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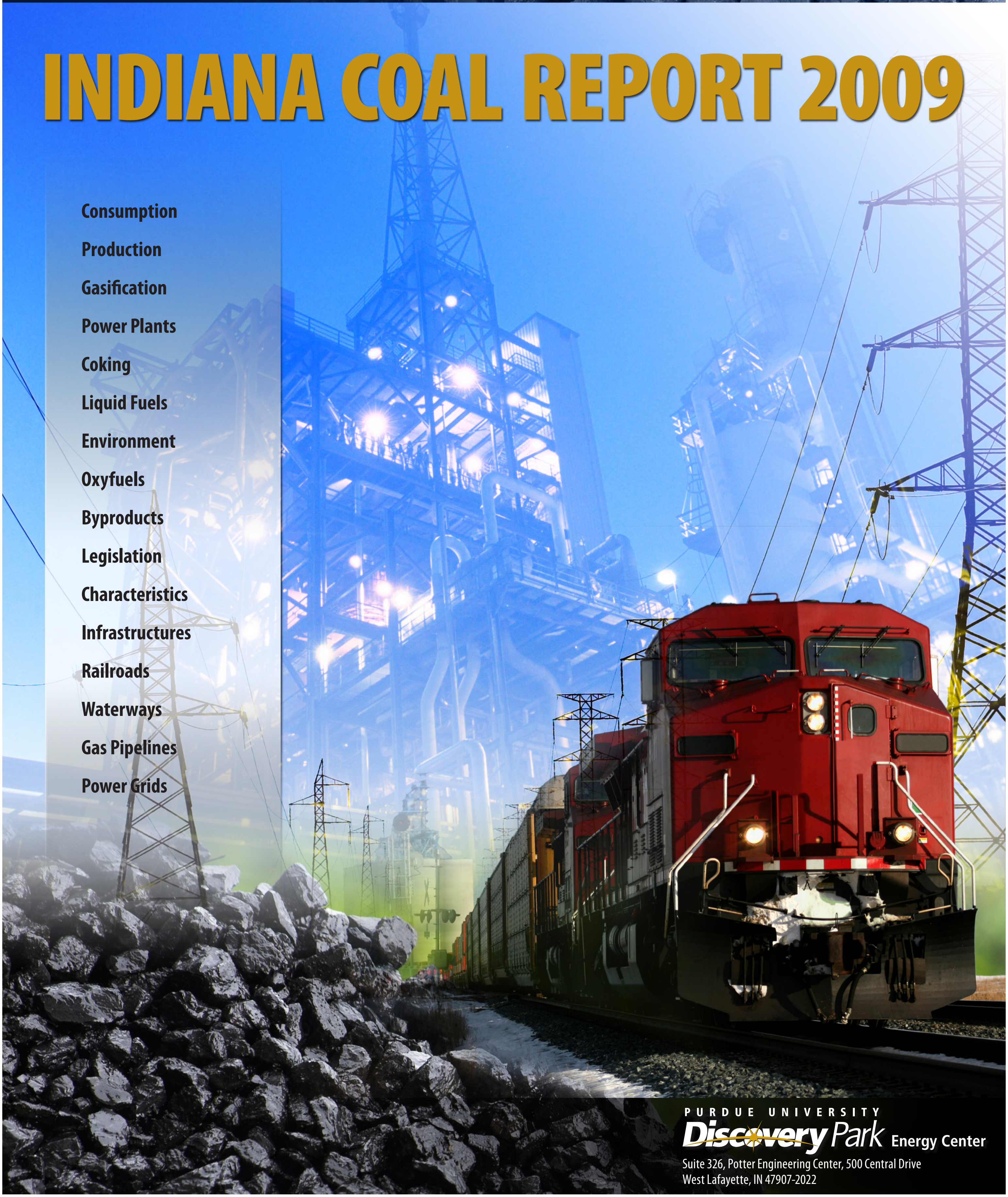
INDIANA COAL REPORT 2009



- Consumption
- Production
- Gasification
- Power Plants
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- Environment
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- Byproducts
- Legislation
- Characteristics
- Infrastructures
- Railroads
- Waterways
- Gas Pipelines
- Power Grids

PURDUE UNIVERSITY
Discovery Park Energy Center
Suite 326, Potter Engineering Center, 500 Central Drive
West Lafayette, IN 47907-2022

INDIANA COAL REPORT 2009

Center for Coal Technology Research, CCTR
Located in the Energy Center at Discovery Park

Potter Building, Suite 326
500 Central Drive
Purdue University
West Lafayette, IN 47907-2022, USA

Phone 765-494-7037
Email cctr@ecn.purdue.edu
http://www.purdue.edu/dp/energy/CCTR/

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INDIANA COAL REPORT 2009

Contributors

Marty W. Irwin, Brian H. Bowen, Barbara J. Gotham
Indiana Center for Coal Technology Research, Purdue University, West Lafayette, IN

Maria Mastalerz, John Rupp, Agnieska Drobniak, Denver Harper, Nelson Shaffer
Indiana Geological Survey, Indiana University, Bloomington, IN

F.T. Sparrow
F.T. Sparrow & Associates, West Lafayette, IN

Robert Kramer
Energy Efficiency and Reliability Center, Purdue University Calumet, Hammond, IN

Thomas F. Brady, Chad M. Pfitzer
Purdue North Central, Westville, IN

Paul V. Preckel, Zuwei Yu
State Utility Forecasting Group, Purdue University, West Lafayette, IN

Arvind Varma, Evgeny Shafirovich, Fabio H. Ribeiro, Rakesh Agrawal, W. Nicholas Delgass
School of Chemical Engineering, Purdue University, West Lafayette, IN

Gerald K. Hill, Stephen Gootee, Ronald Thompson, Dale Keairns
Science Applications International Corporation, SAIC Indiana Operations Center, Bloomfield, IN

Melanie Thom
Baere Aerospace Consultants LLC, West Lafayette, IN

Jay P. Gore, Steven F. Son, John Abraham, Bill Anderson, Robert Lucht, Yuan Zheng
School of Mechanical Engineering, Purdue University, West Lafayette, IN

Wallace E. Tyner
Department of Agricultural Economics, Purdue University, West Lafayette, IN

Matt Atkinson
Solar Sources Inc.
Petersburg, IN

Nat Noland
Indiana Coal Council
Indianapolis, IN

Wayne Parke
CCTR Advisory Panel
Evansville, IN

Kenneth R. Richards
School of Public and Environmental Affairs, Indiana University, Bloomington, IN

Stephanie Hayes Richards
Bloomington Energy and Environmental Intelligence, Bloomington, IN

Linda S Lee, T.P. Seager, D. Mu
School of Civil Engineering, Purdue University, West Lafayette, IN

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Indiana Coal Report 2009

Executive Summary

In 2006 the Daniel's/Skillman administration ordered a review of energy use in the state, and to prepare a plan that will benefit the citizens of Indiana with secure, low cost, environmentally sound energy supplies. The result of the effort was the Indiana Strategic Energy Plan's "Hoosier Homegrown Energy." The vision statement sums it up best:
Grow Indiana jobs and incomes by producing more of the energy we need from our own natural resources while encouraging conservation and energy efficiency.

The "Hoosier Homegrown Energy" plan includes discussion and evaluations of all of Indiana's indigenous energy resources but the key to the growth of the State's energy supply is the continued effort to increase the use of Indiana's primary source of energy, coal. Coal constitutes 52.8% of the primary energy consumed in Indiana (Figure E-1).

Hoosiers pay approximately $25.3 Billion per year for energy. This is the total for residential, commercial transportation and industrial uses. Of that amount, approximately $1.4 Billion is from domestic sources and internal value added. This means that about $23.9 Billion Hoosier dollars ($65.5 Million per day) are leaving the state for the purpose of purchasing energy. Economic growth from "Hoosier Homegrown Energy" asserts its first goal:
Trade current energy imports for future Indiana economic growth recognizing:

- ***Importing energy will export jobs***
- ***New plants will bring new jobs***
- ***Potential growth from reducing energy dependency and increasing reliability***

The challenge is to keep overall energy cost relatively low, while working to retain more of the capital that has been used to bring energy into the state. To do so, we must focus on domestic energy production, and not export capital to import energy into the state. This means increasing the net use of Indiana's coal and all other indigenous energy resources. CCTR is working with the Indiana Lt. Governor's Office of Energy Development to detail how Indiana's economy, quality of life, and well-being will once again be built on home grown energy.

In 2006, according to the EIA, over 72 Million Tons (MTons) of coal were consumed in Indiana (Figure E-2). From the 60.58 MTons delivered to Indiana utilities, only 30.5 MTons were mined in Indiana. Imports from Western mines accounted for 14.5 MTons, other Illinois Basin states 7.8 MTons, and eastern states 9.6 MTons. The recent CCTR forecast showed the future consumption of coal in the state, by 2025, might vary from 52 MTons/year to 80 MTons/year. Regarding Indiana and imported coal use by Indiana businesses a wide range of uses might be considered but so much will depend on adjustments to likely CO_2 legislation.

Coal gasification appears to be the technology best suited for the conversion of Indiana coal into a clean fuel for power production, the feedstock for substitute natural gas, or the creation of liquid fuels. CCTR in its investigations of this and other technologies has recognized the need for upgrades of the state's and the region's infrastructure. Be it rail, water or the grid, there is a need to find ways to improve and expand the movement of energy from producer to end user.

Development of commercially viable coal technologies is now high on the national agenda. Indiana, and its Illinois Coal Basin partners (Illinois, Kentucky), is supportive and leading this long-term policy. The following report is a summary of activities of CCTR, and the many individuals and companies that have ideas or technologies that can achieve the goals of Indiana and the nation.

Figure E-1. Indiana Primary Energy Consumption Source & Sector 2006

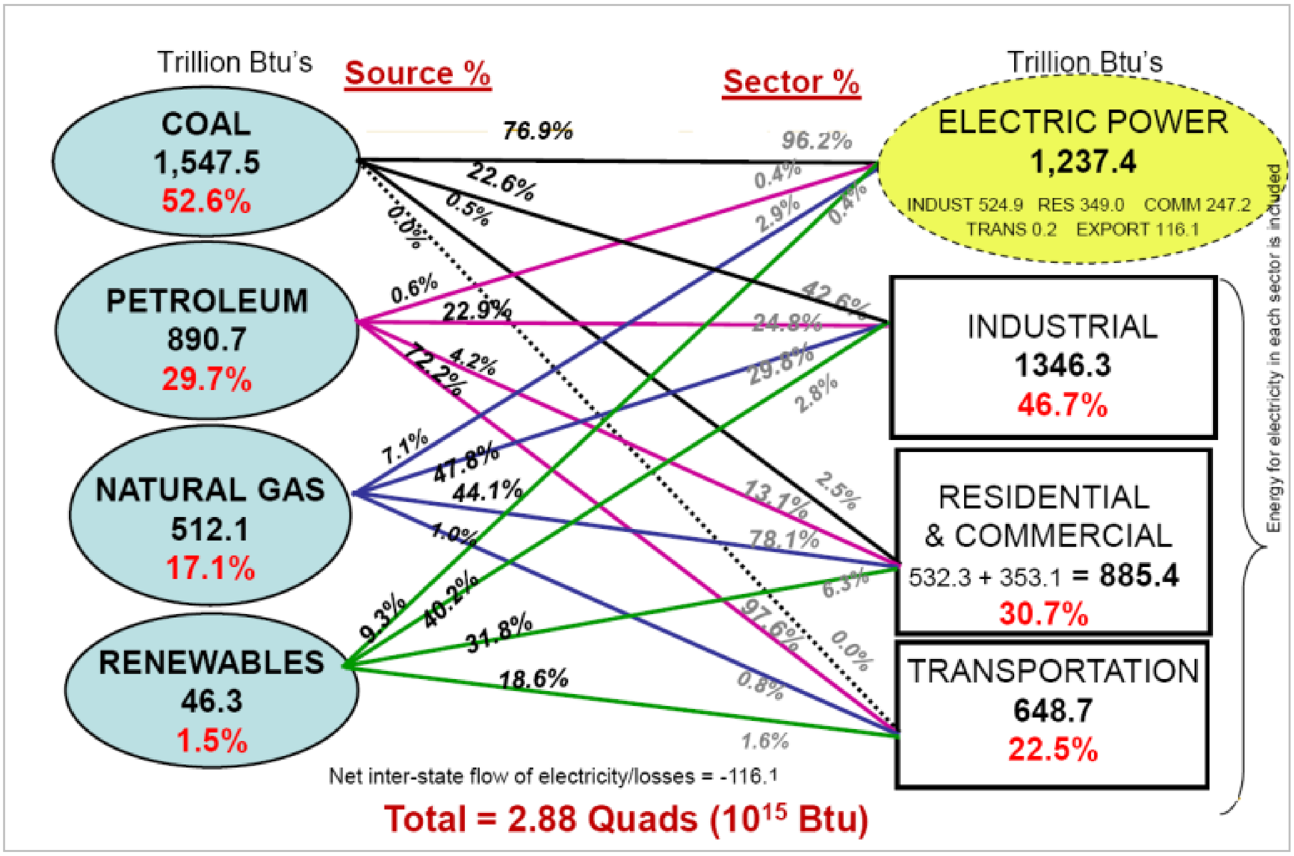
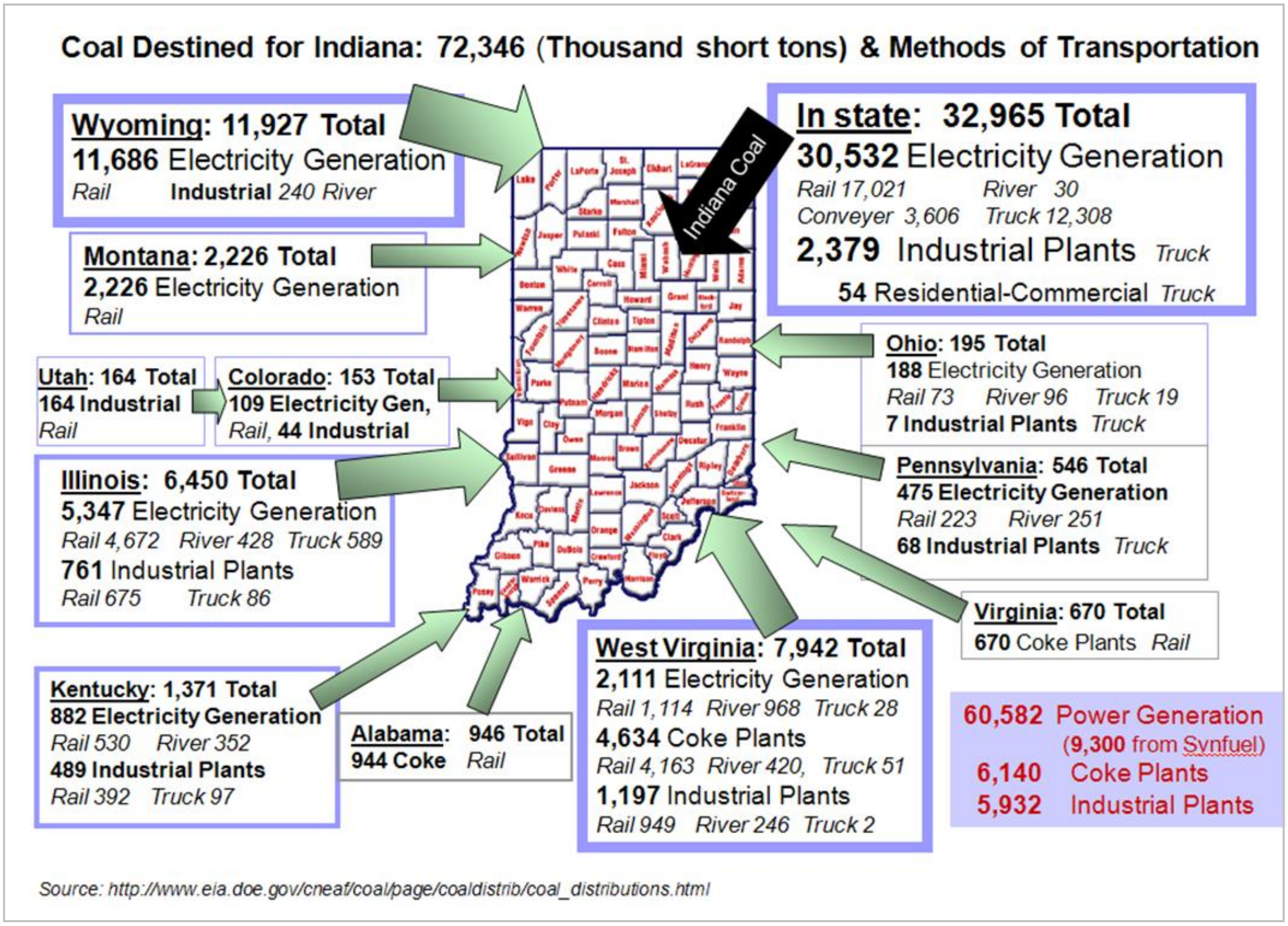


Figure E-2. Coal by Destination: Indiana 2006

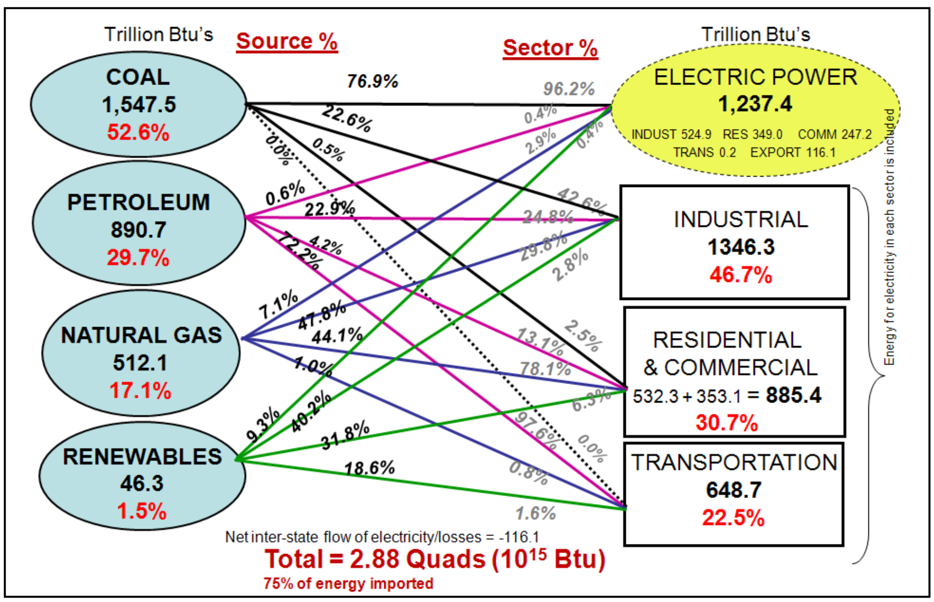


CHAPTER 1

CCTR PERSPECTIVES

The economic and environmental interests of the people of Indiana are intimately linked with coal. 52.8% of the primary energy consumed in Indiana comes from coal (Figure 1.1) which is more than petroleum, natural gas, and renewables combined. Indiana is a coal state. The state is a major coal producer with large reserves and a major coal user. Indiana's role as a major heavy manufacturing state was in part built on its geographic location, the proximity of rail and highway, water (for both use and transportation), and the availability of low-cost energy. The location of the coalfields and the relative ease of surface access to the high Btu coal has been a factor in Indiana having very low electricity costs. 95.0% of electricity produced in this state comes from coal, half of that from Indiana coal.

Figure 1.1. Indiana Primary Energy Consumption Source & Sector, 2006



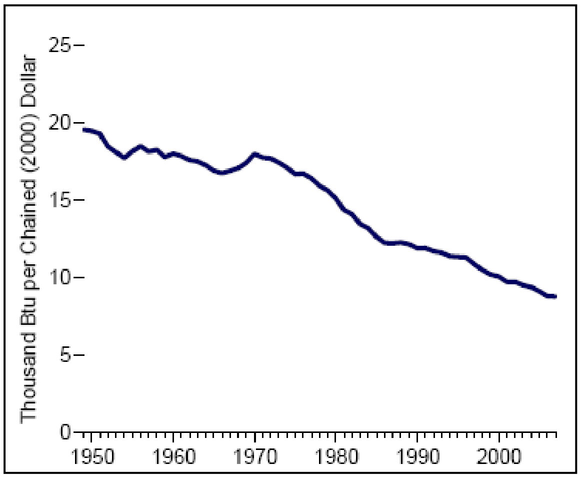
Source: [1.1]

Indiana, along with the rest of the nation, has become more energy efficient (Btus per $GDP). In 2007 the U.S. as a whole used half the energy to produce $1 of goods and services than it did in 1948. But despite this, we still have increased our energy consumption (Figure 1.2). The citizens of Indiana pay approximately $25.3 Billion per year for energy. That is the total for residential, commercial transportation and industrial uses. Of that amount, approximately $1.4 Billion is from domestic sources and internal value added. This means that about $23.9 Billion Hoosier dollars ($65.5 Million per day!) are leaving the state for the purpose of purchasing energy.

Coal and the natural gas from the fabled Trenton Fields were part of a low cost energy supply system and was one reason Indiana was able to become a manufacturing leader in the 20th century. Coal's availability and relative ease of extraction makes it a low cost supply for those companies that need large-scale bulk fuels or large volumes of electric power. Coal prices have stayed relatively stable for the past two decades, while natural gas and residual fuel oil prices have risen significantly (Figure 1.3). While efficiency, renewables, and biomass are key parts of

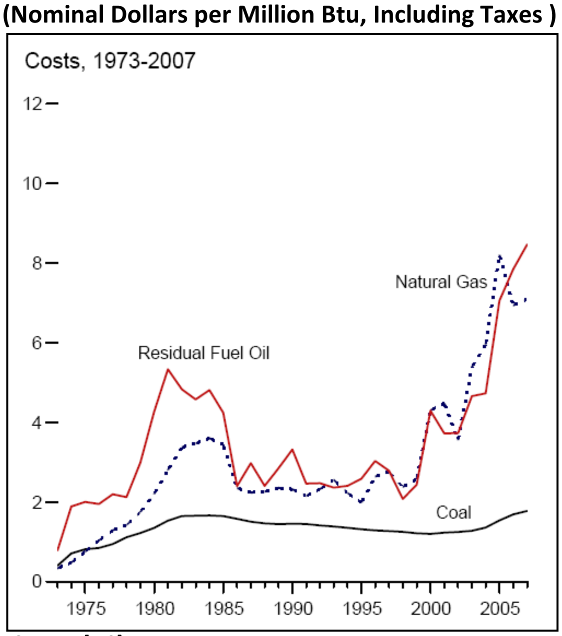
Indiana's energy future, the fact remains any significant impact on the state's energy use must involve the coal and the electric power industry.

Figure 1.2. U.S. Energy Efficiency (Great Improvements over past 50 years, Thousand Btu Consumption per Real Dollar of GDP), 1949-2007



Source: [1.2]

Figure 1.3. Cost of Fossil-Fuel Receipts at Electric Generating Plants (Nominal Dollars per Million Btu, Including Taxes)



Source: [1.3]

1.1 The Issue

For too long, our approach to energy has been conflicted, contradictory, and shortsighted. We demand more energy and complain about high prices, but we restrict energy exploration and production. We embrace the promise of energy efficiency, but we are slow to make adjustments in our energy-intensive lifestyles. We take the production of electricity almost for granted, yet we oppose the construction of new power plants and transmission lines. We are betting on the development of new and transformational energy technologies, but we under invest in the energy research and development needed to bring it about. (Source: Open Letter to the President of the United States and the 111th Congress, From U.S. Chamber of Commerce Institute for the 21st Century Energy.)

1.2 The Possible Solution

Technology is the cornerstone of a new energy policy. The United States is currently spending 50% less on energy research and development than during the 1970s' oil embargo. We spend less than four Billion dollars a year on clean energy R&D, which is less than we currently spend in three days on imported oil. New industry and government relationships are needed, and liability issues must be addressed. The demonstration and application of promising clean technologies must be carried out on an ambitious and cost-effective scale; small, tentative steps are not sufficient.

Commit to the Use of Clean Coal

Currently, coal provides approximately 50% of the U.S.'s electricity supply, making it the largest source of domestic, reliable, and affordable energy. Coal will necessarily be a critical and expanding source for our future electricity and fuels needs. To use coal cleanly and to address CO_2 emissions, we need to greatly increase our research, development, and demonstration of clean coal and carbon capture and sequestration technologies. We also must establish a fair and predictable regulatory environment.

Modernize and Protect U.S. Energy Infrastructure

Our energy infrastructure is increasingly inadequate for our growing demand and economy. Blackouts, brownouts, service interruptions, and rationing could become commonplace without new and upgraded capacity. Critical energy infrastructure must also be adequately protected from both terrorist threats and natural disasters.

Address Critical Shortages of Qualified Energy Professionals

Our energy industry employs well over one million people today, yet nearly half of this workforce is expected to retire in the next 10 years. Presently, American universities are graduating fewer and fewer students in science, engineering, and mathematics. We need additional education and training programs, incentives, and visa policies that enable the American energy sector to attract and retain a new generation of human capital in an increasingly technological and globally competitive industry. We must entice young people to enter technical fields to build, maintain, and manage our nation's energy systems.

Reduce Overly Burdensome Regulations and Opportunities for Frivolous Litigation

Energy infrastructure systems, including both generation and transmission, require massive amounts of new investment in the face of rising difficulty in locating, permitting, and building new infrastructure. Industry estimates that it will take 10 years to license and construct a new nuclear plant in the United States. Construction of numerous electricity transmission lines, natural gas terminals, and wind projects has been abandoned as a result of frustration and the inability to get siting approval. This may require us to address new federal eminent domain issues. Current regulatory uncertainty and liability issues discourage the development of clean energy alternatives and technologies. Failure to reverse this course will imperil our global economic competitiveness.

(Source: Open Letter to the President of the United States and the 111th Congress, From U.S. Chamber of Commerce Institute for the 21st Century Energy.)

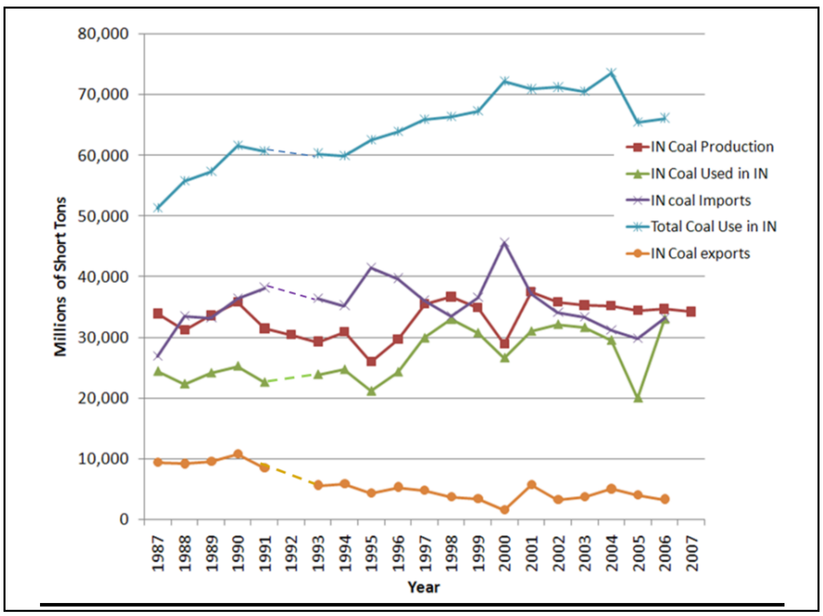
Indiana's challenge is to keep overall energy costs relatively low, while working to retain more of the capital currently used to bring energy into the state. To do so, we must focus on domestic energy production, not exporting the capital needed to purchase energy. This can be done by increasing the net use of Indiana coal and all its other indigenous energy resources (Figure 1.4).

1.3 Importing Energy Means Exporting Capital

Advances in technologies for coal combustion, coal transformation, transportation, and infrastructure issues will allow for increased use of Indiana's coal resources and a reduction in energy dollars leaving the state.

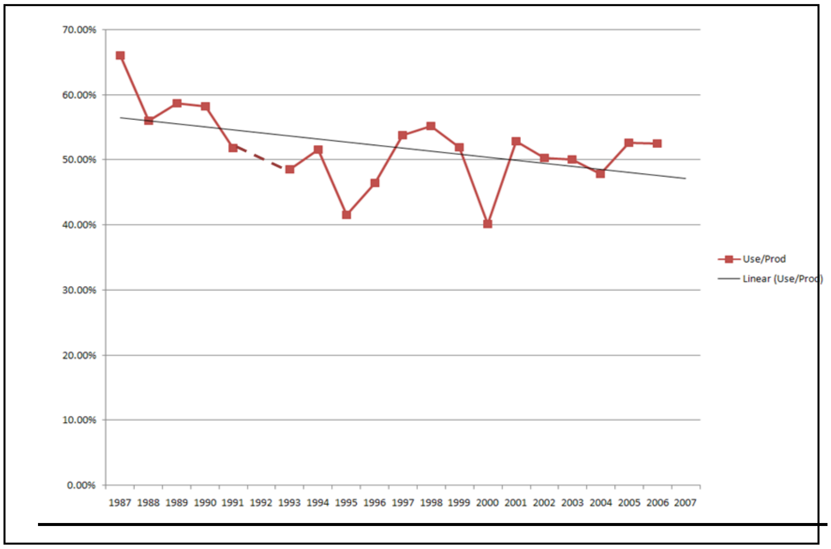
The production of Indiana coal has increased over the past 15 years. But, the production of Indiana coal as a percentage of consumption of coal has declined over the same time period. In 1990 Indiana produced 60% of the coal consumed in the state; by 2007, that rate was around 55% (Figure 1.5).

Figure 1.4. Indiana Coal Statistics



Source: [1.4]

Figure 1.5. Indiana – Total Indiana Coal Used/Total Coal Used



Source: [1.5]

1.4 Goal

The goal of the Center for Coal Technology Research (CCTR) is to increase the use of Indiana-produced coal in an environmentally and economically sound manner.

Increasing the use of Indiana-produced coal in and of itself is of little value unless doing so provides some economic and/or environmental value to the state. CCTR will focus on how increasing the use of Indiana coal will benefit the state both economically while also helping to reduce environmental concerns with its use.

As stated above, nearly $23.9 Billion a year leaves Indiana to purchase energy. The importation of almost all of the state's petroleum and natural gas, along with the importation of up to 50% of the coal used in the state, means that Indiana imports almost 75% of the energy used in the state. As is also stated above, coal provides the greatest amount of primary energy at a relatively low price compared to oil, natural gas, and renewables. In rebuilding Indiana's economy, it is desirable to use more of its indigenous resources to meet its own existing and growing energy needs. This results in increased retained capital and a reduced cost of energy. One way to do this is by maximizing the use of the least cost energy to replace the higher cost imported energy sources and thus reduce the outflow of energy capital.

Rebuilding Indiana's economy is greatly helped by increasing the retention of capital currently leaving the state. The revitalization would also be aided by a stable source of economical, and environmentally sound, energy supplies. Coal is the largest volume supply of fuel that can be used to grow the Indiana economy. The question is: how do we take this abundant fuel and use it in new ways to meet the needs of Hoosier citizens, business and industry?

There exists no shortage of energy resources in Indiana, the U.S., or the world; but there is a scarcity of the cheap energy that was used to build the world's economy. The state and the nation are moving to a new energy paradigm where cheap fuel is no longer plentiful and environmental rules make the status quo use of certain fuels unwise.

Coal in Indiana and the United States has the powerful attraction of being relatively low cost, having relatively stable prices and high in domestic availability. However, the old coal combustion technologies have been a major factor in air pollution. The overriding goal of the new economy should be to move to a more environmentally favorable energy production. The increased use of Indiana coal for energy production is not in conflict with this goal. In fact, current activity will show that the use of Indiana coal will help move the U.S. to a cleaner economy.

The hydrogen economy is not a new idea; it has just been more focused of late. In fact the U.S. economy has been moving to a hydrogen-based economy since its inception. If we look at energy use over time, this becomes clearer (Table 1.1).

Table 1.1. Progression Towards a Hydrogen Economy

Wood Peat	Bituminous	Petroleum	Nat. Gas	Syngas	Nuclear/Hydrogen
1700s	1860s	1900s	1990s	Today	2050

As we progressed through time, the primary energy source used by citizens, industry, and transportation has moved from wood, which has eight carbon molecules for every hydrogen molecule, to Syngas (CH_4) which has one carbon molecule for every four hydrogen molecules. This is a 32-fold improvement of the hydrogen to carbon ratio. This is a dramatic improvement in the air emission quality from energy in that carbon is generally correlated to air pollution while hydrogen is considerably cleaner.

Encouraging the use of Indiana coal may appear to be a move backwards. But a closer examination shows that **Indiana coal is the solution, not the problem**. Indiana coal is the means by which low-cost environmentally acceptable energy will be produced.

1.5 Center for Coal Technology Research

The Center for Coal Technology Research (CCTR) is directed with the task of aiding Indiana coal in getting to the position of addressing those issues and those goals. The CCTR is teamed with the Indiana Lt. Governor's Office of Energy Development, Purdue University, Indiana University, and the Indiana Geological Survey. The CCTR is both a state agency and a research arm of the state.

Increasing the use of Indiana coal in an environmentally sound manner will be based on Clean Coal Technologies (CCT). The term CCT itself raises considerable controversy because traditional pulverized coal (PC) plants are not usually considered clean coal technology, yet emissions can be substantially reduced by adding various cleanup processes.

Emphasis will be on how CCT technologies could be integrated into new and repowered electric power plants in order to minimize cost and investment risk from technology and emerging environmental standards. Byproducts produced along with electricity are also to be considered, including fertilizer, CTL (coal to liquids) transportation fuels (e.g., diesel, ethanol), and coal combustion residues. Properties of the available CCT technologies for both new and repowered electricity plants and industry energy users need to be considered. Among those properties are; maturity of the technologies, preferred fuels, estimated costs, suitability for scaling and retrofit, pollution removal, reliability/availability, chemical and coal to liquid (CTL) fuel production, and external R&D funding.

Another area to address is the Indiana political and environmental concern for CCT. Concerns include the available categories of state coal resources, the utility and environmental regulatory climate, future CO_2 regulation, the available human infrastructure for CCT research and implementation, projected electricity demand growth, the existing power gas and transportation grids, and the aging boiler population. CCT is well suited for the repowering of older coal facilities, capitalizing on existing infrastructure and siting already in place.

Three popular CCTs are considered:

- Circulating Atmospheric Fluidized-Bed Combustion (AFBC)
- Super Critical Pulverized Coal (or Ultra SCPC)
- Integrated Gasification Combined Cycle (IGCC)

Regardless of the environmental impact, the cost of the systems remains very important. Under a regulated system, utilities may not build beyond what state rules say is needed. The question then becomes, which is better for future development, pulverized systems with flue gas controls or the IGCC system?

1.6 Barriers to the Increased Use of Indiana Coal

CO_2 Regulatory Uncertainty

The science of CO_2 and global climate change needs greater general understanding. The views of renowned scientists such as Dr. Roy Spencer are possibly not heard enough [1.7].

Global Warming 101: Global Warming Theory in a Nutshell, Dr. Roy Spencer

We live in an invisible atmospheric sea of water vapor, Earth's primary greenhouse gas. Our atmosphere could hold much more water vapor than it does, which would then lead to a much warmer Earth -- but it doesn't. So, why is the greenhouse effect limited to its current value? We don't know; scientists simply "assume" that it magically stays that way.

Current computerized climate models that predict large amounts of global warming only do so after making very crude assumptions about why the Earth's natural greenhouse effect is limited to its present average value.

Even though all climate models DO contain the "average effects" of precipitation systems -- this is NOT the same as knowing how precipitation systems will act to stabilize (or destabilize) the climate system in the presence of the warming influence of manmade greenhouse gas emissions….

Al Gore likes to say that mankind puts 70 Million tons of carbon dioxide into the atmosphere every day. What he probably doesn't know is that mother nature puts 24,000 times that amount of our main greenhouse gas -- water vapor -- into the atmosphere every day, and removes about the same amount every day. While this does not 'prove' that global warming is not manmade, it shows that weather systems have by far the greatest control over the Earth's greenhouse effect, which is dominated by water vapor and clouds.

Global warming theory starts with the assumption that the Earth's relatively constant average temperature is due to a balance between (1) the amount of absorbed sunlight, and (2) the amount of emitted infrared ("IR") radiation which is continuously being lost to outer space. In other words, energy in equals energy out….

*Now, you might be surprised to learn that the warming from the extra CO_2 is, by itself, relatively weak. It has been calculated theoretically that, **if there are no other changes in the climate system**, a doubling of the atmospheric CO_2 concentration would cause less than 1 deg C of warming (about 1 deg. F). This is NOT a controversial statement...it is well understood by climate scientists. (We are currently about 40% of the way toward a doubling of atmospheric CO_2.)*

BUT...everything else in the climate system probably WON'T stay the same! For instance, clouds, water vapor, and precipitation systems can all be expected to respond to the warming tendency in some way, which could either amplify or reduce the manmade warming. These other changes are called "feedbacks", and they determine whether manmade global warming will be catastrophic, or barely noticeable. Feedbacks are the source of almost ALL SCIENTIFIC DISAGREEMENTS over global warming.

Public opinion seems to be that CO_2 is a source of global warming, it is apparent that science is not in agreement. *"As CO_2 increases, the clouds that have a blanket effect will decrease in coverage, allowing more heat to escape to space and reducing the warming potential" [1.8].*

The story of CO_2 is not complete, yet many have proposed a solution. The logic being that just because we do not know the cause and effect of a situation does not mean that we cannot impose expensive solutions to the yet determined problems. The current public opinion is that CO_2 mitigation would solve the problem of global warming, even though we know that the opposite may be true.

CO_2 is only 5% of the greenhouse gases emitted by earth. Of that 5% humans produce about one-third. Coal fired power plants emit about one-half of that one-third. Therefore, the complete elimination of CO_2 from coal-fired power plants would result in only 1.6% of all of the CO_2 produced on the planet (or 0.8% of total greenhouse gas emissions). This level of reduction would mean that in the year 2050, instead of the atmospheric CO_2 level being 500ppm (parts per Million), it would be 475. This of course assumes that India and China will follow the U.S.'s lead and reduce their emissions also, something that China and India said they have no intention of doing. Either way, this is an insignificant reduction when considering the $1.5 trillion this effort will take (Bingham Spector S.1766).

CO_2 Mitigation through Carbon Capture and Storage

A method for mitigating carbon emissions is through the practice of carbon capture and storage. Carbon capture and storage (CCS) provides a means for deep reductions in CO_2 atmospheric emissions as the world also develops and deploys different energy technologies (such as renewable energy) that are currently more expensive than fossil fuel technologies. Rather than vent into the atmosphere, CO_2 may be captured from the post combustion gases from a traditional power plant, or can be captured through the syngas in an integrated gasification combined cycle plant (IGCC). Unfortunately, CO_2 capture from a PC facility may require up to 30% of the power that the facility will produce, and cost as much as 85% of the cost of the original plant [1.1].

The volume of gas alone is immense, and the logistics of moving this amount of CO_2 to a sequestration site must be considered. There are opportunities for geologic storage in deep saline formations, unmineable coal seams, depleted oil and natural gas fields, or condensed to a solid mineral carbonate. In some cases, the costs required to capture and store CO_2 can be partially offset from new economic activity. For example, in depleted oil and natural gas fields, the injection of carbon dioxide reduces the viscosity of the remaining fuel, allowing more to be extracted. This practice is already in use today. In addition, CO_2 can be used as a flush gas to extract coal-bed methane, while at the same time trapping the injected CO_2.

Geologic sequestration has been used in the fossil fuels industry for years as a means of enhanced oil recovery (EOR). Carbon dioxide gas is pumped into an oil or natural gas reservoir to flush out oil or gas that cannot be removed by conventional recovery. The CO_2 remains trapped in the reservoir once the oil or gas is removed and the bore holes are sealed.

Carbon dioxide emissions will increase as the use of fossil fuels increase and the world population continues to grow and the continued growth in the industrialized and emerging nations. Carbon sequestration will be one tool available to control carbon dioxide levels in the atmosphere.

CO_2 Pipeline

Due to the low cost (relative to the cost of new power plants) of pipeline transportation, the locations of power plants become less important compared with the scale of the plants. It is conceivable that the focus can be on the collection and movement of CO_2 from various sources and then pipe them to a single site for sequestering or for transport to where the CO_2 can be used for EOR. Currently, CCTR is working with the states of Ohio, Illinois, Kentucky, and Tennessee to develop a central collection site for piping of CO_2 to Jackson, Mississippi. This plan will reduce the CO_2 emissions by the three states' gasification projects by 20 Million tons per year and greatly increase the productivity of the near dormant eastern Texas oil fields. The public private partnership that this involves has already set $800 Million for the project.

The storage of CO_2 emissions from the ten largest IGCC or other gasification facilities proposed in the states in the Illinois Coal Basin may provide the optimum sequestration process. But if the sites can be linked, then a certain amount of economy of scale may take place. One large sequestration facility may be advantageous over 20 on-site units. Key to this development is the use of existing right-of-ways to place the needed web of smaller CO_2 pipelines to connect to the one larger pipe that will move the CO_2 south.

The CO_2 capture cost has the most impact on the overall cost of the of the sequestration process. The impact of the CO_2 capture cost is more pronounced with increasing levels of CO_2 emissions control. At the 50% control level, there is a direct relationship between projected sequestration cost and percent reduction in capture cost. This observation indicates that future efforts to reduce the sequestration cost should be focused on developing more cost-effective capture technologies [1.6].

CO_2 Sequestration in Deep Saline Formations

In 2000 Indiana produced 235 Million metric tons of CO_2 from all sources. More than anything else this shows the immense volume of material bring discussed. When CO_2 regulation is implemented, geological sequestration will have the greatest capacity control. The Mt. Simon Aquifer is a deep saline formation that may have between 44 and 218 Billion metric tons of capacity, over 200 years of capacity.

Mt. Simon Sandstone is commonly used for natural gas storage in Indiana and the Illinois Basin. Mt. Simon has fair to good permeability and porosity, and the overlying strata contain impermeable limestone, dolomite, and shale intervals. Mt. Simon should be an appropriate reservoir in which to test injection of carbon dioxide. The depth of the Mt. Simon ranges from less than 2,000 feet to deeper than 14,000 feet below the surface. Areas of fresh water resources are to be avoided, as are areas where natural gas storage occurs; excluding these the basin still leaves approximately the southern half of the basin where the reservoir is brine-filled and no oil or natural gas resources have ever been discovered. Mt. Simon is located in the subsurface throughout Indiana, Iowa, Michigan, and Ohio.

1.7 Options for Growth

"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 a method of increasing the influx of "new money" into the state's economy.

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

Building an Indiana coal powered electric generation facility for the purpose of exporting power has a great advantage to the domestic electric 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.

Increasing Exports

Excerpts from "Expanding the Utilization of Indiana Coals," presented by Brian H. Bowen, Forrest D. Holland, and F.T. Sparrow, Purdue University, at the CCTR Meeting, August 18, 2004, Indianapolis, IN [1.9].

Increasing exports of Indiana coals to surrounding states is a possibility. Historically, Indiana has exported much more coal than the 3 Million tons exported in 2002. In 1990, exports were over 10 Million tons, with the total gradually falling to present levels over the intervening years. Currently, the exports are to Kentucky (1.5 Million tons), Wisconsin (0.7 Million tons) and Illinois (0.5 Million tons). Noticeably absent are Michigan and Ohio. All these states burn significant amounts of imported coals. Michigan imports 32 Million tons (22 Million from western coals); Wisconsin, 22 Million tons (20 Million from Wyoming); Ohio, 18 Million tons (17 Million from eastern coals); Kentucky, (13 Million, mostly eastern coals) and Illinois, 8 Million (7 Million from Wyoming). Thus, the total present export market for coal in neighboring states is over 100 Million tons. Indiana’s current market share of this total is less than 3%.

CCTR sponsored research indicate that with a relative minor investment the railroad infrastructure in Indiana can be altered to allow for easier access of the coal mines with the markets in Northwest Indiana and the export market through Burns Harbor. 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.

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 Million tons of Indiana coals were consumed in Indiana, while over 38 Million tons were imported – an excess of imports over domestic consumption of almost 16 Million tons. In 1995 the excess of imports over domestic consumption grew to over 20 Million tons. 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 (roughly 25 Million tons, half from Wyoming) and coal used to produce coke for Indiana’s blast furnaces (6 to 8 Million tons).

The major issue in the substitution of Indiana coals for imported coals for power generation is identical to the major issue of increasing Indiana coal exports for power generation – the trade– off between lower transportation costs of Indiana coals and the increased costs of burning Indiana coals because of environmental requirements. Again, the task of the CCTR will be to identify what a focused research and development program can do to allow Indiana coals to economically substitute for the coals now imported into Indiana.

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 was estimated that Indiana coals could satisfy 45% of the current coking blends.

The Brazil formation coals in Indiana are the most suitable for coking purposes, but their reserves are limited (about 100 Million tons) and can only be mined economically using surface techniques. The picture is brighter for coal injection 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 from 4.5 to 5.5 Million tons of Indiana coals (68% to 75%)

could technically be substituted for non-Indiana coals. The problem, of course, is again economics. The objective will be to design a focused research and development program whose goal would be to improve the economic recovery of Brazil and Danville formation coals, or to identify other deposits with similar characteristics.

The technological point to this is that the use of Indiana coal by almost any means requires the conversion of that product to another form. IGCC requires that coal be first gasified then used to produce power. Coals to liquids are best accomplished if you first gasify the coal then liquefy the gas. Natural gas use can be supplemented by the direct use of the gas from coal. In each of the alternate fuels described above are best developed if the coal is first gasified then the hydrogen, which is produced in the gasification process, is added to produce methane, propane, and all the way to diesel fuel and even aviation fuel such as JP8.

1.8 Strategic Planning

Indiana's energy and economic come back is detailed in the Indiana Energy Strategic Plan.

In the late 19th and early half of the 20th centuries, Indiana became an industrial powerhouse with huge underground stores of natural gas and fields of coal and oil. Our economy and our Hoosier social fabric, were built on a foundation of natural, homegrown energy resources.

In the 21st century, Indiana's comeback will be cleaner, stronger and more lasting. It will give our children and their children, high tech, high paying jobs by once again being more energy resourceful, and by making Indiana a significant supplier of low cost, dependable, clean energy where it makes economic and environmental sense to do so. The new jobs of the 21st century won't have billowing smokestacks. They'll be located in our neighborhoods, in office buildings and on state-of-the-art farms. Our economy will flourish in part because we won't be as dependent on natural gas from the Gulf of Mexico or fuel oil from the Middle East. We will be able to grow our own.

CCTR is working with the Indiana Lt. Governor's Office of Energy Development 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, home-made synthetic gas from coal and convert it into motor fuels and unleash our ingenuity on the goal of increased energy efficiency.

Some of the new, high paying jobs in our community will be in mining, and in energy operations and management. Purdue University, Indiana University, Ivy Tech, Vincennes University and others will train highly skilled personnel to run sophisticated, computer driven power plans and private sector energy systems while others will manage coal mines and sequestration programs and energy distribution networks. Indiana will retake its place as the best place in the Midwest to live and work in part because our location and our leadership role in coordinating energy production, distribution and research with our neighboring states.

Purdue's Energy Center strives to become a national center for research in clean coal technology, hydrogen and renewable energies. Indiana expects to build new coal gasification and coal processing facilities, creating clean power and energy from local coal and shale and biomass resources. New technologies, opportunities and challenges are emerging. CCTR will aid in the deployment of new coal technologies by focusing on the overall goal of making Indiana coal the answer, not the problem.

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http://www.purdue.edu/dp/energy/CCTR/

CHAPTER 2

INTERNATIONAL & NATIONAL COAL DEMAND

The world's total coal consumption in 2005 was nearly 6.5 Billion Short Tons, of which the U.S. consumed 1.125 Billion (17%). This 2005 global total was a 27% increase over the 2000 total. Both globally and nationally there are steady increases in the consumption of coal. Some independent forecasts are indicating large increases in coal production across the Illinois Coal Basin for the coming decade [2.1].

2.1 Coal Demand in the 21st Century

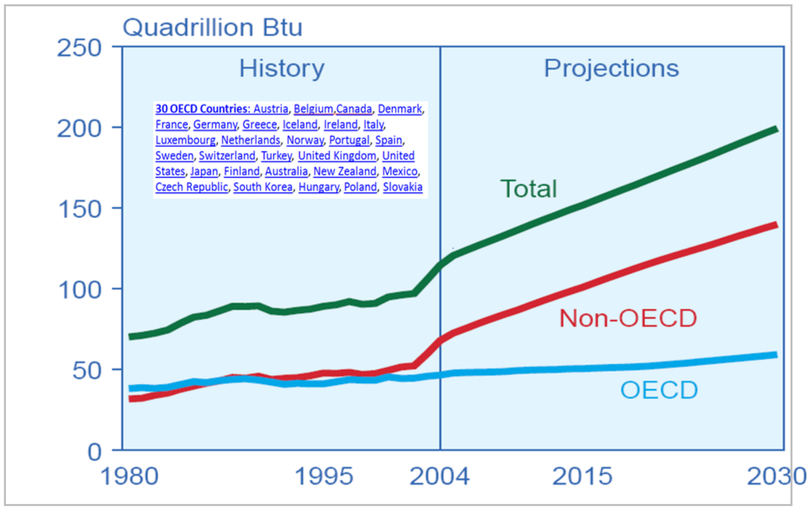
The annual need for more electricity and the implementation of cleaner coal technologies is expected to stimulate the increase in coal production. Coal provides the essential role of providing base load electricity for the U.S. Some of the forecasted increased electricity demand will gradually come from renewable and nuclear power projects but these are unlikely to alter the significant percentage of base load power that is fueled by the coal which is the cheapest and most abundant energy source in the U.S.

The 2008 record high oil prices was a further factor that prompted debate across the U.S., regarding independence of energy imports. With rising energy costs there is as an increasing desire to understand more about the role and impact of using coal for gasification and transportation liquids. A counter balance to this comes with the uncertainty regarding CO_2 legislation and what form it might take and the legislated rate at which CO_2 capture could be implemented. Increased environmental controls, new vehicle designs, clean coal technologies, and renewable energy technologies will all have a special part to contribute to future energy supplies. As new clean coal technologies, new generation facilities, and new regulatory environments take time for implementation it is very reasonable and realistic in assuming there will be a continued gradual increase in demand for coal in the medium term future (next 25 to 50 years).

Over the next two decades the DOE-EIA forecasts a very significant global increase in coal consumption (almost 50%, Figure 2.1.1). Most of the increased global demand is expected to come from non-OECD countries (mainly China and India). The U.S.'s total coal consumption over the past decade of around 1,100 Million tons/year has seen a small steady increase in consumption. In 2000 China consumed just over 1,200 Million Tons (MTons/yr), but by 2005 China's consumption was over 2,300 MTons (Figure 2.1.2). In this relatively short time span China just about doubled its coal consumption. Resulting from the 2008 global financial crisis China's growth rate in demand for coal is expected to slow down but its growth rate will still be considerably higher than in OECD nations.

European countries consume almost as much coal as the U.S. Their production rates satisfy only about 75% of their demand and so their coal imports are much higher than in the U.S. (Figure 2.1.3). The region that is importing the greatest amounts of coal and which is higher than for America or Europe is Asia. The levels of coal imports for Asia (notably China, India) are forecast to be three to four times higher than for America. India's shortages in coal production are likely to prompt greater amounts of coal imports and by 2030 it is expected that India's demand for coal will be doubled the 2005 levels. There are increases in steam coal exports from the U.S. with nearly a 50% increase over the past several years. Increasing imports of coking coal are also taking place. In the increased global demand for coal, there is potential for increasing the exports of Indiana coal. The state has the reserves and strengthening of infrastructure for shipping coal is an important issue being considered by the CCTR (Chapter 6). Indiana is also a major coking coal importer and this topic is also being addressed by the CCTR (Chapter 6).

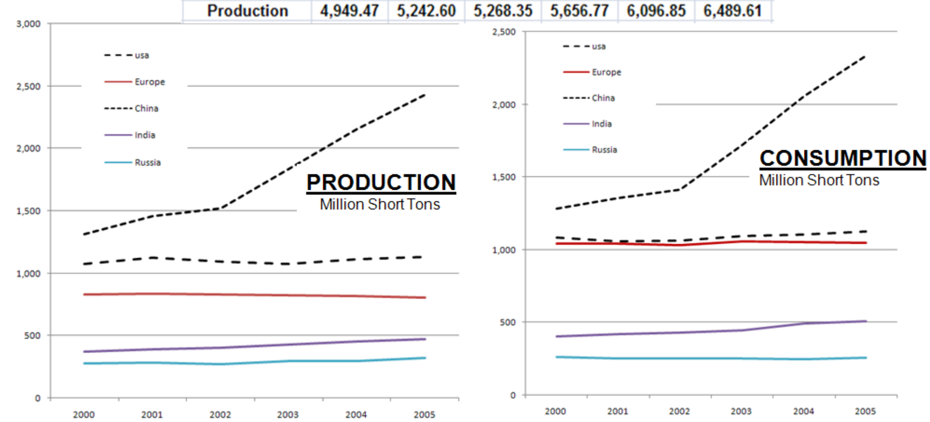
Figure 2.1.1. World Coal Consumption by Region, 1980-2030



Source: [2.19]

Figure 2.1.2. World Total Coal Production & Consumption (Million short tons)

World TOTAL	2000	2001	2002	2003	2004	2005
Consumption	5,097.86	5,190.84	5,272.47	5,705.97	6,149.82	6,482.97
Production	4,949.47	5,242.60	5,268.35	5,656.77	6,096.85	6,489.61



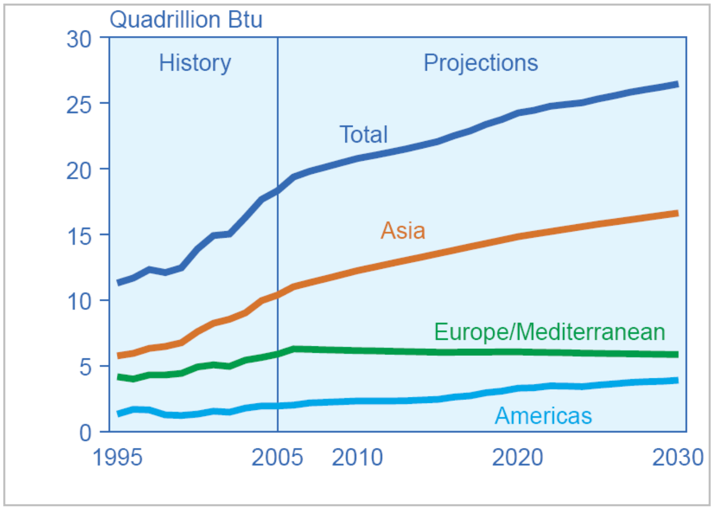
NET U.S. EXPORTS
Million Short Tons
(+ is export)

	N.America	S.America	Europe	Asia	Australia & NZ
2007 US Imports	2.02	30.29	0.21	3.19	0.12
2007 US Exports	19.1	7.2	27.12	1.2	0
Net Trade	17.08	-23.09	26.91	-1.99	-0.12

http://www.eia.doe.gov/emeu/international/coalconsumption.html

Source: [2.15]

Figure 2.1.3. Coal Imports by Major Importing Region, 1995-2030

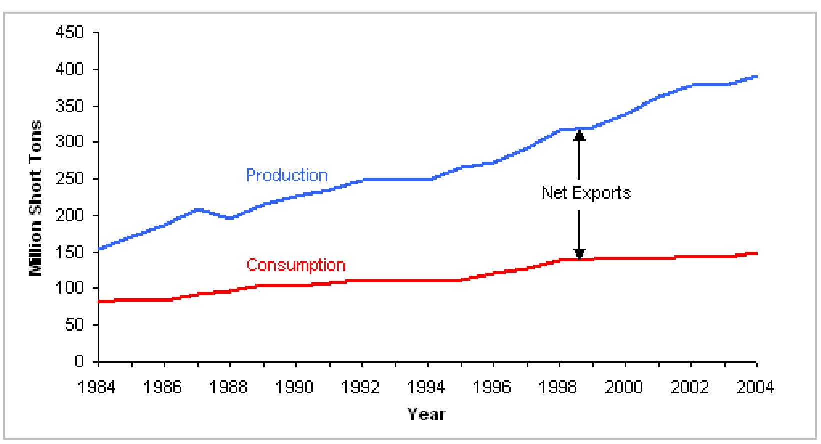


Source [2.1]

In 2007 about 19 MTons of coal was exported from the U.S. to Canada (Figure 2.1.3) and nearly 27 MTons exported to Europe (the main importer of U.S. coal). The only significant coal imports to the U.S. in 2007 came from South America with over 30 MTons which represented about 2% of total national U.S. coal consumption. The highest steam coal exporters in 2005 were Australia, Indonesia, China, and South Africa. For coking coal, Australia, Canada, and the U.S. ranked as the main exporters. During 2000 to 2005 the most significant increase in coal consumption was in China while in other major coal consuming countries there were much smaller increases. No country is recorded as reducing its demand for coal (Figure 2.1.3).

