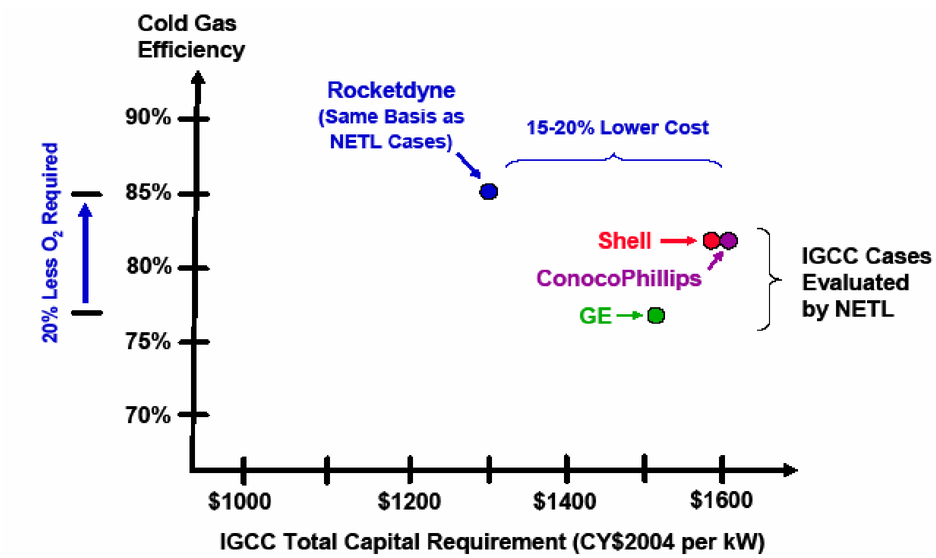

Figure 1.01i. Comparison of capital costs between Rocketdyne and some other EF gasifiers [31]

1.02 IGCC Maturity and Prior Experience

The first IGCC power plant in the world was tested in Germany in the 1970s [6]. The first IGCC power plant in the United States was in operation in Southern California in the 1980s [6]. Today, there are at least five IGCC plants in operation or testing with power as sole output or co-product in the United States (see [7] and [8]), of the five, the Wabash

River Repowering Project is the first modern IGCC plant that has been in commercial operation intermittently since late 1995.

There are many IGCC power plants around the world [7]. More are under planning, pre-development or construction. In addition, IGCC has been considered for co-production of chemicals (e.g., ammonia based fertilizers), clean CTL diesel fuels, and many other products [7].

People have mixed opinions on IGCC. Some think that IGCC power plant technology is relatively mature, while some others think it unproven. Enough experience has been gained with the chemical processes of gasification, coal properties and their impact on IGCC design, efficiency, economics, etc. However, system reliability is still relatively lower than conventional coal-based power plants (pulverized coal (PC) plants) and the major reliability problem is from the gasification section. There are problems with the integration between gasification and power production as well. For example, if there is a problem with gas cleaning, uncleaned gas can cause various damages to the gas turbine. Syngas turbines can also have reliability problems. There are several areas that can make the technology more mature: gasifiers' ability to withstand high temperature, high pressure, and high sulfur coals; hot gas cleaning with high reliability; extending the life of gas cleaning filters, etc.

Even though not entirely mature, IGCC is the cleanest technology so far and it has been considered the most favorable technology for CO_2 capture. However, there has been no actual demonstration in this area in the United States, except some ongoing research programs. One such program is the EPRI "Destination 2004" to research and demonstrate IGCC designs and CO_2 capture efficiency [9], with a target completion around 2012. DOE has been sponsoring CO_2 sequestration research since the mid-90s (see [7], [8] and DOE website at http://www.doe/gov/), and has expressed an interest in the use of the Tampa IGCC power plant for demonstrating CO_2 sequestration.

Supercritical (SC) and ultra supercritical (USC) PC plants may also be ready for CO_2 capture. Some claimed that the USC PC is already a CO_2-ready technology [10]. However, the technology is again not demonstrated.

Table 1.02 illustrates the time when the IGCC power plants were first in operation. Some plants such as the Tampa IGCC and the Wabash River IGCC have been in commercial operation for about 10 years, while others are still under various tests. Note the modified Wabash River IGCC plant, a copy of the project with some minor modifications was moved to the South and produced power for a refinery plant since 2000.

The USC-PC technology has a long history (almost 50 years). According to the Babcock & Wilcox company, it designed the worlds first USC-PC in 1957 for the American Electric Power in Ohio [11]. No doubt that the SCPC technology has a longer history even though we do not know which one was the first SCPC plant in the world. Both the SC and USC PC technologies are mature in many aspects because of their extensive application and history. However, they are still under research and development for meeting new emission standards, of which CO_2 control is a focal point.

In short, SCPC and USC-PC have a longer history than IGCC and are more mature than IGCC. However, IGCC also has a relatively long history of commercial operation since the mid-90s, and the IGCC history can even be traced back to the 1970s when the then West Germany constructed the first IGCC power plant in the world. Neither of the technologies can be considered "mature" in CO_2 sequestration was considered because none of them have been commercially tested for CO_2 sequestration

Table 1.02. Timeline of Some IGCC and PC Power Plants

Technology	Location or name	Operation year	Capacity (net)	Comments
Entrained flow	1. Wabash, IN 2. Wabash-I, LA 3. Tampa, FL 4. Mesaba, MN 5. So. Ill. Clean Energy Center, IL	Dec. 1995 Mid-2000 Oct. 1996 2010 target n/a	262 MW 395.8 MW 250 MW 531 MW 615 MW	In operation In operation In operation Under design Under design
Fluidized bed	1. Pinon Pine, NV 2. Orlando, FL	1998 (KRW) n/a (KBR) [30]	99 MW 240 MW	Test operation Under design
Fixed bed	EKPC, KY	n/a	540 MW	Test operation
Supercritical SC - PC	n/a	n/a	n/a	Much earlier than 1957
USC-PC	Philo, AEP, OH	1957	125 MW	First in world, Babcock design

1.03 Fuel Considerations

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

A. Pulverized Coal, SCPC, and CFB

The coal properties mentioned above all directly affect a boiler's design. They affect both the heat rate (operating costs) of the plant and the size (capital costs) of the plant. For example, a low ash softening temperature requires a lower exit gas temperature so that slagging of the convective pass does not occur. 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 and 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 reduce the efficiency of the boiler even more.

Sulfur content in a fuel has a huge impact on boiler design and operation. In a combustion process the sulfur reacts with the oxygen to form SO_2 and 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 for the operation of the Rankine cycle [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 been forced to switch to low sulfur Powder River Basin coals in order to meet emissions regulations, the plants have been derated slightly due to the use of a lower rank coal.

Combustion type coal plants are constrained in what type of fuel they may use. Once they have been designed for a particular type of coal or other type of fuel, it must generally use that type of fuel. Any change in the type of fuel used usually results in a severe drop in operating efficiency and changes in emissions.

B. IGCC

The design and operation of an IGCC system is also dependent on many of the fuel properties mention above but to a lesser extent than combustion based technologies. Fuel selection is governed by the fact that plant performance decreases and capital cost increases as fuel quality decreases (see Figure 1.03). 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 about 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).

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 and hence the efficiency of the gasifier decreases. An IGCC plant also requires more energy to evaporate the chemically bound moisture content of a fuel and 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 easier 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. This means that IGCC technology is much more flexible in the type of fuel that it may use. The fact that sulfur content of the fuel is of little concern has expanded fuel selection even more. This has been demonstrated particularly in the Wabash IGCC plant which switched from using bituminous coal to using petcoke with a slight improvement in plant performance and much better operating costs. According to the Wabash IGCC operating team, only minor operating condition adjustment is needed for switching from bituminous coal to petcoke.

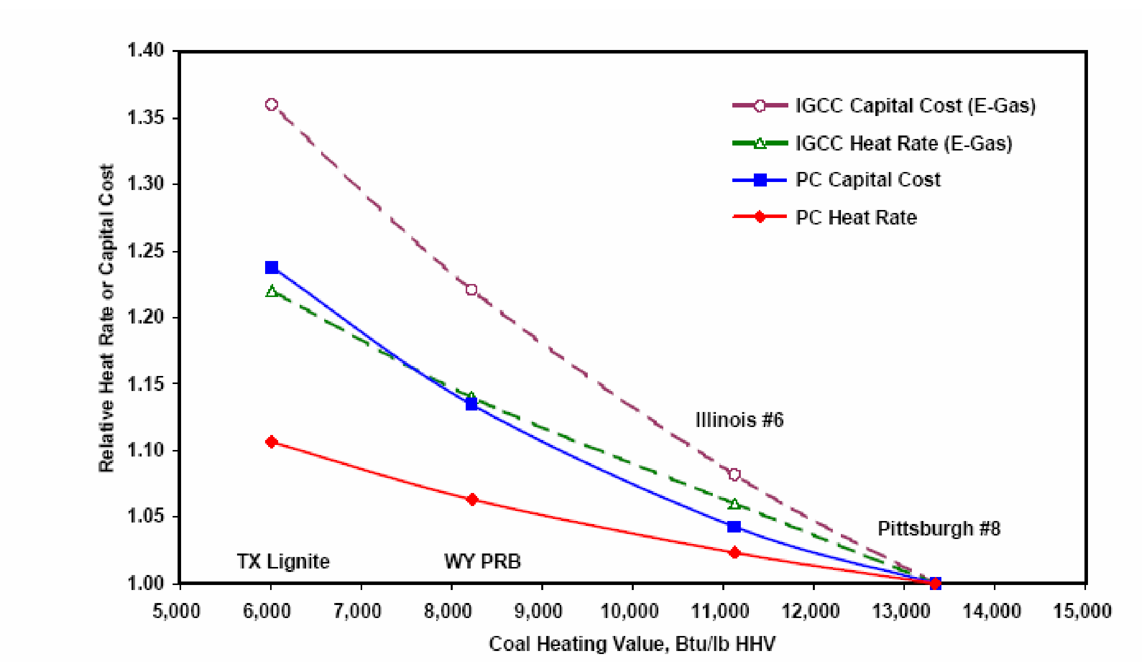

Figure 1.03. Effect of coal quality on heat rate and capital cost [13]

Promoting Indiana Coal

As was previously mentioned, Indiana coal is a bituminous high sulfur coal. This seems to suggest that the logical technology of choice for Indiana coals is the IGCC technology. While this may be true technologically, it is also possible that the use of IGCC technology could reduce the usage of Indiana coals because of the inherent fuel flexibility of the IGCC technology. On the other hand new power plant construction in the form of combustion based technologies provides a stable utilization of Indiana coals if the power plants are designed for Indiana coal.

For mid to small sized power plants that are non-compliant, PC with proper clean up, SCPC, and CFB are attractive options. Not only are the plants likely already designed to operate on Indiana coals, but the capital cost of adding combustion based technology instead of gasification is much smaller and attractive to attain compliance, except for the case of greenhouse gas sequestration.

1.04 Estimated Costs and Efficiencies

The capital costs and efficiencies of the existing IGCC power plants in the U.S. will be listed first, and then some estimated costs and efficiencies of the future IGCC, SCPC and USC-PC power plants will be illustrated.

A. Capital Costs

Table 1.04a lists the capital costs of the existing IGCC power plants and the DOE cost sharing. As can be seen, the DOE share has been declining with time. This indicates that as the technology matures, the U.S. federal assistance will generally be less. The two IGCC projects under design (i.e., the Mebasa project and the Southern Illinois Clean Energy Center) have not been considered for assistance from DOE [7]-[8].

Table 1.04b lists the efficiencies of the existing IGCC power plants in the U.S. The data is incomplete for the EKPC (East Kentucky Power Coop.) project in Kentucky since the project is still under test operation. The efficiency data of the Pinon Pine project is "projected" since the test data is not available [12].

Table 1.04a. Capital Costs of Existing IGCC Power Plants in the United States

Technology	*Location or name*	*Total cost*	*Unit cost*	*DOE share*	*Comments*
Entrained flow	1. Wabash, IN 2. Wabash-I, LA 3. Tampa, FL	\$438.2 million \$993.2 million \$412.5 million	\$1672.5/kW \$2509/kW \$1650/kW	50% 0 50%	Mid 90 dollar Multi-products Mid 90 dollar
Fluidized bed	1. Pinon Pine, NV 2. Orlando	\$335.9 million n/a	\$3393/kW	50% \$ 235 m	Late 90 dollar 2004
Fixed bed	EKPC, KY	\$432 million	\$ 800/kW	18%	Cost not final

Table 1.04b. Efficiencies of the Existing IGCC Power Plants in the United States

Technology	*Location or name*	*Heat rate (Btu/kWh)*	*Efficiency (%)*	*Comments*
Entrained flow	1. Wabash, IN 2. Wabash-I, LA 3. Tampa, FL	8,900 Similar to above 9,000	38.4 38	
Fluidized bed	Pinon Pine, NV	7,800	43.7	Need more test
Fixed bed	EKPC, KY	8560	40	Need more test

It is very complicated to estimate the costs and efficiencies. The cost estimates involve many factors and assumptions such as cost of capital, tax rate, depreciation scheme, and so forth. That is why we see so many different estimates. Table 1.04c illustrates some cost and efficiency estimates from various sources. It could be inferred that the greater the capacity, the less the capital costs from this table. However, inference this can be misleading because the estimates were not consistently done within one organization with the same assumptions. Notice that the estimates are for near term, say the next 10 years. The longer time capital costs should be less due to technology progress (for example, DOE set a target capital cost of less than \$1000/kW for IGCC plants). In the table, heat rate is measured in Btu/kWh and the number can be converted to percent efficiency.

Table 1.04d illustrates some cost estimates for SCPC and USC-PC. Notice that the above estimates often assume high grade coals such as the Pittsburg # 8 coal. According to [13], if the Illinois # 6 coal is used, the capital costs for Sub-PC, USC-PC and IGCC with spare are \$1290, 1340 and 1440 per kW respectively (about \$90/kW higher), without CO_2 capture.

Table 1.04c. Sample Capital Cost and Efficiency Estimates for IGCC (near future)

Technology	Whose estimate	Capacity (MW)	CO_2 capture	Unit cost	Book life/ Heat rate	Backup gasifier	Comments
Entrained flow	1. Bechtel [7], [8]	1,000 (E-Gas)	No	\$1099/kW	20/8800	no	2002 dollar
	2. EPRI [12], [5]	520 (E-Gas)	No	\$1350/kW	20/8630	2 on 1	34% tax rate, 70% debt ratio, Pittsburg #8 coal (P#8)
			Yes	\$1900/kW	20/11000	2 on 1	
	3. Flour [14]	1073	No	\$1111/kW	n/a/8997	3 on 1	
	4. Harvard [15]	n/a	No	\$1400/kW	n/a/8700	n/a	< \$1000/kW w/ 3Party financing
	5. DOE	n/a	No	\$1300/kW	n/a/8800	n/a	Based on the Tampa IGCC
Fluidized bed or fixed bed							No estimate yet

Notes: The EPRI IGCC estimate is for the E-Gas type of gasifier. The IGCC capital cost is lower if the GE-Quench gasifier is used according to EPRI. There are many more estimates, including the Parsons study, which gives a much lower cost estimate [32].

Table 1.04d. Capital Cost and Efficiency Estimates for SC/USC-PC Plants (near future)

Technology	Whose estimate	Capacity (MW)	CO_2 capture	Unit cost	Book life/ Heat rate		Comments
SC or USC	1. Bechtel [16], [17]	800 (SC) 600 (SC)	No	$1100kW	20/9300		2002 dollar
			Yes	$1950/kW	20/12560		
	2. EPRI [13], [5]	600 (USC)	No	$1235/kW	20/8650		34% tax rate, 0.7 debt ratio, P#8
			Yes	$2150/kW	20/11300		Same as above
	3. Siemens [10]	600(USC)	No	$1000/kW	20/7369 or (46%)		Reference plant under design
	4. Harvard [15]	n/a (SC)	No	$1200/kW	?/8700		No need for 3Party financing
	5. DOE *	n/a	No	$1200/kW	?/8800		Based on the Tampa IGCC

* Note that DOE has provided various SCPC capital cost estimates that can be range from $1,000 to 1,400/kW. However, the costs will decline over time according to DOE.

B. CO_2 Sequestration

CO_2 capture can be done using different technologies which will affect sequestration costs. As the possibility for carbon dioxide limits increases, it is important to examine some of the promising technologies that may become necessary in the future. We will briefly describe three different technologies that might play a major role in future power plants. These are: pure oxygen combustion for PC plants, chemical solvents, and physical solvents. It should be noted that there are many more technologies available that may also be evaluated in the second stage of this research.

Oxygen Blown

An oxygen blown (also known as oxy-fuel or O_2/CO_2) system increases the concentration of CO_2 by using pure oxygen instead of air for combustion in PC power plants. By using pure oxygen for combustion the concentration of CO_2 can be increased from 13-15% (wet basis) to 80-90 percent (Dry Basis) [34]. The diagram below shows a model of an oxygen blown system with a natural gas unit to compensate for lost power due to CO_2 capture. The process starts with an ASU (air separation unit) which produces the oxygen that will be used in the boiler of the coal plant. After combustion, the flue gas goes to a LTF (low temperature flash) unit that further increases the concentration of CO_2.

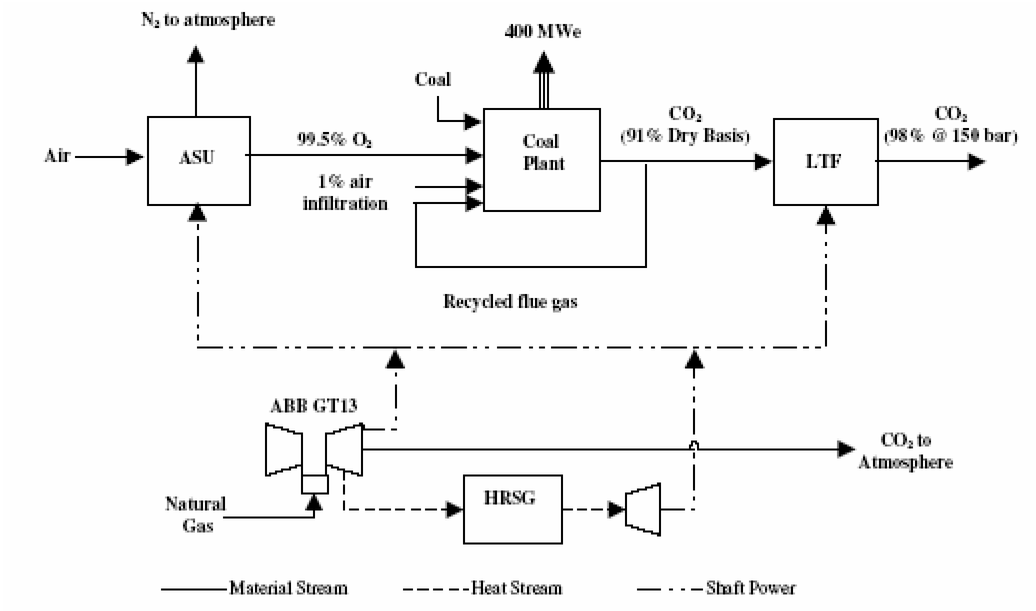

Figure 1.04a. Oxygen blown SCPC with carbon dioxide capture

Chemical Solvents

Chemical solvents show promise for use in both PC and IGCC power plants. The majority of chemical solvents are organic based [35]. Chemical solvents are broken down into three categories: primary, secondary, and tertiary. The diagram below shows a model of a MEA process with chemical/MEA system 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 1.04e shows a comparison of the oxygen blown system with a chemical/MEA amine system in 2001 USD.

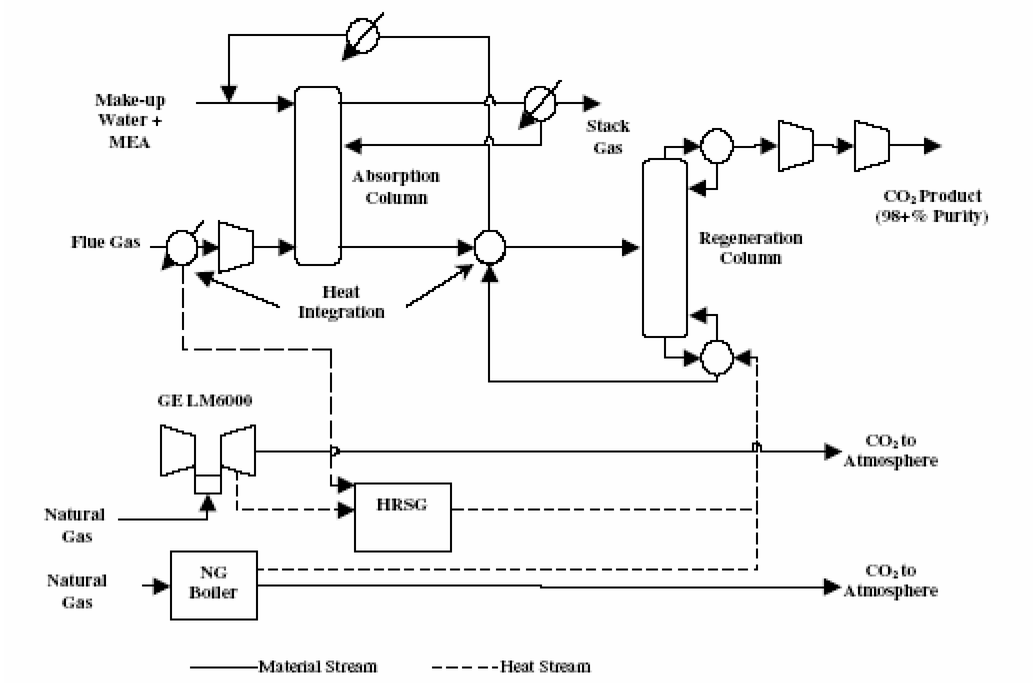

Figure 1.04b. MEA based CO_2 capture

Physical Solvents

Physical solvents show great promise in capturing CO_2 from IGCC, because they are ideally suited for high vapor pressure [36]. The basic types of physical solvents are Rectisol, Selexol, Fluor, and NMP-Purisol. Below is a diagram of a Selexol unit used to treat syngas. The unit creates three separate flows; one of the treated syngas, one of CO_2, and one of H_2S. Physical solvents typically work by absorbing CO_2 at high pressures, then adsorbing CO_2 at lower pressures and higher temperatures. In regards to IGCCs, the Selexol process is less expensive than Rectisol, but is less efficient, and both technologies are more expensive and more efficient than MEA [37]. Table 1.04f shows a comparison of the Selexol and Rectisol processes. The numbers are based on a chemical plant with a feed rate of 2,593 MTD and Cheveron-Texaco Quench Gasifier.

