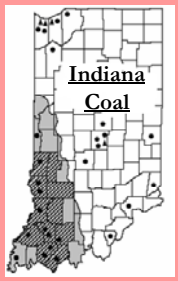
INDIANA COAL REPORT 2006



Center for Coal Technology Research

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Indiana Center for Coal Technology Research

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February 28, 2006

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Tables

ERRATA

Following recommendations from the CCTR Advisory Panel meeting on February 28, 2006, we have:

- An updated version of Table 5.5, Fixed-Bed Gasifiers.
- All references to EKPC are deleted from Tables 5.10, 5.11, 5.15, and 5.16.
- An extra paragraph is added at the bottom of page 60.
- An updated version of Section 6.3 that describes the role and activities of the Coal Fuel Alliance (CFA).

03/14/2006

1. CCTR PERSPECTIVES

The goal and purpose of the Center for Coal Technology Research (CCTR) is to address the vital issue of determining suitable coal technologies which will meet the economic and environmental priorities of Indiana. In the short-run, the current decision processes of purchasers of Indiana coals, primarily the electric utilities, need to be better understood. Then in the long-run, the technology factors that will control future coal use in Indiana, the Illinois Basin and Midwest region generally need to be assessed as they are more varied.

Energy provides a foundation for the economy of Indiana, the U.S., and the world. Increases in the price of oil and natural gas have caused hardships for residential, commercial and industrial users and shifts in the economic activities of the nation. In Indiana like the rest of the U.S. our energy comes from various sources. Coal is particularly vital as it is the fuel used for most of our electricity generation and represents the state's largest natural energy resource.

In the 1990s natural gas was seen as the answer to clean energy for space heating, process heat and new electric generation. It is clean and efficient and in those years was quite affordable. The basic law of supply and demand caught up with its increased use in the 2000s and is now exorbitantly expensive. There is a growing need for other sources of energy but these sources must also be environmentally friendly. Economics and environmental considerations are the two great issues in determining where the clean fuel supplies are to come.

1.1 Energy Prices

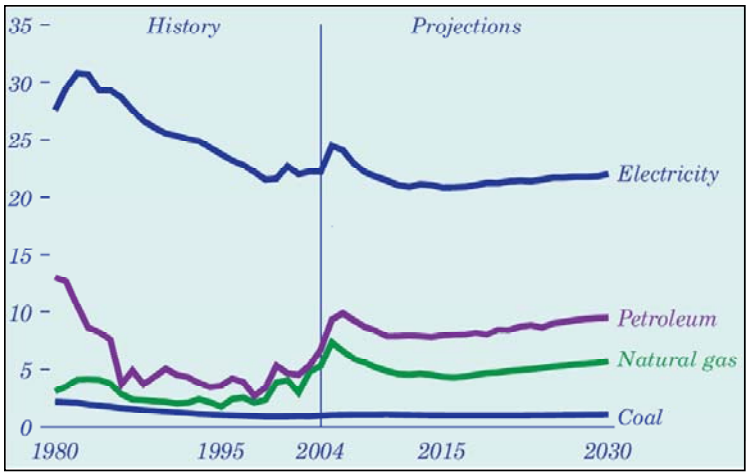
There is no shortage of energy resources in Indiana or the U.S. There is a scarcity, however, of the low cost oil on which the nation has become dependent. Petroleum has increased in price by 50% in the past 2 years; natural gas prices have raised that much in one year. Both have the effect of directly increasing the cost of living and doing business in the U.S.

Indiana's State Utility Forecasting Group (SUFG) forecasts a state need for 10,600 MW of new electric generation capacity by 2023. All levels and uses of energy are on the rise. At the same time environmental concerns are in the forefront. The question to be addressed therefore is how Indiana can meet the energy needs of its people and the region while also maintaining and improving environmental quality, as well as keeping prices relatively low.

Figure 1.1 shows that while oil and natural gas prices have risen dramatically in recent years, coal has remained stable. The price of coal and thus electricity has in fact risen less than inflation over the last 10 years.

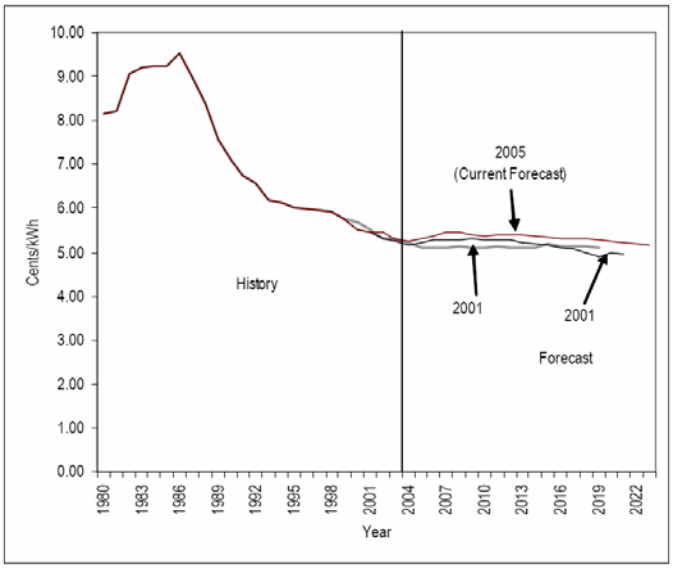
Owing to this stable coal price and to increases in the load factors of utility units the actual real price of electricity in Indiana has been reduced while the national average has increased (Figures 1.1 and 1.2).

Figure 1.1 Energy Prices, 1980-2030 (2004 Dollars/MBtu)



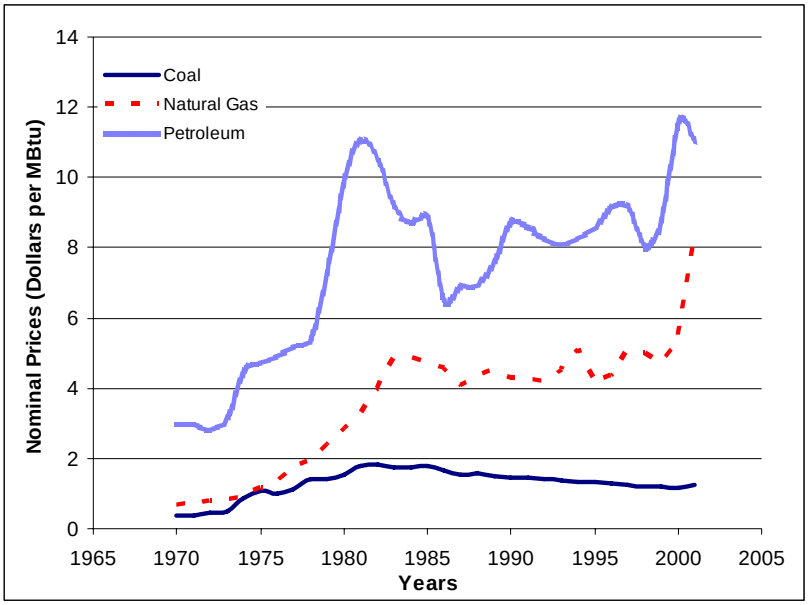
Source: EIA, Annual Energy Outlook 2006, PEMRG/SUFG/Publications_html#Publication
http://www.eia.doe.gov/oiaf/aeo/coal.html, https://engineering.purdue.edu/IE/Research/

Figure 1.2 Indiana Electricity Real Price Projections (2003 Dollars)



Source: Indiana SUFG 2005 Forecast

Figure 1.3 Indiana Historic Fuel Prices (Nominal Dollars)



Source: http://www.eia.doe.gov/emeu/states/state.html?q_state_a=in&q_state=INDIANAPrimary Energy

The nominal fuel prices for Indiana (Figure 1.3) also show the stability in Indiana coal prices. This makes a very strong case for promoting 21st century coal usage that is economically sound and also meets stricter requirements for pollution. Clean coal is a major component in providing the answer for our energy supplies. The new clean coal fired generation technologies are now available and it is only a matter of finding the means and determination necessary to deploy them. These technologies are meeting sound economical and environmental standards and provide the infrastructure needed for co-production of potentially significant amounts of transportation fuels (Coal-To-Liquid).

Currently, Indiana mines over 35 Million Tons (MTons) of coal a year, or about 3.5% of total U.S. coal production. Indiana's demonstrated reserve base is over 9 Billion short Tons, enough to maintain current state withdrawals for over 250 years. The reserve base for the entire Illinois basin, of which Indiana coal is a part, amounts to over 130 Billion Tons, or 25% of total demonstrated coal reserves in the United States – enough to meet entire U.S. coal demands for over 100 years. The point of all this is that the Midwest in general, and Indiana in particular, has an enormous relatively untapped energy source which can increasingly be turned to as the source of future gas and liquid fuels.

The value of the 35 MTons of coal production represented is approximately $930 Million. It is estimated that the sector contributed over $ 2 Billion, 5,500 direct mining jobs, and 28,000 total jobs to the state's economy (Expanding the Utilization of Indiana Coals, 2004, Table 2-5). These calculations understate the true value of Indiana coal reserves, since it ignores the link between coal availability and Indiana's low electricity prices and the impact of these low electricity prices on Indiana's economy.

1.2 Future Coal Production in Indiana

Increased production of Indiana coal will be a decisive factor in future technology investments in the state. Preliminary production forecasts are provided (see Section 3) as demonstrations of future work that will be an important activity within the CCTR. Summaries of results from four demonstration trajectories of Indiana coal production forecasts are illustrated in Figure 1.4. For 2020 the Base Case coal demand forecast (Trajectory [2]) is derived from a Shift-Share Methodology described in Section 3. This Base Case shows a 111% increase, over the 2004 coal production rate. The magnitude of this increase in production, over the next 15 years, has enormous implications for the mining and utility industries of our state if the numbers are indicative of what is to happen.

Figure 1.4 Demonstration Indiana Coal Production Forecasts

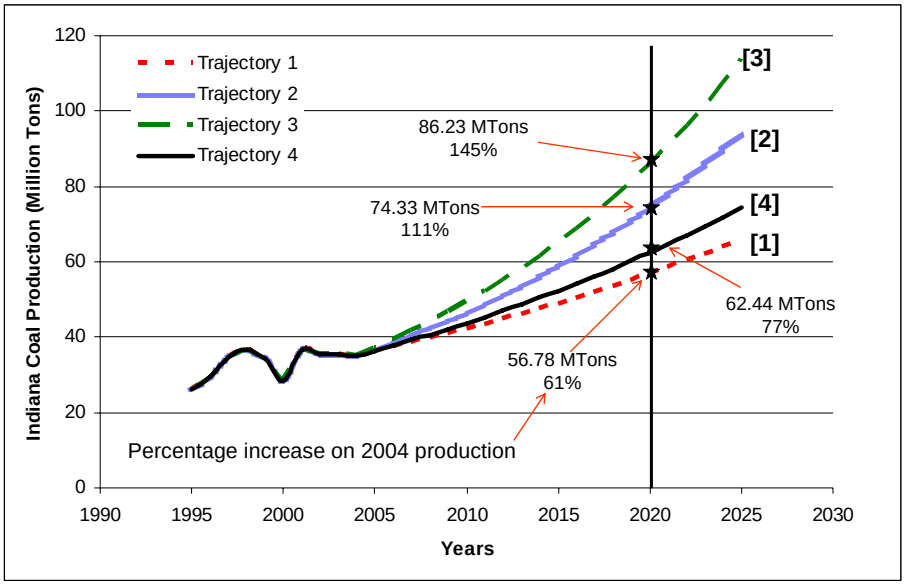


Figure 1.4 also shows another Trajectory [1]. This has been developed by assuming the last ten year growth rate will extend into the future (Section 3). It indicates a more conservative production increase of 61% by 2020. Trajectories [1] and [2], although wide ranging, both indicate the significant expansion to be expected from Indiana coal production. If there is not this magnitude of expansion in the Indiana coal mining sector then massive increases in coal imports to the state are to be expected. The two preliminary coal production forecast methodologies provided do demonstrate the importance for more work in this area. Trajectories [3] and [4] are respectively 1% increases per year and 1% decreases per year on Trajectory [2]. Background discussions on these preliminary forecasts are provided.

1.3 Indiana Coal and Technology Investments

The decision to satisfy the state's growing need for electricity with coal–fired plants, gas–fired plants, or other means will have a profound effect on Indiana coal use. The State Utility Forecasting Group (SUFG) estimates that the state will need access to an additional 10,600 MW of new power resources by 2023. One should not be put off by the fact that the forecast is for 2023, since it takes more than 10 years to build a new power plant, assuming that the utility can secure a site. It also needs to be noted that it takes up to 5 years to open a new coal mine. Therefore, we are not discussing a forecast for 15 years from now, but a decision that needs to be made in the next 3-5 years.

1.3.1 Coal Supplies, Characteristics, and Generation Technologies

The latest SUFG report forecasts an almost 50% net increase in generation capacity over what is currently installed. A portion of this need – 5,870 MW – should be base load resources, economically suitable for generation by coal. The prospect of gas being a fuel source for future electric generation passed with the advent of $5.00/MBtu and higher natural gas prices. These plants should be equipped with the latest pollution control equipment, and use Illinois Basin coal rather than low sulfur western coals. Studies done by SUFG indicate that unless natural gas prices return to the levels they were in the 1990s – in the range of $3.00 to $3.50/MBtu – new coal plants will be the most economical method of meeting base load demands.

One of the 2005 CCTR funded projects (Section 5.1) emphasizes how capital cost decrease with coal rank, primarily because less coal needs to be used when coal has higher heating value. Even though this is a general rule, little is known how various coals will behave in Integrated Gasification Combined Cycle plants (IGCC) of a specific design or an IGCC plant in general. In addition to heating value, volatile matter content, moisture content, and especially ash composition and ash fusion temperature strongly influence the gasification process and smooth slag flow. These fundamental and practical facts are critical design parameters that will ensure that Indiana coal is used in the future for the greatest gain.

1.3.2 Clean Coal Technologies, CCTs

Coal's place in the nation's energy mix lies with the so called "clean coal technologies (CCTs)." The new CCT power stations will have higher system efficiencies (using less coal for the same power output) and have almost zero emissions of SOx, NOx, and Mercury. The clean coal technologies include advanced pulverized coal technologies. Chief among these are IGCC plants, similar in design to Indiana's 260 MW Wabash River Repowering project and proposed by Duke/Cinergy's for the Edwardsport facility. Certainly, a major focus of CCTR's efforts will be the design and efficient operation of plants like those envisioned in the FutureGen project now in the planning stage by the Federal Government. In the coming year a coal demand forecast, based on the preliminary forecast trajectories outlined in this report, is being planned and the future role of clean coal technologies in Indiana is expected to affect long-term coal production projections.

The CCTs discussed in Section 5.2 include flue gas recycling, supercritical pulverized coal (SCPC), circulating fluidized bed (CFB), and 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.

1.3.3 Coal to Coke and to Liquids Technology

The 2005 Energy Act authorized $85 Million funding for the development of coal-to-liquids (CTL) in the Midwest, through the Obama-Lugar Amendment. The CCTR staff has fully supported this development at the several Illinois Basin Coal Fuel Alliance (CFA) meetings of recent months. Several focus areas have now been identified. The CTL technologies proposed in the Obama-Lugar Amendment have great potential for Indiana and the Midwest's bituminous coals. If the CTL program develops as significantly indicated by the EIA, then a much higher increase in coal production can be expected from Indiana.

Indiana is home to roughly 22% of the domestic base steel production for the United States. One essential raw material needed by this industry is coke. At present, essentially no Indiana coal is being used for coke production. In 2002, Indiana's steel industry used an estimated 10.7 MTons of coal. Of this, approximately 8.1 MTons was used for coke production. Most of this coking coal comes from West Virginia and Virginia. There is a high probability that a mix of Indiana Brazil Seam or potentially other Indiana coals could be blended with other coals to meet metallurgical and emissions requirements. Preliminary results indicate that it is highly likely that a coking/coal gasification process can be developed. The CCTR plans to further support this topic in 2006.

1.4 Expanding Indiana Coal Use in an Environmentally/Economically Sound Manner

1.4.1 Increasing Coal Exports

Increasing exports of Indiana coals to surrounding states is a possibility. Historically, Indiana has exported much more coal than the 3 MTons exported in 2002. In 1990, exports were over 10 MTons, with the total gradually falling to present levels over the intervening years. The total potential market for coal in neighboring states is over 100 MTons. Indiana's current market share of this total is less than 3%.

Clearly, the economic trade–off between the higher transportation costs of non-Indiana coals and the lower capital costs of burning low sulfur non-Indiana coals will drive opportunities to increase exports. The impact that pending mercury and other possible environmental legislation will have on this trade–off, and what a focused research and development program can do to tip the scales towards Indiana coals in this trade–off, is a major focus of the CCTR.

1.4.2 Substituting Indiana Coal for Imported Coal

Historically, coal imports have been a higher fraction of total coal use in Indiana than they are now. In 1991, 22.6 MTons of Indiana coals were consumed in Indiana, while over 38 MTons were imported – an excess of imports over domestic consumption of almost 16 MTons. In 1995 the excess of imports over domestic consumption grew to over 20 MTons. Since then, the excess has been falling to the present level of just over 2 MTons.

Despite the improved historical import substitution record, over 50% of the coal consumed in Indiana continues to come from outside Indiana. There are two major markets for imported coals in Indiana – coals imported to generate electricity (over 20 MTons with 15 MTons from Wyoming) and coal used to produce coke for Indiana's blast furnaces (5 MTons).

The substitution of Indiana coals for coal now imported by Indiana's steel industry faces a slightly different set of issues. Because of the particular characteristics required for coking coals, it is estimated that 80% of the current coking blends could be satisfied by Indiana coals. The Brazil formation coals in Indiana are the most suitable for coking purposes, their reserves are about 100 MTons, and can be mined economically using surface techniques. The picture is brighter for coal directly injected into the blast furnace to substitute for coking coal as a source of heat. Danville formation coal, which is quite abundant in Indiana, could be used for this purpose. In total for the two uses, it is estimated that 4 MTons or more of Indiana coals could be substituted for non Indiana coking coals.

1.4.3 Increasing "Coal by Wire" (Exporting Electricity)

The relative economics of expanding direct coal exports versus expanding coal exports by wire (exporting electricity) deserves further attention of the CCTR. Exporting coal has great economic impact on the state. Exported electricity is the cleanest way to export Indiana coal. It also represents an influx of "new money" into the state's economy.

The prospect of building electric power generation solely for the purpose of exporting the electricity to out of state customers, via the national grid has already been reviewed by the Office of the Utility Consumer Counselor. There are no restrictions in Indiana law for an Indiana Investor Owned Utility (IOU) to build coal fired capacity solely for the purpose of exporting power. The only exception to the rule is that the electric utility may not charge its domestic customers the capital or operational cost for the facility. Domestic customers may not subsidize this activity.

The prospect of building for export has another great advantage to the domestic customer. If the utility can build the facility and charge the cost of the facility proportionately to the amount of the power exported, then in fact the export market is paying down the capital cost of the facility until such time that the capacity is needed for the domestic customers. "Rate Shock" will be offset because the great increase is paid by "foreign" customers for the first several years.

1.5 Indiana's CCTR

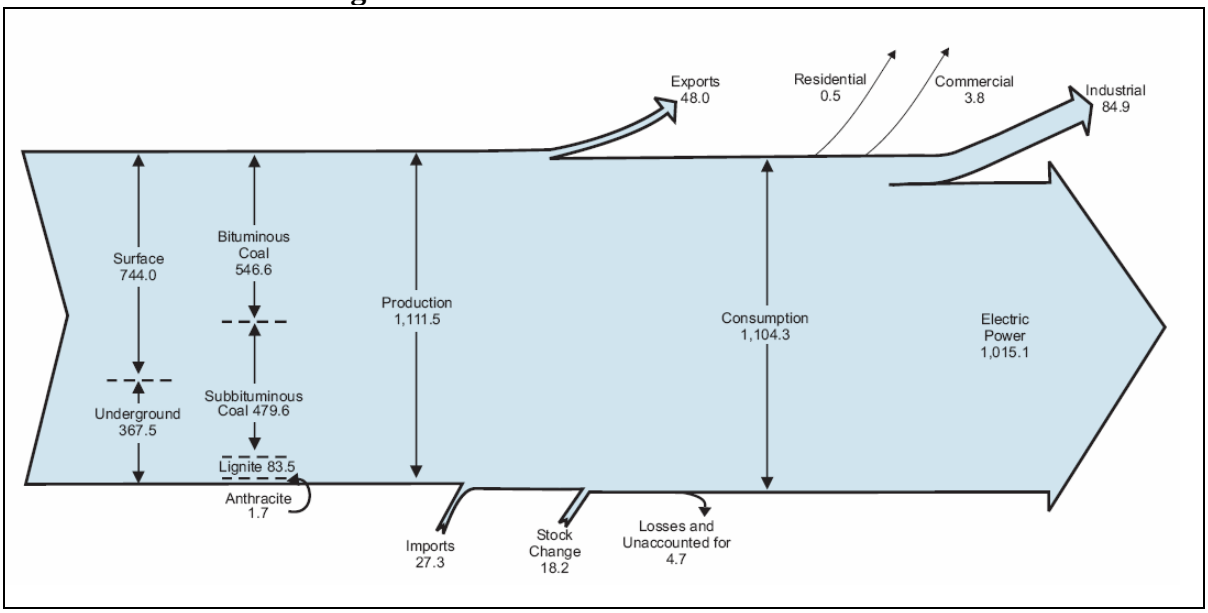
The major coal technology issues of our day have been discussed at the CCTR meetings throughout 2005 at Advisory Panel meetings, various other meetings with coal suppliers and users, and also at a "Clean Coal for Transportation Fuels" Workshop organized by the CCTR for the Purdue Energy Center. CCTR meetings and activities are recorded in Section 4. The project work from 2005 is summarized in Section 5. Described in Section 6 are the new project topics for 2006 including coal transportation, coal-to-liquids, and the use of coal fines. All of these technology development projects have the coordination offered by the CCTR and so ensure that the funded work is immediately related to the economic growth of Indiana, meets the environmental needs of today and the future, and provides the best advice on how to invest in major energy/coal projects within the state. The CCTR is looking at the deployment of technology that meets the needs of the state and the nation. Using our vast energy resources in an economic and environmentally sound manner, is the means to the end of our dependence on outside sources of energy, especially where we can achieve the same or better results by doing it with those resources here in our own state/nation which are fully under our own control.

2. NATIONAL AND INTERNATIONAL COAL DEMAND

Total coal production in the U.S. increased in 2004 by 39.7 MTons (Million short tons) to end 2004 at 1,111.5 MTons. This was 3.7% higher than the 2003 level of 1,071.8 MTons.

During the next 20 years the EIA predicts a 2% national annual increase in the use of coal. For U.S. Interior coal, there is a prediction of an average increase in coal production of 2.5% across the years 2005 to 2030. At these rates there will be about 50% total increase in coal production nationally by 2025 and for the U.S Interior more than a 60% increase.

Figure 2.1 United States 2004 Coal Flow



Of the 1,111.5 MTons of U.S. coal production, 1,015.1 MTons, or 91%, went for electricity power generation (Figure 2.1). The EIA reports that U.S. coal delivery prices increased in 2004 by 6% for the electric power sector, 13% for the industrial sector, and 21% for coking. With increased energy prices in all sectors, it is expected that the demand for Illinois Basin coal will also significantly increase. The likelihood of this happening is further strengthened with continued high oil prices. According to the EIA announcement, in December 2005, it is predicted that oil prices will indeed persist near or above $50 a barrel for the next 20 years (shifting towards alternative fuels and more fuel-efficient cars). The 2005 EIA analysis reflected a significant change from the Department's projections a year earlier when it predicted oil prices in constant dollars would retreat in the long term and then settle at about $31 a barrel by 2025.

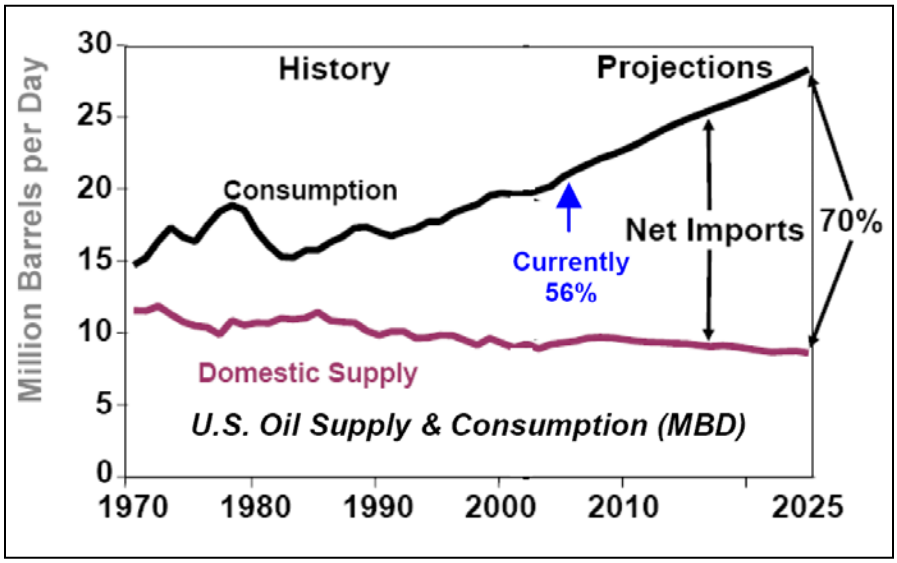
The EIA predicts increases in production at coal-to-liquids (CTL) plants from 62 million short tons of CTL in 2020 to 190 million short tons in 2030. The first commercial CTL plant in the United States, located at Gilberton, PA, will produce 5,000 B/D (barrels per day). Existing SASOL CTL plants in South Africa are producing 150,000 B/D. Similar new CTL plants are being planned in China with each producing 600,000 B/D. The production rate of one of these

new plants is equivalent to half of the U.S. imports from Canada, Saudi Arabia, Mexico and Venezuela. If several large CTL plants are built in the U.S., these will have a major impact on coal production. One ton of Eastern coal will produce about 1 to 1.5 barrels (40 to 60 gallons).

Oil prices will affect the future production of coal in the U.S. Crude oil prices hovered around $60 a barrel and briefly soared as high as $70 in 2005.

The EIA December 2005 Report projected that U.S. reliance on oil imports will remain about the same until 2025. The import projections of about 60% of the oil and refined products that the U.S. uses is slightly less than that projected earlier in 2005. A year ago the EIA said these imports would grow to nearly 70% by 2025 (Figure 2.2).