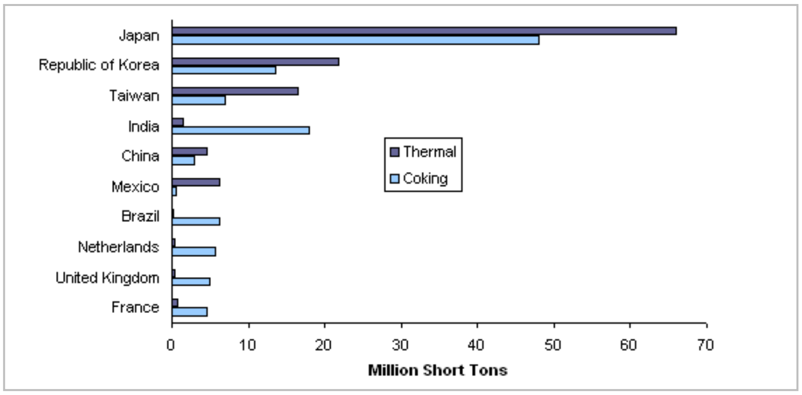
Australia is the world's leading coal exporter and sends out over 200 MTons each year. Its main customer is Japan which takes about 60% of its total exports (coking coal and steam coal). It is anticipated that China will become a more significant importer of Australia's coking coal as China's economy continues to grow (Figures 2.1.4 and 2.1.5). Europe imported more than 15 MTons of Australia's coking coal in 2005 with India importing almost 20 MTons.

Figure 2.1.4. Australian Coal Production & Consumption, 1984 - 2004



Source [2.4]

Figure 2.1.5. Australian Coal Exports by Destination, 2005



Source [2.4]

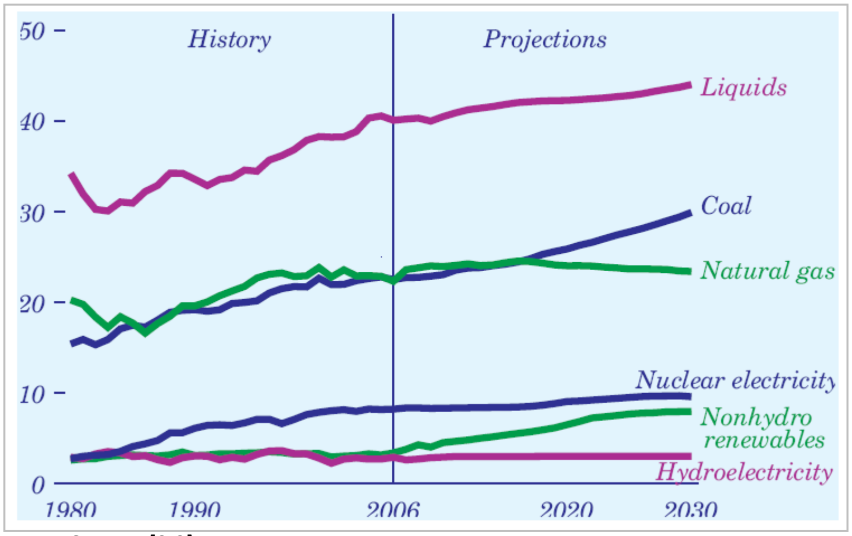
The widely expected environmental legislation will likely have limited effect on global coal demand during the next quarter century. The main reason for this is that both China and India have economic growth at the top of their agendas and purchasing CO_2 controls will probably have greater devastating impact on their economies than it will in the U.S. CO_2 legislation is likely to be introduced in graduated phases in coming years and the demand for coal is also expected to continue to steadily increase. CCTR is paying special attention to CO_2 legislation (Chapter 8).

2.2 U.S. Coal Demand

Coal is a major energy supplier that keeps the U.S. economy moving, and in 2006 supplied 49% of the U.S. electricity demand (1,991 TWh) using 315 GW of coal-fired generation capacity (31% of the total U.S. generating capacity, 1,022 GW). In 2007 the total U.S. coal consumption was 1,128 MTons and 92.7% of this went for power generation, 5.0% for industry, and 2.0% for coke. Increased proportions of renewable energy sources are being welcomed into the future power supply mix in order to respond the issue of global warming but replacing significant portions of the U.S. electricity generation capacity away from coal is going to take decades to accomplish. A most likely development that will be part of the "future power mix" will be a switching to the use of clean coal technology such as with IGCC power plants (integrated gasification combined cycle) that can readily capture CO_2 and sulfur emissions (Chapter 7). In 2006 U.S. coal supplied about the same amount of Btus as natural gas and nearly three times as much energy as that supplied by nuclear power (Figure 2.2.1).

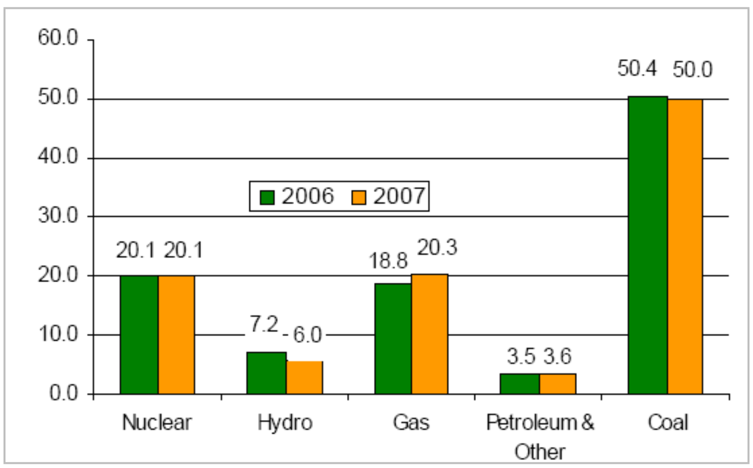
The transportation sector was the only sector that consumed more energy (almost double the amount) across the U.S. economy than the total energy supplied by coal. The DOE projections to 2030 show coal consumption increasing with the U.S. transportation sector emitting about the same proportions of CO_2 (32% of total U.S. emissions) as power plants (39% of total U.S. emissions). The U.S. power sector is in a much stronger situation for controlling CO_2 than the beleaguered U.S. auto industry.

Figure 2.2.1. U.S. Energy Consumption by Fuel, 1980-2030 (Quadrillion Btu)



Source: [2.2]

Figure 2.2.2. Share of Electric Power Sector Net Generation by Energy Source, U.S. 2006 vs. 2007 (Percent)

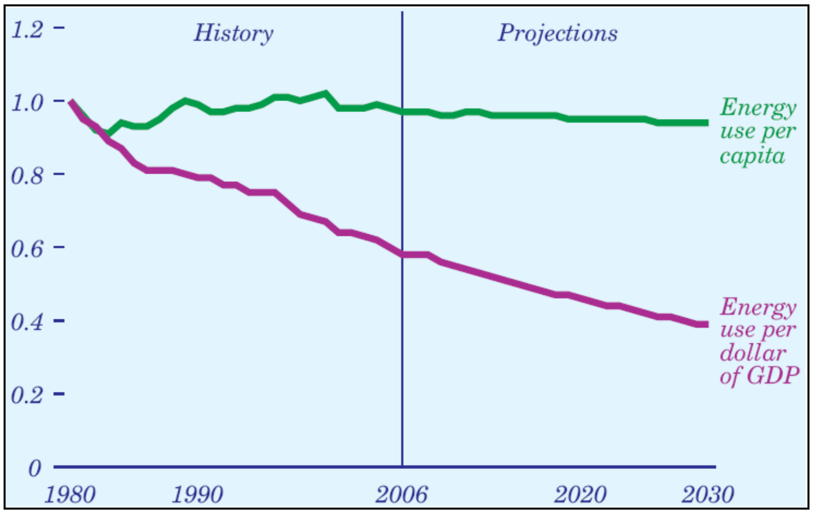


Source: [2.16]

There have been only slight changes in the levels of supply of coal to the power sector over recent years. With increased demand for electricity the percentage share of power supplied by hydropower decreased by more than 1% in 2007 compared with 2006 and there was a comparable increase in share to natural gas for the same time period (Figure 2.2.2). Weather changes can account for the slightly reduced consumption of coal in Figure 2.2.2 and does not detract from the upward consumption trend shown in Figure 2.2.1.

Steady improvements in the efficient use of energy sources have been taking place over the past 20 years. The rate of reduction in energy consumed per dollar GDP is illustrated in Figure 2.2.3. U.S. and energy use per person is slightly reducing (with increased fuel use consciousness).

Figure 2.2.3. U.S. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



Source [2.1]

From 1990 to 2005 U.S. coal production made a gradual increase from 1,108 MTons to 1,128 MTons. An average U.S. increase of about 7 MTons per year when compared with China's 300 MTons per year appears very modest but interestingly reflects the relative economic growth and environmental constraints (or lack thereof) in each.

1990-2005 saw some significant changes also in the structure of coal companies. In the U.S. Peabody Coal continued in the lead position for largest production figures. In 1990 the company was producing 84 MTons and in 2005 is recorded as producing 201 MTons (Figure 2.2.4). By 2005 Arch Coal was recording a production rate of 125 MTons while in 1990 it was producing 22 MTons. Over the 15-year time period, Arch Coal has moved up from being the eighth largest coal producer in the U.S. to being second.

For 1990-2005 the rankings of the most productive coal regions changed with PRB taking a huge lead over other regions by 2005 (Figure 2.2.4). The very thick PRB coal seams (Wyodak Seam, in Wyoming, has an average thickness of 65 feet) with relatively low over burden has made mining much cheaper. In comparison, Indiana's seams are much thinner (Springfield seam has an average thickness of 3.8 feet) and the majority of Illinois Coal Basin coal comes from underground mining as compared with the PRB's 100% surface mining.

The dramatic increase is consumption of PRB coals started in the 1970s and has kept increasing over the past 30 years (Figure 2.2.5). The introduction of SO_2 controls escalated the use of PRB coals and the coal mining business and coal transportation sector were significantly changed. There has been an increased use of the railroads but there is also increased congestion and greater need for new rail capacity.

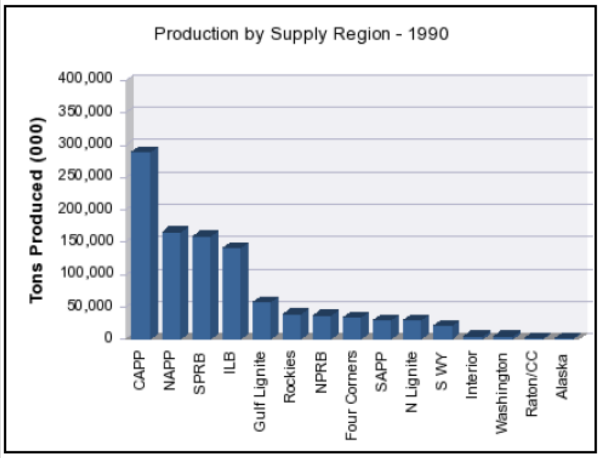
Figure 2.2.4. U.S. Coal Industry Consolidation Timeframe: 1990 vs. 2005

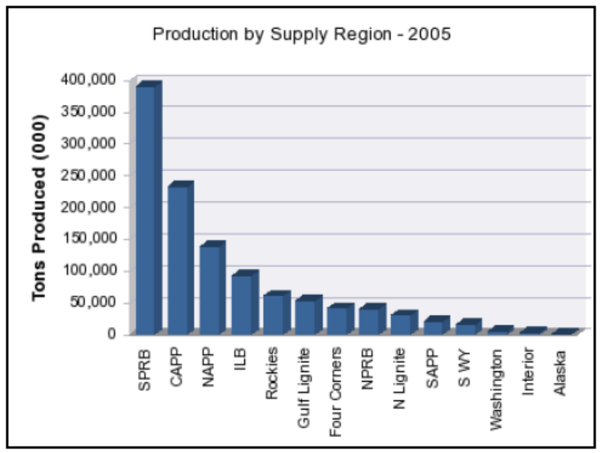
1990

Year	Historic Mine Owner (1990)	Tons Produced (000)	% Total Tons
1990	Peabody Coal Co.	84,249	8.3%
1990	Consolidation Coal Co. (CONSOL)	62,238	6.1%
1990	Amax, Inc.	35,787	3.5%
1990	TXU Corp.	30,321	3.0%
1990	ARCO Coal Co.	29,036	2.9%
1990	Cyprus Amax Minerals Co.	26,744	2.6%
1990	Carter Mining Co.	25,752	2.5%
1990	Arch Coal, Inc.	22,555	2.2%
1990	North American Coal Corp.	21,701	2.1%
1990	Shell Mining Co.	21,254	2.1%
1990	Other	658,531	64.7%
	Sum:	1,018,167	

2005

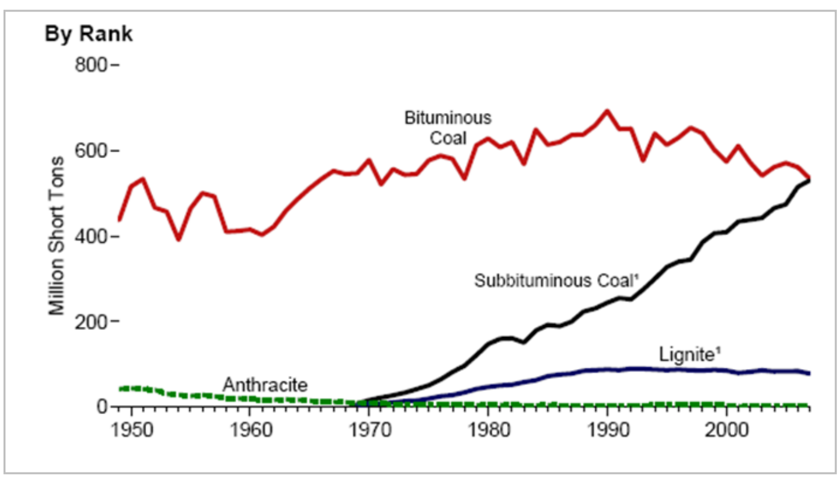
Year	Historic Mine Owner (2005)	Tons Produced (000)	% Total Tons
2005	Peabody Coal Co.	201,410	17.8%
2005	Arch Coal, Inc.	127,127	11.3%
2005	Rio Tinto Energy America, Inc.	123,876	11.0%
2005	CONSOL Energy, Inc.	65,355	5.8%
2005	Foundation Coal Corp.	56,980	5.0%
2005	A.T. Massey Coal Co., Inc.	42,272	3.7%
2005	North American Coal Corp.	30,909	2.7%
2005	Westmoreland Coal Co.	29,911	2.6%
2005	TXU Corp.	23,158	2.1%
2005	Alliance Coal, LLC	21,897	1.9%
2005	Other	405,857	36.0%
	Sum:	1,128,751	





Source: [2.17]

Figure 2.2.5. U.S. Coal Supplies for 1949-2007



Source: [2.18]

Compared with PRB coals, the Midwest coals have lower transportation costs and with improved environmental standards, there have been increased installation of scrubbers and investment in clean coal technologies (CCT). Bear these developments in mind, there could be an increased market for Illinois Basin Coals (IBC). As the CCT technologies become more commercialized, we might expect to see the use of PRB coals leveling out.

Increased global demand for coal will further stimulate increasing the U.S. coal exports. Ready access to ports and waterways which are the cheapest means of shipping coal, reduces transportation rates and this is a significant plus for IBC having access to both the Great Lakes and the Mississippi and Ohio Rivers. Total U.S. coal exports in the first quarter of 2007 amounted to 11.1 MTons and for the first quarter of 2008 they increased by nearly 42% up to 15.8 MTons [2.8]. More than 3 MTons of the increase was sold to Europe. Over the past several years, the U.S. coal imports and exports have been both increasing (Table 2.2.1) but the net trade since 2002 has largely fluctuated around 20 MTons.

Table 2.2.1. U.S. Coal Exports & Imports

	U.S. Total		
Year	Exports	Imports	Net
2002	39,601	16,875	22,726
2003	43,014	25,044	17,970
2004	47,998	27,280	20,718
2005	49,942	30,460	19,482
2006	49,647	36,246	13,401
2007	59,163	36,347	22,816

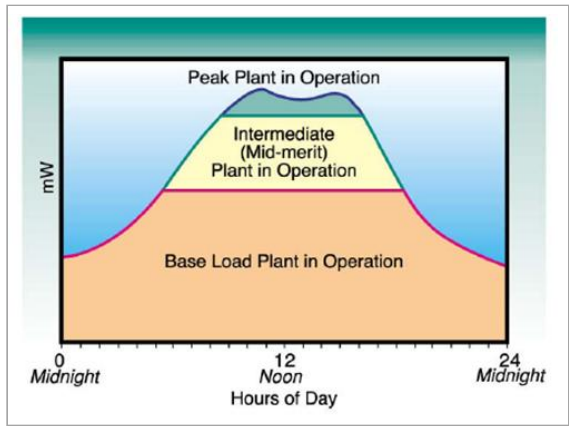
Source [2.9]

U.S. coal imports during the first quarter of 2008 decreased by 1.15 MTons (13%) compared with the first quarter of 2007 [2.10] and the U.S. coal exports during this period increased by 4.7 MTons. The U.S. coal industry might indeed be positively responding to the increased global demand. The extent to which the ICB and Indiana coals are increasing their exports has yet to be fully realized.

2.3 Coal Prices

Low prices make coal the biggest attraction for continued and increased use. Its high heat content and magnitude of reserves place it as America's most obvious fuel choice. Having a low cost per Btu is coals greatest attraction and far outstrips natural gas and other fuels for continuously providing base load power generation (Figure 2.3.1).

Figure 2.3.1. Power Plant Selection & Dispatch



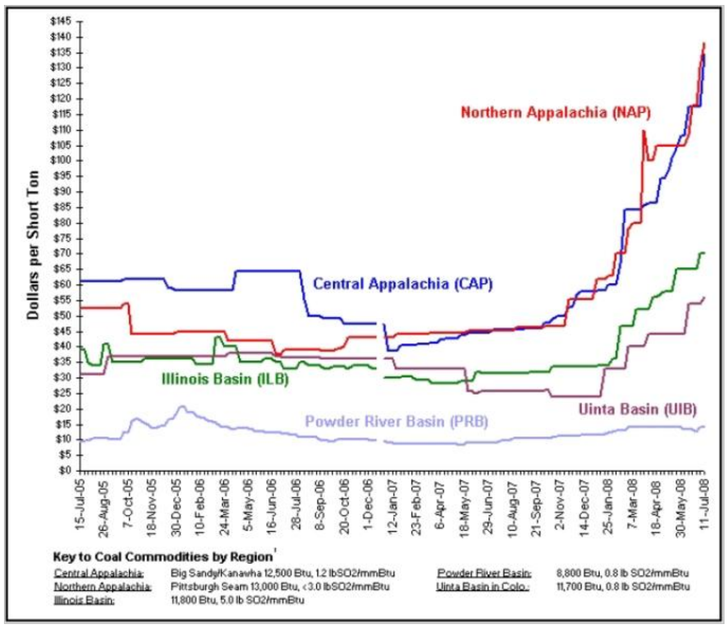
Average coal spot prices can provide an insight into the trend of average coal contract prices. Throughout 2008 spot coal prices rose rapidly (Figure 2.3.2). The spot price of Illinois Basin Coal was about $35 per ton in January 2008 but six months later rose to over $60 per ton in July. The price rise was similar for Appalachian coal except that its spot prices were twice as high as Illinois Basin Coal, ranging from about $60 to $130 per ton.

The 2007 average free-on-board (FOB) coal prices (at point of first sale they exclude shipping and insurance costs) for Illinois Basin Coal were $40.83 (Figure 2.3.3) and for Appalachian coal were $51.23. These average prices for Illinois Basin bituminous coal are only slightly less than the spot prices but for the Appalachian coal the spot prices are much steeper. PRB sub-bituminous coal prices are always the lowest but Figure 2.3.3 does not include shipment costs which could double their final delivery prices. The 1970s experienced the impacts of oil crises and saw a steep rise in coal prices (Figure

2.3.3) but which later came down and similarly in 2008 the high oil prices again increased coal prices.

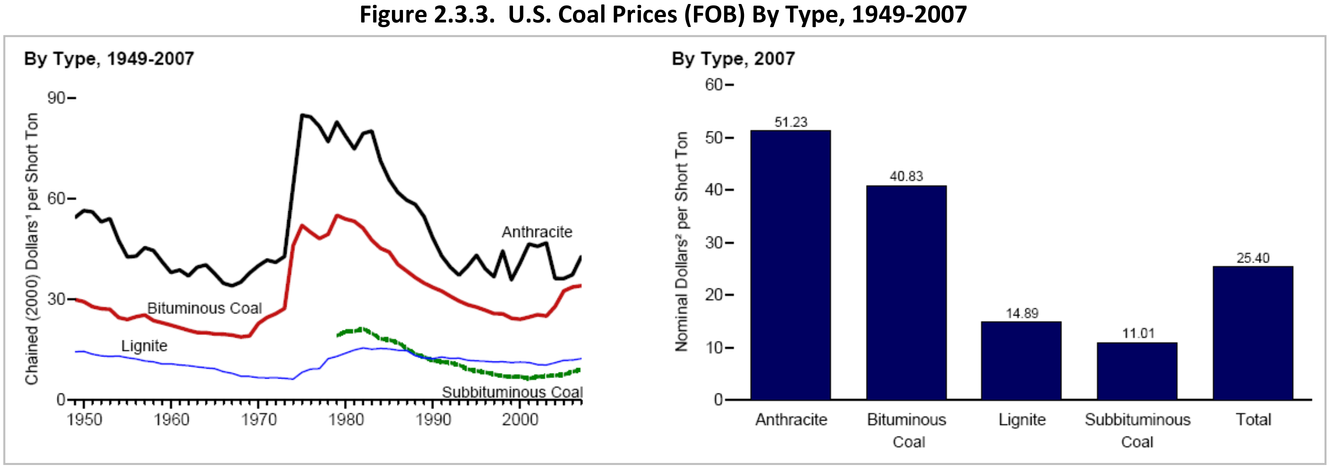
Coal transportation costs depend on distance shipped from supplier to customer and from one region to another (Figure 2.3.4). The loading and unloading costs are also significant and the number of changes from one form of carrier to another (barge to rail, etc.) must be kept to a minimum for lowest transportation costs. Transportation rates can vary from one region to another depending on infrastructure capacities such as railroad delays, the number of modes of carriers, flexibility of the market (how many shipping companies are available), and levels of automation and handling facilities (see Chapter 6).

Figure 2.3.2. U.S. Average Weekly Coal Commodity Spot Prices (July 11, 2008)



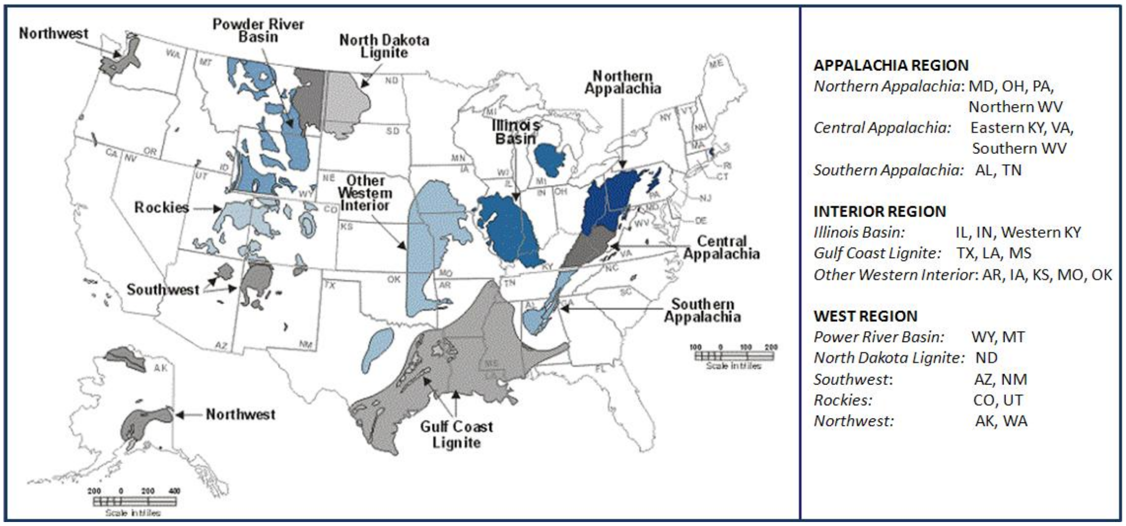
Source [2.11]

Figure 2.3.3. U.S. Coal Prices (FOB) By Type, 1949-2007



Source [2.7]

Figure 2.3.4. U.S. Coal Regions & Coal Fields



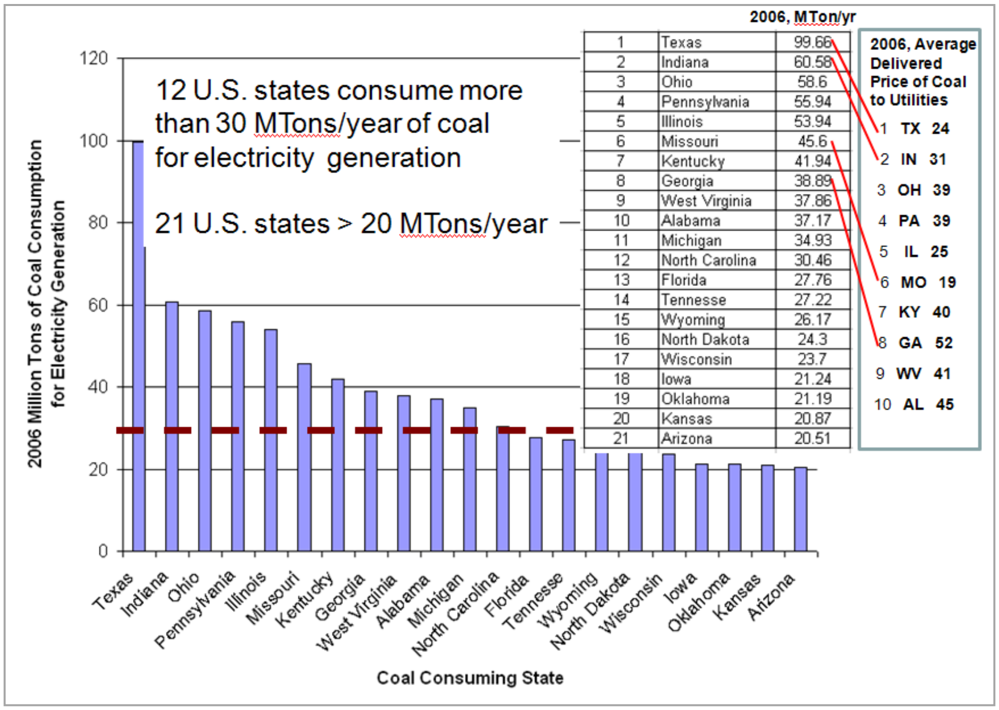
Source: [2.12]

The EIA assessment of coal transportation rates lists a number of factors that impact on the final cost:

> *"Coal customers have experienced a range of differences in coal transportation options. Facilities served by rail can negotiate better rates if, (a) there is a competing railroad they can use, or (b) a feasible competing transportation mode. (c) "Captive" mines and coal consumers - those located where a single carrier or mode is their only practical transportation option - have long claimed that they were offered only higher, take-it-or-leave-it rates. (d) Barges generally offer the least expensive transportation rates, and facilities that can take advantage of barge shipment for all or even a significant part of the shipping distance can usually temper transportation costs. (e) Different railroads use different rate structures and (f) have in recent years implemented new requirements, such as automated loading and unloading equipment or (g) 7-day-per-week loading and unloading, that affect supplier and customer overhead costs but are not reflected in rates. (h) Rates charged may be lower for customers that lease or own their own fleet of coal cars." [2.12]*

In 2006 there were twelve U.S. states (Figure 2.3.5) that consumed more than 30 MTons of coal per year for electricity generation. Texas consumed the most coal for power generation and Indiana was in second place. Of these 12 states, Missouri had the cheapest average delivered price of coal to the utilities at $19 per Ton (Figure 2.3.5) and the most expensive was Georgia at $52/Ton. Indiana's average coal price to the utilities was $31/Ton. The differences in coal rank and transportation costs account for the variations in prices.

Figure 2.3.5. 2006 Coal Consumption for Electricity Generation (MTons/year)

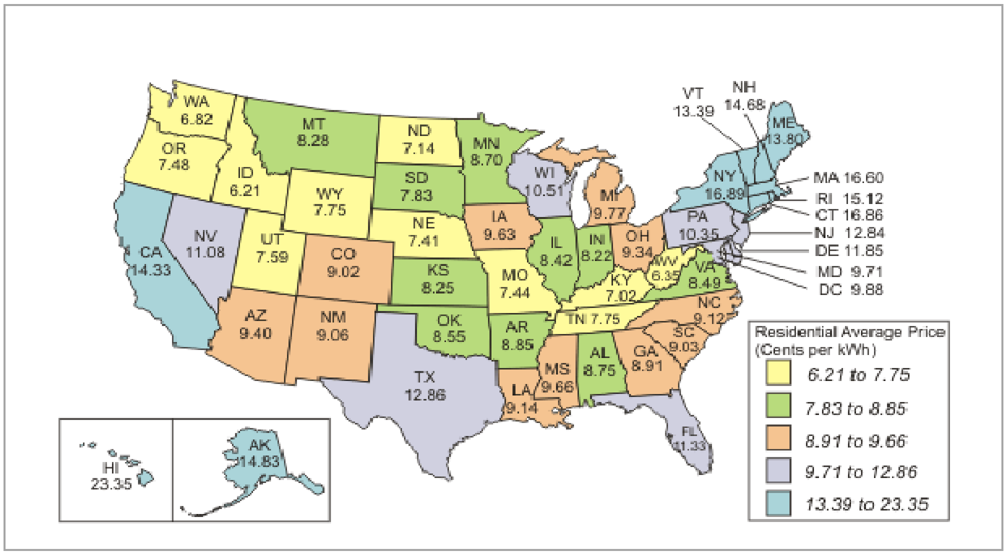


Source [2.5, 2.14]

The price of coal in each state will affect the cost of electricity. Missouri, having the lowest average price for delivered coal, is also among the states with the cheapest electricity rates (7.44 cents/kWh in 2006, Figure 2.3.6). The second to lowest cost of coal delivered was in Texas but this was one of the more expensive electricity rate states at 12.86 cents/kWh. The high electricity rates in Texas are not apparently due to the size of the state and low density of population, as the rates for the commercial and industrial sectors are also higher than other states (Indiana's commercial and industrial rates are 7.66 cents/kWh and 5.42 cents/kWh, respectively, while for Texas they are 10.51 cents/kWh and 8.83 cents/kWh). Regulatory and environmental issues must have some impact on electricity pricing in Texas and other states in that while coal delivery prices may be low, they could have high average electricity rates. Also the average cost of residential electricity in Illinois is 8.42 cents/kWh and its average coal delivery price is $25/Ton but the electricity rate in Indiana is slightly lower at 8.22 cents/kWh and the average coal price is higher at $31/Ton. Out of the top 10 of these coal-consuming states, there were only three states that had cheaper electricity than Indiana.

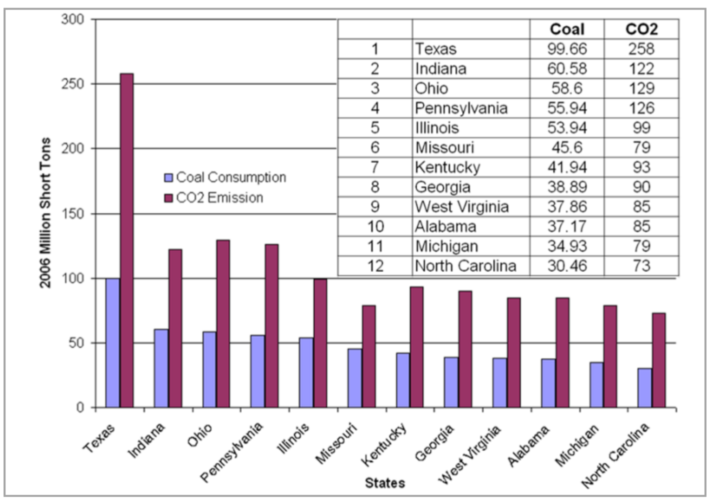
The cost of controlling SO_2 and NO_x emissions has been an expensive exercise for coal consuming states but the impact of potential CO_2 legislation has yet to be fully assessed. Each year Indiana emits more than 120 MTons of CO_2 from its coal-fired power plants but Texas emits more than double this amount (Figure 2.3.7). The cost of CO_2 capture of such huge amounts of CO_2 is expected to produce significantly higher costs of electricity. Piping CO_2 and using it for enriched oil recovery (EOR) is a well-proven technology. The technology for storage of CO_2 and methodology of its use, has yet to be demonstrated. CCTR is supporting initiatives for a CO_2 pipeline project (Chapter 8).

Figure 2.3.6. 2006 U.S. Residential Average Retail Price of Electricity by State, (Cents/kWh)



Source [2.13]

Figure 2.3.7. 2006 Coal Consumption & CO_2 Emissions from Electricity Generation (MTons/year)



		Coal	CO2
1	Texas	99.66	258
2	Indiana	60.58	122
3	Ohio	58.6	129
4	Pennsylvania	55.94	126
5	Illinois	53.94	99
6	Missouri	45.6	79
7	Kentucky	41.94	93
8	Georgia	38.89	90
9	West Virginia	37.86	85
10	Alabama	37.17	85
11	Michigan	34.93	79
12	North Carolina	30.46	73

Source [2.5]

2.4 References

[2.1] Hill & Associates, Review of the Illinois Basin, published in the Coal Supply Service. This update encompasses Indiana, Illinois, and West Kentucky. In total, more than 240 mines and reserves are analyzed.
[2.2] EIA, Annual Energy Outlook 2008
[2.3] The Power to Reduce CO2 Emissions, The Full Portfolio, Energy Technology Assessment Center, Electric Power Research Institute, 2008
[2.4] DOE-EIA International Energy Annual, 2004
[2.5] DOE-EIA, http://www.eia.doe.gov?cneaf/coal/page/acr/table26.html
[2.6] DOE-EIA, http://www.eia.doe.gov/emeu/international/stmforelec.html
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[2.18] EIA, Annual Energy Review 2007
[2.19] EIA, Annual Energy Outlook 2007

CHAPTER 3

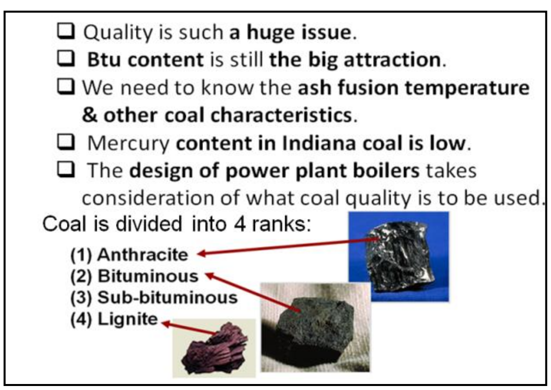
COAL CHARACTERISTICS & RESERVES

3.1 Indiana's Coal Characteristics

Detailed knowledge of Indiana's coal characteristics and reserves is foundational to all of the projects supported by CCTR. The characteristics of a coal have enormous consequences on where and how it will be used and the value of the commodities derived from it. The heat content is one of the most important characteristics for power generation but other characteristics will also determine the extent to which and where the coal will be used (Figure 3.1.1).

The degree of 'metamorphism' undergone by the coal (maturation from peat to anthracite) has an important bearing on physical and chemical properties, i.e., the 'rank' of the coal. Indiana's bituminous coal ranks as a high heat content coal. As carbon content increases, then the higher is the carbon ranking. With increases in carbon content there will be decreases in moisture and volatile matter content (Figure 3.1.2).

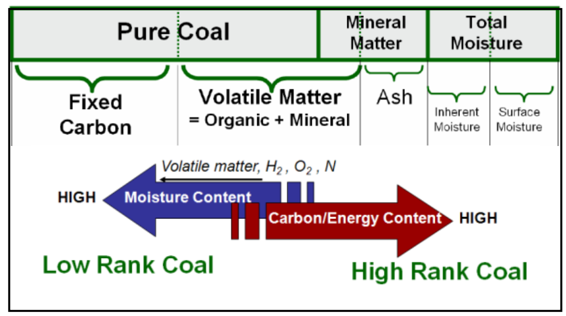
Figure 3.1.1. Coal Characteristics



Source: [3.13]

The highest rank coal is anthracite (e.g., coal in the Appalachian Basin) with 85% to 98% carbon content (Table 3.1.1). Indiana's bituminous coal has a typical fixed carbon content of 45% to 85%. This content level can vary significantly from one coal bed/seam to another. The Indiana Geological Survey (IGS) has the most comprehensive coal data library and bookstore detailing the characteristics of Indiana's coals [3.1, 3.2, 3.3, 3.4, 3.6, 3.7].

Figure 3.1.2. High and Low Coal Rankings



Source: [3.13]

Table 3.1.1. Typical Characteristics of Coal by Rank

% weight	Anthracite	Bituminous	Sub-Bituminous	Lignite
Heat Content (Btu/lb)	13,000-15,000	11,000-15,000	8,500-13,000	4,000-8,300
Moisture	< 15%	2 - 15%	10 - 45%	30 - 60%
Fixed Carbon	85 - 98%	45 - 85%	35 - 45%	25 - 35%
Ash	10 - 20%	3 - 12%	≤ 10%	10 - 50%
Sulfur	0.6 - 0.8%	0.7 – 4.0%	< 2%	0.4 – 1.0%
Chlorine (ppm)	340 ± 40ppm	340 ± ppm	120 ± 20ppm	120 ± 20ppm

Source: [3.13]

The average moisture content of Indiana's coal is typically just over 10% (Tables 3.1.1 and 3.1.2) and its ash content is usually over 9%. The low ash content is a significant factor for coal gasification processes and in the design of integrated gasification combined cycle plants (IGCCs). Only the eastern, Appalachian Basin coals have higher heating contents than Indiana's bituminous coals but eastern coals are considerably more expensive. Spot prices for Appalachian coals can be almost double the price of Illinois Basin Coals (Chapter 5).

Table 3.1.2. Average Indiana Coal Characteristics

	Danville	Springfield
Moisture %wt	11.3	9.9
Ash %wt	13	12.2
Sulfur	2.65	3.27
Btu/lb (dry)	13050	13214
Fixed Carbon	48.4	48
Volatile Matter	39.1	40.9
Chlorine %	0.03	0.15

Source: [3.4, Table 3.1.4]

In 2007 about 30% of Indiana's total coal production came from under-ground mining (70% surface mined). This method is gradually increasing its rate of production (Chapter 4).

Figure 3.1.3. Stratigraphy of the Pennsylvania System in Indiana, bed depth and average thickness

Indiana				depth range (feet)	average depth (feet)	average thickness (feet)
McLeansboro Gp.	Mattoon Fm.		Virg.			
McLeansboro Gp.	Bond Fm.		Missourian			
McLeansboro Gp.	Patoka Fm.		Missourian			
McLeansboro Gp.	Shelburn Fm.		Desmoinesian			
Carbondale Group	Dugger Fm.	Danville (VII)	Desmoinesian	0 - 911	180	2.68
Carbondale Group	Dugger Fm.	Hymera (VI)	Desmoinesian	0 - 582	170	3.10
Carbondale Group	Dugger Fm.	Herrin	Desmoinesian	0 - 963	409	2.50
Carbondale Group	Dugger Fm.	Bucktown (Vb)	Desmoinesian	0 - 932	225	1.71
Carbondale Group	Petersburg Fm.	Springfield (V)	Desmoinesian	0 - 1031	231	3.86
Carbondale Group	Petersburg Fm.	Houchin Creek	Desmoinesian	0 - 1140	391	1.76
Carbondale Group	Linton Fm.	Survant (IV)	Desmoinesian	0 - 1162	355	2.47
Carbondale Group	Linton Fm.	Colchester (IIIa)	Desmoinesian	0 - 1209	436	1.18
Carbondale Group	Linton Fm.	Seelyville (III)	Desmoinesian	0 - 1311	360	3.07
Raccoon Creek Group	Staunton Fm.	Unnamed Staunton Fm. coals	Desmoinesian	0 - 1032	405	1.73
Raccoon Creek Group	Brazil Fm.	Minshall / Buffaloville	Atokan	0 - 1107	111	2.83
Raccoon Creek Group	Brazil Fm.	Upper Block	Atokan	0 - 1148	81	2.30
Raccoon Creek Group	Brazil Fm.	Lower Block	Atokan	0 - 1189	86	2.07
Raccoon Creek Group	Mansfield Fm.	Mariah Hill	Atokan	0 - 304	31	2.62
Raccoon Creek Group	Mansfield Fm.	Blue Creek	Atokan	0 - 144	20	1.78
Raccoon Creek Group	Mansfield Fm.	Pinnick	Morrowan	0 - 148	19	1.71
Raccoon Creek Group	Mansfield Fm.	St. Meinrad	Morrowan	0 - 819	20	2.61
Raccoon Creek Group	Mansfield Fm.	French Lick	Morrowan	0 - 306	16	1.16

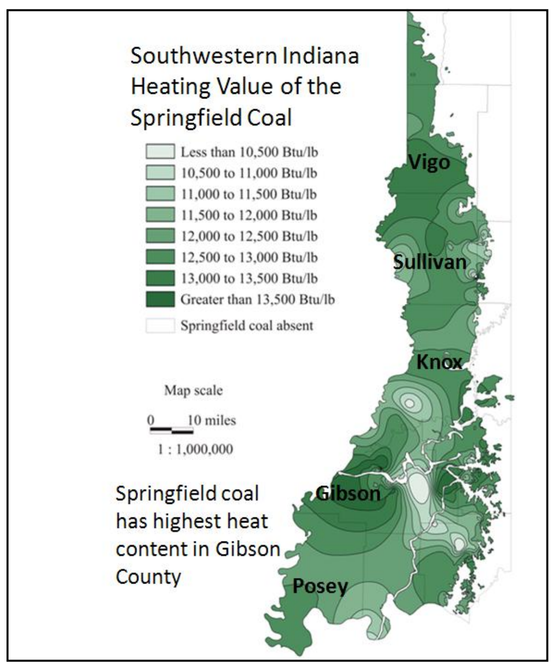
Depth and thickness values from NCRDS database 2004. For coals of the Mansfield Formation (gray area) the data are available only from the surface mining areas, and not from the deeper part of the basin.

Source: [3.4]

The coal characteristics in the above tables are average values with more detailed illustrations in Figures 3.1.3 to 3.1.7. The various coal characteristics can significantly vary from seam to seam and from mine to mine. Indiana's Springfield and Danville coal beds are the most productive coal seams in the state and these seams vary in depth from 500-630 feet (Figure 3.1.3). Most of the Springfield coal reserves use underground mining techniques.

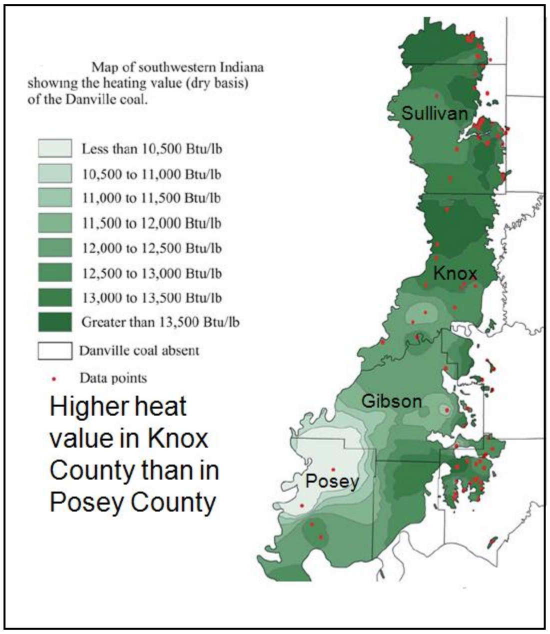
The coal heating values in Springfield coals can vary from 10,500 Btu/lb to 13,500 Btu/lb on dry basis (average 13,214 Btu/lb). Variations across Posey, Gibson, Knox, Sullivan and Vigo counties can be seen in Figure 3.1.4. Variations in heating values of the Danville coal seam are seen in Figure 3.1.5. The IGS gives an average heating value of 13,050 Btu/lb for the Danville seam (Tables 3.1.2, 3.1.4). The Danville coal seam has some of the highest heating values in Knox County and lowest in Posey County.

Figure 3.1.4 Springfield Heating Value Variation



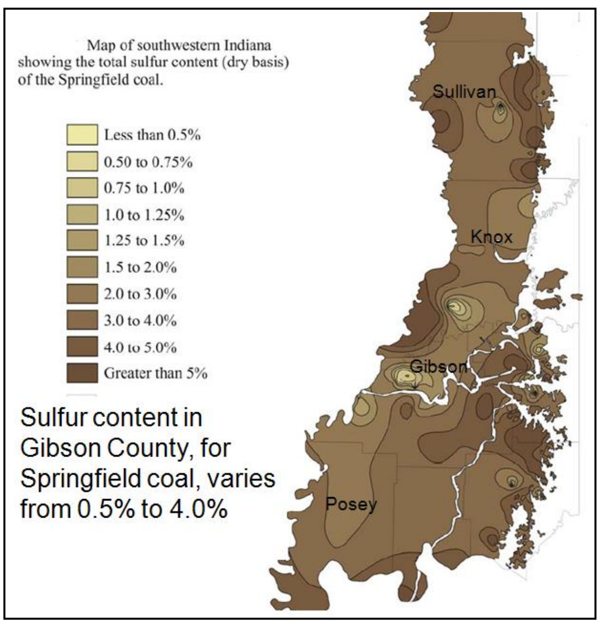
Source: [3.2]

Figure 3.1.5. Danville Heating Value Variation (Dry Basis)



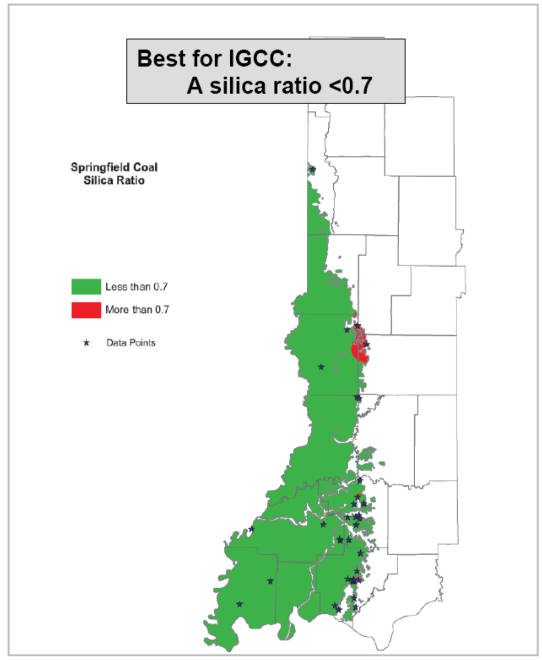
Source: [3.2]

Figure 3.1.6. Springfield Coal Sulfur Variation



Source: [3.4]

Figure 3.1.7. Silica Ratio & IGCC Design Value



Source: [3.3]

Variations in sulfur content and silica ratio for the Springfield coal are shown in Figures 3.1.6 and 3.1.7. In the Springfield coal bed the sulfur content is most varied in Gibson County (0.5% to 4.0%, by weight). In Posey County sulfur content is less varied and is about 1.5% to 3.0%. The IGS gives an average sulfur content of 3.27% for the Springfield bed (Tables 3.1.2 and 3.1.4). The December 2008 comprehensive report on Indiana's coal characteristics for coal gasification is produced by the IGS.

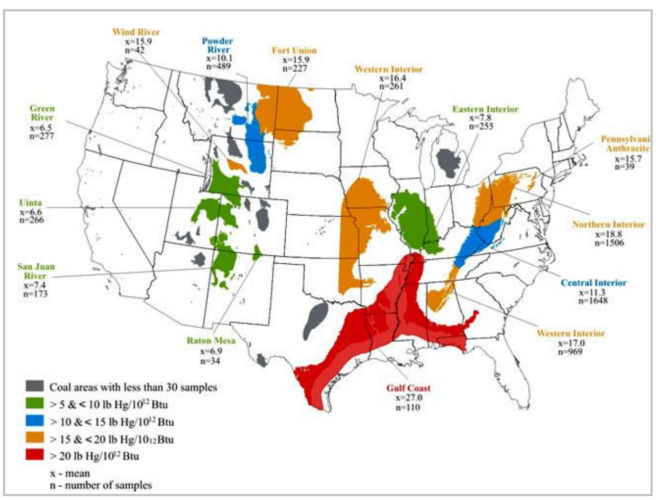
Mercury content in Indiana's coals varies from seam to seam in the order of 0.05 ppm to 0.22 ppm (Table 3.1.3). Indiana's concentrations are generally below the U.S. average mercury concentration of 0.17 ppm. The Illinois Basin coal is one of the lowest mercury-input-loading basins, having an average value of 7.8 lb Hg/10^{12} Btu (Figure 3.1.8).

Table 3.1.3. Average Mercury (Hg) Content (ppm, whole coal basis) of Indiana Coal Beds

	Average
Danville	0.07
Hymera	0.11
Bucktown	0.09
Springfield	0.12
Houchin Creek	0.06
Survant	0.22
Colchester	0.12
Seelyville	0.07
Staunton	0.12
Minshall/Buffaloville	0.10
Upper Block	0.13
Lower Block	0.07
Mariah Hill	0.05
Blue Creek	0.10
Unnamed Mansfield	0.16
Average for all coals	**0.11**

Source: [3.4]

Figure 3.1.8. Levels of Mercury in U.S. Coals



Source: [3.7]

During the 2008 final phase of the IGS Indiana Coal Characterization for Integrated Gasification Combined Cycle Plants (IGCCs), four major coal beds were investigated: Danville, Hymera, Springfield, and Seelyville. New data for these coals were documented with a special emphasis on the characteristics of the mineral matter in the coal. This data was integrated with the earlier 2007 data into a 2008 database. This latest database was then used to map the properties of Indiana coals that are most important for IGCC application. These maps are the basis for grading Indiana coals for IGCC.

Evaluation of the coals was divided into three groups:

(i) Evaluation based on basic coal quality parameters such as heating value, moisture content, ash yield, and sulfur content;

(ii) Evaluation of the ability of coal and coal char to gasify (reactivity); and

(iii) Evaluation of slagging based on mineral matter characteristics.

The complete 2008 IGS Coal Characterization final report for IGCCs is available on the CCTR website at: http://www.purdue.edu/dp/energy/CCTR/researchReports.php

Basic coal quality characteristics such as heating value, moisture content, and ash content indicate that Indiana coals are a good feedstock for gasification. For the four coal beds, Danville, Springfield, Hymera, and Seelyville, the IGS 2008 coal characteristics final report showed average heat contents (12,042 Btu/lb to 13,214 Btu/lb), average moistures (9.9% to 11.3%), and average ash (12.2% to 14.9%) contents. Values of other Indiana coal characteristics were determined and listed in Table 3.1.4.

High sulfur content of the majority of Indiana coals does not create a problem because in IGCC plants sulfur is transformed into sulfuric acid and high purity elemental sulfur, both profitable products. Chlorine content in the coals studied is usually well below the IGCC-preferred 0.2% level, except some areas in the Springfield coal, where at places is a little higher but still below 0.3%.

Char reactivity proxies such as fuel ratio (a ratio of fixed carbon and volatile matter) and O/C ratio were used to evaluate reactivity. The IGS analysis indicated that the Danville Coal and the Springfield Coal will be more reactive than the Hymera Coal. Reactivity of coal/char is more important in gasifiers with two-step char conversion, such as the one used at

Wabash Valley Gasification Plant, than in one stage gasifiers where gasification is a faster process.

Mineral matter characteristics are very important in entrained-flow slagging gasifiers. Entrained-flow slagging gasifiers are the most common gasifier types in IGCC technologies and therefore evaluation of mineral matter properties and prediction of its behavior in the gasifier is of fundamental importance.

For Indiana coals, the IGS recommend two main blending strategies when improvement in slagging characteristics is required: a) blending low SiO_2/Al_2O_3 coals (<1.6) with high SiO_2/Al_2O_3 coals to yield of SiO_2/Al_2O_3 of 1.0-2.2; and b) blending high flux (Fe_2O_3+CaO) coals with a lower flux coals to yield Fe_2O_3+CaO content about 15-20%

Although the evaluation of Indiana coals presented in the 2008 final report was particularly suitable for entrained-flow slagging gasifiers, the data generated is also valuable for other coal-processing technologies. By concentrating on the evaluation based on mineral matter characteristics, but including evaluation of the coal/char reactivity as well as analysis of coal quality parameters, the IGS 2008 study data can be used in the selection of Indiana coals for various gasification and clean coal technology projects.