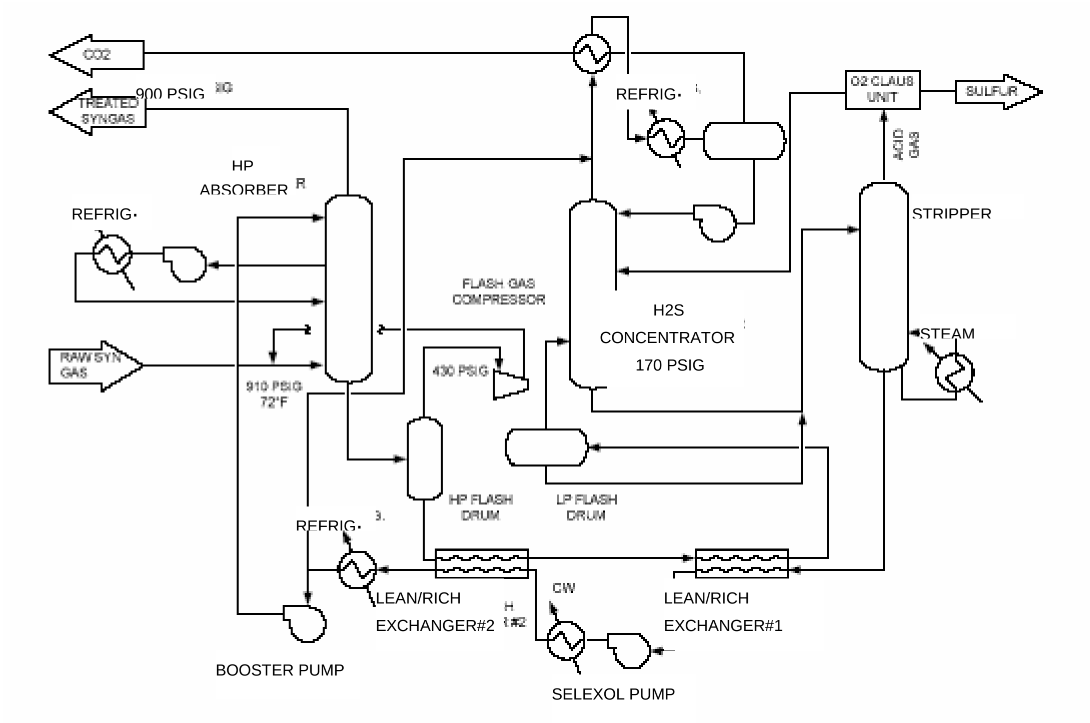

Figure 1.04c. Selexol based CO_2 capture

Table 1.04e.

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

Table 1.04f. Sample cost estimates for CO_2 capture

	Case 1 (Selexol / PSA)	Case 3 (Rectisol / N2 Wash)	Case 2 (Selexol / PSA)	Case 4 (Rectisol / N2 Wash)
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

CO_2 storage is another factor in estimating the sequestration costs. Storage is highly location dependent. In Illinois, CO_2 may be injected to old oil wells for oil production, often called the enhanced oil recovery (EOR). In Indiana, the chance for EOR may be small since oil wells in Indiana are not too many and their formation may be too shallow for CO_2 storage. More research is needed in this area.

C. Capacity Factor Dependence

The final cost of electricity (COE) depends also on capacity factors of plants. A plant with high capital and low fuel costs may have a lower COE when the capacity factor is high enough, say 80 percent.

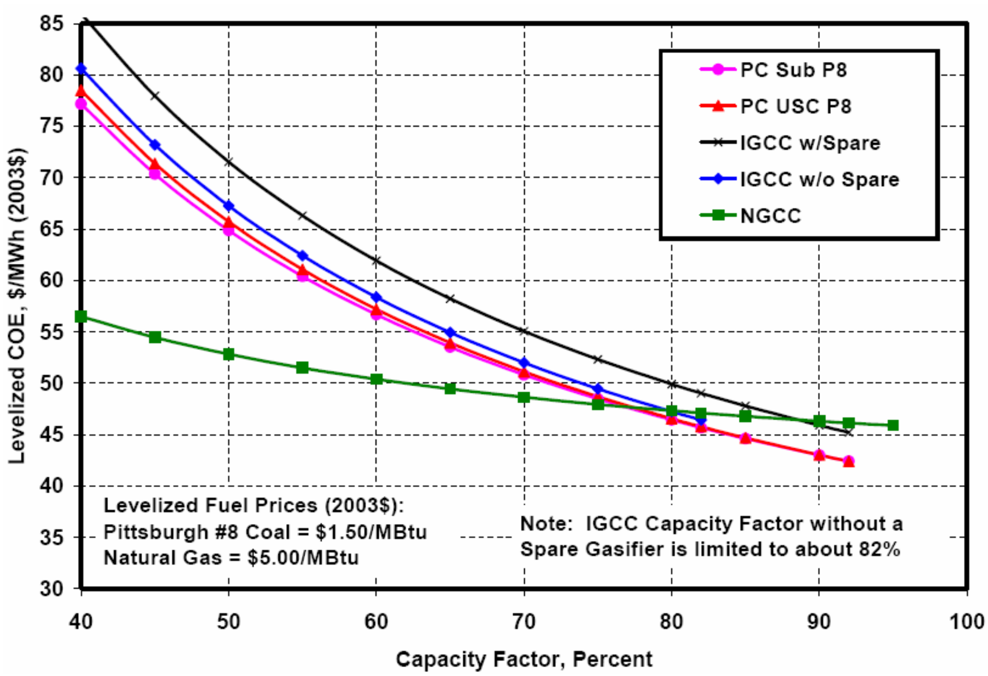

Figure 1.04d. Estimated levelized cost of electricity vs. capacity factor (Pittsburg #8 coal)

Figure 1.04d illustrates estimated levelized COE as a function of plant capacity factor (the estimation was done by EPRI). Given a natural gas price of $5/MBtu, both USC-PC and IGCC will be cheaper when capacity factor is over 79 percent compared to natural gas combine cycle (NGCC) plants.

1.05 Scaling and Preferred Retrofit vs. New Plants

Before the early 1990s, gasifiers faced problems of scaling up because they were relatively small in throughput. This was especially true for the case of the moving bed gasifier when its coal handling was no more than 2000 tons per day (TPD) (see Table

1.05a below). However, the scaling of fixed bed gasifier is no longer a problem . This can be seen from the EKPC IGCC plant where fixed bed gasifiers are used with a net plant capacity of 540 MW (more information is available at www.netl.doe.gov).

Table 1.05a. Coal Handling Capacity of Early Gasifiers [6]

Technology	*Throughput Tons/day (t/d)*	*Temperature Degrees (^{0}C)*	*Comments*
Entrained flow	4,000 – 6,000+	1,200-2,000	
Fluidized bed	3,000 – 4,000	850 -1,100	
Fixed bed or Moving bed	1,000 – 2,000	750 - 900	

The entrained flow gasifier with the Wabash Repowering Project currently drives a gas turbine that is good for a 192 MW generator, and it can match a generator of up to 230 MW.

The EKPC IGCC power plant has a capacity of 540 MW. It has two gasifiers each driving a GE 7 FA's gas turbine generator, plus one steam generator. The gasifiers operate at about 26 bar. Coal and fluxes are placed on the top of a descending bed in a refractory lined vessel. On moving downwards, the coal is gradually heated and contacted with an oxygen enriched gas flowing upwards counter currently.

The temperature at the top of the fixed bed is around 450°C, and at the bottom around 2000°C. Coal feed melts and is tapped as an inert slag. Fixed bed syngas contains tars – which must be condensed and recycled. Tars make downstream gas cleaning more complicated than with other IGCC processes.

PC-based power plants, whether they are sub-critical or (ultra) supercritical, can have a very large capacity. That is, there is basically no scaling difficulty for PC power plants.

As for the retrofitting of old Sub-PC plants, it seems that IGCC is a good candidate technology because there are various gasifiers of different sizes that can be selected to match the sizes of the old Sub-PC plants. For example, moving bed gasifiers can be used for retrofitting smaller Sub-PC plants while entrained flow ones can be used for bigger PC plants.

However, there are other technologies good for retrofitting old non-attainment coal-fired power plant to meet the EPA new emission standards. For example, a study done by the ALSTOM Company has relatively complete alternatives for retrofitting old plants to meet CO_2 capture requirement [19] (also see Table 1.05b). Perhaps, a legitimate research on this subject is how to retrofit the old Indiana power plants so that they can use the Indiana coals. Otherwise, retrofitting old plants are the jobs of the utilities in general.

Whether IGCC or other technologies should be used for retrofitting old power plants, which technology should be used for a specific old power plant, so that the total cost is minimized while meeting all of the constraints? This is a legitimate optimization problem for minimizing total cost subject to various constraints including emission limits, and so forth.

Chemical looping gasification (CLG) is a technology developed by the ALSTOM Company in a cooperative agreement with DOE. The technical details can be found in [20].

Table 1.05b. Technology Options for CO_2 Capture [19]

Process	*Plant Technology*	*CO_2 Capture*
Combustion-Based Process	Natural Gas Combined Cycle (NGCC)	MEA
	Pulverized Coal (PC), Circulating Fluidized Bed (CFB), and/or Circulating Moving Bed (CMB ^{TM})	MES
		Oxyfuel
		CO_2 Wheel
		Biomass co-firing
	Circulating Moving Bed (CMB $^{TM)}$	Calcium Oxide
	Chemical Looping Combustion (CLC)	Calcium Oxide
Gasification-based Process	Integrated Gasification Combined Cycle (IGCC)	Double Selexol
	Chemical Looping Gasification (CLG)	Calcium Oxide

Legend: MEA – Monoethanolamine, a substance that absorbs CO_2 in chemical reaction.

1.06 Pollution Removal

From the beginning, the best selling point for IGCC power production has been the environmental benefits. After many years of demonstration, these benefits have been verified even though more improvement is deemed necessary. Table 1.06a summarizes the environmental performance of the IGCC power plants in the US. As can be seen, in general, the emission levels from the IGCC power plants are just fractions of those from conventional coal fired power plants. Notice that the data of the Mesaba Hoyt Lakes IGCC plant are design targets rather than proved performance data. However, this does not play down the fact that IGCC power plants have much better environmental performance than conventional coal fired power plants.

The US Environmental Protection Agency (EPA) has proposed to tighten emissions control by reducing NO_x and SO_x emission levels and concurrently introducing a new Mercury emission cap. This can be called multi-pollutant control scenario (MPCS). Since IGCC has a competitive edge over other technologies in mercury capture,. If CO_2 sequestration is also considered, say, a carbon constraint similar to the proposed McCain-Lieberman bill, the IGCC will look even more promising as an all-round winner for new capacity in power generation.

Though there is no immediate regulation action in sight in the United States, there are still concerns about future CO_2 regulations in this country. From the global arena, the Kyoto Protocol has been a major driver of CO_2 emissions regulation. Canada has been testing CO_2 sequestration by retrofitting three older power plants using IGCC and other technologies. Other countries in Europe and Asia are also taking steps to address the issue. It can be expected that IGCC may have a greater market penetration internationally due to the enforcement of CO_2 emission control and quota enforcement.

Hg removal has not been tested in IGCC plants. However, it has been concluded that it is relatively easy for IGCC to remove Hg.

Table 1.06a. Environmental Performance of the U.S. IGCC Power Plants

Technology	*Whose estimate*	*SO_x*	*NO_x*	*Carbon monoxide*	*VOC*	*PM*	*Hg*
Entrained flow	Wabash [7], [8]	> 99% or < 0.1 lb/mmBtu	<25 ppmv or 0.15lb/mmBtu or 1.09lb/MWh	0.05 lb/10^6, well below industry standards	n/a	<0.05 lb/ MWh	n/a
	Tampa [7], [8]	>99% or 29lb/hr	15 ppmv or Average 0.7lb/MWh	n/a	< design limit	0.037 lb/ MWh	n/a
	Mesaba, MN [7], [8]	0.022lb /mmBtu	0.058lb /mmBtu	0.03lb /mmBtu	0.002lb /mmBtu		4.3E-6 lb /mmBtu
Fluidized bed	Pinon Pine	>95%	50% less conventional coal	20% less	n/a	n/a	n/a
Fixed bed	EKPC	0.032 lb/mmBtu	0.072 lb/mmBtu	0.032 lb/mmBtu	0.0044 lb/mmBtu	n/a	0.08 mg/dscf (EPA data)

Legend: VOC – Volatile Organic Components. PM – Particulate Matter.

Table 1.06b. Real or Projected Emission Levels for Other Technologies

Technology	*Whose estimate*	*SO_x*	*NO_x*	*Carbon monoxide*	*VOC*	*Hg*
SCPC or USC-PC	Siemens [10]	0.15 lb/ mmBtu	0.15 lb/mmBtu or 1.09 lb/MWh	n/a	0.02 lb/ mmBtu	n/a
	WEC	>99% or 29 lb/hr	15 ppmv or Average 0.7lb/MWh	n/a	< design limit	n/a
	IMPA (Prairie)	0.182 lb/ mmBtu	0.07 lb/ mmBtu	n/a	n/a	n/a
ACFBC (real)	WEC	250mg/nm^3	120mg/nm^3		10mg/nm^3	

Legend: WEC – World Energy Council. ACFBC - Atmospheric Circulating Fluidized Bed Combustion. WEC data is available at http://www.worldenergy.org/ and the results were acknowledged and received the 1992 Power plant Award. IMPA – Indiana Municipal Power Agency.

Some other environmental issues are still under study with the IGCC plants. For example, the frit from combined coal/RDF feed is yet to be tested further to see if it is leaching and hazardous, even though it has been demonstrated that the frit from the EKPC IGCC coal feed is not leaching.

IGCC is not the only technology that can meet the new EPA emission standards. Recently, some studies claim that SCPC or USC-PC may also be able to meet the new EPA standards. Table 1.06b illustrates the data of emission levels for the selected technologies other than IGCC.

The purity of the emissions captured is not 100 percent. SO_x and NO_x plants can be 99 percent pure. The market price of NO_x may be determined from the emission permit trading spot markets, in which NO_x is about \$3500/ton (http://www.evomarkets.com). Food grade CO_2 may be sold at about \$400/ton according to a presentation by the Royster-Clark Nitrogen last year in the Chicago Gasification Conference (see GTI's website – include URL here). However, the market is too limited for large volume CO_2 sales overall.

Equipment costs for pollutants' removal are yet to be found, even though the general cost comparison between PC and IGCC for CO_2 capture is discussed in Section 2.04.

Wastewater Considerations of IGCC Plants

Ratafia-Brown et al. [38] give a good analysis of all the environmental concerns of IGCC systems. They outline the liquid effluent environmental concerns as follows. The primary consumption of water in the IGCC plant is boiler feed water (BFW) for the steam turbine and gasification processes, followed by cooling water requirements, and finally by gas cleanup requirements.

While the BFW requirements of an IGCC plant are just as large as an equivalent pulverized coal fired plant, the cooling water requirements are generally less. Water consumption is further reduced in an IGCC plant because all of the water used in the gasification process is recovered through condensation in the gas cleanup phase.

Water in the gas cleanup phase varies depending on type of fuel used, and the volumetric flow rate of the syngas to be cleaned. This is the step in the IGCC process where fly ash, halogens and trace organic and inorganic compounds are removed.

Considering the BFW, cooling water, and gas cleanup requirements of the IGCC plant, the total water requirements of an IGCC plant are approximately 1/2 to 2/3 of that required by an equivalent pulverized coal power plant.

IGCC plants have two aqueous discharges similar to pulverized coal plants. The first is wastewater from the steam cycle and the second is from the process water blowdown. The second effluent is typically the stream of concern as it has high concentrations of dissolved gases and solids such as trace metals, trace organics, and chloride, fluoride, sulfide, formate, nitrogen species, cyanide, thiocyanate, and bicarbonate ions.

Blowdown discharge is usually recycled to the coal preparation area, the scrubber (after solids have been removed), to a zero discharge system, or to a wastewater treatment system. Since recycling the water causes a buildup of dissolved salts, the recycled water must eventually be replaced with make-up water and sent to a wastewater treatment system or a zero discharge system. Zero discharge systems must address the issue of salt disposal from the brine evaporation. Table 1.06c shows the discharge from the Wabash River gasification plant for the species mentioned above. It can be seen that IGCC plants can handle water pollutants very well.

Table 1.06c. Wabash River Process Wastewater Discharge

PARAMETER/ CONSTITUENT	UNIT	PERMIT LEVEL MONTHLY AVERAGE	PERMIT LEVEL DAILY MAXIMUM	1997 MONTHLY AVERAGE	1998 MONTHLY AVERAGE	1999 MONTHLY AVERAGE
Ammonia (as Nitrogen)	mg/l	27.14	54.29	3.93	6.56	8.8
Arsenic	mg/l	0.018	0.043	0.0077	0.0199[a]	<0.01
Cadmium	mg/l	0.010	0.025	<0.0038	<0.008	<0.01
Chromium	mg/l	3.47	8.07	<0.006	<0.0108	<0.0167
Hexavalent Chromium	mg/l	0.014	0.032	<0.01	<0.0120	<0.01
Copper	mg/l	0.040	0.093	<0.01	<0.0145	0.0185
Cyanide	mg/l	0.019	0.044	0.107[a]	0.2798[a]	0.1438[a]
Lead	mg/l	0.260	0.606	<0.08	<0.08	<0.08
Mercury	mg/l	0.0005	0.001	<0.005	<0.0005	<0.0006
Nickel	mg/l	2.91	6.78	<0.02	<0.0236	<0.1140
Selenium	mg/l	0.017	0.040	0.0714[a]	0.230[a]	0.1380[a]
Zinc	mg/l	0.241	0.560	0.05	0.0414	0.1363
pH	mg/l	6.0 to 9.0	6.0 to 9.0	7.99	8.4	7.5

[a] Originally out of permit compliance, but later corrected

1.07 Reliability/Availability

Availability/reliability of IGCC power plants have been a matter of controversy (availability and reliability are used interchangeably here). Up to this stage, the results have not met the design targets (usually 85 percent). The major reason is that gasifiers break down more often than the electricity generation section (gas turbines, steam turbines, and generators) and require more scheduled maintenance. Table 1.07 summarizes the performance of the United States IGCC plants in this category.

When the PSI Wabash IGCC plant was first in operation, it only reached an availability of 38 percent due to reliability problems with the gasification section. Even the ceramic candle filters experienced serious break downs and were later replaced with metallic ones. The TECO Polk plant also had many problems with the gasification section; including the breakdowns of the exchangers in the ash plugging that caused serious damages to the combustion turbine. Most IGCC power plants also experienced problems with the air separation units (ASU). For the last few years, problems with the gasification have been gradually solved partially or completely. Yet the availability and reliability of the IGCC power plants have not reached the levels of conventional coal fired power plants that usually have availabilities around 90 percent (see Table 1.07 for comparison).

With a back up gasifier, an IGCC power plant will have an availability of greater than 90 percent. This of course will add to the total capital cost, as is the case with the Mesaba Hoyt Lakes IGCC plant.

Table 1.07. IGCC Plant Availability Data (Sources: [7], [21])

Plant	*Gasifier*	*Electrical*	*Others*
PSI Wabash	77-87% in 2002-2003 period	unknown	unknown
Wabash-I	Comparable to the above	n/a	n/a
TECO Polk	82%	95%	93%
Elcogas	84.8%	95.9%	96.7%
EKPC-Kentucky	n/a	n/a	n/a
Mesaba –Hoyt Lakes	> 90% with a backup gasifier	n/a	n/a

People have not reached a consensus on whether it is economical to use a backup gasifier for higher reliability/availability. According to an EPRI study, it would cost more to add a backup gasifier in terms of the final unit electricity cost (see [13]).

However, there have been proposals on various schemes of backup gasifier arrangement. The most popular one is the 2 on 1 scheme in which two gasifiers run on parallel with the third gasifier standing by (see Figure 1.07). Another scheme is the 3 on 1 scheme in which three gasifiers operate on parallel while the forth one stands by (see [14]). It may be beneficial to optimize backup schemes in poly-generation (or co-production) IGCC plants, and this will be a further research topic.

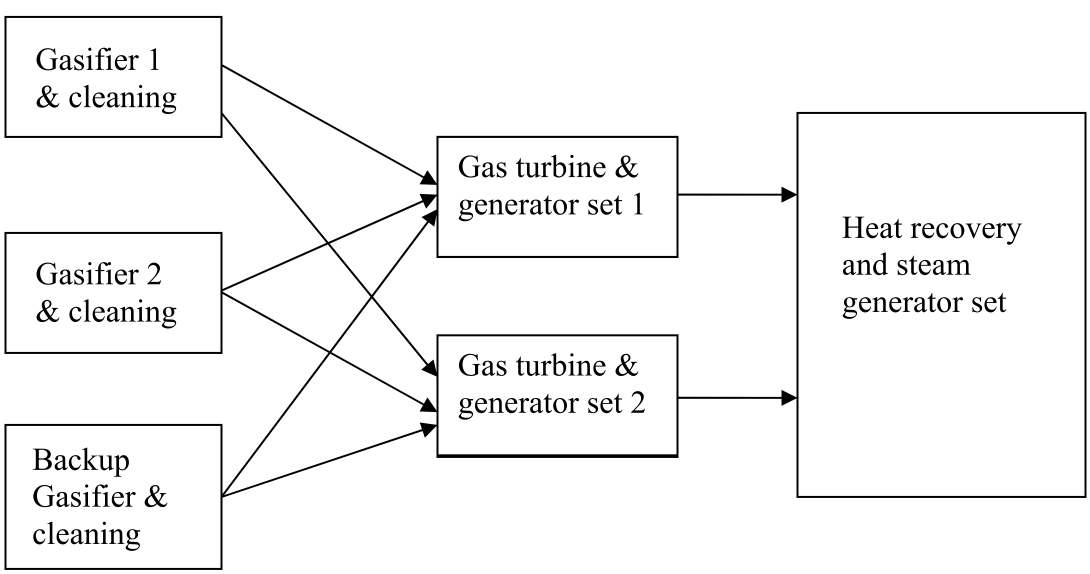

Figure 1.07. Simplified Diagram of an IGCC Plant with One Backup Gasifier

A natural gas backup would improve the availability of the power plant but not the gasification section. The backup may not be feasible if there is no natural gas pipeline around the IGCC plant.

1.08 Compatibility with Coke and Chemical/FT Fuel Co-Production

There might be an opportunity for using IGCC to produce coke that can be used for steel production. There is a different study sponsored by CCTR on the subject. .

Coal can be used for producing many products including chemicals, paper, glass, etc. Recently, the combined fertilizer/clean fuel/electricity production (CFCEP) has emerged as a clean use of coals (Figure 1.08). According to a report prepared by the Royster-Clark Nitrogen, a joint venture by Rentech and Royster-Clark, one ton of Illinois basin coal with a price tag of $30 can yield $150 [22], plus job additions and other benefits.

U.S. fertilizer production has been hurt badly in the past few years due to high natural gas prices. As a result, nitrogen fertilizer production in the U.S. has declined by almost one-quarter and the U.S. is now importing about 50 percent of its nitrogen fertilizer needed [22]. The concern over the decline has recently been echoed by professionals in a Senate Subcommittee on Rural Enterprises, Agriculture, and Technology [23].

The syngas from coal gasification can be used to produce ammonia for fertilizer production. Given a coal price of $1.2/MMBtu, the syngas can have a price tag of $3.5-3.8/MMBtu, which is competitive against pricy natural gas. According to a recent EIA study, the expected natural gas prices would be above $5/MMBtu in the near term and above $4.5/MMBtu in the mid term (20 years) for industrial use [24]. Hence, it is apparently economical to use coal gasification for fertilizer production.
The syngas from coal gasification can also be used for clean transportation fuel production, especially diesel fuel. The U.S. EPA is to enforce in 2006 an earlier ruling to reduce emissions from diesel trucks [25], and sulfur reduction will be the primary target for reduction. According to [22] and [26], the cost of ultra-clean diesel from syngas can be as low as $43/Barrel given a coal price of $0.5/MMBtu (Roughly the current price of the PRB coals). The current price of diesel fuel is about $80/Barrel, the ultra-clean diesel is hence very competitive economically. Rentech has evaluated the potential of coal-to-clean fuel options using Wyoming coals at the request of the state of Wyoming ([27] and [28]).