Figure 2.2 U.S. Oil Net Imports Grow up to 70% by 2025 (EIA 2004)



Major pointers from the EIA 2006 Annual Energy Outlook (AEO2006) include:

- Total U.S. coal consumption is projected to increase from 1,104 million short tons in 2004 to 1,592 million short tons in 2025 (Figure 2.3).
- AEO2006 estimates 84 million short tons more than the 1,508 million tons projected to be consumed in 2025 in the AEO2005 reference case.
- Coal consumption is projected to grow at a faster rate in AEO2006 toward the end of the projection, particularly after 2020, as coal captures market share from natural gas, and as coal use for CTL production grows (Figure 2.3).
- In the AEO2006 reference case, coal consumption in the electric power sector is projected to increase from 1,235 million short tons in 2020 to 1,502 million short tons in 2030, at an average rate of 2.0% per year.
- Coal was not projected to be used for CTL production in the AEO2005 reference case.
- Coal use at CTL plants is projected to increase from 62 million short tons in 2020 to 190 million short tons in 2030.

International energy markets are affecting U.S. coal production, driven by high costs and improved national security. The massive increase in demand for oil from China and India has had a very big impact on the international oil market. Oil consumption in China in 2002 doubled the amount for 1992 (5.0 Million B/D compared with 2.5 Million B/D, Figure 2.4). China oil consumption level is about one third of the U.S. total oil consumption with nearly 7 Million B/D in 2004 (U.S. consumed 22 Million B/D in 2005).

Figure 2.3 U.S. Energy Consumption by Fuel, 1980-2030 (10^{15} Btu), EIA 2006

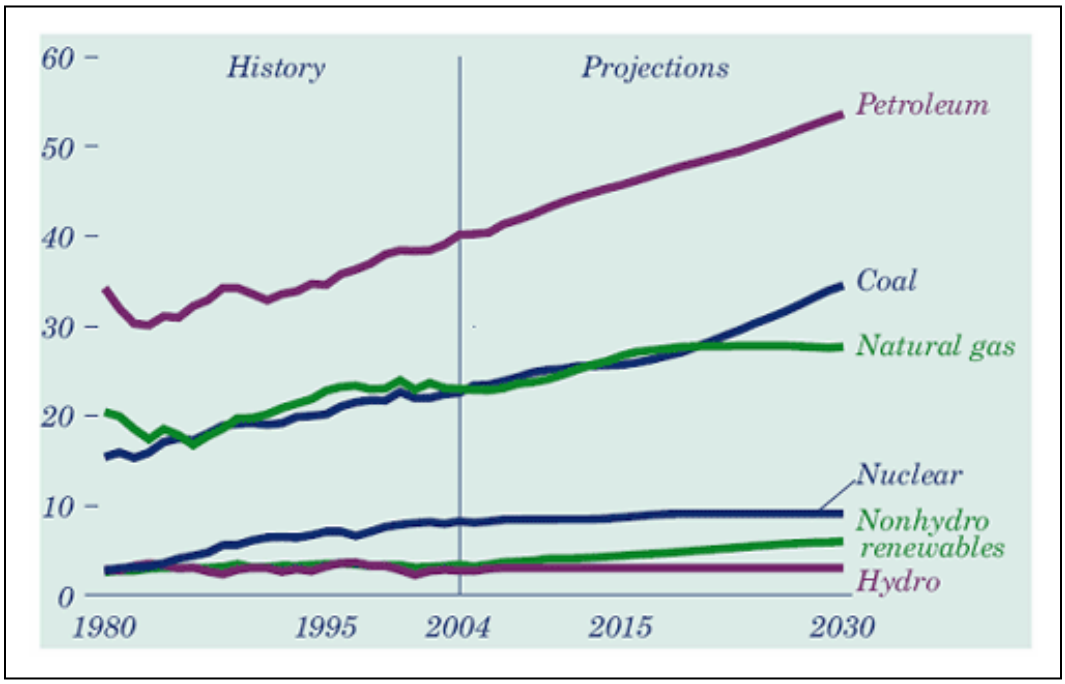
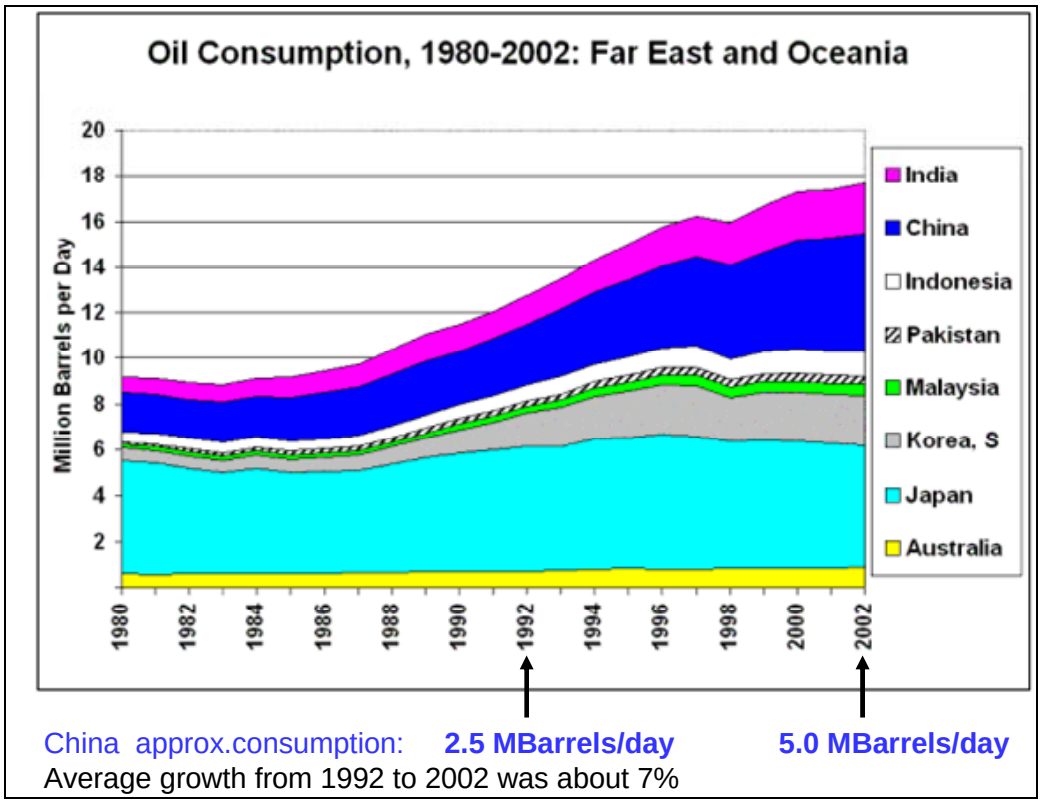


Figure 2.4 Increased Oil Demands in China and India



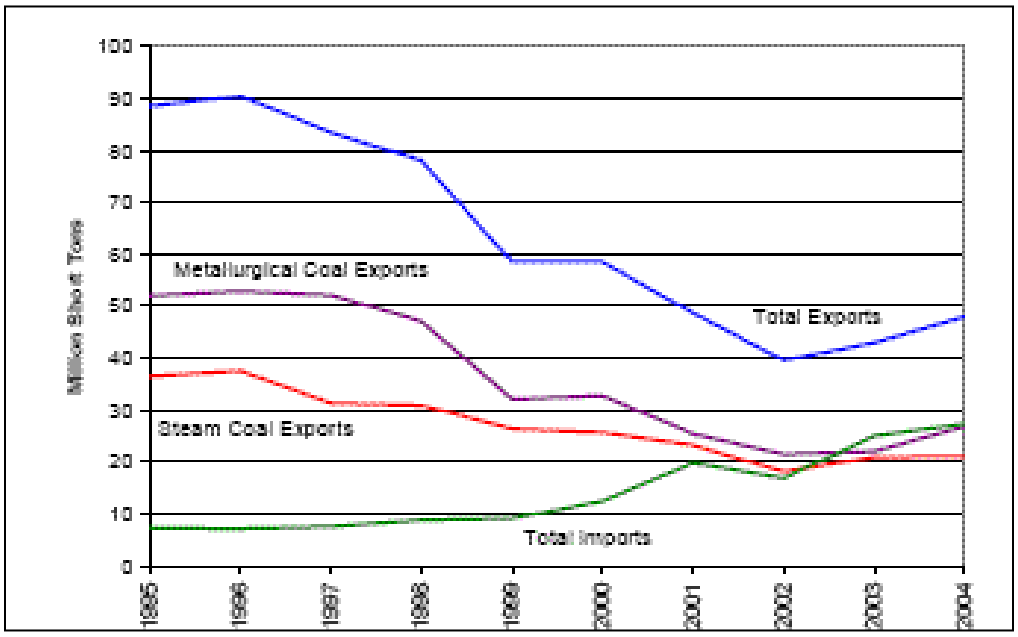
Source:
http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/Dem_image_Consumption.htm#Far%20East

The increased use of coal in China shows similar growth rates as oil. China's increased interest in clean coal technology is a good omen for the environment and a potential means of meeting their liquid fuels needs.

> "Coal makes up 65% of China's primary energy consumption, and China is both the largest consumer and producer of coal in the world. China's coal consumption in 2003 was 1.53 Billion short tons or 28% of the world total (U.S. consumption in 2004 was 1.1 Billion short tons). Over the longer term, China's coal demand is projected to rise significantly. In contrast to the past, China is becoming more open to foreign investment in the coal sector, particularly in modernization of existing large-scale mines and the development of new ones. China has expressed a strong interest in coal liquefaction technology, and would like to see liquid fuels based on coal substitute for some of its petroleum demand for transportation. A coal liquefaction facility is under construction with a projected startup date of 2005. Chinese officials have shown increasing interest in further research into improving coal liquefaction technologies, in the hope that it may eventually provide an economically viable domestic source of liquid fuels." (http://www.eia.doe.gov/emeu/cabs/china.html).

U.S. coal exports increased 11.6% in 2004 by 5.0 MTons (up to 48.0 MTons). U.S. coal imports increased 8.9% in 2004 by 2.2 MTons (up to 27.3 MTons), making the U.S. a net exporter of 20.7 MTons (Figure 2.5).

Figure 2.5 U.S. Coal Exports and Imports, 1995-2004 (MTons)



Source: http://www.eia.doe.gov/cneaf/coal/page/special/feature.html

According to the EIA, coal delivery prices in the U.S. increased in 2004 by:

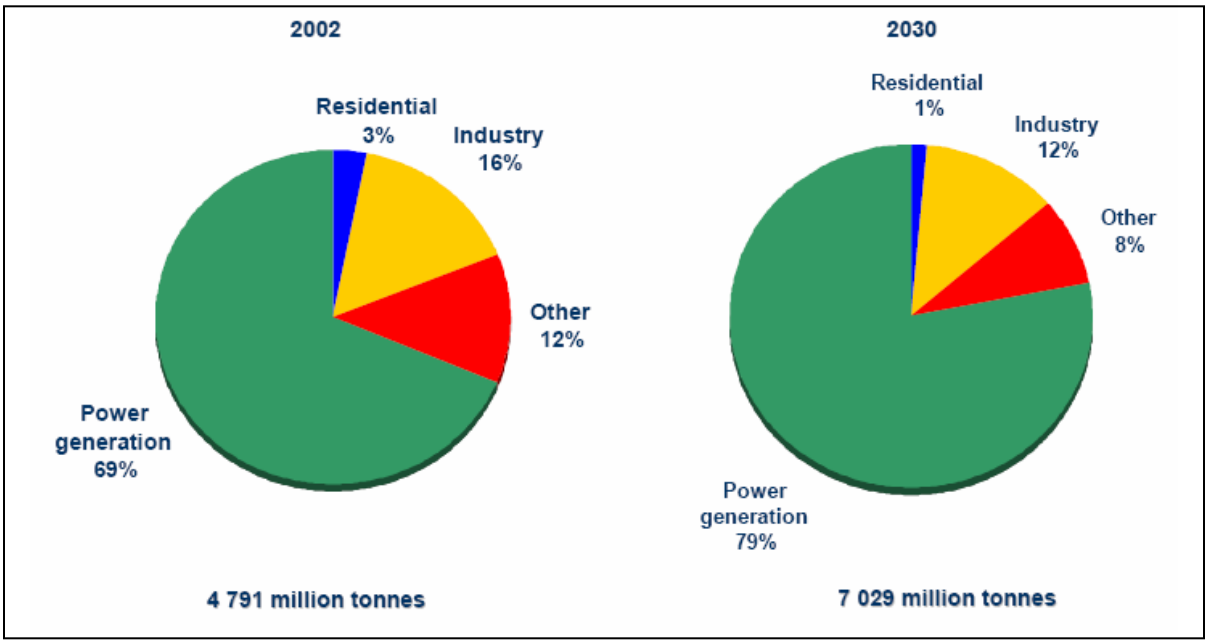
- **6% for the electric power sector**
- **13% for the industrial sector**
- **21% for coking**

Coal delivery prices to the electric power sector, mostly through long-term contracts, increased in 2004. According to preliminary EIA data, coal prices at electric utilities increased for a fourth consecutive year, to $27.28 per short ton ($1.34/MBtu), an increase of 6.0%. The increase in the delivered price of coal to the industrial sectors and for coking coal in 2004 was more evident as both sectors rely more heavily on short-term contracts and the spot market. The average delivered price of coal to the other industrial sector increased by 13.2% to an average price of $39.30 per short ton in 2004. The largest increase of 21.5% in coal consumer prices was in the coking coal sector reaching $61.50 per short ton in 2004 (EIA 2004 Coal Review).

The expected huge growth in demand for coal over the next 20 years together with the growing concern over environmental standards is certainly going to increase the importance and development for using CCTs. The DOE-EIA World Energy Outlook models indicate for up to 2030 an average increase in global coal demand to be in the order of about 1.4% per annum (4.791BTons in 2002 and 7.029BTons in 2030, Figure 2.6). The global perspective shows coal

being projected to provide nearly 80% of the fuel for power generation in 2030 (70% globally in 2002, Figure 2.6). While the U.S. total coal consumption increases to over 1.5 Billion short tons in 2025, the consumption in China reaches over 3.2 Billion short tons (Table 2.1). The projected increase in China's coal consumption is equivalent to the indicated U.S. total coal consumption by 2025. These types of coal consumption statistics confirm the relevance of the coal program at Indiana's Center for Coal Technology Research.

Figure 2.6 World Coal Demand by Sector, 2002 and 2030



Source: DOE-EIA, World Energy Outlook 2004
http://www.iea.org/textbase/speech/2005/kk_melbourne.pdf

Table 2.1 The Four Major Coal Consuming Nations (Million Short Tons)

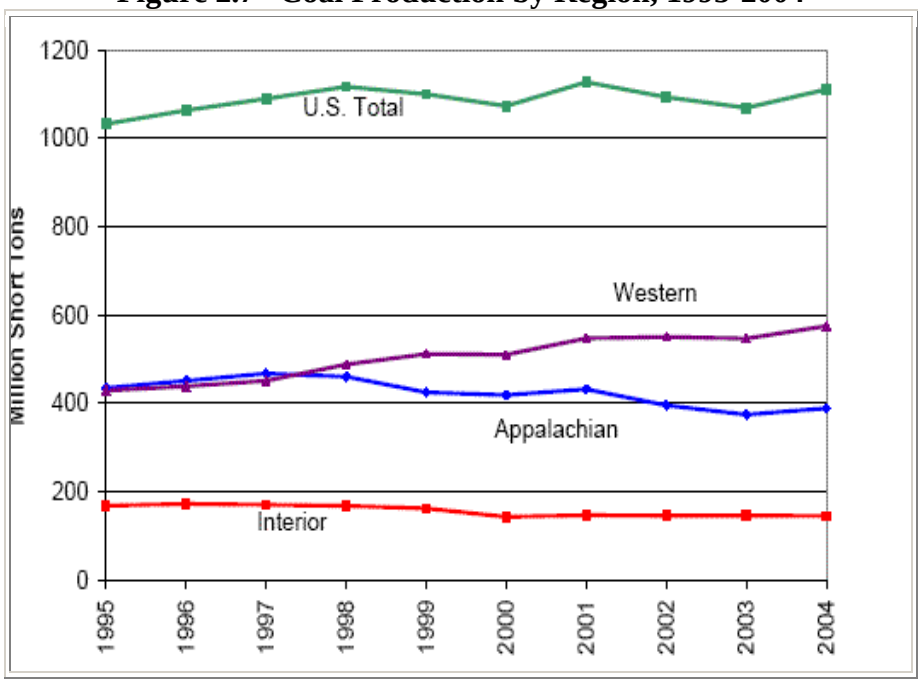
Rank Annual Consumption	Country	2003 Coal Consumption (Million Tons)	2025 EIA projections (Million Tons)	Coal Used for Power Generation (Percentage)
1st	**China**	1,530 [a]	3,242	82%
2nd	**U.S.A.**	1,104 [b]	1,592	50%
3rd	**India**	359 [c]	738	84%
4th	**Germany**	273	-	51%
	World Total	5,262 [d]	8,226	

Note: [a] 28% world consumption, [b] 2004 data for U.S.A, [c] 2000 data for India, [d] 2002 data

In the EIA's 2006 Outlook, for U.S. interior coal, there is an average increase in coal production of 2.5% across the years 2005 to 2030. It is safe to assume that Indiana will continue to depend heavily on coal for power production over this time period. With further technological developments in clean coal technology, it could mean that the increase in Indiana's demand for coal could be higher than the 2.5% Interior coal increase prediction.

Appalachian Region coal production in 2004 was 389.3 MTons (+3.5% from 2003). Interior region coal production was 145.8 MTons in 2004 (-0.1%). Western region coal production in 2004 was 575.2 MTons (+4.8%, Figure 2.7).

Figure 2.7 Coal Production by Region, 1995-2004



Source: U.S. Coal Supply and Demand: 2004 Review by Fred Freme
http://www.eia.doe.gov/cneaf/coal/page/special/feature.html

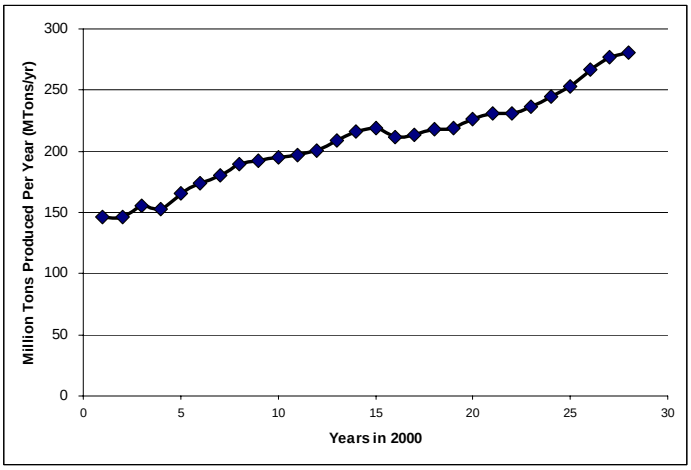
3. INDIANA COAL DEMAND

3.1 EIA Base Growth Rate of 2.5%

The demand and supply of coal for the Indiana economy has been steady for the past several years. The EIA 2006 Annual Energy Outlook predicts that the U.S. Interior average growth in coal demand to be 2.5% over the next 20 years. The extent of future growth in coal demand for Indiana might be higher than this, considering the importance of coal to the state. The increase in electricity demand and the potential replacing of coal imports with Indiana coal resulting from new clean coal technologies and higher emission standards makes this a bigger possibility.

The 2006 outlook coal production in the U.S. Interior is just over 150 MTons/year in 2005 and is not quite doubled by 2030 with about 280 MTons/year (Figure 3.1). Indiana's annual production rate of about 35 MTons represents nearly 25% of this regional production.

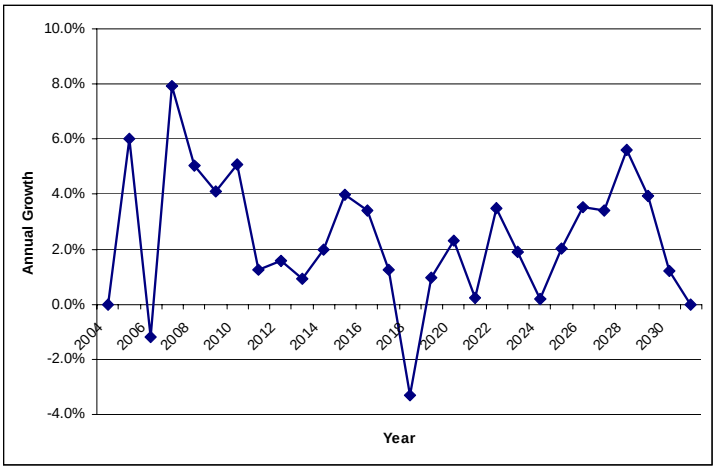
Figure 3.1 EIA 2006 Coal Demand Outlook for U.S. Interior Coal (MTons/yr)



Source: http://www.eia.doe.gov/oiaf/aeo/consumption.html

The variation in the EIA 2006 Outlook for U.S. Interior coal production growth rates is illustrated in Figure 3.2. While coal production in the U.S. Interior continues to increase up to 2020, there is a gradual decrease in the annual rate of growth compared with the previous years. This is accounted for by the fact that fewer new coal fired stations will be built each year. From 2020 there is an increase in the annual rate of growth as a result of coal replacing natural gas and the increased production of coal-to-liquids (CTL).

Figure 3.2 EIA 2006 Outlook for U.S. Interior Coal Annual Growth Rate



Source: http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html, Table 15

There are long-term indications that, with the implementation of new generation clean coal technologies and the development of CTL policies, there is an expected increased use of Illinois Basin coals. The new stricter environmental legislation, growing interest in CCTs, high natural gas and oil prices together with concerns for fuel supply security have prompted expectations for an eventual increase in demand for Indiana coal. The significance and magnitude of this expected increase in demand for Indiana coal needs very careful consideration. An Indiana coal demand forecast is now required.

Indiana is the largest coal producer among the Illinois Coal Basin states (West Kentucky included but not Eastern Kentucky which is Appalachian coal). Indiana is among the interior states that uses the highest amount of coal for power generation. Other states use a significant quota of nuclear (Illinois 48%, Arkansas 30%, Kansas 19%) and natural gas (Oklahoma 35%).

In the first half of 2004 and 2005 Indiana produced more coal than Illinois and Western Kentucky (Table 3.1). During the first half of 2005, coal production in Indiana made a slight decline compared with the same period in 2004. There was an increase in coal imports in 2004 and a similar trend might take place in 2005 (data not yet available). A declining trend took place across all of the Illinois Coal Basin except for Western Kentucky where coal production increased at 15% (Table 3.1). The higher transportation and fuel costs, together with the installation of more scrubbers on power plants, are the attributed causes for the increased coal production in Western Kentucky.

Table 3.1 Coal Production by State (MTons)

Coal Producing State	January to June = 6 months		Coal Used for Power Generation (% MWh)
	2004	2005	
Illinois	**16.9**	**16.8**	35%
Indiana	**18.0**	**17.1**	94%
Kentucky	57.7	59.7	90%
Eastern	46.4	46.6	
Western	**11.3**	**13.0**	
Ohio	11.7	12.2	90%
Wyoming	192.6	201.2	96%
U.S. Total	**549.9**	**562.1**	91%

Source: http://www.eia.doe.gov/cneaf/coal/quarterly/html/t5p01p1.xls

Indiana consumes twice as much coal as it produces. Coal is imported from several other states. The largest coal imports to the state come from Wyoming with 13.6 MTons in 2002, 15.6 MTons in 2003, and 14.8 MTons in 2004 (Figure 3.3). West Virginia is the second largest exporter of coal to Indiana and Illinois is third. Further details of the coal imports to the state are seen in Figure 3.4, which also shows methods of coal transportation. Railways are used the majority of the time for imports from Wyoming and West Virginia. Some river transportation is used.