Table 3.1.4. Indiana Coal Characteristics

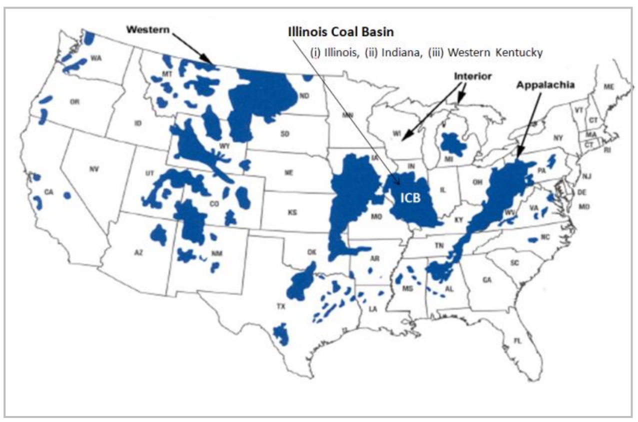
	DANVILLE				HYMERA				SPRINGFIELD				SEELYVILLE				LOWER BLOCK			
	Min.	Max.	Ave	n	Min.	Max.	Ave	n	Min.	Max.	Ave	n	Min.	Max.	Ave	n	Min.	Max.	Ave	n
M [ar]	1.9	28.2	11.3	253	0.8	23.5	10.3	134	0.5	34.7	9.9	654	0.8	29.2	9.9	81	0.7	27.1	13.8	139
A [dry]	4.9	41.1	13.0	255	6.8	72.7	14.5	135	4.9	54.2	12.2	663	6.7	35.6	14.9	88	4.1	31.0	9.0	148
S [tot, dry]	0.33	7.62	2.65	163	1.20	5.34	3.10	36	0.30	12.19	3.27	443	2.50	9.84	5.02	28	0.55	7.0	1.36	111
Btu [dry]	7651	17314	13050	253	2520	13734	12042	134	8362	20648	13214	663	8494	13810	12149	83	9677	14702	13267	147
FC [dry]	32.0	58.2	48.4	131	11.7	54.0	46.7	110	29.0	70.7	48.0	308	19.0	61.1	44.4	73	35.5	59.5	52.6	93
VM [dry]	26.9	46.1	39.1	131	15.6	45.8	38.5	110	19.9	62.0	40.9	308	31.2	65.4	41.4	73	33.5	47.5	38.5	94
Slag viscosity temp. (°F)	2156	2900	2559	30	2150	2900	2421	15	2150	2720	2345	41	2150	2630	2273	9	2150	2900	2649	38
Cl [%]	0.01	0.10	0.03	25	0.02	0.07	0.04	23	0.01	0.24	0.15	31	0.08	0.17	0.11	3	0.01	0.06	0.02	42
SiO_2 [%]	31.0	60.0	48.3	34	17.00	55.00	39.13	20	21.0	53.0	38.6	48	19.0	45.0	31.0	14	0.4	61.7	47.2	39
Al_2O_3 [%]	14.0	26.0	20.9	34	9.10	28.40	18.00	20	9.2	28.0	18.2	48	8.5	25.0	17.2	14	16.4	34.0	25.3	39
Fe_2O_3 [%]	3.5	37.0	16.3	34	4.60	41.00	22.95	20	6.5	49.0	23.3	48	9.2	55.0	35.8	14	3.3	47.2	15.1	39
CaO [%]	0.5	10.0	2.9	34	0.43	27.00	4.80	20	0.3	16.0	4.3	48	0.5	8.2	3.1	14	0.5	7.1	1.9	39
MgO [%]	0.6	1.7	1.2	34	0.37	1.50	0.85	20	0.3	1.4	0.8	48	0.4	0.9	0.5	14	0.3	1.0	0.6	39
SiO_2/Al_2O_3	1.75	2.73	2.31	34	1.60	2.93	2.22	20	1.46	2.59	2.16	48	1.44	2.42	1.85	14	0.02	2.52	1.89	39
Fe_2O_3+ CaO	4.01	38.50	19.26	34	5.12	42.00	27.75	20	7.60	53.80	27.42	48	10.4	58.0	38.84	14	4.80	47.66	16.51	39
Silica ratio*	0.44	0.92	0.71	34	0.28	0.90	0.58	20	0.30	0.86	0.58	48	0.25	0.80	0.45	14	0.02	0.92	0.73	39
AFTR INIT	2095	2540	2275	12	-	-	-	-	2095	2103	2099	2	-	-	2185	1	1970	2800	2430	28
AFTR SOFT	2155	2610	2375	12	-	-	-	-	2131	2151	2141	2	-	-	2275	1	2040	2800	2477	28
AFTR HEM	2210	2665	2436	12	-	-	-	-	2181	2187	2184	2	-	-	2353	1	2080	2800	2525	28
AFTR FINAL	2250	2735	2502	12	-	-	-	-	2208	2232	2220	2	-	-	2425	1	2170	2800	2558	26
AFTO INIT	2340	2705	2535	12	-	-	-	-	-	-	2528	1	-	-	2668	1	2425	2740	2578	9
AFTO SOFT	2370	2730	2570	12	-	-	-	-	-	-	2576	1	-	-	2701	1	2470	2765	2589	7
AFTO HEM	2395	2765	2594	12	-	-	-	-	-	-	2596	1	-	-	2716	1	2495	2780	2608	7
AFTO FINAL	2415	2795	2626	12	-	-	-	-	-	-	2611	1	-	-	2728	1	2540	2800	2638	7

M = Moisture (% weight), A = Ash (% weight), S = Sulfur (% weight), Btu = Heating value (Btu/lb), FC = Fixed carbon (%), VM = Volatile matter (%), Cl = Chlorine (%, whole coal basis), SiO_2 = Silicon dioxide value (%) as determined on coal ash, Al_2O_3 = Aluminum oxide value (%) as determined on coal ash, Fe_2O_3 = Ferric oxide value (%) as determined on coal ash, CaO = Calcium oxide value (%) as determined on coal ash, MgO = Magnesium oxide value (%) as determined on coal ash, Silica ratio: $SiO_2/(SiO_2+Fe_2O_3+CaO+MgO)$, AFTR INIT = Initial ash fusion temperature (deg. F) in reducing conditions, AFTR SOFT = Softening ash fusion temperature (deg. F) in reducing conditions, AFTR HEM = Hemispherical ash fusion temperature (deg. F) in reducing conditions, AFTR FINAL = Final ash fusion temperature (deg. F) in reducing conditions, AFTO INIT = Initial ash fusion temperature (deg. F) in oxidizing conditions, AFTO SOFT = Softening ash fusion temperature (deg. F) in oxidizing conditions, AFTO HEM = Hemispherical ash fusion temperature (deg. F) in oxidizing conditions, AFTO FINAL = Final ash fusion temperature (deg. F) in oxidizing conditions, ar = as received, n = number of data points as of October 2008.
Source: [3.3]

3.2 Indiana Coal Reserves

Indiana, together with Illinois and Western Kentucky, form the Illinois Coal Basin (ICB). The ICB is part of the U.S. Interior Region (Figure 3.2.1) which has bituminous coals with high heating value and high sulfur content. The State of Illinois has vast coal reserves with mainly underground coal mining, while in Indiana the coal production is more by surface mining than underground. The EIA estimates that the U.S. has a Demonstrated Reserve Base (DRB) of nearly 500 Billion short tons (1 short Ton = 2000 lbs) and recoverable coal reserves that exceed 260 Billion short tons (BTons) [3.8].

Figure 3.2.1. Illinois Coal Basin (ICB) in the Interior Region



Source: [3.14]

Major coal reserves are present in Indiana having the potential for supplying the state with cheap energy sources for many years to come.

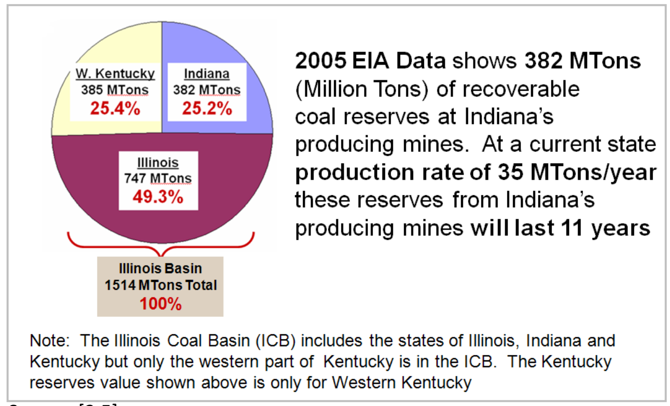
Table 3.2.1. Illinois Coal Basin Reserves (BTons)

	Estimated Recoverable	Demonstrated Reserve Base
Indiana	4.134	9.637
Illinois	38.061	104.648
W. Kentucky	9.082	19.637
TOTALS		
IL Basin Coal	51.277	133.922
U.S. Total	269.457	497.708

Source: [3.10]

According to EIA data, the ICB has a Demonstrated Reserve Base (DRB) of over 133 Billion Tons (BTons, Table 3.2.1) [3.9, 3.10]. With Indiana's DRB of 9.637 BTons and using the current production rate of 35 Million Tons (MTons) per year, there will be coal provision from within the state for the next 275 years. 25% of the ICB recoverable coal reserves at producing mines are located in Indiana. Existing mines in Indiana have an estimated 382 MTons and so at the current rate should maintain its production for at least another 11 years (Figure 3.2.2).

Figure 3.2.2. Illinois Coal Basin (ICB) Recoverable Coal Reserves at Producing Mines



Source: [3.5]

National coal reserves can readily supply the nation with energy for more than 200 years. The National Research Council provides us with a clear definition of the DRB:

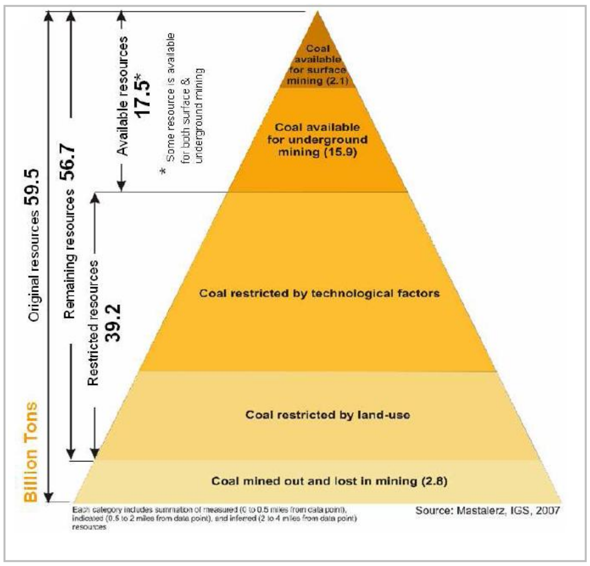
It is a collective term for the sum of coal in both "measured" and "indicated" resource categories, and includes:

- *Beds of bituminous coal and anthracite 28 inches or more thick and beds of sub-bituminous coal 60 inches or more thick that can be surface mined [Ref:3.2j]; and*
- *Thinner and/or deeper beds that presently are being mined or for which there is evidence that they could be mined commercially at this time.*

The Estimated Recoverable Reserve (ERR) is the most widely reported reserve value. It is derived from the DRB but also includes coal mine recovery and accessibility factors. The ERR for the ICB is very large, amounting to 55 BTons.

The large Indiana coal reserves have a DRB of between 9.6 to 17.5 BTons (Figure 3.2.3). At current Indiana mining production rates (35 Million Tons per year), the state can mine coal for hundreds of years (Figure 3.2.4). About one-third of Indiana's DRB is to be found in two coal beds. These are the Danville and Springfield Coal Beds which are mostly mined in the state's southwestern counties, Knox, Gibson, and Posey (Figure 3.2.5).

Figure 3.2.3. Indiana Coal Reserves (IGS 2007)



Source: IGS 2007

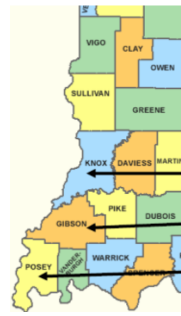
Figure 3.2.4. Indiana Coal Reserves 2002 (MTons)

Recoverable Reserves at Producing Mines	Estimated Recoverable Reserves	Demonstrated Reserve Base
382	4134	9637

At Indiana's current mining rate of 35 MTons/year:
382 MTons will last 11 years
4134 MTons 118 years
9637 MTons 275 years

Source [3.11]

Figure 3.2.5. Location of Danville & Springfield Coal Beds



Source: IGS 2007

About 46% of Indiana's ERR is located in the Danville and Springfield beds (Tables 3.2.2, 3.2.3). Large coal resources in Indiana also exist in the Seelyville Coal Bed but this will involve deeper underground mining (Figure 3.1.3).

Table 3.2.2. Indiana's Coal Reserves & Major Seams

COAL BED	Original Billion Tons	Available Billion Tons
Danville	6.55	0.86
Springfield	13.31	7.35
Indiana TOTAL	59.53	17.55
D & S, % of total	33.4%	46.7%

Source: IGS 2007

The available coal reserves in Indiana's coal beds are much greater for underground mining having several times as much EER than for surface mining (Table 3.2.3). Nearly 16 Billion tons is available for underground mining and over 2 Billion tons for surface mining. The location of these reserves by county is shown in Table 3.2.4. The large reserves of the Danville and Springfield Coal Beds exist in Daviess, Gibson, Greene, Knox, Pike, Posey, Sullivan, Vanderburgh, Vermillion, Vigo, and Warwick counties (Figure 3.2.5, Table 3.2.4).

Table 3.2.3. Indiana's Coal Resources by Coal Bed (Billion short tons)

Coal bed	Original	Mined -out	Remaining	Restricted for mining	**Total available** (Remaining - Restricted)	Available as % of original	Available for surface mining	Available for underground mining
Danville	6.55	0.36	6.19	5.33	**0.83**	**13.89**	0.35	0.52
Hymera	5.53	0.55	4.98	4.10	**0.87**	**17.47**	0.15	0.81
Springfield	13.31	1.31	12.00	4.65	**7.35**	**61.25**	0.82	6.94
Houchin Creek	5.92	0.0022	5.92	5.56	**0.36**	**6.08**	0.18	0.17
Survant	8.47	0.31	8.17	6.86	**1.31**	**16.03**	0.22	1.10
Colchester	5.14	0.001	5.14	4.95	**0.19**	**3.70**	0.11	0.10
Seelyville	14.61	0.33	14.28	7.68	**6.60**	**46.22**	0.30	6.30
Total	**59.53**	**2.8632**	**56.68**	**39.13**	**17.54**	**30.95**	**2.13**	**15.94**

Source: [3.12]

Table 3.2.4. Coal Reserves, by County, at Indiana's Danville & Springfield Coal Beds (Thousand short tons)

County	Mining Type	DANVILLE	SPRINGFIELD	D + S
Daviess	Surface	0.00	16.59	16.59
	Underground	-	0.00	0.00
Gibson	Surface	43.91	95.53	139.44
	Underground	36.35	**1,930.91**	**1,967.26**
Greene	Surface	0.69	70.17	70.86
	Underground	-	5.68	5.68
Knox	Surface	51.63	55.49	107.12
	Underground	228.35	**1,072.42**	**1,300.77**
Pike	Surface	9.75	160.68	170.43
	Underground	0.00	175.11	175.11
Posey	Surface	0.00	-	0.00
	Underground	0.00	**1,527.61**	**1,527.61**
Sullivan	Surface	78.95	72.64	151.59
	Underground	108.11	741.72	849.83
Vanderburgh	Surface	0.07	0.00	0.07
	Underground	0.00	516.07	516.07
Vermillion	Surface	12.03	5.23	17.26
	Underground	11.70	21.12	32.82
Vigo	Surface	98.75	48.30	147.05
	Underground	137.82	335.26	473.08
Warwick	Surface	53.97	295.48	349.45
	Underground	0.00	608.78	608.78
TOTAL	**Surface**	**349.75**	**820.11**	**1,169.86**
	Underground	**522.32**	**6,934.68**	**7,457.00**

Source: [3.12]

Besides the large natural reserves of coal in Indiana, there is also significant economic benefit from the byproducts of Indiana's coal. The most common and economical use of fly ash is for the manufacture of concrete and concrete products. Flue Gas Desulfurization material (FGD) produces synthetic gypsum (a mixture of gypsum, $CaSO_{4,}$ and calcium sulfite, $CaSO_3$) which is used for the production of wallboard. In 1999 the state's Coal Utilization By-products (CUBs) amounted to over 8 MTons (Table 3.2.5), and 42% of this tonnage was economically reused. Indiana's rate of reuse is 12% higher than the 30% national average re-use rate.

Table 3.2.5. Indiana's 1999 Coal Utilization Products (CUBs), Production & Consumption

CUB	Production MTons	Consumption MTons	Percentage Consumed
Fly Ash	3.287	1.130	34%
Bottom Ash	1.162	0.497	43%
FGD Materials	3.779	1.839	49%
Total	**8.229**	**3.466**	**42%**

Source: [3.4]

Further information on IGS reports, publications, maps, and other facilities are available at:
http://igs.indiana.edu/

3.3 References

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CHAPTER 4

INDIANA'S COAL PRODUCTION

4.1 Historic Production

Coal was first discovered in Indiana in 1736 along the Wabash River, and by 1804 coal mines were being included on state maps. In the 1830s coal was on sale in southern counties and the first coal company was officially incorporated [4.1]. The production of coal has always been important to the state, and in Indiana's current economy provides an estimated $1,350 Million of state economic activity. It creates for the state an estimated 14,325 jobs related to coal mining and the industries which provide inputs to the coal mining industry [4.2].

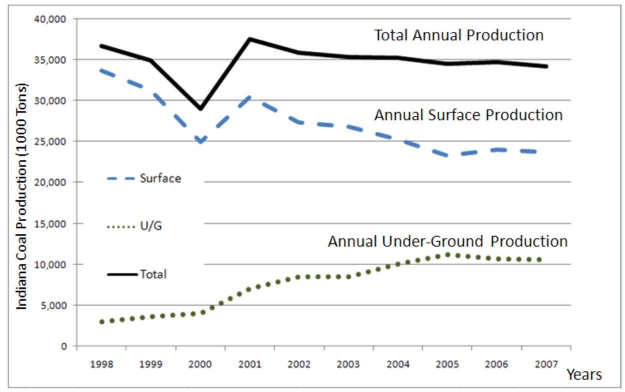
Indiana has large coal reserves but the National Research Council identifies the three important factors relating to future production:

> *"The key issue for policy makers is the amount of coal that is economically recoverable. This is not a fixed quantity, but depends on (i) the geological resource, (ii) the market price, and (iii) the cost of mining." [4.6]*

Previous chapters have considered Indiana's geological resources and this chapter starts to look at production and market prices and the factors that impact costs for new production capacity.

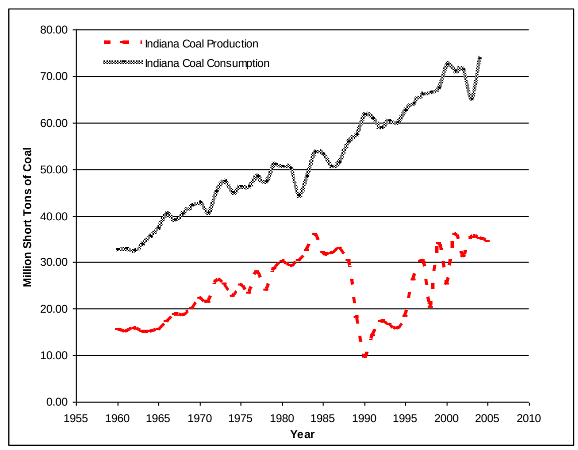
Over the past decade Indiana's coal production has stayed steady at around 35 MTons per year. There has been a steady increase in underground coal mining with a similar reduction in surface mining (Figure 4.1.1). The rate of production, however, is about half of what the state consumes (Figure 4.1.2). National and global trends in energy use are impacting Indiana with higher coal (coking coal and steam coal) prices, increased levels of coal demand, and the various constraints for building new power stations (Table 4.1.1). Details of the coal imports to the state are in Chapter 5.

Figure 4.1.1. Indiana Coal Production 1998-2007



Source [4.2]

Figure 4.1.2. Indiana Coal Production & Consumption



Source [4.7]

Table 4.1.1. Coal Trends in 2007 & 2008

- Prices for **Central Appalachian coal have doubled** in 1 year.
- **Metallurgical coal prices have climbed 200%** in 1 year.
- **U.S. coal exports are booming**, possibly trebling in next 2 years, hitting 79 MTons.
- We are **still building 15,000 MW**, 27 units under construction
- **China & India adding 4 BTons** to annual coal demand?
- Prices for **natural gas** are **climbing** with higher oil prices, clearing $11.43 mcf in June 2007.
- **Nuclear power can't significantly increase** its supply to the grid for another decade or more.
- U.S. coal demand in 2008 is now expected to top 1.21 BTons, a new record (**2006 US coal production = 1.163 BTons**).

Source [4.3]

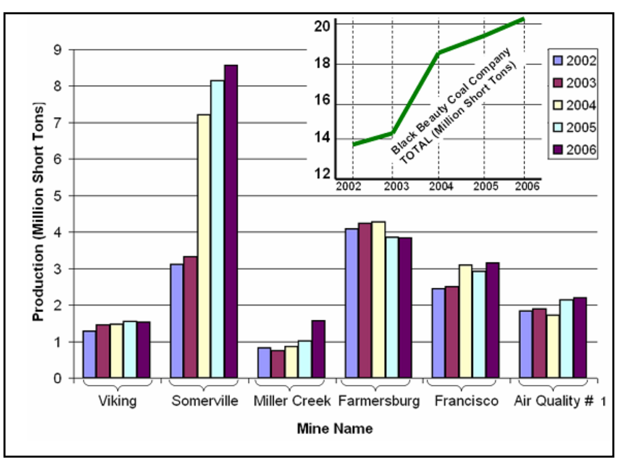
Besides the gradual increase in underground mining in Indiana, there have been market changes that are impacting the selling price of coal more than the level of production. The price of metallurgical coal doubled in 2008 and there has been an increase in international exports with greater demand coming from China and India.

Together with increased natural gas prices and potential for new clean coal power stations it is good economics to consider increasing the levels in Indiana's coal production. Coal is the cheapest fuel source. It is an abundant "home-grown" natural resource and strengthens national security. The big uncertainty, however, over proposed carbon management legislation is a major factor causing some slow-down in the potential production increase.

Indiana's Coal Companies

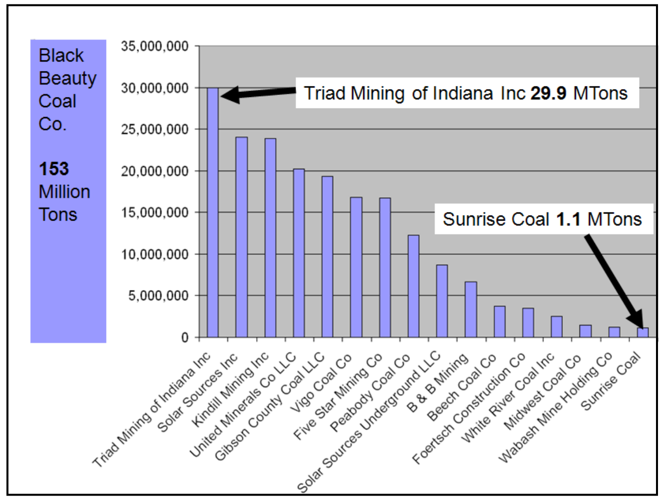
Within Indiana the Black Beauty Coal Company has the largest coal production capacity and their Somerville mine, in Gibson County, has been the largest single producer of coal for the past several years (Figure 4.1.3). Over the past ten years Black Beauty has produced over 150 MTons of Indiana coal (Figure 4.1.4). Triad Mining of Indiana Inc., Solar Sources Inc., and Kindill Mining Inc., over the same time period, have each produced about 16% to 20% of the amount that Black Beauty produced.

Figure 4.1.3. Black Beauty Coal Production by Mine



Source [4.2]

Figure 4.1.4. Ten Year Total Coal Production from Indiana, Coal Operators, 1998-2007 (>1 MTons)



Source [4.2]

From 1998 to 2007 the Black Beauty Coal Company produced two to three times more coal than its nearest competitor and over this time doubled its total annual production from 10 MTons to 20 MTons (Tables 4.1.2, 4.1.3).

Over the past ten years, Indiana has also seen changes in the ownership of its coal companies. In 1998 there were 18 coal mining companies and in 2007 only eight (Table 4.1.2). These ownership changes however have shown little or no change in the level of state total coal production.

Table 4.1.2. 1998 & 2007 Indiana Coal Company Production Rankings (Tons)

1998 Indiana Coal Company Production Rankings (tons)

1. Black Beauty Coal Company	10,654,165
2. Peabody Coal Company	6,255,746
3. Kindill Mining, Inc.	4,017,242
4. Solar Sources, Inc. & Solar Sources Underground, LLC	3,710,900
5. United Minerals Company, LLC	2,603,111
6. Vigo Coal Company	2,483,562
7. Triad Mining, Inc.	2,279,789
8. Midwest Coal Company	1,407,697
9. B & B Mining	929,914
10. Foertsch Construction, Inc.	716,655
11. Beech Coal Company	603,971
12. Little Sandy Coal Company, Inc.	371,660
13. Rogers Group, Inc.	240,075
14. Phoenix Natural Resources	197,541
15. McCawith Energy, Inc.	82,811
16. Collie Coal Company	70,532
17. Squaw Creek Coal Company	62,897
18. Maurice Kane	4,945

2007 Indiana Coal Company Production Rankings (tons)

1. Black Beauty Coal Company	19,648,971
2. Gibson County Coal	3,213,852
3. Triad Mining, Inc.	3,141,517
4. Solar Sources, Inc.	2,983,983
5. Five Star Mining, Inc.	2,624,031
6. Vigo Coal Company	1,403,304
7. Sunrise Coal	972,477
8. White River Coal Company	243,014

Source [4.2]

Table 4.1.3. Coal Production in Indiana 1998 to 2007, by Operator

OPERATOR	TOTAL PRODUCTION Tonnage									
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
B & B Mining	929,914	1,052,457	1,049,198	1,897,608	970,903	477,993	255,664	0	0	0
Beech Coal Co	603,971	917,087	731,475	713,223	661,437	88,905	0	0	0	0
Black Beauty Coal Company	10,654,165	10,692,866	11,140,041	14,158,267	13,559,737	14,114,941	18,603,692	19,598,272	20,816,208	19,648,971
Coal Field Development Co	0	0	0	0	0	0	0	60,012	29,952	0
Collie Coal Co	70,532	91,885	31,121	77,225	0	0	0	0	0	0
Five Star Mining Co	0	0	0	1,242,865	2,340,645	2,206,290	2,345,369	3,154,998	2,777,562	2,624,031
Foertsch Construction Co	716,655	937,391	719,812	778,902	315,415	0	22,748	0	0	0
Gibson County Coal LLC	0	0	35,329	1,662,060	1,938,998	2,422,807	2,977,845	3,506,107	3,551,200	3,213,852
Kindill Mining Inc	4,017,242	4,497,583	3,499,218	3,224,258	3,105,331	3,401,889	2,132,158	0	0	0
Little Sandy Coal Co Inc	371,660	0	0	0	0	0	0	0	0	0
Maurice Kane	4,945	32,438	0	0	0	0	0	0	0	0
McCawith Energy Inc	82,811	207,654	133,514	121,884	83,365	7,401	0	0	0	0
Midwest Coal Co	1,407,697	20,572	0	0	0	0	0	0	0	0
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Peabody Coal Co	6,255,746	5,897,604	111,796	4,542	0	0	0	0	0	0
Phoenex Natural Resources Inc	197,541	77,289	5,114	3,322	0	0	0	0	0	0
Regional Equipment Rental Inc	0	0	18,180	0	0	0	0	0	0	0
Rogers Group Inc	240,075	10,767	0	0	0	0	0	0	0	0
Solar Sources Underground LLC	1,276,123	1,299,634	1,525,635	1,328,975	1,151,599	1,021,619	884,320	231,151	0	0
Solar Sources Inc	2,434,777	1,701,028	1,849,305	2,675,703	2,481,333	2,448,883	2,615,121	2,438,274	2,423,695	2,983,983
Squaw Creek Coal Co	62,897	0	0	0	0	0	0	0	0	0
Sunrise Coal	0	0	0	0	0	0	0	24,196	142,606	972,477
Triad Mining of Indiana Inc	2,279,789	2,237,882	2,249,681	3,080,964	3,264,130	3,396,468	3,391,181	3,546,086	3,348,316	3,141,517
United Minerals Co LLC	2,603,111	2,377,427	3,138,830	4,133,408	3,947,857	3,993,981	0	0	0	0
Vigo Coal Co	2,483,562	2,257,674	1,850,016	2,086,576	1,789,936	1,198,239	1,299,820	1,288,390	1,186,789	1,403,304
Wabash Mine Holding Co	0	226,254	389,272	339,484	228,798	0	0	0	0	0
White County Coal LLC	0	410,946	482,566	0	0	0	0	0	0	0
White River Coal Inc	0	0	0	0	3,650	527,157	712,595	612,463	439,383	243,014
TOTAL	36,695,211	34,948,437	28,962,103	37,531,267	35,845,136	35,308,576	35,242,517	34,461,954	34,717,717	34,233,156

Source [4.2]

4.2 Future Production

With growth in electricity demand, availability of new generation technologies (such as integrated gasification combined cycle power plants), and increased numbers of scrubber installations, there is expected to be an increase in bituminous coal demand (see coal forecast in Chapter 5). The increased transportation costs for Western coals and with more sulfur scrubber installations in the state, there is an improved possibility of displacing some of the 14 MTons of Western coals that are now being consumed in Indiana.

Where to start a new Indiana coal mine, however, is a huge issue and depends on the economics of mineable reserves, getting the rights to mine, and the critical need for a good transportation infrastructure that connects with the mine site. Many aspects have to be taken into consideration when planning new coal production.

Some important planning parameters, besides geological characteristics, are listed in Table 4.2.1. The demand for a specific coal quality will normally be specified in each new coal contract and the time needed to find a new mine site can be 5 to 10 years. Starting a mine will involve looking at investments of \$50 Million to \$300 Million. Issues of controlling the roof and floor and quantity of make-up materials all come into play. Typically every 10 Tons of in-place coal, for underground mines, yields 4.0 to 4.5 Tons of coal product, and for surface mines, almost 8.0 to 9.0 Tons.

Infrastructures and benefits of having the railroads that are readily available for coming straight into the mining area are enormous (see Chapter 6). Rights to mine and good transportation are two of the major issues influencing starting up new coal mines (Table 4.2.2). Complications also arise when potential reserve areas encroach into more populated areas (NIMBY, not in my backyard). Regulations and future new production can be approached from one of two directions; either

(a) find a reserve and try to market it, or

(b) develop a long term demand and a reserve which meets the criteria.

Table 4.2.1. New Mine Guideline Parameters

❑ **Time needed** to find mineable coal reserves & acquire mining & mineral rights - can take **5 to 10 years**.
❑ To start a major new mine (surface or under-ground) then investments of **\$50M to \$300M** might be required.
❑ In underground mines the **geological characteristics** (coal thickness, roof & floor strength), are **primary planning parameters**. Under ground mining gets difficult when the seam is < 4 ft thick.
❑ **Uncertainty of compliance costs** associated with Mine Safety & Health Administration (MHSA)regulations.
❑ Typically for **every 10 Tons of in-place coal,** for under-ground mines **it yields 4.0 to 4.5 Tons of coal product**, and for surface mines **almost 8.0 to 9.0 Tons.**

Source [4.4]

Table 4.2.2. Where to Locate A New Mine

Determining the location where to mine new large coal supplies is a huge issue & depends on:
(1) Economics of mineable reserves,
(2) Acquiring the **rights to mine** coal, &
(3) Critical need for a **good transportation infrastructure** that connects with the mine site.
(4) **Over burden** to seam thickness ratio is a critical factor for surface mining.
The need for a specific **coal quality must match the demand** when considering future levels of production.

Source [4.4]

Other planning issues include emissions standards, coal quality requirements, worker skills, increasing transportation costs, availability of new mining equipment, contracting mechanisms, improved infrastructures, and large investment requirements (Table 4.2.3).

Table 4.2.3. Major Issues Facing New Production

1) **Permitting** & land acquisition.
2) Changes in power plant **emission standards** & regulations for SO_2, NO_x, Hg, & potential CO_2 legislation.
3) Coal **quality** & expected volumes/sales.
4) Attracting/developing **qualified workers**.
5) Rising **transportation costs**.
5) Availability/delivery of **mining equipment**.
7) Types of **coal contracts**.
8) **Transportation & infrastructure**.
9) **Large capital** investments are required.

Source [4.4]

The Army Corps of Engineers (ACOE) has regulations which also impact potential new mining sites, as well as the established processes of post mining reclamation. The Corps regulates "jurisdictional" waters (i.e., waters of the U.S.). The actual water quality standards at a mine are controlled by the state (IDEM) and generally regulated through the NPDES (National Pollutant Discharge Elimination System) program. Costs of purchasing farmland and mineral rights are increasing (Table 4.2.4).

Table 4.2.4. The Permitting Process

❑ **Permitting** can take **a long time** (for data gathering & regulatory approval) & is **possibly the biggest time issue** when considering investment for a new mine.
❑ The ACOE (**Army Corps of Engineers**) has regulations affecting mining as well as post mining reclamation.
❑ **Permitting** is a long process involving **regulatory uncertainty**.
❑ ACOE regulates **jurisdictional quality** for U.S. water-ways & the state (IDEM) handles mine water outflows & air permitting.
❑ Costs of surface coal reserves are increasing**.** Typical **costs for purchasing Indiana farm land can exceed \$4,000/acre**. Depending on strip ratio (*cubic yards/ Ton product*) purchasing mineral rights can involve a further \$8,000/acre - **total cost is often > \$12,000/acre for surface mining**.

Source [4.4]

Climate change legislation could potentially have an enormous impact on future coal production. In 2008 the uncertainty on this topic made it difficult to invest in new production capacity. Carbon control legislation will reduce much of the uncertainty but could produce huge energy prices increases. Sulfur is no longer such a significant issue with increased scrubber installations. The design of power plant boilers is largely determined by what coal quality will be supplied and how the coal characteristics vary, but heat content remains the most important parameter insofar as power generation is concerned. The high heat content of Indiana coals makes it a favorite for power generation while its high sulfur content requires scrubber installations.

Having a qualified coal mining workforce is increasingly becoming a matter of great concern. The issue of shortages of skilled operators, mechanics and electricians becomes acute with the current retirement of the "baby-boom" workforce group. Recruitment of new employees and provision of training is now a high priority for most mining companies. Pay for the coal mining work force is attractive and conditions of working are enormously improved compared with earlier generations.

Expanding coal production requires purchasing mining equipment and this takes more and more time as a result of shortages in supply and increased mineral costs for steel and copper. There are shortages in machinery components (Table 4.2.5.) and often more than a year elapses between ordering equipment and receiving it. In recent years there have been severe shortages in supplies of off-highway tires (Indiana has needed to purchase them from Russia and China) for heavy moving equipment.

Transportation and infrastructure development needs are becoming even more significant when considering increased tonnage in coal production. When buyers purchase coal from a mining company, the extra cost of transportation is always added. Each ton of coal requires two gallons of diesel fuel for surface moving machinery and this has some noticeable impact when there are higher fuel costs. With the 2008 high fuel prices diesel fuel consumption added an immediate cost of $8 per ton of coal even before the coal was moved from the mine site (Table 4.2.6).

Table 4.2.5. Purchasing Mining Equipment

- ❑ There is a **shortage of equipment**.
- ❑ **New equipment has a long lead time** to arrive > year.
- ❑ **Increased mineral costs for steel & copper** is raising the costs of electrical & mechanical machinery.
- ❑ **Severe shortages** in very large off-highway tires (high demand & limited production); Indiana has purchased tires from Russia & China for off-highway mining equipment.
- ❑ **High prices of mining-supplies** makes planning very difficult, Examples: - roof bolts for underground mining, and diesel fuel & explosives for surface mining equipment.

Source [4.4]

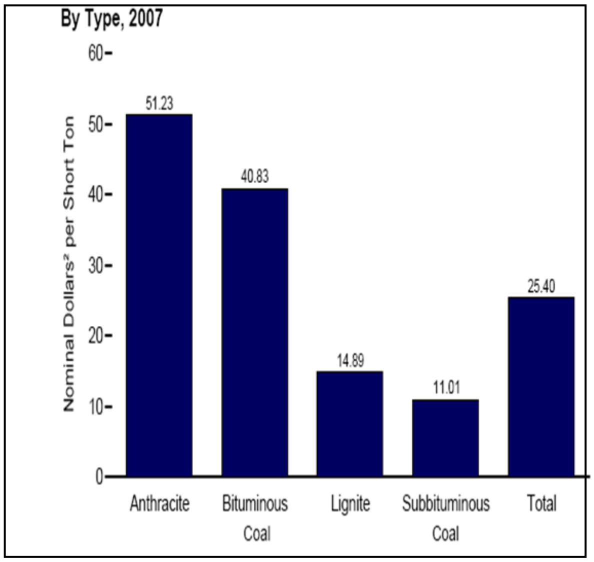
Table 4.2.6. Rising Transportation Costs

- ❑ **Increased fuel prices** are having their impact on the railroads, highway trucks & other mine equipment.
- ❑ For **each ton of surface coal produced approximately two gallons of diesel fuel** are consumed by mining machinery. **This adds an immediate cost of $8 per ton of coal** even before the coal has been moved from the mine site.
- ❑ **Problems in obtaining spare parts** for mining equipment especially non-availability of large off-highway tires.
- ❑ Always a **great advantage if a coal-fired power plant is located at the mine mouth** or very close to it.

Source [4.4]

Western coals coming into Indiana are likely to become more expensive as a result of limited railroad capacity from west to east. While this should encourage the use of more Indiana coal, any increased railroad capacity will generally help appease rising transportation costs. According to the EIA, the average coal price for bituminous coals in 2007 was $40.83/Ton (Figure 4.2.1). Costs of coals are increasing (Chapter 5) but, unlike gasoline, the bulk of coal is not sold through spot markets. It is sold mainly through arranged contracts (85% by contracts in the U.S.) that have indexing allocations to protect against increased costs. Trucking companies, rail companies, and county road agencies will not invest or allow for new transport capacity until long-term coal contracts are known to exist and that long-term capacity expansion is certainly going to be beneficial for the very long-term. In 2008 metallurgical coal was being sold at $200 to $300 per ton while Indiana coal had increased to $50 to $70 per ton. The best plan, whenever possible, will always be to have a coal-fired power plant at the mine mouth or near to it, therefore reducing or eliminating altogether the transportation costs.

Figure 4.2.1. EIA Average Coal Prices 2007



Source [4.5]

> **About 85% of U.S. coal supplies are via contracts** & the rest via futures/spot markets. Coal supply **contracts will vary** with changes in the market, levels of demand, & regulatory climate.

Types of coal contracts vary depending on whether it is a buyer's or seller's market. About 85% of all current U.S. coal supplies come through contracting. The 15% from forward markets depend on spot pricing with agreements to buy or sell at certain times and prices. For most liquid commodities and financial assets, minute-by-minute values or spot prices are involved. Frequently, investment development for new coal production will occur with an extension to an existing coal mining site. This is less expensive than starting with a totally new mine site and can provide an increase in production of up to 10% at a time. This might not provide dramatic increases in coal production, if thinking in terms of extra million tons per year, but more often than not provides a sound investment in resources.

4.3 References

[4.1] Indiana Coal Council, http://www.indianacoal.com/
[4.2] Brian H. Bowen, Forrest D. Holland, F.T. Sparrow et al, "Expanding the Utilization of Indiana Coals", Purdue University, August 18, 2004
[4.3] Luke Popovich, CoalAge, June 2008
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[4.5] EIA Annual Energy Review 2007, http://www.eia.doe.gov/emeu/aer/coal.html
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[4.7] http://www.eia.doe.gov/emeu/states /sep_use /total/use_tot_in.html

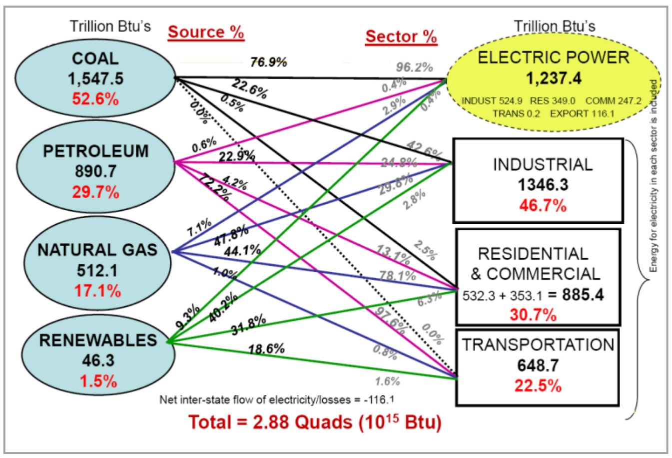
CHAPTER 5

INDIANA'S COAL CONSUMPTION & FORECAST

5.1 Indiana's Coal Consumption

In recent years Indiana's total annual coal consumption has represented over 52% of the state's total energy needs, with nearly 77% of the coal being consumed to generate 96% of the state's electricity (Figure 5.1.1).

Figure 5.1.1. Indiana Primary Energy Consumption Source & Sector 2006

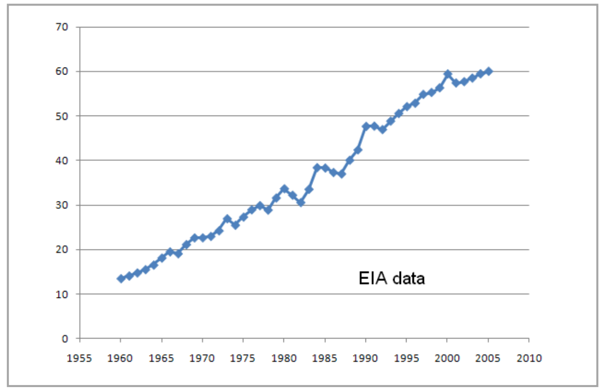


Source: [5.1]

Coal is such a critical commodity for Indiana as it fuels most of the state's electric power stations and provides industry, commerce, and the residential sectors with some of the cheapest electricity in the nation. Over 22% of the coal consumed goes to Indiana industry. Coal therefore supplies Indiana industry with cheap energy which amounts to about 46% of the total energy needs for this sector. The largest Indiana industrial consumer of coal is the steel industry which has a high demand for coking coal.

Over the past 50 years the consumption of coal has steadily increased. The consumption by Indiana's electricity power plants has risen from about 15 Million tons (MTons) in the early 1960s to over 60 MTons per year in the early 2000s (Figure 5.1.2).

Figure 5.1.2. Indiana Coal Consumption (MTons) for Power Generation: 1960-2006

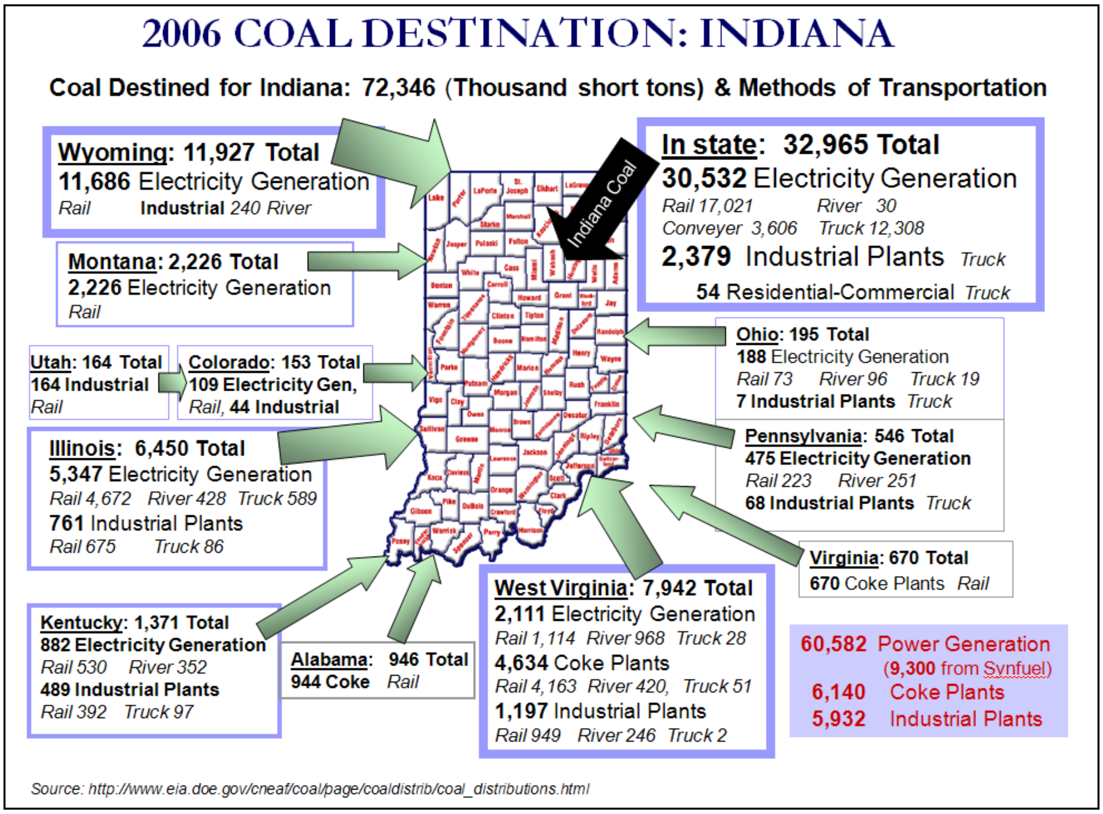


Source: DOE, EIA [5.1]

Indiana's total coal consumption in 2006 was about 72 MTons (including 9.3 MTons of "synfuel" consumption at Indiana's power stations). About half of this total was mined in state (35 MTons) with the rest being imported from Wyoming, West Virginia, Illinois and other states. Coal consumption in Indiana's power sector amounted to 60.58 MTons in 2006 (Figure 5.1.3).

Wyoming has been the major coal exporter to Indiana with 11.9 MTons (16% of total state consumption in 2006). The low sulfur WY coals have aided the state to comply with the clean air act SO_2 emissions requirements. In 1975 WY was producing 434 Trillion Btu (TBtu) of coal and 30 years later in 2005 had amazingly increased to 7,019 TBtu, which amounted to a sixteen-fold increase (1 TBtu WY coal ≈ 58,000 Tons). The clean air act and WY low production costs have had a big impact on Indiana [5.2]. With an increased number of scrubbers now installed on Indiana's power plants, it is relevant to reconsider the extent to which WY coal imports should continue.

Figure 5.1.3. Coal by Destination: Indiana 2006



West Virginia is the second largest coal exporter to Indiana, with 7.9 MTons annually (11% of total consumption). The bulk of the WV coal is for coking (4.6 MTons) coal to supply Indiana's steel industry. If Indiana's steel industry can consume some Indiana coal in its coking processes (Chapter 6) then dependence on WV coal can be reduced. Illinois is the third largest coal exporter to Indiana, with 6.4 MTons annually (9% of total consumption). The coal characteristics of IL coal are very similar to Indiana's bituminous coal (both are part of the Illinois Coal Basin) and so a commercial study to see how the consumption of Indiana coal might replace some of the IL coal would be valid. The limited displacement of imported coals (steam coal and metallurgical coal) with Indiana coals will make a significant boost to Indiana's mining industry.

Indiana Coal Prices

Indiana's average price of delivered coal for both electric utilities and "other industrial" consumers, at 6.46 cents/kWh, is relatively close to regional average coal prices (Table 5.1.1).

Table 5.1.1. EIA State Electricity Profiles, 2007 Average Retail Price (Cents/kWh)

Illinois	7.07
Indiana	6.46
Kentucky	5.43
Michigan	8.14
Ohio	7.71
Wisconsin	8.13

Source: [5.10]

Indiana (IN) generates 95% of its electricity (MWh) from coal and Kentucky (KY), at the very low price of 5.43 cents/kWh, generates 92% from coal. The state of Michigan (MI) generates 60% of its electricity from coal (MWh), and Wisconsin (WI) 65%. The 2006 electricity average retail prices are 50% higher for MI and WI compared with KY and 26% higher compared with Indiana. The high use of coal and negligibly use of natural gas for power generation in IN and KY maintains the low cost electricity compared with national figures.

Average prices of coal delivered to end users rose by about 6% for Indiana from 2005 to 2006, increasing from $30.15 to $31.94 for electricity utility plants (Table 5.1.2). The average price of coal delivered to other industrial users in Indiana was almost double the amount paid by the utilities. These higher prices are similar to the commodity spot prices for coal in mid 2008 (Figure 5.1.4). Although selling coal through the spot markets account for only about 15% of total U.S. coal sales these prices provide a forewarning of more general future coal prices.

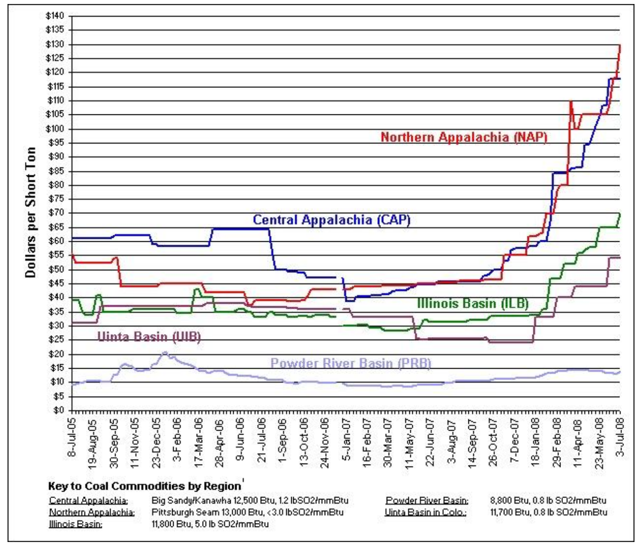
Table 5.1.2. Average Price of Coal Delivered to End Use Sector by Census Division and State, 2005, 2006

	2005		2006	
	Electric Utility Plant	Other Industrial	Electric Utility Plant	Other Industrial
Illinois	21.43	33.1	25.16	36.95
Indiana	30.15	58.11	31.94	59.83
Kentucky	36.01	65.42	40.29	70.68
Michigan	30.95	70.05	32.67	71.34
Ohio	37	58.87	39.92	64.81
Wisconsin	22.7	59.25	26.14	64.32
Average	*29.71*	*57.47*	*32.69*	*61.32*

Source: [5.3]

Some states will be impacted by carbon controls much more than others. Indiana's high dependence on coal for production of electricity will make it one of the states most seriously affected by any future carbon management legislation (Chapter 8).

Figure 5.1.4. Average Weekly Coal Commodity Spot Prices (for business week ending July 3, 2008)



Source [5.2]

The Clean Air Act amendments of the past 40 years have caused major reductions in SO_2, NO_x and particulates. Future formulations to control CO_2 emissions could be more complex and considerably more expensive.

Different coal rankings emit different amounts of CO_2. Anthracite will emit about 227 lbs of CO_2 per Million Btu (MBtu) and the Midwest bituminous coal will emit at 205 lbs per MBtu (Table 5.1.3). Whatever carbon management controls are legislated in future years they are frequently anticipated having a significant adverse affect on Indiana's attractive competitive low energy costs.

Table 5.1.3. CO_2 Emission Factors for Coal

Different rank coals produce different amounts of lbs CO_2 per MBtu

In pounds of CO_2 per Million Btu
U.S. average factors (EIA):

227.4 lbs/MBtu for **anthracite**
216.3 lbs/MBtu for **lignite**
211.9 lbs/MBtu for **sub-bituminous coal &**
205.3 lbs/MBtu for **bituminous coal** (IN 203.6)

Indiana Coal = 22.2 MBtu/Ton
≈ **2.28 Tons CO_2 per Ton Coal**

Source: DOE, EIA

Quite unlike SO_2 and NO_x the amounts of CO_2 emitted per Ton of coal are so much greater. Indiana power plants emit around 148 MTons of CO_2 per year (2002) compared with only 901 Tons of SO_2 and 279 Tons of NO_x (Table 5.1.4). Transportation and other CO_2 emission sources emit more than the state utilities (173,739 MTons). Controls on the utilities are usually given first reference because it is considered easier to capture CO_2 on stationary sources.

Table 5.1.4. 2002 Emissions in Indiana

INDIANA EMISSIONS	2002 (Thousand Metric Tons)		
	SO_2	NOx	CO_2
Utilities	901	279	148,000
Transportation	19	318	64,348
Other	93	119	109,391
Total	1,013	716	321,739

Indiana Power Plants produce 148 MTons of CO_2/ year

Source. DOE, EIA

The CCTR wishes to partner with climate control research groups in the state for future projects.

5.2 Forecast of Indiana Coal Use

Likely changes in the use of Indiana coal, in Indiana and elsewhere, for the period 2008-2025 have been considered by a CCTR supported study and five developments were noted that will probably make future use of coal substantially different from its historic use [5.5]:

1) Likely passage of some form of legislation limiting CO_2 emissions;
2) Phases I and II of the Clean Air Interstate Rule (CAIR) going into effect;
3) The dramatic rise in transportation costs for coal;
4) For coal use by the Indiana iron and steel industry, the replacement of by-product recovery coke ovens by non-recovery units; and
5) The near doubling of eastern US coal exports to Europe and elsewhere in response to the withdrawal of China as an exporter of coal, and the resultant run-up in Eastern coal prices relative to Illinois Basin (IB) and Powder River Basin (PRB) coals.

In 2006, according to the EIA, over 68 Million Tons (MTons) of coal were either delivered to Indiana coal users or exported from Indiana [5.11]. EIA shipment data, rather than use data were used as a point of reference, since EIA use data does not keep track of the source of coals. Table 5.2.1 (and Figure 5.1.3) summarizes the 2006 flows. As the table shows, of the 52.9 MTons delivered to Indiana utilities, only 30.5 MTons were mined in Indiana, the balance coming from Western mines (14 MTons), other Illinois Basin states (6.5 MTons) and eastern states (1.8 MTons). Coal shipments to Indiana's iron and steel industry totaled over 6 MTons, all from eastern states, while deliveries to industrial plants totaled an additional 6 MTons, including 2.7 MTons to Alcoa's Warrick electricity generating units. Finally, 3.4 MTons of coals were exported in 2006, mostly to utilities. Projections are considered for each of the three uses:

(a) electricity generation,

(b) iron and steel, and

(c) other industrial use.

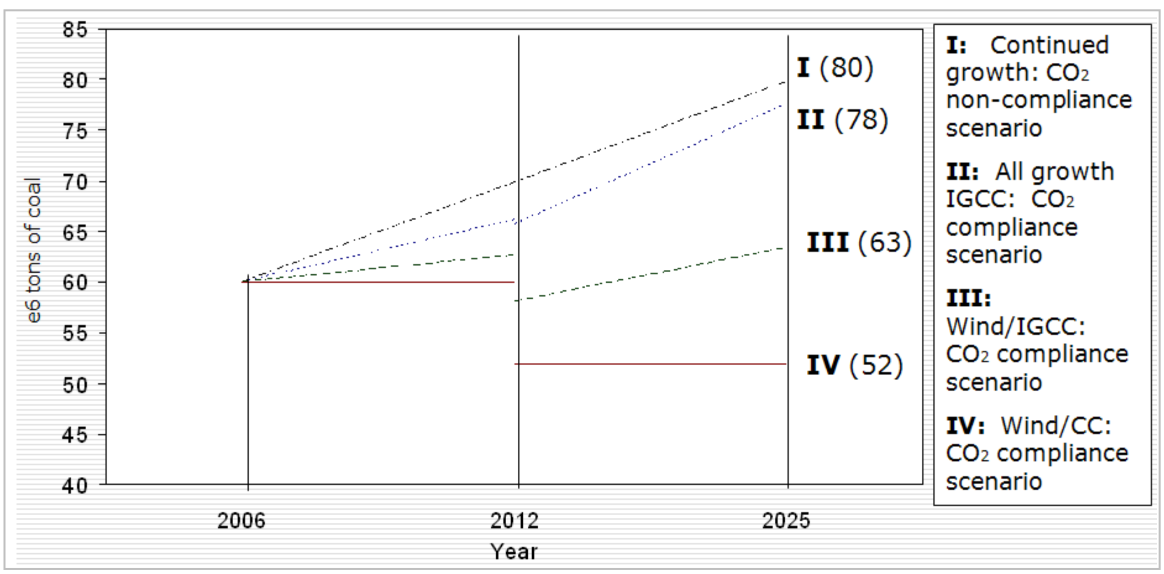
Projections of Coal Use by Utilities

Regarding Indiana and imported coal use by Indiana and other utilities, a wide range of use trajectories is considered, depending on utility adjustments to likely CO_2 legislation. Figure 5.2.1 summarizes four forecasts. All projections start with Indiana utility coal use (not shipments) in 2006, which totaled 60 MTons.

Table 5.2.1. Total Coal Delivered in Indiana Plus Exports, 2006 (Million Tons, MTons)

Delivered to Indiana Utilities *Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006." MTons= Million Tons*	30.53 MTons from Indiana mines 5.7 MTons from Illinois mines 0.8 MTons from Kentucky mines 11.7 MTons from Wyoming mines 2.2 MTons from Montana mines 1.1 MTons from Virginia mines 0.7 MTons from other mines **Total: 52.9 MTons**	Note: 52.9 MTons shipped, 60 MTons consumed in 2006; data on use by source not available. Source: EIA, "US Coal Consumption by End Use by State, 2006"
Delivered to Coke Plants	0.9 MTons from Alabama 0.7 MTons from Virginia 4.5 MTons from West Virginia **Total: 6.1 MTons** [amount consumed withheld by EIA]	Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."
Delivered to Industrial Plants	2.4 MTons from Indiana 1.8 MTons from West Virginia 0.8 MTons from Illinois 0.5 MTons from Kentucky 0.4 MTons from other **Total: 5.9 MTons** [5.6 MTons consumed]	Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."
Exports	2.67 MTons to utilities 0.57 MTons to industry 0.17 MTons to other **Total: 3.41 MTons**	Source: EIA, "Domestic Distribution of US Coal by Origin State … 2006"
GRAND TOTAL	Shipments: 65.046 MTons Exports: 3.4 MTons **Total: 68.4 MTons**	Source: EIA, "Domestic Distribution of US Coal by Origin State … 2006"

Figure 5.2.1. All Cases, Coal Use, 2006-2025 (Million Tons)



Source [5.11]

In Case I (historical growth rates assumed) if legislation limiting CO_2 emissions were not enacted, the future could be expected to look very much like the past. Trajectory I in Figure 5.2.1 is based on extrapolating the 1995-2005 growth rates in the use of coal by Indiana utilities reported by EIA [5.4]. Extrapolating these historical growth rates into the future shows that coal use could be expected to grow to almost 80 MTons a year by 2025, an increase of 20 MTons from current levels.

If CO_2 legislation were to be enacted, two questions must be answered – what legislation and what compliance strategy would be used by utilities? Fortunately, Purdue's State Utility Forecasting Group (SUFG) report (February 2008) [5.7] discusses the consequences of two possible compliance strategies if the bill eventually passed were to be the Lieberman-Warner Climate Security Act, SB2191 before amendments. The SUFG report considers two compliance strategies – one meeting the CO_2 targets of the bill by construction of IGCC plants with CO_2 sequestering, the other using a combination of wind and gas-fired combined cycle technology. This CCTR study adds yet a third compliance strategy – wind in combination with IGCC plants. In all three cases, the compliance strategy assumes SB2191's "cap and trade" system is adopted, which applies to all fossil-fueled generating units and industrial units which emit more than 10,000 Tons per year CO_2 equivalent of greenhouse gases. The U.S. cap starts at 5,200 MTons of CO_2 in 2012, dropping to 3,592 MTons by 2025, the end of the forecast horizon of the SUFG report. All three strategies assume companies will purchase non-covered offsets up to the specified maximum, and will construct new base load generation capacity to meet the demand growth forecast by SUFG over the horizon as shown in Table 5.2.2.