In addition to the CFCEP products, coal gasification can produce some other products such as hydrogen and wax, and some by-products for commercial purposes. Figure 1.08 illustrates a block diagram of the Royster-Clark Nitrogen plant under development in Illinois.

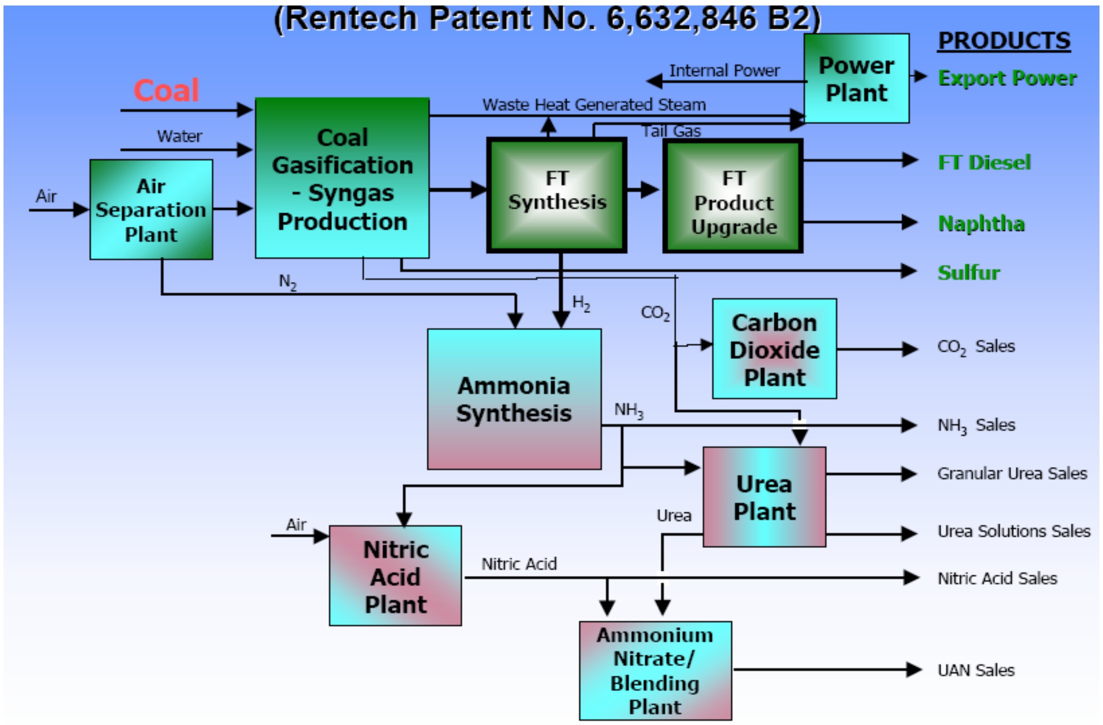

Figure 1.08. Royster-Clark combined fertilizer/fuel/…/ project in Illinois [22]

Notice that the Fischer-Tropsch (FT) process is needed for converting syngas to ultra-clean fuels. The FT process is a method for the synthesis of hydrocarbons and other aliphatic compounds. Syngas is reacted in the presence of an iron or cobalt catalyst; much heat is evolved and such products as methane, synthetic gasoline and diesel, waxes, and alcohols are made, with water or carbon dioxide produced as a byproduct. The process is named after F. Fischer and H. Tropsch, the German coal researchers who discovered it in 1923 (More information is available at http://www.fischer-tropsch.org/site_map.htm). Recently, the U.S. Department of Defense (DOD) has shown a great interest in CTL FT fuels. According to [33], DOD has allocated about $500 million for testing and certifying FT jet fuels using coal gasification. DOD is also interested in FT diesel from coal gasification, and would like to invest in the area as well. Private firms such as Sasol and Shell have also shown interest in investing in FT fuels. All these new developments may have very positive impact on Indiana coal production and use if the state can act promptly. Several other states and even countries have been competing for the Sasol and Shell investment.

As for fertilizer production, currently, the Royster-Clark project has been in the detailed design phase and Flour Enterprises has been hired to conduct plant optimization [29]. The plant will use about one million tons of Illinois coals. The capital cost is estimated at $450 million dollars [22]. Table 1.08 illustrates the values realized through different products using one ton of Illinois coal. From this table, it can be seen that product combination set 3 yields the highest value from one ton of Illinois coals. Of course, the capital costs would be higher too in product combination set 3. Hence, there is a legitimate optimization problem there that can maximize the net value from one ton of coals. Note that the state of Illinois has allocated over $2 million dollars for the project. The major products from the project are: Ammonia – 950 tons/day, diesel – 1,800 barrels/day, and power – 15 to 20 MW. There are other minor products such as hydrogen, wax, food grade CO_2, commercial sulfur, etc. Rentech is also conducting preliminary studies for a similar project in Wyoming [28].

Table 1.08. Valuations of Various Uses of Illinois Coals (one ton)

Set of Product Combinations	*Electricity (MWh) $35*	*Naphtha (bbl) $44*	*Diesel (bbl) $70*	*Ammonia (ton) $348*	*Total value ($)*
1. Electricity	2				70
2. Electricity, naphtha, diesel	0.41	0.34	1.36		124
3. Electricity, naphtha, diesel, ammonia	0.07	0.17	0.78	0.25	149

1.09 CO_2 Sequestration Regulation and Legislation

Global warming and climate change have been a big concern around the world. It has been generally agreed that fossil fuel burning has been contributing to the problem. The Kyoto Protocol signed by over 170 countries in the world is the first step to tackle the problem, which requires 38 industrialized countries to reduce their GHG emissions 5.2% relative to the 1990 levels by 2012 [39].

The McCain-Lieberman Climate Stewardship and Innovation Act would impose modest but mandatory caps on greenhouse gas emissions, enforced through a flexible, market-based trading system. Under this "cap and trade" plan, firms with better emissions control can sell their excess credits to others that need them. This mechanism may be an efficient one for controlling GHG emissions. As pointed by [40], the worst case of the “cap and trade” system would freeze GHG emissions at the 2010 levels, even though the McCain-Lieberman bill would require GHG emissions reductions to 2000 levels by 2010 and to 1990 levels by 2016.

Even though the McCain-Lieberman Act was not passed in the Senate, discussions have been very active. This year, a plan was drafted by the nine northeast states for controlling GHG emissions, which may bear some similarity to the McCain-Lieberman proposal [41]. The nine states have agreed to freeze CO2 emissions from 600 electric power plants at their current levels starting from 2009, and then reduce them by 10 percent by 2020. It is estimated that the plan would cut carbon dioxide by an estimated 150 million tons per year. The participating states are still working on details of the plan, including terms of the emissions trading system.

At the United Nations World Environment Day today in San Francisco in June 2005, California Governor Arnold Schwarzenegger called for the state to reduce its greenhouse gas (GHG) emissions to 2000 levels by 2010; to 1990 levels by 2020; and to a level 80% below 1990 levels by 2050. The Governor signed Executive Order S-3-05 that sets these GHG targets and charges the secretary of the California Environmental Protection Agency (CalEPA) with the coordination of the oversight of efforts to achieve them [42]. California, Oregon and Washington have been discussing a regional GHG emissions control agreement on the West Coast, including a "cap and trade" system.

The above mentioned proposals and initiatives on GHG emissions control are summarized in Table x. They are representative even though there have been more proposals for GHG control in the U.S.

Table 1.09. Characteristics of Existing and Proposed CO_2 Emission Controls

Initiative	Freeze time	Reduction time	Reduction (% or levels)	Comments
Kyoto Protocol		2008-2012	5.2	For 38 countries only
McCain-Lieberman	Worst case: 2010	2010 2020	To 2000 levels To 1990 levels	
9 Northeastern states	2009-2019	2020 & beyond	10	
California		2010 2020 2050	2000 levels 1990 levels 80% below 1990	

1.10 External R&D Funding

Coal R&D funding opportunities are plentiful in the United States. The major sources of funding are from federal agencies including DOE, EPA, etc. Some states with coal production are also active in coal R&D activities. Many private organizations such as coal producers, utilities, EPRI, the Energy Foundation also support coal R&D programs/projects.

The Office of Fossil Energy (OFE) within DOE has sponsored many coal R&D programs/projects. One is the University Coal Research Program (UCRP) that has been there since 1979. In 2003, the core programs under UCRP are: Advanced Coal System By-Product Utilization, Partitioning and Mechanism Studies for Hg &Trace Metals with Coal-Fired Processes, Sensors and Controls, Innovative Concepts – Phase I (CO_2 Sequestration from Coal Gasification Process), Direct Utilization of Carbon in Fuel Cells, Innovative Concepts – Phase II (CO_2 sequestration, Mercury and Other Emissions from Advanced Power Systems), etc. The programs in many cases involve in coal gasification and emission control. In 2004, more programs were related to gasification including advanced materials, sensors, processes etc. The annual funding for the UCRP programs are about $3-5 million.

A. Major OFE-DOE Programs

Coal & Natural Gas Power Systems

Currently there are nine Key R&D Programs under this category. They are the Clean Coal Technology & the President's Initiative (CCTPI), FutureGen, Vision 21, Pollution Control Innovations for Today's Power Plants (PCITPP), Gasification Technologies (GTs), Advanced Combustion Systems (ACS), Future Fuel Cells (FFCs), the Turbines of Tomorrow (ToT), and Advanced Research (AR). Table1.10a has a brief summary of these sub-programs.

Other Programs

Other major programs are Carbon Sequestration, Oil & Gas Supply, Petroleum Reserves, Gas and Electricity Regulation etc. These are either related to the first category listed above or not directly related to coal gasification, and will not be discussed further.

DOE in March 2005 also announced 32 projects funded under the title of "clean coal" R&D, with a total fund of $62.4 million. Universities and research institutions are the recipients of the funding (information available at DOE website).

Table 1.10a. Programs under the Coal & Natural Gas Power Systems

Sub-program	Budget	Time period	Comments
CCTPI	$ 2 billion	2003 - 2012	
FutureGen	$ 1 billion	2003 - 2012	Zero emission hydrogen power plant
Vision 21	n/a	2003 - 2015	60-75% efficiency (IGCC – CCGT)
PCITTP	n/a	2003 - 2010	Emission reduction, by-product use
GTs	n/a	2003 - 2010	IGCC < $1000/kW, 50% efficiency
ACS	n/a	2003 - 2015	Part of the GTs
FFCs	n/a	n/a	Reduce $4500/kW to about $1500/kW
ToT	n/a	2003 - 2015	Associated with Future Gen, GTs
AR	n/a	n/a	Associated with FutureGen & V-21

B. Some Current DOE Funding Opportunities

Coal-related R&D programs under DOE are often administered by the National Energy & Technology Laboratory (NETL). In 2005, NETL has issued many solicitations for targeted R&D programs, of which a few of them are summarized below (Table 1.10b).

Table 1.10b. Selected DOE Solicitations for Energy or Energy-Related Research

RFP Code	Title	Posted date	Close date	Fund ($)
DE-PS26-05NT42464	Oxycombustion and Other CO_2 Capture Technologies	4/28/2005	6/30/2005	No ceiling, matching
DE-PS26-05NT42346	Fuel Cell Coal-Based Systems	3/18/2005	6/7/2005	n/a
DE-PS26-05NT42470-00	High Temperature Electrochemistry Center (HiTEC) Advanced Research Program	4/07/2005	5/19/2005	n/a
DE-PS26-05NT15540	RUSSIAN TECHNOLOGY PROGRAM	4/01/2005	5/26/2005	1.23 million
DE-PS26-04NT42072-0	Round 2: Advanced Diagnostics and Imaging	1/25/2005	3/31/2005	n/a
DE-PS26-05NT42381	FreedomCAR and Vehicle Technologies Program	1/14/2005	3/10/2005	n/a
DE-PS26-05NT42255	Regional Carbon Sequestration Partnerships - Phase II	12/14/2004	3/15/2005	n/a (10 sub-programs including one for Midwest)

C. DOD Funding Opportunities

As mention in the above, DOD has decided to invest $500 million for testing and certifying CTL based jet fuel. It may also invest in CTL diesel demonstration.

D. The Obama-Lugar Amendment

In 2005, Senators Obama (IL) and Lugar (IN) made an amendment to the Senate Energy Bill 2005 allocating $85 million for demonstrating FT fuels using the Illinois Basin coals. Purdue University is selected as one of the three centers for carrying out the demonstration.

E. Private Funding Opportunities

Sasol has shown a great interest in CTL fuels. It plans to invest $5 billion USD for one to several CTL plants in the world. Sasol executives have visited Montana and Illinois looking for potential sites. Some smaller firms have also been very active in CTL projects, including Baard etc.

F. Funding Opportunities from Financial Firms

Financial firms have been watching the progress in IGCC and CTL development. There can be significant investment from them if they are convinced the opportunities are economically rewarding.

In short, investment in research, demonstration and even commercial development is plenty, and the problem with Indiana is how to land the investment. Fortunately, Purdue University has been designated by the Obama-Lugar Amendment in the Senate Energy Bill 2005 for CTL fuel demonstration, and the state of Indiana can take this advantage for promoting CCTs and the use of Indiana coals.

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Dimension Two:
Indiana Characteristics

2.01 Available Types of Indiana Coal

All of Indiana's coal supplies are from the Illinois basin. The Illinois basin is located mainly in Illinois and runs through southwest Indiana into the western tip of Kentucky. Illinois basin coal is characterized as bituminous coal with heating and sulfur contents higher than Powder River Basin coal, but lower than Eastern coals.

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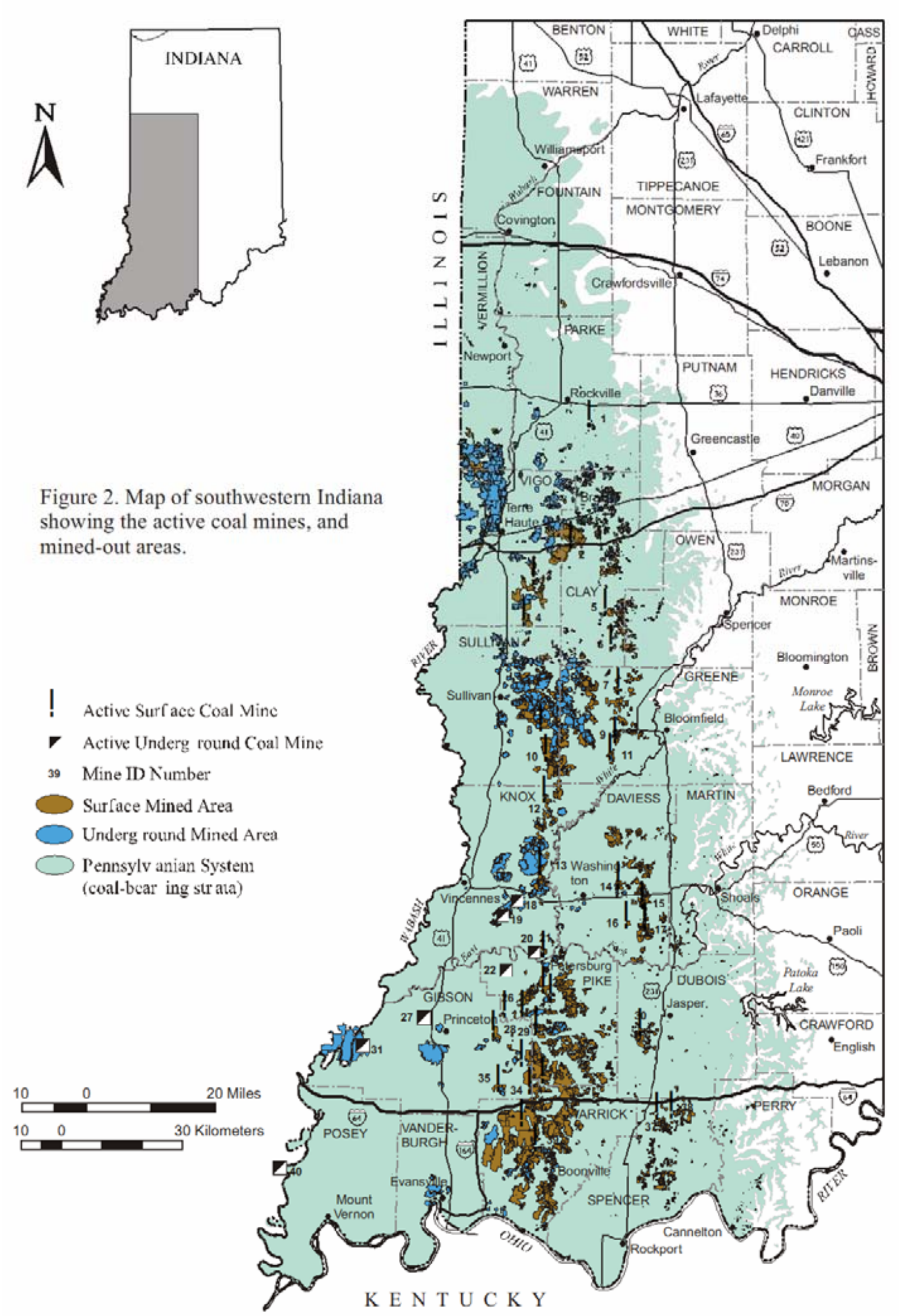


Figure 2.01. Active Coal Mines in Southwestern Indiana, including Mined-Out Areas [9]

Illinois basin coal is divided into three groups: the McLeansboro, Carbondale, and Raccoon Creek. The Carbondale and Raccoon Creek groups are of economic importance and are divided into six formations. These formations are further classified into 19 different seams of varying depth and characteristics. Of these 19 seams, 11 are of economic importance and are listed below with their individual characteristics.

Indiana also imports a great deal of coal from other states. The majority of this imported coal is from the Powder River basin for its low cost and low sulfur. Tables 1.01a and 1.01b list some basic comparisons of each.

Table 2.01a. Characterization of Indiana's Coal Resource

All values are on a dry basis

Coal Seam	Calorific Value (Btu/lb)	Moisture (% Weight)	Volitile Matter (% Weight)	Fixed Carbon (% Weight)
Danville	12304	11.2	39.7	47.9
Hymera	11967	10.5	38.8	46.7
Springfield	12525	10	41.4	47.2
Survant	12518	11.4	40.7	48.7
Colchester	12403	11.4	40.7	48.7
Seelyville	12073	9.6	41.6	43.5
Minshall/Buffaloville	12517	10.5	40.9	47.2
Upper Block	12894	15.4	39.1	51.2
Lower Block	13299	14	38.9	49.8
Mariah Hill	12884	13	38.9	49.9
Blue Creek	13074	14.9	39.4	52.9

Coal Seam	Sulfur (% Weight)	Ash (% Weight)	Mercury (ppm, whole coal basis)	Avaliable Reserves (BST)
Danville	2.6	12.3	0.07	0.83
Hymera	3.1	14.3	0.11	0.87
Springfield	4.1	11.3	0.12	7.35
Survant	2.7	10.9	0.22	1.31
Colchester	2.7	10.9	0.12	0.19
Seelyville	3.5	14	0.07	6.6
Minshall/Buffaloville	3.5	11.2	0.1	
Upper Block	1.8	9.3	0.13	
Lower Block	1.3	8.8	0.07	
Mariah Hill	2.6	9.8	0.05	
Blue Creek	2	7.6	0.1	

M. Mastalerz, A. Drobniak, J. Rupp, N Shaffer, "Characterization of Indiana's Coal Resource: Availability Of The Reserves, Physical And Chemical Properties Of The Coal, And The Present And Potential Uses." July, 2004

Table 2.01b. Illinois Basin vs. Powder River Basin

As Received

	Calorific Value (Btu/lb)	Moisture (% Weight)	Volitile Matter (% Weight)	Mercury (ppm)	Sulfur (% Weight)	Ash (% Weight)
Illinois Basin-In	11386	10.1	34.7	0.11	3.13	9.42
Powder River Basin	8088	18.7	33.9	0.1	0.072	7.59

United States Geological Survey, April, 2004
http://energy.er.usgs.gov/coalqual.htm

2.02 Utility Regulatory Environment

Of the states listed in Table 2.02, Indiana, Kentucky and Wisconsin are still regulating electric generation utilities, especially those investor-owned utilities (IOUs). Transmission and distribution systems are all regulated because they are considered "natural monopolies."

Table 2.02. Regulatory Status of the Six Midwest States

	Generation	*Transmission*	*Distribution*	*Others (e.g., general plants)*	*Comments*
Indiana	Regulated	Regulated	Regulated	n/a	
Illinois	Deregulated	Regulated	Regulated	n/a	
Kentucky	Regulated	Regulated	Regulated	n/a	
Michigan	Deregulated	Regulated	Regulated	n/a	
Ohio	Deregulated	Regulated	Regulated	n/a	
Wisconsin	Regulated	Regulated	Regulated	n/a	

A. Generation

In Indiana, the IOUs under regulation are IPL (Indianapolis Power & Light), a subsidiary of AES), I&M (Indiana and Michigan Power, a subsidiary of AEP), NIPSCO (Northern Indiana Public Service Corp, a subsidiary of NiSource), PSI (PSI Energy, a subsidiary of Cinergy) and SIGECO (Southern Indiana Gas and Electric Corp, a subsidiary of Vectren). The rate of return on investment, often more than 10 percent per year, varies according to time, plant type, interest rate, tax levels, emission control and other factors. Usually, the IOUs assume more than 50 percent in debt against their book values [1].

Kentucky is in a similar situation to Indiana. Both states have low electricity costs due to their heavy reliance on cheap power production primarily using low cost coals. Both states have been producing large quantities of coals for power production as well. Interesting enough, both states have IGCC power plants in operation and/or testing.

Wisconsin has not deregulated its electricity industry. However, discussions on deregulation have been on and off, especially after electricity rates in the state have been increased for the last few years to pass the rates of its neighboring states [2]. Unlike Indiana, some IOUs in Wisconsin have been against deregulation. It is said that Wisconsin regulators ruled down an IGCC power plant proposed by WE Energy in 2003 and the reasons are yet to be found.

Illinois also has retail electricity competition test programs. In 1999, the Illinois Commerce Commission (ICC) issued an order (Docket 98-0544) for certifying retail suppliers [3]. Rate freeze before full retail competition may be appealed by ComEd this year. Illinois has a reciprocity requirement in retail competition: suppliers from other states are allowed to enter retail competition if their local states allow Illinois suppliers to enter retail competition in their states [4]. Even though Illinois has deregulated its electric power industry, it is still very active in promoting the environmentally friendly use of Illinois coals. The Office of Coal Development (OCD) under the Illinois Department of Commerce and Economic Opportunity is in charge of coal research and development. For coal development programs, the state would share up to 50 percent of the cost; for coal infrastructure, the state would share up to 20 percent of the cost. OCD has sponsored the preliminary studies of the Royster-Clark Nitrogen and Southern Illinois Clean Energy Center (Coal gasification and power production).