- **2004: Indiana coal supplied 48% of total state demand**
- **2003: Indiana coal supplied 45% of total state demand**

Figure 3.3 Coal By Destination (MTons): Indiana 2002-2004

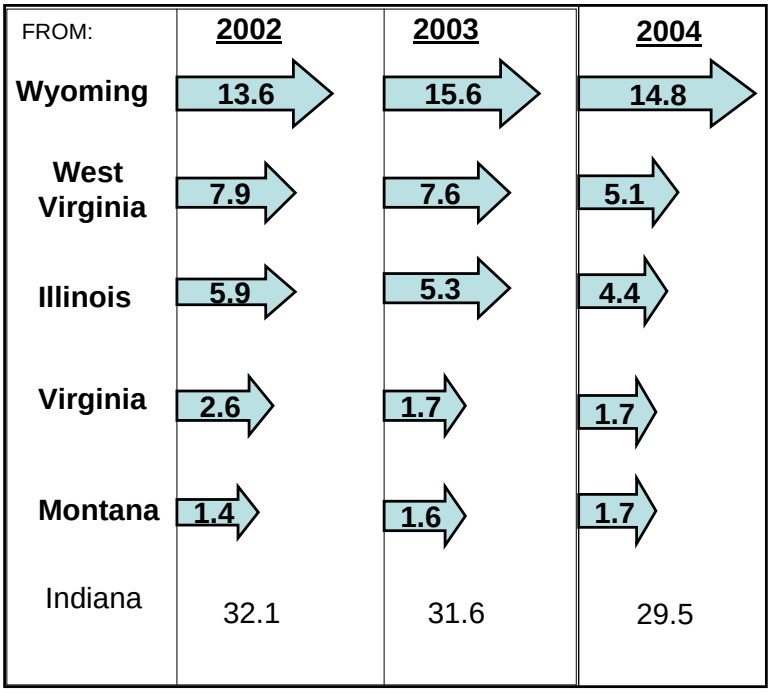


Figure 3.4 Coal Destination: Indiana 2004

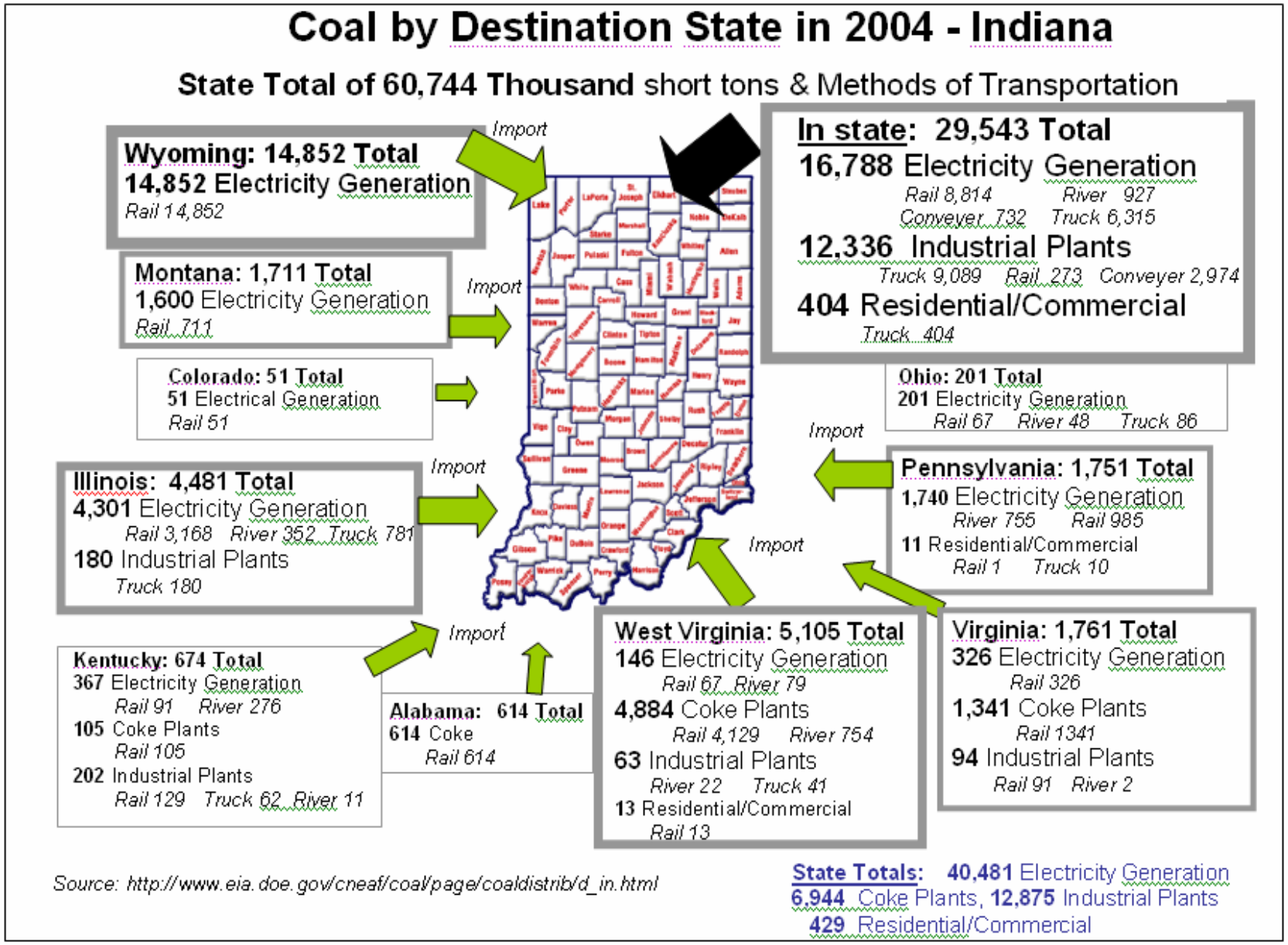


Table 3.2 U.S. Coal Consumption by End Use Sector, by State
Indiana, 2003, 2004 (Thousand Short Tons)

2003					2004				
Electric Power	**Other Industrial**	**Coke**	**Resid -ential and Com- mercial**	**Total**	**Electric Power**	**Other Industrial**	**Coke**	**Resid -ential and Com- mercial**	**Total**
58,493 **81%**	**5,298** **7%**	**8,008** **11%**	**357**	**72,156**	**59,459** **81%**	**5,766** **8%**	**7,898** **11%**	**357**	73,571

Source: EIA, DOE, Annual Coal Report 2003 Data Tables
http://www.eia.doe.gov/cneaf/coal/page/acr/acr_html_tabs.html

Indiana consumed 72.156 MTons of coal in 2003 and 73.571 MTons in 2004, a 1.96% annual increase. The bulk of this coal went to power generation with just over a tenth going to the iron and steel industry in the north of the state to be used in the coking process (Table 3.2).

The sectoral consumption percentages in 2004 were

- **Electricity - 81%**
- **Industrials - 8%**
- **Coke consumed - 11%**

There was very little coal consumed (less than 1% of total) in the residential and commercial sectors (Table 3.2). Over the past couple of years this total consumption pattern has varied by a very small amount.

A comparison of the estimates of total Indiana coal consumption in 2004 contained in Figure 3.4 and Table 3.2 show a difference of 12.8 MTons – 60,744 thousand tons in Figure 3.4 versus 73,571 thousand tons in Table 3.2. This significant difference is caused by the inclusion of "synfuel" coal production in the EIA reports of state coal consumption which is not included in the EIA coal distribution estimate, which is the basis of Figure 3.4. This "synfuel" production, which involves agglomerating coal fines produced during the coal washing process, qualifies the tonnage for a substantial tax credit. This difference in totals is expected to significantly decrease as the tax credit is phased out. *Synfuel Source: (http://www.eia.doe.gov/cneaf/coal/page/special/feature.html).*

The EIA's methodology of coal classification varies with datasets. It appears that coal for industrial plant use is higher in Figure 3.4 (12.8 MTons) than in Table 3.2 (5.766 MTons). This is caused by Table 3.2 values classifying coal used at industrial plants to generate electricity as electric power use, not industrial use. As discussed already, if the EIA could publish synfuel production by site, this would also improve the Indiana dataset.

3.2 Indiana Coal Production and Electricity Generation

The CCTR is starting to assess the state coal demand forecast. One of the most important factors in this work will be the amount of coal that will be used in Indiana's future power generation. In 2003, 81% of the total coal consumed in Indiana was used in power generation (utilities and merchant plants, Table 3.3).

Table 3.3 Coal Supplies to Indiana's 10 Largest Power Stations, 2003

Station	MW	Station Efficiency	Tons/MW/yr (2000 data)	% IN coal	% WY coal
1. Gibson	3,131	32.2	2,630	79%	0%
2. Rockport	2,600	35.4	3,452	16%	84%
3. R M Schahfer *	1,780	30.6	2,692 *	21%	58%
4. Petersburg	1,672	32.6	2,868	100%	0%
5. Clifty Crk.	1,209	32.7	3,257	22%	78%
6. Cayuga *	1,096	33.7	2,438 *	64%	0%
7. Merom	1,000	32.4	2,963	100%	0%
8. Tanners Crk.	980	34.1	2,221	92%	5%
9. Harding St. *	924	34.2	1,568 *	100%	0%
10. Wabash R. *	918	32.4	2,073 *	100%	0%

*Notes: * The Coal Tonnage per MW is lower on these plants with some units using Natural Gas*
** Schahfer has 2 of its 6 units, 155MW, using Natural Gas*
** Cayuga has 1 of its 3 units, 99MW, using Natural Gas; 36% coal supply from Illinois*
** Harding St has 3 of its 8 units, 322MW, using Natural Gas*
** Wabash River has 1 of its 6 units as an IGCC (Petcoke) & 2 units using Natural Gas*
Source: Form EIA 767, 2003

3.2.1 Coal Supplies to Existing Power Plants

We can determine the quantities and sources of coal that are delivered to existing power plants. At present four of Indiana's ten largest power plants import significant amounts of low sulfur coal from Wyoming (Table 3.3). Rockport (IMPCo) is supplied 84% of its coal tonnage from Wyoming and Clifty Creek (IKECorp) 78%. We will need to assume or determine if the power companies plan to renew their current coal supply long-term contracts. The four power stations that currently use 100% Indiana coal are Petersburg (IPL), Merom (Hoosier), Harding Street (IPL), and Wabash (PSI).

Existing power stations are planning to install scrubbers to meet environmental standards. As investments are made on new scrubbers we might ask if the utilities will reconsider their coal sources when their existing contracts come to an end on the basis that with scrubbers they can then handle higher sulfur/higher heat content Indiana coals. This will be a cost driven decision but with continued bottlenecks for Western coals coming to the Midwest there could be a possibility of coal switching or additional blending which will demand a greater production rate of Indiana coals. This will need to be considered on a plant by plant and company by company

case. Table 3.4 shows the results of a recent EPA simulation at least-cost compliance strategies for Indiana's ten largest power stations.

Table 3.4 Proposed Scrubbers on Indiana's 10 Largest Power Stations, 2003

Station (Age of units)	**Utility**	**MW**	**SO_2 (Tons)**	**MW with Scrubbers in 2005 (MW)**	**% MW Scrubbed in 2005**	**Scrubber Efficiency in 2005 (%)**	**Scrubber Installations Date installed per unit *EPA Model Results for 2015***
1. Gibson 1975-1982	**PSI**	3,131	136,536	**1,336**	**43%**	89%	Unit 1 – 2007 Unit 2 – 2007 Unit 3 – 2006 Unit 4 – Upgrade in 2005 Unit 5 – Upgrade in 2008
2. Rockport 1984-1989	**IMPCo**	2,600	53,561	**0**	0		Unit 1 * Unit 2 *
3. RM Schahfer 1976-1986	**NIPSCo**	1,780	35,301	**847**	**48%**	90%	Unit 1 - * Unit 2 - * Unit 3 - * Unit 4 - * Unit 5 - * Unit 6 - *
4. Petersburg 1967-1986	**IPL**	1,672	42,535	**1,672**	**100%**	95%	Units 1 – 7, *Already scrubbed*
5. Clifty Creek 1955-6	**IKECorp**	1,209	32,753	**0**	0		Units 1 – 5 ***2015 (five units)*** Unit 6
6. Cayuga 1970-1972	**PSI**	1,096	66,962	**0**	0		Unit 1 - ***2015*** Unit 2 – ***2015***
7. Merom 1982-1983	**Hoosier**	1,000	14,689	**1,000**	**100%**	90%	Units 1 – 2 *Already scrubbed*
8. Tanners Creek 1951-1964	**IMPCo**	980	53,175	**0**	0		Units 1 – 3 * Unit 4 – ***2015 (580MW)***
9. Harding St 1973-2002	**IPLCo**	924	51,016	**0**	0		Units 1 – 8 *
10. Wabash R. 1953-1995	**PSI**	918	64,606	**0**	0		Units 1 – 5 * Unit 6 - ***2015***
	TOTAL	**15,310**	**551,134**	**4,855**	**32%**		*Note: * No installation predicted*

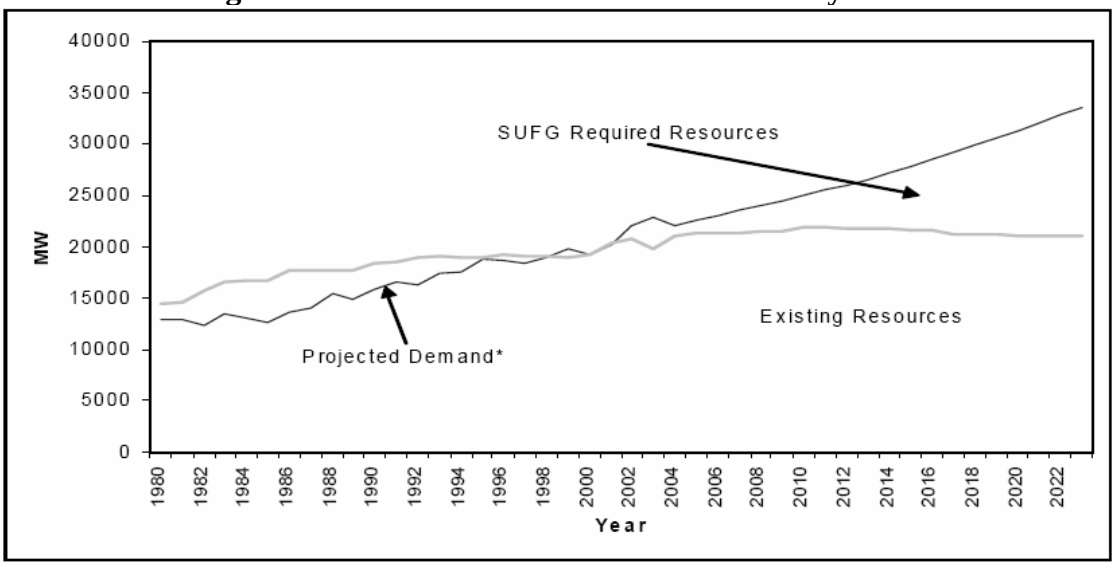
Coal switching to Indiana coals could take place, if scrubbers were installed, in the four larger power plants at Rockport, Schahfer, Clifty Creek, and Cayuga. Three of these consume Wyoming coal (Table 3.3). Only two of Indiana's ten largest power plants currently have all units scrubbed. These are Petersburg (IPL) and Merom (Hoosier) and each of these plants uses 100% Indiana coal. Extensive work on scrubbers is taking place at Gibson (PSI) over the next

couple of years. Gibson uses 79% Indiana coal and most of its other coal supplies come from Illinois. Additional scrubbers have been modeled by EPA, indicating that there could be an increased use of Indiana coal similar to the trend currently seen in Kentucky. The EPA identified new scrubbers, for 2015, are recommended for Clifty Creek, Cayuga, Tanners and Wabash (Table 3.5, italicized text in right-hand column). The work being conducted by IDEM with the EPA modeling indicates that by 2015 it will be beneficial for installation of more scrubbers on Indiana power plants and this will further enable switching to take place (Table 3.4).

3.2.2 Coal Supplies for Proposed Power Plants

SUFG's most recent Electricity Forecast shows an increasing electricity demand of 2.22% per year or 500 MW of increased peak demand per year (Figure 3.5).

Figure 3.5 The SUFG 2005 Indiana Electricity Forecast



* Projected Demand includes 15% Reserve Margin

Source: Indiana Electricity Projects, The 2005 Forecast, SUFG, Purdue University, September 2005
https://engineering.purdue.edu/IE/Research/PEMRG/SUFG/PUBS/2005Forecast.pdf

Over the next ten years it is estimated that Indiana will need about 5,000 MW of new base-load generating capacity. Unless there is a significant increase in electricity imports to the state this increased demand will come from new base-load generation capacity that is to be constructed in the state.

If all this baseload capacity were to be met by pulverized coal units using Indiana coal similar to the technology in place at the Gibson unit (2,630 Tons/MW/year) an additional 13 MTons/year of Indiana coal production would be required by 2015. If half of this capacity were to be IGCC units whose efficiency is substantially higher (45% vs. 33%) than conventional units, only an additional 11.2 MTons per year of Indiana coal would be needed by 2015.

If all this baseload capacity were to be met by using Wyoming coal in units similar to the Rockport unit which uses 3450 tons/MW/yr of lower heat content coal than Illinois Basin coal (8,800 Btu/lb vs. 11,000 Btu/lb, then an additional 17 MTons/year would have to be imported to meet this demand in 2015. This figure would drop to 14.7 MTons/year, if half the units were the higher efficiency IGCC units. All this is summarized in Table 3.5.

Table 3.5 Increases in Coal Use/Year by 2015 with Various Assumptions (MTons)

	All PC	**50% PC 50% lGCC**
All Indiana coal	13.0	11.2
All Wyoming coal	17.0	14.7
Note: PC = Pulverized Coal IGCC = Integrated Gasification Combined Cycle		

What quantities of coal are being consumed at existing and proposed power stations in Indiana is the most important issue in forecasting a coal demand for the state. We have heard already about the new coal fired capacity being discussed for Cinergy's 600 MW Edwardsport facility. Cinergy may use IGCC technology from General Electric/Bechtel and Chevron/Texaco Gasification to reactivate this plant. Other new plants are also going to be planned but how much coal and what source is to be tapped? The imports of coal for coking is another factor that will have to be considered in the coal demand forecast as well as the coal supplies for power stations. The coking coal needs and coal transportation studies being planned for 2006 by the CCTR will help in the process of building the foundation for an Indiana coal demand forecast methodology.

3.3 Forecasting Indiana Coal Production

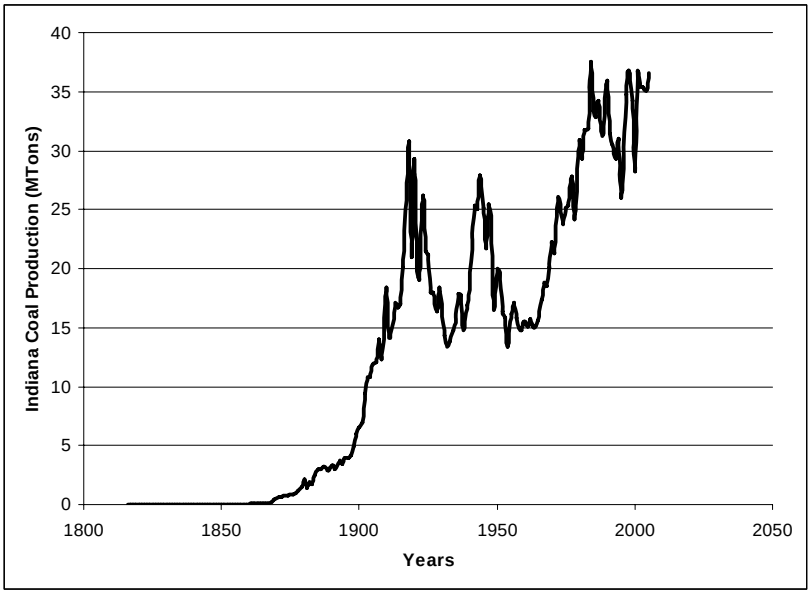
3.3.1 Introduction

Figure 3.6 and Table 3.6 show the historical pattern of Indiana coal production since 1818 when coal was first mined in our state. A natural question we might now ask is "where will we go from here?" Will Indiana coal production continue failing to keep up with Indiana coal use, as it has since 1987? With better gasification properties than PRB coals, will the emergence of clean coal technologies allow Indiana to recapture lost markets? With the aid of organizations like the CCTR, will our state's efforts to stimulate the use of Indiana coals be successful in stemming the tide of coal imports from the east and west, and re-establish our export markets?

CCTR forecasting techniques are currently inadequate to definitively answer these questions, since the development of the CCTR forecasting methodology is just underway. At present CCTR has developed methodologies that can only estimate the impact on Indiana coal use of answers to these questions. In other words, though CCTR is not currently in a position to predict when and if the commercialization of clean coal technologies will take place, CCTR can estimate the potential impact on Indiana coal use when and if such commercialization does occur.

A systematic method of forecasting the use of Indiana coals is needed. We believe this method should be similar in intent and design to the forecasting methodologies used by the SUFG to forecast Indiana electricity supply and demand. The resulting forecast would be able to reflect projections regarding key factors that are known to affect coal use. By varying the set of chosen assumptions the forecasts of coal use can thus be compared.

Figure 3.6 Indiana Historic Coal Production Data



Source: http://pubs.usgs.gov/of/1997/of97-447/illinois_basin.txt

Such methodologies are not created overnight. It took over three years before the SUFG forecast methodology was developed to the point where it could be used with confidence. Therefore, the forecasts and methodologies presented in this section should be considered a work in progress. The forecasts and data sets which support the forecasts will be improved over time. This will take place as more is learned about the factors that influence the use of Indiana coal, forecasts of these factors, and the best way to combine these factor drivers into a consistent Indiana coal use forecast.

Table 3.6 Indiana Historic Coal Production Data (MTons)

Year	MTons	Year	MTons	Year	MTons	Year	MTons	Year	MTons
1900	6.484	1925	21.225	1950	19.957	1975	25.124	2000	28.285
1901	6.918	1926	17.936	1951	19.451	1976	25.369	2001	36.714
1902	9.446	1927	17.936	1952	16.360	1977	27.797	2002	35.391
1903	10.795	1928	16.379	1953	15.812	1978	24.182	2003	35.35
1904	10.842	1929	18.344	1954	13.400	1979	27.49	2004	35.11
1905	11.895	1930	16.490	1955	16.149	1980	30.873		
1906	12.093	1931	14.295	1956	17.089	1981	29.313		
1907	13.986	1932	13.324	1957	15.841	1982	31.763		
1908	12.315	1933	13.761	1958	15.022	1983	31.835		
1909	14.834	1934	14.794	1959	14.804	1984	37.555		
1910	18.390	1935	15.754	1960	15.538	1985	33.316		
1911	14.201	1936	17.823	1961	15.106	1986	32.852		
1912	15.286	1937	17.765	1962	15.709	1987	34.208		
1913	17.166	1938	14.758	1963	15.100	1988	31.271		
1914	16.641	1939	16.943	1964	15.075	1989	33.641		
1915	17.006	1940	18.869	1965	15.565	1990	35.907		
1916	20.094	1941	22.484	1966	17.326	1991	31.468		
1917	26.539	1942	25.388	1967	18.772	1992	30.466		
1918	30.679	1943	25.065	1968	18.486	1993	29.295		
1919	20.912	1944	27.962	1969	20.086	1994	30.927		
1920	29.351	1945	25.183	1970	22.263	1995	26.007		
1921	20.320	1946	21.697	1971	21.396	1996	29.666		
1922	19.133	1947	25.449	1972	25.949	1997	34.805		
1923	26.229	1948	23.849	1973	25.253	1998	36.774		
1924	21.480	1949	16.550	1974	23.726	1999	34.215		
Source:	*http://pubs.usgs.gov/of/1997/of97-447/illinois_basin.txt*								

3.3.2 An Overview of the Forecasting Options

There are many ways to predict the use of Indiana coals.

The simplest method is to assume that the best predictor of the growth of future use is growth in past use. But how should past growth be defined, the last ten years, twenty years or fifty years? Figure 3.6 shows as complete a picture of the historical production of Indiana coals as can be assembled from consistent data sources. As can be seen, the calculation of the growth rate will depend heavily on what year is chosen to start the analysis (Table 3.6).

A second way is to use the so-called "shift-share" methodology. Here predicted changes in identified shares of various markets are combined together to create a forecast of Indiana coal use. Thus, changes in Indiana coal use are determined by changes in Indiana's share of

Illinois Basin coal production, Illinois Basin's share of total U.S. coal production, U.S. coal production's share of total U.S. energy use, etc..

A third possibility is to forecast each major use of Indiana coals separately, just as SUFG creates a statewide forecast of electricity use by combining separate forecasts of residential, commercial, and industrial use in each of the major utility service areas in the state. This approach would break down the forecast into a forecast of Indiana coal use by electric utilities (now 21 million tons, 45% of total use by Indiana Utilities), by Indiana steel mills (now 0 tons, since all 6.2 million tons are brought in from other states) by industrial plants (now 10.8 million tons, 87% of total use by Indiana industrial plants) and new uses, such as the use of Indiana and other Illinois Basin coals as feedstock for chemical plants that convert coal into transportation fluids.

While this last methodology is by far the best approach, the methodology and supporting data bases are not yet developed to the point of usability for this report. The CCTR staff, with the assistance of the SUFG staff, will be developing this technique over the coming year, and will present the results in a later report.

Thus, the results of only the first two methods will be presented in this initial forecasting effort. Each will be discussed in turn, and each will be used to forecast Indiana coal use in 2020.

3.3.3 The Use of Historical Trends to Predict Future Coal Production

Consider the historical 10 year period from 1995 to 2004; a period that starts at the lowest point of the most recent gradual increase in production rates, with 26.007 MTons being produced in 1995. The average annual production growth rate for this interval is 3.05%.

Note that changing the starting point will change the historical growth rate. For instance, if a 45 year period is chosen, starting in 1959 at the commencement of one of the longest periods of continued growth in Indiana coal production with 14.804 MTons to 2004, then average growth rate will be 1.94% and not 3.05%.

- 1995-2004 Average Growth Rate in Coal Production: 3.05%
  $26.007(1+x)^{10} = 35.11, \; x = 0.0305$

- 1959-2004 Average Growth Rate in Coal Production: 1.94%
  $14.804(1+x)^{45} = 35.11, \; x = 0.0194$

Now, if it is expected that the future will simply be a repeat of Indiana's experience during the more recent chosen interval, then we can expect Indiana coal use to grow at 3.05% per year. Using this assumption, Indiana coal production in 2020 would be 56.78 MTons, a 61.7% increase over the 2004 production rate.

3.3.4 Using the Shift Share Methodology

A simple way of understanding the interplay of the factors which will govern future use of Indiana coal is to think of Indiana coal production as being governed by the following equation:

$$CPi = \frac{CPi}{IBCPi} * \frac{IBCPi}{USCPi} * \frac{USCPi}{USenergyi} * \frac{USenergyi}{USGDPi} * USGDPi \qquad \textbf{Equation 1}$$

Notation

CPi	Indiana Coal Production in year i (Million Tons)
IBCPi	Illinois Basin Coal Production in year i (Million Tons)
USCPi	United States Coal Production in year i (Million Tons)
USenergyi	United States Energy Use in year i (Quadrillion Btu, 10^{15} Btu)
USGDPi	United States Gross Domestic Product in year i ($ Billion)

Indiana Coal Production = (Indiana Coal Production / Illinois Basin Production)
x (Illinois Basin Production / Total U.S. Coal Production)
x (Total U.S. Coal Production / Total U.S. Energy Use)
x (Total U.S. Energy Use / GDP)
x (GDP)

On the one hand, Equation 1 is a tautology, in that after canceling out the common variables appearing in the numerator and denominator, the left side of the equation must equal the right side. On the other hand, if the equation is interpreted as a predictive equation and rewritten as the following relationship between the percentage change in Indiana Coal Production and the percentage change in the right hand terms, we have (neglecting cross product change terms):

$$\%\ change\ CPi =$$

$$\{\%change \frac{CPi}{IBCPi}\} + \{\%change \frac{IBCPi}{USCPi}\} + \{\%change \frac{USCPi}{USenergyi}\} + \{\%change \frac{USenergyi}{USGDPi}\} + \%changeUSGDPi \qquad \textbf{Equation 2}$$

Forecast Change in Indiana Coal Production =
Forecast percentage change in Indiana's share of Illinois Basin Production (Term I)
+ Forecast percentage change in Illinois Basins share of U.S. Coal Production (Term II)
+ Forecast percentage change in U.S. Coal Productions Share of Total U.S. Energy Use (Term III)
+ Forecast percentage change in Total U.S. Energy Use's Share of GDP (Term IV)
+ Forecast percentage change in GDP (Term V)

Thus, if all the ratios are forecast to remain unchanged in Equation (1), then Equation (2) would conclude that Indiana Coal production would grow at the same rate as Gross Domestic Product. The benefit of Equation (2), of course, is to allow the forecaster to isolate and predict the factors

that are expected to govern each of the percentage changes, and to construct a forecast which is the sum of each of these predicted changes.

3.3.4.1 Term I: Change in Indiana's Share of Illinois Basin Production

Figures 3.7, 3.8 and Table 3.7 show the pattern of values of Indiana's share of Illinois Basin Production over the interval 1995-2004. As the figure indicates Indiana coal production has been about one third of the total Illinois Basin coal production and in recent years the Indiana share has increased. Indiana's share of the Illinois Basin coal production has nearly doubled from 22% in 1995 to 39% in 2004 (Figure 3.7). In 1995 Indiana produced 25.5 MTons and the Illinois Basin 110 MTons while in 2003 the numbers were respectively 35.3 MTons and 94 MTons. The average yearly increase in Indiana's share of Illinois Basin coal during the period 1995-2004 was 5.9% per year.