Table 5.2.2. New Indiana Baseload Requirements (MW)

Year	Baseload
2006	120
2007	120
2008	240
2009	480
2010	730
2011	1020
2012	2020
2013	2090
2014	2270
2015	2520
2016	2860
2017	3130
2018	3380
2019	3700
2020	4000
2021	4300
2022	4660
2023	5040
2024	5440
2025	5890

Note: MW is cumulative
Source: SUFG/PCCRC report

Since the CO_2 targets cannot be met by just constructing low CO_2 emissions units to meet new demand, additional units must then be retired and replaced in 2012 to meet the cap requirements, as shown in Table 5.2.3.

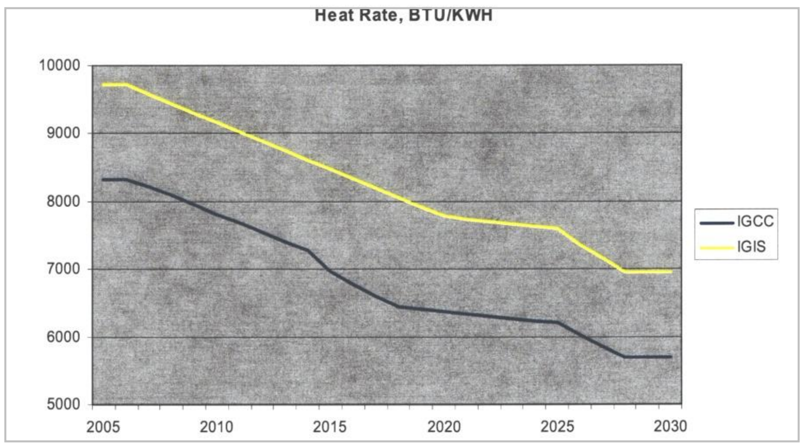
Table 5.2.3. New Indiana Baseload Requirements: Retiring Facilities in 2012

Facility	Nameplate MW
Tanners Creek 1-3 (1.2e6 Tons BIT)	519
Eagle Valley/Pritchard 3-6 (0.79e6 Tons BIT)	301
Bailly 7, 8 (1.3e6 Tons BIT)	615
Edwardsport 7, 8 (0.18e6 Tons BIT)	109
Gallagher 1-4 (1.3e6 Tons BIT)	600
Wabash River 2-5 (1.65e6 Tons BIT)	472
Warrick 4 (1.1e6 Tons BIT)	323
TOTAL: ~ 8e6 Tons BIT (3.4 non-IN)	**2939 MW retired**

Source: EIA Form 767 data
Note: 2006 Indiana utility coal Tonnage is use, not deliveries

In the Case II IGCC with sequestering compliance, if it were assumed that the new units to meet new and replacement base load demand were IGCC plants, then coal use by Indiana utilities could be expected to grow to 78 MTons/year by 2025, assuming the plants operate at a 90% capacity factor. The key to this forecast is determining the increase in the heat rate for the IGCC plants caused by having to use a good portion of the electricity generated to compress, ship, and inject CO_2 into storage areas. This study takes the forecast of IGCC heat rates found in a DOE/NETL 2008 report referenced in Figure 5.2.2.

Figure 5.2.2. Case II: Calculation of Coal Use Projections by Utilities in Indiana for IGCC Scenario



Source: [5.12]

As the figure shows, IGCC heat rates with CO_2 injection derating are expected to drop to the 9,750 Btu/kWh range by 2015, a bit less than the current average base load heat rate in Indiana. Since the embedded heat rates in existing base load plants are roughly equal to these derated IGCC plants, the retirement and replacement of older capacity in 2012 only slightly alters the trajectory in 2012, when the older units are replaced by the IGCC units.

With the Case III wind/IGCC compliance, if on the other hand, compliance were to be achieved by a combination of wind and IGCC plants, Figure 5.2.1 shows use would grow to only 63 MTons/year by 2025. The replacement of the roughly 3,000 MW of coal fired capacity in 2012 necessary to meet the CO_2 limits causes 2012 coal consumption to drop by 4 MTons/year, since the heat rates of the replaced units are higher than the heat rates of the IGCC units, even with the derating necessary for CO_2 injection. This projection is based on the SUFG assumption that each 60 MW of wind generation capacity must be backed up by 50 MW of IGCC generation capacities in order to guarantee the availability of energy during peak demand periods. This results in the IGCC units operating at only a 48% capacity factor in this case. While the SUFG report estimates that this case releases roughly the same amount of CO_2 as the wind/combined cycle case discussed below, SUFG projects it to be 12% more expensive than the wind/combined cycle case.

Finally in the Case IV, wind/Combined Cycle compliance, if the compliance strategy were to be a combination of wind and gas-fired combined cycle plants, coal use could be expected to decrease to 52 MTons a year, well below the current use level of 60 MTons a year. As in the wind/IGCC case, SUFG assumes that each 60 MW of wind must be backed up by 50MW of conventional capacity, in this case gas-fired Combined Cycle (CC) units. As Figure 5.2.1 showed, coal use is constant until 2012, since all growth in demand is assumed to be met by a combination of wind and as fired CC units. Coal use drops by 8 MTons in 2012 as a result of the retired coal units being replaced by the combination of wind and natural gas-fired units, and is constant thereafter, since all new demand is assumed to be met by the combination of wind/CC.

In conclusion, with this range of four scenarios a perfect forecasting storm could be considered. As Figure 5.2.1 showed, coal use by Indiana utilities can range from 52 to 80 MTons a year by 2025, depending on the enactment of CO_2 legislation, and the technologies the utilities use to comply with such legislation. This compares with current use of around 60 MTons/year. Such a wide range of estimates makes the forecast essentially useless for planning purposes. It is no wonder that Indiana coal producers, like those in other states, are reluctant to open new mines until the uncertainty regarding the impact of CO_2 legislation on coal's share of the electricity generation business is reduced. Add to this uncertainty the impact of uncertain higher oil prices on natural gas prices results in a near perfect storm for utility planners.

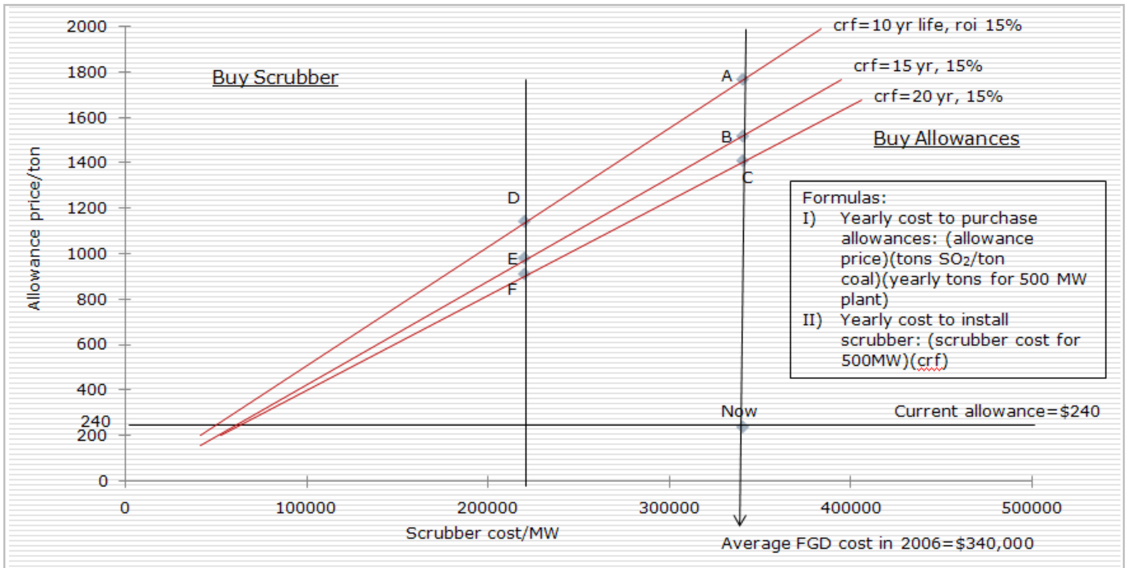
Use of Indiana Coal for the Generation of Electricity

What does all this mean for the use of coal mined in Indiana to generate electricity? Forecasting the use of coal mined in Indiana by Indiana's utilities and others is much more speculative than forecasting total utility coal use as was done in the above section 5.2.1, since, in addition to the factors previously discussed which apply to the competition between coal in general and other sources of base load power, it involves first projecting how Illinois Basin (IB) coal will compete with Powder River Basin (PRB) coals, and then projecting how Indiana coals will compete with Kentucky and Illinois coals for their share of the IB market. Since most IB coals are near indistinguishable from one another when mined from the same horizon (some minor differences arise because of differing depths of the deposits as one approaches the middle of the basin), shifts in the three states' market shares of total IB coals are probably going to be nearly unpredictable. They will be governed by a host of factors including the relative success of each of the three states in encouraging mining and utility coal using activity within their states, movement of coal within the states, encouragement of coal exports from the states, and the like. A more tractable question is to examine the impact of the factors mentioned earlier on the relative competitiveness of IB coals and Western coals. Starting with the passage of clean air legislation in the mid-1970s, PRB coals have dramatically reduced the markets for IB coals, due chiefly to PRB coals' lower sulfur content and the economics of unit trains. This trend has continued up to the present day; the question is: are there developments which could reverse this trend, and recapture some of the markets IB coals have lost to their PRB competitors? The answer seems to be a qualified yes, depending on whether coal switching in existing plants or coal choice in new plants is being considered.

Regarding coal switching in existing units now using PRB coals, it appears that compliance with Phases I and II of the CAIR legislation will result in existing units buying allowances and continuing to use PRB coals, rather than purchasing scrubbers and switching to IB coals.

Figure 5.2.3 shows the outcome of the factors determining the scrub and switch versus allowance purchase choice decision as a function of the three major factors that enter into the choice: (i) the cost of purchasing allowances, (ii) scrubber equipment costs, and (iii) the capital recovery factor used to annualize the equipment costs. Figure 5.2.3 assumes the existing plant is a 500 MW pulverized coal plant with a heat rate of 10,000 Btu/kWh, operated 90% of the time, burning PRB coals with a heat content of 8,800 Btu/lb and a sulfur content of 20 pounds/Ton. The figure also assumes that the cost per million Btu of IB and PRB coals are the same, that if utilities choose to scrub and switch to IB coals, no allowances need to be purchased, and the operating costs for scrubbers are minimal. All these assumptions tend to make IB coals more competitive with PRB basin coals than they really are, so if scrub and switch is not competitive under these circumstances, it will not be competitive with more realistic assumptions regarding these factors.

Figure 5.2.3. PRB Coal User Choice: Buy/Not Buy Scrubber?



Assumptions: 500 MW PC plant, 90% utilization rate, heat rate 10,000 Btu/kWh, using PRB coal with 20 lbs/ton CO_2, heat content 8800 Btu/lb.

To construct the figure, the annual costs of the two alternatives for 500 MW plant were calculated as a function of the three key variables. The annual cost of the allowance strategy is simply the forecast allowance price per Ton of SO_2 times the Tons of sulfur per Ton of coal times the Tons of coal purchased annually for a 500 MW plant. The yearly cost of the scrubber option is the forecast cost of the scrubber times the assumed capital recovery factor. The diagonal lines divide the space into two areas – areas in the upper-left hand corner of the diagram where the unit would be expected to install scrubbers and switch to IB coals, and areas in the lower right where the units would be expected to continue to use PRB coals by purchasing allowances. The lines themselves represent combinations of input values which make the units indifferent to the use of the two options. As Figure 5.2.3 indicates, given that current SO_2 allowances are selling at around $240/Ton and scrubbers costing well over $300,000/MW, there is little likelihood that units now burning PRB coals will switch. Only if SO_2 allowance prices rise above $800/Ton and scrubber costs drop to below $220,000/MW will there be any chance for the scrub/switch option.

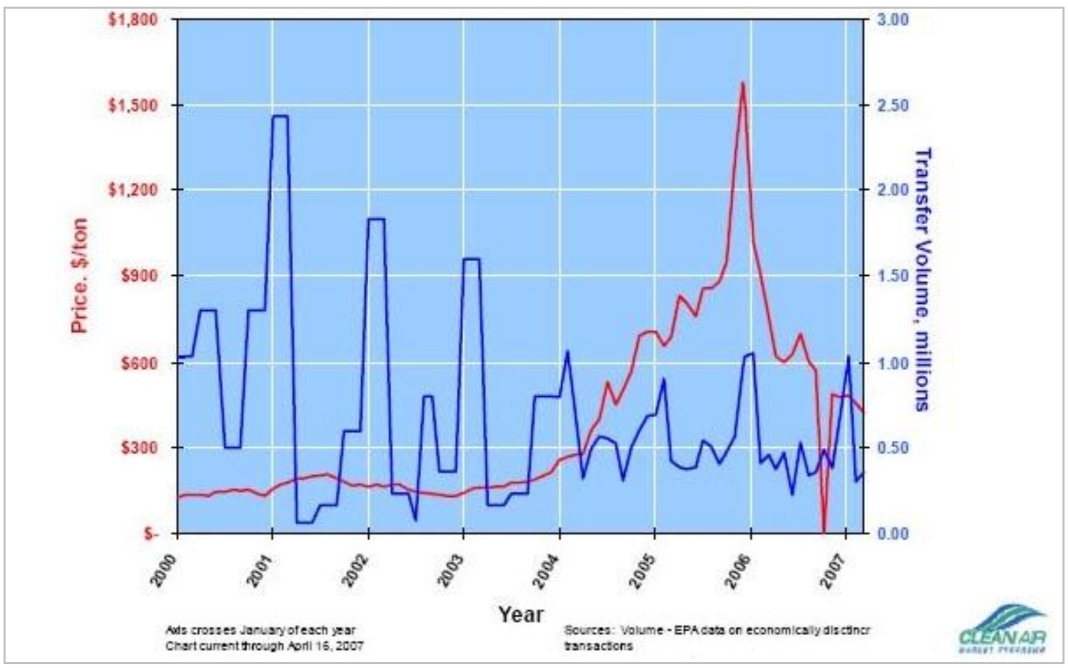
Table 5.2.4. Indiana Power Stations with Scrubbers, 2008

Company	Station	Boiler ID	MW scrubbed	Scrubber Technology	2010	2008
Alcoa Power	AGC Division	#4	300	FGD 2008	300	300
Hoosier Energy	Merom	#1,2	507+ 493	Wet scrubber FGD	1,000	1,000
IKEC	Clifty Creek	#1,2,3,4,5,6	209+206+209+187+211+195	FDG 2010	1,217	
IPL	Petersburg	#1,2,3,4	232+407+530+530	Wet scrubber FGD	1,699	1,699
IPL	Harding St	#70	422	FDG 2008	422	422
NIPSCO	Schahfer	#17,18	361+361	Wet lime slurry FGD	722	722
NIPSCO	Bailly	#7,8	31+160	Wet scrubber - FGD	191	191
PSI	Gibson	#1,2,3,4,5	617+617+617+615+619	FGD & wet scrubber 1,2	3,085	3,085
PSI	Cayuga	#1,2	490+464	FGD under construction	954	954
RPL	Richmond	#2	63	Dry scrubber	63	63
SIGECO	A.B. Brown	#1,2	265+265	Wet scrubber - FGD	530	530
SIGECO	F.B. Culley	#2,3	104+265	Wet scrubber - FGD	369	369
Source: IDEM July 2008				TOTAL scrubbed MW	10,552	9,335

With improved scrubber technology being further implemented in the state the consumption of Indiana's higher sulfur content coals becomes more environmentally acceptable and with increased demand for electricity the increased coal consumption could be supplied from Indiana mines. To some extent the installation of scrubbers will also allow the substitution of Power River Basin with Indiana coal. By 2010 an extra 1217 MW of generation will have scrubbers (Clifty Creek Power Station, Table 5.2.4) making a total of 10,552 MW scrubbed capacity (approaching half of the total state capacity).

Figure 5.2.4 shows that only once in its history has the historical pattern of SO_2 allowance prices ever exceeded $800/Ton; recent costs have stayed below the $500/Ton figure for the last year and a half. By the same token, there appears to be little likelihood that units which have already invested in scrubbers and are using IB coals will switch to PRB coals, given the dramatic increase in coal transport costs for the 1,200 mile trip from Western mines.

Figure 5.2.4. Simplified Historic SO_2 Price and Volume



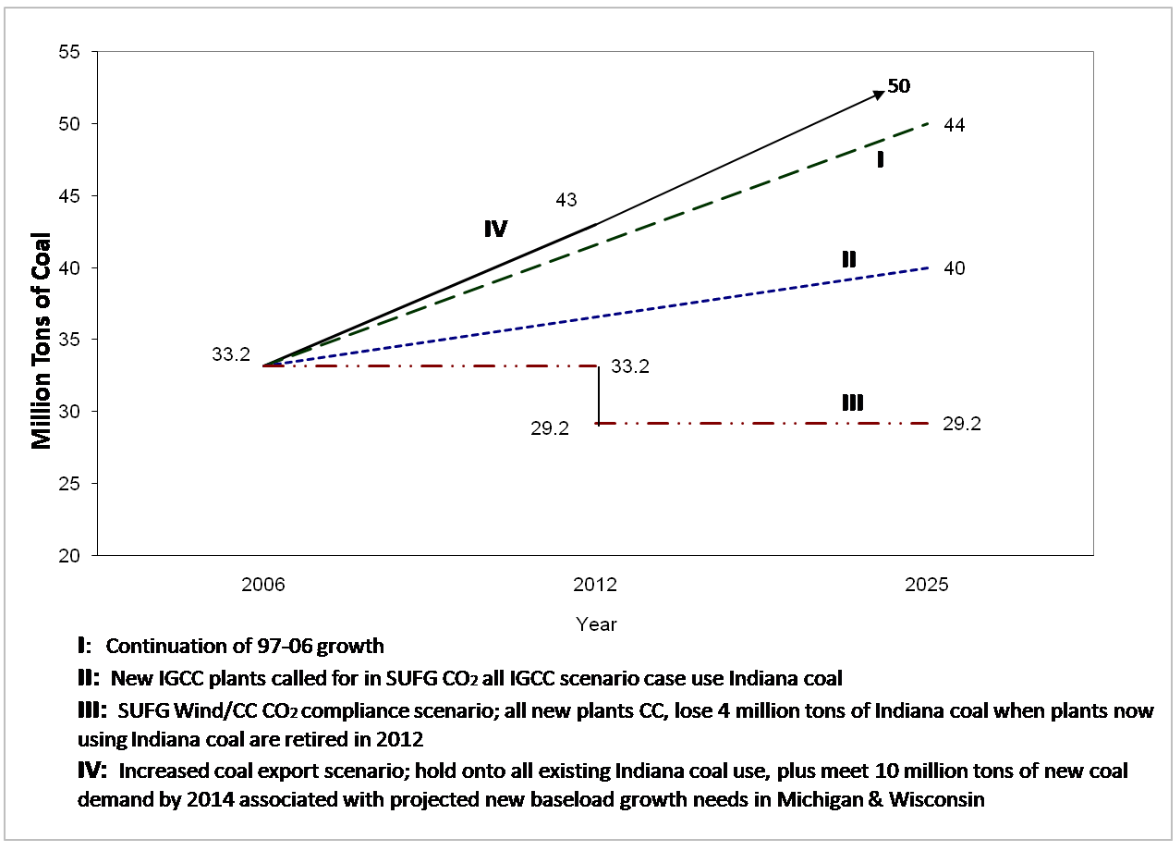
Source: http://www.epa.gov/airmarkets/presentations/docs/EMA2007.pdf

There appears to be little economic gain in any switching from one coal source to another in the foreseeable future; any increase in the use of Indiana coals must come from their use in the new units installed to serve demand growth in the state. The forecast sees little likelihood that IB coals will replace PRB coals in existing units as a result of adjustments to CAIR rules, since the least cost compliance strategy for utilities now using PRB coals appears to be by a wide margin buying SO_X allowances and continuing to burn PRB.

The picture is mixed for **the use of IB coals in new plants**. All indications are that the first level of competition will be between gas-fired combined cycle units and coal-fired IGCC plants; the days of new coal-fired pulverized coal plants serving Midwest electricity generators seems about over, as utilities anticipate CO_2 legislation by choosing to build CO_2 capture ready IGCC units. Within the IGCC option, the choice of IB or PRB coals will likely be governed by two factors: (a) the persistence of current increases in coal transportation costs, and (b) the growing consensus that IB coals are more suitable for gasification than PRB coals because of their higher heat content and the additional revenue stream available from easily recovered sulfur impurities.

With all this in mind, Figure 5.2.5 presents four possible trajectories for future use of IB mined coal to generate electricity. All four trajectories start with 33.2 MTons of Indiana coal shipped to electricity generating units in 2006, as reported by the EIA [5.8] 30.5 MTons sent to Indiana generating units, and 2.6 MTons exported to generation plants outside the state. As Figure 5.2.5 indicates, the four scenarios are: (I) a "business as usual" scenario; (II) a scenario which assumes all IGCC plants are built in Case II, as in Figure 5.2.1 is the scenario which assumes all new IGCC plants are constructed to meet the CO_2 limits of the Lieberman-Warner bill, and will use IB coal; (III) a scenario which assumes the compliance strategy used by utilities will be a combination of wind and combined cycle units; and (IV) an optimistic scenario which assumes that the Case II scenario just described, IB coals recapture a portion of the export markets in Michigan and Wisconsin now served by PRB coals. Each will be discussed in turn, following a discussion of a few issues which cut across all the scenarios.

Figure 5.2.5. Forecast Use of IB Mined Coal for Electric Generation (Million Tons, MTons)



Note: 33.2 MTons shipped to Indiana and out of state utilities
Source: EIA "Distribution of US Coal by Destination, 2006"

Turning now to a discussion of Figure 5.2.5, **Trajectory I** is based on the assumption that the factors which controlled the **growth in the use of IB coals in the past will continue** to govern their use in the future; more specifically, the scenario assumes that the 1.5% per year growth rate for the consumption of IB coals by the electric power sector contained in the latest EIA state statistics [5.6] for the period 1995-2005 will continue into the future. This scenario is unlikely to take place. It is presented simply as a point of reference for the other forecasts and this assumption results in a forecast of 44 MTons consumed in 2025, an increase of about 30%.

Trajectory II in Figure 5.2.5 assumes that the IGCC plants built to satisfy the CO_2 limits of the Lieberman-Warner bill if the utilities choose to meet the emissions limits by constructing nothing but IGCC plants, that is, Case II in Figure 5.2.1 will use IB coals. If this is the case, then IB coal use in Indiana will grow from 33.2 million to only 40 MTons by 2025. This lower figure is partly due to the fact that 4 MTon of the 8 MTons of coal being used by the plants retired in 2012 already use IB coals, so the net gain in IB coal use as a result of the retirements is smaller than might be expected.

As would be expected, since no coal is used in new units in **Case III scenario**, IB coal use is constant until 2012, and then drops by 4 MTons in 2012 as the plants which are retired at that time which are using IB coals are replaced by a combination of wind and as fired combined cycle plants.

Case IV, increased IB coal exports, assumes IB coals successfully recapture some of the export market in Michigan and Wisconsin lost to PRB coals in recent years. Currently, exports of Indiana coal to other states for power generation are very small, about 2.7 MTons, according to EIA figures [5.5], but this has not always been the case. As recently as 1990, over 9 MTons of coal mined in Indiana was shipped to other states. These markets have been presumably lost to PRB coals because of cost considerations. Is it possible that with the dramatic increase in unit train transportation costs, IB coals could recapture some of these markets? Regarding the increase in coal transportation costs, the BNSF “Coal and Unit Train and Trainload Mileage Table” [5.8] indicates that the coal surcharge rate for unit trains has increased from $0.21/mile per carload in March 2007 to $0.48/mile in June 2008, a staggering 130% increase in 15 months! What this means is that the fuel surcharge per Ton of coal (not the full transportation cost, just the surcharge) transported 1,200 miles from Wyoming to Michigan is now over $6.00 a Ton, a cost greater than current estimates of the cost of mining the coal itself. Add to this the fact that US railroads face a “Congestion Calamity” in the next few years as rail freight capacity cannot keep up with increasing demands, which is forcing rail lines to look for higher margin business to substitute for the low margins received in the transport of commodities such as wheat, coal, lumber, and the like.

Table 5.2.5 shows the origins and destinations for coal imports into the states surrounding Indiana in both 2004 and 2006. The two markets that stand out in the table as likely targets for recapture are the Wisconsin and Michigan markets. In 2006, Michigan imported 20 MTons of PRB coals by port (15 MTons) or unit train, and Wisconsin almost 26 MTons. Neither have any domestic sources of coal, and in the case of Michigan, unit trains from the West must pass through Indiana on their way to Michigan, and have the longest delivery distance (1,200 miles) for Western coals of any on the five states considered. Michigan, then, seems to be the logical target for export development. The only problems are getting such a large volume of coal from southern to northern Indiana, and the response of PRB coal producers to the invasion of their markets by IB coals; would they simply reduce their mine mouth prices in the face of developing competition?

Table 5.2.5. Export Potential for IB Coal Use by Utilities: Current Use, 2004/2006 (Million Tons)

To / From	KY	OH	IL	MI	WI	Total
West	7.1/6.0	7.3/20.3	42.2/51.4	28.6/25.4	25.1/26.3	110/129
East (incl E Ky)	4.6/9.4 **	23/37	0.3/0	5.1/7.8	0.2/0.53	34.2/55
IB (incl W Ky)	2.4/1.99 **	0.6/1.6 *	0.4/0.3 *	0/0	0.5/0.3	3.9/4.1
Home	13.8/23.9	14.4/15.1	5.7/4.1	0/0	0/0	33.9/43.1
Totals	29.4/41.4	45.3/74	45.3/56	34.2/33.6	25.9/27.1	-

* Non home only   ** E & W KY included in home
Source: EIA Distribution of US Coal by Destination

In any event, Case IV assumes that in addition to the use of coal in Case II – the case where compliance with the CO_2 limits are met by utilities using just IGCC plants, IB coal producers will capture 25% – 10 MTons – of the combined Michigan/Wisconsin markets from PRB sources. This forecast is probably more a wish than a forecast, but does draw attention to a potential market for IB coals that certainly deserves the careful analysis only the coal companies can give it. As in the case of the forecasts for total use of coal by Indiana utilities, the spread of forecasts in Figure 5.2.5 from 29 Million to 50 MTons by 2025 make the forecast useful only in spelling out the consequences of various assumptions regarding the expansion or contraction of the markets for IB coals.

Use of IB Coals by the Indiana Iron and Steel Industry

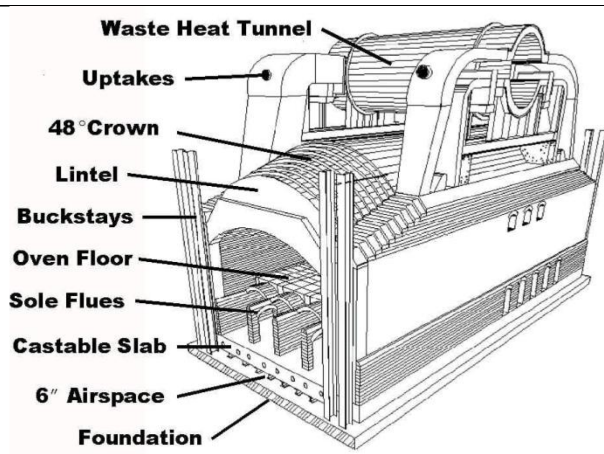
In 2006, the EIA [5.11] reports that 6.1 MTons of coal were shipped to Indiana's iron steel industry, all from eastern states, although industry sources indicate the total could be substantially higher. Coal was used for two purposes; provide the raw material for the states four coke making facilities, and as an injectant into the blast furnaces.

Let's now consider the possible use of IB coals in coke ovens. Coke facilities in Indiana include:

1) The **Indiana Harbor Coke Company (Ispat/Inland),** a recently constructed non-recovery coke plant which has a coke production capacity of 1.3 MTons /year (approximately 1.8 MTons /year coal input), and a 94 MW electric generation plant;
2) **Burns Harbor Coke Plant (ArcelorMittal Steel),** a by-product recovery coke plant with a coke production capacity of 1.8 MTons /year (2.4 MTons /coal); coke oven and blast furnace gases are used in a 177 MW electric generation unit;
3) **Gary Coke Plant (US Steel),** a by-product recovery coke plant which has a coke production capacity of 1.6 MTons/yr (2.2 MTons coal); the coke oven gas is used in various steelmaking processes in the plant;
4) **Citizens Gas and Coke plant in Indianapolis**, which had a coke production capacity of 500,000 Tons/yr until its closure in July 2007.

Figure 5.2.6 is an illustration of a non-recovery coke oven, and a picture of the Indiana Harbor Coke Company facility. Rather than capture the coke oven gas for use in other steelmaking processes, as is the case with recovery ovens, non-recovery ovens burn all the gases in the oven itself, a much less polluting process than the recovery ovens. For this reason, the EPA has effectively mandated that all new ovens be of the non-recovery type, which has implications for the future location of such facilities. Dr. Robert Kramer, at Purdue Calumet, has completed a study of the possibility of IB coals being blended with stronger eastern coals for coking purposes in order to minimize problems associated with the use of lower strength of IB coals. He and his colleagues have concluded that blends with up to 30% Indiana coal are practical. Thus, if the Indiana coke ovens are operating at capacity, Kramer concluded that up to 2.1 MTons of Indiana coal could be utilized [5.9].

Figure 5.2.6. Non-Recovery Oven

Jewell-Thompson Heat Recovery Coke Oven	
Indiana Harbor Coke Co	

Source: http://www.epa.gov/guide/ironsteel/pdf/jewell.pdf

All three of Indiana’s blast furnace complexes now use West Virginia coals as injectants into the furnaces; the amounts vary from 200 to 400 pounds per Ton of hot metal produced from the furnaces. Since injected coal can substitute on a pound for pound basis for coke, up to certain limits, there is much current interest in injection, given the extraordinary coke prices that now prevail in world coke markets. (Spot prices are forecast to be in the $700/Ton range for fall 2008, five times the $140/ton prices that prevailed in 2003), [5.11]. Further, the possibility of using IB coals as injectants is being actively explored, since IB coals have not seen the price increases experienced by eastern coals (Figure 5.1.5) attributed to rapid expansion of export markets for eastern coals in response to China dropping out of the coal export markets.

The concept has been around for a long time; interest first peaked in the US during the 1970s when operators were looking around for ways to reduce coke charges in the furnaces. From 1995 to 1998, DOE funded a coal injection demonstration project at the Burns Harbor blast furnace complex which indicated that coal could replace coke on a pound for pound basis up to a limit of around 270 pounds per Ton of hot metal, almost 30% of the normal coke charge. The experiment also concluded that a wide range of coal types could be used in addition to the West Virginia low volatile coals used in the demonstration. One problem identified with the use of IB coals is the need to remove moisture from the coals prior to injection. This problem has led blast furnace experts to conclude that a mix of IB and eastern anthracite coals may be the best injectant. If use of IB coals as blends in both the coke making and coal injection processes were to be implemented, up to 2.1 MTons of IB coals could be used in coke blends, and up to 1.3 MTons in blends injected directly into the blast furnaces. This seems to be a very promising new market for IB coals, given the dramatic price increases seen in recent months in the cost of the eastern coals now used for these purposes (Figure 5.1.5).

DOE reports [5.11] indicate that 5.6 MTons of coal were delivered to industrial users in Indiana. Of this total, almost half, 2.7 MTons, were delivered to Alcoa's Warrick electricity generating units, and should be counted in the total of coal delivered to plants for the generation of electricity, and the forecasts for such use presented in previous sections. IDEM reports that of the remainder, 0.9 MTons were used at five cogeneration sites in Indiana, and 0.5 MTons were used in six process steam plants in Indiana. The 1.5 MTon remainder is unaccounted for. It is likely that all these plants use IB or eastern coals, since the individual volumes are so small as to preclude the use of unit trains from the west. No forecast of IB use for these purposes will be included here, except to note that growth in coal use for cogeneration and process stream will be governed by the price of electricity to large industrial users, and the cost of coal and gas for cogeneration and process stream to such users.

There appears to be a number of **important conclusions** relating to the design of future CCTR projects that arise from this forecast.

1, 2, 3) The Use of IB Coals to Generate Electricity
4) The Use of IB Coals by the Iron and Steel Industry
5) The Use of IB Coals by the Industrial Sector

1) **The Use of IB Coals to Generate Electricity**
First and foremost, CCTR needs to take a careful look at the competition between IB and PRB coals in the new environment of dramatically increased transportation costs for all coals. Certainly IB coals have become more competitive, but by how much, and for how long? How will the competition between IB and PRB coals play out when used in IGCC plants with CO_2 injection capabilities? What will PRB coal producers do to offset the decline in their competitive advantage? Will they accept lower margins on the mining of their coals to maintain their market shares?

2) Next, **CCTR should consider investigating** the possibility of IB coals expanding into the export market potential offered in the Michigan and Wisconsin markets, both markets now served by PRB coals. This 10 MTon export market potential should give additional impetus to efforts to find a low cost way of moving IB coals from south to north, over and above the markets for Indiana electricity generation and use by the iron and steel industry already identified in this and previous studies.

3) **CCTR might consider a follow-up study** to the SUFG CO_2 compliance report which looks more closely at the least-cost compliance options open to utilities, and the implications for IB coal use in these

options. Are scenarios which include widespread use of wind power really realistic here in the Midwest without government mandates requiring their use? If widespread use is likely, how can IB coals take advantage of the fact that back-up power will be needed for such plants, if they are to be used as base load generators?

4) **The Use of IB Coals by the Iron and Steel Industry**
The continued support of Dr. Kramer's work regarding IB coal use in coke blends is certainly justified. It might be wise to consider expanding the project to include the use of IB coals as injectants into the blast furnaces. Members of Dr. Kramer's team, in particular Dr. Valia, are well qualified to carry out such investigations.

5) **The Use of IB Coals by the Industrial Sector**
No CCTR projects seem warranted in this area, except to support the work of IDEM in continuing to track coal consumption in all areas of the state – in particular, the work of IDEM in expanding our knowledge of other industrial uses of coal in Indiana besides use by utilities and the iron and steel industry.

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CHAPTER 6

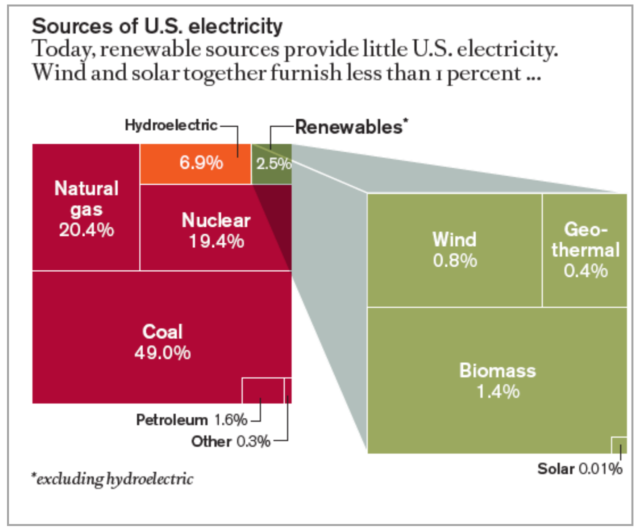
INDIANA'S ENERGY SHIPMENTS INFRASTRUCTURE

The supply of electricity, natural gas and coal is totally dependent upon shipment infrastructures; the transmission grid, gas pipelines, and rail networks. Future demand growth for electricity and coal will have a direct impact on transmission and railroads across Indiana. The most consistent and significant factor affecting energy supply infrastructures will in fact be the growth in demand for electricity. Renewable power supplies will have some impact on transmission, especially if such proposals, as those in the Dakotas, which involve construction of 40,000 MW of wind power. Eventually, major investment in new infrastructure will be required and improved energy efficiency programs, which will help in the shorter term, will only postpone the need for improved infrastructure capacity.

Reduced growth in demand for coal could result from CO_2 legislation particularly if significant new renewable and nuclear power supplies are constructed. Nationally renewable power supplies (excluding hydropower) account for about 2.5% of total electricity supplies with less than 1% coming from wind and solar (Figure 6.1.1). With the operation of the Indiana's Benton County wind power project, the share of wind MW in the state will more than double the national average.

Complexity, geographic scope, and uncertainty in infrastructure issues demand a regional approach as in the case of the transmission grid with MISO (Midwest Independent System Operator). Future coal-fired power plant infrastructure might involve each of the following: (1) transportation of coal by rail, barge or road, (2) moving coal by wire, i.e., generating electricity at the mine-mouth and having transmission lines to ship out the power, or (3) future capturing of CO_2 gas from and pumping it to out-of-state locations for enriched oil recovery, i.e., EOR and CO_2 gas pipelines. CCTR anticipates that regional collaborative studies will take on more significance and especially for the three states in the Illinois Coal Basin (Illinois, Indiana, and Kentucky).

Figure 6.1.1. Wind & Solar Provide Less than 1% of Total U.S. Electricity



Source [5:15]

Figure 6.1.2. Freight Movement is Economy in Motion

Source [6.19]

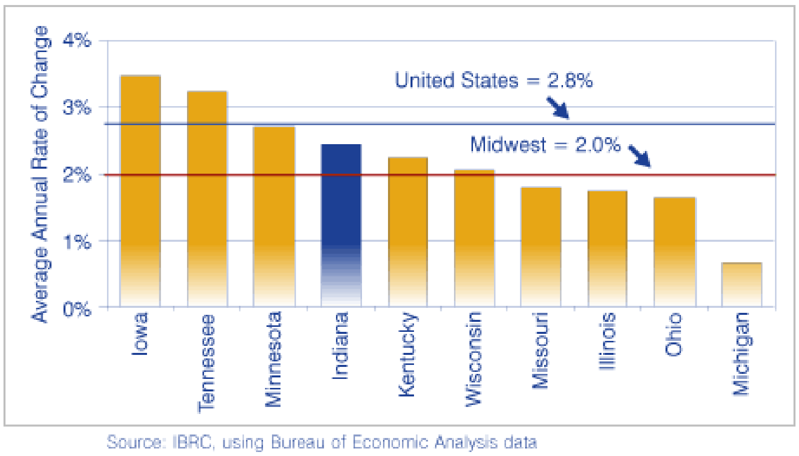
The existing and future coal related infrastructures will have long-term impacts, especially on the economies of coal-producing states (Figure 6.1.2). The CCTR has been supporting a study on coal transportation and has been engaged in discussions on regional transmission and CO_2 gas pipelines.

Section 6.1 provides an overall economic picture of various infrastructure projects within Indiana, while Section 6.2 covers coal transportation. Section 6.3 introduces transmission issues being analyzed by MISO, and Section 6.4 provides a summary of the Midwest CO_2 Pipeline project. Adequate infrastructure is essential for economic growth.

6.1 Economic Development & Indiana Infrastructures

At the start of the 21st century Indiana had an economic growth rate of about 2.5% which was higher than the Midwest average of 2.0% (Figure 6.1.3) but slightly lower than the national average of 2.8%. Sustaining significant future economic growth will require advanced infrastructures to be in place for Indiana and the Midwest region. In 2007 the state's GDP was $246 Billion.

Figure 6.1.3. Economic Growth in the Midwestern States, Real GDP by State, 2001 to 2006



Source [6.1]

So much economic development is dependent on infrastructure. The use, for example, of southwest Indiana coal in northwest Indiana power plants is a very important issue for the state. This has been a topic of one of the CCTR supported projects over the past few years (Dr. Tom Brady at Purdue North Central). Improvements and options to the Indiana railroad network are being proposed (Section 6.2). Utilities, mining companies, and government agencies (state and federal) know the importance of investment in infrastructure for economic growth.

Quote:
Congressman Pete Visclosky, Indiana 1st District.

> *"I believe that America can invest and invent its way out of the energy crisis and these particular investments help make sure that Northwest Indiana plays an important role in inventing new energy solutions."*

Environmental improvements play an increasingly important part in long-term planning issues. In the 1980s NIPSCO was faced with the same problem as all coal-fired utilities, how to reduce sulfur emissions from their coal-fired power plants. The options were to build flue gas desulfurization scrubbers and use Illinois Basin coal (high sulfur, high heating value) or begin to import low sulfur (low heating value), Powder River Basin (PRB) coal, which does not require scrubbing. The present rail system actually allows PRB coal to be brought to northwest Indiana more easily and cheaply than bringing Indiana coal from the southwest part of the state. This has meant that the SO_2 solution for NIPSCO and its customers had to be western coal. Recent EPA rulings will require NiSource and other coal-fired utilities to put scrubbers on the existing power plants regardless of the actual SO_2 emission. This removes the SO_2 advantage inherent in the western coal. Since the utility must now put scrubbers on their coal-fired plants anyway, why not investigate the use of lower cost, higher Btu Illinois Basin coal? Unfortunately, while air emission standards have changed, the transportation infrastructure has not.

Reliable low cost energy supplies and transportation systems capable of carrying increased loads and raw materials for steel production each have a strategic part in supporting future industrial, commercial, and economic growth. If adequate railroad capacity were available from Indiana's southwest coal mining region, then Indiana coals could make a significant contribution towards both the supply of coking coals for the northwest area of the state as well as coal for power stations in the northwest.

Steel production in Indiana's northwest represents 28% of the total steel production of the top five steel producing states in the United States (Table 6.1.1). To maintain and strengthen steel production in the state, reliable coking coal supplies are required. The majority of coking coal for Indiana's steel industry is currently transported across the state from West Virginia. Chapter 9 outlines the CCTR supported project working on initiating coke production in Indiana, using as a percentage of the coal needed to be coming from Indiana mines.

Table 6.1.1. Value of Steel Shipments to Indiana, $12 Billion per year

Value of Shipments for Top Five States – 2000

State	Value of Shipments (billion dollars)	Employment (thousands)	Percentage of Total Gross State Product
Ohio	12.8	35.7	1.14%
Indiana	12.0	32.0	1.75%
Pennsylvania	9.8	31.6	0.63%
Illinois	5.0	14.9	0.27%
Michigan	3.7	11.2	0.39%

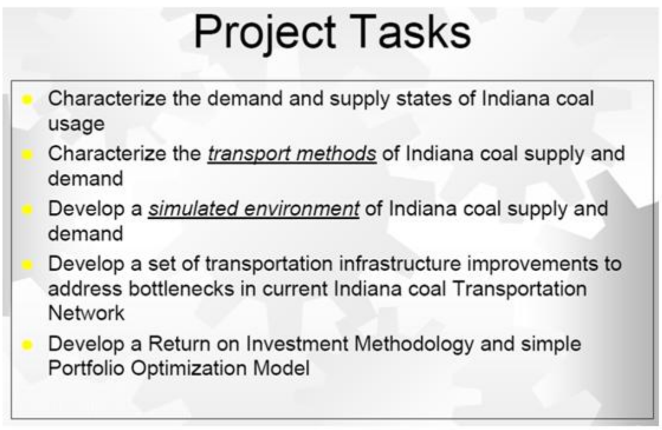
Source: DOC 2001b, BEA 2002

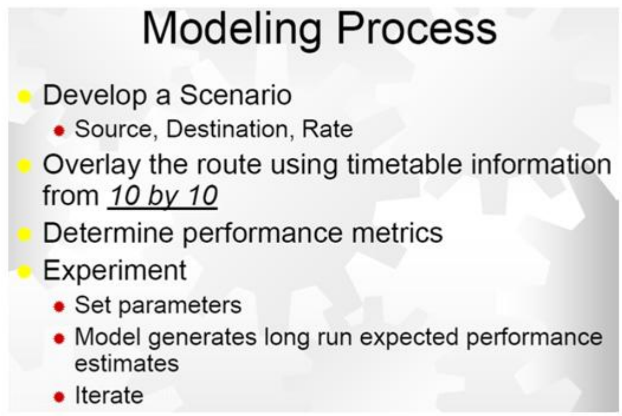
Source [6.2]

The Indiana/Illinois eastern border rail line would also make the Newport military facility, which is due to be mothballed in the near future, a very valuable piece of property. Newport has the best location for advanced energy study in the U.S. It is located on a water source, has 345kV power line access, and is crossed by a 24" natural gas line. It is also on an active rail line with access to coal, it is very secure, and, more importantly, it is in the heart of biomass country. The USDOE, State of Indiana, and Purdue University have all been discussing biomass conversion to energy, but to date there still exists no facility in the U.S. to do this work on the scale necessary for commercialization. Gasifiers at Newport would be able to conduct biomass gasification experiments, with a ready market for the gas at Duke Energy's Cayuga power plant 6 miles upriver. The gasifier could be used to conduct experiments and serve as a training facility for all forms of non-coal conversion (biomass, MSW, pet-coke, waste tires) and supply Cayuga with the fuel needed to keep it operational even in the summers months. The rail line mentioned above will also enable the easy movement of BP's pet-coke from its refinery in Whiting to Newport turning this commodity into a clean source of energy.

The Indiana Rail Road Corporation is conducting a survey of the above stated rail line to estimate the cost of implementing the infrastructure changes that would make the system operational. That study will go through the state and federal transportation analysis to see if the cost is warranted and justified. What we do know is that without it the status quo remains, and Northwest Indiana will fall precariously in economic activity because of the inability to supply its imbedded industry with the clean fuel it needs, a supply that is within reach if we act.

6.2 A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure





http://www.purdue.edu/dp/energy/CCTR/byTopic.php#Infrastructure
http://www.purdue.edu/dp/energy/CCTR/researchReports.php

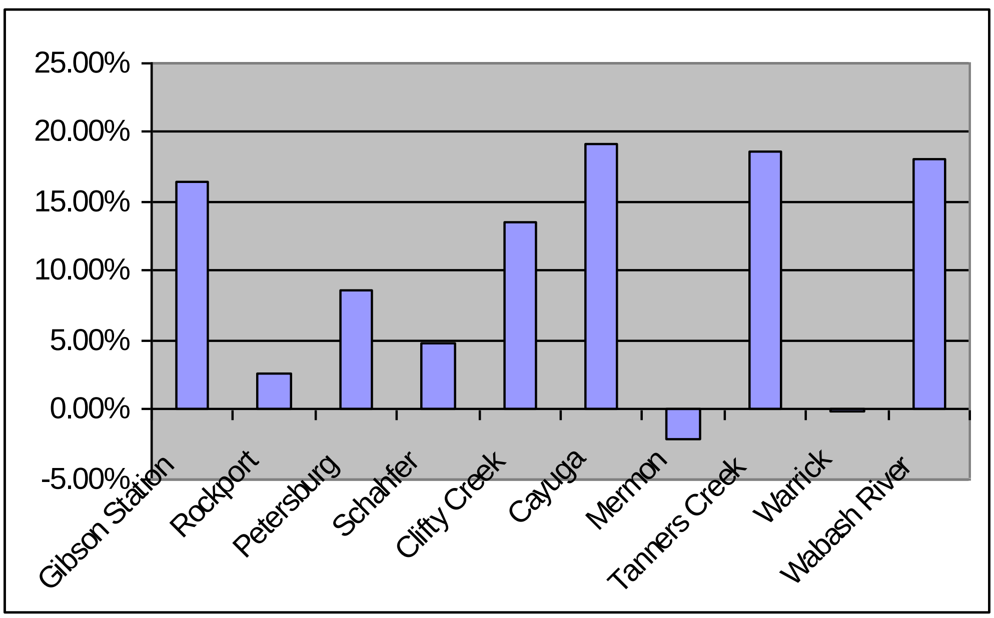
The CCTR is supporting a coal transportation study. This study provides a simulation-based analysis environment of Indiana's coal transportation infrastructure (based at Purdue North Central). The United States possesses a vast railroad infrastructure and approximately 140 thousand miles of rail is maintained and managed by over 500 railroad companies. The railroad infrastructure is a driving force in the globalization of the U.S. economy. As cross country container traffic has increased, traditional national rail transport commodities such as coal are forced to compete for scarce locomotive and track right resources. This competition has increased the cost of coal transportation.

The state of Indiana ranks ninth nationally in the number of miles of railroad tracks. Numerous literature sources point to a growing awareness of the importance that transportation plays in the domestic coal industry. Evidence even suggests that transportation costs are significantly higher than the cost of the coal itself. Other studies suggest that coal transportation infrastructures can be developed and utilized by states for significant competitive economic advantage. The Powder River Basin area in Wyoming is a stellar example of how the combination of a large natural resource with strategic transportation planning can result in tremendous economic advantage. It is estimated that nearly 40% of the coal burned in U.S. power plants comes from this area, which has increased coal production nearly 40% since 1997. Significant rail infrastructure investments have been made to connect this region to the national rail infrastructure, making it cost advantageous to ship Wyoming coal nationwide.

The basis of the coal transportation study is to use simulation and 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 by the state of Indiana due to its central geographic location. Through the use of simulation modeling analysis, the capacity of the Indiana coal transportation infrastructure will be determined. Once accurate projections of the capacity are known, improvement scenarios will be developed and analyzed to optimize the efficiency of Indiana's coal transportation infrastructure, adding competitive value to the state of Indiana's vast coal industry.

Coal-fired power production has increased 26% since 1995 [6.3]. There are approximately 120 new coal-fired power plants valued at $99 billion in the planning or construction phases. During heat waves in summer months, coal-fired power plants work overtime to supply consumer demand. Schahfer generating station in Wheatfield, Indiana set a new power use record on July 26, 2006, as the station's coal handling department bunkered more than 21,000 tons of coal [6.4]. Figure 6.2.1 shows the percentage increase in production at the largest coal-fired power plants in Indiana over the last five years.

Figure 6.2.1. Indiana Power Plant Generation Growth



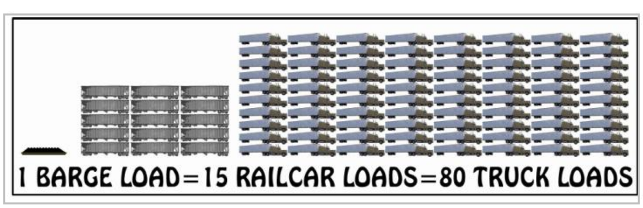
Source [6.20]

As the demand for coal increases, significant challenges exist in the coal supply chain. It is not at all clear, moreover, how well the current coal transportation rail infrastructure could support the rapid adoption of hybrid vehicles that draw on electricity. This wealth of coal cannot flow freely through the U.S. economy until costly and difficult fixes are applied across the whole business of mining, transporting, and burning coal [6.3]. Railroad congestion is seen as the biggest bottleneck to expansion of coal-fired power plants [6.5].

Transportation is a Significant Component in Coal Economics

Coal is a unique commodity in that the transportation cost in today's market is more than the extraction cost. Thus, when coal is purchased, a majority of the contract price goes towards moving it to the required destination. Depending on the proximity of the customer to the mine and the transportation resources available for delivering coal to that customer, transportation charges can range from 4 to 41% of the delivered cost. As a consequence, the availability and cost of transportation constitute one of the most important factors in the marketability of coal [6.6]. Estimates indicate that coal from the Powder River basin in Wyoming can be purchased for as little as $6 per ton with a transportation cost of $30 per ton [6.5]. The least cost means of shipping coal is via barge but this is limits access to rivers and lake access (Figure 6.2.2). The miles travelled per ton of coal with one gallon of fuel do not vary so much when comparing rail with truck (Figure 6.2.3).

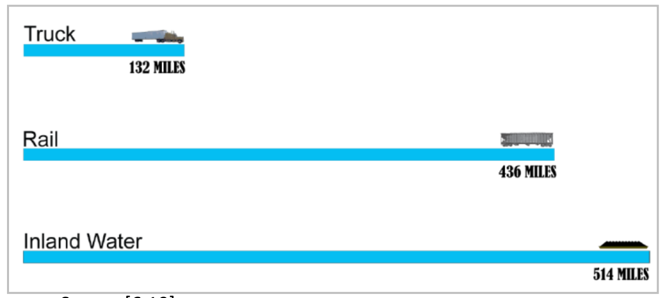
Figure 6.2.2. Coal Transportation & Modal Comparisons



Source [6.19]

To capitalize on the varying costs of coal transportation, investment is being made in the shipping aspect of coal. Shipping costs of coal on transcontinental railroads such as the BNSF have helped Western-mined coal make significant inroads into traditional Illinois coal markets [6.7]. Efforts have been made to secure federal funding to create additional rail infrastructure including plans to "morph the DM&E, a decrepit $220 Million a year line into a 2800 mile, 1 Billion plus per year coal carrying artery" [6.3].

Figure 6.2.3. Modal Comparisons, Miles/Ton Freight with One Gallon of Fuel



Source [6.19]

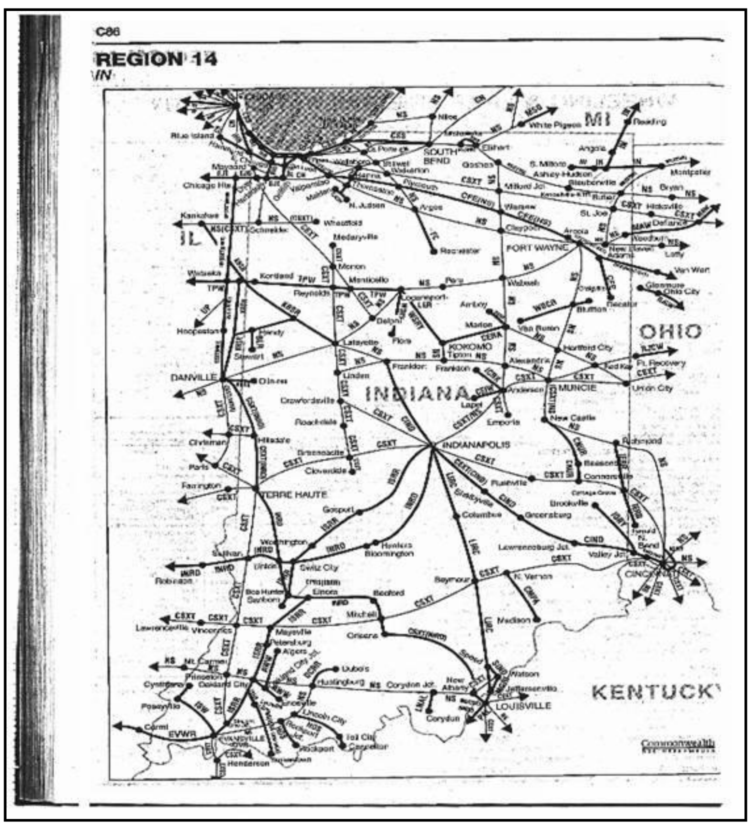
The movement of commodities over a rail system is complex due to the structure of the rail ownership system in the United States. Consolidation of rail companies over the years has created a small number of mega-carriers who operate large multi-state networks. These are referred to as Class 1 railroads and include CSX, Norfolk Southern, BNSF, etc. The remainder of the railroads are smaller, many of which operate less than ten miles of total track. Thus, the development of point-to-point rail connections is a complex process that is analogous to the interstate highway system or a fiber optic cable network. Large mega-railroads such as the CSX move large volumes of cargo efficiently along Class 1 rail between distribution points across the United States. The cargo is then broken down into loads for specific industry or distribution sites and is often moved by small regional railroads over local tracks. This type of system is referred to as the 'last mile' problem.

Figure 6.2.4 shows the current rail infrastructure in the State of Indiana. Noticeably absent are north-south routes. Table 6.2.1 lists the general parameters that are available in each simulation scenario for the analyst to experiment with. Global variables are applied to every link in the timetable routings. Local variables are specific to the link with which they are associated. The location column identifies the specific area in the simulation scenario where the parameter is applied. *Speed Factor* is a random variable that is applied to calculation of train speed. *Weather Factor* is a random variable that is applied to logic between links. *Mechanical Delay* is a random variable that is applied to logic between links. *Congestion Delay* is a random variable that is applied to logic between links. *Station Delay* is a random variable that is applied to logic between links. *Train Length* is a user supplied value that denotes the number of cars in a train. *Car Size* is a user-supplied value that defines the capacity of each car. *Days of Supply* is a user-supplied value that defines the target coal inventory at a power plant.

Through a simulated environment, trains move from station-to-station via links. Prior to entering a link, the appropriate station logic is applied. This allows very detailed routing logic to be included, which greatly increases the precision and accuracy of the results obtained.

The major contributions of this project include the development of railroad timetables between coal producers and coal consumers in the state of Indiana and a simulation framework that can provide insight and detailed supply chain projected metrics for current and proposed rail-based scenarios. These timetables can be used as the basis for an unlimited amount of further analysis. This project has demonstrated that the methodology works and can provide useful insight into rail operations along with accurate predictions of rail route capacity, rail equipment utilization, and coal supply chain metrics.