In 2000, Michigan's Governor, John Engler, signed into law the Customer Choice and Electric Reliability Act giving the Michigan Public Service Commission (MPSC) the authority to oversee electric competition. Michigan regulators require customers who switch to a competitive supplier to have a new meter installed that the utility can read over a phone line connected to the meter. Customers will not be charged for the installation of the meter, but must make a phone line available. The state also has a rate freeze in the transition period to full retail competition (more information is available at MPSC’s website: http://www.winsconsinpublicservice.com).

Ohio has been testing retail electricity competition since 2001, and some customers have been charged “transition costs” if they have chosen to leave the original power supplier(s). These transition charges will be collected until 2008 in some cases. If they stay, their rates will be frozen at the levels before deregulation until the end of 2005 [5]. Full retail competition will be in place from early 2006 if everything goes as well as planned.

B. Transmission and Distribution

Transmission systems are considered as “interstate” commerce tools and are under the Federal Energy Regulatory Commission’s (FERC) jurisdiction. That is, FERC sets rules for regulating transmission systems. States have been fighting with FERC over some transmission issues.

Currently, the Midwest Independent System Operator (MISO) runs the electricity markets in the Midwest. MISO has the authority of allocating transmission rights to market participants. There has been complaint that MISO does not allow long-term transmission rights, which is considered a risk by load serving entities (LSEs) in their long-term transmission rights and pricing, and barrier for cost effective baseload plant construction and renewable resources. A group of LSEs has filed formal appeal to MISO for changing market rules to reduce the risk/uncertainty in the long-term.

Distribution systems are still regulated by the states because they are also considered "natural monopolies." Investors are allowed to earn fair rates on their investment.

C. Advantages of Regulation for Clean Coal Technologies

In general, states with generation regulation would benefit from the deployment of IGCC and other clean coal power plants. Two aspects of this are that (1) IOUs would be less hesitant to construct IGCC plants because of the guaranteed rate of return on investment, and (2) interest rates would be lower due to this guaranteed rate of return. In other words, regulation and guaranteed rate of return will reduce the "risk premium" for IOUs to borrow money, which would result in lower rates for consumers.

For Indiana, the state legislature has passed State Bill 378 to give clean coal plants a tax credit of up to $10 million per year, which would be even more attractive for IGCC and other clean coal power projects.

2.03 Environmental Regulatory Process

The United States Environmental Protection Agency (U.S. EPA) enforces a complex set of federal laws and regulations regarding emissions of many air borne pollutants from several sources including electric generation facilities. U.S. EPA delegates much of the permitting and compliance activities regarding these emissions to state agencies. The complexity of these laws and regulations, their interpretation and administration, and frequent revision result in major uncertainty regarding the construction and operation of electric generation facilities. This section summarizes some of the main air emissions laws and rules and their administration as the project has come to understand them, but is not intended to be comprehensive.

A. Emission Limits

Table 2.03a summarizes the main legislation on which U.S. EPA acts. In conjunction with United States laws, EPA issues regulations regarding various emissions and timelines for meeting the regulations. The regulations are often legally challenged and revised as needed in response to court decisions.

In March 2005, the U.S. Environmental Protection Agency promulgated new regulations effecting electric power plant emissions. The Clean Air Interstate Rule (CIAR) lowers allowed emissions of SO_2 and NOx by roughly 56 percent (SO_2) and 68 percent (NOx) from currently allowed levels. CAIR is a cap and trade type program for SO_2 and NOx emissions with new emissions caps to be fully implemented in two phases. The first phase takes place in 2009 (NOx) and 2010 (SO_2), and the second phase in 2015 for both SO_2 and NOx. At nearly the same time, U.S. EPA also finalized a rule for mercury emissions called the Clean Air Mercury Rule (CAMR). The mercury rule is also a cap and trade, two-phase rule and is projected to reduce mercury emissions from electric power plants by approximately 70 percent by 2018. The first phase of CAMR depends upon the co-benefits of control measures implemented under phase one of CAIR, while the second phase is expected to require additional mercury specific control measures.

Table 2.03a. Major U.S. Laws and Regulations Regarding Air Emissions

1963 Clean Air Act (Original)	
1967 Clean Air Act Amendments	• Requires New Source Performance Standards (NSPS)
1970 Clean Air Act Amendments	• Requires National Ambient Air Quality Standards (NAAQS) • Requires State Implementation Plans (SIPs) to achieve NAAQS • Requires National Emissions Standards for Hazardous Air Pollutants (NESHAPs) • Mandates New Source Reviews in non-attainment areas
1977 Clean Air Act Amendments	• Prevention of Significant Deterioration (PSD) of air quality
1990 Clean Air Act Amendments (complete rewrite of the old Clean Air Act)	• Revises the Titles and requires EPA to issue 175 new regulations, 30 guidance documents, and 22 reports • Requires EPA to establish interstate air pollution transport regions. • Mandates maximum achievable control technology (MACT) for 189 airborne toxics by 2003. • Mandates reduction of SOx emissions by 8.9 million tons per year by 2000. • Requires EPA to establish an allowance trading and tracking system for SOx emissions. • Mandates permit and emissions fee system for acid rain emissions • Basis for regulations including two phase SO_2 reduction program, Title IV NOx reductions, NAAQS NOx reductions, 2005 Clean Air Interstate Rule, and 2005 Clean Air Mercury Rule.

Source: http://www.co.mendocino.ca.us/aqmd/pages/CAA%20history.html

B. Environmental Administration

U.S. EPA rules and regulations are administered in Indiana and surrounding states by the state's agencies show in Table 2.03b. The permitting process is similar but not identical across the states although each states is required to meet U.S. EPA rules as a minimum requirement (state rules may be more stringent but not less stringent). The appeals process for state issued air permits vary state by state (Table 2.03c). In some cases, the appeal process is through a state agency and in others by U.S. EPA

Table 2.03b. Permitting Authorities for Each State

State	*Permitting Authority*
Indiana	Indiana Department of Environmental Management Office of Air Quality
Illinois	Illinois Environmental Protection Agency Division of Air Pollution Control
Kentucky	Division for Air Quality Dept. for Environmental Protection[1]
Michigan	Michigan Department of Environmental Quality Air Quality Division[2]
Ohio	Ohio EPA District Offices and Local Air Pollution Control Agencies[3]
Wisconsin	Wisconsin Department of Natural Resources Permits Section[2]

[1] Jefferson County also controlled by Air Pollution Control District
[2] Indian areas of Michigan and Wisconsin are also controlled by Air and Radiation Division, US EPA
[3] Ohio controlled by 21 local agencies
Source: http://www.epa.gov/nsr/where.html

Table 2.03c. Appeal Authorities for Each State

State	*Appeal Authority*
Indiana	Indiana Office of Environmental Adjudication (OEA)
Illinois	Illinois Environmental Protection Agency Division of Legal Counsel (DLC)
Kentucky	Kentucky Division for Air Quality Department of Air Quality
Michigan	US EPA Environmental Appeals Board (Attainment Area) Michigan Circuit Court (Nonattainment Area)
Ohio	Ohio Environmental Review Appeals Commission
Wisconsin	Wisconsin Department of Natural Resources

Source: http://www.epa.gov/nsr/where.html and related links.

C. Non-attainment Areas

Under the Clean Air Act, U.S. EPA is required to determine areas that do not meet the National Ambient Air Quality Standards (NAAQS) for several air borne pollutants such as ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide and particulate matter. Areas that do not meet the NAAQS for one or more of these air pollutants are referred to as non-attainment areas; and conversely, areas that meet the standards are referred to as attainment areas. Figure 2.03a shows the Indiana Counties that fail to meet the ozone and/or the new fine particulates standards. (These pollutants are among those targeted by the 2005 CAIR.)

D. New Sources

Any new source or existing source which undergoes major modification must meet the most recent New Source Performance Standards (NSPS) during a New Source Review

(NSR). The NSPS differ depending upon the location of the source facility. Facilities which are located in the attainment areas must meet current U.S. EPA emissions limits for the pollutions included in the NAAQS using the Best Available Control Technology. Determination of BACT is a state level decision using U.S. EPA guidelines and includes consideration of technology, energy source, environmental, and economic impacts of BACT choice. For facilities located in non-attainment areas, the emission control device(s) must be Lowest Achievable Emission Rate (LAER) without regard to the energy, environmental or economic impact of the control devices. Also, the NSR applicant must prove that all other facilities owned by the applicant in the state meet all applicable emissions rules, and obtain emissions offsets from other parties to cover emissions from the facility under review.

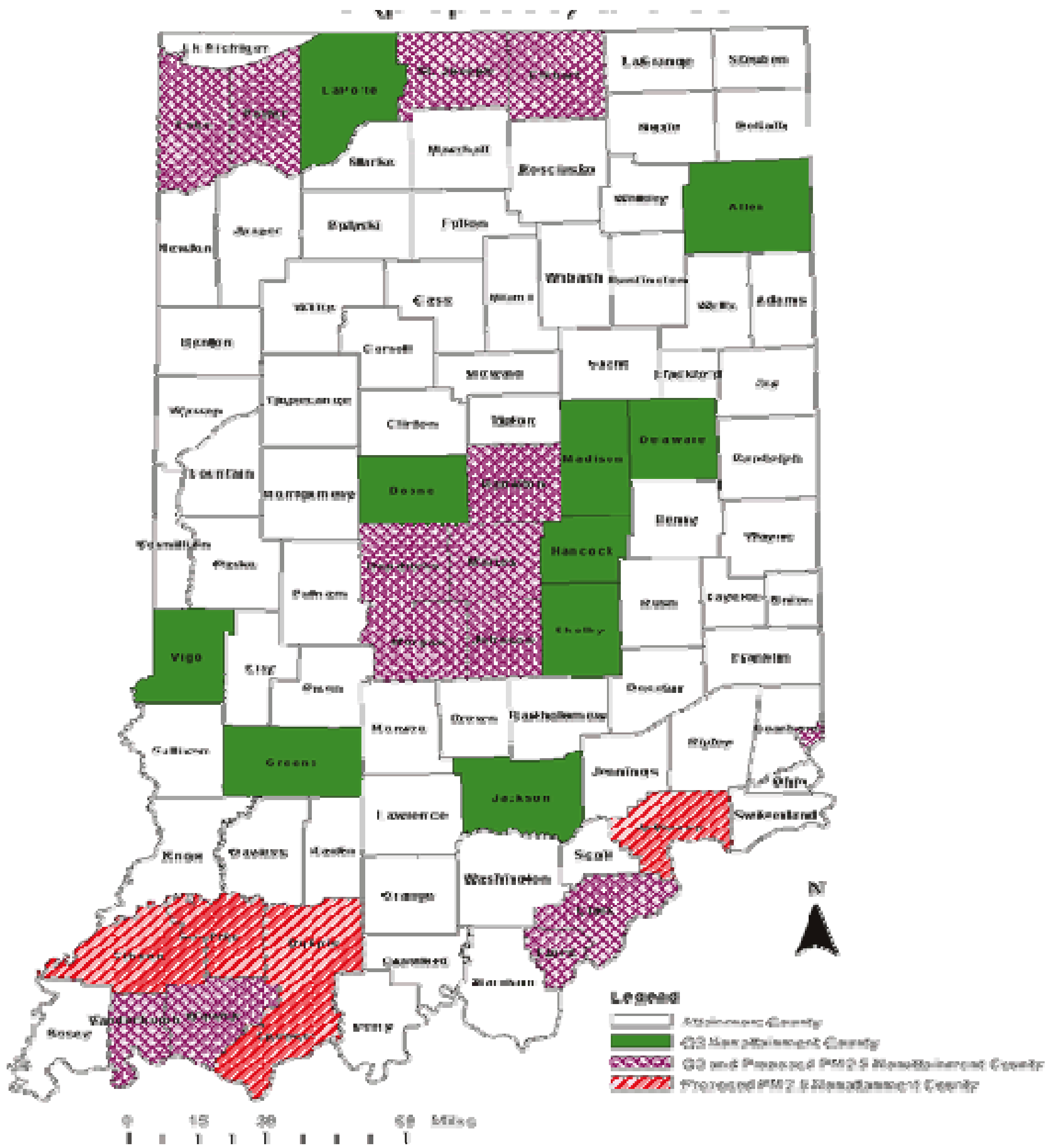


Figure 2.03a. Indiana Designated Nonattainment Counties for PM2.5 and O3
Source: http://www.in.gov/idem/air/8hourstandard/ozoneandmp_map.html

E. Combustions Byproducts

U.S. EPA does not regulate coal combustion products (CCPs) as hazardous materials. Regulations of those materials (Table 2.03c) is under state and local authorities since they are considered non-hazardous and are either typically disposed of in on-site landfills or used for beneficial purposes. U.S. EPA, several state agencies, and interested industry partners are exploring ways to increase the beneficial use of CCPs.

Table 2.03d. Major Coal Combustions Products, Uses and Values

Combustion Product	*Use*	*Value*
Boiler Slag	Blasting Grit Roofing Applications	
Bottom Ash	Concrete Structure Fill Road Base Snow and Ice control	 $4-$8/ton $3-$6/ton
Flue Gas Desulphurization Materials	Wallboard	
Fly Ash	Concrete Structure Fill Waste Stabilization	$20-$45/ton $1+/ ton $25/ton

Sources: http://pubs.nsgs.gov/fs/fs076-01/fs076-01.html, http://www.acaa-usa.org/FAQ.htm

F. CO_2 Sequestration

CO_2 sequestration is a matter of great debate and uncertainty. In 2000 Indiana produced 235 million metric tons of CO_2 [6]. If regulation is ever implemented, geological sequestration will have the greatest capacity for none terrestrial sequestration. The Mt. Simon Aquifer is a deep saline formation that may have between 44 and 218 billion metric tons of capacity [9]. The formation is over a large portion of the Midwest and the map in Figure 2.03b gives depths of the formation in Indiana.

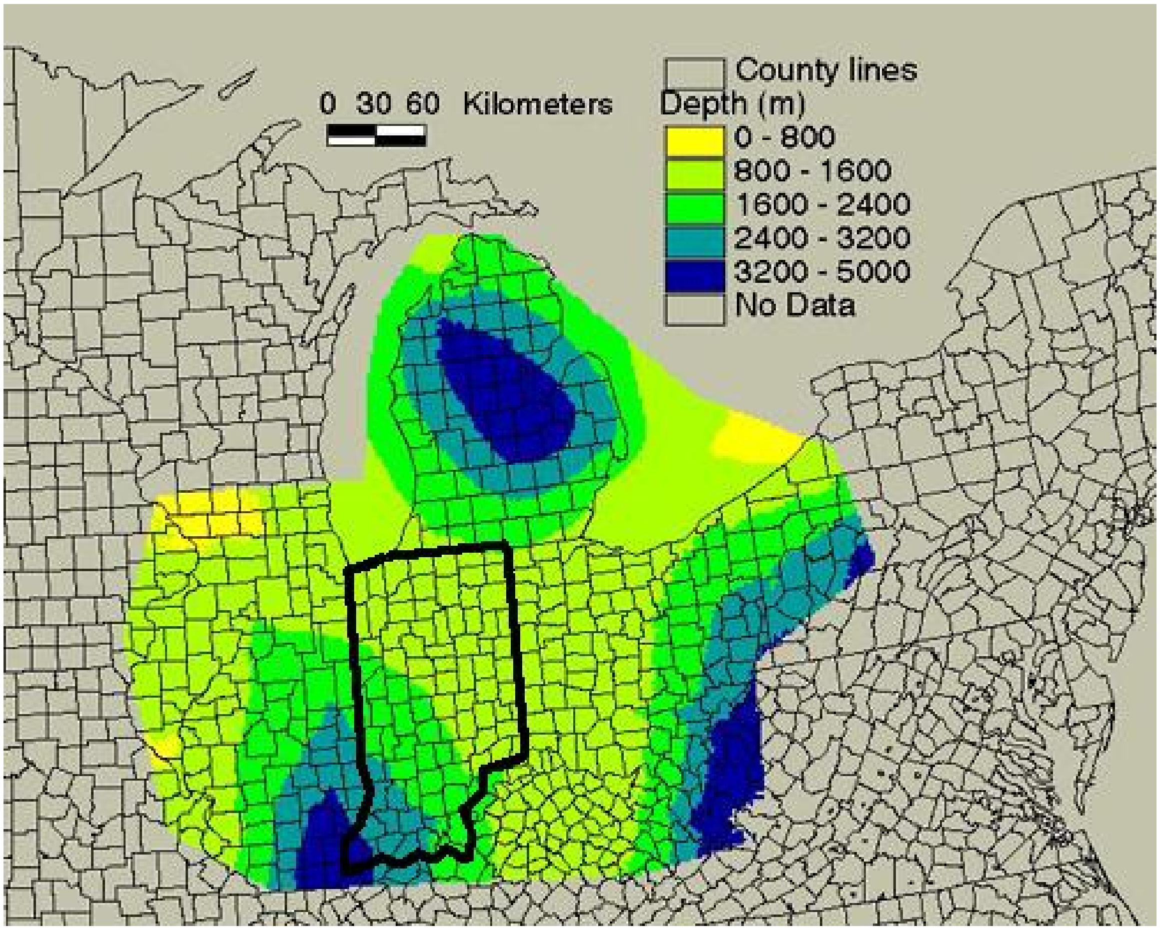


Figure 2.03b. Mt. Simon Aquifer
Source: http://www.beg.utexas.edu/environqlty/co2seq/1mtsimon.htm

2.04 Technology/Human Structure of Coal Research in Neighboring States

A. Indiana

Coal research in Indiana has been very limited to date except coal characterization that has been carried out by the Indiana Geological Survey at Indiana University. The state legislature mandated the establishment of the Center for Coal Technology Research; however, state funding for the center has yet to materialize. As indicated below, Indiana's neighboring states with significant coal production all have strong coal research and substantial state funding. It should also be noted that the Ivy Tech campus at Terre Haute has a mining training program.

B. Illinois

Of Indiana's neighboring states, Illinois conducts the most coal research. The state founded the Illinois Clean Coal Institute (ICCI) more than 20 years ago. The Coal Research and Development Program under ICCI is the technical component of the Office of Coal Development (OCD) of the Illinois Department of Commerce and Economic

Opportunity (DCEO). OCD deals with developing and conducting the Illinois Coal R&D program. The ICCI is a funding organization and is to: *promote the development and application of new and/or improved technologies that contribute to the economic and environmentally sound use of Illinois coal. This will be accomplished using outside contractors to conduct R&D, evaluation studies and the development of concepts to assist producers and users of Illinois coal..., and to create new markets for Illinois coal* [7]. The annual budget is about $2.6 million for the past few years, and open bids are conducted for coal research across the state [8]. In addition to R&D, OCD has supported many demonstration and development programs in the state, and the Southern Illinois Clean Energy Center and the Royster-Clark Nitrogen are two typical examples

The coal research center at the Southern Illinois University at Carbondale (SIUC) is one of the leading research groups competing for the ICCI grants (the SIUC center also received a $25 million donation from ComEd in 2000 for coal research). Currently, the SIUC center has seven regular research staff, one training specialist and some support personnel.

There are also some private research and development institutions and the most well known is the Gasification Technology Institute (GTI).

C. Kentucky

Kentucky also has a strong capability in coal research and development. The best known research organization in the state is the Center for Advanced Energy Research (CAER) whose research is focused on clean coal technologies. Recent annual funding from the state for the center was about $4.5 million, of which about $1 million was for operating costs [8]. CAER has also obtained funding from federal and industry sources (Table 2.04a provides a few examples). CAER currently has one director, four associate directors, 30 plus regular research staff, eight faculty research associates and some support personal. More information is available at http://www.caer.uky.edu/. CAER has a group specializing in the Fischer-Tropsch process, a process for gas to liquid conversion patented in the early last century in Germany.

Table 2.04a. Sample CAER Project Funds (KSEF = Kentucky Science & Engineering Foundation)

Project	*Outside source (in $1,000)*	*CAER match (in $1,000)*	*Comments*
IGCC by-products	200 (DOE)	50	Match < 50%
Fly-ash-concrete	49.286 (DOE)	49.963	
Nanotube for coal extract	111.292 (DOE)	112.877	
Bulk carbon fibre (coal use)	57.541 (DOE)	58.388	
Catalysts for NOx control	49.575 (KSEF)	49.985	

Source: http://www.caer.uky.edu/

D. Michigan

There is basically no coal production in Michigan, and hence no coal research center. However, some small-scale coal research programs are distributed in the state. For example, Michigan State University has been doing research in the use of coal ash and Michigan Technological University has researched a novel, algae growing bio-scrubber that could be retrofitted to existing power plants or applied to new power plants (a DOE-sponsored project).

E. Ohio

Ohio has a strong coal research capability. The Ohio Coal Research Center, hosted at Ohio University, is the leading coal research identity in the state. There is an "Ohio Coal Research Consortium (OCRC)" administered by the Ohio Coal Development Office (OCDC). The OCRC consists of six universities and industry, and the annual funding from OCDC is a bit over $1 million, plus federal and private sources. The Ohio Coal Research Center currently has about seven regular research staff members, four of them are faculty. More information can be found at http://www.ent.ohiou.edu/~ohiocoal/.

The state has co-sponsored with DOE a research program on ultra supercritical pulverized coal (USC-PC) plant design.

F. Wisconsin

Wisconsin is in a similar situation as Michigan: basically no coal production, not much proved coal reserve.

G. Summary

The R&D and training capabilities of the six states is summarized in Table 2.04b. As is shown in the table, Indiana's neighboring states all have significant coal research capability and substantial state funding for clean coal technologies.

Table 2.04b. Coal Research & Training Capability by State in the Midwest

	State funding per year	*Industry*	*Research organizations*	*Training organizations*	*Comments*
Indiana	150,000	n/a	IGS, Purdue	Ivy Tech	
Illinois	2,600,000	> 2,000,000	SIUC, UCUI, GTI, etc.	One in SIUC	SIUC website
Kentucky	4,500,000	n/a	CAER, etc.	Online program & a college	Online program is by the KY Foundation
Michigan	n/a	n/a	MSU, UM, MTU	none	
Ohio	> 1,000,000	n/a	OU, OSU, Akron Univ., etc.	n/a	
Wisconsin	n/a	n/a	UI-Madison	none	

2.05 Electricity Demand Growth

Table 2.05 shows average compound growth rates of projected electric energy use prepared by three organizations: the State Utility Forecasting Group (SUFG) at Purdue University; the Energy Information Agency (EIA) of the U.S. Department of Energy and the North American Electric Reliability Council (NERC), a voluntary organization of ten Regional Reliability Councils which in turn are voluntary organizations of electricity generation, transmission, and distribution providers.

SUFG develops long-term projections of retail electricity sales in the State of Indiana. EIA develops similar projections but focuses on the entire U.S. and reports consumption forecasts by census region (Figure 2.05a). NERC develops regional projections for the Regional Reliability Councils (Figure 2.05b) by aggregating projections provided by the members of the Regional Reliability Councils.

The EIA projections for the East North Central (ENC) census region includes Indiana and all surrounding states except Kentucky which is the northern most state in the East South Central (ESC) census region. The NERC region East Central Area Reliability Coordination Agreement (ECAR) includes Indiana, Kentucky, the lower peninsula of Michigan, and Ohio while the Mid-American Interconnected Network (MAIN) includes Illinois, eastern Wisconsin, and the upper peninsula of Michigan. The table includes all of the EIA census regions projections for the census regions east of the Rocky Mountains to illustrate the variability across geographic regions. The NERC regional projections exhibit similar variations.