Figure 3.7 Indiana's Percentage Share of the Illinois Basin Coal Production

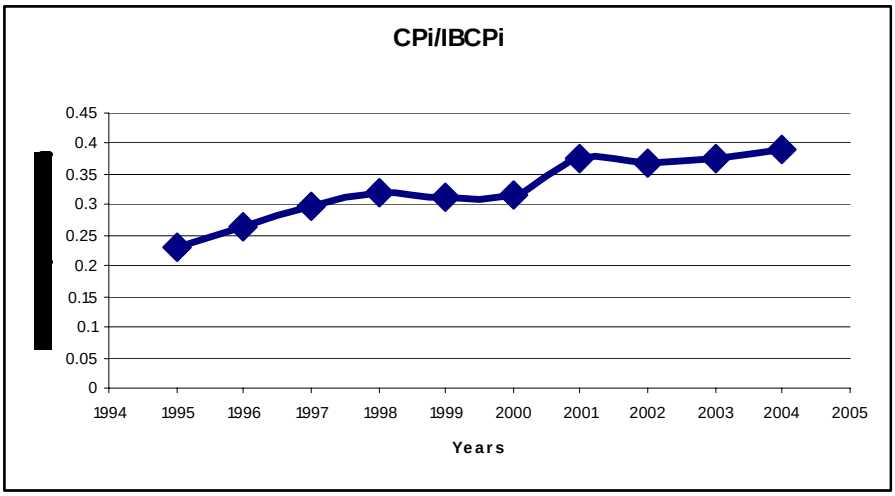
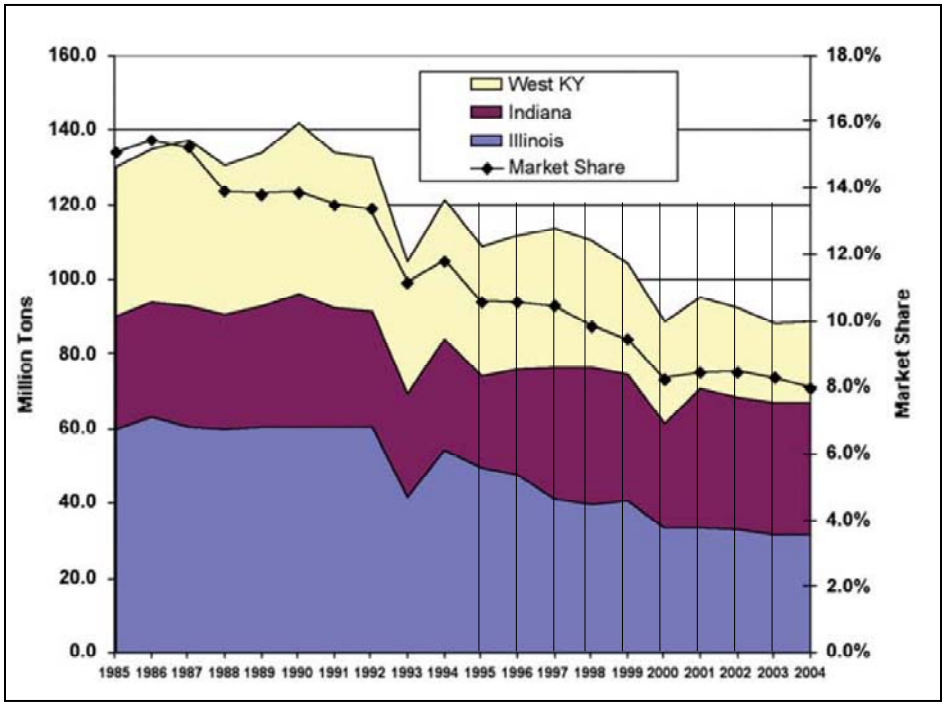


Figure 3.8 Illinois Basin Coal Production



Source: Illinois Coal, A Second Coming?
http://www.google.com/search?hl=en&q=ILLINOIS+COAL+BASIN+PRODUCTION

Table 3.7 Illinois Basin Coal Production (Million Tons)

Year	Illinois	Indiana	Western Kentucky [a]	Illinois Basin TOTAL
1995	48.18	25.57	36.58	110.33
1996	46.66	29.67	40.58	112.91
1997	41.16	34.81	43.14	117.51
1998	39.73	36.77	35.83	115.18
1999	40.42	34.22	31.03	109.02
2000	33.44	28.29	27.55	89.28
2001	33.78	36.71	28.21	97.71
2002	33.31	35.39	27.22	95.92
2003	31.64	35.36	23.42	94.22
2004	31.85	35.11	23.16	90.33

Source; http://www.eia.doe.gov/cneaf/coal/page/acr/table1.html
http://www.eia.doe.gov/cneaf/coal/statepro/imagemap/il1p1.html
http://www.coaleducation.org/ky_coal_facts/default.htm
http://www.google.com/search?hl=en&q=ILLINOIS+COAL+BASIN+PRODUCTION
[a] *Kentucky Coal Council, January 6, 2006, fax*

Future changes in Term I can be expected to be governed by changes in the cost advantage or disadvantage of Indiana coals relative to other Illinois Basin Coals. While there are some physical differences between coals in the Illinois basin, in particular, chlorine and sulfur content, essentially, Illinois Basin sub-bituminous coals all come from the same seams and tend to share

the same characteristics (see the Maria Mastalerz report in Chapter 5 of this Report for more details on the similarities and differences).

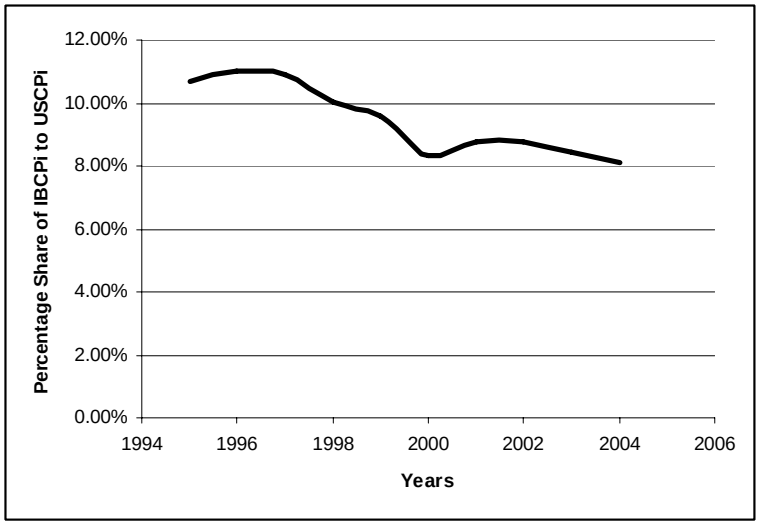
Factors that have affected Term I and can be expected to govern it further in the future would include:

(a) The impact of Indiana legislation designed to encourage the production of Indiana coals for export and domestic use, and legislation designed to mitigate the environmental impact of the use of such coals.
(b) Changes in the transportation costs of Indiana coals relative to other Illinois Basin coals.
(c) Changes in the costs of mining Indiana coals relative to the costs of mining other Illinois Basin coals, particularly as Indiana coal production shifts to higher cost underground and less surface mining.

3.3.4.2 Term II: Changes in Illinois Basin's Share of U.S. Coal Production

Figure 3.9 shows the pattern of values of Illinois Basin's share of total U.S. coal production. Factors expected to govern changes in Term II are similar in nature to those for Term I, except they deal with changes in the costs and government incentives of Illinois Basin Coals relative to other Basin Coals, in particular, Western Basin and Appalachian Coals, the chief competitors for Illinois Basin coals in the Markets shared by the three.

Figure 3.9 Illinois Basin Share of the National U.S. Coal Production, 1995-2005



In addition there are marked differences in coal characteristics with Western coals tending to have lower Btu/lb and sulfur/lb values than Illinois Basin coals. Appalachian coals tend to be of a higher rank than Illinois coals and will play a role in forecasting changes in Term II values particularly regarding use in coke production. In addition, there are forecast changes in the cost of mining coals in these regions. Western coals mining costs could decrease or remain the same. Illinois and Appalachian coals tend to increase as the low cost seams are worked out. This might partially be offset by the expected increases in transportation costs for Western coals. Changes in

regional legislation designed to encourage or discourage the use of Illinois Basin coals are not expected to play a significant role in determining changes in Term II in the immediate future. There is a possible exception to this if the impact of the Obama-Lugar Amendment designed to encourage the use of Illinois Basin coals in the production of transportation fuels is successful.

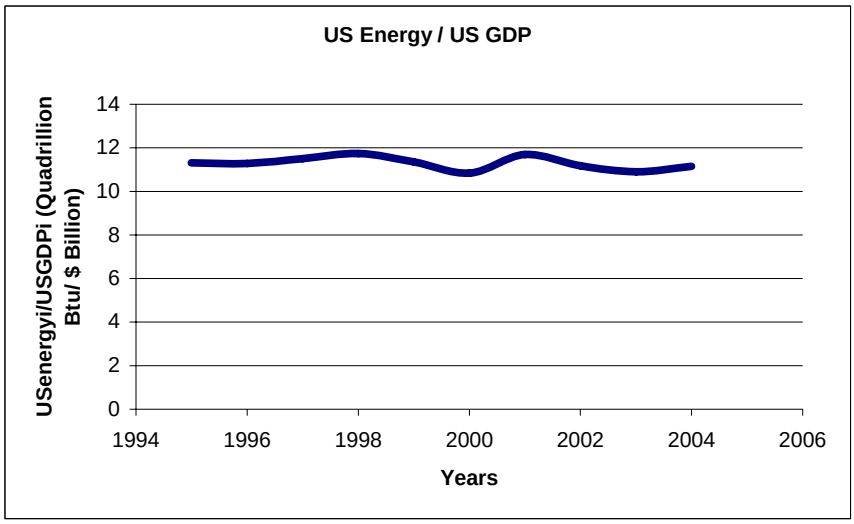
Illinois Basin coals share of U.S. national coal production over the past decade has gradually decreased from around 11% to 8% as a result of federal clean air legislation making it more economical to import western low sulfur coals than to build scrubbers which allow high sulfur Illinois Basin coals to be utilized (Figure 3.9).

The average yearly% decrease in the Illinois Basin's share of total U.S. coal production was 3% per year.

3.3.4.3 Term III: Changes in U.S. Coal Production's Share of Total U.S. Energy Use

As Figure 3.10 shows, there has been little change in coal's share over the entire 10-year interval, although an unexplained cyclic component is evident in the figure. A fluctuating range of 10.8 to 11.7 MTons of coal per Quadrillion Btu consumed is observed.

Figure 3.10 Changes in U.S. Coal Production with Total U.S. Energy Consumption (MTons per Quadrillion Btu), 1995-2005



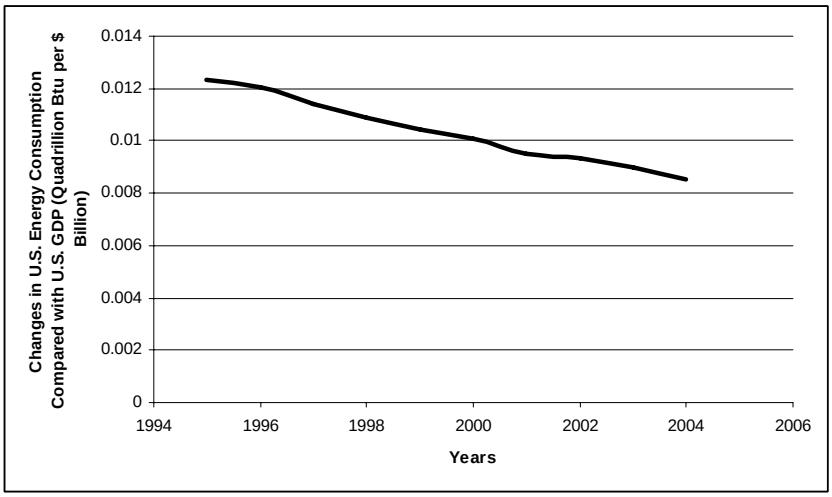
The average yearly% decrease in coal's share of total U.S. energy consumption was 0.3% per year during the period.

3.3.4.4 Term IV: Changes in U.S. Energy Consumed as a Share of U.S. GDP

Figure 3.11 shows the time pattern of our economy's energy intensity – the ratio of Quadrillion Btu per Billion dollars of GDP – from 1994 to the present. The figure shows the effectiveness of our country's efforts to reduce our energy consumption, due to the combination of high energy prices and government programs to encourage energy conservation.

During the 10-year interval, the ratio fell from 0.0121 in 1995 to 0.0083 in 2005, an annual rate of decrease of 4.5% per year.

Figure 3.11 Change in U.S. Energy Consumption Compared With U.S. GDP (Quadrillion Btu per $ Billion), 1995-2005



3.3.4.5 Term V: Changes in GDP

Since 1995 GDP has been growing at an average real rate of about 3.7%. Explaining the time pattern of the growth in the economy is a major industry in itself.

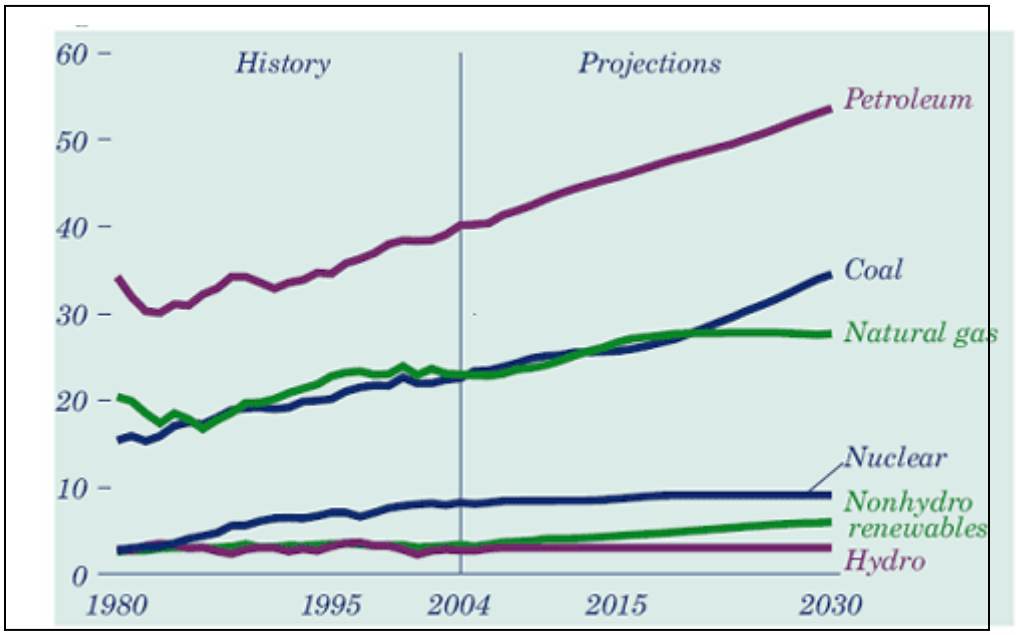
3.3.4.6 Forecasting Changes in Terms III, IV, and V

Changes in coal's share of U.S. energy consumption, energy consumption's share of U.S. GDP (energy intensity) and GDP are routinely forecasted by government agencies.

According to the Presidents Council of Economic Advisers, GDP is expected to grow at a rate of 3.1% per annum. The EIA expects coal's share of total energy consumption to grow at .55% per year, and U.S. energy's share of GDP to decrease at a rate of 1.8% per year for the period, continuing the historical decline in U.S. energy intensity shown in recent years.

The reduced role of natural gas and developments in the coal-to-liquids (CTL) industry are factors sited for the increased coal share in the EIA's Annual Energy Outlook 2006 (AEO2006) given in Figure 3.12 below.

Figure 3.12 Energy Consumption by Fuel 1980-2030 (Quadrillion Btu)



Source: EIA Annual Energy Outlook 2006
http://www.eia.doe.gov/oiaf/aeo/figure_3.html

In the AEO2006 reference case, coal consumption in the electric power sector is projected to increase from 1,235 million short tons in 2020 to 1,502 million short tons in 2030, at an average rate of 2.0% per year; and coal use at CTL plants is projected to increase from 62 million short tons in 2020 to 190 million short tons in 2030 (Figure 3.12).

3.3.4.7 Demonstration Forecasts Using the Shift/Share Methodology

As was stated earlier, Equation 2 can be used to predict the expected percentage growth in Indiana coal us by using a variety of estimates of the changes in the share percentages.

For instance, suppose it was assumed that:

(a) The yearly percentage increase in Term I (Indiana's share of Illinois Basin coal production) were to remain at the 5.9% value observed from 1995 to 2004.

(b) The yearly percentage decrease in Term II (Illinois Basin's share of U.S. coal production) were to remain at the 3% per year level observed over the same interval.

(c) The yearly percentage increase in Term III (U.S. coals share of U.S. Energy) were to increase at the .55% rate forecast by EIA.

(d) The yearly percentage decrease in Term IV (U.S. Energy Intensity) were to decrease at the 1.8% annual rate forecast by the EIA.

(e) The yearly% increase in GDP was the 3.1% rate forecast by the Council of Economic Advisors.

Then we could conclude that an estimate of the likely change in the use of Indiana coal over the forecast horizon would be the sum of these forecasted percentage changes:

Forecast Change in Indiana Coal Production
= 5.9% - 3% + 0.55% -1.8% + 3.1%
= 4.8%

This is well above the 3.1% annual historical rate of growth of Indiana coal shown in Table 3.7 for the period 1995-2004.

3.3.5 Summary of the Forecasts Developed by the Various Methods

Figure 3.13 Demonstration Plots of Indiana Coal Production Forecasts

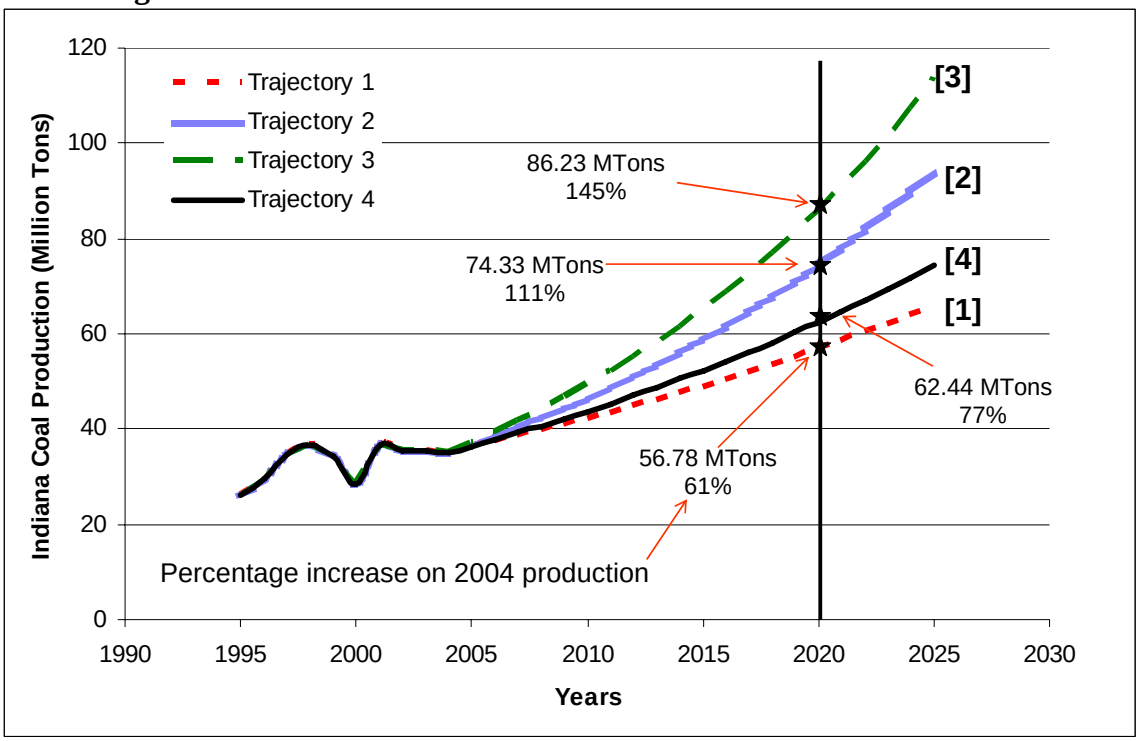


Figure 3.13 presents demonstration plots of four possible trajectories of Indiana coal production forecasts, for 2005 to 2020, as well a actual use from 1995 to 2004, each based on separate assumptions about the growth rates for use to be expected in the next 20 years.

Figure 3.13 illustrates the four trajectories. The forecast data is supplied in Table 3.8. Each trajectory is described below:

Trajectory 1 – Base Case or "business as usual"

This shows the trajectory if it is assumed that the 3.05% annual growth rate experienced during the interval 1995-2004 were to hold during the forecast period. As the figure indicates, if history repeats itself, Indiana coal use will grow to 56.78 MTons by 2020, an increase of 61% during the interval.

Trajectory 2 – Shift-share methodology

The shift-share methodology described in section 3.3.4 above resulted in a forecast annual growth of 4.8% per year. Under these assumptions, Indiana coal use can be expected to grow to 74.33 MTons by 2020, an increase of 111% during the interval.

Table 3.8 Demonstration Indiana Coal Production Forecasts 2005 to 2025

Year	Trajectory 1	Trajectory 2	Trajectory 3	Trajectory 4
2004	35.110	35.110	35.110	35.110
2005	36.181	36.795	37.163	36.427
2006	37.284	38.561	39.333	37.790
2007	38.422	40.412	41.625	39.200
2008	39.593	42.352	44.046	40.658
2009	40.801	44.385	46.604	42.166
2010	42.045	46.516	49.307	43.725
2011	43.328	48.748	52.161	45.336
2012	44.649	51.088	55.175	47.001
2013	46.011	53.540	58.359	48.722
2014	47.414	56.110	61.721	50.499
2015	48.861	58.804	65.272	52.335
2016	50.351	61.626	69.021	54.231
2017	51.887	64.584	72.980	56.188
2018	53.469	67.684	77.160	58.209
2019	55.100	70.933	81.573	60.293
2020	56.780	74.338	86.232	62.444
2021	58.512	77.906	91.150	64.662
2022	60.297	81.646	96.342	66.950
2023	62.136	85.565	101.822	69.307
2024	64.031	89.672	107.606	71.738
2025	65.984	93.976	113.711	74.241

Trajectory 3 – Trajectory 2 plus 1% per year

Trajectory 3 is an adjustment of Trajectory 2 upwards by increasing the rate of growth each year by 1%. The first 1% is added to the growth rate in 2005, and then 2% is added in 2006, etc., up to 16% added by 2020. This scenario results in a projection of Indiana coal production of 86.22 MTons by 2020, an increase of 145%.

Trajectory 4 – Trajectory 2 minus 1% per year

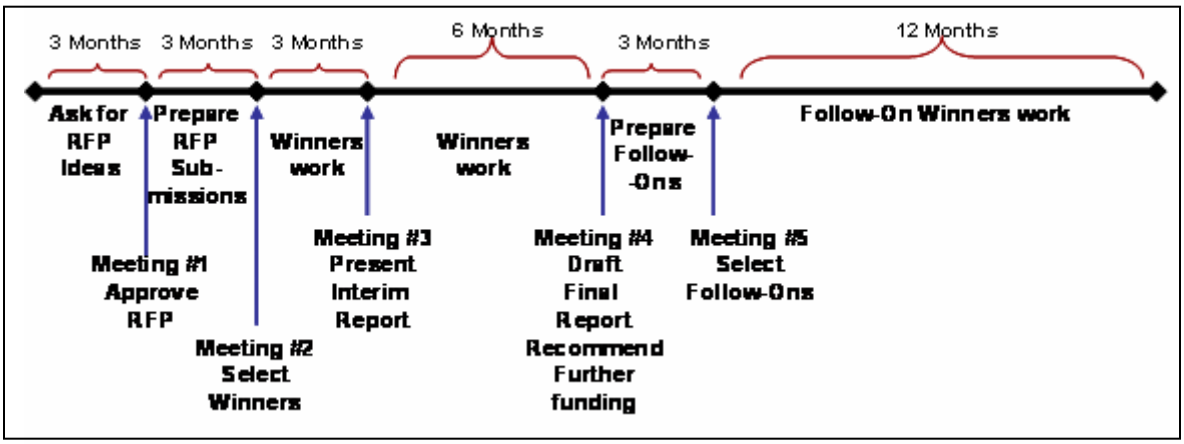
Trajectory 4 is an adjustment of Trajectory 2 downwards by the same increments as with Trajectory 3. The first 1% is subtracted from the growth rate in 2005, and then 2% subtracted in 2006, etc. This scenario results in a projection of Indiana coal production of 62.44 MTons in 2020, an increase of 77%.

In summary, Figure 3.13 presents two plausible demonstration forecasts of Indiana coal production with Trajectories 1 and 2 predicting 61% to 111% increases. Trajectories 3 and 4 represent reasonable bounds on the range for Trajectory 2. The forecasts in Figure 3.13 should be considered only as demonstration forecasts, not forecasts to be considered formal by any means. They are presented as examples of the type of forecasts that CCTR will be making in the future, as CCTR develops and improves the techniques to be used.

4. REVIEW OF CCTR EVENTS 2004/5

Over the past year, the Indiana Center for Coal Technology Research (CCTR) has been considering several important coal technology research topics that are significant in helping to promote Indiana coal in an economically and environmentally sounds manner. Decisions on these topics have taken place at three CCTR Advisory Panel meetings (October 2004, February 2005 and June 2005). Three projects were funded and three more were launched in fall 2005. Progress has been seen at the legislative level and with CCTR funding. The creation of the Coal Transformation Laboratory (CTL, Energy Center at Purdue, Discovery Park) produces an informally affiliated partnering center for the CCTR.

Figure 4.1 2005/6 Scoping Study Timeline



The CCTR scoping studies typically last for a 9 month period. The CCTR Advisory Panel will first of all approve the coal research topics and the RFP and then at the next Panel meeting will select the winners who responded to the RFP (Figure 4.1). The winners of the RFP will present an Interim Report at the next Panel meeting and finally present the Final Report 6 months later. This was the pattern established in 2005 and is expected to continue in 2006. In 2005 there were several significant events and meetings that took place.