Figure 6.2.4. Indiana Rail Infrastructure



Source [6.20]

Table 6.2.1. Coal Transportation Simulation Parameters

Parameter	Type	Location
Speed Factor	Global	All Rail Links
Weather Factor	Global	All Rail Links
Mechanical Delay	Local	Specific Rail Link
Congestion Delay	Local	Specific Rail Link
Station Delay	Local	Specific Rail Link
Train Length	Local	Specific Train
Car Size	Global	All Trains
Days of Supply	Local	Specific Power Plant

Source [6.20]

The results and methodology of this project can be extended in two directions:

Extension 1: Analyze More Scenarios
Many scenarios have been suggested for analysis, but could not be accommodated due to the scoping nature of this project. In its present form, the timetables and simulation model can be used to analyze issues including but not limited to:

1) The shipment of Southern Indiana coal to Crane.
2) The integration of water as a means of coal shipment, including the Great Lakes and the Ohio River.
3) Movement of southern Indiana coal into the national coal transportation rail networks in the Chicago area.

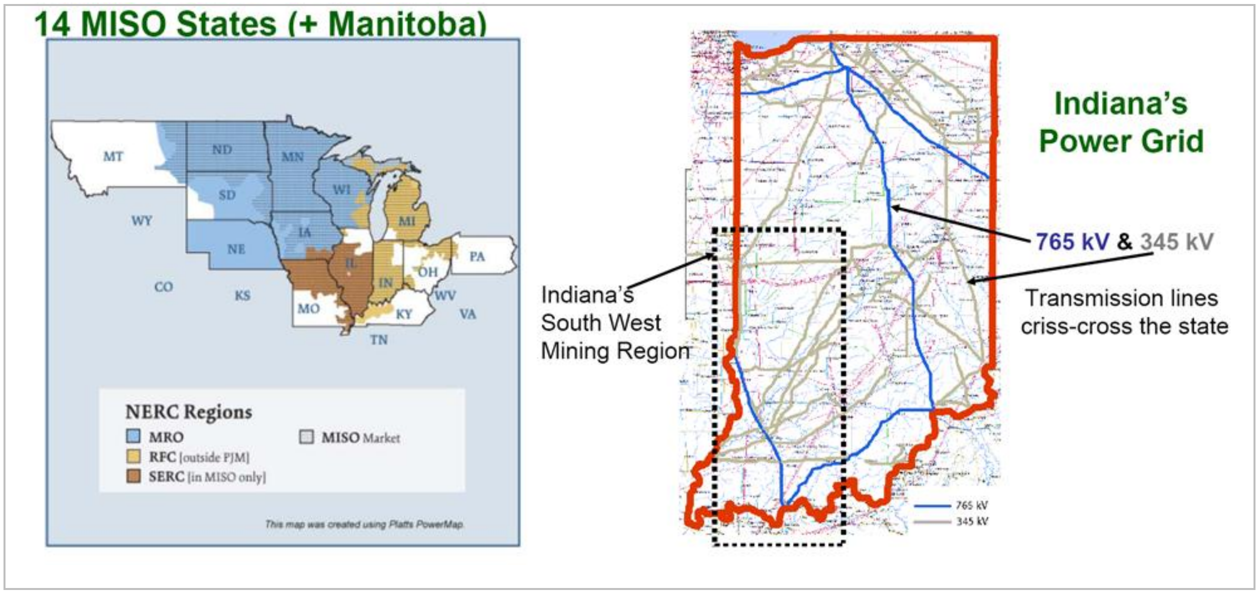
Extension 2: Extend the Methodology
Expand the scope of the analysis to include the following items:

1) All users of coal in the state, with emphasis on the Northwest Indiana steel industry and their coking needs.
2) All coal-fired power plants in Indiana.
3) All coal mines in Indiana.
4) All rail commodities, including intermodal and grain. This would allow analysis concerning the substitution effects of grain for coal, etc., in anticipation of ethanol and bio-diesel transportation needs.

The most significant extension of the project would be to include the possibility of adding new rail links to the present rail infrastructure. There are several links suggested that could be added in the north part of the state that would allow convenient rail traffic to avoid the congested south Chicago rail interchange.

Extensions to this project can be leveraged into a significant full-scale study of the Indiana coal transportation infrastructure. This would allow policy makers to acquire detailed, accurate estimates of supply chain performance over the Indiana rail infrastructure for coal producers and users.

6.3 The Midwest Power Grid



The U.S. Midwest power grid infrastructure is designed for transmitting electricity to customers (residential, commercial, industrial) within and across the region and for transmitting across each state for inter-state energy trading. Site locations for new power plants are affected by the existing availability of transmission load carrying capability. The prospect of exporting more of Indiana's coal in the form of electricity is dependent upon available line capacity. Over the past ten years the role of the Midwest Independent System Operator (MISO) has increased in operational importance and now provides a very strategic planning function. The MISO oversees the current regional electricity market and is instrumental in the planning for new major transmission projects.

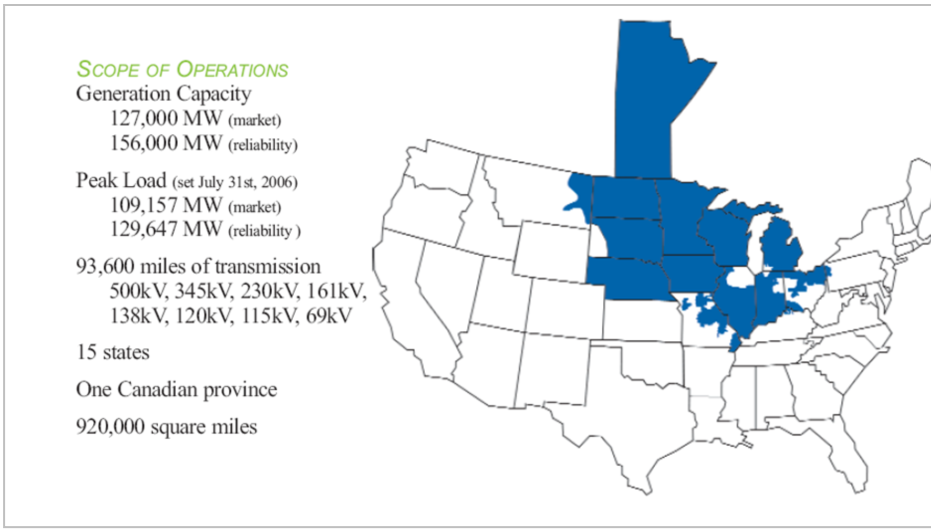
The MISO has many Midwest stakeholders.

MISO is classified as:
"a non-profit, member-based organization committed to being the leader in electricity markets by providing our customers with valued service, reliable, cost effective systems and operations, dependable and transparent prices, open access to markets, and planning for long-term efficiency" [6.8].

A MISO member (in 15 U.S. states plus the Canadian province of Manitoba, Figure 6.3.1) can be a representative of one entity or may be a single membership representing several entities that share a membership and hold a single vote [6.8]. Member applicants may join one of nine sectors within the MISO regional organization:

- Transmission Owner
- Independent Power Producers and Exempt Wholesale Generators
- Power marketers and brokers
- Municipals, cooperatives, and transmission dependent utilities
- Public consumer advocates
- State regulatory authorities
- Environmental/other advocates
- Eligible end use customers
- Coordinating members

Figure 6.3.1. Midwest ISO Scope of Operations



Source [6.10]

The MISO modeling teams have been considering the future of the Midwest power grid, following the concerns about congestion (Figure 6.3.2), and during 2007/8 looked into four possible modeling scenarios. These included:

(a) a reference scenario,

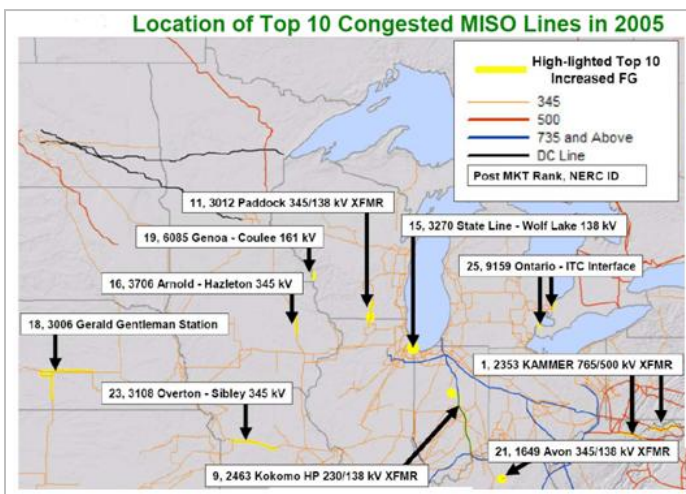
(b) environment scenario,

(c) renewable mandate scenario, and

(d) a limited fuel supply mandate (Table 6.3.1).

These comprehensive and imaginative scenarios have developed valuable and long-sighted discussion sessions among the MISO transmission and utility companies.

Figure 6.3.2. Transmission Congestion in the U.S. Midwest and Indiana



Most Congested Flowgates (FG) in Indiana

Monitored Element Friendly Name	Balancing Area	1st Year Congestion FG-Hr/Year Apr 05 - Apr 06	2nd Year Congestion FG-Hr/Year Apr 06 - Apr 07	MISO Ranking 2005-2006	MISO Ranking 2006-2007
Kokomo HP 230/138 kV XFMR (flo) Jefferson - Greentown 765 kV	CIN	132 1.5%	750 8.6%	40	2
Miami Fort 345/138 kV XFMR (flo) East Bend - Terminal 345 kV	CIN	247	20	18	164
New London - Webster 230 kV (flo) Jefferson - Greentown 765 kV	CIN	137	92	39	46
Dune Acres -Michigan City 138 kV ckts 1&2 (flo) Wilton Center - Dumont 765 kV	NIPS	241	107	19	44
Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	SIGE	539	284	11	13
Culley - Grandview 138 kV (flo) Henderson - A.B. Brown 138 kV	SIGE	586 6.7%	84 1.0%	9	51
A.B. Brown - Henderson 138 kV (flo) Culley - Grandview 138 kV	SIGE	220	6	21	367
Culley - Grandview 138 kV (flo) Henderson 161/138 kV XFMR	SIGE	164	33	27	111

Source [6.9]

Table 6.3.1. MISO's Four Demonstration Modeling Scenarios, 2008-2027

(a) Reference	Status Quo Future. This future models the power system as it exists today with reference values and trends based on recent historical data while preserving existing standards for resource adequacy, renewable mandates, demand response & environmental legislation.	
	Key Uncertainties	
	Economic Variables	Inflation Rate = 3% Uneconomic Coal Retirement = Retire as scheduled
	Capital Costs	Values based on the EIA 2006 Assumptions to the Annual Energy Outlook and Stakeholder Inputs
	Fuel Prices	Gas and Oil prices are based on MISO developed 2006 Data. Coal prices are based on Consultant Data
	Fuel Supply	Unlimited
	Environmental Costs	SO2, Nox & Mercury use PowerBase data. CO2 has no cost.
(b) Environmental	Environmentally Friendly Future. Models the uncertainties assuming a mid-range carbon initiative with a carbon price of $25 per ton.	
	Key Uncertainties	
	Economic Variables	Inflation Rate = 4.5% Demand Growth = 25% Reduction in Rate of Demand Growth Uneconomic Coal Retirement = Retire 7,000 MW of coal based on Promod Retirement Analysis.
	Capital Costs	CC & CT are 10% higher than reference, others unchanged
	Fuel Prices	Gas and Oil are 10% Higher. Coal is 10% lower.
	Fuel Supply	Unchanged from Reference
	Environmental Costs	SO2, NOx use PowerBase Data. CO2 is $25/ton and Mercury has a 25% higher cost.
(c) Renewable Mandate	Future requires 20% of the energy consumption come from a renewable energy source by 2020. Assumes wind will be the resource. 40% Capacity Factor of new units applied toward mandate, and 15% Capacity counted toward Reserve Margin Calculations	
	Key Uncertainties	
	Capital Costs	Wind is 10% Higher than Reference and Wind Energy Credit Removed, Others unchanged
	Fuel Prices	Unchanged from Reference
	Fuel Supply	Unchanged from Reference
	Environmental Costs	Unchanged from Reference
(d) Limited Fuel Supply	Future represents a limitation to the supply of Natural Gas as a fuel source	
	Key Uncertainties	
	Economic Variables	Inflation Rate = 4.5% Uneconomic Coal Retirement = Unchanged from Reference
	Capital Costs	Unchanged from Reference
	Fuel Prices	Gas is 50% higher than Reference, others unchanged
	Fuel Supply	CT and CC are limited to 70% of Max capacity
	Environmental Costs	Unchanged from Reference

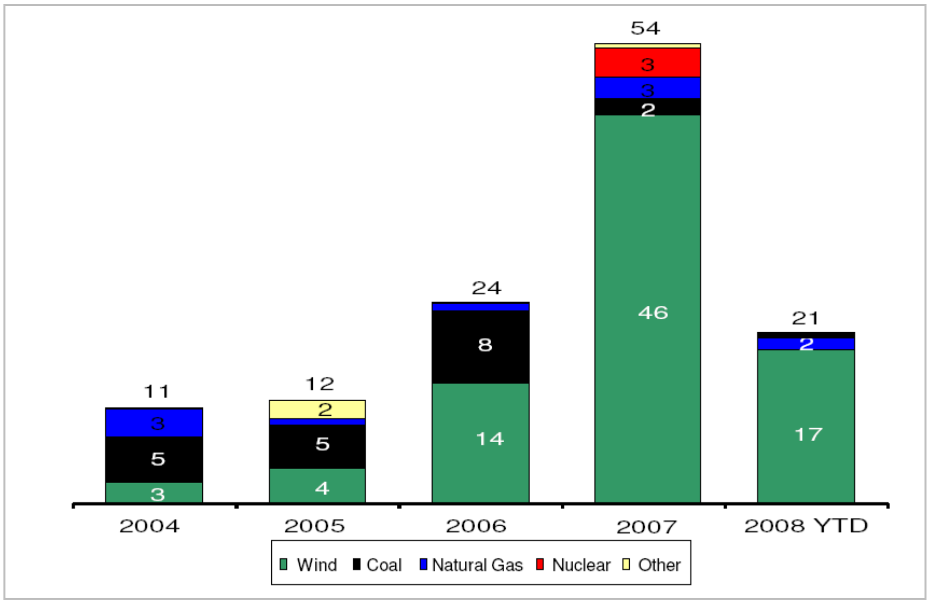
Source [6.11]

One major factor that is influencing transmission planning options in MISO is the potential use of new wind power for the region. In 2007 there was a massive increase in the planning capacity for proposed new wind power. In 2006 the MISO had received queuing requests for 14,000 MW of wind power but in 2007 this had increased to 46,000 MW (Figure 6.3.3).

> *"The influx in queue requests in the Midwest ISO is driven in large part by the introduction of Renewable Portfolio Standards in four states (Illinois, Iowa, Minnesota, and Wisconsin) in the Midwest ISO footprint. These requests are often in locations distant from load, and thus distant from sufficient transmission infrastructure to support interconnection. For example, in the Buffalo Ridge area, there are approximately 23,000 MW of wind generation requests for interconnection by 2014, with only 2,000 MW of outlet capacity planned for the region by that same date." [6.12]*

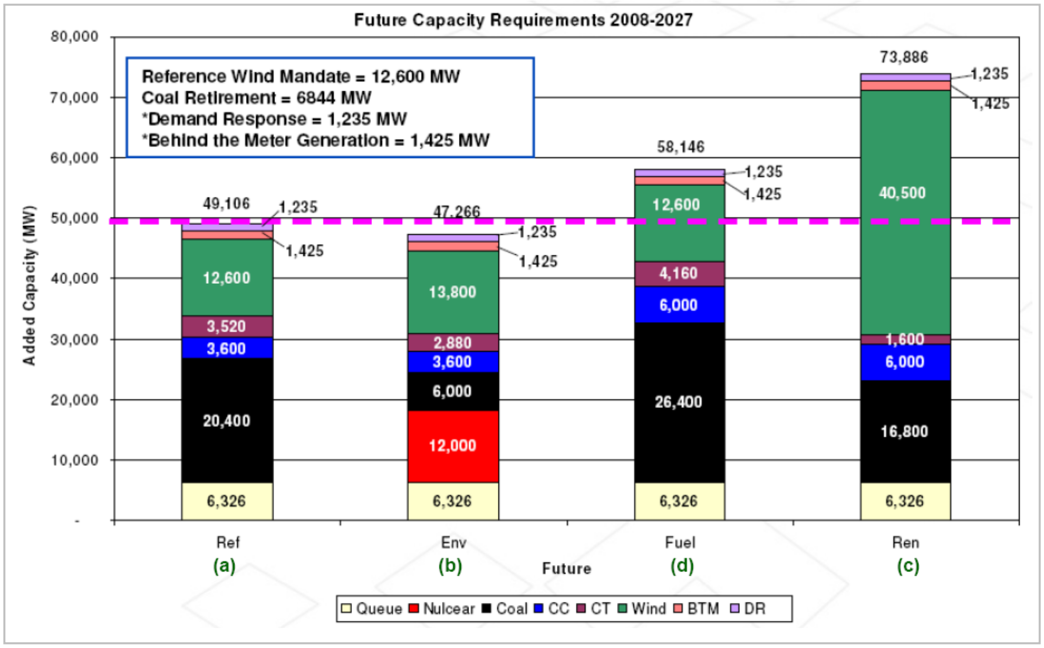
The results from these 2007/8 modeling exercises have provided demonstration outputs as shown in Figure 6.3.4 having huge new wind capacities in the MISO queue as well as large new coal capacity.

Figure 6.3.3. Total GW of Generator Interconnection Requests by Type for the Midwest ISO from 2004 through June 26, 2008



Source [6.12]

Figure 6.3.4. MISO 2008-2027, Demonstration Futures Scenarios Cumulative New Generation Capacity (MW)



Source [6.11]

The total cost estimates of supplying the MISO load including capital costs for new wind generation, fuel, and operating and maintenance (O&M) costs for all generation provide valuable insights for the important ongoing transmission capacity expansion debate. The amount of nameplate wind generation capacity that has the least cost is considered by many as the optimum amount of wind generation that can be accommodated in the MISO footprint. The great uncertainty about future carbon management legislation and the desire for improving environmental standards are factors which being given very high priority. It can be argued that adding more wind generation than the least cost optimum could lead to diminishing returns. Additional wind generation affects O&M costs and availability of existing low cost generation. Wind power increases the likelihood that quick start generation is more frequently required to meet load pick up ramp rates due to base load units being forced to cycle off due to minimum generation constraints.

Increased electrical demand in Indiana will require expansion of the transmission network and this will include accommodating new wind power farms. In the instance of shipping large wind generated power from the west of the country to the east, large amounts of new transmission capacity will be needed across the MISO footprint. The need for more transmission capacity can be considered with the option that Indiana also has the capability of increasing its coal production for fueling increased generation capacity. Increased demand for Indiana coal could come from:

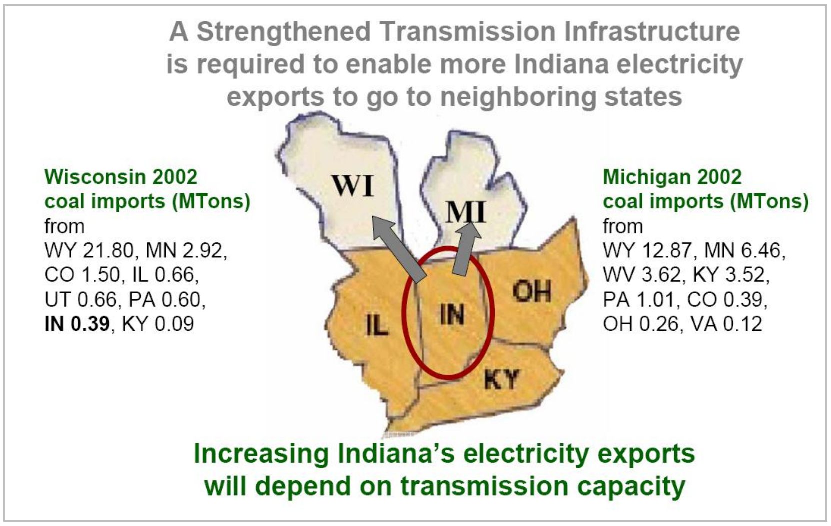
(i) increased coal exports,

(ii) new thermal power stations, or

(iii) limited substitution of PRB coal.

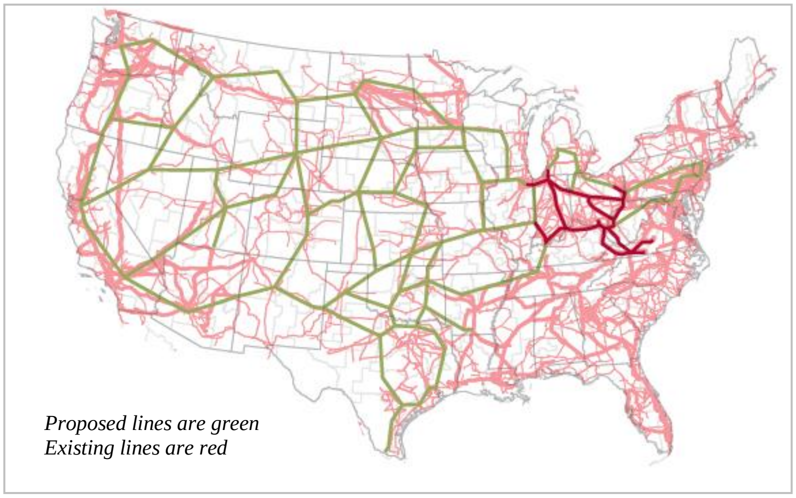
Whatever technology is employed for meeting the need of increased generation capacity and however much Indiana coal production might increase, there will definitely be need for more transmission capacity in the immediate and longer term future. There is also the potential substitution of shipping energy in the form of coal on the railroads with electricity via the transmission grid (i.e., coal by wire). As a specific application for example, at present, the state of Michigan is a major importer of western coal (Figure 6.3.5) and it might be worth considering the possibility of electricity imports from Indiana being more economical and beneficial to the state. This calls for an economic analysis of the combined networks of transmission grid and the railroads. This is a topic of much interest to CCTR, although no project has yet been funded. This potential project would have to be considered in the wider national debate of investing in the national power grid (Figure 6.3.6).

Figure 6.3.5. Exporting Indiana Coal by Wire



Source [6.21]

Figure 6.3.6. Revamping the U.S. Grid



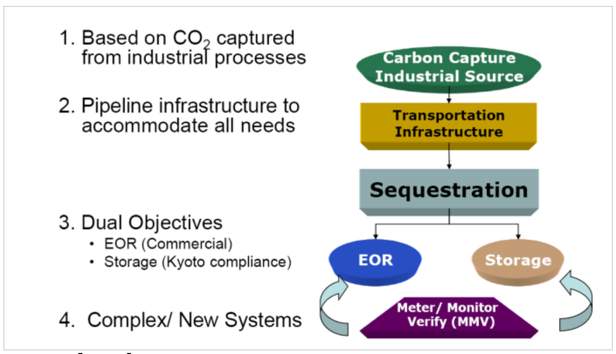
Source [6.15]

Note from "Revamping the Grid":
Distributing wind and solar power produced in remote areas would require new transmission lines. This map shows one possible expansion of the grid: proposed lines are shown in green, existing ones in red. The U.S. Department of Energy says that it would cost about $60 Billion to build enough new transmission capacity to let wind supply 20% of U.S. electricity. Former vice president Al Gore's proposal for a fossil-fuel-free electricity infrastructure calls for a $400 Billion investment in transmission lines and smart-grid technology. [6.15]

6.4 Midwest CO_2 Gas Pipelines

Over the past few years there has been so much discussion on carbon capture and storage (CCS) which tended to assume that CO_2 will be buried in the earth (sequestered). The best long-term solution for CO_2 will be in finding a way to use it. With enhanced oil recovery (EOR) there already exists a significant demand (over the medium term) for CO_2 (Figure 6.4.1). In developing EOR the main issue is one of transporting the gas to the oil fields. It can be transported by pipeline, barge, truck, or rail tanker but, because of its huge volumes, is best moved by pipeline. The cost of moving CO_2 is determined by the pipeline distance and the volume needed to be pumped.

Figure 6.4.1. Future CO_2 Possibilities



Source [6.16]

Gas transportation costs are relatively small compared to the value of the commodity. In the case of CO_2 the value of the commodity can be the determinant of whether to and/or how far to move the product. In instances where CO_2 had no perceived value, the best option would be to move the CO_2 the shortest distance to a location where geological sequestration is possible. In the case where CO_2 is known to have a value, the question is how to move the amount of the CO_2 needed to where it is needed in a form that allows for its best use. CO_2 transportation in itself poses no safety risks, provided the equipment is appropriately sited and regulations are observed. CO_2 has been transported by pipeline for decades and thus is not a new technology. Several companies have substantial experience in this area. Pipeline technology is not a concern in that it is proven and well documented. Typical specifications for CO_2 pipelines are listed in Table 6.4.1. The gas needs to contain at least 95% (moles) CO_2, no free water (less than 30lbs per Million cubic feet in the vapor phase), and less than 20 ppm (parts per million) by weight of hydrogen sulfide.

CO_2 control is economically and environmentally viable only if a benefit can be derived from the sequestration or an alternative use such as with EOR. Making CO_2 some value as it is removed from the environment is the only way that CO_2 can begin to become less of an economic burden. The real issue is the cost of control by making CO_2 a useful commodity versus the concept of treating CO_2 as a pollutant with no potential benefit.

Transporting CO_2 through a pipeline is an established technology capable of moving millions of tons of CO_2 per day. Shipping is an important issue because the prime locations of underground CO_2 storage are unlikely to coincide with CO_2 source locations. For example, the bulk of conventional oil reserves that can greatly benefit from EOR are not located where the current activity in developing clean coal technology is. The main CO_2 sources, coal-fired and natural gas fired electric utilities and the oil refineries, are located elsewhere. The capture of CO_2 is relatively easier with advanced clean coal technology systems and these systems stand out as the best hope for CO_2 capture. Unfortunately there remains the disconnect of distances from where the CO_2 can be captured to where it can be used.

Table 6.4.1. CO_2 Pipeline Specifications, Kinder Morgan 2008

9.1 Specifications. The Product delivered by Seller or Seller's representative to Buyer at the Delivery Point shall meet the following specifications, which herein are collectively called "Quality Specifications":

(a) **Product.** Substance containing at least ninety-five mole percent (95%) of Carbon Dioxide.

(b) **Water.** Product shall contain no free water, and shall not contain more than thirty (30) pounds of water per mmcf in the vapor phase.

(c) **Hydrogen Sulfide.** Product shall not contain more than twenty (20) parts per million, by weight, of hydrogen sulfide.

(d) **Total Sulfur.** Product shall not contain more than thirty-five (35) parts per million, by weight, of total sulfur.

(e) **Temperature.** Product shall not exceed a temperature of one hundred twenty degrees Fahrenheit. (120°F).

(f) **Nitrogen.** Product shall not contain more than four mole percent (4%) of nitrogen.

(g) **Hydrocarbons.** Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed minus twenty degrees Fahrenheit (-20oF).

(h) **Oxygen.** Product shall not contain more than ten (10) parts per million, by weight, of oxygen.

(i) **Other.** Product shall not contain more than 0.3 (three tenths) gallons of glycol per MMcf and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

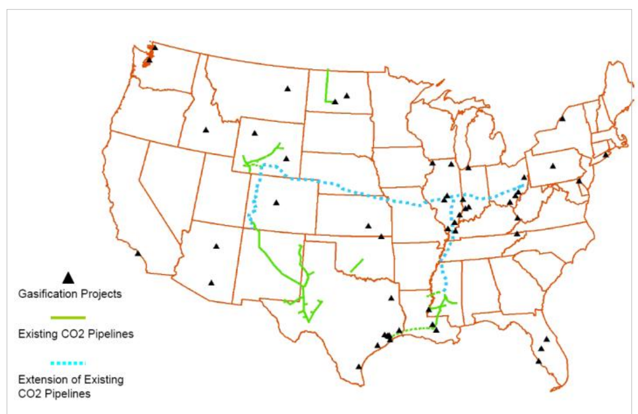
Source [6.16]

The Midwest Pipeline

Indiana, Illinois, Ohio and Denbury Resources of Plano, Texas, are planning to install a pipeline and transport CO_2 from clean coal technology, coal gasification sites to a natural storage site in Jackson, Mississippi. The pipeline is intended to connect sources of man-made CO_2 in the Midwest to the Gulf Coast for enhanced oil recovery using CO_2 injection. The CO_2 will then be used for EOR recovery projects already underway and being developed in the Eastern Texas oil fields (Figure 6.4.2).

Denbury has currently entered into agreements to study the process of building a network of CO_2 feeder pipes to a central location in southern Illinois, Indiana or Kentucky. It plans to connect the CO_2 from those sources to one 24-inch pipeline and then 400 miles to Jackson, Mississippi. Denbury has an early estimate of $800 Million to build the Midwest Pipeline and will not use government funds for this construction. This pipeline will be feasible if there are man-made (anthropogenic) sources of CO_2 from proposed IGCC and coal conversion plants in the three states, if at least three plants are built. Coal conversion plants can convert petroleum coke or coal into a variety of products including ammonia, methanol, synthetic diesel fuel, or electrical power generation.

Figure 6.4.2. Extensions & Existing CO_2 Pipelines in Relation to Gasification Projects



Source [6.17]

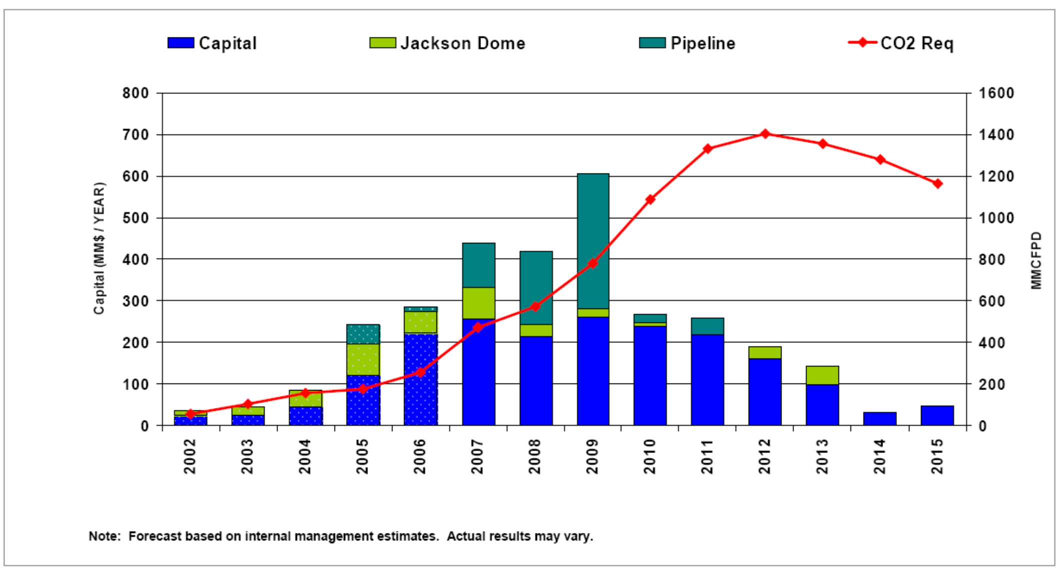
As a byproduct of these plants, large quantities of CO_2 will be produced, estimated to be around 100 Million cubic feet per day. Denbury plans to use this CO_2 to recover oil that may otherwise not be economically productive. In addition to this use of CO_2, it will eliminate the release into the earth's atmosphere.

Denbury Resources has budgeted $1 Million towards a detailed study and develop their plans for connecting the proposed sites in the three states, possibly for interconnection beginning in late 2009. Key to this study will be the states working to use existing right-of-way systems to reduce the time needed for permitting and siting. Illinois has offered additional funding for this program. Through the Center for Coal Technology Research, Indiana will offer technical and inter-agency support. Ohio will work with its state siting board to aid in the web design and potential site selection.

To date, the only advanced clean coal technology plant to start construction in the three states is the Duke Energy IGCC Plant at Edwardsport, Indiana. It is not clear that this facility will be providing man-made CO_2 to the Midwest Pipeline and thus challenges Indiana to provide a source of man-made CO_2 to cause the lateral line into Indiana. This is because the Edwardsport facility is not required to have CO_2 storage ability, although it must have CO_2 capture if capture requirements are legislated. The State of Indiana does not allow for construction cost to be included in the rate base unless the construction is deemed used and useful. Under the state rules until CO_2 capture becomes required Duke is not to build the required billion plus dollar CO_2 capture system. In the mean time Duke is working on defining and establishing the process by which CO_2 capture will be done if required.

SAIC Crane has a project that is under study and is working towards front end engineering and design (FEED). This project will include CO_2 capture. This is the double edged sword. The pipeline will not be built if there is no man-made supply of CO_2. Denbury is in various stages of discussions with several other entities that are considering building other coal or petroleum coke gasification plants that want Denbury to sequester their CO_2. Denbury's business model indicates a big need for CO_2 over the next several years (Figure 6.4.3).

Figure 6.4.3. CO_2 Requirements Business Model, Denbury Resources 2008



Source: [6.18]

Facts About Proposed Midwest Pipeline

- ***Size:*** 24" diameter pipeline.
- ***Length***: Approximately 400 miles.
- ***Volume***: Designed to transport up to 1,000 Million standard cubic feet per day of CO_2.
- ***Design and Operations***: The pipeline will be designed and operated under the rules and regulation of the Department of Transportation (DOT).
- ***Regulatory***: Compliant with local, state and federal regulations. Pre-pipeline construction involves approvals for wetland delineation, habitat evaluations and culture resource studies along with other environmental and safety statutes.
- ***Construction:*** Will occur after permitting and approvals are received from all governmental agencies including federal, state, county, township and city.

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[6.14] http://www.purdue.edu/dp/energy/ CCTR/researchReports.php

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[6.17] Klaus Lambeck, "A Regional Concept for a CO2 Pipeline Network," Indiana CCTR Panel Meeting, Bloomington, IN, June 5, 2008

[6.18] "EOR, The Economically Viable CCS Solution," Denbury Resources, Indiana CCTR Panel Meeting, Bloomington, IN, June5, 2008

[6.19] Keith Bucklew, "Coal Transportation in Indiana," Indiana CCTR Panel Meeting, Hammond IN, Dec 12, 2008

[6.20] Thomas F. Brady, Chad M. Pfitzer, "A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure", Purdue North Central, May 2007

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CHAPTER 7

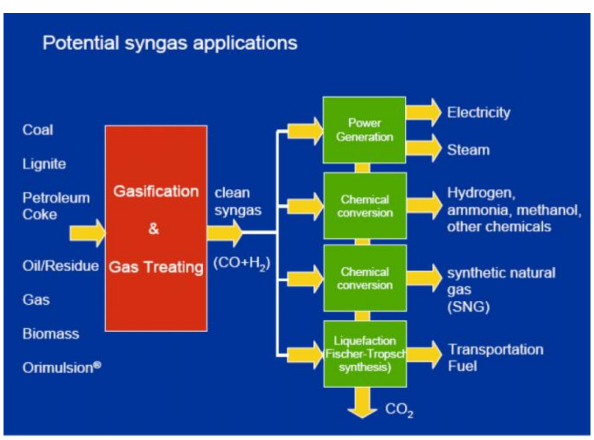
COAL GASIFICATION INITIATIVES

It is anticipated that coal gasification will become a much more important process nationally and to the state of Indiana. The CCTR is giving attention to this important topic, and each section in this chapter relates to it and has been prepared by different CCTR associated researchers. Extracts from their various CCTR reports and presentations are provided here (authors are listed at the beginning of this publication). The Science Applications International Corporation (SAIC), Indiana's State Utility Forecasting Group (SUFG), the Indiana Geological Survey (IGS), Purdue University's College of Engineering, and Baere Aerospace Consulting Inc have been funded by the CCTR to assess the value of coal gasification for Indiana.

With continuing high natural gas prices, the economics for coal gasification continue to be very attractive. In this chapter, Section 7.1 provides a summary of the assessment made by SAIC for coal gasification for coal-to-liquids (CTL) and power generation in Indiana as being specified by the Department of Defense (DOD). Section 7.2 was supplied from the report by SUFG which considers the criteria for selecting coal-to-liquids production sites in Indiana. Section 7.3 comes from the CCTR report which specifically considers the Crane Naval Base as a potential CTL site. Sections 7.4, 7.5, and 7.7 summarize the reports from Purdue engineering faculty concerning the fundamentals of the CTL process and testing of CTL in jet and diesel engines. Section 7.6 summarizes an early CCTR study of the economics of CTL. The Civil Aviation Alternative Fuels Initiative (CAAFI) is outlined in Section 7.8 and is provided by Baere Aerospace Consulting Inc. In Section 7.9 there is an outline of the Indiana Gasification LLC proposal. These CCTR-supported activities involve both technical and policy-related aspects for coal gasification in Indiana.

7.1 Coal Gasification and Liquid Fuel, Opportunity for Indiana

SAIC approached this study by defining criteria, based on Indiana goals, for a reference design facility concept that could be evaluated for technical and economic feasibility.



Source: Ross Rava, Shell Global Solutions (US) Inc., Coal-Gen, Milwaukee, Wisconsin, August 1-3, 2007.

- **Potential Customer/Partner Communications**
  - Air Force
  - Air Liquide
  - American Patriot Energy LLC
  - Conoco Phillips
  - CountryMark
  - Crane/NAVFAC
  - Cummins
  - Delphi
  - DOE
  - Hoosier Energy
  - National Rural Electric Cooperative Association
  - Wabash

Approach

SAIC recommends that a product/product mix is needed to be determined early as such decisions drive facility design, process, and cost. The facility design criteria used in this study are as follows:

- Generate 25 Megawatts (MW) of continuous power to the local grid, sufficient to supply NSA Crane peak load, independent of the national grid
- Locate on or near NSA Crane to enhance Crane's value through future BRACs, and be supportable logistically (e.g. coal and water) at that location
- Facility must be large enough to be commercially viable
- Facility must be capable of meeting all existing environmental requirements, and adaptable to future legislative/regulatory requirements relative to greenhouse gases as solutions develop
- Suitable for coal-based Energy R&D up to and including commercial scale
- Adaptable to present and future Department of Defense (DoD) and Department of Energy (DOE) needs
- Projected capital investment of less than $1 billion

Within the context of our criteria, SAIC performed a "quick look" business case, by modeling available facility size, product, and capital cost data; and by researching local and national product markets; and discussing product sales with potential credible customers.

SAIC further characterized the types of R&D capability of primary interest to academia and industry. SAIC then developed a baseline facility design and business model, and perform a feasibility level economic and technical analysis around the baseline design.

Reference Feasibility Concept

As part of the product analysis, SAIC investigated local markets and determined that there is a foreseeable future market in Southwestern Indiana for liquid fuels including low sulfur diesel, and commercial electric power; although certainly other coal gasification products such as synthetic natural gas could also have been considered. A local market can also be projected for plant by-products including sulfur and slag; and early discussions indicated a potential local market for a significant percentage of CO_2 output. SIAC's basic production design concept is a CTL facility based on commercial coal gasification and Fischer-Tropsch technologies. The small scale concept facility would be designed to process 2,700 tons of Indiana coal per day to produce 25 MW minimum continuous electric power delivered to the grid, or to Crane in an emergency, along with 6,000 barrels of synthetic fuel per day (bpd). A larger facility could present greater economic benefits, but would be difficult to support logistically on the base.

In SAIC's design concept, simply put, an Indiana coal which is readily available with characteristics similar to Illinois Basin #6 such as Springfield coal, enters the gasifier(s) as feedstock. Once in the gasifier(s), the temperature is increased and oxygen is added into the system. This process creates a carbon monoxide and hydrogen gas mixture. The impurities are removed from the gas mixture creating a clean Syngas. The Syngas is then fed to the F-T process to produce synthetic liquid fuels with the remaining fuel value in the gas used to produce electricity to run the facility, with a net electric power generation for sale to the commercial grid.

Recommendations

Energy experts such as the DOE Energy Information Agency (EIA) predict that the percentage of energy supplied by coal will actually increase over the next twenty years. It seems prudent to continue to plan, to develop advanced clean coal technology, and to be well positioned as a state to react as solutions develop and market conditions dictates.

SAIC specifically recommends the State of Indiana continue to aggressively motivate and incentivize the pursuit of clean coal technologies. Indiana has the natural resources readily available, the land required, the utilities necessary, and the drive to advance its technological aptitude in order to compete in today's rapidly evolving market. It is recommended that additional planning be done to accomplish the following:

- Develop a state-wide coal to alternative products strategy (liquid fuels, synthetic natural gas (SNG), fertilizer, chemicals, electric power), including policy options and initiatives
- Position Indiana as a lead player in the effort to implement solutions to CO_2 management, with special attention to product resale options, new technologies, and enhanced oil recovery via pipeline and sequestration
- Determine the feasibility of coal/bio-mass feedstock mix for clean coal applications.
- Evaluate optimum locations state-wide, including Army National Guard sites.

Process and Evaluation

SAIC approached this study by defining criteria based on Indiana goals for a reference design facility concept that could then be evaluated for technical and economic feasibility. It concluded that a product/product mix needed to be determined early as such decisions drive facility design, process, and cost. The facility design criteria used in this study are as follows:

- Generate 25 Megawatts (MW) of continuous power to the local grid, sufficient to supply NSA Crane peak load, independent of the national grid
- Locate on or near NSA Crane to enhance Crane's value through future BRACs, and be supportable logistically (e.g. coal and water) at that location
- Facility must be large enough to be commercially viable
- Facility must be capable of meeting all existing environmental requirements, and adaptable to future legislative/regulatory requirements relative to greenhouse gases as solutions develop
- Suitable for coal-based Energy R&D up to and including commercial scale
- Adaptable to present and future Department of Defense (DoD) and Department of Energy (DOE) needs
- Projected capital investment of less than $1 Billion

Facility Design, Selecting a Starting Point

Selecting a minimum potential commercial size for the reference design was accomplished by including as many of the state planning goals as possible into an SAIC model developed based on DOE/National Energy Technology Laboratory (NETL) studies on coal gasification and F-T liquids production. Table 7.1.1 summarizes some of the facility scale characteristics from these studies that were used for evaluation. As the design concept was iterated, a facility design on the order of 2,000 to 3,000 tons / day was selected for the following reasons:

- Smallest commercially viable CTL facility that was scalable
- Capital cost fell in the $1 Billion range
- Local demand for F-T liquids
- Continuous net electricity production supported the Crane grid independence goal
- Minimizes the CO_2 output to enable potential solutions short of full-blown geologic sequestration
- Compatible with resource and infrastructure availability for alternative sites across Indiana, including on or near Crane

Table 7.1.2 contains generalized estimates based on reviewing multiple studies that reflect different plant outputs for 2700 Tons coal/day.

Table 7.1.1. Plant Scaling Analysis

Coal, tons per day	Potential F-T Liquid Output, BPD	Illustrative Capital Cost,* US$ Million	Capital Cost per BPD Output $/BPD
300	500	$200	$400,000
1,200	2,000	$400	$200,000
3,000	5,000	$800	$160,000
6,000	10,000	$1,300	$130,000
20,000	30,000	$3,000	$100,000
30,000	50,000	$4,000	$80,000

Source: SAIC based on NETL data.
Capital cost is mid 2006 dollars and includes CO_2 capture, but not compression and
* storage, or sequestration

Table 7.1.2. Reference Plant Performance

Plant Output	2700 tons coal/day Refined F-T Liquids
Naphtha, bpd	2,704
Distillate, bpd	3,394
Total hydrocarbon product, bpd	6099
Gross power, MW	71.8
Net power, MW	25.1
Carbon dioxide, tons/day	3362
Sulfur, tons/day	78.2
Slag, tons/day	267.9

Process Flow Diagram

The facility configuration selected for this study is based on the recent *Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities* published by the National Energy Technology Laboratory, February 27, 2007 [7.1]. This analysis was carried out by NETL, SAIC, Parsons, and Nexant.

For the purposes of this feasibility study, SAIC selected a minimum commercially viable reference design of 2,700 tons of coal per day and producing over 6,000 barrels per day (bpd) of F-T liquids. Obviously, a larger facility could yield greater economic advantages but would not meet other decision criteria for this feasibility study.

Facility Design

A summary of the major equipment included in the facility design follows:

a) ***<u>Coal receiving and handling</u>***

Coal is received by rail in 100 ton hoppers, with conveyors, crushers, and storage bins. The site has been configured to handle a 60 day supply. Control of storm water runoff is an important environmental consideration.

b) ***<u>Fuel slurry preparation and fuel injection</u>***

Feeders, conveyors, hoppers, rod mill, slurry pumps, storage tanks. Although this portion of the process is a common design, the unscheduled interruption of flow to the gasification units would cause a system shut down and considerable expense if for a prolonged period. Planning for redundant pumping capacity is an important consideration.

c) ***Condensate and feedwater system***

Storage tanks, feedwater pumps deaerator, liquid waste treatment, makeup demineralizer, cooling water pumps, instrument air dryers, air compressors. The entire process must include an evaluation of equipment failure impact for each step with redundant capacity included where risk to the Syngas/F-T process continuity is marginalized.

d) ***Gasification***

A minimum of two pressurized slurry-feed entrained bed gasifiers, Syngas cooler, Syngas scrubber, flare stack. While each reference facility capacity could be achieved with a single gasifier train, two gasifier trains are assumed to provide increased facility availability and running at less than full capacity extends the periods between scheduled shutdowns for maintenance. Shutting down one of the gasifiers for routine maintenance would allow the F-T process to continue.

e) ***Air Separation Unit (ASU)***

Conventional cryogenic Air Separation Unit. This unit provides the oxygen to the gasification process and is a key and expensive part of the process. Site planning must consider future expansion of the ASU to provide for an increase in number of gasifiers and number of F-T product trains.

f) ***Syngas cleanup***

COS hydrolysis reactors, sulfated carbon bed for mercury removal, acid gas absorber, acid gas stripper, pumps, exchangers, Claus sulfur facility. For the F-T process this is one of the most critical portions of the process as particulate removal and sulfur removal are key requirements for a successful F-T process.

g) ***Fischer-Tropsch process***

Sulfur polisher, F-T synthesis reactors, carbon dioxide removal using amine, fractionator, Pressure Swing Absorption (PSA) hydrogen recovery (for refined product option), hydrotreating reactors (for refined product option). The maintenance of the catalyst is a critical step in the reliability and cost of the F-T licensing arrangement. The facility configuration uses hydrogen capture and hydrotreating to produce more refined liquid products.

h) ***Carbon dioxide capture***

The facility concept includes carbon dioxide capture from the F-T synthesis effluent. Carbon dioxide is not captured from the gas turbine exhaust. The facility design uses an amine system following the F-T synthesis that produces CO_2 at nominal 250 psia pressure for commercial or industrial use.

i) ***Power generation***

Combustion turbine and auxiliaries, waste heat boiler, ducting, steam turbine, condenser, stack. The steam turbine is used to make power using the waste heat from the gasification, Syngas quenching process, and the Syngas combustion turbine. The Syngas combustion turbine provides about 30% of the total facility gross power and the steam turbine provides the balance. Between the two power sources 25 MW of constant net power is exported to the grid. Environmental control equipment for the combustion turbine is selected to meet all Best Available Control Technology (BACT) guidelines.

j) ***Cooling water system***

Circulating water pumps, cooling tower. The site might support the space required for a lagoon as an alternative for cooling process water. The facility design includes an evaporative cooling tower and all process blowdown streams are treated and recycled to the cooling tower.

k) ***Slag recovery and handling***

Slag quench, crusher, separation, storage, pumps. The slag is suitable for resale as an aggregate for highway construction and other purposes.

Comparison to Other Analyses

The analysis presented herein is in line with a variety of other recently published studies of CTL from various sources and using various coals. All of these studies tend to find that CTL is economic at crude oil prices substantially below current market prices ($100+/bbl). Depending upon a variety of assumptions, such as those listed below, and scale of the facility, these reports find that commercially profitable liquid fuels can be produced at risk adjusted crude oil prices in the range of $35 to $65/bbl without sequestration. The major recent reports are briefly summarized below.

- A SAIC/NETL Alaska-based 11,700 ton/day sub-bituminous (14,640 bpd F-T liquids) CTL facility design estimated [7.1]:
  - Total project cost of $2.24B
  - Operating cost (excluding coal) of approx. $100M
  - Production price (@12% Return on Investment (ROI)) of roughly $45/bbl oil equivalent (delivered sub-bituminous coal price of $15.30/ton)
- A Kentucky-based 5,000 ton/day (10,000 bpd F-T liquids) CTL facility design estimated [7.2]:
  - Total project cost of $966M to $986M
  - Operating cost (excluding coal) of $58.1M to 61.0M
  - Production price (@15% ROI) of $50 per bbl oil equivalent (at $35/ton western KY coal)
- The recent Southern States Energy Board assessment of 16 CTL facility configurations from 5,400 to 33,600 ton/day (10,000 to 60,000 bpd F-T liquids) estimated:
  - Total project costs from $977M to $4.67B
  - Annual operating cost (excluding coal) of $63.5M to $296.0M
  - Production price (@15% ROI) of $35/bbl to $55/bbl oil equivalent (bituminous coal price $36/ton)
  - Various risk contingencies raised the oil threshold price to some $65/bbl oil equivalent
- A 2007 NETL study on small scale CTL facilities using a 4,254 ton/day (9,609 bpd F-T liquids) estimated [7.3]:
  - Total project cost of $976M
  - Annual operating cost (excluding coal) of $52M
  - Production price (@14% ROI) of $55/bbl oil equivalent (bituminous coal price $55/ton)
- 2008 SAIC/CCTR base case using a 2,704 ton/day (6,099 bpd F-T liquids) estimated:
  - Total project cost of $934M
  - Annual operating cost (excluding coal) of $43M
  - Production price (@18% ROI) of $75/bbl oil equivalent (bituminous coal price $55/ton)
  - Production Price (@ 10% ROI) of $60/bbl oil equivalent (bituminous coal price $55/ton)

Key CTL Risks

- Economic Risks
  - Collapse in market price of oil
  - Financing of large, complex, projects
    - Identification of lead investor/source of funds
    - No US-based team with track record in commercial CTL
- Design/Build/Operation Risk
  - Systems engineering and integration

  - Rapid construction cost escalation
  - Skilled labor availability
  - US commercial scale F-T system operations not demonstrated
- Competitive technology risk
  - Alternate processes for synthetic liquid fuels
  - Electric vehicles
- Political/policy changes
- Environmental

Total carbon footprint of Coal to Liquids facility compared to alternatives

SAIC Conclusions

This study concludes that while additional planning is required and risks exist in this volatile energy environment, this design concept and/or related concepts could be economically and technically viable, contingent upon acceptable mitigation of risk. The only exception from a commercial viability standpoint may be the ability to provide an R&D capability as it may require a substantial non-commercial subsidy. Risk areas as described above that must be addressed include the price of crude oil, systems engineering and integration, construction and commodity costs including coal, and any possible CO_2 tax, legislation, and regulation. The opportunities realized may be quite substantial. Benefits could include reduced reliance on foreign oil, enhanced use of Indiana coal, more Indiana jobs, advances in technology and processes, industry profitability, and creation of regional supply for transportation fuels. In terms of risk, we believe the following:

Cost

It appears likely that the price of crude oil will remain high enough to support a business case for a CTL plant, even assuming an adjustment to a historically more appropriate exchange rate for the dollar.

Technical

The technical risk that the United States has not yet demonstrated the ability to build a full cycle CTL plant can be mitigated. This can be done to a reasonable level by assembling the right team of “sub process” industry, academia and government experts, e.g. coal gasification, power generation, fuel refining, F-T process, construction, systems engineering, CO_2 compression and storage, and applying rigorous system engineering processes.

CO_2

The management of CO_2 issues represents a major technical and financial risk. The next 12 to 18 months should clarify the nation’s position on CO_2 taxation and associated legislation and regulation. Numerous initiatives have been and are being mobilized to address CO_2 emissions, from algae to full scale geologic sequestration, via DOE and state initiatives. Indiana, for example, is a member of a DOE funded state regional coalition and is in turn funding an initial sequestration project in Southwest Indiana. A project with output the size of this plant might not have to wait for a global solution to geologic sequestration, which may be potentially years away. As described, there are local CO_2 sale opportunities, and multi-state planning is ongoing for a CO_2 pipeline joining Indiana with EOR opportunities in the southwest, in the next 3 or 4 years. These two opportunities could satisfy future CO_2 emission requirements, especially for a “first plant” that could negotiate long term sales contracts. The inclusion of biomass as a feedstock with coal feedstock could also be evaluated, especially in Southwest Indiana, to further reduce carbon footprint.

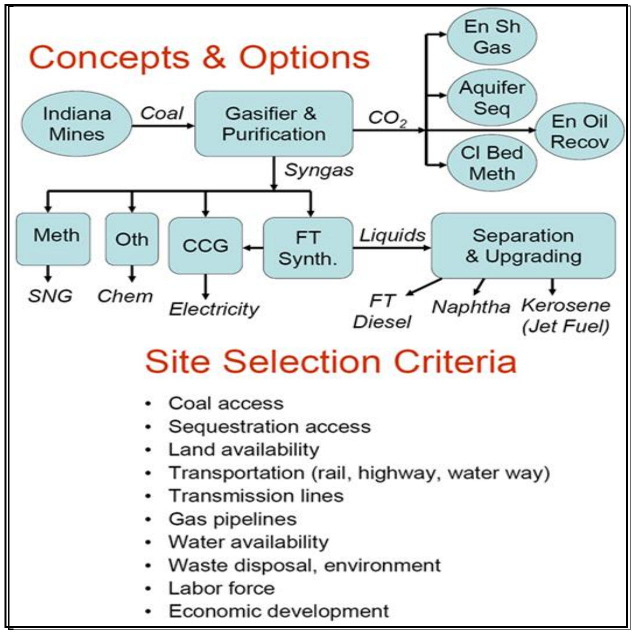
Coal

The DOE’s Energy Information Agency (EIA) predicts that the percentage of energy supplied by coal will actually increase over the next twenty years. It seems prudent to continue to plan, to develop advanced clean coal technology, and to be well positioned as a State to react as solutions develop and market conditions dictate.

We specifically recommend the State of Indiana continue to aggressively motivate and incentivize the pursuit of clean coal technologies. Indiana has the natural resources readily available, the space required, the utilities necessary, and the drive to advance its technological aptitude in order to compete in today's rapidly evolving market. It is recommended that additional planning be done to accomplish the following:

- Develop a state-wide coal to alternative products strategy (liquid fuels, SNG, fertilizer, chemicals, electric power), including policy options and initiatives
- Position Indiana as a lead player in the effort to implement solutions to CO_2 management, with special attention to carbon dioxide management, product resale options, new technologies, enhanced oil recovery via pipeline and sequestration
- Determine the feasibility of coal/bio-mass feedstock mix for clean coal applications.
- Evaluate optimum locations state-wide, including Army National Guard sites.

7.2 Synfuel Park/ Polygeneration Plant Feasibility Study for Indiana



The preliminary assessments in this SUFG project focused on the availability of resources and infrastructure that will permit the development and operation of coal conversion facilities. A number of U.S. states, with substantial coal reserves within their borders, are mounting efforts to site coal to liquids (CTL), coal to gas (CTG) and coal-based chemical plants. Indiana is no exception, and the goal of this SUFG study was to do a preliminary assessment of the suitability of several sites in southwest Indiana for the location of one or more coal conversion facilities.

The major resources for such a project include land and water. There is also an evaluation of proximity of coal resources and the potential for CO_2 sequestration or other use (e.g., for enhanced oil recovery or enhanced coal bed methane or shale gas production). The infrastructure needs also include assessing the access to the electric power grid, natural gas and petroleum product pipelines, major roads, and rail systems [7.5].

The major conclusions arrived at were:

(1) all of the sites examined are feasible for the development of a synfuel park,
(2) due to limited water resources, some sites may not be appropriate for large capacity plants or for production of SNG or pure hydrogen,
(3) special considerations must be given to the transportation of large pieces of equipment such as gasifiers and reactors to the plant site, which makes the sites located along major rivers that could accommodate barge deliveries advantageous,
(4) generally there is some sequestration potential associated with each site although some sites clearly have significantly higher potential for the enhanced production of petroleum using produced CO_2, and
(5) although the proximity of major infrastructural components, including transportation systems for products and feedstock, occur near each of the sites, the ability of these systems to handle the increased loads associated with such a synfuels park will need to be further evaluated.