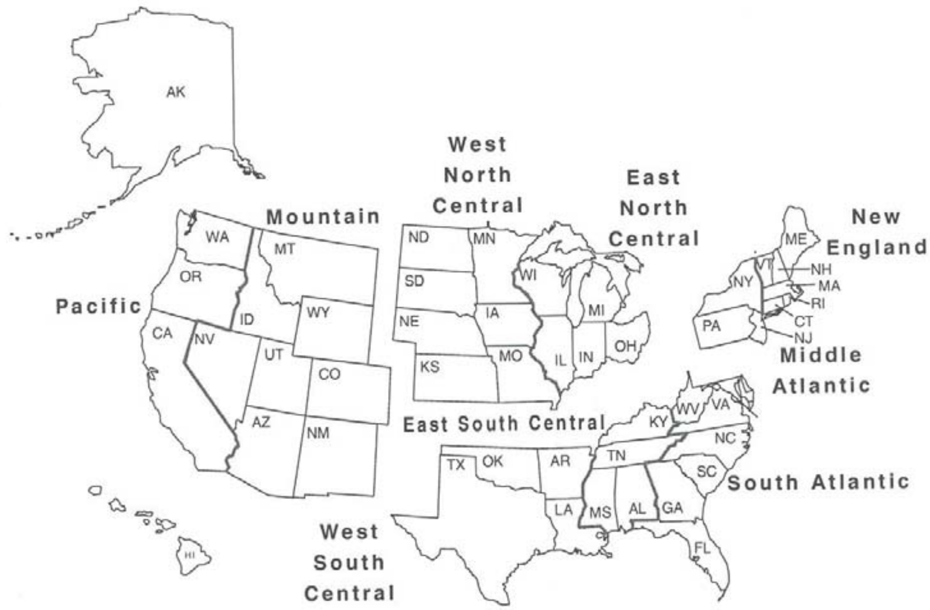
SUFG's total energy requirements (Figure 2.05c) exhibit more growth than the more modest growth projected by EIA for the ENC region and NERC for the ECAR and MAIN regions. Speculation leads one to suspect that the differences are due to the differences in key input assumptions such as fossil fuel prices, population growth and regional economic activity; and perhaps the different time periods over which the average growth rates apply.

SUFG projects that the state of Indiana will require 9100 MW of additional resources by 2020, of which nearly 5500 is expected to be baseload resources. Baseload electricity resources in the Midwest have traditionally been composed of coal and nuclear power generation plants, although more recently some gas-fired combined cycle plants have been built by independent power producers (before the recent increase in natural gas prices), and conservation measures may reduce the need for additional generation resources somewhat. Since EIA and NERC both project slower growth than SUFG, one would expect that the need for additional baseload resources would be somewhat lower using these projections.

Table 2.05. Electric Energy Requirements (ACGR)

			Residential	Commercial	Industrial	Total
SUFG	Indiana	2002-21	1.95	2.71	1.97	2.16
EIA	NE	2003-25	1.10	1.90	0.80	1.40
	MA	2003-25	0.90	1.60	0.80	1.20
	ENC	2003-25	1.30	2.10	1.10	1.50
	WNC	2003-25	1.60	2.20	1.20	1.70
	SA	2003-25	2.00	2.90	1.40	2.20
	ESC	2003-25	0.70	3.00	1.40	1.60
NERC	ECAR	2004-13				1.62
	MAIN	2004-13				1.44

SUFG https://engineering.purdue.edu/IE/Research/PEMRG/SUFG
EIA http://www.eia.doe.gov/oiaf/aeo/supplement/index.html
NERC http://www.nerc.com/~esd/nel.xls



Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 2.05a. United States Census Divisions

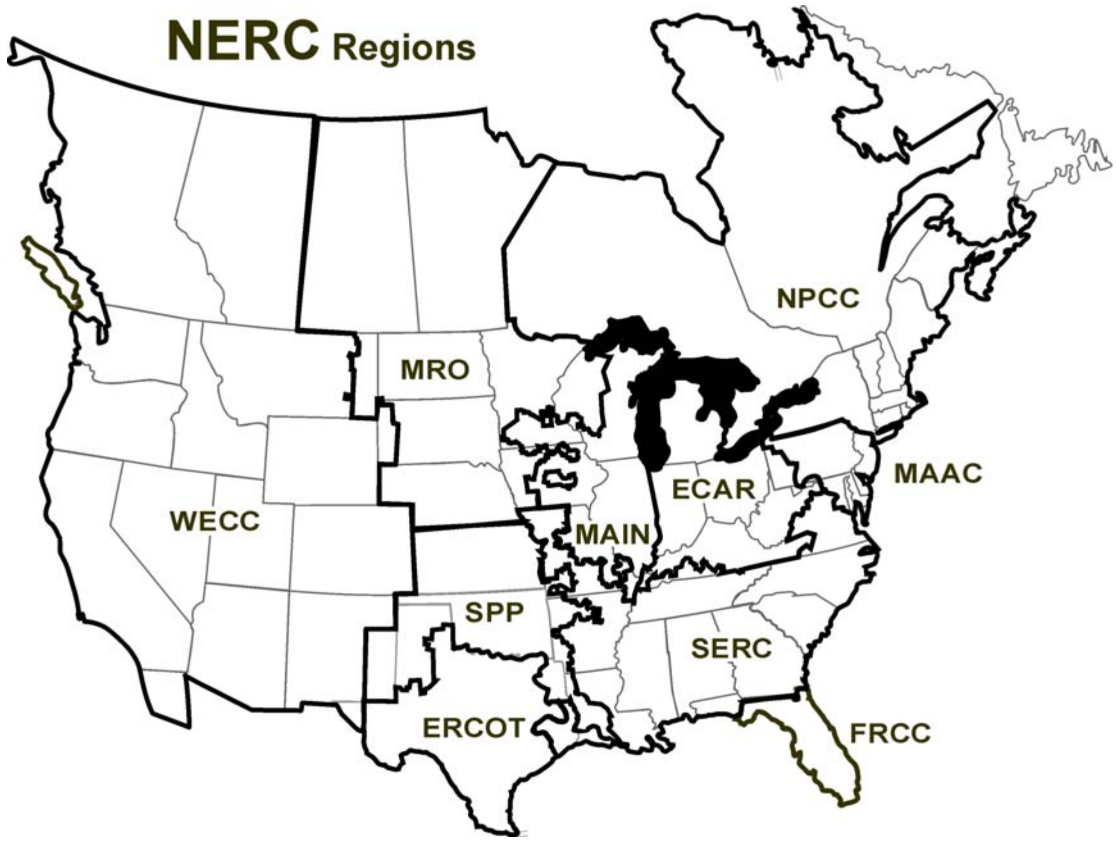
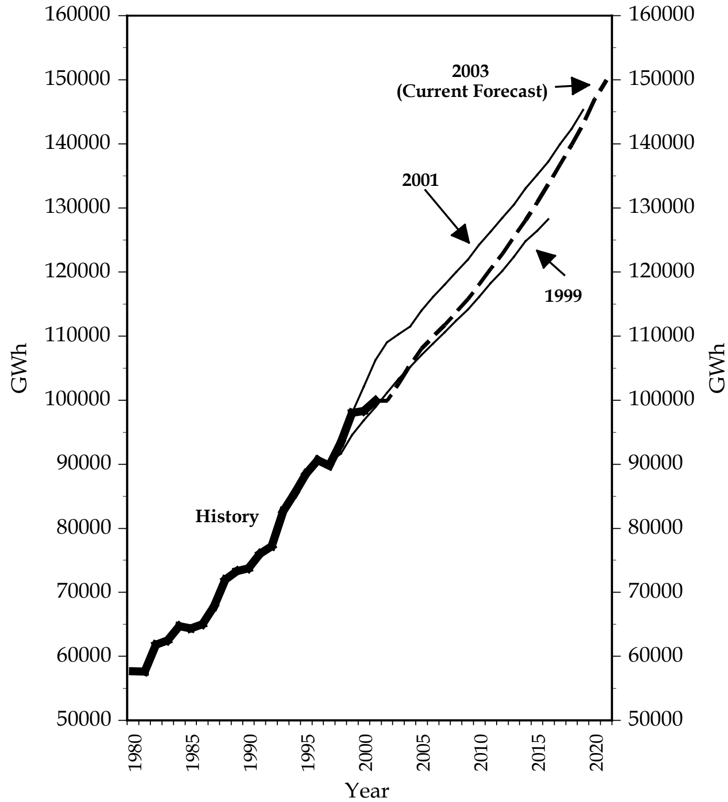


Figure 2.05b. NERC Reliability
Source: http://www.nerc.com/~esd/nel.xls

Year	1999	2001	2003
1990	73742	73742	73742
1991	76034	76034	76034
1992	77207	77207	77207
1993	82669	82669	82669
1994	85446	85446	85446
1995	88514	88514	88514
1996	90637	90637	90637
1997	90237	89773	89773
1998	91634	93429	93429
1999	94561	98001	98001
2000	96867	102116	98332
2001	98922	106257	99933
2002	101170	109014	99934
2003	103298	110294	102680
2004	105179	111515	105592
2005	107058	113997	108053
2006	108833	116118	109944
2007	110601	118017	111758
2008	112433	120012	113769
2009	114148	121892	115798
2010	116124	124225	118115
2011	118291	126317	120546
2012	120130	128418	122899
2013	122389	130497	125532
2014	124797	133048	128116
2015	126406	135161	130895
2016	128237	137244	133805
2017		139973	136839
2018		142342	139920
2019		145333	143145
2020			147067
2021			150013



Note: the shaded numbers in the table and the heavy line in the graph are historical values.

	Average Compound Growth Rates		
Forecast Period	**1997-16**	**2000-19**	**2002-21**
	1.87	1.87	2.16

Figure 2.05c. Indiana Electricity Requirements in GWh (Historical, Current and Previous Forecasts)

Source: https://engineering.purdue.edu/IE/Research?PEMRG/SUFG

2.06 Legacy Boiler Population

One aspect of clean coal technology that is important to Indiana is the repowering of existing boiler units. The following figures give information about the various boilers in Indiana. It can be seen from Figure 2.06a that most coal boilers in Indiana are at least 20 years old and some are up to 50 years old. As these older boilers get replaced, clean coal technologies will play a major role. Figure 2.06b shows the increasing size of installed units over the years and the how coal units tend to be much larger in size than natural gas units. From Figure 2.06c, it can be seen that sulfur removal technology is already playing a major role in the production of electricity in Indiana from coal. As new emission standards are put in place, more and more units will have pollutant controls. Lastly, Figure 2.06d show the breakdown of electric capacity ownership in Indiana between Indianapolis Power and Light, Indiana Michigan Power Company, Northern Indiana Public Service Company, Southern Indiana Gas and Electric Company, Hoosier Energy, Independent Power Producers, and others. All data was obtained from the Federal Energy Regulatory Commission 2003 form 767 data and only includes combustion facilities of 25 Megawatts or more and may be incomplete.

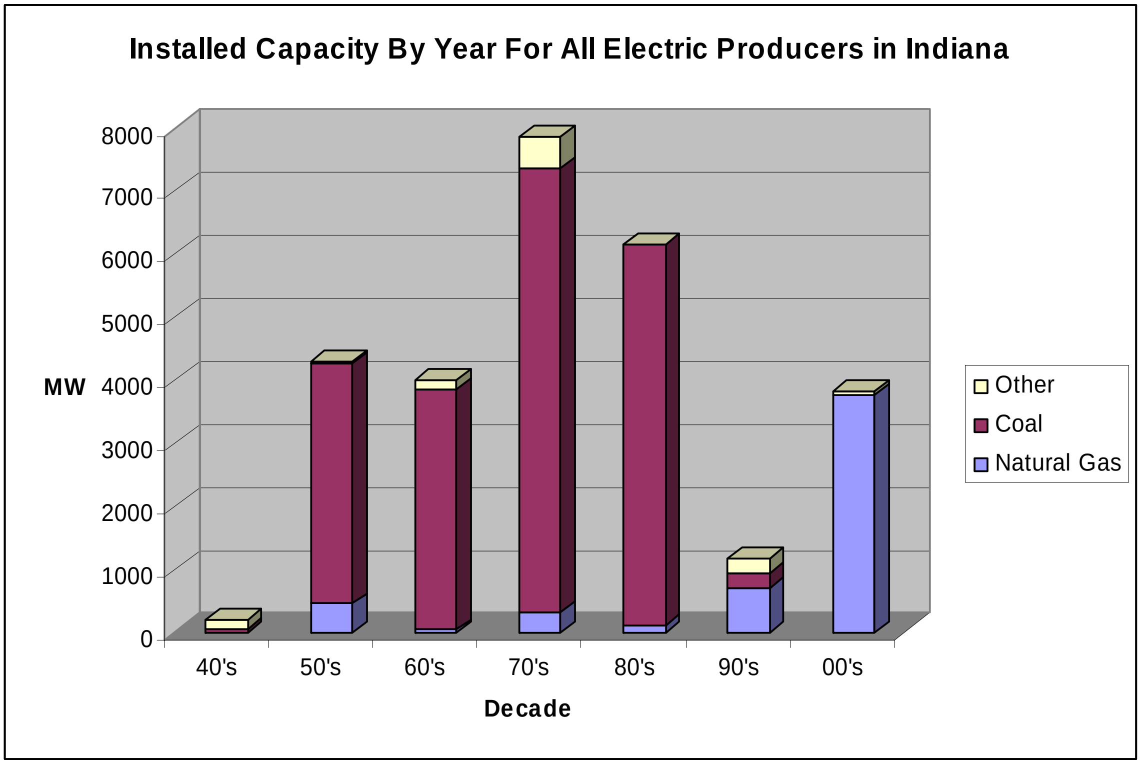


Figure 2.06a. Installed Capacity by Year

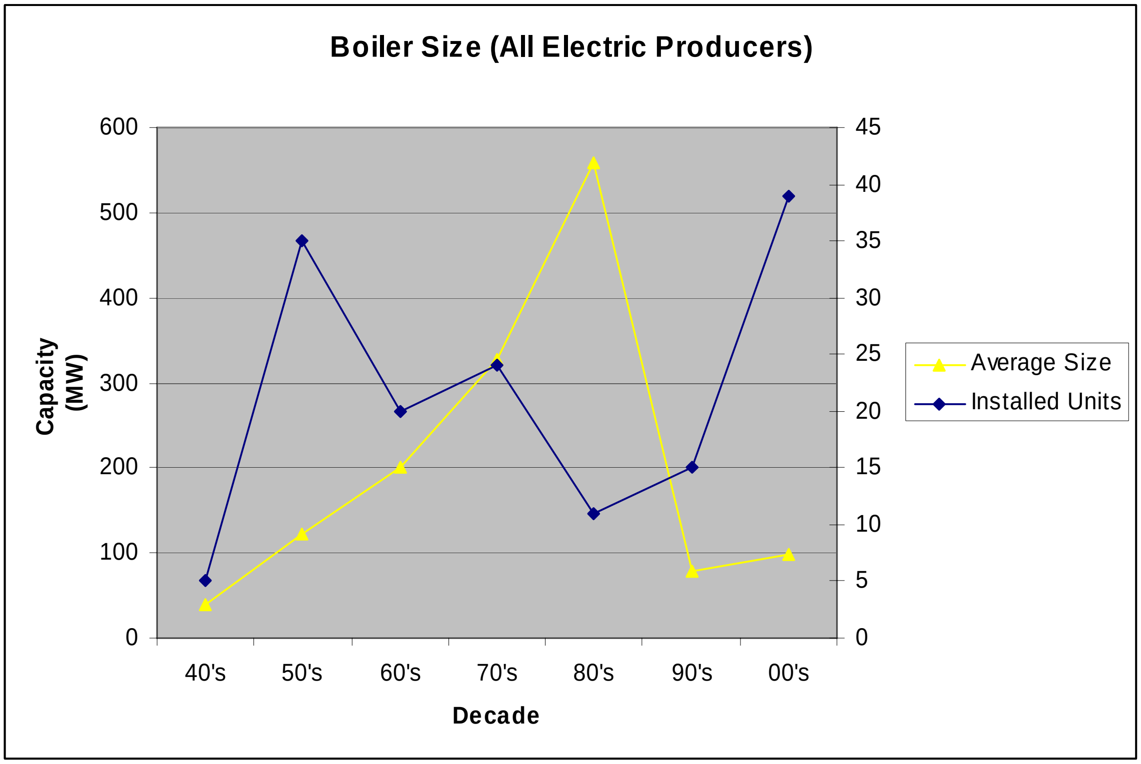


Figure 2.06b. Boiler Size (All Electricity Producers)

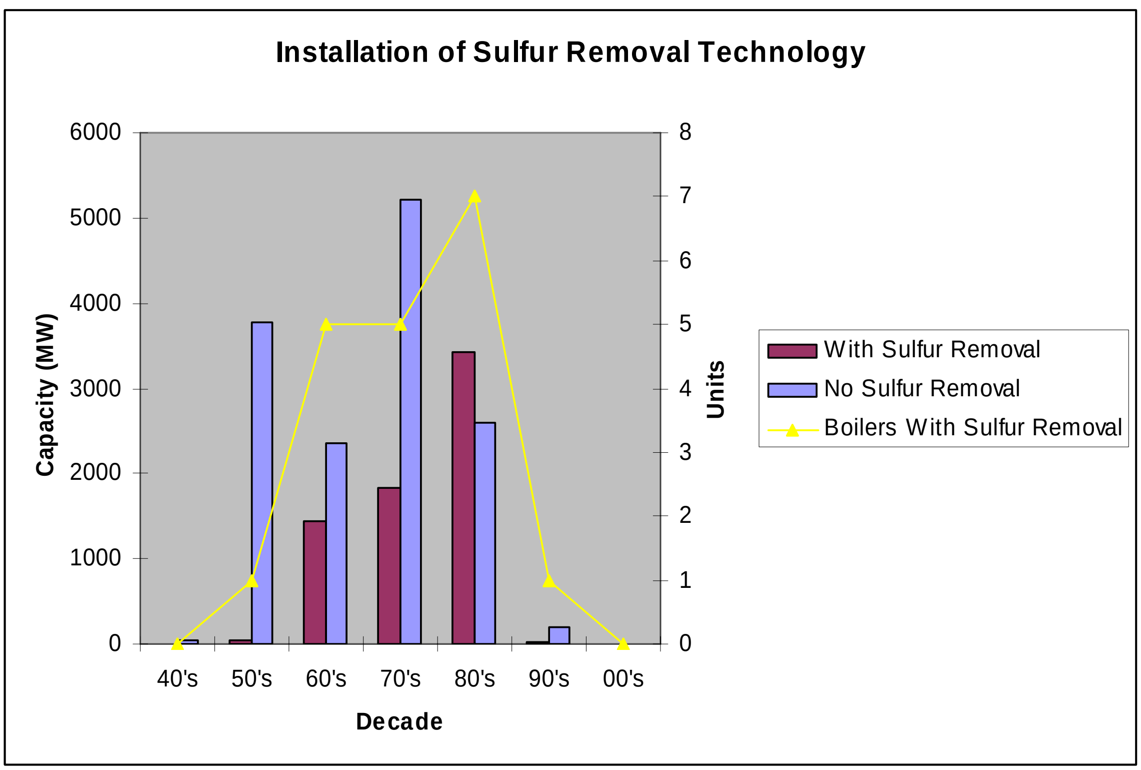


Figure 2.06c. Installation of Sulfur Removal Technology

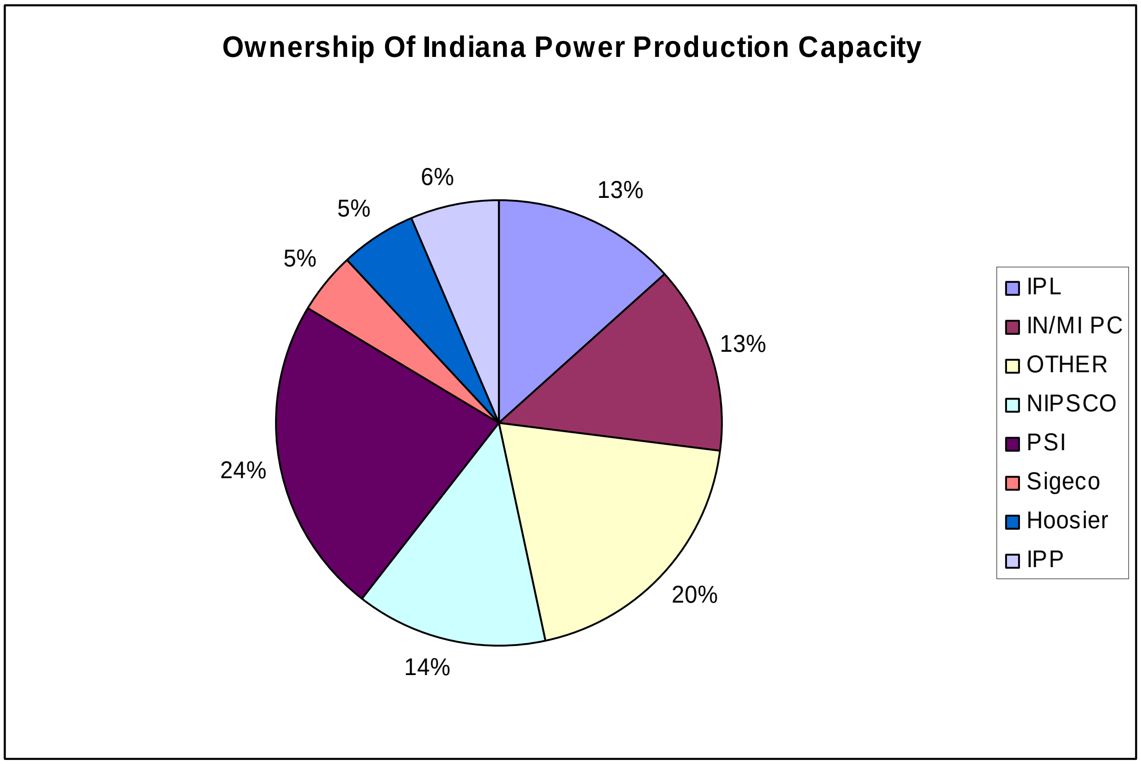


Figure 2.06d. Ownership of Indiana Power Production

2.07 Electricity Power Transmission Network

A major consideration in the installation of clean coal technologies will be access to major transmission lines. Figure 2.07 is a representation of the major transmission lines in Indiana with the location of existing electric production facilities. Locations of plants and transmission lines are not exact and are to be used for representational purposes only.