4.1 Indiana Legislative Proceedings, State Bill 378

The Indiana State Bill 378 provides a tax credit for a taxpayer who places into service an integrated coal gasification power plant. It requires the taxpayer to enter an agreement with the economic development corporation requiring the taxpayer to use Indiana coal and satisfy other requirements relating to the operation of the power plant. It will provide for allocating the credit among co-owners of an integrated coal gasification power plant or owners of a pass-through entity.

4.2 Advisory Panel Meeting, Farmersburg, October 15, 2004

The October 2004 CCTR Panel Board meeting, at the Black Beauty Farmersburg Mine, reviewed CCTR Request For Proposal (RFP) procedures, and discussed twelve potential research topics. The CCTR presentation from Farmersburg is available at the address below.
https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Farmersburg-10-04.pdf

The Farmersburg meeting prioritized the research topics for the CCTR 2005 Round 1 Research Topics. Following this meeting an RFP was prepared and advertised. The detailed RFP is available at the address below:
https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/RFP.html

4.3 Advisory Panel Meeting, Indianapolis, February 22, 2005

Three research submissions were approved at this Indianapolis meeting. The CCTR presentation from this meeting in Indianapolis is available at the address below:
https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Indianapolis-02-05.pdf

Contracts were set up between CCTR/Purdue and the three successful submitting institutions:

(a) *"Assessment of the Quality of Indiana Coal for IGCC Performance,"* $25,360, Indiana University.
Project Director: Maria Mastalerz
Indiana Geological Survey
Ph: 812-855-2862, Em: mmastale@indiana.edu

(b) *"Factors that Affect the Design & Implementation of Clean Coal Technologies in Indiana,"* $30,000, Purdue University.
Principal Investigator: Ronald L. Rardin
Purdue Energy Modeling Research Groups
Ph: 765-494-5410, Em: rardin@purdue.edu

(c) *"Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke & Bulk Electric Power,"* $29,995, Purdue University Calumet.
Principal Investigator: Robert Kramer
Energy Efficiency & Reliability Center
Ph: 219-989-2147, Em: kramerro@calumet.purdue.edu

4.4 Advisory Panel Meeting, Bloomington, June 10, 2005

The results from the June 10, 2005, questionnaire exercise indicated that the CCTR Advisory Panel's top four research priorities, for the 2005 Round 2 RFP, were:

(a) **The Impact of New and Proposed Environmental Legislation on the Competitiveness of Indiana Coals**
All CCTR Advisory Panel members unanimously agreed on the need for this scoping study. It was ranked as top priority.

(b) **Key Issues that Encourage or Inhibit the Increased Use of Indiana Coals at Existing Facilities**
The low cost of PRB coals is the main issue. How should Indiana prevent further switching to PRB coals? How long will it take before PRB coal costs (production plus transportation) approach the cost of Indiana coals? How much blending is currently taking place? We need also to remember that 10 MTons of coal comes into Indiana for the iron and steel industry.

(c) **Coal Transportation Infrastructure In and Around Indiana**
There is a break in the links between northern and southern Indiana. Should there be incentive packages for unit trains? It is very costly to connect lines to the mines. Exactly how costly is it for spur lines? There is need to further study the Indiana and Illinois infrastructure reports/programs. Who are the present coal customers and where are their coal supplies coming from? How are we to ensure the continued use of Indiana coals? We need to identify where there are constraints and bottlenecks in the coal transportation infrastructure.

(d) **Expanding the Capacity and Improving Efficiency of Indiana Coal Mining and Production**
Productivity ratios (tons of coal per person) for the Indiana surface mines are high and discussions following the Bloomington meeting are recommending that coal mining research priorities for Indiana should be in the area of coal preparation.

4.5 Advisory Panel Meeting, West Lafayette, November 17, 2005

Confirmation was given to proceed with the coal transportation scoping study and for an extended follow-on project to collect further data on Indiana coal characteristics. The team based at Purdue North Central will lead the transportation study. This project will be jointly funded by the Indiana Department of Transportation. The team from the Indiana Geological Survey will continue to work on the coal characteristics with a follow-on grant of $100K.

(a) "*Assessment of the Quality of Indiana Coal for IGCC Performance*," $100,000, Indiana University.
Project Director: Maria Mastalerz
Indiana Geological Survey
Ph: 812-855-2862, Em: mmastale@indiana.edu

(b) *"Coal Transportation In and Around Indiana,"* $23K (+ $25K from INDOT)
Project Director: Thomas F. Brady
Purdue University North Central
Ph: 219-785-5456, Em: tbradyjr@pnc.edu

Consideration was also given to follow-on work for the clean coal technology and the Indiana coal to coke projects. Final decisions on these projects will be taken in early 2006.

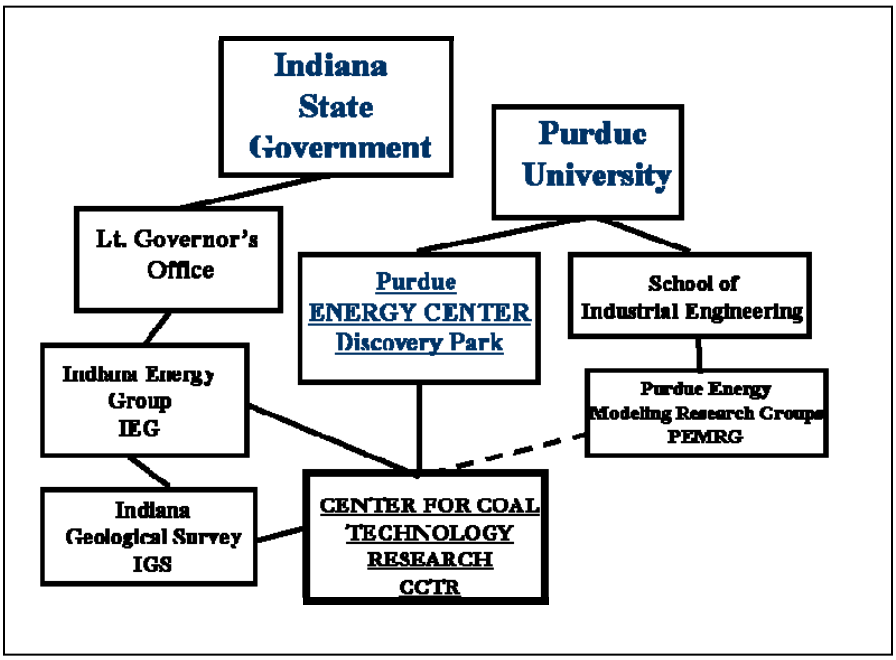
After further consideration of the environmental study proposed at an earlier Panel meeting it was decided that for the time being this topic should not be given a high priority for receiving funds.

4.6 CCTR and the Energy Center at Purdue

The CCTR continues to build links with the Purdue Energy Center at Discovery Park.

In 2005 Purdue University announced the creation of the Energy Center at Discovery Park. This new Center will consolidate current short-term and long-term energy projects in agro-fuels, process efficiency, forecasting, pollution control, hydrogen production, storage and utilization, discovery informatics, hybrid vehicles and fuel cells. There is an informal affiliation between the CCTR and PEMRG (through the Coal Transformation Laboratory, CTL; see Figure 4.2).

Figure 4.2 Affiliations: CCTR and Purdue Energy Center



The CCTR will prioritize and administer coal research funds for Indiana's coal technology research and the Coal Transformation Laboratory at Discovery Park will conduct basic and applied coal research activities.

In 2005 the CCTR staff gave support to the Energy Center in two major activities:

- with the promotion of the Coal Fuel Alliance (Illinois, Indiana, and Kentucky) for using Fischer-Tropsch technology in the process of converting coal to transportation liquids (Obama-Lugar Amendment to the 2005 Energy Act), and
- secondly, with the organization of the December 2, 2005, "Clean Coal to Transportation Fuels" workshop which was held at Purdue.

4.7 CCTR and the Office of the Lieutenant Governor

In 2005 the responsibility for administering the CCTR was transferred from the Indiana Department of Commerce to the Office of the Lieutenant Governor and the Indiana Energy Group (IEG). Figure 4.2 illustrates the relationship between the IEG and the CCTR. On December 8, 2005, the role of CCTR Director transferred from Dr. F. T, Sparrow to Mr. Marty W. Irwin.

4.8 CCTR and the Purdue Energy Center December 2 Workshop – "Clean Coal for Transportation Fuels"

This first coal research workshop presented by the new Energy Center on December 2, 2005, attracted more than 100 participants. Over 75% of the participants were Purdue faculty with interests in coal research and Purdue staff. Representatives also came from industry and government.

There were seven significantly relevant morning plenary sessions and in the afternoon there were six break-out discussion groups. The Agenda consisted of:

"The 2005 Energy Policy Act and Illinois Basin Coal"
Marty W. Irwin, Indiana Energy Group
Center for Coal Technology Research

"Clean Coal Gasification, FT Process Design and Implementation"
Michael Reed, Strategic Center for Coal
National Energy Technology Laboratory, NETL DOE

"Impact of FT Transportation Fuels on the U.S. Economy and National Security"
Ted Sheridan, Department of Defense, DOD

"Usage of FT Transportation Fuels in Engines and Turbines"
Vinod Duggal, Cummins Engine Company Ltd.

"Clean Coal with Environmental and Health Issues"
Evan Ringquist, School of Public and Environmental Affairs Indiana University

"Clean Coal and Co-Production Potential"
Thomas Lynch, ConocoPhillips Company

Break-Out Sessions – Break out into 6 working groups
F.T. Sparrow, Center for Coal Technology Research

- Group 1 Obama-Lugar Amendment and Test Center, Ron Rardin
- Group 2 Fischer-Tropsch Process Design/Catalysis, Nick Delgass
- Group 3 Clean Coal with Environmental and Health Issues, Linda Lee

Group 4 FT Transportation Fuels in Engines and Turbines, Bob Lucht
Group 5 FT Transportation Fuels and Economics and Policy, Otto Doering
Group 6 Clean Coal and Co-Production Potential, Tom Sparrow

All presentations from the December 2, 2005, Workshop can be downloaded from:
https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/#CleanCoal

4.9 CCTR Staff Support the Obama-Lugar Amendment CFA Planning Meetings (Illinois, Indiana, Kentucky)

Trends in world energy prices since September 11, 2001, have renewed interest in the production of transportation fuels from domestically plentiful sources of energy such as coal and biomass. In response to this renewed interest and in recognition of the significant coal reserves contained in the Illinois Basin, Senators Barack Obama (IL) and Richard G. Lugar (IN) attached an amendment to the Energy Policy Act of 2005, which was passed by Congress and signed by President Bush August 7, 2005. The Amendment, known as the Obama-Lugar Amendment to the Energy Policy Act of 2005 (OLA) authorizes the Secretary of the U.S. Department of Energy (DOE) to expend $85 million over 5 years in support of a joint program run by Purdue University, Southern Illinois University, and the University of Kentucky for the purpose of selecting Fischer-Tropsch synthesis process (F-T) technologies for commercialization, development and construction of a 500 gallon per day demonstration facility. No funds were appropriated in the FY 2006 budget, however a request for a $14.5 million appropriation has been made to DOE for inclusion in the FY 2007 budget.

Representatives of Purdue University, Southern Illinois University, and the University of Kentucky have formed a group referred to as the Coal Fuel Alliance (CFA). Over the course of three meetings the CFA has signed a memorandum of understanding, established basic operating principles and agreed upon the following three step approach to the project the project:

Phase I: Identification and analysis of technological bottlenecks and commercialization barriers associated with the process of converting coal into transportation fuel; and

Phase II: Designing and implementing a focused R&D program to address these bottlenecks and barriers;

Phase III: Development of the test center, preferably with commercial partners.

Purdue's Phase I effort relies upon leadership from four areas:|

- Transportation Fuel Production
  W. Nicholas Delgass, Professor of Chemical Engineering
  Hilkka Kenttamaa, Professor of Chemistry
- Transportation Fuel Use
  Robert P. Lucht, Professor of Mechanical Engineering
  John Abraham, Professor of Mechanical Engineering

- Environmental Issues
  Linda S. Lee, Professor of Agronomy
  Ronald F. Turco, Professor of Agronomy
- Economic/Policy Issues
  Wallace E. Tyner, Professor of Agricultural Economics
  Ronald L. Rardin, Professor of Industrial Engineering

Since the Bill was passed on August 7, 2005, the CCTR staff provided support for the various activities associated with the development of Purdue's contribution to the bill's objectives.

4.10 CCTR Coal Funding

In 2005 three coal scoping studies were funded ($85K total).

By the end of 2005 a list of nine coal projects had been identified. The three topics from 2005 were proposed to be expanded into larger scale projects (Topics 1, 2, 3, listed below).

The titles of the six scoping studies and three coal research projects are listed below:

Topic 1: Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)

Topic 2: Factors that Affect the Design & Implementation of Clean Coal Technologies in Indiana

Topic 3: Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke & Bulk Electric Power

Topic 4: The Impact of Environmental Legislation on the Competitiveness of Indiana Coal for New and Existing Facilities

Topic 5: Coal Transportation Infrastructure In and Around Indiana

Topic 6: Reclaiming Coal Fines from the Settling Ponds of Indiana

Topic 7: The Obama-Lugar Barriers Study

Topic 8: Role for FutureGen and CCT in Indiana

Topic 9: Carbon Policy and Strategic Planning for Indiana

By the end of 2005 a lower level of funding commitment of $383K had been made and it is expected that total funding for Indiana coal projects in 2006 will be at an upper level of $723K.

Proposed funding allocations for 2006:

	Lower	Upper
Follow-Ons from Coal Topics 1, 2, 3 for 2006	$100K	$350K
Two new scoping study Topics 5, 6 for 2006	$123K	$123K
New Research for 2006: Topics 7, 8, 9	$150K	$250K
Total	$383K	$723K

5. SUMMARIES OF 2005 FUNDED PROJECTS

Summaries from the three funded coal research projects in 2005 are given below.

The full text for the final report of each 2005 project can be obtained from the following address: https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Rnd1Final.html

5.1 Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle (IGCC) Performance

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

5.3 Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Build Electric Power

Note: All references quoted in this Section are not listed due to space limitations.

5.1 Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle (IGCC) Performance

5.1.1 Executive Summary

Evaluation of Indiana coals for their application in Integrated Gasification Combined Cycle (IGCC technologies) is important and timely. Indiana has large coal resources that could be utilized as feedstock in IGCC plants with very low emissions. This would be very advantageous for Indiana's coal industry and our state in general.

The purpose of this 2005 scoping study was to outline new research that needs to be conducted on Indiana coals to adequately predict their performance in IGCC processes. In order to identify needs and propose new research, assessment of the existing data on Indiana coals has been made during this project, and the specific objectives were to:

1. Identify properties of Indiana coals that are of major importance for IGCC performance;
2. Assess availability of data on coal properties needed to access IGCC performance; Identify the areas in which more data are necessary to adequately assess coal performance for IGCC; and
3. Provide a preliminary assessment of the Indiana coal properties that influence IGCC behavior.

During this project, we have identified coal properties that are of critical importance for IGCC and have generated a database that, among other parameters, includes those coal parameters that are of primary importance to IGCC. This database was used for the analysis of data availability and identification of the areas that have poor data coverage. Table 5.1 shows ranges, averages,

and numbers of data points available for selected coal properties, and demonstrates that while many analyses exist for moisture, fixed carbon and volatile matter, no data are available for ash fusion temperature and slag viscosity, parameters very important for IGCC.

We have mapped distributions of coal properties such as moisture, heating value, sulfur, ash yield, volatile matter, and fixed carbon. These maps, together with maps of fuel ratio (fixed carbon/volatile matter) and O/C ratios were used to provide preliminary assessments of Indiana coals for IGCC. This analysis demonstrates that Indiana coals are generally good feedstock for IGCC, although variations in properties exist both between the coal beds and within coal beds, and the maps generated can help in identifying the most favorable areas.

Table 5.1 Coal Properties and Values at Four Indiana Coal Beds

	Danville				Hymera				Springfield				Lower Block			
	Min	Max	**Ave**	n	Min	Max	**Ave**	n	Min	Max	**Ave**	n	Min	Max	**Ave**	n
Moisture, ar	1.9	28.2	**11.2**	252	0.8	23.5	**10.26**	135	0.5	34.7	**9.91**	651	0.7	27.1	**13.57**	156
Fixed carbon, dry	32	58.24	**48.43**	131	11.7	54	**46.75**	110	29	70.7	**48.03**	306	35.5	59.5	**50.52**	53
Volatile matter, dry	26.9	46.1	**39.15**	131	15.6	46.8	**38.54**	110	19.9	62	**40.89**	306	33.5	47.5	**38.75**	53
Ash (dry)	4.9	41.1	**13**	254	6.8	72.7	**14.5**	136	4.89	54.21	**12.12**	651	4.1	31	**8.82**	158
Btu (dry)	7651	17314	**13051**	252	2520	13734	**12043**	135	8362	20647	**13229**	651	9677	14726	**13333**	156
AFTred, init	2095	2540	**2274**	12									1990	2800	**2399**	14
AFTred, soft	2155	2610	**2376**	12			no data				no data		2040	2800	**2445**	14
AFTred, hem	2210	2665	**2435**	12									2080	2800	**2491**	14
AFTred, final	2250	2753	**2502**	12									2170	2800	**2551**	14
Slag viscosity	2419	2900	**2672**	12							**2460**	1	2155	2900	**2626**	14
Cl (%)	0.01	0.1	**0.03**	24	0.02	0.07	**0.04**	24	0.03	0.24	**0.15**	28	0.01	0.05	**0.02**	28

Insufficient data on mineral matter properties and slag behavior in a gasifier and chlorine content are identified as major coal quality related barriers of using Indiana coals for IGCC application. Other barriers are the same as for IGCC plants in general and they include: high capital cost, unfamiliarity of the technology to utilities, relatively long time to gain full plant capacities, reliability concerns, project financing, and economic and public perception about any new coal-fired power plants.

New research to provide good evaluation of Indiana coals for IGCC should include new laboratory testing of coal and integration of the new findings into the currently available data. We propose to conduct new testing of major coal beds in the following areas:

1. Mineral matter composition;
2. Ash melting point and slag viscosity; and
3. Chlorine content.

These new data, in conjunction with the currently available information, will allow more complete evaluation of coal properties critical for IGCC, and will help to give recommendations about modeling of the performance of Indiana coals in IGCC plants. It is expected that Indiana mining companies will actively participate in the project. Other potential collaborators are CCTR and Purdue University researchers, power plants (e.g., Cinergy) and researchers from Center for Coal in Sustainable Development in Australia.

5.1.2 Importance and Justification of the Study

There are several reasons to evaluate the applicability of Indiana coals for IGCC technology. First, more than 90% of Indiana's electricity comes from coal. The overwhelming majority of the coal mined in Indiana (73%) is used for generating electricity. Annually, Indiana uses twice as much coal as it produces (70 million short tons used versus 34 million short tons produced). Most of the non-Indiana coal that is consumed is imported from Wyoming. These simple facts demonstrate that coal is vital to the economy of our state.

Secondly, Indiana has significant coal reserves (~ 57 billion short tons); approximately 17.5 billion short tons are available for either surface or underground mining (Mastalerz et al., 2004) which, at the current level of production, can suffice for hundreds of years. However, most Indiana coals are high in sulfur (average sulfur content for all coal beds is 3.1%) and, as such, cause significant SO_2 emissions from power plants upon combustion. Wet scrubbers have to be used in power plants to reduce these emissions. In addition, recent mercury regulations from coal-fired power plants (EPA, 2000, 2005) force the plants to search for the most efficient and least-cost ways to address these issues.

Thirdly, IGCC units are much cleaner than standard power plants; they can achieve greater than 99% SO_2 removal. Another benefit is the possibility of removing mercury and carbon dioxide upstream of the combustion process at a lower cost than conventional plants. The technology uses less water than a conventional coal-fired power plant with currently required pollution control equipment. However, the total cost of an IGCC plant is high. At present, IGCC cost projections are 10 to 30% higher than for plants using pulverized coal with wet scrubbers, with similar time needed for their construction. The cost, however, decreases with time and experience and it may become especially attractive when additional installations of new pollution control devices become necessary.

Lastly, IGCC technology is continuously gaining momentum both nationally and internationally. The first IGCC plant with CO_2 capture is being built in Australia, and several IGCC plants are being considered in China. Two IGCC power plants currently operate in the U.S., and more are being planned. Also, Cinergy/PSI, the General Electric Company and Bechtel Corporation signed a letter of intent to study the feasibility of constructing an IGCC generating station, and Edwardsport, Indiana, is being the favored location (press release of October 26, 2004, Pashos, 2005).

5.1.3 IGCC Process Overview

IGCC technology is becoming increasingly more competitive and may be a technology of choice in the future of electricity generation. In the IGCC process, plants turn coal to gas, removing most of the sulfur dioxide and other emissions before the gas is used to fuel a combustion turbine generator. The hot gases are then used to heat steam, driving a steam turbine generator. In this technology, coal could be gasified in various ways, by properly controlling the mix of coal, oxygen, and steam within the gasifier.

In a typical IGCC unit, coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurized reactor, and the product is a mixture of $CO + H_2$ (called synthesis gas, syngas, or fuel gas). The product gas is cleaned and then burned with either oxygen or air, generating combustion products at high temperature and pressure. The sulfur present mainly forms H_2S that can be readily removed from the system. No NO_x is formed during gasification (see Table 5.2).

Table 5.2 Options in IGCC Plant Design (from Innes, 1999)

Primary operations	Design options
Coal preparation • Delivered coal is milled to desired size specifications and, if necessary, combined with a flux	• Slurry feeding • Dry pneumatic feeding • Fine coal briquetting
Coal gasification • Coal is fed into a high temperature and pressure environment where it undergoes partial oxidation with air, Oxygen, or steam	• Gasifier design • Oxidant type
Gas cleaning • Raw fuel gas undergoes a series of physical and chemical processing steps to eliminate particulates, alkali metals, sulfur and ammonia from the gas	• Hot or cold gas cleaning • Sulfur removal system • Ammonia removal
Combined cycle system • Clean fuel gas is mixed with compressed air and undergoes combustion with expansion through a gas turbine (GT) • The hot combustion gases pass through a heat recovery steam generator (HRSG) to produce superheated steam to drive a steam turbine (ST) generator	• Air compressor integration • NO_x emissions reduction system
Air delivery • Air undergoes compression before entering gasifier and GT combustor or; • Air undergoes separation to produce high purity oxygen and nitrogen. Oxygen is fed to the gasifier; nitrogen and compressed air are fed to the GT combustor	• Gasifier oxidant type • Air separation unit (ASU) selectio • Level of integration between ASU and remainder of IGCC plant
Auxiliary operations	
By-product solids & water treatment • Slag and fly ash disposal systems • Process water cleaning systems • Brine removal systems	• Pneumatic or slurry removal
Sulfur recovery	• Present or absent

5.1.4 Influence of Coal Quality on IGCC Processes

Understanding the influence of coal properties on IGGC plant performance is an important part in plant design and will be a factor in its ability to compete with other plants. Capital cost for IGCC and pulverized coal (PC) technologies depending on coal rank, comparing Pittsburgh #8 coal, Illinois #6 coal, Wyoming Powder River Basin coal, and Texas lignite. Capital cost decreases with coal rank, primarily because less coal needs to be used when coal has higher heating value. Even though this is a general rule, little is known how various coals will behave in IGCC plants of a specific design or an IGCC plant in general. In addition to heating value, volatile matter content, moisture content, and especially ash composition and ash fusion temperature strongly influence the gasification process and smooth slag flow. See Table 5.3.

Table 5.3 Temperature, Feed Coal and Capacity of the Gasifiers

	Temperature	Coals	Capacity
Fluidized bed	950-1100°C 1742-2012°F	Reactive, low rank coals. AFT> 950-1100°C >1742-2012°F	<200MW
Entrained flow	>1400°C >2552°F	More variable properties AFT <1400°C,<2552°F	>500 MW

5.1.5 Indiana Coals and IGCC

The Illinois Basin coal is a proven feedstock in IGCC processes (Lizzio, 1997). High sulfur Indiana coals have been used in the two U.S. gasification plants that produce electricity: the Wabash River Coal Gasification Plant and Polk Station Power Plant. The Wabash River Gasification plan was designed to use a range of local Indiana coals having a maximum sulfur content of 5.9%.

Some Indiana coals, along with Illinois #6 coal, have also been tested in Polk Power Station (http://www.tampaelectric.com/pdf/TENWPolkDOEFinalTechReport.pdf) and Table 5.4 summarizes their testing.

Table 5.4 Coal from Indiana Tested in Polk Station Power Plant, Florida

Coal	Mine	Year and days in operation
Indiana		
Indiana #5 and #6	Somerville	1997 (6 days)
Indiana #7	Somerville	2001 (28 days)
Indiana coal blended with pet coke	Somerville	2001 (63 days)

Indiana coals performed well in tests, giving 95.5 to 96% per-pass conversion with a two year liner life. Successful results were achieved also on blends of low fusion temperature Indiana #7 coal with South American coal and petroleum coke; this gave excellent liner life and acceptable conversion.

These examples of performance of Indiana coals are a testimony that Indiana coal can be a successful feedstock for IGCC technology.

5.1.6 Wabash River Gasification Plant, Facts

- Entrained flow two stage slurry fed gasifier – Phillips/Conoco Technology
- 260MW plant opened in 1990 as DOE IGCC demonstration project
- Sulfur recovered as sulfuric acid

The Wabash River Coal Gasification Project, a joint venture of Destec Energy of Houston, and PSI Energy of Plainfield, Indiana. The plant opened near Terre Haute, Indiana, in 1990. In this plant, coal is gasified in an oxygen-blown, entrained-flow gasifier with continuous slag removal and a dry particulate removal system. The resulting synthesis gas is used to fuel a gas combustion turbine generator. Its exhaust is integrated with a heat recovery generator to drive a refurbished steam turbine generator. The carbon conversion rate was more than 95% and emissions of SO_2 and NO_x were far below regulatory requirements (CCT Topical Report No. 20, 2000), making it one of the cleanest coal-based power generation facilities in the world. Currently the plant is part of SG Solutions.

5.1.7 Feeds and Products

Feed: Feed changes. The plant was designed to use high sulfur Indiana coal from Hawthorn mine (currently closed). Currently, the feed is petroleum coke of high sulfur content (>5%), low mineral matter content (<1%) and high Btu (>15000). Approximately 2000 tons of petroleum coke is used daily.

Products: Electricity, elemental sulfur (100 tons a day)

Comments: Mixing feeds of different properties (for example, coal and petroleum coke) could be a problem because of two-stage gasifier design; second stage requires consistent char properties. Current feed (petroleum coke) has very low mineral matter content and they need to add more mineral matter to the gasifier. Their slag after previous gasification of coal is used and proves to be an excellent resource for this purpose. Mineral matter properties of the feed are of major influence on the gasification operation.