The findings of this project focused on a preliminary assessment of the potential of several sites in Indiana to serve as the location of one or more Synfuel Park/Polygeneration Plants. Synfuel is short for synthetic fuel, which can be produced from a variety of feed stocks, including coal, biomass, algae, etc. [7.7]. The synfuel product can take various forms such as liquid, solid and gas. In this report, coal is the primary feed stock for synfuel production, with biomass serving as a secondary feed stock. SUFG focused on liquid and gaseous synfuels, including liquids derived from the Fischer-Tropsch (FT) process (Department of Trade, 1999), synthetic natural gas (SNG), and, for some sites, the possibility of hydrogen. Co-production of electric power is included via an integrated gasification combined cycle (IGCC) generating unit [7.9]. Direct coal liquefaction (DCL) is not considered in this report due to the higher capital cost of DCL. A flow chart diagram of the synfuel park/polygeneration plant (hereafter referred to as a synfuel park) is illustrated in Figure 7.2.1 in which FT diesel, jet fuel, gasoline, wax/lubricants, hydrogen and power are the likely finished products. Other products, such as methanol and DME (dimethyl ether) can also be produced. However, SUFG concentrated on the analysis of FT diesel, jet fuel, SNG, hydrogen and power in this study.

The report assessed the feasibility of locating a synfuel park at each of eight sites according to the following criteria:

- Coal availability
- CO_2 sequestration potential
- Transportation infrastructure/logistics
- Land/real estate requirements
- Transmission lines and power availability
- Gas and oil pipelines
- Water requirements and resources
- Waste disposal and environmental issues
- Risk factors
- Labor force/availability

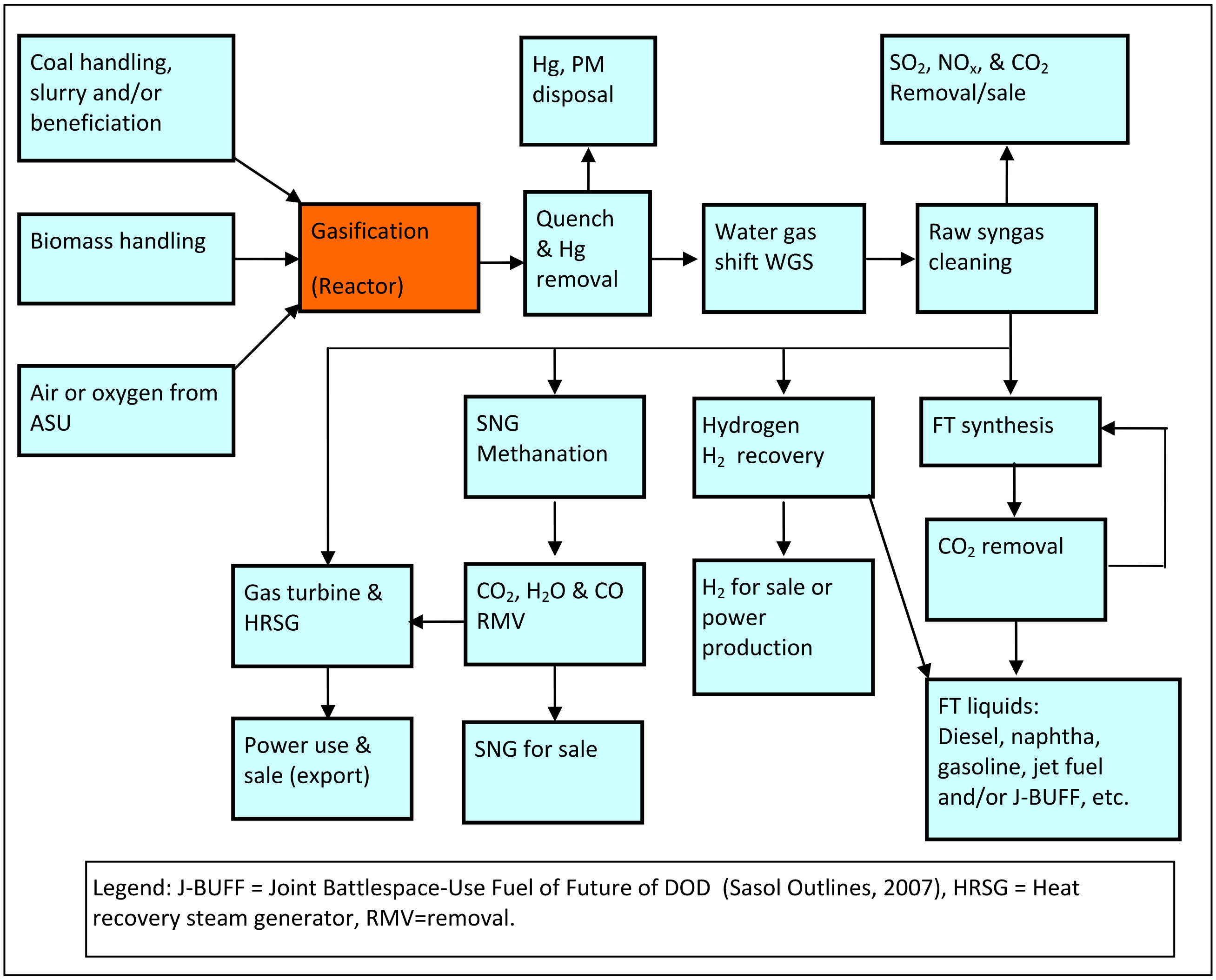
Eight sites were evaluated in detail as potential locations for synfuel parks in this report:

1) One near the Francisco Mine in Gibson County;
2) One near the Fairbanks/Breed in Sullivan County;
3) One near the Minnehaha Mine in Sullivan County;
4) One near the Merom Power Station in Sullivan County;
5) One near the Southwind Maritime Center, Port of Indiana in Mount Vernon;
6) One near the CountryMark Refinery in Mt. Vernon;
7) One at the Naval Supporting Activities at Crane (NSA Crane) in Martin County; and
8) One at the NSA Crane site in Sullivan County.

In addition, seven backup sites are also preliminarily evaluated and compared, including

1) One by the Gibson Power Station in Gibson County;
2) One by the A.B. Brown Power Station in Posey County;
3) One by the F.B. Culley Power Station in Warrick County;
4) One by the Rockport Power Station in Spencer County;
5) One near Tell City in Perry County;
6) One at the Indiana Arsenal, Jefferson; and
7) One near the Wabash Valley Power Association's IGCC power plant west of Terre Haute.

Figure 7.2.1. Flow Diagram of the Synfuel Park/Polygeneration Plant



Coal gasification is one of the critical sections of the synfuel park. Gasification can be carried out *above ground* or *underground*. In an above ground gasification system, high temperature, high pressure reactors are used to create precisely controlled chemical reactions with primary inputs of coal to produce raw syngas, plus steam and/or oxygen. The resulting heat content of the syngas is very stable. Coal gasification can also be performed *underground*, in which case an underground tunnel in a coal bed is used as a "gasifier" without the use of an actual steel reactor vessel. The advantage of this scheme is lower cost because the coal does not need to be mined or transported, a costly steel gasifier containment vessel does not need to be used, and the slag/ash does not need to be handled and transported for disposal purposes. The disadvantage of underground coal gasification (UCG) is that the syngas stream may have less consistent heat content. A number of UCG projects have been proposed around the world, including the Chinchilla UCG IGCC in Australia (Chincilla Pilot, 2007), the ESKOM 2,100 MW UCG/IGCC electricity generation plant in South Africa (Olivier, 2007), and the UCG synfuel project in China (Global Energy Network, 2007). In this report, however, we consider *aboveground gasification* exclusively because site evaluation is far more complicated due to the need for a detailed evaluation of the underground coal bed, water issues and other aspects of geology [7.6].

Here are general descriptions of the site selection criteria. More detailed descriptions of these criteria are provided in sections II-IX and XVIII of the SUFG full report (see CCTR website).

- Coal resources – In general, coal is plentiful in Southwestern Indiana in particular and in the Illinois Basin in general [7.10]. However, each site may be closer or farther away from coal sources, which may affect plant economics and railroad congestion.
- CO_2 sequestration and other uses – CO_2 capture and sequestration is not currently required in the U.S. However, it may become economically advantageous due to the potential imposition of carbon taxes or a cap-and-trade policy in the future [7.11]. It appears that Southwestern Indiana has good potential for sequestration, including deep aquifers [7.12]. In addition, other uses including enhanced oil recovery (EOR) from nearly exhausted oil wells/fields, enhanced coal bed methane (CBM) production, and enhanced shale gas/oil production may prove to be economical uses of CO_2 [7.13]. Each potential synfuel park site may be closer to or farther away from these resources, which will affect plant economics and construction lead times.
- Transportation infrastructure/logistics – Southwestern Indiana has a good rail system and is also accessible to the Ohio and Wabash Rivers. However, each site has its own unique transportation features [7.5]. For example, low overpasses may impede the transportation of very large equipment, which in turn may affect costs of plant construction. In addition, the impacts of congestion may be site specific and may affect costs of coal supply and finished products distribution.
- Electricity transmission lines and gas/petroleum pipelines – These resources are needed for different purposes during the construction and operation phases. Electricity and gas may need to be imported to the site during the construction phase. However, most designs investigated involve some export of electricity during the operation phase. In addition, either gas or petroleum pipelines may be needed during the operation phase for export of products.
- Water resources – Water requirements are substantial, with the majority of estimates ranging from 7-15 barrels of water per barrel of FT liquids. The use of air cooling or hybrid systems can substantially reduce the water needs. There is also the potential for realizing economies of scale in water use for larger operations through increased recycling of water.
- Land resources – a small synfuel park (i.e., 10,000 barrels per day) with FT production capacity is estimated to require about 120 acres for the plant, including water cooling and treatment, and co-production of electric power. An additional 20 acres is required for coal handling, and substantial land 500-1,000 acres (depending on topography) is needed for slag and ash disposal.
- Waste disposal and environmental considerations – Synfuel plants with CO_2 sequestration are relatively benign from an environmental perspective. Waste water can be treated to remove pollutants. Based on IGCC experience, air emissions are superior to pulverized coal power plants [7.14]. Solid wastes, primarily in the form of slag and ash, are inert and may be useful as construction materials while also maintaining all appropriate safe storage and handling procedures.
- Labor resources – The National Energy Technology Laboratory (NETL) estimates 144 direct operations personnel for a 50,000 barrel per day (bpd) plant. Administrative, maintenance and other support personnel are likely to add another 40-50%. The scaling

of the labor needs is probably not linear, with smaller scale operations requiring more labor per barrel of capacity.

- Economic impact – NETL estimates that revenues (including power export) are on the order of about $80 per barrel of FT liquids. Even for a small plant (i.e., 10,000 barrels per day) running at a 90 percent capacity factor, this amounts to revenues of three quarters of a million dollars per day. The indirect impact would be much larger through the economic multiplier effect, which is particularly high for the coal mining sector. More information regarding the economic impact of synfuel park/polygeneration plants can be found in Irwin et al [7.8].

SUFG major conclusions were as follows:

1) Coal, natural gas, water, and geological sequestration resources are available, to varying degrees, at each of the eight sites to operate synfuel parks with co-production of electric power. The capacity varies with the sites, from a very large plant with a potential capacity of 50,000-100,000 bpd at Mount Vernon, to about 10,000-20,000 bpd in the Minnehaha area or the NSA Crane site in Sullivan County.
2) Power and gas transmission lines are available either onsite or nearby and should be able to handle the added load required during construction. However, if significant amounts of power and/or SNG are to be exported, these infrastructures may have to be further evaluated for enhancement.
3) The Mount Vernon site can take delivery of large equipment such as the FT reactors. A port on the Ohio River at Mount Vernon has a crane that can lift up to 1,000 tons per load, which would allow the use of very large FT reactors. The apparent economies of scale in ICL production as a function of reactor size give the Mount Vernon site an advantage in terms of production efficiency. Other sites would be restricted to smaller FT reactors due to transportation limitations imposed by overpasses and tunnels on the rail or highway systems.
4) Water may be a limiting factor for some sites such as the Minnehaha mine-mouth site. This gives an advantage to sites with access to large, flowing bodies of water such as the Ohio and Wabash Rivers.

The full SUFG report is available on the CCTR website and is arranged as follows: Section II analyzes coal resources, while Section III focuses on carbon dioxide sequestration. Section IV examines the infrastructure requirements; Section V describes water requirements. Section VI analyzes land resources. Section VII discusses the environmental issues associated with the synfuel park. Emissions and waste disposal issues are analyzed in detail. Sections VIII and IX address labor requirements and economic impacts. Sections X through XVI cover the analysis of the seven primary sites, including their advantages and disadvantages. Section XVII presents preliminary analysis of a few more sites that could be good synfuel park candidates. Section XVIII discusses some policy and regulatory issues related to synfuel park development in Indiana. Section XIX presents a report summary and suggests directions for future work. Various background documents are provided in Appendices A-D, and the results of the evaluation of sequestration, enhanced oil recovery, enhanced coal bed methane, and enhanced shale gas production potential are presented in Appendix E.

The following has become clear from the analysis. In order to take advantage of economies of scale and to have maximum flexibility in the mix of outputs produced by the plant, it is important for the plant to be located on a body of water with substantial recharge – typically a major, navigable river. Such a location allows the delivery of large equipment and possibly coal, and for water to be used for processing and cooling. It is important that infrastructure (roads, rail, electric transmission network, and gas and refined petroleum product pipelines) be available to support both the construction and operation phases of the synfuel park. In addition, it is ideal for the area not to be too densely populated in order to facilitate the acquisition of land. Finally, it is important to have a means to sequester the CO_2 that will be emitted by the plant [7.12].

The primary focus of the project reported here has been the location of a synfuel park in southwestern Indiana. SUFG focused primarily on coal to Fischer-Tropsch liquids as the primary type of plant, recognizing that the precise mix of liquids can be changed somewhat through plant design and that such a plant will typically have excess electricity generation capacity. In addition, the analysis takes into account the possibility that by redirecting the syngas stream and including additional processing steps, it is possible to produce synthetic natural gas. Future work should recognize an even broader spectrum of uses for gasified coal, including production of methanol, fertilizers, and other chemicals.

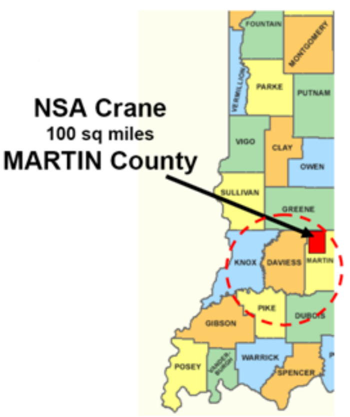
There is a need to prioritize development efforts based on estimates of the benefits and costs of alternative types of plants. As noted in this study, some sites may be better suited for some mixes of products than others.

SUFG has been indicating a need to expand electric generating capacity for several years. There may be synergies to be obtained by thinking simultaneously about ways to develop clean coal transformation technology businesses within Indiana and to redesign the electric power supply system. One possibility is replacing or repowering existing generating facilities using substitute natural gas derived from coal. This approach would obviate the need to find new sites for power plants, which has become an increasingly thorny problem. As the repowering options are considered, priorities should be based on several factors. One consideration is power plant emissions, and one clear priority would be to focus repowering efforts on the "dirtiest" plants – unscrubbed coal-fired plants – first. Another consideration is the transmission and distribution network. If repowered capacity is to be expanded relative to existing capacity, it is critical to evaluate whether the existing network can handle the increased load or if a simultaneous plan for network capacity expansion needs to be implemented. Understanding this part of the overall problem will require working closely with the State Utility Forecasting Group and the Midwest Independent Systems Operator.

A key part of clean coal technology is finding a way to deal with the CO_2 that is created by the conversion and combustion processes. A number of potential options have been addressed in this report, including sequestration in deep saline aquifers as well as options that produce revenue streams but may be less effective in sequestering, such as enhanced oil recovery, enhanced coal bed methane production, and enhanced shale gas production [7.13]. Experiments such as FutureGen, and potentially other demonstration projects, will create important case study data regarding the feasibility and cost of these options. SUFG and CCTR will need to continue its collaboration with the Indiana Geological Survey to analyze these data to identify promising future strategies as Indiana develops its clean coal technology sector [7.15].

7.3 A Feasibility Study for the Construction of a Fischer-Tropsch Liquid Fuels Production Plant with Power Co-Production at NSA Crane (Naval Support Activity Crane)

COAL AVAILABILITY



County & Mining Type Danville & Springfield Beds		Available Million Tons
Daviess	Surface	16.59
	Underground	0.00
Gibson	Surface	139.44
	Underground	1,967.26
Greene	Surface	70.86
	Underground	5.68
Knox	Surface	107.12
	Underground	1,300.77
Pike	Surface	170.43
	Underground	175.11
Posey	Surface	0.00
	Underground	1,527.61
Sullivan	Surface	151.59
	Underground	849.83
Vanderburgh	Surface	0.07
	Underground	516.07
Vermillion	Surface	17.26
	Underground	32.82
Vigo	Surface	147.05
	Underground	473.08
Warwick	Surface	349.45
	Underground	608.78
TOTAL D & S Beds	Surface	1,169.86
	Underground	7,457.00

10 Criteria

1 Coal & natural gas availability for 10,000 B/D FT fuel
2 CO_2 sequestration potential
3 Land/real-estate requirements
4 Transportation infrastructure (rail, roads & waterways)
5 Electricity transmission lines & available power
6 Gas & oil pipelines
7 Water requirements & resources
8 Waste disposal/environmental issues
9 Labor force requirements/availability
10 Economic impact

This preliminary feasibility assessment (prepared by CCTR and SUFG) focused on ten criteria specified by Crane Technology Incorporated (CTI) to determine whether to proceed with a more in-depth study of the construction of a Fischer-Tropsch (FT) transportation fuel production facility with an approximate capacity of 10,000 barrels of FT liquids per day. The goal of the study was to identify any clear indications that such a plant could *not* be sited at Naval Support Activity Crane (NSA Crane) [7.8], taking into account Indiana's Strategic Energy Plan for using the state's homegrown energy [7.16]. The study indicated there were generally good technical grounds to consider construction of a FT facility at Crane and that an in-depth technical and financial evaluation is not contra-indicated by any insurmountable problems.

Planning rationale should be based on:

- Proven reserves of coal are within easy transportation range of the Crane site [7.17]. Natural gas, once plentiful in the state of Indiana, is now supplied primarily from the Gulf region. Pipelines supplying Indiana homes and business are within easy access to the Crane site.
- CO_2 sequestration potential remains a large issue for all fossil fuel development [7.18]. CO_2 needs to be viewed as a potential energy development resource rather than as an environmental hazard. CO_2 could be used to produce additional energy via advanced coal bed methane or oil shale methane production.
- Land/real estate requirements are estimated to be approximately 120 acres of land with no more than 75 acres needed at any one site for fuel production and materials handling. Crane has more than adequate land for these facilities and has adequate topography for the estimated less than 1,000 acres that will be needed for landfill to allow disposal of slag and ash.
- Transportation infrastructure appears to be sufficient to meet the needs of a Fischer Tropsch (FT) plant of the proposed size. Rail lines are adequate for import of coal and export of final products [7.5]. Crane is served by class 1 rail lines and has within its borders excellent rail mobility. The rail system allows for movements of raw materials into the facility and the movement of product out.
- Transmission lines and power availability appear to be adequate since the site is

connected to the grid through 2 substations: one owned by Duke Energy/Indiana the other by Hoosier Energy System. Crane also has access to a 345kV line that passes through the site. Crane is also close to Duke Energy's proposed 625MW IGCC plant at Edwardsport [7.19].

- Gas pipelines transverse or are within relatively close proximity of the Crane facility. Oil pipelines are not in close proximity, but they are not an essential resource. In the future, it may prove advantageous to build a pipeline for exporting the final product, but for the proposed scale of operations, it is not necessary.
- Water requirements and resources are a major concern for the development of coal-derived (as well as biomass-based) synthetic fuels. The coal to liquid process requires approximately 15 barrels of water per barrel of final product. The volume is large but does not pose an insurmountable problem. On-site sources are likely not sufficient to sustain the plant, but adequate resources are available from the East Fork of the White River only 2 miles to the south of Crane [7.20].
- Waste disposal and environmental issues are a direct reflection of the technology chosen for the process. In general, the waste stream will consist of sour water from the treatment plant. Crane already has a history of environmental compliance and the ability to work with the State of Indiana to develop the needed procedures.
- Labor force requirements for the production of the fuel once the plant is built will be relatively small, less than 150 people. The range of labor needs is well within those already on site at Crane. However, training programs will be a key to the success of the operation. Education and training will be addressed by Purdue University, surrounding institutes of higher education and Ivy Tech Community College. There will be a need for more coal miners than there will be for CTL workers. There will be a need for 160 coal miners if the entire capacity of the facility is to be met with coal from Indiana mines.
- Economic impact of this plant comes in the form of the value of the coal produced and the value added via the products produced [7.21]. The value of the coal produced (2 million tons per year) and the ancillary jobs created would be about $120 million annually. The transportation fuel and the naphtha, plus elemental sulfur and electricity come to about $80 per barrel of product, or $266 million per year, for a value added amount of $146 million per year.

No significant problem area was identified that would make further pursuit of this project unjustified. There are challenges but no insurmountable problems.

CCTR and SUFG together with the Indiana Geology Survey (IGS), contracted with Crane Technology Inc. (CTI) to conduct the preliminary feasibility study to determine whether it would be possible to build an FT plant for producing synthetic fuels at the Naval Support Activity Crane (NSA Crane or simply Crane) [7.22]. Crane is located in Martin County, in southwestern Indiana. An additional site was identified in Sullivan County at a later stage of development. The advantages and drawbacks of that site were addressed. The potential plant would co-produce diesel, jet fuel and naphtha, as well as electrical power, and use coal as its primary feedstock.

The FT process was developed by the two German scientists Franz Fischer and Hans Tropsch in 1923. The process is an indirect coal liquefaction (ICL) process. ICL, including the FT process, is a mature technology. In the past, commercialization of the ICL technology was not widespread, for the simple reason that oil prices did not remain high enough for long periods of time. However, due to the high crude oil prices of the past few years and concerns about energy security, many countries have been considering the development of ICL plants for producing synthetic fuels [7.23]. The current leader in plant construction and development is China, with a few large commercial projects under development, and many more at the planning stage.

ICL and the FT process have been developed and used successfully for some time. At the end of World War II Germany was operating nine indirect and 18 direct coal liquefaction plants. Direct coal liquefaction, or DCL, plants involve a somewhat different technology from ICL, but have the same ultimate goal to create liquid fuels from coal. These plants supplied Germany with almost four million tons of fuel per year (both diesel and gasoline) [1].

Since the early 1950s, South Africa has been the world leader in production of ICL liquids, with three large commercial plants. The Sasol Company is the major force in ICL research, development, and operation. They have achieved substantial improvements over the original FT synthesis process, including the use of iron-based catalysts, the high temperature FT (HTFT) fluidized circulating bed technology, and the Sasol Advanced Synthol (SAS) technology. The fuels, which have been the primary products, offset up to 60% of South Africa's oil demand. The plants also yield a substantial amount of various chemical feedstocks (see [1] and Figure I.2).

The U.S. has conducted significant research in the ICL area with sponsorship from both industry and government. ExxonMobil, Rentech and Syntroleum have independently developed ICL processes. One commercial plant using ICL technology, the Eastman Kingsport methanol plant, has been operating successfully for the past 10 years, with co-sponsorship from the U.S. Department of Energy (DOE).

Water resources

a) Lake Greenwood

There are several sources of raw water in and around Crane. First of all, some water can be drawn from Lake Greenwood, especially during rainy seasons. The lake has an area of 812 acres, with an average depth of about 15 feet. The total water volume is over 3 billion gallons. However, the lake provides water for various processes at Crane and may not be able to provide all of the water requirements for the large FT plant with co-production of power because the average annual inflow of water is limited.

b) The East Fork of the White River

The East Fork of the White River is about 2 miles southeast of Crane. The monitoring station closest to Crane is near Shoals. The locations of the river and the Shoals monitoring station are shown in Figure 7.3.1.

At Shoals, the mean stream flow rates are greater than 5,000 cfs (cubic feet per second) for about half of the year (indicated in Figure 7.3.2). On average, September tends to have the least flow, with a lowest mean daily flow rate of about 1,280 cfs. The daily mean flows of the East Fork at Shoals for the last 40 years (USGS 40 year data from 1966 to 2006) are shown in Figure 7.3.3.

The percentage of water withdrawn from the river offers a helpful measure for understanding the water usage of the potential FT plant at Crane. The average stream flow rate of the East Fork at Shoals, 5,000 cfs, equals about 865 barrels per second or about 74,736,000 B/D (865 barrels/sec*3,600 sec/hr*24 hrs/day). Given that one barrel of FT liquid fuels requires about 15 barrels of raw water, the potential percentage of water withdrawal from the river is tabulated in Table 7.3.1 as a function of the FT capacity and power. From 7.3.1 we can see that water withdrawal from the East Fork is very limited, ranging from 0.1 to 0.3% for a modest-sized FT plant.

The West Fork of the White River, a few miles to the northwest of Crane, also has significant amounts of water that could be used if needed.

Figure 7.3.1. Water Resources around Crane (IGS map)

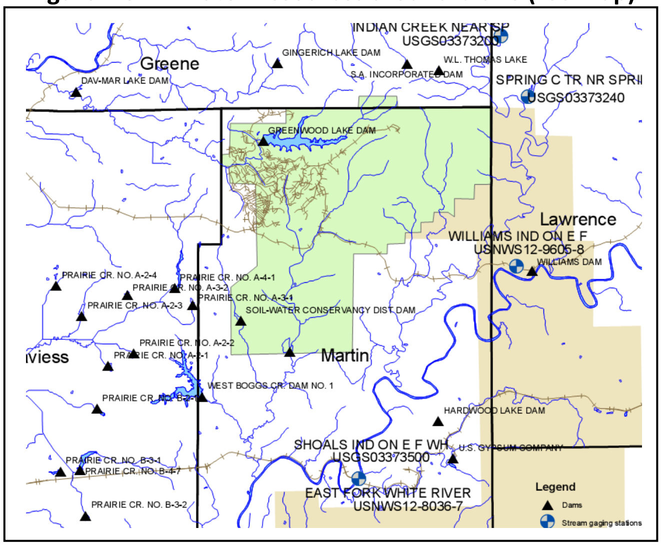


Figure 7.3.2. Stream Flow of the East Fork River at Shoals (Source: Division of Water, Department of Natural Resources of Indiana)

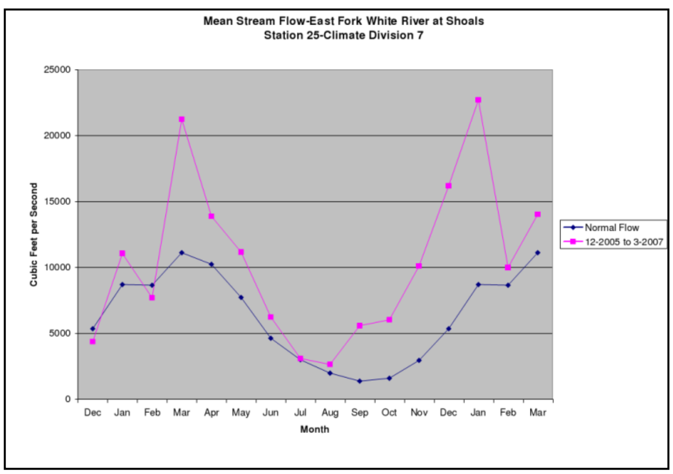


Figure 7.3.3. Daily Mean Stream Flow of the East Fork at Shoals from 1967 to 2007 (Source: USGS)

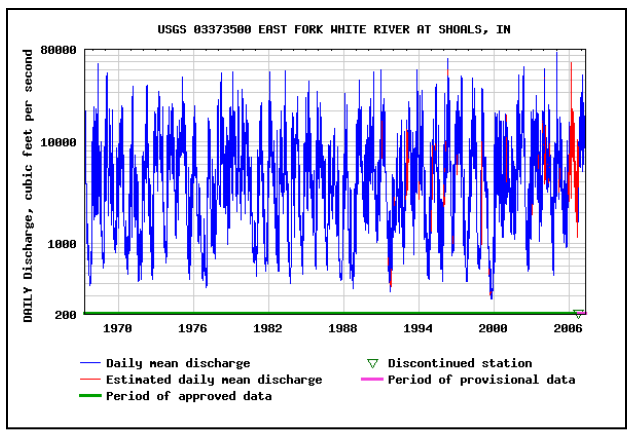


Table 7.3.1. Percentage Water Withdrawal from East Fork near Shoals

	5,000 B/D FT 41 MW export	10,000 B/D FT 82 MW export	15,000 B/D FT 123 MW export
Average flow 5,000 cfs	0.1%	0.2%	0.3%
Low flow 1,280 cfs	0.39%	0.78%	1.17%

CO_2 Capture in IGCC and FT

Greenhouse gases such as CO_2 may be regulated by the U.S. Government in the future. Fortunately, synfuel and IGCC power plants with coal gasification can capture CO_2 because they use existing technologies such as the two-stage Rectisol, and because the syngas stream is under high pressure with concentrated CO_2 content. According to Lynch [13], Rectisol can capture 90-95% of the CO_2 in the syngas stream. One commercial project capturing CO_2 from syngas production is the Great Plains Synfuel Plant in North Dakota, where CO_2 is captured and transported via a 200-mile pipeline to the Weyburn oil field in Saskatchewan, Canada [14] (see Figure IX.3). According to Perry and Eliason [14], the Rectisol unit at the Great Plains Synfuels Plant already produces a 95% pure CO_2 stream just due to the nature of the process. It is also “bone-dry,” with a dew point of -100º F, because of the cold methanol absorption and regeneration processes used to remove the CO_2 from the product gas stream.

CO_2 from the FT vapor stream can be captured by an absorption tower with the amine acid gas removal process. The CO_2 can be regenerated from the amine-based solvent, and then compressed for pipeline transportation.

The IGS reports the potential for sequestration in the deep subsurface of Indiana, including injection into saline aquifers, as well as potential for use in enhanced oil recovery by CO_2 flooding, enhanced coal bed methane production, and enhanced shale gas production. There is another commercial CO_2 removal project in the U.S. of smaller scale – the ammonia plant in Coffeyville, Kansas, owned by Farmland Industries (see Figure IX.4). At this facility, petcoke, which has much higher sulfur content than bituminous coal, is the primary feedstock. The Selexol process is used for sulfur and CO_2 removal instead of a Rectisol unit as in the case of the Great Plains Synfuels Plant [7.24]. The separated CO_2 is partially used for the manufacture of fertilizer, with the excess vented to the atmosphere. These plants demonstrate that CO_2 removal technologies are commercially viable.

Labor Force Requirement and Availability

The National Energy Technology Lab (NETL) estimates that a 50,000 B/D facility requires 144 direct operations people. Increases in the capacity of a coal to liquids facility do not correspond with an equal increase in employees needed; thus the manpower savings in scaling down from 50,000 B/D to 10,000 B/D is far less than a factor of 5. Thus, for the purpose of this study, CCTR will assume that 144 people, including administrative personnel, are necessary to operate the Crane 10,000 barrel per day Coal to Liquids facility. The level of expertise and training will be varied but, as described below, it will not be beyond the level of education and training that already exists at Crane.

The Educational and Training Component of Clean Coal Technology

The exploitation of the West Texas and Gulf oil and gas fields has resulted in an explosion of “oil patch” vocational and higher education programs in that region over the last 50 years. As coal and biomass (conversion of biomass to liquid fuels via gasification involves many of the same processes as coal gasification), rather than imported oil and gas, become the fuels of choice, we envision the same occurring with coal and the Illinois basin becoming the national center of the emerging synfuels industry.

None of this can happen, however, without a trained workforce ready to meet the demands of this emerging industry. To put the problem in perspective, just the mining of the coal required to support a Coal to Liquids Plant will require about 150 new miners. The coal conversion processes require a higher level of skills. Coal gasification plants and Fischer-Tropsch units, the two technologies that set Coal to Liquids Technology apart from conventional plants, are massive chemical plants, thus requiring a more sophisticated work force than ordinary power plants. The same is true for the downstream processes that gather, condense and transport CO_2. Thus, the training task is a formidable one.

However, the challenge is one that Indiana is ready to meet. The region is primed to become an educational and training center and to create programs in Coal Conversion Technology, producing individuals who will run clean coal technology and other such plants as they are introduced into the region and the nation. Sustainability is very important insofar as the ultimate goal of clean coal technology is to build a facility that can be replicated throughout the U.S. Multiple sites mean an increased demand for a new type of energy operations professionals.

Educational Infrastructure

The question of training and education for clean coal technologies has been addressed by Indiana and the CCTR. As a partner with the State of Illinois in the FutureGen proposal, Indiana has assembled an education component based on the fact that the largest and longest operating coal gasification facility in the U.S. is located in Terre Haute, Indiana. CCTR is also working with the Coal Fuel Alliance, which was created for the Energy Act of 2005, to promote coal conversion activities by establishing the education component and the long term use of coal derived fuels.

Fortunately, the region has in place an educational infrastructure which can be expanded to meet this challenge. Vincennes University already provides mine worker training and safety programs, and academic programs in coal conversion exist at Southern Illinois University and the University of Kentucky. Resources of the Purdue University Energy Center include the Coal Transformation Lab, the Coal Fuel Alliance and the CCTR. These institutions combined have the capability and the resources to aid in the advanced training and future research needed to support this project as well as other advanced coal conversion projects. Vincennes University, Indiana State University, the University of Evansville, Indiana University Southwest, Purdue University and Rose-Hulman Institute, will work together to develop a curriculum in consultation with State Higher Education Commissions. The Illinois basin states, Kentucky, Illinois, and Indiana, will lay the groundwork now for creating a regional program in Coal Conversion Technology through the Coal Fuel Alliance (CFA). The CFA will prepare workers for the opportunities that will be created as the region takes the lead in clean coal technology commercialization with projects such as FutureGen, Duke-Edwardsport IGCC, Indiana Gasification LLC, and Crane FT Plant.

The CCTR is prepared to workshops for the educational institutions and the Wabash Gasification facility for the purposes of establishing the education needs of Clean Coal Technology and to muster the available resources to meet those needs. This meeting could be coordinated with the Indiana Higher Education Commission for the purpose of certifying any new programs for technicians and professionals wanting to work in the newly established industry. The Crane region already has a major research university and has relatively easy access to a number of state and private universities. Indiana University (IU)-Bloomington, IUPUI, Purdue University, Rose-Hulman Institute of Technology, Vincennes University, Ivy Tech Community College, and Indiana State University have substantial programs in science, engineering, medicine, electronics, etc., that serve the region. Crane itself has a long history of working closely with academic partners. The region's two technology parks have already formed partnerships with IU-Bloomington, Purdue University, and Rose-Hulman.

Crane's Economic Impact

NSA Crane is a major economic force in southwestern Indiana, with its total estimated economic impact approaching $1.5 billion. The multi-county area around the base shares a total annual benefit of $844.7 million. Much of this impact is generated by wages and purchases. The number of highly paid professionals and contract expenditures equals and even exceeds those of many of Indiana's large private enterprises.

The most notable economic impact delivered by Crane is employment. Crane is the twelfth largest single-site employer in Indiana and the second largest single-site employer in the southwestern part of the state. Its wide range of professional and technical jobs provides comparatively high pay in an otherwise mostly rural area. Crane's on-site employment of approximately 4,780 workers is supported by an additional regional workforce of approximately 3,700 workers. This brings the total employment level of NSA Crane to about 8,500 jobs, approximately 7,400 of which are in Martin County and the contiguous counties of southwest Indiana.

Moreover, wages earned by NSA Crane workers are among the highest in Indiana. The average wage of workers at Crane is approximately twice the average wage in Martin County. The highly skilled and highly paid jobs offered through the Navy, defense contractors, and other operations at the base have enabled this region of Indiana to attract educated and talented professionals to communities that would otherwise have few scientific, engineering, and technology positions. Crane's impact is the greatest at the individual county level, where Crane's economic impact constitutes a large proportion of regional income. Thus, from numbers of jobs supported, to wages and income, to commuting patterns, NSA Crane is the major force supporting key elements of the area economy. Crane is an economic engine of significant importance and on a par with the private sector industrial giants of the Hoosier state.

A 10,000 B/D coal to liquid plant will have a big impact "outside the fence" of Crane, creating new and desirable jobs and having significant economic multiplier effects. The major reason this facility can work at this site is because the infrastructure and capability to do the project is already in place. Production of 10,000 B/D of liquid fuel from coal requires about 5,000 tons of coal per day, or about 1.8 million tons of coal per year. There are an estimated 1.17 billion tons of coal within 100 square miles of Crane accessible from surface mining and another 7.46 billion tons available from underground mining. Thus, the resources to meet this demand of 1.8 million tons per year already exist through expanding existing mine production.

Mining this additional 1.8 Million tons of coal per year will require about 150 new jobs in mining itself and about 760 secondary and ancillary jobs. The income from these jobs will be around $62 million annually. The overall economic impact of 1.8 million tons of coal is over $108 million annually and represents new money into the region. Establishment of a coal to liquids plant will allow Crane to maintain its role as the primary source of high paying jobs in an area of Indiana with the lowest income levels.

The coal will need to be moved by rail car. A rail car holds 131.5 tons of coal per unit, compared to 25 tons of coal capacity of an over the road truck. 5,000 tons of coal per day will require 38 rail cars per day (compared to 200 trucks) or one train a day. The rail line servicing the Crane complex is class 1 track owned by Indiana Rail Road.

The Indiana Rail Road (80% owned by CSX) owns that trackage exclusively. The trackage continues on with rights to Chicago (via Terre Haute) and Louisville (via Bedford). Indiana Rail Road is the only company which operates that right-of-way. The route was rehabilitated years ago with new roadbed, wooden ties and welded rail. The route was originally part of the Chicago, Milwaukee, St. Paul & Pacific Railroad's Terre Haute Division: commonly known as "The Southeastern." This rail line is included in the CCTR report "A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," Tom Brady, Purdue North Central, which details among other things the opportunity for a Coal Corridor in Indiana [7.5].

Regional Economic Impact

The 10,000 B/D facility will create products of value for direct use and for sale on the open market (Table 7.3.2). The 10,000 B/D is the total amount of FT liquids; it is not all one fuel. A 10,000 B/D plant will produce 5,563.8 barrels of diesel equivalent military type fuel, and 4,434.6 barrels of naphtha, the feedstock for gasoline. The facility would also produce about 1,200 MWh of electricity for export and 180 tons of elemental sulfur on a daily basis.

Table 7.3.2. Products of Value from a 10,000 Barrels per Day Facility

The estimated value of the 10,000 B/D production is as follows:

5,563.8 barrels of diesel	@ $82.32/barrel	$458,012.02
4434.6 barrels of naphtha	@$63.00 /barrel	$279,379.80
1,200 MWh of electricity	@ $.06 / KWh	$ 72,000.00
180 tons of elemental sulfur	@ $10.00/ton	$ 1,800.00
Daily production value		$811,191.82
Average value per barrel of FT production		**$81.12**
Annual values based on 90% capacity (7,889 hours of operation)		**$266,659,031.03**

Conclusions

The goal of this study was to identify whether there are any clear indications that a coal to liquids FT plant with electricity co-production could *not* be sited at NSA Crane. This study was not intended to be a comprehensive evaluation that identified precisely how, and at what cost, such a plant can be built at Crane; rather, it was a preliminary feasibility assessment. The conclusion was that there are no clear reasons why the plant cannot be sited. On the contrary, a number of features make Crane an attractive location for the construction of such a facility. These are recapped below.

Coal supplies are available in abundance in the region around Crane. Through a combination of existing and new mines, sufficient coal resources can be obtained to support the plant over its 20-25 year useful life. While a modest amount of natural gas may be needed to run the plant, the existing pipeline infrastructure should be adequate to supply these needs.

The deep subsurface geological environment has significant potential to sequester the carbon dioxide produced by the plant. Saline aquifers, mature oil fields, and shale gas fields are all available either directly under the property or in close proximity to the west. Sequestration into coal beds and associated enhanced coal bed methane production is not possible in the immediate area due to the shallow nature of the seams on the site. Enhanced oil recovery (EOR) and enhanced gas recovery (EGR) offer significant potential for value-added production of energy resources via the injection of CO_2 into oil fields and in the gas shale.

Sufficient land for the various components of the plant, for coal inventory and handling, for water cooling and treatment, and for disposal of solid wastes (mostly slag and ash) appears to be available on-site. A more detailed study to identify their precise locations within the facility should be performed as this project moves into its next phase. Considerations in site selection should include terrain, distance to various elements of infrastructure (power grid, gas pipelines, water sources, etc.), proximity to landfill areas for slag and ash, economics of necessary infrastructure enhancements, etc.

The rail and road systems to and within Crane appear to be sufficient to support the operation of a CTL plant. It is expected that much of the coal will be brought in by rail, and many of the products of the plant can be sent out by rail or truck, depending upon the results of the economic analyses. The biggest remaining question is the feasibility of transporting the largest pieces of equipment – namely the FT reactors – to the plant site. In 1989, a similarly large and heavy piece of equipment was delivered via barge to Jeffboat in Jefferson, Indiana and then via rail to Crane. It may be possible to use this strategy to deliver the FT reactors. A more detailed analysis will be needed once the precise size and weight of the components of the CTL plant have been identified.

The configuration of CTL plant we focus on in this study produces electricity in excess of the plant's needs. The net export capacity of the plant would likely be on the order of 40-50 MW, and it appears that the grid should be able to absorb this level of export, perhaps with some moderate modifications. A more detailed power flow and stability analysis is beyond the scope of this report, but should be performed as this project moves forward.

While water supplies for cooling and the various processing stages of the CTL plant initially appeared to be a substantial challenge, the two nearby forks of the White River can provide sufficient water without great impacts on the river. More detailed engineering and economic analysis will be needed to determine the precise design of the cooling system and the water treatment systems, as well as the optimal sourcing of water for the project.

A secondary site in Sullivan County to the west of NSA Crane was also evaluated. However, the primary site appears to be superior due to the limited water availability at the western site and the proximity of the East and West Forks of the White River to the primary site.

No insurmountable problems were identified with respect to waste disposal or plant emissions. However, because no CTL plants are currently operating in the U.S. on a commercial scale, our knowledge of the exact composition of wastes and emissions is still imprecise. Nonetheless, environmental permitting is "fast-tracked" at NSA Crane under the provisions of the Military Base Protection Act (MBPA) passed by the 2005 Indiana General Assembly. The MBPA provides for first priority by the Indiana Department of Environmental Management (IDEM) for any IDEM permitting in support of operations at Crane.

The labor force requirements will be substantial. A significant expansion of the coal mining labor force will be needed. Of greater concern is the need for technicians and chemical engineers with the skills and knowledge to operate the CTL plant. However, substantial educational and training facilities are available in the region and the state. In addition, the IGCC plant operated by Global Energy and Wabash Valley Power Association is located in the area, and the gasifier at that plant could serve as an ideal training facility for a significant part of the CTL plant.

The economic impacts for this region of Indiana could be quite large. The area is depressed with relatively high unemployment and low skill levels in the labor force. The proposed project would create a large number of high-skill, high-paying jobs in the area. When combined with an economic multiplier effect, the result will be a substantial economic development thrust.

Thus, it appears that it would be feasible to locate a CTL plant at NSA Crane. Indeed, Crane seems an attractive site because of the proximity of coal resources; excellent infrastructure, including rail, the power grid and pipelines for gas and refined products; available water access; available land within the facility; and available labor resources. Of course, a full-blown engineering/economic study will be needed to determine the precise location, design, and operating characteristics to best meet the project goals. In the end, however, there does not appear to be any factor that would prohibit locating a CTL plant at Crane.

7.4 Process Analysis for Producing Transportation Fuels from Coal

Coal To Liquids, CTL

Molecular level characterization of F-T fuels needed to establish relationships between fuel composition and

- Fischer Tropsch reaction conditions
- Fuel refining methods
- Fuel performance in engines

F-T Fuel Characterization

- No commercial methodology exists for detailed characterization of very complex hydrocarbon mixtures
- Hence, new analytical methods must be developed for F-T-fuel analysis
- These special methodologies are best implemented on ultra-high resolution mass spectrometry because of the molecular complexity of the fuels

The Coal To Liquids (CTL) process is a proven technology but there are areas in which more analysis is needed before they are to be widely implemented in engines of various types. Over the past three years the Purdue engineering schools have outlined their commitment to seek funding to pursue coal-to-liquids research [7.26].

Countries which are rich in coal reserves are looking at CTL processes as a means to wean their dependence on foreign oil. Although this process is feasible once the crude oil prices are above $43/bbl [7.27], large inefficiencies in the coal-to-liquid (CTL) processes comes from conversion of coal to carbon dioxide in the coal gasifier and in the Fischer-Tropsch (FT) reactor. Due to this reason, more than two times the amount of carbon dioxide is generated for each unit of CTL fuels utilized as compared to fuel from crude oil. Generally, this carbon dioxide is released from the chemical processing system to the atmosphere and contributes to the green house gases in addition to the release of CO_2 from the exhaust of internal combustion engine. An alternative to produce liquid fuels which will minimize the release of carbon dioxide is thus a priority.

A frequently mentioned procedure to avoid release of CO_2 in the atmosphere during the coal conversion process is geologic carbon sequestration. Carbon capture at the source is done using amine absorbers and strippers. The captured carbon is stored in brine formations or in depleted oil or gas fields [7.28]. The control and monitoring of the captured CO_2 over geological time frames is a potential show-stopper[5] [7.29]. In addition, this sequestered carbon dioxide would be a liability for millions of years to come. Also, CO_2 can only be captured from stationary sources like power plants.

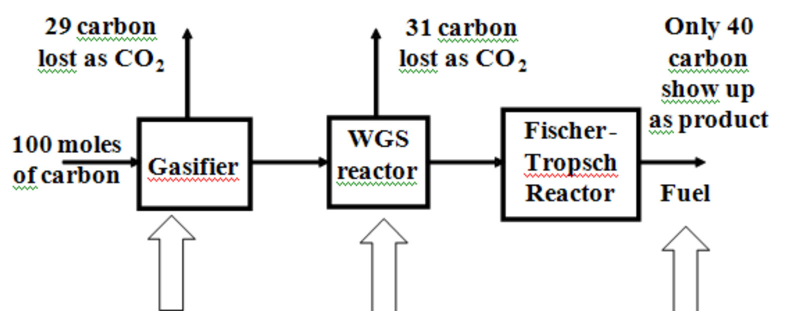
For the transportation sector, CO_2 capture is not viable. Therefore, alternate energy carriers like H_2 and battery powered vehicles have been proposed [7.30, 7.31]. A hydrogen economy has been cited as the perfect solution to the present growing energy crisis as well as a solution to greenhouse gas emissions from transportation fuels usage. Hydrogen has the potential to be derived from carbon-free energy sources but methods to store it in high volumetric density are not available. Hydrogen has very high energy content on a mass basis compared to other fuels. However, transportation of fuels is limited by the volume of the vessels or diameter of pipe and hence, an accurate comparison can be only made on the basis of energy content per unit of volume [7.32]. On this basis, H_2 fares poorly in comparison to all other fuels because it is the lightest gas. Thus, even though H_2 can be generated at 60% efficiency, it can be delivered for end use only at 30% efficiency or less. Thus, a major challenge is the H_2 storage problem as a high density fuel.

Rechargeable battery powered vehicles are another option proposed to reduce greenhouse gas emissions. A major challenge involved with batteries is that the storage density of most commercial batteries is in the range of 75 to 150 Whr/kg which is only sufficient for short distance driving [7.33].

Research Accomplishments to Date

While reviewing coal to liquid fuels literature, we realized that a significant portion of the carbon atoms in coal is lost to the atmosphere during the conversion process, leading to a low liquid fuels yield and necessitating a need to sequester the CO_2 produced during the atmosphere. The reason for this low carbon conversion efficiency is the usage of energy content of coal to provide the energy for the process. This problem can be alleviated if the energy for the conversion process is derived from another carbon-free energy source. The process of loss of carbon atoms is depicted in Figure 7.4.1.

Figure 7.4.1. Process of Loss of Carbon Atoms in the Conversion Process



H_2	31
CO	44
CO_2	18
CH_4	6
T (C)	1100-1300
H_2/CO	0.7

Data for Fluidized bed reactor from Steynberg and Dry, Fischer-Tropsch Technology, 2004

Planned Future Work

Task 1: Once this validation is done, demonstration of the novel gasifier configuration is needed. This demonstration will involve co-feeding of H_2 and CO_2 in the gasifier along with coal, O_2 and steam. The effects of the following parameters on the exiting syngas from the novel gasifier needs to studied:

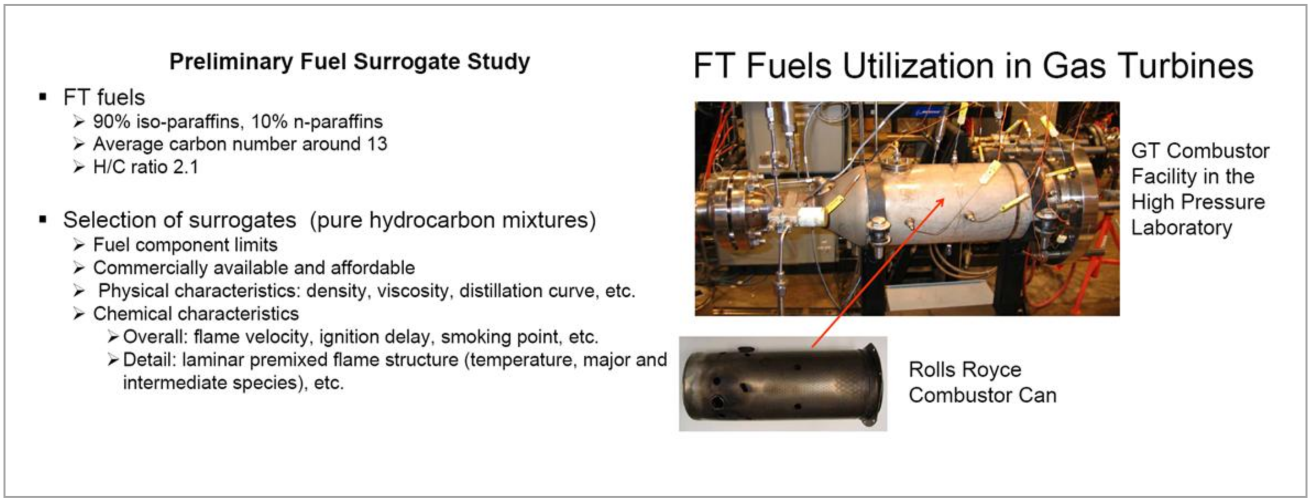
1) Temperature
2) Pressure
3) Amount of CO_2 fed
4) Amount of H_2 fed

Task 2: Kinetic data will be gathered for this novel configuration so that it can be modeled.

Task 3: Once the kinetic data is available, modeling of this gasifier is required. Modeling of the novel gasifier will provide many insights that are not easily accessible using experiments.

Task 4: For the feasibility calculations using ASPEN Plus, we assumed that a single type molecule ($C_{15}H_{32}$) is formed from the Fischer-Tropsch reactor. However, in reality the FT catalysts give a distribution of products and the longer chain molecules must be hydro-cracked to diesel range molecules. There is a need to find an ideal chain growth probability value for the H_2CAR process which will maximize diesel production.

7.5 A Preliminary Study of Surrogates for Fischer-Tropsch Jet Fuels



The compositions of commercial FT (Fischer Tropsch) jet fuels are very complicated. FT fuels consist of approximately 90% iso-paraffins and 10% n-paraffins, mainly in the C8 to C17 range, with an average carbon number around 13 and H/C ratio near 2.1. Purdue's School of Mechanical Engineering has started to consider the impact of FT fuels on gas turbine engines [7.26].

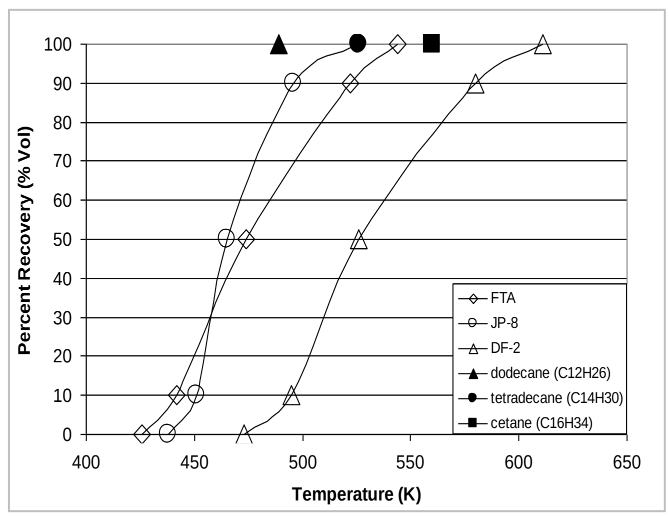
To understand the effects of the fuel components on combustion and emission under aviation gas turbine conditions, surrogate mixtures that are commercially available at reasonable cost should be selected. Since summer 2006, the Purdue team conducted a preliminary investigation to select surrogate or surrogate mixtures to represent physical and/or chemical characteristics of FT jet fuels.

Physical Surrogate

Physical surrogate is a mixture of pure fuels that has generally same physical properties as the FT jet fuel. Physical properties, such as density, viscosity, etc., have effects on fuel spray and eventually on gas turbine design and modification.

Fuel spray characteristics, such as droplet life time and liquid fuel length (fuel penetration), may be determined by the 90% distillation temperature (T90) of the fuel (Siebers, 1998, SAE paper 980809). By comparing T90 of the commercial fuel to the boiling point of a single component fuel, the surrogate for spray study can be selected.

Figure 7.5.1. Percent Recovery and Temperature

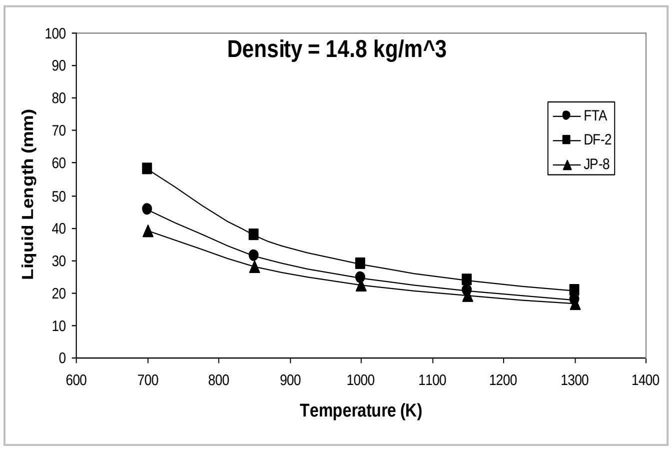


Purdue's School of Chemical Engineering produced Figure 7.5.1 (% recovery vs. temperature) shows that dodecane ($C_{12}H_{26}$), tetradecane ($C_{14}H_{30}$) and cetane ($C_{16}H_{34}$) are good surrogates for JP-8, a specific FT fuel (FTA) and No. 2 Diesel (DF-2) respectively. After choosing the surrogates, the different spray behaviors of these three fuels can be investigated under combustor conditions.

With same ambient condition (1000 K, 40 bar) and nozzle diameter (0.5 mm), the droplet life times of JP-8, FTA and DF-2 are 0.72s, 0.77s and 0.86s respectively.

The liquid length of these three fuels also changes under the same combustor design as illustrated by the Figure 7.5.2. With a same condition, the liquid length becomes longer from JP-8 to FTA to DF-2. This difference is significant at lower temperature and pressure but becomes not appreciable at higher temperature and pressure. The ambient density keeps the same.

Figure 7.5.2. Liquid Length of Fuels with Temperature



The effect of these spray characteristics on final gas turbine combustor design needs to be further investigated. Also, a very helpful tool in selecting physical surrogates developed by the National Institute of Standards and Technology, NIST Thermophysical Properties of Hydrocarbon Mixtures Database: Version 3.1, may be purchased to facilitate future investigations.

Chemical Surrogate

Chemical surrogate is a mixture of pure fuels that has generally same chemical properties, for example combustion properties, as the FT jet fuel. Soot emission may be dependent on some trace species therefore more consideration in choosing surrogate is desired.

A surrogate mixture of 14 pure hydrocarbon fuels was used to represent JP-4 [7.34]. This surrogate followed the distillation curve and compound class composition of JP-4 except having a much higher smoke point. In the experimental tests, the mean droplet velocity and Sauter mean diameter profiles and mean temperature contours of the surrogate and the parent fuel matched very well.