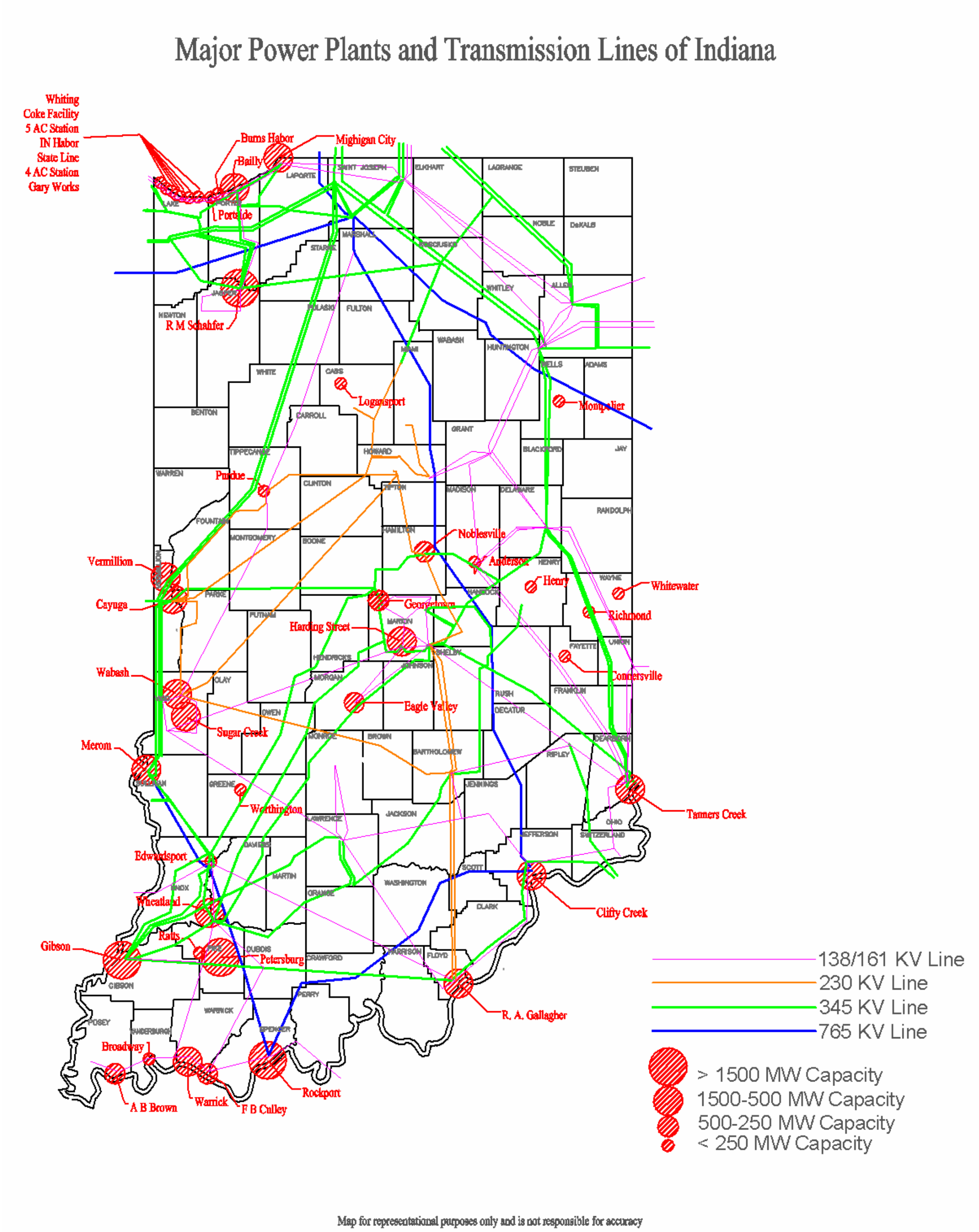


Figure 2.07. Indiana's Major Power Plants and Transmission Lines

2.08 Natural Gas Transmission Network

An aspect of IGCCs that must be considered in the future is the possibility for natural gas backup systems as well as the possibility of producing syngas for use in the natural gas transmission lines. Figure 2.08 shows the location of major gas transmission lines in Indiana. As with Figure 2.07, all information is not exact and should be used for representational purposes only.

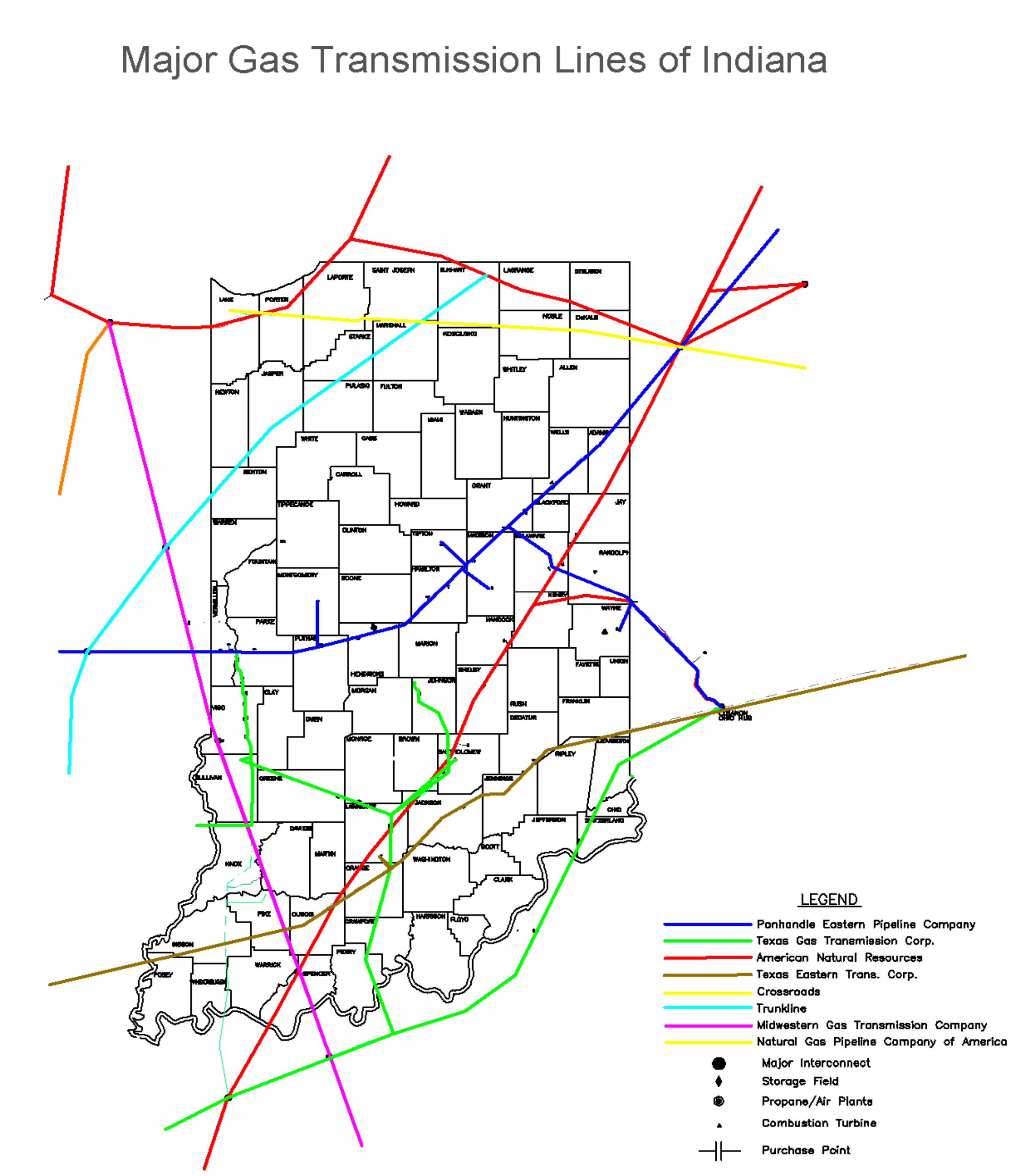


Figure 2.08. Indiana's Major Gas Transmission Lines

2.09 Coal Transportation Infrastructure

Figure 2.09 shows the network of Class I railroads serving the Midwest. Virtually all the coal used in Indiana for electric power production (other than at mine-mouth plants) moves over either this rail system or by barge to plants near the Ohio River.

With almost all Indiana's coal resources being in the southwest part of the state along the Illinois border, this rail configuration creates a significant barrier to increased use of Indiana coals by power plants in the northern part of the state. Coal mined in Southwest Indiana must be shipped through Illinois and Chicago to reach those markets.

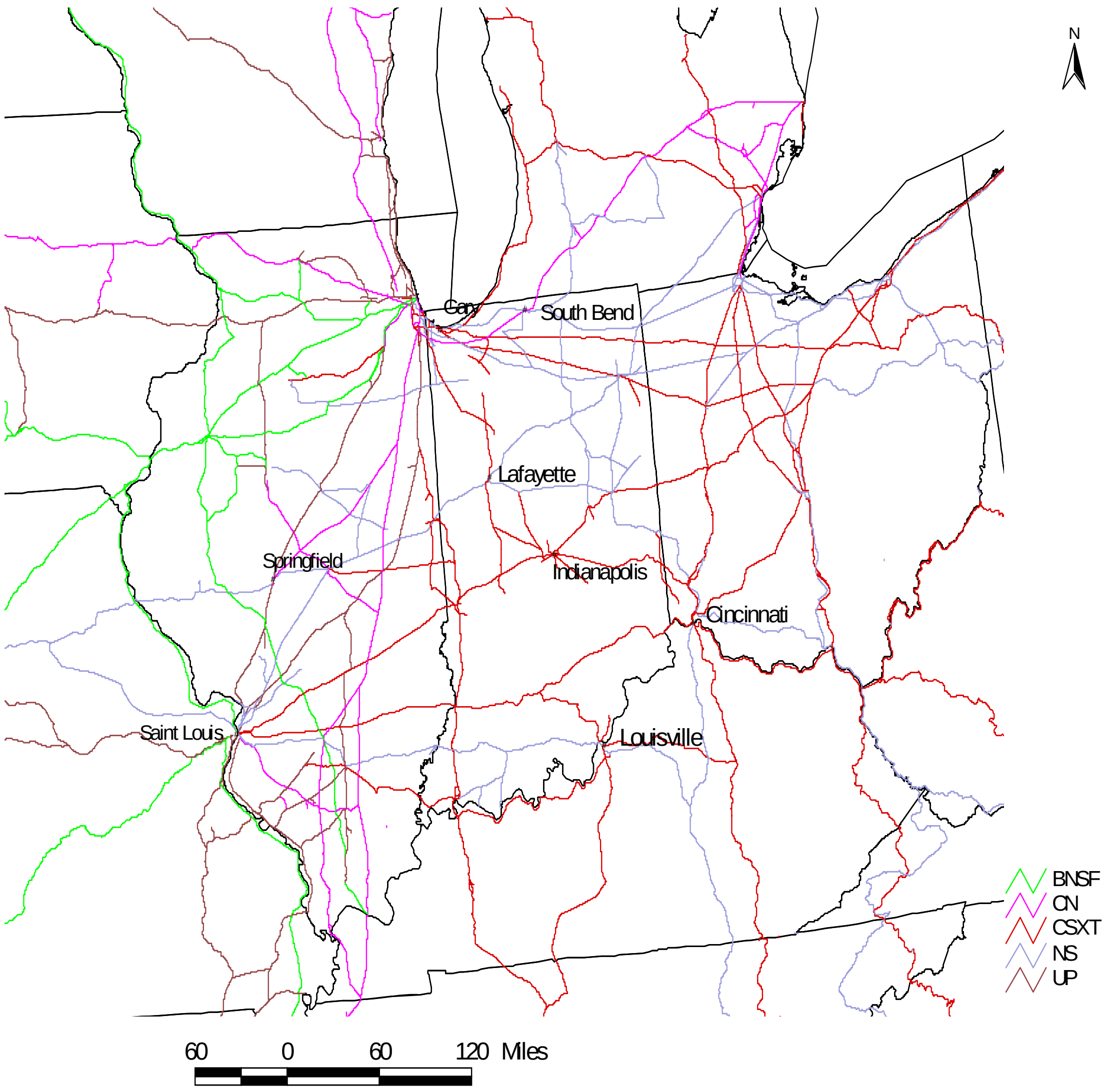


Figure 2.09. Class I Railroads in the Midwest

References

[1] FERC Form 1, Dec. 2003.

[2] Powermarketers Association, "Rates worry PSC chief; 3 state utilities take top spots in 4-state region," April 17, 2005.

[3] EIA, Status of State Electric Industry Restructuring Activity, available online at: http://www.eia.gov/.

[4] Illinois Commerce Commission (ICC): Docket 98-0544, Final Order.

[5] ICC: Certification Application Form: Instructions.

[6] http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/SVDN5SZKKA/$File/state_co$_2$_ffc.pdf

[7] ICCI website at http://www.icci.org/.

[8] Structure of Neighboring State Coal Research Centers Summary, August 18, 2004, CCTR Workshop, Indianapolis.

[9] M. Mastalerz, A. Drobniak, J. Rupp, N. Shaffer, "Characterization of Indiana's Coal Resource: Availability of The Reserves, Physical and Chemical Properties of the Coal, and the Present and Potential Uses." July, 2004.

Preliminary Scenarios and Results

Resources and time available for this scoping study have not permitted major modeling analyses. However, the proposal did call for some broad, preliminary scenarios to help focus thinking about future actions and research. Recognizing that the potential impact of CO2 limits is probably the biggest single issue in Indiana implementation of clean-coal technologies, it was decided to focus those scenarios on the CO2 question. This section describes the scenarios investigated and the results obtained.

3.01 Preliminary Scenario Designs and Assumptions

Table 3.01 details the twelve scenarios investigated, including the identifier used for each. They consist of all combinations of four technologies and three CO_2 capture penetrations.

- Three popular CCTs are considered: Circulating Atmospheric Fluidized-Bed Combustion (AFBC), Supercritical PC (or Ultra SCPC) and IGCC in variants with and without a backup gasifier.
- Each of these technologies is run without CO_2 capture, with CO_2 capture on new baseload capacity after 2010, and with CO_2 capture on 150% of new baseload capacity after 2010 to simulate repowering.
- The Pulverized Coal scenario without CO_2 capture (bold) serves as a base case if CCTs are not implemented.

Table 3.01 Scenario Definitions and Identifiers

	No CO_2	CO_2 Recovery on New Baseload Required	CO_2 Recovery on 150% of New Baseload Required
Super Critical Pulverized Coal	**PC no CO_2**	PC CO_2	PC CO_2+50
IGCC with No Backup	IGnobk no CO_2	IGnobk CO2	IGnobk CO2+50
IGCC with Backup	IGbk no CO_2	IGbk CO_2	IGbk CO_2+50
Atmospheric Fluidize Bed Combustions	FB no CO_2	FB CO_2	FB CO_2+50

A. Cost and Heat Rate Assumptions

Table 3.02 shows cost and heat rate assumptions used in the scenario analysis. Some elements are common to all:

- Costs are in 2003 dollars and assumed constant per unit of capacity or production even though economies of scale would probably arise in real operation. Real capital unit costs do decline 1% per year beginning 2011 to reflect technology improvements.
- All cost values are intended to reflect plants that are fully compliant with environmental regulations (other than possible CO_2 limits).

- In every case, including CO_2 capture not only increases capital costs per MW, but also increases Heat Rates (BTUs per kW hour) due to lost efficiency when running the CO_2 process.
- Costs with CO_2 treatment include CO_2 capture, but not CO_2 sequestration, which can only be evaluated when site geography relative to sequestration locations is modeled.

Capital cost estimates for new SCPC plants depending on many factors, including plant size, design details, the trade-off between efficiency and cost, etc. Currently, the estimates are from about \$1,000 to \$1,400/kW without CO_2 capture (see [5] and Table 1.04d). The median new SCPC capital cost estimate is about \$1,200/kW which is used in this report. This number is also very close to the estimate by [6]. The current capital cost estimate for IGCC is about \$1,350/kW without CO_2 recovery and without a backup gasifier. This number is consistent with the number quoted in Section 1 in the above. With a 2-on-1 (two trains with one spare gasifier) backup gasifier design and without CO_2 recovery, this number would be increased to about \$1,490/kW. The cost would be reduced over time by about 1 percent each year from 2011 to 2023 (the target IGCC cost is about \$1,000/kW in about 15 years by some estimates).

IGCC heat rate is about 8,800 without CO_2 capture depending on the design preference. The heat rate of the Wabash River IGCC is about 8,900 and we assume a 100 point improvement in the nest few years. The fixed O&M is estimated from [1] as \$40/kW-year, and the variable O&M cost is about \$0.8/MWh.

Table 3.02. Cost and Heat Rate Estimates (2003 \$)

Plant type	Heat rate	Capital cost	Fixed O&M (5)	Variable O&M
IGCC (no CO_2 no backup)	8,800	\$1,350/kW (1)	\$40/kW-year	\$0.8/MWh
IGCC (no CO_2 w/ backup)	8,800	\$1490/kW (7)	\$41/kW-year	\$0.85/MWh
IGCC (w/ CO_2 no backup)	11,200	\$1750/kW	\$41/kW-year	\$0.85/MWh
IGCC(w/ backup & CO_2)	11,200	\$1,900/kW(4)	\$42	\$0.90/MWh
PC-SC (no CO_2)	9,600	\$1,200/kW(2)	\$35/kW-yr	\$0.7/MWh
AFBC (no CO_2)	9,700	\$1,120/kW(3)	\$31	\$0.85/MWh
PC-SC (with CO_2) [3]	11,600	\$2,100/kW (6)	\$37	\$0.80/MWh
AFBC (with CO_2) [3]	11,860	\$2,000/kW (6)	\$33	\$0.95/MWh

Notice that the IGCC cost estimates are for the E-Gas type of technology. The GE Quench type of IGCC may be cheaper in terms of capital cost. Other specific notes are: (1) This number is based on the E-Gas quench type of gasifier and is consistent with the estimates by the Worldbank, EPRI (Table 10.04c), Eastman, and others. Some estimate can be as low as $1,170/kW. (2) This SCPC cost estimate is from Eastman and other sources and some estimate is as low as $1,000kW (e.g., Baumgartner & Kern from Siemens, as reported in Table 1.04d). (3) This AFBC cost number is consistent with the estimate from [3] and other sources. (4) This is estimated from figures by EPRI (with a 2-on-1 backup gasifier) and others, as reported in the J2 interim report. In reference [3], it is estimated that IGCC capital cost would be a bit less than $1,600/kW with the use of Selexol for a 75 percent CO_2 recovery. The capital cost for an 85 percent CO_2 recovery may be around $1,700/kW without backup gasifier. (5) O&M costs are from [1] and [2], plus an adder for a 2 percent inflation since the early 1990s. (6) These estimates are close to EPRI estimates. IGCC capital cost with a 3-on-1 backup gasifier will add about $93/kW, and the availability will increase by about 10 percent. (7) Assume that a backup ARC (acid gas cleaning) is added to the backup gasifier ONLY. If an ASU is also added, cost would be higher.

Also note that according to the Senate Energy Bill 2005, DOE is asked to provide load guarantee to IGCC plants whose capacity is no less than 400 MW. This might reduce the capital costs of IGCC plants to the level around $1,200/kW from $1,350/kW (Sec. 414. Goal Gasification – page 495, the July 2005 version of the Bill).

B. Availability and CO_2 Capture Assumptions

Two other critical parameters of CCTs are the assumed availability of production and the assumed fraction of CO_2 exhausts captured by the installed technologies. It is assumed that 85% of the total will be capture for all technologies. As discussed previously, 85% capture is a reasonable assumption because it is in the middle of various capture rate estimates. Table 3.03 details values used for these variables in the scenarios.

Table 3.03. Availability and CO_2 Recovery

Plant type	Availability	Comments	Percent of CO_2 Recovered
IGCC (no CO_2 and no backup gasifier)	80	90% is assumed for the case with backup	85
PC-SC (no CO_2)	86		85
AFBC (no CO_2)	85		85
IGCC(with CO_2 but no backup)	78	88% for the case with CO_2 and backup	85
PC-SC (with CO_2)	84		85
AFBC (with CO_2)	83		85

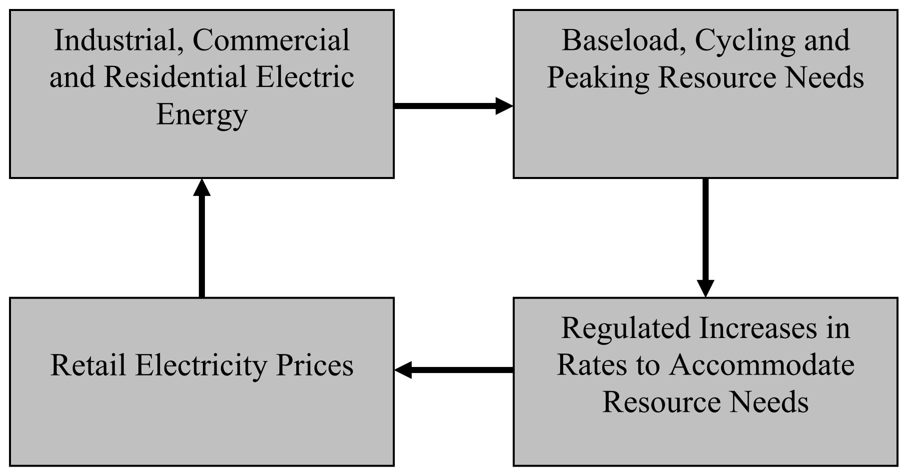


Figure 3.01. Dynamics of the SUFG Modeling System

C. Scenario Running and the SUFG Modeling System

All scenarios were run by applying the same modeling used to develop biannual Forecasts from the State Utility Forecasting Group (SUFG). That system is detailed and complex, but its dynamics that are most important to this scenario analysis are captured in Figure 3.01. Price-responsive demand estimated from economic and demographic trends is met through simulated dispatch to project capacity needs for Baseload (always on), Cycling (on and off), and Peaking (peak hours only) capacity. Needed capacity implies additions to the regulated rate base, which in turn, affects electricity prices. New prices yield new estimated demands, and the loop continues until equilibrium is reached.

Limited resources and time available for these analyses mandated a series of simplifying assumptions:

- Underlying economic growth though 2010 is the same as the 2005 (Draft) SUFG Forecast**.**
- All scenarios run through the last convenient year for SUFG modeling – <u>2023</u>.
- CO_2 standards are assumed effective after <u>2010</u>.
- All added baseload in each scenario, including the extra 50% where appropriate, is assumed to be produced by the scenario's technology option and used on a <u>must take</u> basis. That means the new baseload capacity must be fully used whether or not economics suggested that it is the preferred choice.
- Rather than speculate about which plants might be retrofitted with CCT technology to meet CO_2 regulations, an extra 50% is added to baseload needed capacity growth to <u>simulate retrofit</u>. Under the must take assumption, this

capacity would be dispatched ahead of less production, older, non-CCT units, in effect rendering them off line.

- All CCT capacity is assumed added at <u>generic sites</u> without consideration of geography or transmission costs, and in proportion to utility demands.
- Lacking geographic information CO_2 sequestration is not modeled.
- Cycling and Peaking capacity growth are assumed to use natural gas technology.
- For purposes of CO_2 analyses, the electricity industry in Indiana is modeled as a <u>closed system</u>. That is, other sources of CO_2 are ignored as are any cap-and-trade allowance trading in CO_2 credits.
- Coal consumption estimates assume all new construction after 2010 will be <u>required to use Indiana coal.</u>
- Reported scenario values for Energy and Price represent only the approximately 85% of the state electric energy produced by investor owned utilities because price data is incomplete for the nonprofit utilities.
- Fuel prices assumed: coals, gas, etc. are the same as those used in SUFG Forecasts.

3.02 Results and Analysis

Tables 3.04-3.11 in the Appendix to this part of the report provide detailed time vs. scenario results for all the output variables measured. The next several subsections present summary information and analyses of results.