5.1.8 Identifying Properties of Indiana Coals that are of Major Importance for IGCC Performance

Based on the review of available material, we have identified several parameters of coal quality are very important for the performance in an IGCC system, and they include:

a) **Moisture** influences gasifier efficiency and can determine whether the process must be dry or slurry fed.

b) **Heating value** influences generation capacity. To obtain the same energy from a lower heating value coal (for example, Western coal), a greater tonnage must be gasified.

c) **Mineral matter properties** such as ash content, ash fusion temperatures (AFT), and slag viscosity have a number of critical impacts on an IGCC system. In general, low ash content (<10%) coals are preferable for IGCC. Ash fusion temperature is very important, but its influence varies drastically between different plant designs. For example, for entrained flow gasifiers, AFT should be below 1500°C (2732°F), but for fluidized bed gasifiers temperatures above 1100°C (2012°C) are preferred.

d) **Volatile matter and char reactivity** determine the extent and rate of gasification reactions. Coal consumption during gasification consists of two steps: volatile pyrolysis (fast process) and char gasification (slow process). Generally, the higher the char yield and the lower the char reactivity, the longer the time required for complete gasification. Therefore coals that have low char yield and high char reactivity are generally preferred, although these requirements vary depending on the gasifier type.

e) **Other important parameters include sulfur, nitrogen, and chlorine**.

The tables below summarize the importance and requirements of selected coal quality parameters for three types of gasifiers, Fixed-Bed Gasifiers (Table 5.5), Fluidized-Bed Gasifiers (Table 5.6), and Entrained Flow Gasifiers (Table 5.7). These compilations are based on published papers and unpublished reports, such as Innes (1999), Collot (2006), and others. These requirements need to be considered as general guideless only, because specific requirements can vary significantly between individual units.

Table 5.5 Fixed-Bed Gasifiers (requirements change with gasifier type, e.g., Lurgi, BGL)

Parameter	Importance	Requirements
Moisture	• influences gasifier efficiency	- A range of moisture contents is used
Volatile matter	• determine the extent and rate of gasification reactions	- A range of volatile matter contents are used
Heating value	• determines plant dimensions • influences generation capacity	- A range of heating values are used
Ash content	• lowers system efficiency • increases slag production and disposal cost in BGL gasifier	Usually <15%
AFT (flow, reduction)	• influence melting ability of discharged slag in BGL gasifier (it needs to be melted below performance temperature)	<1400°C (2552°F)
Slag viscosity at 1400°C (2552°F)	• viscosity must be sufficiently low to ensure smooth slag flow between packed bed particles	<5Pa-s (pascal second) <50 poise
Coal (char) reactivity	• influence the extent of carbon conversion	- A range of reactivities can be used because of high operational temperature
Sulfur	• can cause corrosion of heat exchanger surfaces	- Preferred S <1.5%
Nitrogen	• contributes to NOx emissions	
Chlorine	• forming HCl can poison gas cleaning system catalysts • HCl can cause chloride stress corrosion	<0.4% (air dry) <0.2% preferred

Table 5.6 Fluidized-Bed Gasifiers

Parameter	Importance	Coal Requirements
Moisture	• influences gasifier efficiency (higher moisture - lower efficiency)	- A range of moisture contents are used
Volatile matter	• determine the extent and rate of gasification reactions	- A range of volatile matter contents are used
Heating value	• determines plant dimensions • influences generation capacity (higher heating value – higher capacity and efficiency)	- A range of heating values are used
Ash content	• influences net cycle efficiency • influences flux addition rate	<40%
AFT (flow, reduction)	• Since mineral matter is expelled as ash, it is important that AFT is higher than operation temperature for the ash particles not to become sticky and agglomerate	>1100°C (2012°F)
Slag viscosity	• Not much of concern	
Coal (char) reactivity	• Fundamental importance	- Low reactivity chars are not suitable because of low carbon conversion at relatively low temperature
Sulfur	• can cause corrosion of heat exchanger surfaces	- Preferred S <1.5%
Nitrogen	• contributes to NOx emissions	
Chlorine	• forming HCl can poison gas cleaning system catalysts • HCl can cause chloride stress corrosion	<0.4% (air dry) <0.2% preferred

Table 5.7 Entrained-Flow Gasifiers

Parameter	Importance	Coal Requirements
Moisture	• influences gasifier efficiency (higher moisture - lower efficiency)	- A range of moisture contents are used
Volatile matter	• influences the extent and rate of gasification reactions	- A range of volatile matter contents are used
Heating value	• determines plant dimensions • influences generation capacity (higher heating • value – higher capacity and efficiency)	- A range of heating values are used
Ash content	• influences net cycle efficiency (higher ash – lower efficiency) • influences flux addition rate	<25%
AFT (flow, reduction)	• influence melting ability of discharged slag (it needs to be melted below performance temperature • influences operating costs (higher temperature– higher costs)	<1500°C (2732°F)
Slag viscosity	• viscosity must be sufficiently low to ensure smooth slag flow down the gasifier walls	- <15Pa-s (150 poise) - Used up to 25 Pa-s (250 poise)
Coal (char) reactivity	• influence the extent of carbon conversion (higher reactivity – higher cycle efficiency) • influences oxygen consumption	- A range of reactivities can be used because of higher operational temperature
Sulfur	• can cause corrosion of heat exchanger surfaces • influences operating costs (higher sulfur – higher costs)	- Preferred S <1.5%
Nitrogen	• contributes to NOx emissions	
Chlorine	• forming HCl can poison gas cleaning system catalysts • HCl can cause chloride stress corrosion	<0.4% (air dry) <0.2% preferred

5.1.9 Preliminary Evaluation of Indiana Coal for IGCC

Heating value shows a range from less than 10,500 to greater than 13,500 Btu/lb for the three types of coal beds, with large portion of the resource having heating value higher than 12,000 Btu/lb. Heating value determines IGCC plant dimensions and generating capacity. To obtain the same energy from a lower heating value coal, a greater tonnage must be gasified, contributing to higher cost. Therefore, lower heating value coals such as Powder River Basin sub-bituminous coals or lignites are less desired for IGCC than bituminous coals, such as those from Indiana.

Moisture content in Indiana coal vary from less than 5% to, locally, more than 20%, with the highest moisture generally occurring close to the basin margin, that is in shallow coals. Moisture content influences gasifier efficiency and can determine whether the process can be dry or slurry fed. The higher the moisture, the more water must be injected into the slurry-fed gasifier. High moisture content is also a problem, because, in order to maintain gasifier temperature, additional coal and oxygen must be used to evaporate the water. Significant resources of Indiana coals have more than 10% moisture, which is somewhat high for IGCC use. On the other hand, with regard to moisture, Indiana coals are far better for IGCC than lower rank high moisture coals of the Powder River Basin (28% on average).

Ash yield distribution maps show that the Danville and Springfield coals have lower ash yield than the Hymera coal, making them more suitable for IGCC. Low ash contents are favorable because lower coal volumes need to be gasified to get the same amount of energy, and also because the slag yield will be lower.

Significant resources of Indiana coals have high sulfur contents. In the Danville Coal, there is a split between low sulfur (<1.5%) areas in the north and high sulfur (>2.5%) in the south. In the Hymera Coal, sulfur content is dominantly high. In the Springfield Coal, sulfur content is more than 3%, except some areas in Gibson and Sullivan Counties. For IGCC plants, high sulfur content are preferred, because in the process, sulfur is transformed into sulfuric acid and high purity elemental sulfur, profitable saleable products. As a result of sulfur recovery, sulfur emissions from IGCC plants are minimal. For instance, in Polk Station IGCC plant and Eastman Gasification plant, the feed with ~3.5% is preferred, while they can use feed with up to 5.8% sulfur.

Thus, with regard to sulfur content, Indiana coals are ideal for IGCC.

5.1.10 Barriers to Using Indiana Coals in IGCC Plants

As discussed in this report, Indiana coals have adequate properties for use in IGCC plants, either as coal-exclusive feedstock on in mixtures with other feeds, such as petroleum coke. Sulfur content of the majority of Indiana coals is ideal for most IGCC plants, providing desirable amounts of commercial sulfuric acid and elemental sulfur produced. Chlorine content is usually low enough not to cause much slagging problems. Yet, not much Indiana coal has been used in IGCC so far, and to our knowledge, no Indiana coal is being used in IGCC currently.

What are the barriers of using Indiana coals in IGCC? The main barriers are the same as those for using IGCC technologies and building new IGCC plants in general, and they, among others, include:

1. High capital cost,
2. Unfamiliarity of the technology to utilities (IGCC plants are more chemical plants than boilers),
3. Relatively long periods to gain full plant capacities (this, however changes with experience),
4. Reliability concerns,
5. Project financing – bankers need guarantees or assurance that gasifiers will perform well,
6. Economic uncertainties – tax incentives, multi-pollutant legislations, and
7. Public perception about any new coal-using power plants, and others.

The barriers that are specifically related to the properties of Indiana coals and that might prevent potential IGCC plants from selecting Indiana coal as IGCC feedstock include:

1. Insufficient information about mineral matter characteristics such as ash composition and ash melting properties and, consequently, difficulty of predicting slag behavior in a gasifier. Contents of both major oxides in the feedstock influences ash melting characteristics are responsible for the ability of the slag to flow smoothly through the gasifier. Contents of trace elements such as mercury, arsenic is also important because these are the elements that need to be captured. Neither oxide composition of the ash nor trace element contents are routine coal analysis, and therefore, far fewer data are available than for such parameters as heating value, sulfur content, etc.;
2. Insufficient information about chlorine content of Indiana coals. High chlorine content is not desired in IGCC plants; chlorine can cause chloride stress corrosion and can also poison gas cleaning system catalysts (e.g., COS hydrolysis shift catalysts). Specifications for Cl in IGCC plants are <0.4%, but the feed with Cl content <0.2% is preferred. Most Indiana coals have Cl content <0.2, however, there is a perception that Indiana coals, similar to some Illinois coals, are high in chlorine. This is not the case, but not enough data are available to disprove it, and
3. Price of the coal. Most IGCC plants are relatively flexible with regard to the feed. In numerous cases, plants that were designed for a specific coal, made a successful switch to a feedstock composed of mixture of coal and petroleum coke, or petroleum coke exclusively, and economics played a significant role in the switch. In order to be selected as feedstock, Indiana coal needs to be competitive with regard to price with other types of feedstock, unless special tax credits, etc. become available.

We believe that new research outlined in chapter 8 below would contribute to reducing, if not eliminating, the barriers related to the insufficient information about the coal properties of Indiana coals.

5.1.11 Proposed New Research

The main deficiency towards understanding of IGCC behavior of Indiana coals is in the lack of direct data on the reactivity of chars produced from our coals, and on properties that govern slag behavior in a gasifier. Proxies for char reactivity were discussed, and they demonstrate that Indiana coals have adequate reactivities for IGCC. Therefore, in proposing new research we concentrate on studying parameters that will help to predict slag behavior in the gasifier.

Properties of mineral matter, and specifically, ash chemical composition, ash melting point, slag viscosity and possibility of forming buildup and corrosion of the gasifier is one of the most critical issues for IGCC plants.

Ash fusion characteristics, dependent mainly on the nature of mineral matter in coal, are extremely important in pulverized fuel boilers. They are also very important in gasifiers. Coals that have low ash fusion temperatures may cause slag deposits on gasifier surfaces. Moreover, ash melting point and slag viscosity are critical for smooth slag flow in slag-type gasifiers.

Within a given gasifier, changes in ash melting point of the feed coal frequently cause serious and costly maintenance consequences.

We propose to obtain new analyses of ash fusion temperature and ash viscosity on Danville, Hymera, Springfield, and Lower Block coals. The sampling locations will be the same as for ash composition, which is approximately 15 locations for each coal bed. However, because very few data of this type are available on Indiana coals, in addition to whole seam channel samples, bench samples (subsections of a coal bed) will be collected and analyzed. On average, 3 bench samples from each location will be collected, resulting in 60 samples for each coal bed (15 whole seam channel samples plus 45 bench samples). This number of samples will permit documenting regional lateral variations of these parameters in each coal bed, and also help us understand factors that influence these parameters on a local scale.

In order to determine controls on ash fusion temperature and ash viscosity, other coal analyses need to be performed on coal samples. The number of samples may vary depending upon the available funding.

In addition to mineral matter characterization, all the coal samples collected will be characterized petrographically, including both maceral composition of coal and mineral composition. Whereas chemistry of ash will be obtained on ash samples, mineralogical composition of mineral matter will be investigated microscopically. Maceral composition of the organic fraction will also be conducted, and vitrinite reflectance will be measured. Maceral composition influences coal reactivity, while vitrinite reflectance reflects changes in coal rank. Char reactivity increases from inertinite (lowest reactivity) through vitrinite to liptinite (highest reactivity).

Chlorine in coal is of special concern because it may contribute to the formation of gasifier deposits and severe corrosion during gasification. For IGCC plants, Cl content should not exceed 0.4%. The average Cl content in the Illinois Basin coals 0.06% (Mastalerz et al., 2004). This is not a high value, thus it is adequate for coal utilization; however, it is important to note the Cl content may be elevated locally. For example, Gluskoter and Rees (1964) reported values as high as 0.65% for Illinois coals. In fact, high chlorine is frequently mentioned as one of the major concerns for Illinois coals for IGCC applications.

The average concentration of Cl for all Indiana coals is 0.05%, and ranges from 0.02% in several coals to 0.19% in the Springfield (Mastalerz et al., 2004). In the Danville coal, the majority of the analyses available show Cl content below 0.02%. In the Springfield coal, Cl content is higher, dominantly above 0.2%. In the Lower Block coal, Cl content is low.

However, the number of data points with Cl values is currently too low to map the variations.

An addition of Cl data in 15 new locations for each coal bed would significantly enhance our understanding of their consistency and distribution, which would contribute to fuller evaluation of our coals for IGCC.

Note: Full report is available at: https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Rnd1Final.html

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

5.2.1 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% of electricity produced in this state comes from coal, which is a major reason average state electricity prices are among the nation's lowest. The state's steel industry, which out produces all other states, consumes large quantities of coke derived from coal.

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) 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.

Table 5.8 Details of the Twelve Scenarios Investigated

	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

5.2.2 Clean Coal Technology Overview

The clean coal technologies discussed (Table 5.8) 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.

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.

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.

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, with a target completion around 2012. DOE has been sponsoring CO_2 sequestration research since the mid-90s, 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. However, the technology is again not demonstrated.

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 (Table 5.9).

The USC-PC technology has a long history (almost 50 years). According to the Babcock & Wilcox Company, it designed the world's first USC-PC in 1957 for the American Electric Power in Ohio. 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.

Gasification technology used on the largest scale worldwide is the technology as practiced by Sasol in South Africa. Since this technology is not used for IGCC, it is not included in this report. A development variation to the Lurgi technology is the British Gas Lurgi (BGL) which is operated in Germany at a waste disposal facility and for methanol production but not for IGCC.

Table 5.9 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)	99 MW 240 MW	Test operation Under design
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

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 because none of them have been commercially tested for CO_2 sequestration.

5.2.3 Promoting Indiana Coal

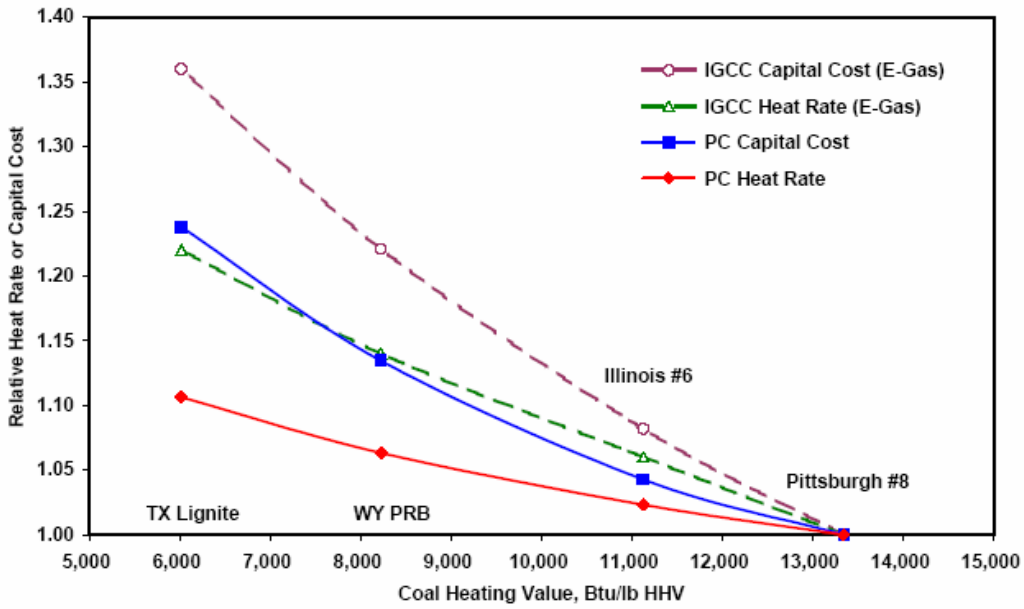
As was previously mentioned, Indiana coal is a bituminous high sulfur coal. This seems to suggest that the logical technology of choice for Indiana coals is the IGCC technology. While this may be true technologically, it is also possible that the use of IGCC technology could reduce the usage of Indiana coals because of the inherent fuel flexibility of the IGCC technology (Wabash IGCC has been using petcoke instead of coal since August 2005). 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.

It is very complicated to estimate the costs and efficiencies (Figure 5.1). 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. It could be inferred that the greater the capacity, the less the capital costs. Table 5.10 lists the capital costs of the existing IGCC power plants and the DOE cost sharing. 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). Table 5.11 measures heat rate in Btu/kWh and the number can be converted to% efficiency.

Figure 5.1 Effect of Coal Quality on Heat Rate and Capital Cost



(Source EPRI)

Table 5.10 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

Table 5.11 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

Table 5.12 gives sample capital costs and efficiency estimates for IGCC. Table 5.13 illustrates some cost estimates for SCPC and USC-PC. Notice that the estimates often assume high grade coals such as the Pittsburg #8 coal. 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 5.12 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	1,000 (E-Gas)	No	$1099/kW	20/8800	no	2002 dollar
	2. EPRI	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	1073	No	$1111/kW	n/a/8997	3 on 1	
	4. Harvard	n/a	No	$1400/kW	n/a/8700	n/a	< $1000/kW w/ 3-Party 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.

Table 5.13 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	800 (SC) 600 (SC)	No	$1100kW	20/9300	2002 dollar
			Yes	$1950/kW	20/12560	
	2. EPRI	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	600(USC)	No	$1000/kW	20/7369 or (46%)	Reference plant under design
	4. Harvard	n/a (SC)	No	$1200/kW	?/8700	No need for 3Party financing
	5. DOE *	n/a	No	$1200/kW	?/8800	DOE has various

* 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.

There are technologies good for retrofitting old non-attainment coal-fired power plants to meet the EPA's new emission standards. Table 5.14 summarizes a study done by the ALSTOM Company and lists the alternatives for retrofitting old plants to meet CO_2 capture requirements.

Table 5.14 Technology Options for CO_2 Capture

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 ™)	MES
		Oxyfuel
		CO_2 Wheel
		Biomass co-firing
	Circulating Moving Bed (CMB ™)	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.

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 5.15 summarizes the environmental performance of the IGCC power plants in the U.S. The emission levels are just fractions of those from conventional coal-fired power plants.

Table 5.15 Environmental Performance of the U.S. IGCC Power Plants

Technology	*Whose estimate*	*SO_x*	*NO_x*	*Carbon monoxide*	*VOC*	*PM*	*Hg*
Entrained flow	Wabash	> 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	>99% or 29lb/hr	15 ppmv or Average 0.7lb/MWh	n/a	< design limit	0.037 lb/ MWh	n/a
	Mesaba, MN	0.022 lb/mmBtu	0.058 lb/mmBtu	0.0 3 lb/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

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

The purity of the emissions captured is not 100%. SO_x and NO_x plants can be 99% 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 – http://www.gti.com). However, the market is too limited for large volume CO_2 sales overall.

5.2.4 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%). 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 5.16 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% 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% (see Table 5.16 for comparison).

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

Table 5.16 IGCC Plant Availability Data

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%
Mesaba –Hoyt Lakes	> 90% with a backup gasifier – design target	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. 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. Another scheme is the 3 on 1 scheme in which three gasifiers operate on parallel while the forth one stands by. It may be beneficial to optimize backup schemes in poly-generation (or co-production) IGCC plants, and this will be a further research topic.

5.2.5 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. Table 5.17 summarizes the main legislation on which U.S. EPA acts.

Table 5.17 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) • Required 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.

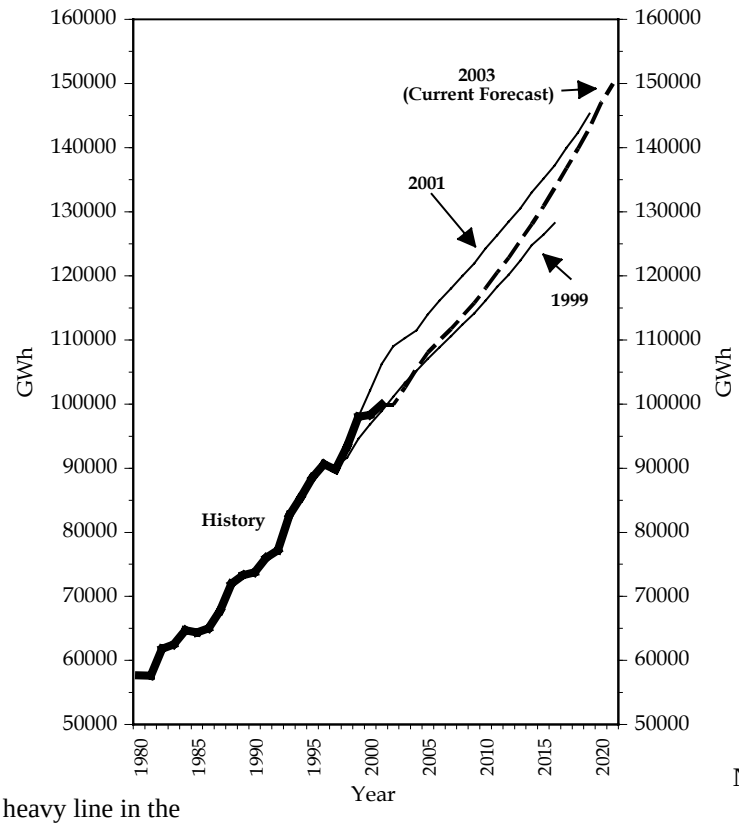
Source: http://www.co.mendocino.ca.us/aqmd/pages/CAA%20history.html

5.2.6 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. SUFG's total energy requirements (Table 5.18) exhibit more growth than the EIA projection. 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.

Table 5.18 Indiana Electricity Requirements in GWh (Historical, Current and Previous Forecasts)

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

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

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 in four different subsections.

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

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.

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. 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.

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 hikes in natural gas and oil prices.

D. CCT Risk Analysis

CCT implementation is fraught with uncertainties and risks that need to be studied and modeled. 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?

5.2.7 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.

5.2.7.1 Indiana Clean-Coal Summit

Review of available cost information shows that without CO_2 capture the SCPC and AFBC may result in lower electricity costs for the state. 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%% higher vs. SCPC without CO_2 if the new baseload capacity in the state is solely by IGCC plants. 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 capacity 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?

5.2.7.2 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.

5.2.7.3 Increased Coal Mining Capacity

If clean-coal technologies are introduced into 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.

5.2.7.4 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.

5.2.7.5 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 Billion 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."

a) Many states have been actively competing for the FutureGen project, specially our neighbor Illinois. Indiana is now partnering with Illinois for Fourteen to be sited in the Midwest.
b) Indiana has abundant coal reserves.
c) The Wabash River IGCC project provides valuable experience with clean-coal technologies.
d) 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.

e) Purdue has a research program in hydrogen, including fuel cells.
f) 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.
g) Southwest Indiana has many sites for sequestration of CO_2.
h) Participation in FutureGen is one of the best available ways to build intellectual infrastructure for clean-coal research in the state.

Note: *Full report is available at:* *https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Rnd1Final.html*

5.3 Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Build Electric Power

5.3.1 Executive Summary

Although coke is an absolutely essential part of iron making and foundry processes, currently there is a shortfall of 5.50 million tons of coke per year in the United States. The current shortfall of this critical raw material is being filled by imports, mainly from China and, to a lesser extent, from Japan. The result of the shortfall internationally has been that recent coke prices have risen sharply. For example, coke delivered FOB to a Chinese port in January 2004 was priced at $60/ton, but rose to $420/ton in March 2004 and in September 2004 was $220/ton. This makes clear the likelihood that prices will remain high with considerable volatility.

The significant shortfall of needed coke has placed an enormous strain on Indiana's steel industries. A resolution and/or mitigation of this formidable problem through the use of Indiana coal in a mine mouth, environmentally friendly, high efficiency coking/coal gasification facility which would increase coke supply and production, while, at the same time, reducing the cost for Indiana's steel and foundry industry. In addition, such a high efficiency coking facility would produce electricity for sale to the wholesale electric market, thereby reducing costs and environmental emissions and, at the same time, enhancing electric system reliability.

Expansion of the capability to produce coke is being planned by Indiana's steel industry and at present essentially all of the coal used in the coking process is imported from outside Indiana. This report addresses a new concept for producing coke that would use Indiana coal as the main feed stock.

Indiana is home to roughly 22% of the domestic base steel production for the United States. One essential raw material needed by this industry is coke. Current 2005 forecasts indicate that the United States will produce 11,500,000 net tons of coke, but will require 17,000,000 net tons for blast furnace, foundry, and related uses. At present, essentially no Indiana coal is being used for coke production. In 2002, Indiana's steel industry used an estimated 10.7 million tons of coal. Of this, approximately 8.1 million tons was used for coke production. Most of this coking coal comes from West Virginia and Virginia.

5.3.2 Major Results from Study

1. There is a high probability that a mix of Indiana Brazil Seam or potentially other Indiana coals, as previously identified by the Indiana Geological Survey, could be blended with other coals to meet metallurgical and emissions requirements.

2. There is interest in the coal and steel industry to consider establishing a coke production process at an Indiana coal mine. Moreover, there may be an opportunity to consider the value of some emissions credits, due to the "clean coal technology" as well as the different geographic location.

3. The total transportation cost would be reduced, since the mass of the product coke is less than the coal needed to produce it and also because coke is less dense than coal. Thus, a significant cost savings from the reduced weight per mile of material being transported would result.