Detailed FT fuel combustion chemistry is critical to combustion efficiency and pollutant formation. To validate the surrogate combustion/emission properties, laminar premixed flame structure data, including major and intermediate species profiles and temperature profiles can be very informative [7.35]. In addition, in order to implement “fuel tuning” task of this overall coal to liquid transportation fuel project, the effects on combustion and emission of single component of the FT fuels can be first investigated through this kind of flame structure studies. Gas chromatographer with high order hydrocarbon capability and advanced laser-based temperature diagnostics are desired for this investigation.

Future Work

In the near future, the School of Chemical Engineering may make an FT fuel surrogate using one iso-paraffin (90%) and one n-paraffin (10%) as the first approximation. This surrogate should follow the distillation curve of a FT fuel and has similar smoking point, flame velocity and ignition delay to the parent fuel. The School can further validate this surrogate through spray and combustion tests using facilities available at Zucrow and/or ME laboratories. Spray drop size distribution, spray patternation and laminar premixed flame structure will be measured and compared to the measurements of the parent FT fuel and JP-8.

This study will facilitate fuel/air mixing investigation, tests in subscale gas turbine combustors and the fuel tuning study in the long term.

7.6 Economic Analysis of Coal Liquids Policy Options

Risks of Doing Nothing

- The "Oil Shockwave" simulation experiment in 2005 indicated that taking a small amount of oil off the world market could cause prices, at least in the short term, to rise to $160/bbl.
- Supply disruptions of this type, which are likely in the future, will impose severe economic costs on our country.
- Is it better to pay some up front costs in implementing alternatives such as coal liquids, or pay more severe costs down the road?

Policy Alternatives to be Evaluated

- An investment guarantee, such that the federal government would guarantee some percentage of the investment in the event the plant could not produce fuels at market prices.
- A purchase guarantee, such that the government would agree to purchase the product at some minimum price. The purchase guarantee would not obligate the plant to sell to the government.
- A purchase contract wherein companies would bid for a purchase price at which the government would acquire all the plant's production.
- A fixed subsidy per gallon such as is now available to ethanol and bio-diesel.
- A variable subsidy in which the subsidy would be a function of the oil price, rising as the oil price falls and falling as the oil price rises.

A break-even price of $44/bbl. crude oil equivalent for producing FT (Fischer Tropsch) transportation fuels was calculated by Purdue's Department of Agricultural Economics in an economic analysis supported by the CCTR. The study was based on CTL plant cost information contained in the Southern States Energy Board report, *American Energy Security: Building a Bridge to Energy Independence and to a Sustainable Energy Future*, which was released in July 2006. The Department used the case of a 60,000 barrel per day plant with sequestration of CO_2. The total capital cost of the plant was $3.9 Billion [7.26]. Following the case authors, the Purdue team assumed one third equity and two-thirds debt financing. The debt interest rate was 8% and the required minimum return on equity was 15%. The assumed inflation rate was 3%. Other economic assumptions provided by the study authors are listed in Table 7.6.1.

Stochastics were introduced into the analysis, in the form of capital cost uncertainty and oil price uncertainty. Capital cost uncertainty was modeled as a simple triangular distribution. However, oil price was much more complex. We calculated the mean and standard deviation of real annual oil price change over the past 25 years. Twenty five years was chosen because the prices changes were much lower in earlier years. The mean price change was very close to zero, and the standard deviation was $9.20 per year. We constrained annual price changes to plus or minus $23 per year, the largest experienced in the past 25 years. Future price scenarios were then simulated with a constraint that the future price could not fall below $15 (2006$), the lowest price in the past 25 years nor higher than $200, chosen arbitrarily (results were not very sensitive to the level of this upper limit). Under these conditions, we simulated a series of future prices with base prices ranging from $40 to $70. All of this uncertainty was captured in a Monte Carlo simulation using @Risk software and doing 10,000 iterations for each simulation.

Outputs included net present value of the project, internal rate of return, chance of a loss, and present value and annualized value of the sum of diesel and naptha sales. For each of these outputs, we have the mean (expected value), standard deviation, and all elements of the probability distribution.

Table 7.6.1. Economic Assumptions for the Coal Liquids Policy Analysis

Economic Parameter / Assumption		Value
Construction Period		3 years
Year 1Incurred Capital Cost Construction		20%
Year 2 Incurred Capital Cost Construction		50%
Year 3 Incurred Capital Cost Construction		30%
1st Year Availability		45%
2nd Year Availability		81%
3rd Year and Beyond Availability		90%
Plant Lifetime	years	25 years
Return on Equity		15%
Depreciation Method		DDB-16 yrs.
Debt:Equity Ratio		2/1
Interest Rate		8%
Inflation Rate		3%
Tax Rate		36%
Electricity Selling Price	$ / MWhr	$35.60
Sulfur Price	$ per ton	$80
Bituminous Coal Price	$ per ton	$36
Subbituminous Coal Price	$ per ton	$11
Lignite Price	$ per ton	$10
Woody Biomass Price	$ per ton dry	$20
Naphtha Value	times diesel value	$0.714

The simulations to date were done for the base case and the policy of a variable subsidy. The team tested different levels of the variable subsidy with it kicking in at $35, $40, and $45. That is, there is no subsidy if crude oil average annual price is above the stipulated level, but a variable subsidy equal to the difference between the market price and the stipulated level if the market price is below the subsidy floor. For example, if market price was $40 and the price floor $45, there would be a subsidy of $5 per barrel of crude oil equivalent fuel produced. If the market price is above $45, there is no subsidy. The actual subsidies were converted to diesel using a historic regression relation between crude oil prices and diesel prices.

The key output values are chance of a loss for each price and policy simulation and government cost for each policy alternative. Figure 7.6.1 illustrates the probability of a loss for each base price case and for the $45 price floor policy alternative.

The interpretation of the graph is as follows. The first number in the number pairs is the base price, and the second is the price floor. For this graph, the price floor is always $45. One can see that if the base price is $40, the chance of a loss with no policy intervention is greater than 50 percent. If the base price is $70, then the probability of a loss is around 10 percent. One can think of the base prices as the central tendency, that is. the price around which future prices are expected to move. Just barely visible along the X axis, one can see that the chance of a loss with a $45 price floor subsidy is always zero, regardless of the base price. So clearly, a $45 price floor policy is quite effective at reducing risk and thereby stimulating investment in coal liquids.

Another question is how much would this subsidy cost the government? The answer, of course, depends on what future crude oil prices do. Figure 7.6.2 displays the expected government cost for each of the base prices. These costs are expressed in terms of $/gal. of diesel produced. They were calculated as the difference between the diesel sales revenue with and without the policy in effect. The expected costs range from 11 cents per gallon with a $70 base price to 40 cents per gallon with a $40 base price. Any of these costs are less than most estimates of the national security cost of imported oil. Also, of course, if the crude oil price were to remain above $45 for the 25 year life of the plant, the government cost would be zero.

In the future with additional funding, we intend to apply this general approach described to other policy options and to examine other ways of incorporating future price uncertainty. We will also add uncertainty in other variables such as coal cost.

Figure 7.6.1. Probability of Loss With & Without the Floor Price Subsidy at $45

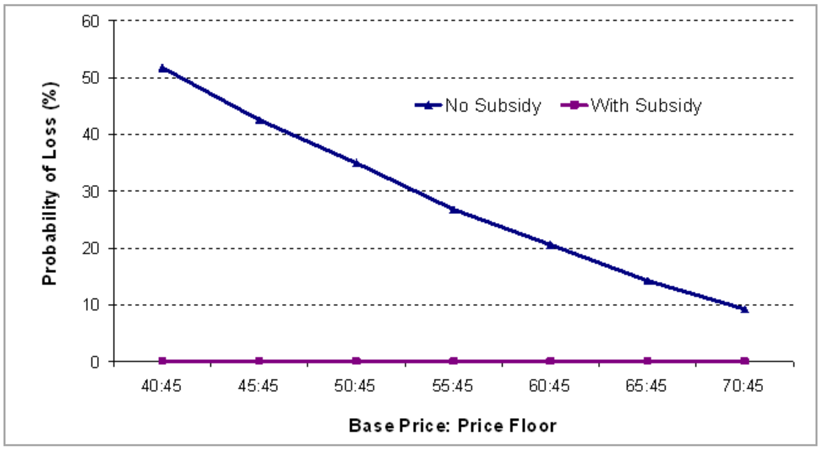
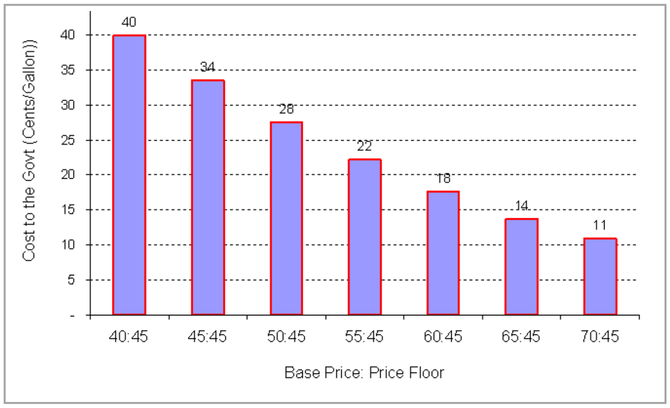
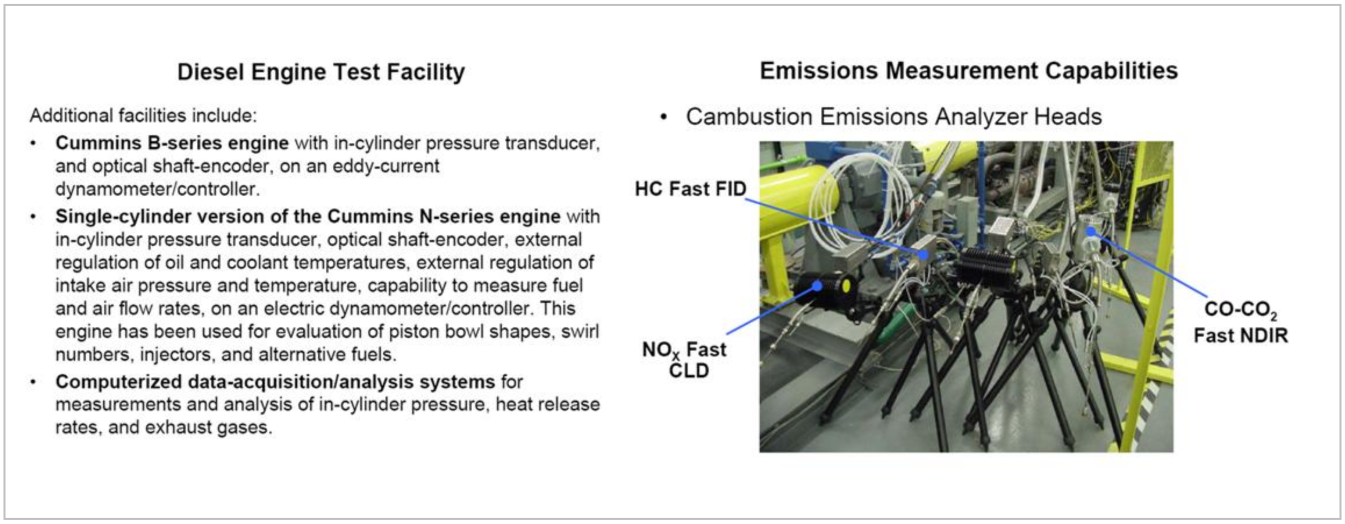


Figure 7.6.2. Government Cost of a Floor Price Based Subsidy at $45 & Different Base Prices



7.7 Testing Fischer-Tropsch (FT) Fuels in Gas Turbines and Diesel Engines



Purdue's School of Mechanical Engineering has extensive engine testing facilities for assessing the impact of Coal To Liquid fuels (CTL) [7.26]. The CTL fuels can provide a secure and environmentally friendly energy resource for U.S. trucks and for commercial and military aircraft. Recoverable coal in U.S. has the energy content comparable to all of the world's known oil reserves and CTL fuels derived from the FT (Fischer Tropsch) process are virtually free of aromatics and sulfur. Combustion of FT jet fuel therefore produces much less particulate matter (PM) compared to conventional petroleum-derived jet fuels, such as Jet A (commercial) and JP-8 (military), and no SO_X . FT fuels are also of great interest to U.S. Air Force for the development of paraffinic endothermic jet fuels. Comprehensive knowledge of FT jet fuel combustion is one of the enabling components for the commercialization of CTL transportation fuels but fundamental combustion data is lacking.

The major emissions from aircraft engines are particulate matter (PM), NO_x, CO and unburned hydrocarbons (HC). Most airborne PM consists of particles smaller than 2.5 μm in diameter (PM2.5). Soot is formed in the rich regions of nonpremixed combustion and the amount of PM emitted from a combustion system depends on the competition between soot formation and soot oxidation. The molecular structure of the fuel is a very important factor in determining the level of PM emissions. The combustion of aromatics fuels, especially poly-aromatics, is much more likely to produce soot than paraffin combustion. The smoke point is the measure of a fuel's sooting propensity. Conventional jet fuels contain approximately 20% aromatics and usually have a smoke point around 20 mm. Neat FT fuels typically contain only n-paraffins and iso-paraffins and usually have smoke points above 43 mm. Since the utilization of neat FT fuels in current engines is complicated by problems with lubricity and compatibility with elastomers and seals, blends of FT and conventional jet fuels or FT fuels containing synthetic aromatics have been used commercially in South Africa. These approaches, of course, dilute some benefits of FT fuels. Gas turbine engine design is another very important factor in determining PM emission. PM emission becomes more severe with increasing operating pressure due to shorter spray penetration and accelerated chemical reaction at higher pressures.

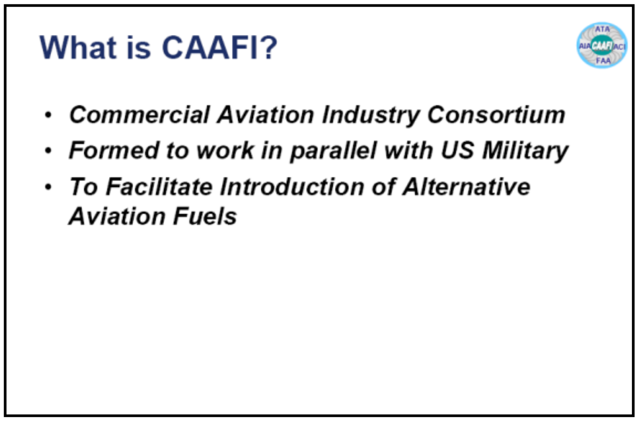
The swirler-stabilized turbulent flames facility and simultaneous stereo PIV and PLIF measurement facility at the Turbulent Combustion Lab and the gas turbine combustor facility at the High Pressure Lab (part of the Rolls-Royce Center of Excellence) provide unique capabilities for the proposed research. At the High Pressure Lab, the recently modernized air system can provide dry air at 950^{o}F and 700 psi at flow rates up to 9 lbm/s. The well-instrumented gas turbine combustor facility with an air-cooled liner is designed in a modular fashion to facilitate rapid hardware changes. In addition, the recently installed advanced FT-IR MultiGas Analyzer provides the capability of monitoring a large number of infrared-active species (CO, CO_2, H_2O, NO, NO_2, etc.). Instrumentation to measure total HC and O_2 is also available.

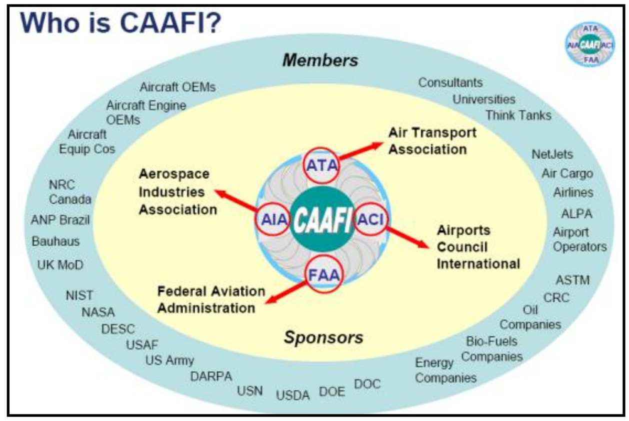
The proposed project will significantly enhance our understanding on key combustion and emission issues in the development of advanced aircraft engines using CTL FT fuels. The proposed project will also promote the development of diagnostic technologies suitable to investigate combustion and emission in aircraft engines. The knowledge obtained in the proposed project will strongly facilitate the utilization of CTL FT jet fuels in civilian and military aircraft. The Purdue team has also studied many issues associated with combustion of FT fuel in diesel engines. An attractive feature of FT diesel fuels is that the production process of the fuel may be modified to change its properties. For example, the cetane number of the fuel may be changed to achieve slower ignition. This may allow better premixing prior to the start of combustion and make it possible to inject the fuel earlier in the compression cycle, thereby approaching premixed combustion. This, in turn may result in lower particulate emissions and either lower or higher NO_x emissions based on the degree of premixing achieved. Similarly, changes in the volatility and lubricity of the fuel can be effected by changing the production process. Increasing the aromatic composition of the fuel may enhance lubricity, but may result in greater PM emissions. Hence, the changes are likely associated with costs and benefits. Careful evaluation is needed to optimize the fuel, the combustion system and the level of after-treatment required.

As part of the CCTR scoping grant diesel combustor facilities and emissions analysis equipment were identified that can be used for future FT fuels research. FT diesel fuel obtained from Syntroleum, FT diesel fuel mixed in different proportions with diesel fuel #2, low-sulfur diesel fuel, and with bio-diesels, will be evaluated.

In addition, a comprehensive plan for the development of an after-treatment system suitable for diesel engines operating on FT fuels was formulated. The most promising technology for the reduction of NO_x compounds in diesel emissions is the use of NO_x storage and reduction (NSR) catalysts. To take advantage of the lean (i.e. excess oxygen) operation of a diesel engine, the NSR catalyst is operated in a cyclic manner. While the engine is running lean, the catalyst adsorbs NO_x onto an alkaline earth or alkali metal component, i.e. barium or potassium, while the NO is converted to NO_2 on a noble metal that is typically platinum. When the catalyst has been partially saturated, the engine is switched over to rich (i.e. excess fuel) operation for a short period of time. In this rich part of the cycle, the stored NO_x is converted to nitrogen and water which are released to the environment and the storage capacity of the catalyst is regenerated, allowing the cycle to repeat. Because of the large number of potential operating parameters in the engine duty cycle, mathematical models are needed to aid in the understanding of the NSR catalytic system.

7.8 Civil Aviation Alternative Fuels Initiative (CAAFI)





Purpose

Baere Aerospace Consultants LLC has been providing valuable reports and recommendations on the alternative fuel initiative for the CCTR. The Commercial Aviation Alternative Fuels Initiative (CAAFI) seeks to enhance energy security and environmental sustainability for aviation through alternative fuels. The goal is to promote the development of alternative fuels options that offer equivalent levels of safety and compare favorably with petroleum-based jet fuel on cost and environmental basis, with the specific goal of enhancing security of energy supply. The group is divided into four specific areas: 1) Certification and Qualification, 2) Research and Development, 3) Environment, and 4) Economics, Business and Policy.

In this role, CAAFI acts as a focal point and umbrella organization for communication and coordination of projects being performed at the USAF, DARPA, and private organizations. Representatives from the multitude of members come together and present progress on internal programs, develop synergies between organizations, and share information and challenges. The goal is to facilitate the identification and approval of alternative fuels in a cost effective and timely manner.

December 2008 Ballot on ASTM D-1655

During 2008, the majority of CAAFI's efforts have been focused on the approval of the inclusion of synthetic fuel on the commercial specification, ASTM D-1655, headed by the Certification and Qualification panel. The original goal was for the ASTM to approve the addition by December 2008. Current issues with achieving a successful ballot are focused around three issues:

- a consensus on the criteria defining "synthetic fuel"
- a criteria for blended fuel or the blend component
- the "ASTM Research Report which is a requirement of the approval process.

Examples of potential criteria for defining synthetic fuels include:

- Source material
- Refining and synthesis process
- Chemical composition
- Performance

The role of the Research and Development panel is being re-evaluated and may be restructured early in 2009. This panel has the most relevance to the development of synthetic aviation fuel in Indiana.

In general research continues in two major areas of near-term alternative fuel, synthetic and bio-renewable.

USAF Synthetic Fuels Efforts

The USAF remains committed to approving all aircraft and fuel distribution systems in the USAF inventory for use of up to 50/50 blends of synthetic fuel by 2011. By mandate, 50% of USAF consumption is to come from alternative fuels by 2016.

- USAF is addressing concerns with the environmental impact of synthetically derived fuels by stating they will only procure the fuel from U.S. organizations that have a carbon sequestration plan in place.

To date a number of fighters, tankers, and heavy lift aircraft have been tested and approved for the use of a 50/50 blend. As of October 2008, efforts for full approval for all military equipment and systems are being hampered by the potential delay in approval of synthetic fuels being added to ASTM D-1655, Jet A.

Procurement of synthetic fuel is problematic; there is currently no commercial scale manufacturer of synthetic fuel in the U.S. A number of challenges exist for the building and operation of a synthetic fuel facility in the U.S.

- Organizations are concerned about the environmental implications even with carbon sequestration.
- Procurement of the necessary reactors is a challenge; China has a near lock on the near-term available market.
- Initial cost requirements continue to make investors cautious.

For aviation use there is a further challenge. As of September 2008 it is more profitable to produce a synthetic diesel fuel than a synthetic aviation kerosene fuel.

Carbon Footprint Challenges

At a CAAFI meeting held in Washington D.C. in November 2007, a representative of the DOE presented on the three awards for large-scale demonstration projects for studying coal sequestration. One of the sites was the IL/IN sequestration test planned for Illinois.

There were significant pressures being placed on the U.S. military not to use synthetic fuels. It was observed throughout much of 2007 that there was a general feeling of prohibition on the use of coal in any form given by the environmental activists. Some general observations include:

- A law was passed to require that any fuel purchased by the DoD must have an equal or smaller carbon footprint than current petroleum-based fuels. However, no agreement could be reached on what that measure was. As of September 2008, it appeared that that zero point had been determined and the U.S. military was moving forward with the 50/50 project using that measurement.
- There continues to be a challenge with CTL as it appears that the environmentalists do not believe that there is any way to make CTL acceptably carbon neutral or beneficial.
    - Furthermore, it has been observed that they do not appear to care if it CAN be, as they do not like it, period. This was indicated in a DOD anecdote – “CTL has too large a carbon footprint.” “Okay, we’ll only buy it from places that have carbon sequestration in place.” “No, that’s not good enough.” “Okay, they will have to have a market for the captured carbon and sequestration.” “No, you don’t understand, it is never going to be good enough for us. You should be looking at something else.”

Despite these pressures and even with a change in political party, the military will continue to be under the directive of EPAct 2007 requiring domestic, military installations to increase their use of alternative fuels.

As research has progressed, interest in coal/biomass synthetic fuels, (CBTL) has grown as a way to address the carbon footprint and reduce environmental impact of a synthetic fuel facility.

Bio/renewable fuels

When considering the use of bio-derived fuels, the U.S. military has stated it does not want to be in the position of dealing with blending, and thus is requiring the fuel be a BJ100.

There is a consensus that crop oils are a piece of the bio-derived fuel puzzle, but not the ultimate answer. It is agreed that there are concerns of what other impacts the use of bio-derived and crop oils has on the environmental state of developing nations.

- Crop oil requires too much land and it competes with food
- The current DARPA BAA project for a synthetic fuel from bio-derived materials is progressing on schedule
- There is a second BAA that will research renewable beyond crop oils
- Efforts to determine the inputs to models based on changes in land use are underway

There is growing interest in algae as an oil crop due to its potentially high productivity. Current research and development activities are focusing on how to make a sustainable and profitable process, assessing means to handle byproducts (possibly the CBTL process) and how to maintain the desired oil algae colony over the more common indigenous species.

Economic Efforts

In November 2007, discussion was held regarding the economic analyses for the use of alternative fuels. For example, the Transportation Research Board of the National Academies began work on the "Handbook for Analyzing the Cost and Benefits of Alternative Turbine Engine Fuels at Airports". The effort consists of five tasks and is to be complete in March 2009.

There is a debate growing on the applicability of the GREET model used in predicting environmental impact. One point of view is it does not adequately utilize all available inputs. Others feel that for continuity and the ability to compare analyses, it should continue to be used. A project under the direction of the USAF is being undertaken to improve the inputs used in the economic models so they more accurately reflect reality.

The National Resources Defense Council [NRDC] (what appears to be a lobbyist group) is supporting "Low Carbon Fuel Legislation."

- The group likes the efforts in California
- The group feels that CTL cannot compete and is therefore supporting bio-renewable fuel development.
- The group believes that coal plants with the infrastructure already in place with consume all available carbon
- The group suggests that the answer is not a new fuel for aviation but rather a modal shift to rail.

Based on presentations made by environmental lobbyists, it was suggested that the aviation market should not be transformed, but rather a shift to other modes of transportation should be undertaken. It was observed that the desire to force a change in modal transportation appears simplistic.

- Rail still utilizes significant liquid fuel
- As of November 2007 there was a continuing growth in air traffic

- The U.S. air system is viewed as critical to National security.

The NRDC, as well as a number of other individuals with a strong environmental agenda appear to feel that aviation "should just change fuels, now." They ignore the certification and approval ramifications.

Observations of Particular Interest to Indiana Goals

Synthetic Fuel Development

As of November 2007 SASOL expressed they had no interest in evaluating Indiana as a location for a CTL plant. The coal reserves and the production levels were assessed as too small. SASOL was focusing their investigations on locations reported to them by their experts as having a reasonable expectation of success. Reasons given why Indiana was not being considered:

- Indiana's expressed size was too small
- The state was assessed as water limited
- Their coal consultant told SASOL that Indiana coal was too expensive (partly due to the costs of mining it)
- SASOL cannot pay "$30" / ? for coal

In September 2008, it was announced that Rentech was interested in evaluating smaller sized facilities, more in line with the projected size of an Indiana facility, for example, that at Crane.

Epact 2005 369H – Strategic Unconventional Fuel Sources. This is a 3-volume report that is available on line: www.unconventionalfuels.org

Pratt & Whitney Rocketdyne is using their space shuttle rocket engine technology to develop a new smaller, cheaper gasifier.

- They had a 3000 ton/day test rig at EERC that will be scalable.

Baard was looking at a fuel/power plant in Ohio.

- This is something that has been discussed at the CCTR meetings and is supported by the USAF.

Bio/renewable

In November 2007 it was presented that coal/biomass to liquid plant was planned for Ohio. It was to have co-gasification of coal and biomass.

- The carbon sequestration plan involved building up soil with mixed prairie grasses. They have found that marginal soils are made better.

Other

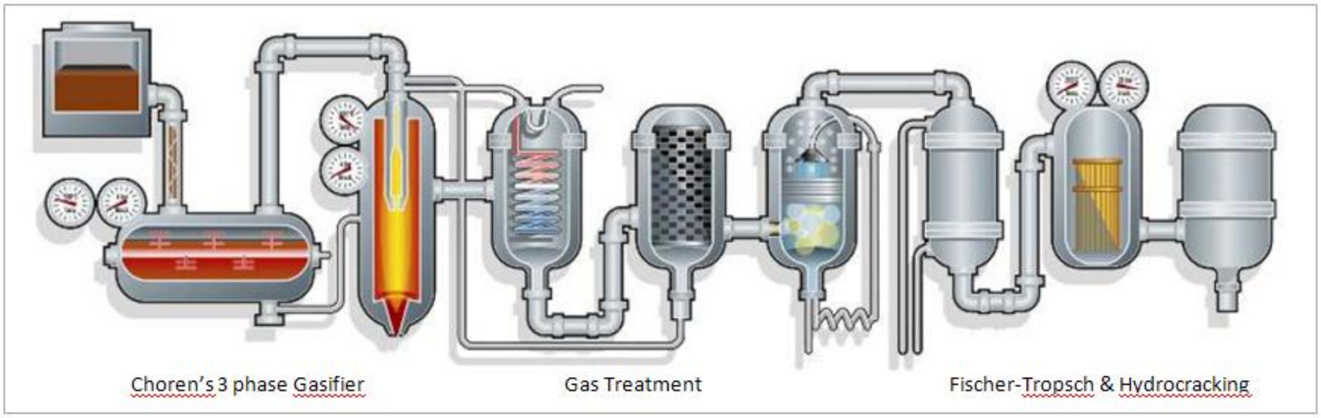
It appears there may be a disconnect between the groups (aircraft/airlines, distribution and peripheral equipment) regarding what properties need to be considered for "drop-in"

Boeing flight-tested a fuel-cell powered aircraft in Spain.

- It was about the size of a Cessna 152
- Sufficient charge density / discharge rate was still a problem.

Indiana and Purdue activities are being maintained on the CAAFI R&D timeline.

7.9 Indiana SNG Project



Source [7.36]

The development of processes for the production of synthetic natural gas (SNG) in Indiana is of great interest to the CCTR. Designing a coal to gas plant that converts Indiana coal to pipeline quality gas (SNG) and then is sold to gas distribution utilities under long-term contracts at prices substantially below high natural gas market price is considered achievable. Processes may be included for the capture of excess CO_2 to be used for enhanced oil recovery (EOR) for expanding production from Indiana oil wells or to be sent to the Gulf Coast where EOR has well proven high EOR potential in the older east Texas oil fields.

Public Benefits of SNG

- Reduces cost of natural gas for home heating and industry over time due to long term natural gas fluctuations
- Produces syngas gas that can be used by Hoosier homes and businesses in Indiana from Indiana coal
- Reduces economic and supply risks from reliance on gas delivery from liquefied natural gas (LNG) associated with hurricane, terror, and other external risks
- Establishes a boundless market for Indiana coal, including high sulfur coal
- Restores jobs (construction, mining and technology), wealth and tax base to coal communities that will host $500 Million plants
- Positions Indiana as a technology leader jump-starting production of fuels, chemicals and electricity from domestic coal that will reduce U.S. reliance on imported oil and LNG

Project Elements

- Gasification and methanation to produce SNG that meets pipeline standards
- Project to be located in southwest Indiana proximate to Indiana coal resources, natural gas pipeline infrastructure, and EOR opportunities
- SNG output to be sold under long-term contracts to regulated gas and electric distribution utilities and delivered through existing natural gas pipelines
- 20-30 year long-term contracts established with gas distribution utilities that would be approved by the Indiana Utility Regulatory Commission (IURC) to establish a "3 Party Covenant" between IURC, federal government and development team [3.27].
    a) 30 year contract provides ~ 14% lower annual financing cost vs. 20 years

b) Net costs associated with CO_2 capture covered by contract

- Financing for Indiana SNG Project to take advantage of federal loan guarantee program established under Title XVII of EPACT 2005
  a) IURC orders approving gas purchase contracts and will establish “assured revenue stream” that meets EPACT 2005 requirements and minimizes financial risk to the federal government loan guarantee thereby producing a low budget score and eliminating need for budget appropriations.
  b) Guarantees will provide favorable financing terms to reduce project costs (AAA credit, 20-30 years. term, 80% of project costs, ~ 5.5% rate)

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CHAPTER 8

COAL & THE ENVIRONMENT

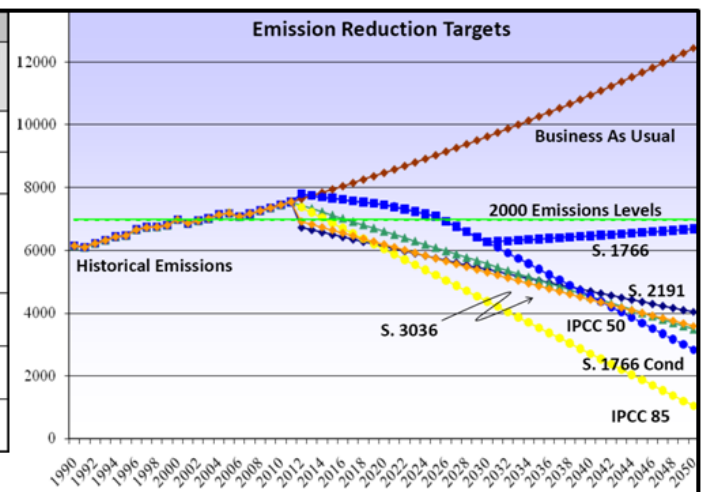
CCTR's goal is to promote the use of Indiana's coal reserves in an economically and environmentally sound manner and this chapter summarizes some important environmentally-related research initiatives which have been discussed at the quarterly Advisory Panel Meetings. Section 8.1 considers climate change and potential emissions legislation, the major uncertainly in all planning activities for new construction projects and a topic of enormous significance for next generation clean coal technologies. Section 8.2 looks at oxyfuel combustion to reduce CO_2 emissions, instead of post-combustion or pre-combustion CO_2 capture processes. Section 8.3 reviews wind energy, recognizing need for back-up power during periods of no wind. Section 8.4 introduces environmental impacts of coal to Fischer-Tropsch fuels and section 8.5 provides a reconnaissance of coal slurry deposits (CSDs) that can be recycled for reuse.

8.1 Climate Change Legislation

Until recently [8.1] the two leading broad-based climate change bills in the U.S. Senate were America's Climate Security Act of 2007 (Lieberman-Warner Bill [8.13]) and the Low Carbon Economy Act of 2007 (Bingaman-Specter Bill, Figure 8.1.1 [8.14]). The Lieberman-Warner Bill, S.2191, was the successor to the McCain-Lieberman Bill, one of the first broad climate change bills introduced in Congress. The Bingaman-Specter Bill, S.1766, was introduced after Senator Bingaman (D-NM) circulated a draft bill based on a report developed by the National Commission on Energy Policy. As these two bills evolved, they showed convergence from their earlier incarnations, but substantial differences between them remained.

Figure 8.1.1. Summary of Most Recent Proposed Environmental Legislation

Energy Source	Direction of Regulation		
	Lieberman-Warner **S. 2191**	Bingaman-Specter **S. 1766**	Manager's Amend **S. 3036**
Coal	Downstream	Downstream	Downstream
Natural Gas	Downstream	Upstream	Upstream
Oil	Upstream – transportation fuel; Downstream – industrial	Upstream	Upstream
Nonfuel chemicals	Upstream	Upstream	Upstream
% Emissions Regulated	80 percent	85 percent	84 percent
% Emissions Excluded	15 percent	15 percent	16 percent



Source [8.1]

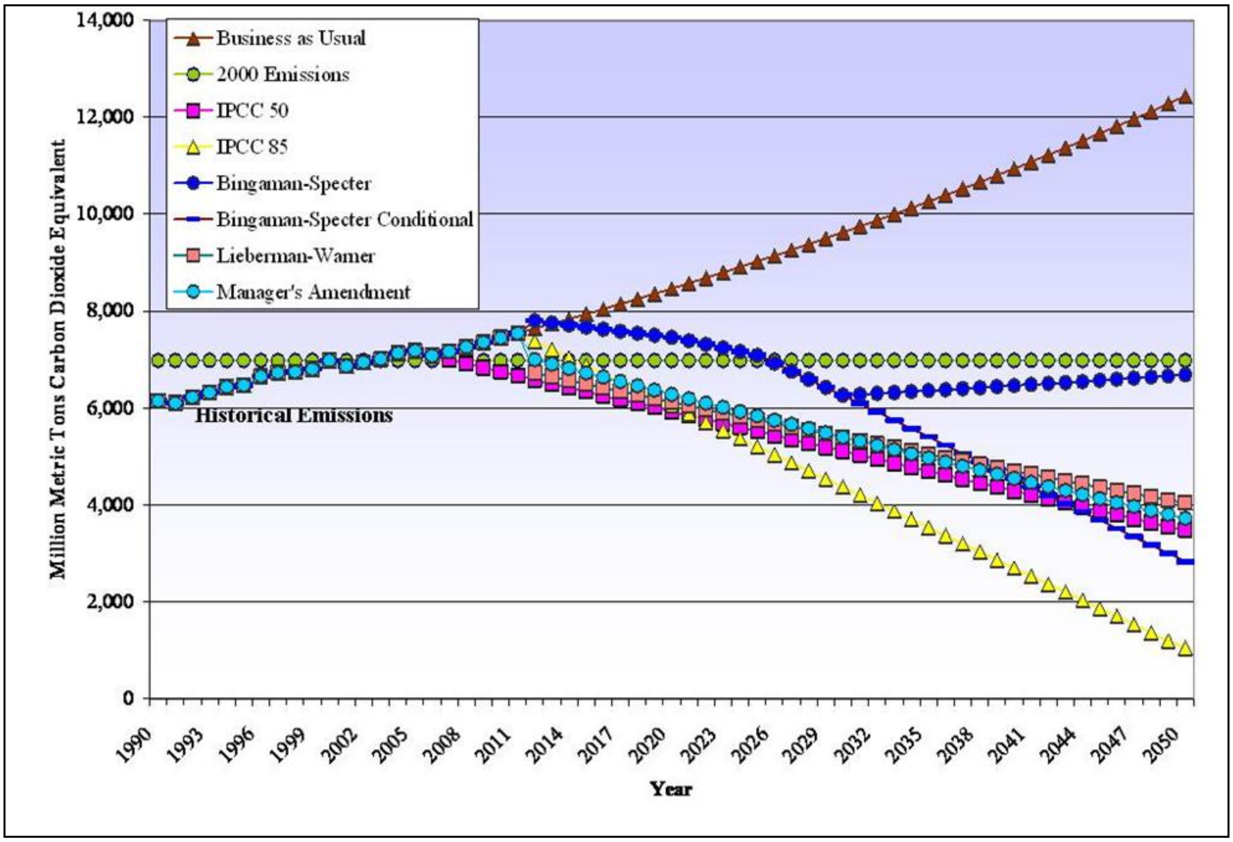
On May 20, 2008 Senator Boxer, Chair of the Senate Committee on Environment and Public Works, introduced a Manager's Amendment to the Lieberman-Warner bill. In fact, while the new version retains the short title "Lieberman-Warner Climate Security Act of 2008" and is described by many as a modification of S.2191, the new legislative language itself describes the change as a complete substitute and is embodied under a new bill number, S.3036. The revised bill is better understood as a blending of many of the features of both the Bingaman-Specter Bill and the original Lieberman-Warner Bill, with liberal amendments adopted from other parties. Since the Manager's Amendment (S.3036) was the climate change bill that was considered by the entire U.S. Senate in June 2008 and will likely be reintroduced during the 2009-2010 session, it becomes important to pay particularly close attention to this bill and make recommendations for further improvements.

First and foremost, it is important to recognize what all three comprehensive climate change bills have in common. They are all cap-and-trade legislation, which means that a set number of pollution allowances are issued via grandfathering (free distribution based on historical emissions or energy output) or auction (sale). After this initial allocation, the covered facilities are allowed to freely buy or sell allowances to take advantage of differing pollution abatement costs. Presumably, the companies with the lowest abatement costs would achieve a disproportionate share of the emission reductions. To alleviate mitigation costs, the three Senate bills also include other cost containment mechanisms such as offsets and banking, though they differ in the details.

The Manager's Amendment (S.3036) contains key features of the Lieberman-Warner Bill:

- **The projected emission levels associated with the Manger's Amendment are similar to those of the Lieberman-Warner bill –** a bit less precipitous at the outset, and a bit more ambitious in the later year**s** (Figure 8.1.2). The Manager's Amendment would achieve a 16% reduction in U.S. carbon dioxide emission levels by 2012 and a 47% reduction in emission levels by 2050, relative to 2000 levels. S.3036 incorporates a slightly less dramatic decrease in carbon dioxide emissions than is required by the Lieberman-Warner Bill, which requires a 17% decrease in emission levels by 2012. The Manager's Amendment emission targets are closely aligned with the Intergovernmental Panel Climate Change's (IPCC) recommendation that global emissions must be reduced by 50 to 85% below 2000 levels by 2050 to stabilize climate change.
- **The allocation of allowances under the Manager's Amendment closely resembles that of the Lieberman-Warner Bill.** In the early years of the climate change program, S.3036 "grandfathers," or gives away, a significant portion of allowances (44.5% in 2012) to industry groups in an attempt to alleviate the costs of compliance. The new bill also sets aside allowances to support climate-related programs, such as agriculture and forestry projects, early action, carbon capture and storage, state programs, international forest carbon projects, technology development, adaptation efforts, energy assistance, worker training, and program administration.
- **Like the Lieberman-Warner Bill, the Manager's Amendment includes a borrowing provision to mitigate the costs of compliance.** Covered facilities are allowed to borrow allowances to cover up to 15% of emissions each year at a compound interest rate of 10%. While the language in the original Lieberman-Warner Bill was somewhat confusing, the sponsors clarified their intent in the Manager's Amendment.

Figure 8.1.2. Emissions Targets for the U.S. Senate Climate Change Bills



The Manager's Amendment reflects important features of the Bingaman-Specter Bill:

- **The Bingaman-Specter Bill and the Manager's Amendment both regulate covered facilities almost entirely upstream.** To reduce administrative complexity, the Bingaman-Specter Bill and the Manager's Amendment both regulate oil refineries and natural gas processors, as well as nonfuel chemical plants (upstream) rather than place limits on the actual emitters (downstream). Under both bills, emissions derived from coal are controlled downstream through regulation of electric companies since approximately 92% of coal is used by electric companies.
- **The Manager's Amendment adapts the Bingaman-Specter's safety valve to limit the costs of compliance.** The Bingaman-Specter Bill includes a technology accelerator payment (TAP) that would begin at \$12/metric ton of carbon dioxide in 2012, so if the costs of compliance are greater than expected, the government can issue additional allowances at the TAP price. **T**he Manager's Amendment has transformed the TAP provision of the Bingaman-Specter Bill to an annual cost containment auction, at which the government can sell up to 450 Million allowances per year during years 2012–2027 taken from allowances planned for use in years 2030–2050 beginning at a price of \$22 - \$30/metric ton.

In many other instances, however, the Manager's Amendment has adopted entirely new provisions from outside either bill:

- **The Manager's Amendment acknowledges the potential conflict between the Clean Air**

Act and a national climate change bill. Unlike its predecessors, the Manager's Amendment acknowledges there may be future conflicts between the new legislation and the CAA, calling for a study of the potential regulation of carbon dioxide under the CAA.

- **The Manager's Amendment includes an "environmental safety valve" to ensure that environmental objectives are pursued more aggressively if the costs of compliance are lower than expected.** Each year, the Manager's Amendment will auction off between 25 and 59% of allowances. At these regular auctions, allowances will not be sold below a minimum price (beginning at $10/metric ton in 2012). This will give covered facilities an incentive to meet the environmental goals more quickly if compliance costs are lower than expected.
- **The Manager's Amendment requires stricter requirements for offset projects.** Unlike its predecessors, the Manager's Amendment includes a provision that requires that offset projects use methodologies that produce reproducible results when tested by three independent teams of experts to ensure that such projects result in verifiable carbon dioxide emission reductions.
- **S.3036 assigns a portion of auction revenues to deficit reduction.** Unlike earlier climate change bills, the Manager's Amendment does assign some of its auction revenues to the General Fund for the purpose of deficit reduction. Given the current state of the economy, this will likely become an increasingly important component of a national climate change bill.
- **By placing less emphasis on carbon capture and storage, S.3036 avoids technological lock-in and preserves the environmental integrity of the bill.** The Manager's Amendment eliminates the nearly four billion tons of allowances that comprised the initial balance in the account for CCS bonuses under the original Lieberman-Warner Bill. This change ensures that CCS will only be pursued if it proves cost effective. It also better preserves the environmental goals of the bill.

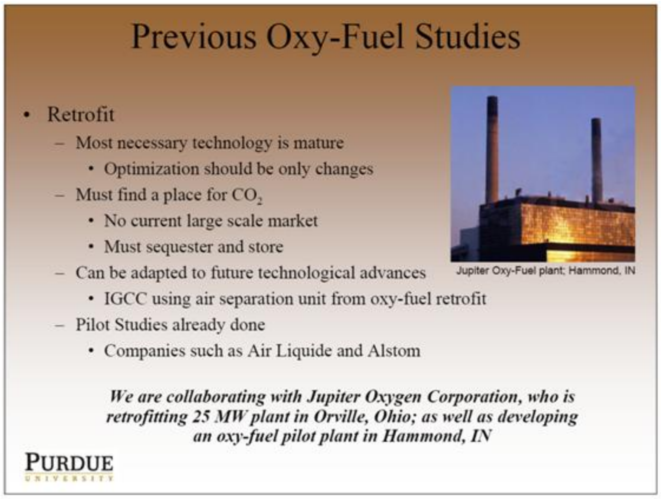
The changes embodied in the Manager's Amendment, taken as a whole, represent important improvements over either of the predecessor bills. However, there is substantial room for improvement. Based on the policy analysis in the report, the authors offer several recommendations U.S. Senate, including:

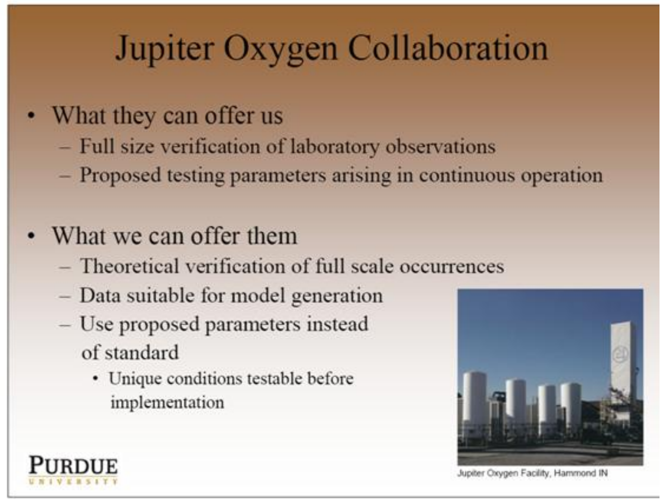
- **Clarify the Role of the CAA** - Unlike its predecessors, the Manager's Amendment at least acknowledges the important relation between new climate change legislation and the Clean Air Act. Given the recent Supreme Court ruling in Massachusetts v. EPA, it is possible that EPA could be petitioned, and even be forced by the courts, into a dual regulatory system that would be both burdensome and counterproductive. Congress should clarify that the new legislation is intended to supersede the CAA in matters of GHG emissions.
- ***Allow the Price Signal to Work*** - One of the primary advantages of cap-and-trade systems like those employed in these three bills is that they use prices to allocate CO_2 emissions to their highest valued users--they promote economic efficiency even as they protect the environment. Consequently, Congress should be careful to avoid provisions that might compromise the power of the price signal. The Manager's Amendment includes several provisions – allowances to the states, energy assistance programs, and to industry – that provide energy assistance to consumers. Depending upon how they are implemented, these provisions could interfere with the ability of the cap-and-trade system to affect consumer energy demand through price increases, and they need to be reconsidered to preserve the environmental goals of the bill.

- ***Address the differences among states with regulated electricity and those without -*** The new bill would allocate allowances to the electric power sector without discriminating between regulated and restructured states. Under the ratemaking procedures in the regulated states it is likely that utilities will be unable to include in their rate base the value of the allowances that have been freely allocated to them under these programs. As such, rates in regulated states will not reflect the real cost of electricity. Consumers in states that have restructured are likely to pay more for electricity, something closer to real cost. In those states the power company stockholders will be the primary beneficiaries of the allowances allocated to the electric power sector.
- ***Develop a Clearer Approach for Offsets*** - It is important that Congress protect against compromising the environmental integrity of whatever emissions cap it adopts. To this end, it is necessary that there be real reductions in emissions or increases in sequestration equal to or exceeding any new allowances created in an offset program. The Manager's Amendment not only directs the Administration to develop rules to assure the integrity of the proposed offset systems, but requires that the methods employed for estimation produce results that are consistently reproducible by independent teams of evaluators. This is a step in the right direction. Unfortunately, there remains ambiguity in the bill regarding the role of the estimation methods. At no point is the role of the offset estimation methods clearly stated. The Senate should clarify the role that the offset estimation methods play. Moreover, international offset projects should be subject to the same set of rules, including rigorous estimation methods leading to independently reproducible results, as the domestic offset program.
- ***Direct Auction Revenues to the General Fund*** - The Manager's Amendment has at least acknowledged the benefits of auctioning allowances and assigning the revenue to the General Fund. Many regulatory design problems – price distortions, unanticipated distributional effects, technological and programmatic lock-in – are ameliorated or eliminated by adopting a more principled approach: auction of all allowances and assignment of all revenues to the federal government's General Fund. The programs and projects currently promoted by the bill could then compete on an even footing with other important public investments and goals, including the reduction of highly distortionary taxes.

By incorporating the aforementioned recommendations into the Manager's Amendment, the U.S. Senate can ensure its environmental goals are achieved.

8.2 Ignition and Combustion of Pulverized Coal Particles with Oxygen/Carbon Dioxide





Source [8.2]

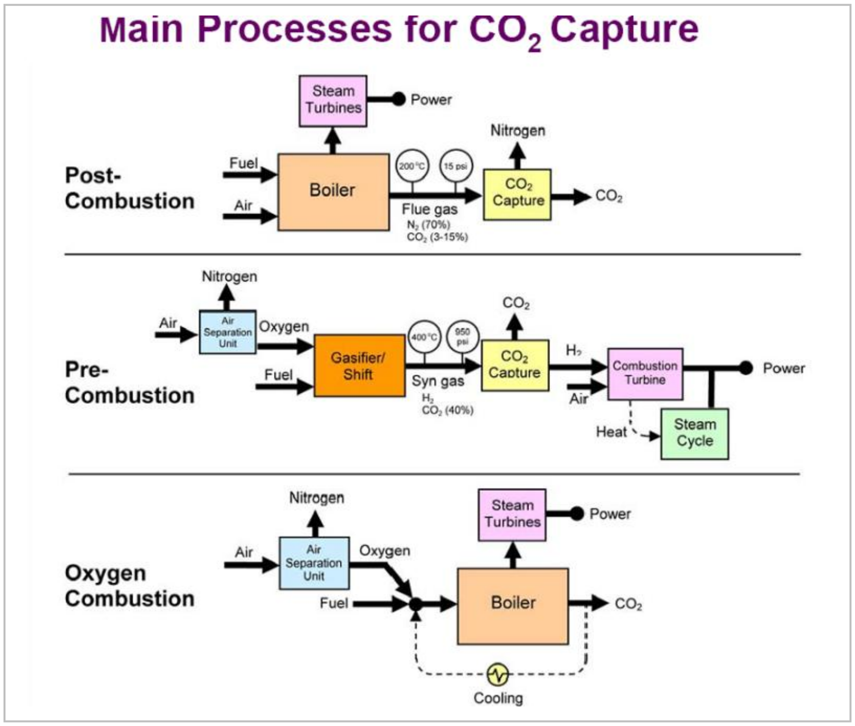
Oxyfuel Overview

The capture of CO_2 by post-combustion or pre-combustion processes, and then storing (or sequestering) the gas in underground reservoirs, are frequently considered the approaches for future commercialization. The role however of oxy-fuels is also now being given significant attention as a viable option in the global warming debate (Figure 8.2.1). Coal combustion with oxygen/carbon dioxide instead of with air (oxy-fuel combustion) is actively being investigated because of its potential to both facilitate CO_2 sequestration as well as emission reductions. This reduction in the production of CO_2 becomes increasingly important for the future use of coal.

Some recent studies show oxy-fuel combustion as the least costly alternative for a new plant, while others lean toward IGCC [8.2]. A significant economic strength of oxy-fuel is that it could be introduced as a retrofit to existing coal power plant technology. This is not the case for the leading clean coal technology known as Integrated Gasification Combined Cycle (IGCC). An IGCC plant is one technology option that can capture carbon dioxide but will require a totally new power plant being constructed. Indiana's Duke Energy Edwardsport plant is pioneering this technology. Money spent on today's problems will be used in tomorrow's solutions and some estimates of the economics for the oxy-fuel option are made. Based on these estimates from the literature, we argue that oxy-fuel coal combustion should be considered as an option in Indiana. Research is needed to support industry in considering oxy-fuel.

The CCTR supported project (Dr. Steve Son) examines enhanced oxygen levels and CO_2 bath gas independently for their influence on particle-cloud pulverized coal ignition and combustion. Some previous studies [8.1] have considered this for single particles, but a particle-cloud much more closely replicates conditions in a coal furnace. The project designed and built a reactor that produced a particle-cloud in a chamber that could also be pressurized. Pressurization allows exploration of the effects of pressure that have not been explored for oxy-fuel combustion. The project also examines this effect for other air-coal systems such as coal gasification that operate at elevated pressures. The experiments examined the effects of the presence of CO_2 and O_2 concentration on the ignition delay time and on the deflagration rate. The project does direct comparisons to a coal-air system and determines the requirements for the equivalent CO_2/O_2 system.

Figure 8.2.1. How To Capture CO_2



A significant question is whether both the reaction propagation and ignition can be simultaneously matched to a single CO_2/O_2 ratio. In addition, we plan to compare our results using the same coal used in the pilot-scale power plant being built by Jupiter Oxygen in northern Indiana. No comparisons of this kind exist of a laboratory scale reactor to a functioning furnace. The PI has visited Jupiter Oxygen in northern Indiana and we expect to continue to collaborate with them during this project. Future collaborations create a unique opportunity within the clean coal technology realm to directly combine knowledge learned in the research lab with knowledge learned in application. In addition we plan to do a survey to assess the potential interest in this oxy-fuel among the state's major electricity utilities and we have compiled a list of contacts.

We will leverage this funding with other startup funds provided (Startup support for Prof. Son) to establish a unique capability at Purdue to study the combustion of coal at various pressures and with various oxidizers (O_2, air, metal oxides, etc.). This apparatus will also allow us to study other related systems, such as chemical looping combustion (CLC) as well. In addition this apparatus could be used to study coal dust explosion and pursue strategies to protect against coal explosions in mines. The understanding and data obtained from this study will enable oxy-fuel combustion to be more effectively implemented in existing and new coal furnaces, including those in Indiana. The data will also be useful to modeling efforts that will help improve the design of coal burners using the oxy-fuel process.

Oxyfuel Background

Requirements for the reduction of pollutant emissions and lower-cost CO_2 separation have prompted the study of oxygen/carbon dioxide recycle (O_2/CO_2) firing for existing pulverized coal systems. Although new compact boiler units may be designed for the use of more strongly oxygen-enriched oxidizer mixtures (limited only by material limits), retrofitting of existing air-based coal boilers to O_2-firing is limited by the existing system in place. For temperature control and to maintain the necessary convective heat transfer to steam tubes and similar swirl in the burner, O_2-firing in existing boilers requires the recycling of substantial quantities of CO_2 into the boiler. Both systems are expected to require some flue gas recycling (dilution with CO_2 or CO_2/H_2O) because of existing systems and material limitations.

A recent review argues that oxy-fuel coal combustion is economically promising and technically feasible with current technologies, decreasing the risk associated with the development of new technologies. This review also concludes: "fundamental research needs include fuel reactions at pressure, and in O_2/CO_2 atmospheres, as few studies have been made in this area." Successful implementation of the O_2/CO_2 technology in conventional PC boilers depends on fully understanding the differences that result from replacing N_2 with CO_2 or CO_2/H_2O in the oxidizer stream. In addition, flue gases could potentially include water vapor if the flue gases are not cooled first to condense the water. The addition of both water vapor and CO_2 has not been previously studied, and could be considered with some modifications of the current system. Previous results have shown that the application of O_2/CO_2 combustion can cause differences in furnace operation parameters such as burner instability, char burnout, heat transfer and gas temperature profiles. No direct comparisons between a laboratory reactor and large-scale system have been made. We plan to make those comparisons in this study.