A. Energy Demand and Price

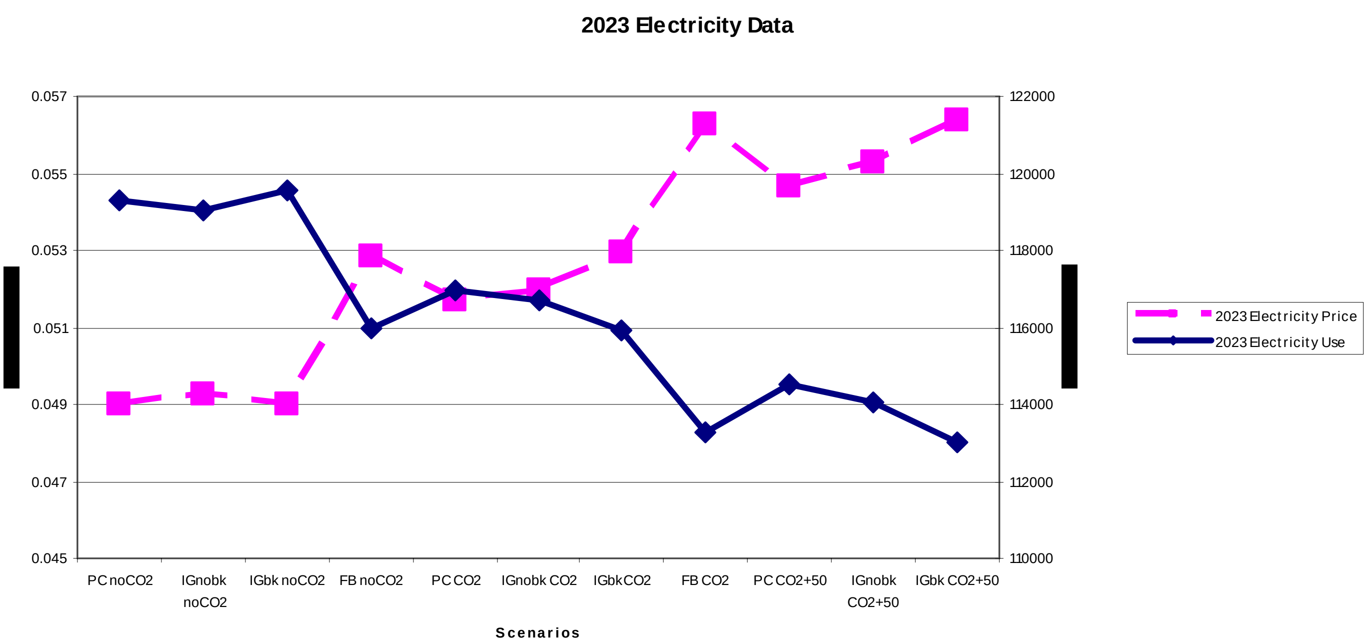


Figure 3.02 Energy demand and price by scenario

Figure 3.02 compares total electric energy demand and average price by scenario for the final simulation year of 2023. The last year is selected because prices increase continually as new capacity is placed into the rate base, typically for a total of 30 years or so. The rate impact by year 2023 is roughly in the middle of the 30 years of capital recovery for new capacity added around 2010, and may better reflect the price impact of CO_2 capture than the first few years when the price impact since the capacity is gradually added and the cost of recovery is spread over time. The price impact of CO_2 capture on Indiana consumers is not severe if the quantities of capture are limited. For example, for the SCPC case, when CO_2 capture is not required, the average price is \$0.0478/kWh, as compared with the price of \$0.0528/kWh for the case with CO_2 capture in SCPC (see Table 3.05). The percentage price change is about 11%. When 150% of new SCPC capacity is assumed with CO_2 capture, the state average price becomes \$0.0563/kWh, and the percentage change is 17.8% by 2023. If IGCCs are used for coping with CO_2 capture in 2011-2023, compared against the base case of SCPC without CO_2, the percentage price increases are 8.8% and 15.7% respectively for the scenarios of IGCC with backup and 150% IGCC capacity with backup, which shows that price increase in 2023 is about 2% less using IGCCs than SCPCs and that. This shows that the price impact is rather moderate using IGCCs for CO_2 capture. Notice that this price changes reflect only generation capacity expansion with CO_2 capture, CO_2 transportation, storage and monitoring, as well as the possible transmission lines for power have not been considered. However, according to some study, the likely cost of transport, storage and monitoring of CO_2 is about \$10/ton [7], which may add only a small percentage to the total cost of electricity in Indiana. The costs of using AFBC plants are very similar to the SCPC cases in this preliminary study.

Prices and demand move in different directions in Figure 3.02, with higher priced technologies constraining demand. This illustrates how increased electricity prices harm the State in both direct and indirect ways. The direct impact is increased economic burden. But higher price also results in lower demand and thus constrained economic activity and diminished quality of life.

B. CO_2 Results

Results in Tables 3.06 and 3.07 yield time lines for each of the technologies. Figure 3.03 illustrates CO_2 releases over time from a few selected scenarios: IGbk no CO_2, IGbk CO_2, PC no CO_2, IGbk CO_2+50, and the 2010 release as a reference.

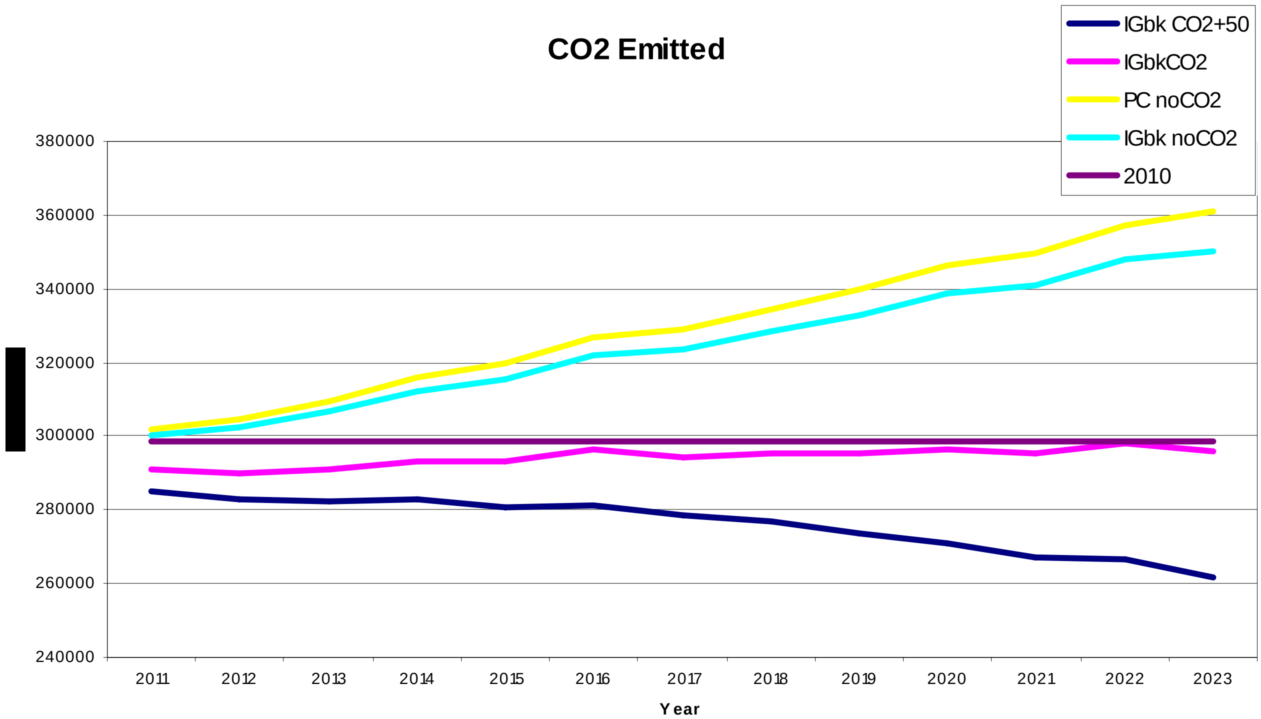


Figure 3.03. Net CO_2 emissions from electricity production by scenario and year

The top line in Figure 3.03 illustrates the continuing growth of CO_2 emissions from power generation in the SCPC base case. The two lines below the 2010 emission level are the IGCC results for new baseload CO_2 recovery, and 150% of new baseload CO_2 recovery, respectively. IGCC results are lower than the base case, even with no CO2 recovery, because of the higher efficiency combustion of IGCC plants. It is interesting to notice that the scenario IGbk CO_2 (capacity expansion using IGCC with a backup gasifier and with CO_2 capture) almost freezes CO_2 release from the 2010 level, except for the first few years with certain reduction of CO_2 release. This reflects the effects of both the assumed 85% capture and demand suppression from higher energy prices. The +50% option simulates repowering results in CO_2 reductions against the 2010 levels.

Figure 3.04 provides comparative results for net emissions in all twelve scenarios in year 2023. As with energy and price results, the last year is most informative because of growth through the modeled period. Results show again the emission growth without CO2 capture, near stability with capture on new construction alone, and actual reductions with simulated retrofit.

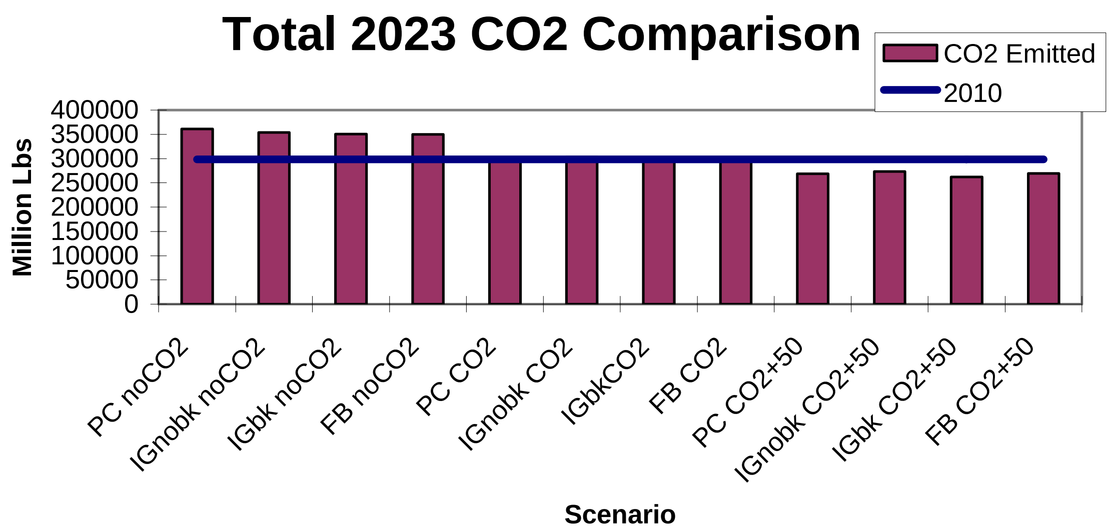


Figure 3.04. Net CO_2 emissions in 2023 by scenario

C. Capacity Growth

Figure 3.05 shows cumulative capacity growth for all twelve of the scenarios, divided into baseload, cycling and peaking resources. All results show relatively large capacity growth in the range of 10-12 thousand megawatts through 2023. This would imply significant construction during that period. Expansion requirements decrease with the CO2 capture options because higher prices reduce demand.

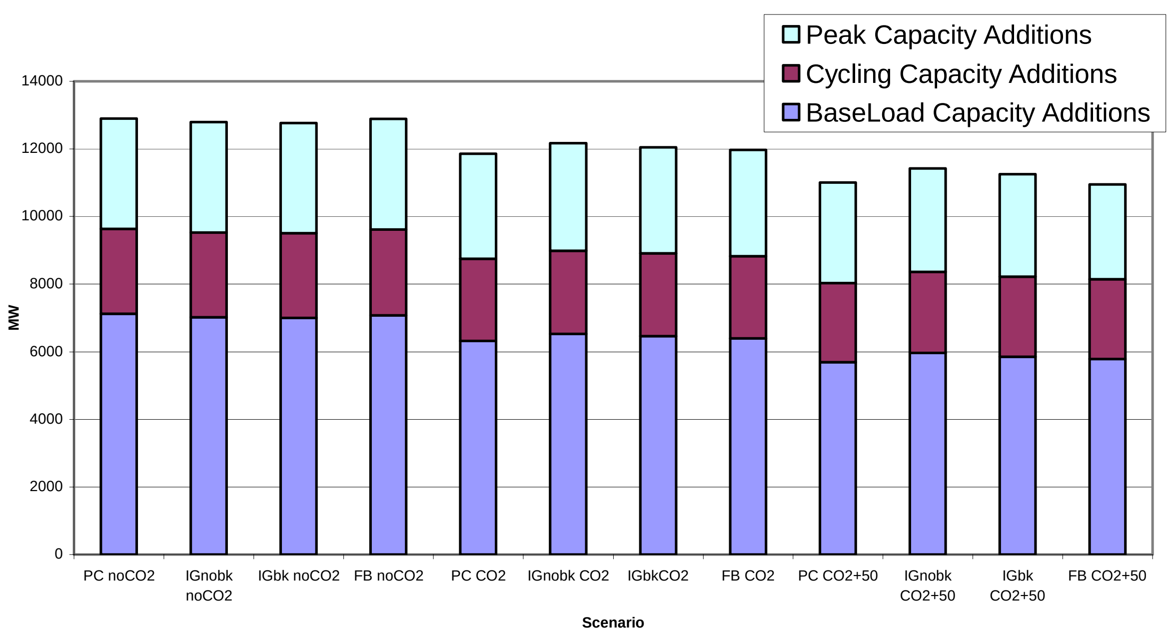


Figure 3.05. Cumulative capacity additions through 2023 by scenario

D. Coal Use

Figure 3.06 compares coal use for electricity production in the ultimate year 2023 across the twelve scenarios. Results for Indiana coal use are probably the most tenuous of this scenario investigation because (i) they assume all new baseload capacity uses coal, and (ii) data available on coal use at existing plants is incomplete with regard to whether it comes from the Indiana or elsewhere. Still, they suggest the opportunities to increase the Indiana coal industry's share of electric power coal-fired production well above its current level of approximately 50% with the advent of CCTs.

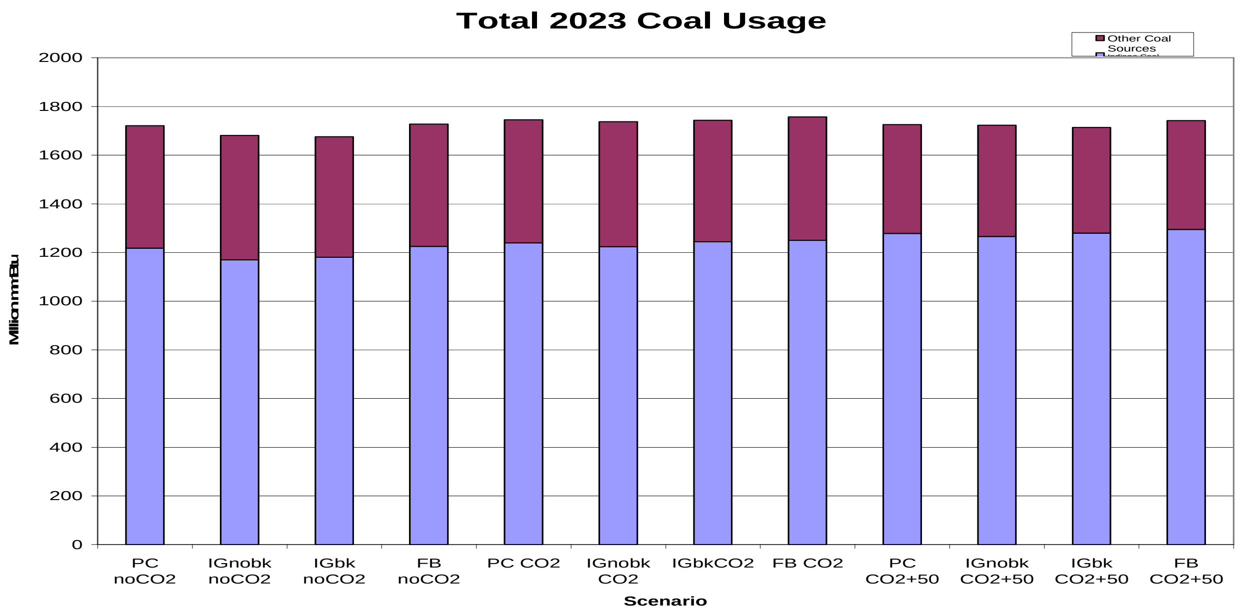


Figure 3.06. Total and Indiana Coal Consumption for Electricity in 2023

References:

[1] Harry G. Stoll, Least-Cost Electric Utility Planning.
[2] L.M. Abadie, J.M. Chamorro, "Valuation of Energy Investments as Real Options: The Case of an IGCC Power Plant," Feb. 2005.
[3] Parsons, "Evaluation of Fossil Fuel Power Plants with CO_2 Recovery," the final report prepared for DOE and NETL, Feb. 2002.
[4] Draft Staff report, "The 2005 Statewide Electricity Forecast," prepared for the Indiana Utility Regulatory Commission, Nov. 2005.
[5] R. Baumgartner, J. Kern, The 600 MW Advanced Ultra-Supercritical Reference Power Plant Development Program for Northrhine Westphalia, Electric Power Conference 2005, Session 6, Chicago.
[6] N. Moock, W. Trapp, "Coal Gasification: what are you afraid of?" proceedings in the Power Gen conference, Dec. 1, 2004, Orlando, Florida.
[7] J. David, H. Herzog, "The Cost of Carbon Capture," an MIT report prepared for DOE, 2000.

Table 3.04. Total Energy Demand by Year and Scenario (GMh)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	62002	62002	62002	62002	62002	62002	62002	62002	62002	62002	62002	62002
2005	80304	80304	80304	80304	80304	80304	80304	80304	80304	80304	80304	80304
2006	82490	82490	82490	82490	82490	82490	82490	82490	82490	82490	82490	82490
2007	84613	84613	84613	84613	84613	84613	84613	84613	84613	84613	84613	84613
2008	86142	86142	86142	86142	86142	86142	86142	86142	86142	86142	86142	86142
2009	87618	87618	87620	87618	87620	87620	87620	87620	87620	87618	87620	87618
2010	89151	89150	89152	89151	89152	89152	89152	89152	89152	89151	89152	89151
2011	90960	90960	90961	90960	90961	90961	90961	90961	90961	90960	90961	90960
2012	92774	92719	92698	92800	92486	92574	92555	92516	92268	92374	92332	92307
2013	94760	94638	94594	94801	94160	94322	94277	94211	93722	93940	93848	93788
2014	96887	96687	96612	96955	95938	96188	96116	96016	95262	95593	95462	95365
2015	99148	98860	98758	99248	97836	98177	98076	97952	96933	97368	97203	97061
2016	101518	101138	101005	101650	99836	100256	100130	99973	98715	99239	99053	98882
2017	104016	103550	103393	104182	101975	102474	102320	102130	100630	101260	101036	100843
2018	106479	105916	105750	106668	104102	104665	104492	104277	102581	103303	103041	102807
2019	109041	108391	108211	109266	106302	106942	106764	106515	104606	105401	105128	104865
2020	111696	110949	110748	111952	108582	109299	109102	108821	106674	107564	107242	106950
2021	114463	113619	113399	114755	110950	111753	111541	111223	108792	109795	109419	109113
2022	117347	116392	116149	117672	113406	114292	114071	113705	110987	112092	111676	111334
2023	120348	119282	119015	120704	115972	116949	116703	116314	113274	114501	114028	113665

Note. Sum of five investor owned utilities.

Table 3.05. Average Energy Prices by Year and Scenario (in 2003 $/kWh)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	0.0586	0.0586	0.0586	0.0537	0.0586	0.0586	0.0586	0.05368	0.0586	0.0586	0.0586	0.0537
2005	0.0527	0.0527	0.0527	0.05309	0.0527	0.0527	0.0527	0.05309	0.0527	0.0527	0.0527	0.0531
2006	0.0530	0.0530	0.0530	0.05327	0.0530	0.0530	0.0530	0.05449	0.0530	0.0530	0.0530	0.0555
2007	0.0535	0.0535	0.0535	0.05320	0.0535	0.0535	0.0535	0.05483	0.0535	0.0535	0.0535	0.0560
2008	0.0543	0.0543	0.0543	0.05275	0.0543	0.0543	0.0543	0.05473	0.0543	0.0543	0.0543	0.0562
2009	0.0545	0.0545	0.0545	0.05244	0.0545	0.0545	0.0545	0.05478	0.0545	0.0545	0.0545	0.0564
2010	0.0537	0.0537	0.0537	0.05185	0.0537	0.0537	0.0537	0.05458	0.0537	0.0537	0.0537	0.0564
2011	0.0531	0.0531	0.0531	0.05110	0.0531	0.0531	0.0531	0.05415	0.0531	0.0531	0.0531	0.0563
2012	0.0533	0.0536	0.0536	0.05101	0.0546	0.0542	0.0543	0.05438	0.0555	0.0551	0.0552	0.0567
2013	0.0532	0.0536	0.0537	0.05051	0.0549	0.0544	0.0546	0.05423	0.0561	0.0555	0.0557	0.0567
2014	0.0528	0.0532	0.0534	0.04992	0.0548	0.0543	0.0544	0.05396	0.0563	0.0555	0.0558	0.0567
2015	0.0525	0.0530	0.0532	0.04920	0.0549	0.0542	0.0544	0.05353	0.0565	0.0557	0.0560	0.0566
2016	0.0519	0.0525	0.0527	0.04846	0.0546	0.0540	0.0542	0.05316	0.0565	0.0556	0.0559	0.0564
2017	0.0511	0.0518	0.0520	0.04778	0.0542	0.0535	0.0537	0.05269	0.0563	0.0553	0.0557	0.0562
2018	0.0510	0.0519	0.0520	0.0537	0.0545	0.0537	0.0539	0.05368	0.0567	0.0556	0.0560	0.0537
2019	0.0506	0.0514	0.0516	0.05309	0.0544	0.0535	0.0537	0.05309	0.0568	0.0556	0.0559	0.0531
2020	0.0500	0.0509	0.0512	0.05327	0.0541	0.0531	0.0533	0.05449	0.0568	0.0555	0.0559	0.0555
2021	0.0492	0.0503	0.0505	0.05320	0.0537	0.0526	0.0529	0.05483	0.0567	0.0552	0.0558	0.0560
2022	0.0485	0.0496	0.0499	0.05275	0.0533	0.0522	0.0524	0.05473	0.0565	0.0550	0.0556	0.0562
2023	0.0478	0.0490	0.0493	0.05244	0.0528	0.0517	0.0520	0.05478	0.0563	0.0547	0.0553	0.0564

Note. Energy weighted sum of five investor owned utilities.