4. Preliminary results indicate that it is highly likely that a coking/coal gasification process can be developed that would produce metallurgical grade coke using a significant percentage of Indiana coal and, at the same time, would produce a byproduct gas stream that would be usable in a cogeneration facility for the production of electricity to be sold in the electric market. Preliminary Computational Fluid Dynamic results from current blast furnace modeling efforts indicate that it may be possible to increase the percentage of coke produced from Indiana coal blended with coke from other coals in blast furnace operations.

5. With a mine mouth operation, blending and storage of coal feed streams would be done on site and would thus allow for scheduling the production of electricity to correlate with times of high market value.

6. Preliminary discussions and analysis indicate that there is a possibility to utilize coke oven gas to produce liquid transportation fuels by means of a Fischer-Tropsch process, possibly enhanced with nano catalyst technology. There are also indications that it may be possible to sequester carbon dioxide as part of the process.

This report details the results of a scoping study that conceptually evaluates the feasibility of developing a mine mouth coking/coal gasification concept that uses Indiana coal. The general conclusion of this study is that there is significant potential to use Indiana coal for the purpose of producing coke for use in various industrial applications. In addition, there is also meaningful potential to also use gas produced in the coking process for a variety of purposes including electric generation.

5.3.3 Coke Characteristics

One key issue in blast furnace iron making is the strength of the coke. The coke produced from Indiana coal has less strength than coke produced from current metallurgical coal sources and consequently is smaller in size (Table 5.19). This means that it will be used in upper portions of the blast furnace.

Table 5.19 Typical Blast Furnace Coke Characteristics

Physical: (measured at the blast furnace)	**Mean**	**Range**
Average Coke Size (mm)	52	45-60
Plus 4" (% by weight)	1	4 max
Minus 1"(% by weight)	8	11 max
Stability	60	58 min
CSR	65	61 min
Physical: (% by weight)		
Ash	8.0	9.0 max
Moisture	2.5	5.0 max
Sulfur	0.65	0.82 max
Volatile Matter	0.5	1.5 max
Alkali (K_2O+Na_2O)	0.25	0.40 max
Phosphorus	0.02	0.33 max

This report details research that was conducted from March 1, 2005 to the present to determine the viability of using Indiana coal for the production of coke. Specifically, the concept of locating a modified non recovery coking facility at a mine in Indiana with energy recovery for the generation of electricity was considered. In addition, extension of the technology to include gasification and local power production were also considered. The results of this study indicate that there is a high potential to use Indiana coal for coking as well as other industrial purposes both within and outside Indiana.

The coke produced from Indiana coal has less strength than coke produced from conventional metallurgical coal and this results in coke sizes that fall into two general classes. One class, often referred to as Buckwheat or Nut coke, is on the order of 1 inch x ¼ inch as compared to conventional blast furnace coke which is on the order of 1 inch x 4 inches. The other class is called coke breeze and is much finer. It is used as a source of carbon in steel making, for palletizing, sintering, as well as in the elemental production of phosphorous. It can also be made into briquettes and used to feed blast furnaces in combination with iron ore pellets. Other industries that use coke breeze include cement, paper, fertilizer, as well as others. Buckwheat/Nut coke is classically used in the steel industry as a carbon source for electric furnaces, in the production of ferromagnesium and ferrosilicon products, and in the production of elemental phosphorous.

An investigation of ways to increase the use of coke produced from Indiana coal in various industrial processes is under way. One effort preliminarily considered concepts for how current Computational Fluid Dynamic Research efforts for blast furnace hearth modeling could be extended to increase the use of coke produced from Indiana coal in the steel making process. Computational fluid dynamics (CFD) simulation has become a cost-effective tool that can provide detailed information on flow properties and that can be used to conduct extensive computer experiments for design and optimization of flow systems. Several steel manufacturers

have expressed interest in considering how Indiana coal might be used for various production processes. They also indicate that they have considered and/or are currently considering using Indiana Coal usually at low levels in blends. A formal CFD coke research effort could significantly extend this use.

Research efforts regarding blast furnace CFD at Purdue University Calumet, currently funded by the 21st Century Fund at $1.29 million, will be leveraged to provide additional support for this proposal. Preliminary concepts for the inclusion of CFD technology in mine mouth coking processes, as well as the use of the produced coke in blast furnace operations, will be considered. Due to the physical characteristics of Indiana coal, the coke produced will tend to be of a smaller size, but there are many opportunities to use this type of coke in blast furnace and other operations. The use of CFD analysis will assist in maximizing the applicability and value of coke generated from Indiana coal.

When coal is viewed under a microscope, it can be seen to be composed of three main components, or macerals, analogous to the minerals found in rocks. The first of these, vitrinite, softens on heating. It in association with the other components, liptinite and inertinite, forms the coke matrix. These components reflect light at different intensities. In general, the reflectance of the vitrinite is a measure of the rank of the coal and is inversely proportional to the volatile matter content. Usually a coal blend for blast furnace coke should have a reflectance between 1.25% and 1.35%. The reflectance of coals blends tends to vary linearly, but having the average reflectance of a blend in this range is not sufficient to assure that the produced coke will have the desired qualities. For this reason the reflectance distribution is considered.

Concerns with the relative strength of the coke produced from Indiana coal can be reduced by carefully blending various types of coal. Through blending many potential issues with coke characteristics can be reduced or eliminated. Classically, coal blending for coke production has been considered to contain a level of "art" to the process. Two examples of coke quality produced via pilot oven carbonization using Indiana coal are given in Table 5.20.

Table 5.20 Examples of Coke Quality

	100% Indiana (Brazil Block Coal)	100% Indiana Danville, No. 7 coal)
Coke Stability	33	33
Coke Hardness	54	69
CSR*	48	30
Coke size, mm	53	55
Coke yield,%	67.9	67.0
Coking Time, hr	18.6	20.15
Max. Pressure, kpa	2.07	2.96

Four visits to Argonne National Laboratory were made to discuss various aspects of the proposal. Specifically there was discussion regarding the possibility for partial gasification.

Argonne currently uses the Aspen model for much of its coal gasification modeling. Should additional funding become available it may be possible to arrange for scoping studies to be conducted using the Aspen model. Access to the Aspen model licensed to Purdue University is currently being obtained. Efforts to use Aspen for coking operation modeling will also be pursued at Purdue University Calumet should additional funding become available.

In the performance of the initial scoping study, it was also been determined that there is a significant possibility to use existing or new coking facilities as a source of pyrolysis gas for the production of liquid transportation fuels through a Fischer-Tropsch process. In this approach, existing or planned coke production facilities would be used as part of the developmental process thereby reducing the process development risk as compared to construction of a dedicated test facility.

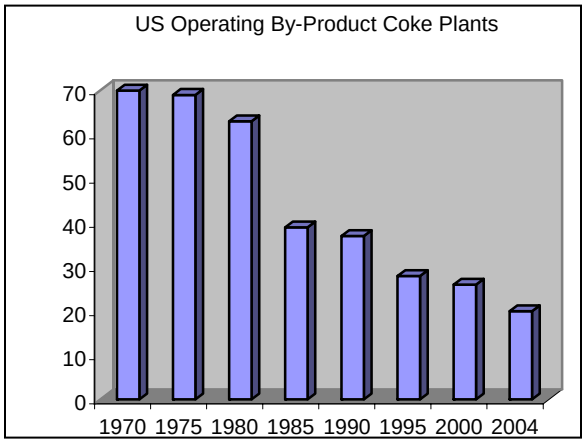
5.3.4 Importance to Indiana Coal Use

A mine mouth coking/coal gasification facility will have many positive economic and employment effects for Indiana. This facility will be located in Indiana. Typically, a 1.3 million ton per year coke facility employs about 130 people. In addition, it is estimated that 13 new employees would be required in the Indiana mining industry. A new facility of the type considered would provide a significant employment opportunity for Indiana. Such a facility would allow the Indiana Coal Industry to open a new and expanding market. Metallurgical coal contracts increases by 20% to 40% in 2004. In 2002 Indiana imported 8.093 million tons of coking coal. The potential for use of Indiana coal for coke production for use in Indiana is between 2.0 and 3.6 million tons per year. Export potential is estimated to range from 6 to 11 million tons per year. Current coke production at Indiana Harbor facilities is 1.2 million tons per year screened. The proposed facility would be of a comparable size and would result in an estimated cost savings of at least 5% for delivered coke due to reduced transportation costs and would meet a portion of future demand growth. It would also reduce imports of metallurgical coal by several million tons per year and replace it with coal produced in Indiana. There would also be a potential to export coke to adjacent states including Ohio, Kentucky, and Illinois. The sale of electric power from the cogeneration function would also result in a significant revenue stream to further enhance the benefit of the project.

The U.S. coke industry has two primary product markets (i.e., furnace and foundry coke) that are supplied by two producing sectors—integrated producers and merchant producers. Integrated producers are part of integrated iron and steel mills and only produce furnace coke for captive use in blast furnaces. Therefore much of the furnace coke is produced and consumed by the same integrated producer and never passes through a market.

Due to a variety of circumstances including the tightening of emissions regulations, the number of coke ovens is decreasing (Figure 5.2). This indicates that there is clearly a need for new environmentally friendly coking production capability. The proposed research would support the development of such capability using Indiana coal.

Figure 5.2 U.S. Operating By-Product Coke Plants



5.3.5 Policy, Scientific and Technical Barriers

In the early 1900s Indiana coal was used for producing coke. As natural gas decreased in price and increased in availability along with decreasing energy costs in general, Indiana coal was used much less for industrial purposes. This also was the result of economics and environmental concerns and to some degree expediency in ramping up steel production levels.

Today, there have been considerable advances in coke oven, emissions control, catalysis, and other related technologies that provide an opportunity to gain operational and economic benefits by using Indiana coal in heavy industrial applications such as the production of coke for blast furnaces. This use will require reconsideration of blending and other process operational functions, but the benefit can be significant. Using tools such as CFD and blending strategies, it is possible to develop methods to significantly increase the level of Indiana coal that could be used to produce coke for blast furnace and other operations.

Issues regarding transportation of coke from central to south western Indiana will need to be considered. It will be necessary to assure that transportation bottlenecks do not negate the benefits. Locating a coking facility at mine mouth will tend to reduce net transportation costs. Issues regarding local emissions requirement will need to be addressed further.

One byproduct of the proposed technology is electricity. It will be necessary to consider associated electric system issues in optimizing the value of generated. Issues regarding integration of the unit into a local control area will need to be addressed as well as any concerns with ancillary electric system services.

Since this technology has the potential to increase sales of Indiana coal as well as creating jobs, there may be possibilities to gain economic development incentives. There is also the possibility that coke markets can be established outside Indiana. Relationships at a state level will need to be arranged for such opportunities.

Further research and development is needed to assed the viability of further developing the technology for the production of liquid transportation fuels through Fischer-Tropsch processes. Research regarding coke oven gas composition, catalysis, processes to use the gas in Fischer-Tropsch processes, and system optimization will be required to assure the feasibility of the concept. It will be necessary to establish contacts for a possible demonstration with either a coal mine or coke facility operator.

5.3.6 Additional Resources

The research plan to continue the development of this concept has been divided into two parts. The first part will last one year and will consist of efforts to conduct more detailed process modeling for using Indian coal in industrial processes such as blast furnaces, including consideration of Fischer-Tropsch processes for the production of liquid transportation fuels from coke oven gas. Issues regarding potential transportation and relevant electric system issues will also be considered. It will be necessary to purchase computer hardware and software for the modeling effort.

One of the most important outcomes from this part will be the development of a feasibility study for appropriate portions of the process. This study will recommend a Go/NoGo decision for the second stage of the project. The feasibility study will be based on modeling results, analysis, and input from various advisory sources including the coal and steel industry. Funding at a level of $100,000 would be required for this part. It is anticipated that of this funding, $15,000 would be devoted to computer equipment and software and the remainder to labor and supply expenses contingent on the treatment of overhead.

The second part of the recommended research plan will last two years and will include development of a test facility to gain further information regarding the value of Indiana coal, alone and in combination with other metallurgical coals, for use in industrial processes. This facility will have the capability of conducting bench-top testing of the processes considered. It will be located in existing laboratory space. It will be necessary to purchase test equipment for the construction of the preliminary process modeling facility.

The characteristics of coke and coke oven gas produced from various blends of Indiana and other metallurgical coals will be tested to assess the viability of using this gas for production of Fischer-Tropsch liquid transportation fuels. Gas blending and conditioning options will be considered. The use of nano catalyst technology for the Fischer-Tropsch as well as possible carbon dioxide sequestration processes will also be considered. A preliminary economic study of the proposed concept will conducted. This will include issues regarding the value of coke, electricity, and possibly electric ancillary services.

One of the most important outcomes from this part will be the development of a feasibility recommendation for the next step of the development which would be to construct a demonstration facility at a coal mine or operating coke plant. Funding at a level of $600,000 would be required for this part. It is anticipated that of this funding, $200,000 would be used to purchase and installing equipment for the test facility, $10,000 would be used to purchase

computer equipment and software, and the remainder would be expended on labor and supplies contingent upon treatment of overhead.

5.3.7 Research Plan

The following research plan is presented as a possible way of continuing and expanding the effort that is the subject of this final report. Preliminary results indicate that there is significant benefit to continuing with the current research effort and to consider next steps leading to construction of an industrial test facility should additional analysis and development continue to support the concept. Based upon the preliminary results it is recommended that further development of the proposed concept for mine mouth coking/gasification should be initiated and expanded to include consideration of the production of liquid transportation fuels.

Tasks and Milestones (anticipate funding level: $100,000, 1 year duration)

1. Develop initial plan details and submit for approval – A detailed work plan for the project will be developed during the first three weeks. This plan will assist in establishing a clear understanding of work activities, schedule, and reporting requirement details for all parties to the project.
2. Establish new and refine existing interface with industry contacts – Contacts with industrial, governmental, regulatory, technical, and other appropriate sources will be formalized. Communication and information exchange procedures will be established to provide assistance in assuring the success of the project.
3. Obtain data and models for pyrolysis and Fischer-Tropsch processes.
4. Obtain coal samples and initiate analysis and evaluation of coking and Fischer-Tropsch processes for producing liquid fuels.
5. Initiate investigation of using nano catalysis for gas composition changes and Fischer-Tropsch processes.
6. Initiate non recovery coke oven and pyrolysis modeling.
7. Perform initial Computational Fluid Dynamics scoping appraisal of influence of produced coke on blast furnace operations.
8. Analyze the feasibility and options for using or selling generated electricity.
9. Initiate discussions with coal mine and coke production facilities regarding feasibility of developing a facility.
10. Determine impact of transportation issues.
11. Evaluate economic factors and influence on use of Indiana coal.
12. Develop process feasibility appraisal.
13. Make recommendations for a go/no-go decision point for future research.
14. Prepare final report.

Phase 2 (anticipated funding level: $600,000, 2 years duration)

1. Initiate discussions to obtain additional funding for the development of an onsite industrial prototype test of the process. Initiate an advisory group for the industrial prototype test.
2. Expand and complete coal sample analysis and appraisal. Complete an assessment of available Indiana coal sources and their value for coking. Coordinate this with mine owners to evaluate feasibility of coal supply and potential plant locations.
3. Construct bench top prototype testing facility for the processes and conduct tests. This facility will be used to gain information regarding the proposed processes and their feasibility. Coordinate this effort with production personnel from operating coking facilities.
4. Complete initial non recovery coke oven and pyrolysis modeling.
5. Perform preliminary Computational Fluid Dynamics appraisal of initial design. This will facilitate the interface of this project with ongoing research efforts regarding blast furnace operation and optimization.
6. Determine the feasibility and options for using or selling generated electricity.
7. Perform initial economic evaluation.
8. Obtain letters of support from potential industrial participants in the prototype test.
9. Prepare and submit proposals to obtain additional funding for the development of an onsite industrial prototype test of the process.
10. Develop technical feasibility study.
11. Develop coal market impact evaluation.
12. Initiate discussions with coal mines, coke producers, and interested parties regarding construction of onsite industrial prototype test.
13. Make recommendations for a go/no-go decision point for efforts to pursue construction of an industrial test at an operating mine or coking facility.
14. Prepare final report – A detailed final report will be prepared and presented within 30 days of the completion of the project.

5.3.8 Conclusion

This study has shown that it is highly likely that Indiana coal can become an important resource for the production of coke for the steel and other industries both inside and outside Indiana. As was noted in the study, currently there is a shortfall of 5.50 million tons of coke per year in the United States. This research effort has shown that Indiana coal can become one way to reduce current and future coke supply issues as well as reducing price by as much as 10%.

The significant shortfall of needed coke has placed an enormous strain on Indiana's steel and foundry industries. The need for additional coke production capacity is evident given plans for coke plant expansion being considered by Indiana's steel industry and others. This results of this study indicates that the coke supply and high price volatility situation can be mitigated through the use of Indiana coal in a mine mouth, environmentally friendly, high efficiency coking/coal gasification facility. Such a facility would also increase coke supply and production, while, at the same time, reducing the cost for Indiana's steel and foundry industry. In addition, such a high efficiency coking facility would produce electricity for sale to the

wholesale electric market, thereby reducing costs and environmental emissions and, at the same time, enhancing electric system reliability.

The work for this proposal started in March 2005 and was completed in November 2005. All the tasks from the original milestone and schedule chart, depicted in Figure 5.3 and Table 5.21, were completed on schedule. It was possible to initiate discussions and produce interest in this technology through discussions with a variety of parties including steel mills and coke producers.

Figure 5.3 Phase 1 Milestones and Timeline

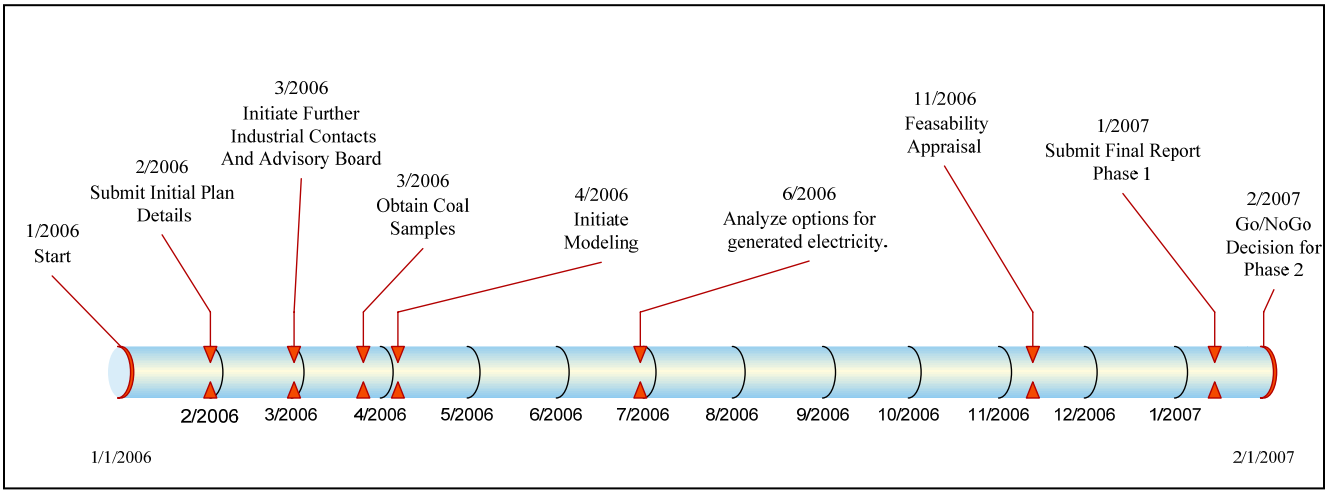


Table 5.21 Work Plan Dates

ID	Task Name	Start	Finish	Duration	2006 Q1	Q2	Q3	Q4
1	Develop Initial Plan Details	1/2/2006	2/1/2006	23d				
2	Initiate Further Industry Contacts	1/16/2006	6/1/2006	99d				
3	Obtain Coal Samples	2/1/2006	4/3/2006	44d				
4	Modeling for coke oven, Fischer-Tropsch & nano catalysist	3/1/2006	11/1/2006	176d				
5	Analyze options for generated electricity.	6/1/2006	9/1/2006	67d				
6	CFD Scoping Analysis	3/1/2006	9/29/2006	153d				
7	Evaluate Economic Facotrs	4/3/2006	10/31/2006	152d				
8	Develop Process Feasibility Appraisal	6/1/2006	12/29/2006	152d				
9	Prepare Final Report	9/1/2006	1/15/2007	97d				

Indiana's steel and foundry industries are major employers, as well as significant sources of revenue to the state in the form of taxes. This project would help to assure the health of these vital industries, generate new jobs and revenue streams through the use of Indiana coal at a facility to be located in Indiana, and advance the technical state of the art by using Indiana coal and simultaneously reducing environmental emissions. A recommendation for continuation and extension of this effort is included in this final report.

Note: Full report is available at:: *https://engineering.purdue.edu/IE/Research/PEMRG/CCTR/Rnd1Final.html*

6. NEW COAL PROJECTS

In 2006 it is expected that four new coal projects will be started, as well as have the three scoping studies, that were conducted in 2005, be further funded for a significant follow-on period.

The four new projects include (1) Indiana coal transportation, (2) Indiana Coal Fines, (3) Coal Fuel Alliance Response to the Obama-Lugar Amendment (Coal-To-Liquids), and (4) the State Strategic Energy Plan and Regional Partnership.

6.1 Coal Transportation Infrastructure

Improving the rail, truck, and barge coal transportation infrastructure in and around Indiana will be an essential component to support increases in production of Indiana coal. While the demand for coal escalates in light of higher natural gas prices the rail system that transports most of the nation's coal is constrained. At the Fall 2005 meeting of the CCTR Advisory Panel meeting it was recommended that the current importance of coal transportation infrastructure in the state justified funding for a new scoping study.

A proposal submission was approved from

- Purdue University North Central (Dr. Tom Brady) in partnership with
- The Transportation Team, School of Civil Engineering, Purdue West Lafayette.

This topic is to receive matching funds from the Indiana Department of Transportation, INDOT. The North Central team will work on issues of coal transportation for rail and barge and the Transportation Team at West Lafayette will consider mainly the roads network for coal transportation. In the development of this proposal, significant conversations have been held between the principal investigator Dr. Tom Brady (Purdue North Central) and Dr. Kumares Sinha (Purdue School of Civil Engineering, West Lafayette). Dr. Sinha is an expert in transportation issues and has had a long and productive relationship with the Indiana Department of Transportation (INDOT). The additional $25,000 grant from INDOT will extend the methodology to examine issues particular to the State of Indiana's highway system. When this additional funding is appropriated, Dr. Sinha will provide in-kind support and insightful Civil Engineering transportation-based knowledge to the project.

The EIA reports that the rail industry set a new high in 2005 for freight traffic transporting more than 1.5 trillion revenue ton-miles (rail unit of measurement incorporating weight and distance)

with coal making up 40% of that total. The concerns increasingly being expressed are that it would be a mistake to think that coal can meet the nation's expected future demand because of the massive reserves but the weak link is now in the inadequate transportation system that carries the product from point to point.

Regarding coal imports into Indiana from Power River Basin (PRB) there are currently major rail bottlenecks:

> *"As the mines (PRB) have grown, the railroads have consistently gotten behind as they build track in response to demand, and not in anticipation of it. This creates a short-term bottleneck, but the problem mushrooms if the situation becomes chronic as others in the region now believe it has"* (COAL AGE, July 2005, p.18).

This is one of the major issues in coal transportation infrastructure that this proposal will investigate. The multi-modal nature and potential of coal delivery within the State of Indiana, the nature of current coal supply contracts, transportation infrastructure projections, and supply and demand positions of large coal consumers, take on equal significance. Use of the proposed simulation model will allow accurate cost and time representations of current, as well as projected coal transportation routes and modalities between identified users and suppliers.

The main basis of this proposal is to use the supply chain concept to analyze and suggest improvements to the Indiana coal transportation network. While the actual price of coal mining/extraction may be constant across major producers, the cost of transporting it to the customer may be highly variable, thus suggesting a major competitive dimension that may be exploited. The objective of this proposal is to examine the transportation component of coal movement using the Indiana transportation infrastructure and develop knowledge as to why the current inflow and outflow environment exists. Once the coal transportation infrastructure is defined, we will seek to optimize it to competitive levels through suggested capital improvements.

Movement of goods through a transportation infrastructure is subject to numerous external factors that can be characterized by two attributes: process variation and dependency. Process variation is present in any activity and presents numerous challenges to efficiency. In particular, the current United States rail infrastructure includes many bottlenecks that can add significant incremental time to accepted 'average' transport times. Dependency refers to the concept that any supply chain is composed of a number of links and the interdependencies of the links determine overall efficiency of the supply chain.

Modeling and analysis of supply chains that possess characteristics of variation and dependency pose many challenges to conventional static methodologies. Computer simulation has proven to be a very mature, effective tool for analyzing and optimizing complex systems, including transportation infrastructures. The basis of this proposal consists of the development of a simulation model that accurately represents the rail, road, and water transportation infrastructure of Indiana and all relevant interfaces. This model will be used to verify current coal movements

and develop optimal movements that are necessary for Indiana coal companies to compete with competitors such as the Powder River Basin.

A primary benefit of this proposal will be the *characterization of the capacity of the Indiana transportation infrastructure along time and cost dimensions* as a link in the national coal transportation infrastructure. Once accurate projections of the capacity are known, improvements will be developed and analyzed that optimize the efficiency of Indiana's coal transportation infrastructure. The primary output of this proposal will be a simulated environment that can be used to accurately project and build Indiana's coal transportation infrastructure into one that can add competitive value to Indiana's coal industry, allowing the state to compete nationally.

Particular strengths in this proposal lie in the composition of the research team and industrial partners who have pledged their support to the project. To successfully carry out the tasks detailed in this proposal, an experienced interdisciplinary team is required. Dr. Brady is a subject matter expert in simulation modeling and optimization. This knowledge will allow the models to be built quickly, efficiently, and to the correct level of accuracy. Mr. Chad Pfitzer is a subject matter expert in current and historical railroad transportation. His vast knowledge of current rail operational practice will make the task of rail route definition and operational aspects of rail transportation research quick and seamless. Northern Indiana Public Service Company operates several of Indiana's largest coal burning power plants and is one of the largest importers of coal into Indiana. The Ports of Indiana participate in the global transportation industry and are subject matter experts in moving large commodities. The pledged cooperation of Dr. Sinha in the School of Civil Engineering will add expertise in the development and characterization of transportation infrastructure improvements.

6.1.1 Proposal Tasks

1) Characterize the demand and supply states of Indiana coal usage

This task will define the major inflows and outflows of coal in the state of Indiana. Major Sources (Coal production sites) and Sinks (Coal usage sites) of coal will be identified. The basis of this task will be a report titled "Indiana Rail Plan[2] and the PA Associates report referred to in the CCTR RFP document.

2) Characterize the transport methods of Indiana coal supply and demand

Using the data from Task 1, this task will define current and projected transportation routes and methods used to move coal from each source to sink in the coal network. Each method will including but not limited to items such as:

a) Routes
   i. Capacity
   ii. Route Conditions
   iii. Operating Rules
   iv. Weather
b) Equipment

c) Modes
d) Operating Rules and Policies
e) Terminal Operations

3) Develop a simulated environment of Indiana coal supply and demand

This task will develop a computer simulation model of the coal transportation infrastructure as defined in Tasks 1 and 2. This simulated environment will include all relevant transportation modes and facilities between sources and sinks defined in Task 1. The simulation model input will consist of an Excel spreadsheet. This will allow simple definition and creation of alternative scenarios. This task will produce two major outputs:

a) A bottleneck analysis of the Indiana coal transportation infrastructure.
b) A cost curve detailing the expected transportation cost per ton shipped between sources and sinks defined in Task 1.

4) Develop a set of transportation infrastructure improvements to address bottlenecks in current Indiana coal network

This task will develop a set of transportation infrastructure improvements to alleviate bottleneck situations in either cost or time as generated from Task 3.
Using the simulated environment developed in Task 3, projected economic benefits for each potential improvement will be determined.

5) Develop a Return on Investment Methodology and simple portfolio optimization model

This task will use output generated in Task 4 as the basis for the development of simple return on investment models that will be used to rank and prioritize the transportation infrastructure improvement alternatives posed in Task 4. A portfolio-based optimization model will be developed that will optimally allocate potential capital investment budgets to the alternatives based upon decision maker criteria.

Tasks 1, 2, and 4 will require significant input from a variety of subject matter experts from industry, government, and the transportation sector, along with public domain research reports and operational statistics. The success of this proposal will be highly dependent upon securing the cooperation of industry and governmental sources. The vast railroad knowledge of Mr. Pfitzer, along with the pledged cooperation of INDOT, Northern Indiana Public Service Company, and the Indiana Port Commission give us confidence that we can successfully carry out the tasks outlined in this proposal.

6.1.2 Proposal Deliverables

1) Interim Report
   a) Requirements definition for project tasks
   b) Status Report

2) Final Report
   a) Database of Source and Sink production/consumption figures
   b) Graphical representation of coal transportation routes between Source/Sink destinations:
      i. Rail
      ii. Road
      iii. Barge
   c) Computer simulation model
      i. Model documentation
      ii. Spreadsheet input
      iii. Output Analysis, including a projected cost per delivered ton matrix of source/sink/mode
   d) Optimization Model
      i. Model documentation
      ii. Spreadsheet input
      iii. Output Analysis
   e) List of Potential Transportation Infrastructure Improvements
   f) Economic Analysis of Indiana Transportation Infrastructure Improvements
   g) Recommendations for Infrastructure Improvements

6.2 Reclaiming Indiana Coal Fines

The CCTR Fall 2005 Request For Proposals received three proposals concerning Indiana coal fines. Following discussions with the Advisory Panel and the three PIs and their teams it was recommended that a combined proposal would be prepared and submitted to the Advisory Panel in early 2006.

The coal fines proposals were received from:

- Indiana Geological Survey, Indiana University
- Purdue Water Institute, Purdue University Calumet
- R.E. Mourdock & Associates, LLC

The proposed combined proposal is being led by R.E. Mourdock and Associates (REMA) and their plan of work will be presented at the February 28, 2006, meeting of the CCTR Advisory Panel meeting.

Over the years, there has been recurring interest in reworking Indiana's accumulated inventory of coal fines discarded in the coal washing process of the past century that is part of the estimated two Billion tons of such fines available for recovery in the United States [1]. There are significant financial benefits from using these discarded amounts of coal fines.

Secondly, the protection and improvement of the Indiana environment is significant to the project. For example, the *E. coli* levels in the Patoka River watershed have been recorded as six times higher than the state standard. It is theorized that the high Fe content in the Patoka River (due in part to runoff from abandoned mine sites and settling ponds) enhances *E. coli* levels. The Patoka River is the only water supply available for the city of Jasper and one thing for sure is that the fines may have a negative effect on groundwater quality.

It is proposed that this scoping study will address both financial and environmental issues, and working with Indiana's DNR and existing coal mining companies provide recommendations on the use of coal waste to help avoid the construction of new slurry ponds and suggestions as to what might be done with the old ones.

The REMA team views the Indiana Coal Fines Scoping Study as a critical first step in the complete evaluation of the potential of Indiana's coal settling ponds. As such, REMA sees the purpose of the scoping study to:

1. Document the benefits possible in recovering the energy present in Indiana's coal settling ponds.
2. Document the environmental potential (both positive and negative) inherent in the re-mining of such sites.
3. Define the existence of relevant published resource material available to assist in the development of Indiana's settling ponds in the areas of (but not limited to):
    (a) Geologic publications
    (b) Mining or equipment publications

   (c) Environmental publications
   (d) Legal publications or citations
4. Define, as specifically as possible, major impediments that could prohibit the re-mining of the settling ponds.
5. Suggest possible strategies for effective resolution or removal of impediments.
6. Outline in detail a complete research project that would
   (a) Define the potential resources available in acres and/or tons,
   (b) Define specific "type areas" of high environmental sensitivity or risk for re-mining,
   (c) Accurately define funding requirements necessary to perform a full research project,
   (d) Define potential markets for recovered material,
   (e) Provide detailed recommendations to state and/or federal government authorities to allow for the subsidization or to otherwise encourage the re-mining of coal settling ponds and present a strategy to enact such recommendations.
7. Provide a list of "deliverables" resulting that will constitute the product of the Scoping Study.
8. Identify potential funding sources or organizations that might partner with the CCTR for a formal research project.

While there is currently limited data available on the exact coal fine tonnage in Indiana residing in the remnants of the settling ponds around the state, one estimate has suggested 60 MTons. This accounts for 3.1% of the national total of 2 GTons (derived from 35 MTons of coal produced in Indiana in 2004 compared with 1,111 MTons nationally [1]). It is estimated that each year Indiana loses about 1 to 1.5 MTons of coal as "waste" in the cleaning process. Complete recovery of the Indiana coal fines could be worth over $1Billion for reinvestment in the coal mining companies and for improving Indiana's environment.

Reclaiming coal fines is hardly a new idea. One Pennsylvania utility has been using such fines as a fuel since 1940. The Vigo Coal Corporation in Indiana undertook a feasibility study to determine if such a recovery process would be economic at their Columbia mine site. The economic effect of the reclaiming of coal fines is still being assessed with the subject generating considerable interest. A quick search of the literature on reclaiming coal fines lists over 18,000 citations. This scoping study will provide a response to the many questions and give guidelines for further work in this area.

The REMA Team is proposing a scoping study with the following essential elements:

A. Determine where abandoned coal settling ponds exist in Indiana.
B. Determine the status of each abandoned coal settling pond.
C. Determine, as accurately as possible, the total tons of potentially recoverable coal reserves within the state's abandoned settling ponds.
D. Determine, as accurately as possible, estimated coal quality from selected settling ponds.
E. Determine what methods of recovering coal from settling ponds are practical.

F. Determine the estimated cost of recovering material from settling ponds.
G. Determine the estimated cost of beneficiation of coal from settling ponds.
H. Determine existing and potential markets for coal recovered from settling ponds.
I. Determine, in addition to the hard costs, the "social" costs of effecting settling ponds.
J. Determine if "drivers" for development exist in either economic costs or regulatory requirements (i.e., environmental motivations or economic subsidies, etc.)
K. Determine if existing wetlands on settling ponds are of sufficient environmental quality to deter development.
L. Determine if regulatory impediments exist to development of settling ponds and if so, suggest a strategy for the removal of such impediments.
M. Develop a compendium of titles of recent research and/or a bibliography of published technical materials that may address critical areas of development potential or potential impediments to development of coal settling ponds.
N. Determine if new markets might me developed that could capture the benefits of recovering material from settling ponds.
O. Determine if other potential financial partners exist to help fund further research to aide in the recovery of product from Indiana's settling ponds.
P. Determine if other states have implemented programs to develop settling pond re-mining that may have application in Indiana.
Q. Develop a plan or plans that might cause Indiana to be on the "cutting edge" of settling pond re-mining and restoration.

REMA has assembled a proven and experienced team to perform the scoping study and, if warranted, the full research project that will follow-on from the initial 9-month study.

Purdue Water Institute
Indiana Geological Survey (Coal Section)
Hull & Associates, Inc.
Mr. Charles B. Lee
Mr. James R. Holden, Esq.

The team includes and essential duties are assigned as below:

Principal Investigator:	Richard Mourdock Principal, R.E. Mourdock & Associates, LLC
Site Verification	Indiana Geological Survey (IGS) Denver Harper serving as Lead Researcher within IGS
Market Potential	Mr. Charles B. Lee & Purdue Water Institute PWI (research potential and existing "conventional" markets)
Market Potential	Indiana Geological Survey (research potential or "innovative" markets)

Environmental / Cartography	Douglas Stuart (primary point of contact) Partner, Hull & Associates Technical resources, watershed mapping, satellite imagery, wetlands issues
Legal Issues	James R. Holden, Esq. Summary of potential legal issues

The REMA team has an impressive breadth of both technical and policy related skills.

In summary it is to be noted how in 2005, the DOE supported the first commercial use of an advanced coal-cleaning system comprising two advanced separation technologies. This project will produce clean, upgraded coal from a large fine-coal waste pond located in southern West Virginia. This innovative system will create useable fuel from discarded "waste," and could be used to clean up hundreds of potentially hazardous coal-waste "impoundments." A similar potential exists for Indiana as well as providing a plan for improving environmental standards.

Reference:
[1] http://www.fe.doe.gov/news/techlines/2005/tl_coal_cleaning_wva.html
DOE, Coal Supply and Demand, 2004 Review, "The Energy Department estimates that 30–50 million tons of coal fines are discarded annually into impoundments because of the high cost of processing fine coal. This adds to the more than 2 billion tons of coal already in about 700 fine coal impoundments, ….."
http://www.eia.doe.gov/cneaf/coal/page/special/feature.html
2004 U.S. coal supply total = 1,111 MTons
"Premium Fuels from Coal Refuse," EPRI TR 103709, Feb 1994

6.3 Coal-To-Liquids – Appropriations Request in Response to Section 417 of the Energy Policy Act of 2005

The section provides the updated planned response (dated March 3, 2006), in the form of an Appropriations Request resulting from the Energy Policy Act of 2005, which describes the role and activities of the Coal Fuel Alliance (CFA) for 2006.

6.3.1 Request

We request that $14.5M be appropriated for the first year's activities under Section 417 of the Energy Policy Act of 2005, which is directed to the production of transportation fuels from Illinois Basin coals at Purdue University, Southern Illinois University and the University of Kentucky. The funding will kick-start the establishment and expansion of capabilities at the participating institutions to deliver test quantities of synthetic fuels for evaluation in civilian and military applications.

6.3.2 Background

There are significant opportunities for the expanded use of coal as a means to replace crude oil for transportation fuels and chemicals by using coal-to-liquids (CTL) technology. The use of coal for this purpose can provide additional independence from oil imports, safeguard the nation's security, allow for the development of new industries, and provide new incentives for coal mining. The Department of Defense has a keen interest in securing alternatives to petroleum for reliable supplies of battlefield fuels, and this effort is well aligned with that objective. Moreover, Fischer-Tropsch coal-derived fuels are environmentally superior to petroleum-derived fuels. The products include ultra-clean diesel and jet fuel of interest to the aviation, heavy equipment and trucking industries. Illinois Basin coals are excellent feed stocks for these purposes.

Recognizing these facts, the Congress per Section 417 of the Energy Policy Act of 2005 requested the Department of Energy to evaluate the commercial and technical viability of advanced technologies for coal-derived transportation fuels. The Congress further requested DOE to enter into agreements with SIU's Coal Research Center, UK's Center for Applied Energy Research, and Purdue's Energy Center to carry out the purposes of the Act. The universities subsequently entered into a Memorandum of Understanding to create the "Coal Fuel Alliance" (CFA) for purposes of sponsoring complementary and joint development and demonstration of technologies for converting Illinois Basin coals to fuels.

The prospect of CTL technologies is alluring, however, the deployment of pioneering energy technologies bring with them certain financial, construction, operating and technical risk not normally associated with proven technologies. Risk can be reduced and deployment stimulated by a variety of means, including price supports, product take-off agreements, tax breaks, and financing incentives for early adopters. It can also be reduced by making "learning investments"

for research, development and demonstration (RD+D) to reduce the technical hurdles of new energy technologies. It is for this purpose that the universities have formed this Alliance – to provide a base of "enabling research" and development (RD), and to support demonstration (+D) of the technology at commercially-meaningful scale.

6.3.3 Deliverables

The universities will expand existing and establish new capabilities in the area of CTL technologies, including improvements in facilities and development of human capital. The universities intend to collaboratively concentrate resources, create a critical mass of expertise, and provide a focal point for RD+D on fuels derived from Illinois basin coals. The effort will address current unmet needs for CTL technologies, emphasizing carefully applied and developmental needs. The effort will provide open-access facilities and information in the public domain to aid the wider scientific and industrial community. A means to independently review vendor claims will be established with open-access facilities that can provide a neutral platform to validate performance and product quality. An organizational and programmatic structure will be put in place to minimize duplication, exploit the capabilities of each university, and coordinate the effort to maximize synergies.

The Universities will work together to build up human capital – the future generation of skilled energy technologists, engineers and operating personnel – that will be needed to sustain a CTL industry. Due to the cyclical interest in CTL, the scientific and engineering capabilities which were devoted to energy programs of the 1980's and 90's have dissipated. A new generation of technologists needs to be nurtured. One of the best ways of creating this skills base is to stimulate and fund RD+D at appropriate institutions which have the facilities to teach and train students in the practical applications of science and engineering. The relevance of training can thus be assured while the stimulus of a creative environment will lead to further technological innovations.

6.3.4 Project Thrusts

The three universities have excellent and complementary capabilities, and the division of labor between them will be highly integrated. The UK team has a long and proven track record in synfuels catalysis, Purdue in engine testing, and SIU in advanced coal technologies. SIU intends to construct and operate bench and process development units for gas cleanup and conditioning. They also will develop a modular, bench-scale, fast-screening experimental facility – the so-called "Innovations Lab" – for studies of gas conversion. UK intends to build and operate a larger, continuous and integrated pilot plant for syngas conversion and product workup. The facility will produce larger quantities of refined products for testing and evaluation (up to ½ barrel, about 20 gallons per day) by the CFA partners. The know-how, show-how associated with these facilities at SIU and UK is expected to be a key benefit in that they can be used as test beds for new concepts at a level of expenditure that is affordable. Purdue will develop advanced fuel characterization, process simulation and quantitative modeling capabilities related to syngas conversion and product work-up. The work will also involve the substantive capabilities of

Purdue's engine test facilities - supported by Cummins, Rolls Royce and Caterpillar. Their role will be critical in testing, validating and improving fuel quality, performance and acceptability for end-users. Purdue, SIU and UK will also contribute to environmental, economic and policy analyses related to CTL. Finally, the combined efforts of the universities will contribute to the development and operation of a demonstration-scale Products Test Facility capable of producing larger quantities of fuel products for evaluation by the military and the auto, trucking and aviation industries.

6.3.5 Funding Required

For project scoping purposes, the table below shows the initial budget and timeframe for development of the above capabilities. The Year 1 request is for an amount of $14.5M to be leveraged by the universities and states by an additional 20 percent cost share. Out year funding is also indicated. The budget leaves $41M - the difference between the authorized $85M and the federal share of $44M shown below - for work associated with the larger Products Test Center. Details of that facility will be developed as the project progresses. All amounts and the split of resources are subject to negotiation among the member institutes.

Table 6.1 Coal-To-Liquids Funding Requirements

TASKS	Budget ($M)	Year 1	Year 2	Year 3	Year 4
Gas Cleaning and Conditiong:					
Bench & PDU-scale Gas Cleanup Units	$9.9	$4.5	$1.8	$1.8	$1.8
Gas Conversion and Product Workup or Refining:					
Modular "I-Lab" for Gas Conversion/Prod Characterization	$4.4	$1.4	$1.1	$0.9	$1.0
Pilot Plant for Gas Conversion/Product Work-up or Refining	$19.4	$6.5	$6.5	$3.2	$3.2
Gas Conversion by FT Synthesis	$7.9	$2.8	$1.7	$1.7	$1.7
Fuel Product Utilization:					
Engine Testing for Fuel Quality and Performance	$10.2	$2.5	$3.3	$2.2	$2.2
Other Activities:					
Environmental, Economic and Policy Studies	$2.0	$0.1	$0.6	$0.6	$0.7
Administration	$1.2	$0.3	$0.3	$0.3	$0.3
TOTAL	**$55.0**	**$18.1**	**$15.3**	**$10.7**	**$10.9**
State/University Cost Share (20%)	**$11.0**	**$3.6**	**$3.1**	**$2.1**	**$2.2**
Federal Share/Appropriations Request (80%)	**$44.0**	**$14.5**	**$12.2**	**$8.6**	**$8.7**

6.4 State Strategic Energy Plan and Regional Partnership (FutureGen)

6.4.1 Indiana Energy Policy

The Indiana Energy Policy that is being drafted by the Indiana Energy Group (IEG) considers how the late 19th and early 20th century saw Indiana build its first big industrial powerhouse on huge underground stores of natural gas and fields of Illinois Basin coal and oil, and now considers a similar historic phase to be starting which will again use the state's natural resources for significant economic impact. The CCTR is working with the IEG on an identical objective of restoring greater state independence for energy supplies.

Indiana's new high-tech, high-paying jobs will be derived from the prospect of retaining more of the capital that goes to energy expenditures. As stated earlier, the Hoosier citizens and businesses spent approximately $14 Billion annually on energy costs. Most of this is in the form of carbon based fuels. Although Indiana's petroleum industry is quite mature, it does not have the capability to be a significant contributor to the liquid fuel needs of the state. It is through Indiana's coal and biomass resources that an impact can be made. Our economy will flourish in part because we will not be as dependent on natural gas from the Gulf of Mexico or fuel oil from the Middle East. Through the retention of millions of dollars of capital, that once left the state, we will see it working to strengthen our local economies.

CCTR will work with the Indiana Energy Group to detail how Indiana's economy, quality of life and well being will once again be built on home grown energy. But, this time, new technologies will allow us to fully utilize our high sulfur coal, create new, homemade synthetic gas from coal and convert it into motor fuels and unleash our ingenuity on the goal of conservation and efficiency. The focus of the CCTR will be to lay the ground work necessary for the state to carry out its energy policy function.

CCTR is working in the area of coal characterization where it can be determined how to best use the vast coal resources to meet the future energy needs of the state. The correct characterization will aid in the development of IGCC systems and potential coking programs. Indiana imports 5 Million Tons of coal for the purpose of creating coke for the steel industry. No Indiana coal is used for this function. Preliminary studies sponsored by the CCTR show that certain coals can substitute for the West Virginia coals now used and be capable of producing usable syngas as from the coking process waste gas. This process alone can increase the use of Indian coal by 4 Million Tons in an area where no Indiana coal is now used.

In addition, the CCTR is looking into the transportation infrastructure. It is of little value to recommend an increased use of a certain fuel if that fuel cannot be transported to customers. This issue and others are part of the work program being done by the CCTR to support the Indiana Energy Plan (more details in Section 5 of this report). Now and in the future the CCTR will be working with the Indiana Energy Group, the Lt. Governor, and Governor's office to support energy independence when and where it is economically and environmentally sound.

CCTR will function as a part of the Purdue's new Energy Center which is expected to become a national Center of Excellence in clean coal technology, hydrogen and renewable energies. Indiana will build new coal gasification, coal processing facilities, some in partnership with Illinois to complete the federally funded *FutureGen* project, creating clean power, hydrogen and methane from our local coal. New technologies, opportunities and challenges will certainly emerge. The use of CCTR expertise will aid the deployment of new coal technologies. The overall goal will be to make coal the answer, not a problem.

6.4.2 Role of CCT and FutureGen in Indiana

Indiana and Illinois are working together on the *FutureGen* project. This teaming will combine the resources of both states to achieve the best technology development possible. The Illinois-Indiana team will enable the *FutureGen* site to use varied technologies with various fuel types. Rather than limit the *FutureGen* to one fuel type, the team will be able to convert bituminous, sub-bituminous, lignite, and petrol-coke through a clean gasifier. The Illinois-Indiana recommended site is also the main east/west interchange for the nation's electric grid system. The power produced by Illinois/Indiana *FutureGen* is readily available to a majority of the nation. Site availability, fuel flexibility, waste products to useful power and connections to the national grid make this Team the best bet for *FutureGen's* success.

The knowledge and experience we gain from the design and construction of the *FutureGen* plant will help turn coal from an environmentally challenging energy resource, into an environmentally benign one. *FutureGen* will be one of the boldest steps our nation takes toward a pollution-free energy future. Virtually every aspect of this plant will be based on cutting edge technology. The plant will be a living prototype – a global showcase – testing and evaluating new technologies as they emerge from research and development.

Rather than burning coal as today's conventional plants do, the approximately 275 MW *FutureGen* plant will turn coal into a gas and employ new technology to remove virtually all of the resultant air pollutants – sulfur dioxide, nitrogen oxides, and mercury. The Illinois-Indiana team will provide a unique real-world opportunity to prove the feasibility of large scale carbon sequestration. Carbon capture and storage technologies will be used to separate carbon dioxide from the other gases. Once isolated, the carbon dioxide will be injected into an existing deep unminable coal bed that will result in the production of methane that can be extracted for direct use as an industrial or heating fuel.

The *FutureGen* plant will pioneer carbon sequestration technologies on a scale that will help determine whether this approach to 21st century carbon management is viable and affordable. It will provide other benefits including improved system efficiencies, a cleaner environment, and the production of hydrogen.

February 27, 2003, saw President Bush announce *FutureGen*, as the $1 billion cost-shared project to create the worlds first coal-based, zero emissions electric and hydrogen production power plant. By eliminating environmental issues, as barriers to coal use through employing efficient generation technologies and carbon sequestration, *FutureGen* will enable the continued

use of secure domestic coal resources for meeting our energy needs. *"If rising U.S. electricity demand is to be met, then coal must play a significant role."* This major U.S. project will be ideally located in the Midwest and for this reason the States of Illinois and Indiana have signed a memorandum of understanding.

6.4.3 Illinois-Indiana Memorandum of Understanding

The Memorandum of Understanding (MOU) between the State of Illinois and the State of Indiana (July 20, 2005) seals the agreement between Illinois and Indiana for a strategic partnership to establish the *FutureGen* project in the Midwest. The text of this MOU is provided below:

> WHEREAS, the U.S. Department of Energy has launched a $1 billion initiative, with private sector and international support, to design, construct and operate a nominal 275-megawatt (net equivalent output) prototype plant that will, when operational, produce electricity and clean-burning hydrogen with near-zero emissions and demonstrate the effectiveness, safety and permanence of geologic carbon dioxide sequestration; and
>
> WHEREAS, this full-scale prototype power plant, which has been named *FutureGen*, will turn coal into a gas, employ the latest technology to remove the resultant air pollutants (sulfur dioxide, nitrogen oxides, and mercury), separate carbon dioxide from other gases, and inject and permanently sequester the isolated carbon dioxide in underground formations, all as a means of reducing greenhouse gases; and
>
> WHEREAS, by virtue of its capabilities, *FutureGen* will, according to the U.S. Department of Energy, be one of the boldest steps our nation takes toward a pollution-free energy future and serve as a platform to test and evaluate new technologies as they emerge from research and development; and
>
> WHEREAS, there is a high degree of confidence that the prospects for *FutureGen*'s success will be enhanced by multi-state collaboration with respect to site selection, evaluation of available water sources, access to the electrical grid, and opportunities for geological carbon sequestration; and
>
> WHEREAS, an industry-based consortium, known as the FutureGen Industrial Alliance, expects to partner with the U.S. Department of Energy to develop the *FutureGen* project; and
>
> WHEREAS, being selected by the FutureGen Industrial Alliance as the site for the *FutureGen* plant will lead to valuable opportunities to develop an understanding of, and the necessary infrastructure to support, the low-emissions coal gasification process as a way of meeting future electrical generation and other fuel needs using coal—America's most abundant fossil resource:

NOW, THEREFORE, in consideration of the premises and of the mutual undertakings contained herein, the State of Illinois ("Illinois") and the State of Indiana ("Indiana," and, with Illinois, the "parties"), acting by and through their executives, hereby agree as follows:

1. The parties will pool their collective expertise in a joint effort to secure the *FutureGen* project for that part of the Illinois Coal Basin that is shared by the two states. With goal of ensuring environmental quality, abundant electricity supplies and economic growth, the parties will make all reasonable efforts to assure that the *FutureGen* power plant demonstration project is sited within Illinois and that at least one carbon sequestration demonstration project is sited within Indiana.

2. Illinois already has in place a variety of financial incentives, has established a solid technical collaboration among the Illinois, Indiana and Kentucky geological surveys, and has held initial discussions concerning potential sites for the *FutureGen* plant. Indiana will become a partner in that effort, bringing its expertise and sharing its knowledge base in the process.

3. The parties believe that their joint collaboration and mutual support are essential to affording them the best opportunity to secure, for them and their citizens, the benefits of this important federal initiative, with the goal of continuing to utilize abundant and low-cost coal resources and making preparations for the hydrogen economy, while meeting concerns over the harmful effects of emissions, including greenhouse gases.

IN WITNESS WHEREOF, the parties have, through their duly-elected executives, entered into this Memorandum of Understanding as of the date first written above.

Rod R. Blagojevich
Governor of Illinois

Mitchell E. Daniels, Jr.
Governor of Indiana

6.4.4. State Strategic Energy Plan and CCTR Dates

CCTR projects and activities form an integral part of the State Strategic Energy Plan. The coal technology objectives of the state plan, those objectives of the coal mining companies, utilities and other coal stakeholders will guide the CCTR program and staff members, and will provide the points of reference for future CCTR Advisory Panel meetings.

The dates of the Panel meetings in 2006 are provided below:

Tuesday **February 28, 2006** **Indianapolis**	**CCTR Advisory Panel Meeting, # 2006-1**
Thursday **June 1, 2006** **Terre Haute**	**CCTR Advisory Panel Meeting, # 2006-2**
Tuesday **August 29, 2006** **Indianapolis**	**CCTR Advisory Panel Meeting, # 2006-3**
Tuesday **November 28, 2006** **Calumet or PNC**	**CCTR Advisory Panel Meeting, # 2006-4**