Table 3.06. Net CO_2 Release from Coal by Year and Scenario (million lbs)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	265724	265725	265724	265724	265724	265724	265725	265725	265725	265724	265724	265725
2005	272616	272616	272616	272616	272616	272616	272616	272616	272616	272616	272616	272616
2006	279648	279648	279648	279648	279648	279648	279648	279648	279648	279648	279648	279648
2007	281584	281584	281584	281584	281584	281584	281584	281584	281584	281584	281584	281584
2008	283149	283148	283152	283150	283152	283152	283152	283152	283152	283150	283151	283149
2009	283708	283708	283709	283708	283710	283710	283709	283709	283709	283708	283709	283708
2010	288345	288345	288346	288242	288346	288244	288243	288346	288243	288345	288346	288242
2011	287914	286714	286815	288130	277803	278430	277660	278032	274244	274848	273397	274534
2012	290794	289036	289165	291076	277166	277783	276620	277359	272514	273484	271439	272570
2013	295897	293602	293791	296356	278648	279463	278114	278850	272546	273786	271313	272993
2014	302074	299211	299289	302567	281127	282091	280324	281459	273827	275056	272213	273919
2015	305222	301910	301897	305825	280753	281790	279578	280942	271655	273119	269838	272145
2016	312337	308594	308381	313201	284150	285591	282874	284391	273164	275226	270913	273826
2017	313678	309187	309415	314499	281660	282801	280147	281796	270593	272630	267797	270783
2018	319620	314481	314658	320587	282714	284298	281463	283281	269677	271824	266750	270277
2019	324774	319102	318824	325761	283212	284957	281406	283734	267383	269893	263215	267627
2020	331299	325018	324656	332475	284452	286611	282421	285134	265616	268721	260886	266388
2021	333279	326463	325715	334562	282304	284467	279890	282769	261153	264234	255811	261521
2022	340822	333400	332471	342170	285243	287955	282354	286037	261279	265335	255533	262144
2023	344652	336488	335465	346018	283416	286462	280570	284267	257360	261410	250953	258012

Table 3.07. Cumulative Baseload Capacity Requirements by Year and Scenario (MW)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	350	350	350	350	350	350	350	350	350	350	350	350
2005	470	470	470	470	470	470	470	470	470	470	470	470
2006	620	620	620	620	620	620	620	620	620	620	620	620
2007	780	780	780	780	780	780	780	780	780	780	780	780
2008	710	710	710	710	710	710	710	710	710	710	710	710
2009	930	930	930	930	930	930	930	930	930	930	930	930
2010	910	910	910	910	910	900	900	910	900	910	910	900
2011	1320	1320	1320	1320	1260	1260	1250	1260	1150	1190	1180	1160
2012	1720	1700	1700	1721	1590	1630	1620	1590	1450	1500	1490	1451
2013	2090	2090	2090	2092	1910	1970	1940	1910	1750	1810	1790	1752
2014	2470	2450	2450	2471	2240	2300	2290	2242	2030	2130	2080	2032
2015	2850	2820	2820	2850	2550	2640	2620	2552	2320	2430	2380	2323
2016	3290	3250	3210	3290	2910	3010	2980	2913	2640	2760	2710	2644
2017	3700	3670	3650	3700	3280	3400	3380	3283	2970	3100	3060	2974
2018	4210	4140	4130	4212	3740	3860	3810	3744	3350	3530	3450	3354
2019	4750	4700	4690	4752	4210	4360	4310	4214	3780	3980	3920	3784
2020	5330	5270	5250	5332	4730	4890	4830	4733	4270	4480	4410	4273
2021	5920	5850	5840	5921	5260	5460	5390	5264	4760	5010	4900	4764
2022	6460	6380	6370	6462	5720	5920	5890	5724	5180	5430	5330	5185
2023	7120	7020	7000	7122	6320	6530	6460	6324	5690	5970	5850	5695

Table 3.08. Cumulative Cycling Capacity Requirements by Year and Scenario (MW)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	460	460	460	460	460	460	460	460	460	460	460	460
2005	470	470	470	470	470	470	470	470	470	470	470	470
2006	680	680	680	680	680	680	680	680	680	680	680	680
2007	850	850	850	850	850	850	850	850	850	850	850	850
2008	930	930	930	930	930	930	930	930	930	930	930	930
2009	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
2010	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
2011	1190	1180	1180	1190	1170	1170	1170	1170	1150	1160	1150	1150
2012	1280	1270	1270	1280	1250	1260	1260	1260	1220	1230	1230	1230
2013	1370	1360	1360	1380	1330	1350	1340	1340	1320	1330	1330	1320
2014	1470	1460	1460	1480	1430	1430	1430	1420	1400	1410	1400	1400
2015	1550	1550	1550	1550	1510	1540	1530	1530	1470	1490	1490	1470
2016	1650	1650	1650	1660	1600	1610	1610	1610	1570	1600	1590	1580
2017	2000	2000	2000	2010	1960	1970	1970	1960	1910	1920	1920	1910
2018	2080	2080	2070	2100	2040	2040	2040	2040	2000	2010	2000	2000
2019	2160	2160	2160	2180	2110	2130	2130	2120	2060	2070	2070	2070
2020	2250	2240	2240	2270	2170	2200	2190	2190	2140	2150	2150	2150
2021	2300	2300	2300	2320	2240	2250	2250	2250	2160	2180	2180	2170
2022	2420	2420	2410	2450	2330	2370	2350	2340	2270	2290	2290	2290
2023	2510	2510	2510	2530	2430	2460	2450	2440	2340	2390	2370	2360

Table 3.9. Cumulative Peaking Capacity Requirements by Year and Scenario (MW)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	270	270	270	270	270	270	270	270	270	270	270	270
2005	400	400	400	400	400	400	400	400	400	400	400	400
2006	480	480	480	480	480	480	480	480	480	480	480	480
2007	630	630	630	630	630	630	630	630	630	630	630	630
2008	760	760	750	760	750	750	750	750	750	760	750	760
2009	900	900	900	900	900	900	900	900	900	900	900	900
2010	880	880	880	880	880	880	880	880	880	880	880	880
2011	970	970	970	970	960	960	960	960	950	950	950	950
2012	1100	1090	1090	1110	1080	1080	1080	1080	1060	1070	1070	1060
2013	1300	1300	1300	1320	1270	1290	1280	1280	1230	1240	1240	1240
2014	1480	1480	1480	1500	1420	1430	1420	1420	1380	1400	1390	1380
2015	1750	1750	1750	1770	1680	1710	1710	1690	1620	1640	1640	1630
2016	1920	1920	1920	1970	1870	1880	1870	1870	1790	1810	1800	1800
2017	2200	2200	2200	2230	2100	2140	2130	2110	2040	2060	2060	2050
2018	2350	2350	2340	2380	2260	2310	2270	2260	2180	2220	2210	2190
2019	2490	2470	2470	2520	2380	2410	2410	2410	2290	2340	2320	2320
2020	2800	2770	2770	2820	2670	2700	2700	2690	2580	2610	2600	2590
2021	2900	2900	2900	2930	2790	2830	2810	2790	2690	2720	2720	2700
2022	3120	3100	3100	3160	2980	3030	3000	2990	2850	2920	2880	2856
2023	3270	3270	3260	3330	3110	3180	3140	3140	2980	3060	3030	3000

Table 3.10. Total Coal Consumption for Electricity by Year and Scenario (mmBTU)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	1327	1327	1327	1327	1327	1327	1327	1327	1327	1327	1327	1327
2005	1361	1361	1361	1361	1361	1361	1361	1361	1361	1361	1361	1361
2006	1397	1397	1397	1397	1397	1397	1397	1397	1397	1397	1397	1397
2007	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406
2008	1414	1414	1414	1414	1414	1414	1414	1414	1414	1414	1414	1414
2009	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417	1417
2010	1440	1440	1440	1440	1440	1440	1440	1440	1440	1440	1440	1440
2011	1438	1432	1433	1440	1447	1444	1446	1448	1452	1448	1450	1454
2012	1452	1444	1444	1454	1461	1458	1461	1463	1466	1463	1465	1470
2013	1478	1467	1468	1480	1487	1484	1487	1490	1491	1488	1489	1496
2014	1509	1495	1495	1511	1517	1514	1518	1521	1521	1518	1519	1526
2015	1525	1508	1508	1528	1534	1530	1534	1538	1534	1532	1533	1541
2016	1560	1542	1541	1564	1571	1567	1571	1576	1568	1566	1566	1576
2017	1567	1545	1546	1571	1578	1573	1579	1584	1582	1579	1579	1591
2018	1597	1571	1572	1601	1610	1604	1610	1616	1610	1608	1607	1620
2019	1622	1594	1593	1627	1638	1632	1638	1646	1634	1631	1629	1645
2020	1655	1624	1622	1661	1674	1667	1673	1683	1665	1662	1657	1678
2021	1665	1631	1627	1671	1685	1678	1684	1695	1673	1670	1664	1687
2022	1702	1665	1660	1709	1724	1717	1723	1735	1707	1705	1696	1722
2023	1721	1681	1675	1728	1745	1737	1744	1757	1726	1723	1714	1742

Table 3.11. Indiana-Coal Consumption for Electricity by Year and Scenario (mmBTU)

Year	PC no CO_2	IGnobk no CO_2	IGbk no CO_2	FB no CO_2	PC CO_2	IGnobk CO_2	IGbk CO_2	FB CO_2	PC CO_2 +50	IGnobk CO_2 +50	IGbk CO_2 +50	FB CO_2 +50
2004	928	928	928	928	928	928	928	928	928	928	928	928
2005	939	939	939	939	939	939	939	939	939	939	939	939
2006	954	954	954	954	954	954	954	954	954	954	954	954
2007	957	957	957	957	957	957	957	957	957	957	957	957
2008	963	963	963	963	963	963	963	963	963	963	963	963
2009	963	963	963	963	963	963	963	963	963	963	963	963
2010	966	966	966	965	966	965	965	966	965	966	966	965
2011	954	947	949	955	962	958	961	963	972	968	972	974
2012	976	966	969	977	984	980	985	987	996	992	997	1000
2013	996	984	987	999	1005	1001	1006	1008	1018	1014	1019	1022
2014	1024	1008	1012	1027	1032	1027	1034	1036	1047	1043	1047	1052
2015	1033	1016	1020	1037	1042	1037	1044	1047	1058	1052	1059	1063
2016	1063	1042	1046	1067	1073	1066	1074	1078	1088	1083	1089	1095
2017	1064	1039	1046	1068	1074	1066	1078	1080	1099	1092	1101	1107
2018	1090	1061	1069	1096	1103	1094	1105	1108	1128	1120	1129	1137
2019	1116	1084	1092	1122	1130	1120	1134	1138	1158	1150	1160	1169
2020	1150	1114	1123	1156	1167	1155	1170	1175	1197	1187	1199	1208
2021	1161	1121	1130	1167	1179	1166	1183	1189	1213	1202	1214	1226
2022	1198	1155	1165	1205	1217	1203	1222	1227	1253	1242	1254	1267
2023	1218	1170	1181	1225	1240	1224	1244	1250	1278	1265	1280	1295

CCTR Research Plan and Public/Private Action Plan

Parts 1-3 of this scoping study report arrayed background on which to base decisions about needed further investigations or actions related to design and implementation of clean coal technologies in Indiana. This part of the report offers a CCTR Research Plan describing topics justifying further investigation as follow on to this scoping study, and a Public/Private Action Plan of recommended measures outside the research domain.

4.01 CCTR Research Plan

Four major topics have been identified as appropriate for future research on CCT methods in Indiana as a result of this scoping study. Although they are inter-related and could be managed as a single project, they are presented here in four different subsections.

A. Optimal Deployment of CCTs for Meeting Indiana Demand Growth and Potential CO_2 Regulation

From the analysis of Parts 1-3, it is clear that a great deal of policy planning and analysis will be required as CCTs are implemented in Indiana, especially if, as appears likely, some form of CO_2 emission controls is imposed. Detailed planning for CCT facilities will be the responsibility of the utilities that commission them, but state regulators and government leaders will require a broader, more integrated vision that reaches across individual companies and service territories. Furthermore, transportation and disposal/sequestration of captured CO_2 may very well be a function shared across many producers.

This challenge motivates the main CCTR research recommended from this scoping study: development of optimization modeling tools for analyzing statewide policy on meeting Indiana electric energy demand growth and dealing with proposed CO_2 restrictions, including both generation expansion and sequestering of recovered CO_2. A two year study is recommended, with year one devoted to sharpening understanding of many of the component questions barely touched in part 3's scenario analyses, and year two focused on building and exercising large-scale optimization models.

Component Issues for Optimization

1) Macro design for optimally choosing CO_2 capture technologies

Currently, the most promising CO_2 capture technologies include oxygen-blown combustion and MEA for SCPC, MEA for natural gas power plants, MEA, Selexol and Rectisol for IGCC plants, flue gas circulating combustion in AFCB plants, etc. Even though these technologies have been demonstrated for CO_2 capture, each has its pros and cons in terms of efficiency and cost. The percentage level of CO_2 capture may affect the capture cost significantly (e.g., an 95 percent CO_2 capture may cost a lot more than an 85 percent capture, as some studies indicate [5]). Detailed trade-off studies are needed for balancing cost and capture.

2) New CCT technologies

Three major types of gasifiers are identified in this scoping study, but the KBR gasifier [6] and the Rocketdyne gasifier need to be added in future analysis [7]. This is because they are relatively new and have not attracted enough attention so far. The capital costs and other critical performance factors of these two gasifiers will need to be researched and estimated.

3) Configuration for optimally design to increase availability and minimize costs of energy

There have been arguments over the effectiveness and costs associated with backup gasifiers. Moreover, how to configure the backup scheme remains to be researched. For example, should an ASU be added together with the backup gasifier? Should the acid gas removal unit be added for each backup gasifier? Should the coal handling unit be added with each backup gasifier? How would the different configurations affect availability and cost?

A related configuration topic is the choice between the quench type gasifier and the one with a steam collector for heat recovery from the cooling of the high temperature syngas before cleaning. The choice is between a low cost and lower efficiency gasifier or one with high cost and high efficiency.

4) Further study on CO_2 sequestration in Southwest Indiana, including cost estimation of pipelines, CO_2 injection, insulation and monitoring

Some studies suggests that CO_2 transportation and injection would have a price tag of approximately \$10/ton of CO_2 avoided [11]. However, the price tag is largely site dependent and needs detailed engineering analysis and cost estimation.

5) Transmission impact of constructing mine mouth IGCCs and other CCTs

As has been discussed in Section 2, coal beds in Indiana are concentrated in the West and Southwest of the state. If significant amounts of generation capacity are constructed in those areas, the current electricity transmission system will not be enough for distributing the power to load centers in the state over the long run. The impact should be evaluated, including engineering, environment, regulation policy and economics.

6) Cap and trade mechanisms

Any realistic plan for CO_2 regulation is likely to include mechanisms for trading emission rights among producers, possibly across state lines. Such possibilities must be better understood before wide-scale optimization is possible. The effort should not attempt modeling of the market itself, but instead to see how its major effects can be incorporated in min cost schemes to meet demand within CO_2 limits.

7) Better cost estimates

At the heart of any optimization model of CCT implementation are the cost estimates on which the results are based. More reliable values will be needed in the future, including capital, fuel and O&M costs.

Optimization Modeling

Once the Component Issues discussed above are more completely understood, a full statewide optimization modeling capability should be developed to guide implementation of CCT technologies in Indiana. The core of such an optimization is to minimize the total cost over a specified time horizon of installing and operating power production and CO_2 sequestration facilities to meet projected demand for electricity and comply with likely scenarios for emissions. Unlike the above scenario analysis, that it, the modeling must construct a best plan for dealing with projected demand and regulations rather than merely trying a small set of over-simplified alternatives.

Another contrast with the scenario analysis of part 3 is that such a model must necessarily treat the state in geographic regions or service territories rather than as a single unit. This breakdown is needed because transportation of captured CO_2 to disposal sites and cap-and-trade commerce in CO_2 rights among regions will be important considerations. One natural division would be to divide along boundaries of service territories for the major investor-owned utilities.

B. CO_2 retrofitting of new IGCC plants and existing coal plants

Retrofitting existing power plants, whether recently constructed or older, is a second set of optimization topics needing much deeper investigation than was possible in the current work. First of all, there may be the need to study the idea of constructing IGCC facilities without CO_2 capture but leaving rooms for adding CO_2 capture equipment later to meet potential regulations. According to [12], gas turbine nozzles may have to be re-adjusted for burning syngas after CO_2 is captured. This question can be examined for single sites without regard to the statewide industry.

A second and more complex area of study is repowering old coal power plants for meeting new emission standards including carbon dioxide control. Since Indiana produces its electricity largely from coal power plants, retrofitting the large fleet of coal power plants may present the state with significant challenges, including costs, reliability, etc. Subtopics may include: Which types of plant should be preferred for repowering? How would system reliability and capacity be affected? Is there an optimal repowering schedule with the least cost and minimum impact on system reliability? Is there a need for coordinated repowering within the state of Indiana and how?

C. Co-production Plant Optimization for Power and Transportation Fuels

Power production is just part of the solution to promoting the use of Indiana coals. Recently, co-production has been attracting a lot of attention due to high oil and natural gas prices. According to some studies, coal gasification for fertilizer and transportation fuel production may present a bright future for the Midwest due to natural gas and oil price hikes [9, 10, 13].

Two different kinds of research are needed. The first must deal with optimization of the design and operation of a co-production CCT plant. Co-production may involve the production of at least two of power, FT fuels, hydrogen, fertilizer and other possible products. When power is involved there should be significant opportunities to exploit the large variation in electricity demand over times of day and seasons of the year. Recently, DOD has shown a great interest in FT fuels and has decided to invest significant amounts of money for demonstrating and certifying coal-based jet fuels [8]. Private firms have also been very active in the area [9, 13]. Co-production plant optimization must consider gasification as well as both CO_2 capture and sequestration technologies. However, co-production may require even higher availability, and need to optimize parts/equipment backup schemes to maximize plant outputs with minimum down times. Also, the objective function may be the "return" on investment, not the least cost of the statewide model.

A second set of issues relates to regulation of utility plants doing co-production. Currently, the utility regulatory mechanism does not have clauses on co-production. Should co-production plants even be part of the rate base? If so, financial modeling is required of rate impact on consumers (65 percent financing vs. 80 percent …) etc. Also, how should disputes be settled when power generation is in conflict with other product sales? Should there be guidelines for balancing power and other products so that power system reliability is kept intact.

D. CCT Risk Analysis

CCT implementation is fraught with uncertainties and risks that need to be studied and modeled (see [8] for a start). For example, how can the cost estimate variations for CCTs be measured and incorporated in optimization models? How can CCTs be used to hedge high and volatile natural gas prices to benefit Indiana consumers? How can CCT implementation help to boost national energy security? How can CCTs be used for hedging future emission regulation such as CO_2 control, etc.? What are the risks associated with CO_2 sequestration using various technologies?

4.02 Public/Private Action Plan

Although many issues about the design and implementation of clean coal technologies require further study and research, this preliminary scoping study has revealed several that appear to be ripe for immediate public/private action. This section provides a brief overview of each.

A. Indiana Clean-Coal Summit

Review of available cost information (Section 3.02) shows that without CO_2 capture the SCPC AFBC and AFBC may result in lower electricity costs. However, when considering CO_2 capture, the best strategy for Indiana is to use IGCCs for new capacity, and the capture cost will be roughly 8.8% percent higher vs. SCPC without CO_2. Although there is also strong evidence (Section 1.09) that some form of CO_2 regulation is on the horizon, this cost dilemma has combined with the relative technical immaturity of clean-coal methods and the usual burdens of sitting and permitting to discourage investment in clean-coal power plants. At the same time, the Scenario Analysis above (Section 3.02-C/D) suggests quite clearly that a great deal of investment in CO_2-ready clean-coal technology will be required in the coming decades if Indiana is to meet even modest capture requirements, and Indiana coal production could benefit significantly. Under the simplified assumptions of that analysis, 12,050 MW of new production would be needed by 2023. The results are preliminary because CO_2 cost associated with pipeline, storage and monitoring are not included. Still, the requirements are potentially large.

These considerations lead the research team to conclude that the State government should convene an Indiana Clean-Coal Summit in the near future that brings together senior representatives from the Lt. Governor or Governor's office, the State Legislature, electricity producing and consuming industries, the coal mining industry, environmentalists, regulatory officials, and university researchers. The purpose of the meeting will be to reach consensus on steps necessary to accelerate investment in clean-coal electricity plants within Indiana .What incentives need to be explored other than the ones already in existence and under draft, for attracting outside investment in CCTs? Can they be tied to use of Indiana coal?

B. Diminished Concern About Characteristics of Indiana Coal

Investigations in Sections 1.01 and 1.03 seem to make it clear that clean coal technologies are very robust to properties of the fuel they use. The technologies can be adjusted to function well on everything from petroleum coke to high rank coal. Thus characteristics of Indiana coal no longer seem a major issue in design and implementation of clean coal technologies. On the other hand, diminished concern regarding sulfur content of coal when processed in coal gasification and similar technologies should make Indiana coals relatively more attractive as fuels.

On the other hand, Indiana CO_2 sequestration research may be enhanced in the future.

C. Increased Coal Mining Capacity

If clean-coal technologies are introduced into the Indiana at a sufficient pace to maintain coal as the major fuel for electricity production, total coal demand in the state is certain to grow. Furthermore, incentives for clean-coal plant construction are likely to carry some preferences for much of that new demand to be for Indiana coals, and greater capability of clean-coal technologies to accommodate high sulfur coals also favors increased Indiana coal use.

These developments suggest an impending need for increased coal mining capacity in Indiana and new training programs for coal miners. Perhaps under the neutral auspices of the CCTR, leaders of Indiana's coal industry need to prepare strategies for this expansion, and community colleges should consider expanding mining training offerings.

D. Long-Term Purchase Agreements

One of the major ways to speed investment in larger clean-coal production plants is for utilities to share the output in some agreed contractual arrangement. However, such arrangements often require transmitting power over a considerable distance from plants to the utilities' load serving territories. With the advent of ISOs emphasis has been placed on managing transmission with relatively short-term financial transmission rights (FTRs).

This tends to preclude long-term transmission contracts and thus introduces cost uncertainty for some power purchasers, which acts as a barrier to new clean-coal construction. Changes need to be pursued with federal regulators to permit restoration of traditional long-term transmission agreements.

E. FutureGen

The U.S. Department of Energy has expressed widely its interest in giving grants for demonstrating a FutureGen power plant with zero emissions. The investment may be around one billions dollars. Power, F-T transportation fuels and hydrogen are the primary products for demonstration. CO_2 sequestration is also included in the demonstration, which will have a very significant impact on the future power industry. The Office of Fossil Fuel, DOE stated on March 4, 2004: "One of FutureGen's fundamental goals is to overcome environmental constraints, especially potential climate change impacts of CO_2 emissions, associated with producing electricity and other forms of energy from coal.".

1) Many states have been actively competing for the FutureGen project, including our neighbor Illinois [12-13]. However, Indiana's interest has been rather passive, even though the state has at least the following advantages in competing for FutureGen:
2) Indiana has abundant coal reserves

3) The Wabash River IGCC project provides valuable experience with clean-coal technologies.
4) Purdue University has been identified as one of the three centers for demonstrating FT transportation fuels from Illinois Basin coals in the Obama-Lugar amendment in the recently passed Federal Energy Bill 2005
5) Purdue has a research program in hydrogen, including fuel cells
6) Regulated Indiana utilities need considerable growth in electric power baseload capacity. Supplying part of it from the FutureGen would reduce the risk of that effort because capital costs can be included in the regulated rate base.
7) Southwest Indiana has many sites for sequestration of CO_2 [16].
8) Participation in FutureGen is one of the best available ways to build intellectual infrastructure for clean-coal research in the state.

Accordingly, Indiana should put a priority on exploring opportunities to bring at least a part of the FutureGen effort to our state. A natural partner in this effort is Illinois which has already done a great deal of FutureGen planning. Indiana's initial role could emphasize regulated markets for power and sequestration, with growth into transportation fuels and hydrogen as the project continues.

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