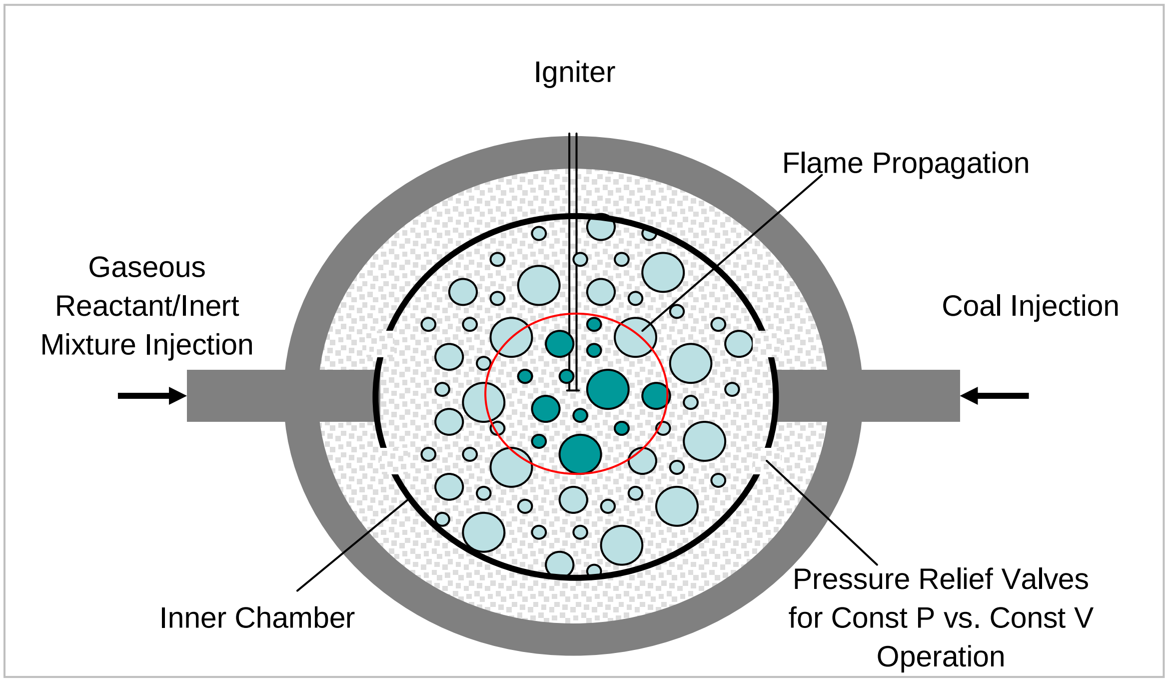
Issues in burners involving O_2/CO_2 mixtures originate, in part, from the lower flame temperatures associated with CO_2 use because of its higher heat capacity. This difficulty can generally be overcome by increasing the oxygen concentration of the oxidizer to values, which give comparable flame temperatures to coal combustion in air. Nevertheless, some studies have found that coal ignition is retarded in an enhanced O_2 environment, even for a comparable gas temperature profile. Information on the effect of elevated levels of CO_2, and eventually water vapor too, on the ignition of coal particles is important both for understanding how to switch existing burners from operation on air to operation on O_2/CO_2 mixtures, and for computational fluid dynamic (CFD) modeling of the performance of PC burners in O_2/CO_2 systems. To examine these issues, we will study the effects that the presence of CO_2 and enhanced O_2 levels has on the ignition of pulverized coal in a dust cloud reactor [8.3, 8.4, 8.5].

Research Plan & Timeline

Figure 8.2.2 shows schematically the experiment to be designed and built. The design will feature a nearly constant pressure (up to several atmospheres) to simplify interpretation of flame propagation data. Both ignition and propagation studies can be considered. The proposed research will performed in the follow tasks:

1) *Literature search & Survey.* The relevant studies will be accessed. (First quarter)
2) *Design and construction of the test apparatus.* (First experiment by end of first year)
3) *Ignition studies and analysis of data.* We will examine the effect of O_2/CO_2 concentration, and pressure, and compare as much as possible results to full-scale systems and limited data available in the literature. (2^{nd} year)
4) *Propagation studies*. We will examine the effect of O_2/CO_2 concentration, and pressure, and compare as much as possible results to full-scale systems and limited data available in the literature. (2^{nd} year)
5) *Publish results.* We will publish results and prepare final report. (2^{nd} year)

Figure 8.2.2. Schematic of the particle cloud constant pressure ignition & flame propagation experiment



Source [8.2]

Project Deliverables

This project built a unique reactor capable of not only meeting the current objectives but was made applicable to other future studies. Publications and quarterly reports are being published and submitted with the data obtained from these experiments. This data can be provided to industry, especially those pursuing work in Indiana. The understanding and data obtained from this study will enable oxy-fuel combustion to be more effectively implemented in existing and new coal furnaces. The data will also be useful to modeling efforts that will help improve the design of coal burners using the oxy-fuel process.

8.3 Wind Energy

As Indiana's demand for electricity increases every year, new appropriate sources of power must be found. In 2008 Indiana was installing hundreds of MW of wind turbine power. The impact of this development is of importance to Indiana's coal production, and particularly for the back-up power that is needed when little or no wind is available. As wind velocity fluctuates, it is necessary to supplement the wind power output with a natural gas combined cycle unit in order to produce a constant level of power to go onto the grid. When there is little or no wind, the natural gas combined cycle generators units will be used to keep power outputs steady. So we must ask: where will the gas supply come from for these units? For 2009 and beyond, therefore, we need to assess the extent to which this might affect Indiana's coal consumption and coal production.

In response to increases in demand for electricity, wind energy has emerged as a partial answer to the energy crisis in Indiana and the United States. Wind is seen as a low cost, zero emissions alternative to fossil fuel electricity production. Due to the intermittency of wind, some non-intermittent, fast-response power source will be needed to supplement wind power. At present, natural gas fired units appear to be the most economical supplementary technology.

Large-scale wind power is generated on wind farms with as many as several hundred 1 to 3 MW wind turbines. The greatest downfall to wind power is the low reliability due to the inconsistent levels of wind. Wind cannot be a) predicted, b) scheduled, and c) can only be stored in rare cases and limited amounts. A wind turbine only works when the wind blows and then only if wind strength is within the operating range of the turbine. This unpredictability makes wind difficult to integrate onto the grid system as part of a consistent low emission supplier of electricity. For example, a wind turbine only generates its full nameplate capacity if the wind is blowing at 35mph; this happens less than 1% of the time in Indiana and the Midwest. The amount of energy generated by a wind turbine is directly related to the speed and consistency of the turning turbine. In order for wind energy to be effective, there needs to be a relatively constant flow of wind above 8mph at 300ft above the ground. Wind patterns have been studied several times over the past few decades.

Wind power potential is measured on a 1-7 scale, with 7 being the highest or best for sustained wind potential. A National Renewable Energy Laboratory (NREL) study indicated that just under a half of Indiana is class 1 (the levels needed for sustained energy production) and more than a half is class 2. The areas of the state that are of class 3 or higher are located in an area that borders Lake Michigan; an area that is bordered by the State of Illinois on the west, I-65 on the east, Lake County on the north and I-74 on the south; and a small area near LaGrange, Indiana. The current development of the Lake Michigan shoreline precludes more than just a few wind turbines being placed there. The best area for deployment of a wind farm is the rural section of northwest Indiana near the Illinois border. Though the majority of the region is only class 2 it does represent the best area available for development. This is the location of the large wind system project currently under construction, the Benton County Wind program, initially a 130 MW program, with a further 400 MW capacity (Table 8.3.1).

The State Utility Forecasting Group (SUFG), in its December 2007 Forecast, stated that Indiana will have about 585 MW of increased peak electricity demand per year for the next 20 years [8.16]. This amounts to approximately a 60% increase in state demand over the next 20 years. This increased demand could be met by building an Edwardsport-sized electric facility every 13 months. This being the case, we are already behind schedule.

Some contend that wind will be able to meet this demand with free fuel and emission free electricity production. As we will see, wind is not fuel free or zero emissions if it is to be fully incorporated into the state's power generation capacity mix. But it does have a very positive place in the future energy mix as a stimulus for new industrial growth. If we look to wind to supply some of the replacement capacity, we need to assess the reliability and availability of the power.

Table 8.3.1. Status of Wind Generation in Indiana

Project Name	Counties	Developer	Rated Capacity (MW)	Construction Schedule	Status
Benton County Wind Farm	Benton	Orion Energy	130	Completed Spring 2008	Completed
Fowler Ridge Phase 1	Benton	BP Alternative Energy & Dominion	400	To be completed by end of 2008	Under construction
Hoosier Wind Project	Benton	enXco	100	2009	Pending
Fowler Ridge Phase 2	Benton	BP Alternative Energy & Dominion	350	Begin early 2009	Approved
Tri-County Wind Energy Center	Tippecanoe, Montgomery, Fountain	Invenergy	300-500	Begin 2010	Proposed
Meadow Lake Wind Farm	Benton, White	Horizon Energy	600-1,000	Begin 2010	Proposed
	Randolph	Horizon Energy	100-200		Proposed
	Howard	Horizon Energy	200		Proposed

Source [8.15]

The Benton County wind farms claim their wind turbines will have a capacity factor of 30%. Recent Midwest Independent Systems Organization (MISO) reports indicate that on the peak demand days over the past 4 years, wind systems produced at an average of 18.25% of their capacity. This is not a good indication of overall productivity in that peak demand days in the MISO region occur in late July and early August when the wind blows the least. But if the wind power systems can produce at 18.25% on the worst wind days, then 30% is conceivable for the average for the year. In comparison with baseload coal-fired plants which have capacity factors of 90% to 95%, the wind unit capacity factors are significantly lower.

The major reason for supporting wind energy is that it produces electricity without producing CO_2. The CO_2 is a big issue in the discussion of new power generation. So much so that SUFG was asked to assess the cost impact of CO_2 control legislation on the electric rates paid by Indiana citizens, business, and industry. SUFG reviewed the possibility of using wind power systems to affect a rapid reduction of CO_2 emission if such legislation is passed. The SUFG study indicated that a combination of wind and combined cycle generators may be a component of future CO_2 emission reduction in the electric power mix, but they need to be brought on line together at the same substation or grid interface [8.18]. When viewed in terms of CO_2 control, the analysis becomes interesting.

SUFG's analysis suggests that 100 MW of wind power could be tied to 50 MW of combined cycle generation in order to maintain a constant 60 MW of base load power. Tying these together would mean that as wind power generation fluctuates with the wind changes, the natural gas units can compensate in the opposite direction and produce a steady supply of power. This teaming is necessary since natural gas units can be accelerated to produce more power or decelerated to produce less power more quickly than a coal or oil fired unit. This makes the power produced available as base load, where Indiana has the greatest need. In 2008 wind energy purchase-agreements were already in place for Indiana amounting to 138 MW with a further 200 MW having been approved (Table 8.3.2).

Table 8.3.2. Wind Energy Purchase Agreements by Indiana Utilities

Utility	Project	State	Power Purchase Agreement (MW)	Status
Duke Energy	Benton County Wind Farm	Indiana	100	Operational
SIGECO	Benton County Wind Farm	Indiana	30	Operational
WVPA	AgriWind	Illinois	8	Operational
Indiana Michigan	Fowler Ridge	Indiana	100	Approved
NIPSCO	Buffalo Ridge	South Dakota	50	Approved
NIPSCO	Barton Windpower	Iowa	50	Approved
IPALCO	Hoosier Wind	Indiana	100	Pending

Source [8.15]

Let's consider 100 MW of wind power being supplied by 40 x 2.5 MW wind turbines units. Having these units configured with 50 MW of combined cycle generation would result in one quarter of the CO_2 that would have been produced by a 60 MW Pulverized Coal (PC) plant. The bad news is that the capital cost of the wind/gas system is more than two times the cost of a similar sized PC plant and has a greater fuel cost (natural gas) than a similar sized coal unit. This also assumes that the natural gas needed to back up the wind system is even available. The good news is that if gas prices remain at the level they were in 2008, then the Levelized Cost of Electricity (LCOE) of the wind/gas combination would be 12% lower than the same size PC *unit with carbon capture*. CO_2 control will be an enormous cost factor in future electric production. If passage of the CO_2 control act reduces the cost of coal (reduced demand) and increases the cost of natural gas (increased demand), then the LCOE could be in favor of the PC units.

Under this combined system, the natural gas combined cycle generators will run on average about 44% of the time. To make the entire system operate at the least possible cost it is important to not use the gas system unless it is necessary for demand requirements. It should be noted that gas units make up 25% of the electric generation capacity in Indiana but only operate 4% of the time. This is mainly due to the very high cost of natural gas to run the units.

SUFG noted that in the initial period of the CO_2 reduction, utilities around the state could “retire” a total of 2,300 MW of coal power production. This would create a CO_2 credit by no longer using these specific coal-fired units. But it also exacerbates the shortage of generation capacity we are already experiencing. It would be important to replace this generation capacity as fast as possible. Wind power systems have much shorter construction lead times than coal-fired boilers or IGCCs.

If we were to focus on replacing the 2,300 MW of to be retired coal-fired power plants with wind/gas systems and we use the SUFG formula of 100 MW of wind plus 50 MW of combined cycle generation to produce 60 MW of reliable power, we can start the evaluation of the impact of the wind/gas power systems process. Using the SUFG parameters, we can assume that it will take 3,833 MW (100 MW of wind for 60 MW baseload [(2300/60])x100) of wind power and 1,916 MW (50 MW of gas units for 100 MW wind [3833x50/100]) of gas units’ power to replace the 2,300 MW of coal-fired plant that will have to be retired. As stated earlier due to the peculiarities of wind and its inherent unreliability, wind needs to be balanced with the gas-fired units in order to obtain the equivalent baseload power production. It is important to note that the gas units must be used at a minimum for reduced emission and cost factors.

To assess how much electricity each system needs to produce, we assume a baseload 2,300 MW coal facility will operate 90% of the time producing 18,133,200,000 kWh of electricity annually. If the wind system can produce at 30% capacity, then the 3,833 MW of wind power will produce 10,073,124,000 kWh of electricity. This leaves 8,060,076,000 kWh of electricity to be produced by the gas units (Table 8.3.3).

Table 8.3.3. Power Production from Baseload, Wind Turbine, and Gas Unit Technologies

Generation	Capacity	Operation time	kWh produced	%
Baseload	2,300 MW	8760 hrs * 0.90	18,133,200.00	100%
Wind	3,833 MW	8760 hrs * 0.30	10,073,124,000	55.6%
Combined Cycle	1,916 MW	8760 hrs * 0.48	8,060,076,000	44.4%

It requires about 7,250 Btus of natural gas to produce a kWh of electricity. This means that the wind/gas system will require 59 Trillion Btus of natural gas. This is nearly a 65% increase in the amount of natural gas currently consumed by Indiana's electric industry [8.17]. The key questions now are: What is the source and cost of this increase in natural gas use, and, what are the emissions associated with the energy use?

First, we need to look at the wind turbines; 3,833 MW of wind power would require 1,533 turbines. Each turbine needs a minimum of 250,000 square feet of area to operate. This limits the number of wind turbines to about 112 per square mile. (The land need is for the turbine structure and blade clearance, it does not preclude the simultaneous use of the land for agricultural purposes.) At 112 turbines per square mile the 1,533 turbines will require 13.7 square miles of area. Basically the wind farm can occupy less than a 4 x 4 mile area. This is easily achieved in Northwest Indiana especially in Benton, Warren, and Newton counties.

The key to making this system work is the gas units. Currently there is enough combined cycle capacity to meet the needs of the system. But remember, these gas units are already needed to meet the peak demand needs which occur about 4% of the time in Indiana. Now, instead of needing to replace PC (pulverized coal) units, we must look at adding 1,000 MW of gas units for peak demand load. While it is not as costly as PC baseload units, it is still a capital cost. A coal-fired gasifier can operate 92% of the time producing gas for the wind turbine/gas unit system needs now and store extra gas for needs during the peak demand.

59 Trillion Btus of natural gas would cost $472 Million at current rate. Should Indiana increase its dependence on imported energy supplies or should we try to provide it from sources in the state? One premise of the Indiana Home Grown Energy Strategic Plan is that importing energy is the same as exporting dollars. Options 1 & 2 greatly increase the money sent out of state to purchase energy. An Attractive option is to produce the natural gas within the state using state resources, in this case using the state's largest and least expensive energy resource coal.

The proposed Indiana Gasification Inc. project would consume 3 Million tons of Indiana coal and produce 40 Billion cubic feet of natural gas. This one facility would meet 45% of the energy needs of the wind/gas system. Gas units, unlike wind turbines, can be located anywhere within the electric dispatch services area. You can place the gasification plant at the mine mouth and pipe the gas to the gas units. Or, you can locate the gasifier next to the gas units and ship the coal via rail cars to the gasifier. Either method will suffice since the gas units need be in the transmission dispatch area but not necessarily next to the wind turbines.

SUFG estimated the capital cost of the wind/gas system would be approximately two times the cost of a similar size PC plant if built new. The 2,300 MW of combined wind and gas would cost about $3,000 per MW or $6.9 Billion. If natural gas stays at the 2008 cost of around $8 per Million Btus, then its fuel cost would be about $472 Million a year. Conversely, it would take about 3.9 Million tons of Indiana coal to produce the amount of natural gas needed for the full deployment of the wind/gas system. 3.9 Million tons of Indiana coal would result in $235 Million of economic activity in southwest Indiana, versus the exporting of $472 Million from Hoosiers to bring natural gas in from international sources.

Indiana utilities have approximately 20% of their generation capacity (5,000 MW) in the form of gas units. These are used sparingly because of the high cost of natural gas compared to coal. Gas units account for only 4% of the electricity production in Indiana, used almost exclusively as peaking power during the hot (windless) summers. This means that the gas units needed for the wind program already exist. This program will simply mean using them more often. Of course this will leave the state in need of more peaking units, but these are relatively easy to site and build compared to new base load units. In addition, the infrastructures for these gas units are already in place. The capital cost for the wind/gas system would be significantly less if we assume that existing gas units can be used. We need only build the coal gasification systems and the needed infrastructure connections to make the wind/gas systems work.

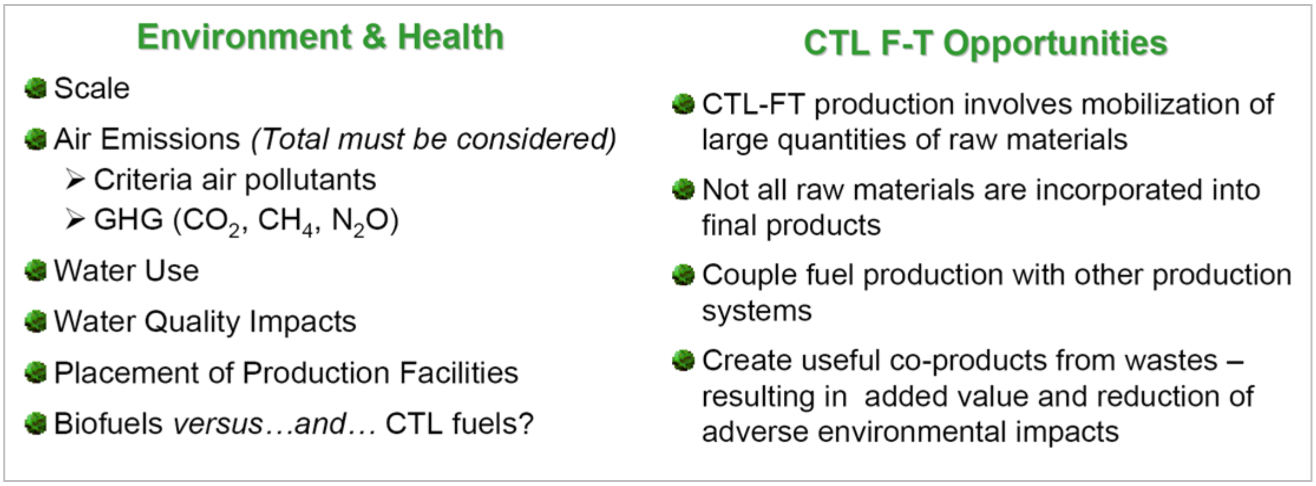
Using Indiana coal to produce the gas needed to supplement the wind system works to retain more energy dollars in the state. This, plus the jobs needed to build the wind systems, to install the gas units, and to operate the entire system, would make wind/gas power a positive economic force in the state. The installation of over 1,500 wind turbines could result in the wind power manufacturer moving its operation to Indiana. Also, the increased need for structural steel will aid the economic growth of the entire state. As gas units and gasifiers are developed and improvements made, Indiana will be in a better position to create a new energy industry that will result in better energy security, more efficient energy production, and advanced manufacturing.

The combined wind/gas system would produce one-fifth of the CO_2 from the existing 2,300 MW of PC units. If we assume that the gasifier is equipped with 90% CO_2 capture and control system, and that gas is used to produce 44% of the replacement electricity, plus the remaining 56% of the electricity produces no CO_2, then the whole process gives 95% less CO_2 than the similar-sized PC unit. However, we must add to this the CO_2 produced by the gas units. Gas units produce about 50% of the CO_2 per Btu relative to a coal-fired power plant. This being the case the total amount of CO_2 produced via this system is 78% less than the CO_2 emission from the PC units if they were run at the same level as estimated for the wind/gas system.

2,300 MW of coal powered capacity could produce about 18,133,200 MWh per year (8760 hours * 0.9 capacity factor) consuming 8.2 Million tons of coal and producing 18.0 Million tons of CO_2. The new system would produce 18,133,200 MW of power, consume 3.9 Million tons of coal, and produce only 3.9 Million tons CO_2 from the utility. The coal gasification process would capture all CO_2. This creates the best of both worlds: reduced CO_2 coming into the atmosphere, retained energy dollars, increased use of Indiana coal, and the expansion of manufacturing. One goal of the CCTR is to find ways to use the state's largest and least expensive energy resource in an economic and environmentally sound manner; wind and gas systems do realize that goal.

There are mixed opinions over promoting the use of wind energy but clearly wind does have its problems. The availability of materials for construction is an initial problem. The turbines require large amounts of steel, adhesive resins, polymer-based compounds, and advanced gear box systems. Except for steel, none of these components are supplied from Indiana. Steel and aluminum are also required to build the transmission lines that connect the wind power to the grid. Secondly, and even more significantly, the right-of-way problems are still a consideration as is also the means of integrating the wind system to the power grid. These problems must be evaluated over the next few years before wind can take its place as a dependable, viable option for reducing CO_2 emissions.

8.4 Investigation of the Environmental Implications of Coal to Fischer-Tropsch Production



Source [8.6]

Background to Environmental Implications

This research outline, which initially received some CCTR support, was motivated by the hypothesis that understanding the life-cycle environmental implications of transitioning from petroleum-based to coal-based transportation fuels would facilitate creation of technological linkages between the coal processing, gasification and Fischer Tropsch (FT) fuel production industries with other industries such as construction materials and chemicals. Fostering these linkages is expected to help overcome the principal obstacles to FT fuel investment: economic risks and environmental objections.

Economic risks result from the relatively high capital expenditures required of coal-to-liquid-fuels (CTL) production facilities, whereas environmental objections result from the production of waste ash, water or other streams at the production site – even as FT fuels are recognized as burning cleaner in automobile engines. The approach to be taken in this research is to identify the waste streams typical of FT fuel production and match those with raw material feedstock requirements in other industries that can be co-located with FT fuel production, such as cement or drywall manufacture. Finally, a research agenda for developing the technological processes necessary to couple two or more mutualistic industries shall be proposed.

Progress to Date

A draft process flow schematic of the FT fuel production process has been completed. The primary material and energetic input and output streams have been identified, and are summarized below (Table 8.4.1). A number of useful co-products from FT fuel production have already been identified and are employed in the chemicals, plastics or other industries (such as fertilizer). However, there are still large volumes of waste material created as by-products of FT fuel production that represent economic and environmental liabilities, including: nitrogen gas, coal ash and fines, waste water (and sludge), and waste heat. Coupling these material streams with the raw material needs of other industries has the potential to reduce both economic costs and environmental effects – thereby speeding adoption of FT fuel technologies.

For example, coal ash has successfully been used as a replacement for limestone and other mineral feedstocks in cement production. However, to date only class C coal fly ash (which contains high concentrations of calcium) has been effectively utilized. Consequently, this project has focused on beneficial reuse alternatives for class F fly ash, which is a by-product of current coal combustion technologies. To date, a literature review has identified geopolymer cements as a promising beneficial reuse technology. Geopolymer cements obtain strength from alumino-silicate bonding in the absence of calcium. Unlike ordinary portland cement, geoploymer cements do not require evolution of carbon dioxide from limestone feedstocks or water to hydrate. Current estimates indicate that the greenhouse gas emissions of geopolymer cements are several times lower than those associated with ordinary cement. Strength and durability characteristics are viewed as favorable. However, the environmental leaching characteristics of geopolymers are untested. If significant concentrations of metals or other environmentally significant chemicals are liberated during use or disposal of geopolymer cements, environmental concerns could present an obstacle to beneficial reuse of FT residues in construction applications.

Table 8.4.1. Input and Output for Coal To Liquid Fuel Process

INPUT	OUTPUT				
	main product	co-product		by-product	
		material	potential user	material	place for disposal
coal	diesel	liquid N_2	ammonia production	waste N_2	atmosphere
air	LPG	Kr/Xe	lamp production and lab agents	coal fines	mine
primary water		phenol	plastic, medical production	ash from gasifier	landfill
electricity		cresylic acid	chemical production	dust	landfill
		naphtha	chemical industries	air from steam generation	atmosphere
		sulfur	sulphuric acid production	CO_2	atmosphere
				wastewater	incinerator

Source [8.6]

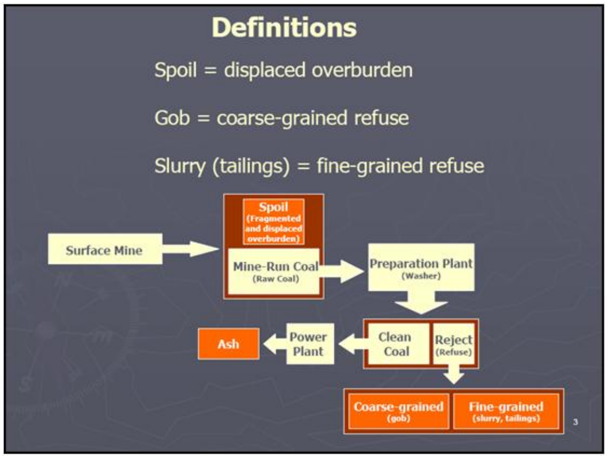
Future Plans

Our present state of understanding is qualitative. Further investigation is required to develop quantitative or semi-quantitative models. Also, the process diagram will be extended to include use of diesel fuel (the primary product) in the transportation sector by coupling the existing model with the life-cycle emissions data available in the GREET model (developed at Argonne National Labs to model alternative fuel technologies). The result is expected to be an integrated, life-cycle model depicting the material and energy flows and balances that can be expected to represent FT fuel production from mining all the way to dissipation of exhaust gases in the atmosphere. Ultimately, this model will facilitate environmental assessment of hypothetical technological linkages between FT fuel production and other industries.

In addition, this research program will leverage Coal Center resources with teaching assistantships, SURF program resources or other Center for Environment funds to identify and develop the technological linkages necessary to link FT fuel production to mutualistic industries. The initial focus of this work is the production of geopolymer cements from ash – however, other by-product material and energy opportunities are expected to be revealed. With regard to geopolymers, production of geopolymers from both pure and ash materials will be undertaken during the next six months. As geopolymer samples are produced, these will be tested for both strength (i.e., suitability for construction applications) and environmental leaching properties. Ultimately, this is expected to lead to a large-scale structural and environmental testing of structures (such as reinforced concrete beams) made from class F coal fly ash.

The overarching vision of this research program is to create a model for environmental assessment of FT production technologies and identification of further research opportunities that would be attractive to funding agencies such as USDOE, NSF and/or USDA that represent potential partner organizations for the Coal Fuels Alliance and Clean Coal Tech Center.

8.5 Reconnaissance of Coal-Slurry Deposits in Indiana



Selected statistical values
for 473 individual samples of coal slurry

AR: as-received; MAF: moisture- and ash-free; wt %: weight percent

	Ash, AR (wt %)	Sulfur, AR (wt %)	Btu/lb, AR	Btu/lb, MAF
Minimum	5.6	0.4	1069	3725
Maximum	76.8	23.7	11720	24975
Average	32.2	4.0	7095	12849
Mode	26.7	2.8	7540	13210

18

Source [8.7]

The CCTR has supported a project that investigates the potential of Indiana's coal-slurry deposits [8.7]. The state has a long history of coal mining by both underground and surface methods, and the state is one of the major coal producing states (34.23 Million tons in 2007). Since the late 1920s, many coal operators in the state have found it necessary to prepare their coal for market by using increasingly sophisticated equipment to size and clean their product. Reject from the preparation facilities can be broadly characterized as "coarse-grained refuse" (also known as "gob") and "fine-grained refuse" ("tailings" or "slurry"). Deposits of the latter type are here referred to as "coal-slurry deposits" or "CSDs." In addition to mineral matter and water, CSDs contain significant quantities of fine-grained coal.

Coal Slurry Background

Since the 1930s, as energy prices have fluctuated and coal-preparation technology has advanced, attempts have been made intermittently to recover the coal in CSDs in an economically feasible manner. Although such recovery has been successfully achieved at a few sites, many CSDs – including some very large individual deposits – remain scattered across southwestern Indiana. Because CSDs also contain significant quantities of pyrite, they are a source of acidic mine drainage. Since 1977, coal operators have been required to reclaim their CSDs by establishing vegetation, and most CSDs that were created before that date have been reclaimed by the Indiana Division of Reclamation with funding from the Abandoned Mine Lands Program.

CSDs were emplaced in a variety of settings, including impoundments behind berms and in dammed valleys, and in final-cut pits, haul roads, and spoil deposits of surface mines. Emplacement typically occurred over a period of years or decades and significant internal variations in mineralogical, chemical, and textural characteristics exist within the deposits. Knowledge of such variations is important in any attempt to recovery slurry from a CSD in an economic and environmentally responsible manner.

The primary purpose of this reconnaissance investigation was to identify and map CSDs and estimate the volumes of slurry in each deposit. The approximate locations of preparation plants and associated CSDs in Indiana were determined from an extensive review of the mining and geological literature. Using techniques of geographic information systems (GIS), exact locations of preparation plants and changes in the configuration of CSDs through time were then mapped from geo-referenced historical aerial photographs and other aerial imagery. These efforts resulted in the production of Environmental Systems Research Institute, Inc. (ESRI) ArcMap shape files showing the locations of coal-preparation plants and extents of coal-slurry deposits. GIS techniques were then used to determine the area of each deposit. Assumptions were made regarding the thicknesses of CSDs that were emplaced in various types of settings, and estimates of thickness were made using information from the National Coal Resource Data System (NCRDS), the Coal Mine Information System (CMIS), and digital line graphs (DLGs) of the U.S. Geological Survey. The volumes of CSDs were then calculated using GIS.

A secondary purpose of the investigation was to collect, compile, and analyze records of chemical analyses of slurry performed in the 1970s and 1980s that are contained in the archives of the Indiana Geological Survey. These efforts resulted in the production of a Microsoft Excel spreadsheet that contains chemical analyses for 473 individual samples, as well as average values calculated for various mine sites. Statistical analyses were performed to identify vertical trends among individual samples within drill holes, as well as lateral trends for average values from drill holes within various CSDs.

Feature Identification

For this investigation, the paper maps of Eggert (1979) and Weismiller and Mroczynski (1978) were digitized to provide a GIS layer showing the approximate locations of CSDs and associated preparation plants in the late 1970s. Locations of additional preparation plants that operated after 1978 were obtained from various reports published by the IGS (Hasenmueller, 1981, 1983, 1986, 1991; Alano and Shaffer, 1994 [8.8]; Blunck and Carpenter, 1997 [8.9]; Eaton and Gerteisen, 2000), as well as from various editions of the Keystone Coal Industry Manual (Coal Age, 1987, 1989, 1991, 1993, 1995, 2000, 2005), [8.10, 8.11, 8.12].

Using the shapefile of approximate locations to identify areas of interest, about 160 historical aerial photographs taken in those areas between 1937 and 1980 were then obtained from the archives of the IGS and georeferenced. Other imagery that was used included Digital Orthophoto Quarter Quads (DOQQs) of the U.S. Geological Survey from 1998, and imagery of the National Agricultural Imagery Program from 2003 and the Indiana Orthophotography Project from 2005. On aerial photographs, preparation plants are recognizable as tall structures that may cast long shadows and are sometimes associated with silos, conveyor belts, or smoke stacks. Preparation plants, particularly older plants and plants associated with underground mines, are often situated on rail lines (with multiple tracks adjacent to the plants), while more recent plants associated with surface mines are often connected to various pits by broad haul roads that are distinctive on aerial photographs. However, the plants (particularly those associated with surface mines) were often dismantled or moved soon after mining activity shifted to other areas.

As part of this investigation, the identification of coal-slurry deposits on imagery involved the evaluation of several factors. CSDs are typically situated close to preparation plants, although in some locations slurry is pumped or flows for considerable distances through pipes or ditches before entering a disposal cell. Other factors indicating the existence of a CSD include the presence of berms, a generally dark gray or black appearance (except where the deposit is highly oxidized or where salts have formed on the surface), the existence of braided or meandering stream channels (indicating a flat-lying deposit), and an absence of shadows (indicating that the deposit has low relief).

Older, unreclaimed CSDs may exhibit erosional features that typically have relatively low relief, in contrast to coarse-grained gob deposits, which were created by dumping refuse in large piles. Unreclaimed gob deposits are also typically dark gray to black in color, but they may also exhibit steep-sided, eroded edges that cast long shadows. Gob deposits may also show evidence of straight travel ways on their upper surfaces where dump trucks traversed the deposit.

Thickness Estimations

In order to provide volumetric estimates of the mapped CSDs, it was necessary to make assumptions regarding the thicknesses of the deposits. For the purposes of this preliminary reconnaissance investigation, the following simplifying assumptions were made:

1) The thickness of a CSD categorized as "FCP" (namely, emplaced in a final-cut pit or inclined haul road) is assumed to be equal to the depth of the coal bed that was mined. Also, the cross-sectional area of such a CSD is assumed to be rectangular. This assumption does not take into account any slurry that was emplaced by overflow above the tops of final-cut pits. Also, for the purposes of this evaluation, inclined haul roads and haul roads transecting spoil ridges are also included in the category of "FCP" at some mine sites.
2) The thickness of a CSD categorized as "GND" (namely, emplaced on unexcavated ground behind a berm) is assumed to be equal to the height of its associated berm. It is assumed that the CSD was emplaced on undisturbed ground (rather than an excavated pit). The cross-sectional area of such a CSD is assumed to be rectangular.
3) A CSD categorized as "SPL" (namely, emplaced within ungraded spoil deposits) is assumed to completely fill the troughs between parallel ridges. Spoil ridges are assumed to have an angle of draw of 30 degrees on both sides, so that the troughs between them are assumed to have cross-sectional areas that are isosceles triangles. For the purposes of this project, the maximum thickness of a CSD within any given trough is assumed to be approximately equal to one-fourth of the average spacing between ridges, and the average thickness is assumed to be approximately equal to one-eighth of the average spacing. This assumption does not take into account any slurry that was emplaced above the tops of spoil ridges.

Results: Areal Estimates

The total acreage of possible CSDs identified in this investigation was 2,765 acres. By category of emplacement, this includes the following:

1) Emplaced in final-cut pits and inclined haul roads (FCP) - 764 acres (75 features);
2) Emplaced on unexcavated ground behind a berm (GND) - 1,213 acres (74 features);
3) Emplaced within ungraded spoil deposits (SPL) - 788 acres (49 features).

Based on inspection of color aerial photographs from 2003 and 2005, the reclamation status of each CSD was subjectively characterized. Of the total area of 2,765 acres, these characterizations are as follows:

1) Active emplacement or reclamation - 223 acres (8%);
2) Soil cap emplaced but not yet revegetated - 304 acres (11%);
3) Revegetated - 1,277 acres (46%);
4) Unreclaimed - 960 acres (35%).

Thickness Estimates

Among the features categorized as FCP, GND, and SPL, there were several subtypes of deposits for which thickness estimates were not possible in the absence of site-specific drilling data. Of the total mapped acreage of 2,765 acres, the total acreage of such subtypes was 409 acres. These subtypes included:

1) Active areas where slurry emplacement (or removal) had recently occurred, as indicated by changes that are evident by comparison of aerial photography taken in 2003 and 2005 (223 acres, 15 features);
2) Graded spoil deposits (162 acres, 11 features);
3) Excavated pits, other than final-cut pits and impoundments on undisturbed ground (25 acres, 3 features).

Thickness estimates for features in the categories of FCP, GND, and SPL (including the 2,356 acres for which such estimates were possible) are summarized in Table 8.5.1. Because a range of estimates was determined for some features, the lower estimates are designated as "MIN," while the upper estimates are designated as "MAX" (units are "feet").

Table 8.5.1. Thickness estimates for coal-slurry deposits emplaced in final-cut pits (FCP), on unexcavated ground (GND), and within spoil deposits (SPL)

	Minimum min	Maximum max	Average min	Average max	Median min	Median max
FCP	0	125	38	56	30	50
GND	0	54	10	14	10	10
SPL	0	49	6	8	7	7

Volumetric Estimates

Using the thickness estimates, volumes of individual features were then calculated. Total volumes, by category of emplacement, are as follows:

1) FCP (742 acres) - minimum = 56,563,329 yd^3, maximum = 85,679,439 yd^3 ;
2) GND (991 acres) - minimum = 29,244,928 yd^3, maximum = 38,527,746 yd^3;
3) SPL (623 acres) - minimum = 8,543,733 yd^3, maximum = 12,151,611 yd^3.

Thus, the total volumetric estimate for CSDs (FCP plus GND plus SPL) ranges from about 94 to 136 Million cubic yards. These estimates do not include 409 acres of features for which thickness estimates are not possible, including deposits emplaced on graded spoil and in excavated pits, and in areas where slurry is being actively emplaced or removed.

Tonnage Estimates

The estimate of 94 to 136 Million cubic yards, given above, is for the volume of raw slurry in situ. In order to convert this estimate to tons of potentially recoverable coal, several additional assumptions are required regarding (1) mineability of raw slurry, (2) weight density of raw slurry, and (3) recoverability of coal from raw slurry by processing. Data on which to base these assumptions are very limited.

With regard to mineability, slurry that was emplaced in ungraded spoil deposits presents the greatest problems for economic extraction because of the irregular profile of the underlying, steep-sided spoil ridges. It might not be possible to extract slurry from much more than 60% of such CSDs without encountering unacceptable contamination of the product with rock (Roger Missavage, Southern Illinois University, written communication, 2007). Similarly, extraction of slurry from final-cut pits would be limited within portions of the deposits that are bounded by spoil, so that perhaps only 70% of such CSDs are subject to economic extraction. Applying such broad assumptions to the CSDs included in this investigation, a more realistic estimate of mineable slurry may be 74 to 106 Million cubic yards. If we assume that raw slurry in CSDs has an average weight density of about 110 to 120 pounds per cubic foot, then these volumetric estimates represent 110 to 171 Million tons of potentially mineable raw slurry.

Based on the results of laboratory washability tests, Miller and Eggert (1982, p. 54-55) indicated that about 40% of CSDs may be recoverable coal. Recovery under actual field conditions would probably be somewhat less - perhaps as little as 20% (Roger Missavage, written communication, 2007). If we assume that 20% to 40% of mineable slurry may be recoverable coal, then the estimate of mineable slurry (namely, 110 to 171 Million Tons) represents 22 to 69 Million Tons of recoverable coal. This compares with an estimate made in 1982 that about 20 Million Tons of usable coal could be recovered from CSDs in Indiana (Miller and Eggert, 1982). All the estimates given above regarding mineable slurry and recoverable coal are based on very limited field and laboratory data, and different assumptions may yield significantly different estimates of recoverable coal.

Chemical Characterization, Average Values

Table 8.5.2 shows selected statistical values for the 473 individual samples that were chemically analyzed by the Indiana Geological Survey during the 1970s and 1980s and whose chemical values are included in the Microsoft Excel spreadsheet named
"COAL_SLURRY_ANALYSES_IGS.XLS":

Table 8.5.2. Selected statistical values for 473 individual samples of coal slurry. AR: as-received; MAF: moisture- and ash-free; wt %: weight%

	Ash, AR (wt %)	Sulfur, AR (wt %)	Btu/lb, AR	Btu/lb, MAF
Minimum	5.6	0.4	1069	3725
Maximum	76.8	23.7	11720	24975
Average	32.2	4.0	7095	12849
Mode	26.7	2.8	7540	13210

Although determinations of moisture content were reported for some samples, those analyses are less reliable and are not included in Table 8.5.2; the more reliable analyses indicate that moisture content was generally less than 30% (as received). Of the 473 archival chemical records, locations are known for 450 samples, which were obtained from 93 drill holes at 10 different mine sites. Average values for each of the 10 mine sites are included in Table 8.5.3.

In general, average calorific values of CSDs are slightly higher at sites where average ash content is lower; however, the range of average calorific values (Btu per pound, moisture - and ash-free) is small, reflecting small variations in the rank of the coal processed by the preparation plants.

Indiana Coal Slurry Summary

Preparation plants and associated coal-slurry deposits (CSDs) in Indiana were identified and mapped using georeferenced aerial photographs that were taken between 1937 and 2005. CSDs were categorized by three major depositional settings. The maps are available in the form of ESRI ArcMap shapefiles (COAL_PREPARATION_PLANTS_IN.SHP and COAL_SLURRY_DEPOSITS_IN.SHP). Supplementary information regarding preparation plants, such as dates of operation and coals that were processed, is available in a Microsoft Excel spreadsheet (COAL_PREPARATION_PLANT_DATA.XLS). The total area of CSDs in Indiana is estimated to be 2,765 acres.

**Table 8.5.3. Selected statistical values for samples from various mine sites.
AR: as-received; MAF: moisture- and ash-free; wt %: weight%**

Mine	ID_IGS	No. of drill holes	No. of samples	Ash AR (wt %)	Sulfur AR (wt %)	Btu/lb AR	Btu/lb MAF
Minnehaha	D3	18	74	20.2	2.2	6893	13680
Green Valley	B4	9	23	20.9	5.1	9780	13305
Otter Creek	B1	4	4	26.7	2.6	8893	13025
Friar Tuck	D4	9	37	28.1	2.1	8092	13663
Buckskin	K3	7	17	29.0	2.7	8589	12873
Chinook	C1	14	81	30.5	3.2	5577	13310
Lynnville	K1	6	36	35.0	4.3	8150	13344
Tecumseh	K2	4	28	35.9	8.9	7168	11942
Airline	E3	11	99	42.4	4.4	7143	12657
Hawthorn	E4	11	55	45.2	5.8	6608	11920
SUM		93	454				
AVERAGE				31.4	4.1	7689	12972

Preexisting data sets were used to estimate the thickness of each CSD. The volume of each deposit was then calculated. Estimates of the total volume of coal slurry in Indiana range from 94 to 136 Million cubic yards. An unknown quantity of additional coal-slurry exists at active coal-preparation facilities, in some water-filled impoundments located in the vicinities of inactive operations, in excavated pits of unknown depth, and in graded spoil deposits. Using certain assumptions regarding the ability to mine slurry from different types of CSDs, the weight density of raw slurry, and the ability to recover coal from raw slurry by processing, it is estimated that, as of 2005, the volume of mapped CSDs represents from 22 to 69 Million tons of recoverable coal. This compares with an earlier estimate made by Miller and Eggert (1982) of about 20 Million tons.

Textural and chemical properties of coal slurry are known to vary greatly within CSDs. In some depositional settings, it may be possible to predict variations based on knowledge of the point where the slurry was discharged from a pipe or ditch into its disposal cell (referred to as a “discharge point”). Inspection of aerial photographs was used to map such points. This map is available in the form of an ESRI ArcMap shapefile (COAL_SLURRY_DISCHARGE_IN.SHP).

The locations of 450 unpublished chemical analyses of samples that were collected by the Indiana Geological Survey in the 1970s through the middle 1980s were mapped, and the data were compiled into spreadsheets (COAL_SLURRY_ANALYSES_IGS.XLS). The map showing sample locations is available in the form of an ESRI ArcMap shapefile (COAL_SLURRY_SAMPLES_IGS_IN.SHP). Preliminary analysis of these data reveal no predictive relationships between the quality of coal slurry (as indicated by ash content and calorific values) and the age of the coal-preparation facility or the character of the coal beds that may have been processed through the facility. In general, however, facilities that processed coal from underground mines are associated with slurry of better quality than are facilities that processed coal from surface mines only.

Although the population of chemical analyses in the preexisting IGS archive was not originally intended for statistical evaluation and, in many cases, was smaller than the minimum number of values recommended for particular statistical analyses, the analyses were nevertheless performed to identify statistically significant spatial trends. The analyses included identification of vertical trends among samples from individual drill holes, as well as lateral trends among average values for drill holes within various CSDs. Among ten mine sites, vertical and lateral trends that are statistically significant at 95- and 99% confidence levels were identified for some CSDs. For example, the statistical analysis seems to support the observation by Eggert and others that chemical and textural trends are “predictable and not random” at the Airline Mine. Statistically significant trends may also exist within CSDs that have relatively complex depositional histories, such as those at the Chinook and Lynnville Mines. However, no significant trends were identified among drill holes at several other sites.

Recommendations

The map that was produced by this investigation showing CSDs in Indiana is based on interpretations of aerial imagery and analysis of preexisting data. Further refinement and revision of the map, as well as volumetric estimates of individual CSDs, could be made in consultation with personnel of government agencies and mining companies who are familiar with conditions on the ground.

In the future, investigators involved in projects to characterize three-dimensional chemical and textural variations within CSDs should consider incorporating knowledge obtained from temporal series of historical aerial photographs to select sample sites.

Three-dimensional characterization of CSDs should include proximate (ash, sulfur, Btu) and ultimate (carbon, hydrogen, nitrogen, oxygen) analyses, as well as grain-size analyses, washability tests, petrographic analyses (involving coal macerals), chlorine and mercury contents, ash-fusion temperatures, and Gieseler plastometry. Collection of bulk samples (for example, samples weighing 500 pounds) should also be considered for selected bench analyses.

A complete report is available on the Web site of the Indiana Geological Survey at: http://igs.indiana.edu/survey/projects/Coal_Fines/index.cfm

The final report submitted to CCTR is available at http://www.purdue.edu/dp/energy/CCTR/researchReports.php

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CHAPTER 9

PROSPECTS & NEED FOR INCREASED COAL PRODUCTION

Indiana's Home Grown Energy plan remains a viable and important part of the state economic revitalization process. This plan encourages the use of Indiana's low-cost coal resources with its significant economic value and gives high regard to environmental standards while promoting the retention of capital resources within the state. Displacement of imported coals, which supply half of Indiana's coal consumption, needs considerably more attention in order for it to be achieved through greater use of Indiana's in-state coal reserves.

While the demand for coal increases, we need to ask: how long will it take and how complex will it be to facilitate the increased coal production rate in Indiana? The opportunity to expand coal mining operations in the state will be affected by the permitting process, prices of new equipment and transportation, as well as the changing prices for coal. Section 9.1 outlines some of these future new coal production issues.

Increased production of Indiana coal can be used to displace some imported West Virginian metallurgical coal. Section 9.2 describes the Indiana coking coal investigation project supported by the CCTR and taking place at Purdue Calumet (Dr. Robert Kramer). The state spends $1 Billion annually to import coal ($700 Million to import coal for electric utilities, and $300 Million for coal to make coke for the steel industry). Coke is the most expensive input into the steel making process and this industry is still vital and vibrant in northwest Indiana. At times in 2008 coke was costing up to $400 a ton on the spot market. It will be greatly beneficial for the Indiana steel industry to be able to produce coke rather than rely on imports 100% of the time.

Increased coal production/consumption in Indiana could come from a less conventional form of coal process, as was considered in 2008 by a CCTR supported project (Dr. Arvind Varma), and this is with underground coal gasification (UCG). Section 9.3 describes the UCG project that was done (phases 1 and 2) by the Purdue School of Chemical Engineering and the Indiana Geological Survey (IGS), for improving the understanding of the site selection criteria for UCG potential in Indiana.

9.1 Plans for Increasing Coal Production

Coal production planning issues include a wide range of activities, including permitting and land acquisition, maintaining emissions standards, meeting coal quality requirements, acquiring skilled workers, rising transportation costs, procuring new mining equipment, setting up contracting mechanisms, obtaining and justifying financing, and investing in improved infrastructures and other capital intensive expansion plans (Table 9.1.1). The Army Corps of Engineers (ACOE) also has regulations that require compliance and which further impacts new mining plans and post mining reclamation.

Table 9.1.1. Issues Facing Increased Coal Production

1) **Permitting** & land acquisition.
2) Changes in power plant **emission standards** & regulations for SO_2, NO_x, Hg, & potential CO_2 legislation.
3) Coal **quality** & expected volumes/sales.
4) Attracting/developing **qualified workers**.
5) Rising **transportation costs**.
5) Availability/delivery of **mining equipment**.
7) Types of **coal contracts**.
8) **Transportation & infrastructure**.
9) **Large capital** investments are required.

Source [9.1]

The Corps regulates "jurisdictional" waters (waters of the U.S.). Water quality standards at the mine are controlled by the state (IDEM) and generally regulated through the NPDES (National Pollutant Discharge Elimination System) program. Costs of purchasing farm land and mineral rights are also increasing (Table 9.1.2).

Table 9.1.2. The Permitting Process

- ❑ **Permitting** involves **regulatory uncertainty.** It is a process that **takes a long time** for data gathering & regulatory approval & is **possibly the most time consuming issue** when considering investing in a new mine.
- ❑ The ACOE (**Army Corps of Engineers**) has regulations affecting mining as well as post mining reclamation.
- ❑ ACOE regulates **jurisdictional quality** for U.S. water-ways & the state (IDEM) handles mine water outflows & air permitting.
- ❑ Costs of surface coal reserves are increasing**.** Typical **costs for purchasing Indiana farm land can exceed $4,000/acre**. Depending on strip ratio (*cubic yards/ Ton product*) purchasing mineral rights can involve a further $8,000/acre - **total cost is often > $12,000/acre for surface mining**.

Source [9.1]

Anticipated new climate change legislation could have an enormous impact on coal consumption and this adds more uncertainty for investment in new coal mining production capacity. Carbon control legislation will introduce more uncertainty while sulfur is now no-longer the most significant issue because of increased scrubber installations. The design of power plant boilers is influenced by what coal quality will be supplied. Indiana coal has a higher Btu heating value compared to western coals and this is important in determining boiler characteristics.

Having a qualified coal mining work-force increasingly becomes an issue as shortages of skilled operators, mechanics and electricians become more common with a retiring work-force. Recruitment of new employees and provision of training is now a high priority for most mining companies.

Expanding coal production requires purchasing mining equipment and this takes more and more time as a result of shortages in supply and increased mineral costs for steel and copper. There are shortages in machinery components (Table 9.1.3) and often more than a year elapses between ordering equipment and receiving it. In recent years there have been severe shortages in supplies of off-highway tires (Indiana has needed to purchase them from Russia and China) for heavy moving equipment.

Table 9.1.3. Purchasing Mining Equipment

- ❑ There is a **shortage of equipment**.
- ❑ **New equipment has a long lead time** to arrive > year.
- ❑ **Increased mineral costs for steel & copper** is raising the costs of electrical & mechanical machinery.
- ❑ **Severe shortages** in very large off-highway tires (high demand & limited production); Indiana has purchased tires from Russia & China for off-highway mining equipment.
- ❑ **High prices of mining-supplies** makes planning very difficult, Examples: - roof bolts for underground mining, and diesel fuel & explosives for surface mining equipment.

Source [4.4]

Improving transportation and infrastructure developments are challenges to be met for enabling increased coal production. Trucking and rail companies are very slow to invest capital in new transportation capacity until contracts are in place. County road agencies may then not allow increased traffic until road improvements are in place. When buyers are purchasing coal F.O.B. at the mine, then the extra cost of transportation needs to be added. Two gallons of diesel fuel are consumed by surface moving machinery for each ton of coal product. With 2008 high fuel prices this rate of diesel consumption adds an immediate cost of $8 per ton of coal even before the coal has been moved from the mine site (Table 9.1.4).

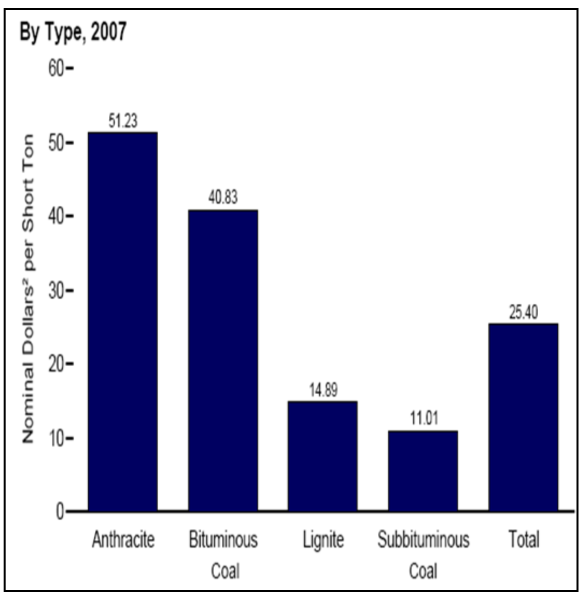
Table 9.1.4. Rising Transportation Costs

- ❑ **Increased fuel prices** are having their impact on the railroads, highway trucks & other mine equipment.
- ❑ For **each ton of surface coal produced approximately two gallons of diesel fuel** are consumed by mining machinery. **This adds an immediate cost of $8 per ton of coal** even before the coal has been moved from the mine site.
- ❑ **Problems in obtaining spare parts** for mining equipment especially non-availability of large off-highway tires.
- ❑ Always a **great advantage if a coal-fired power plant is located at the mine mouth** or very close to it.

Source [9.1]

Importing Western coals into Indiana becomes more expensive and prone to increased delays as a result of limited railroad track capacity from west to east. Increased rail-road and highway capacity will help prevent rising transportation costs. A better option is always to have a coal-fired power plant at the mine mouth or as close as possible to reduce transport costs and handling to an absolute minimum. The EIA 2007 average coal price for bituminous coals was \$40.83/Ton (Figure 9.1.1). Costs of coals are increasing (Chapter 5) but unlike gasoline the bulk of coal is not sold through spot markets but through arranged contracts. In the U.S. 85% of coal supplies are provided through contracts that normally have indexing allocations to protect against increases in costs. The types of coal contracts can vary depending on whether it's a buyers or sellers market.

Figure 9.1.1. EIA Average Coal Prices 2007



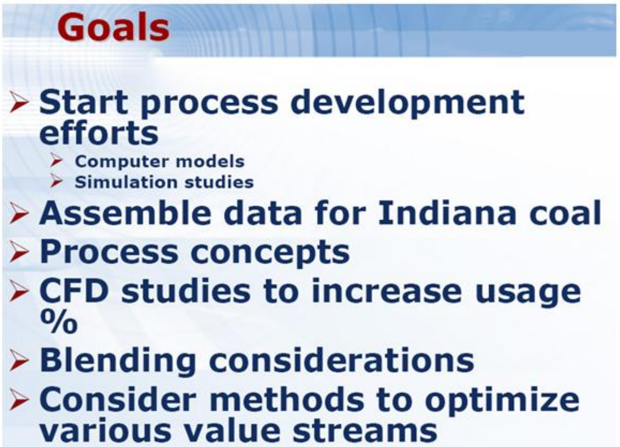
Source [9.2]

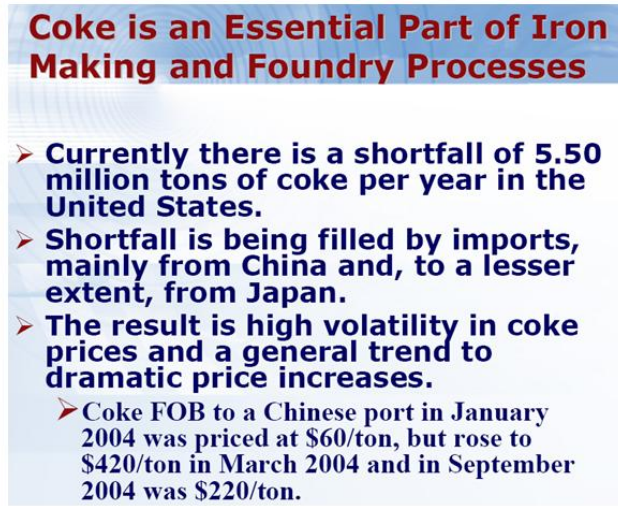
About 85% of U.S. coal supplies are via contracts & the rest via futures/spot markets. Coal supply **contracts will vary** with changes in the market, levels of demand, & regulatory climate.

In 2008 metallurgical coal was being sold at \$200 to \$300 per ton and more, and Indiana coal at \$50 to \$70 per ton.

The extension of existing coal mining sites is less expensive than investing in totally new mine site development and these can provide an increase in production of up to 10% at a time. However, this will not provide dramatic increases in coal production if we are anticipating extra Millions of tons of coal production each year [9.3]. The planning process therefore to provide significant increases in coal production does require several years and more before the required extra new output is seen.

9.2 Using Indiana Coal for the Production of Metallurgical Coke





Indiana's Home Grown Energy plan emphasizes the importance of Indiana's coal for the benefit of the Hoosier economy. Indiana currently spends $300 Million annually for coal purchases to make coke for its steel industry. In 2006 over 4.6 Million Tons of coking coal was imported to Indiana from West Virginia (Figure 5.1.3). At both state and national levels, the trends over the past 20 years have seen increased dependence on imports of coking coal (Figure 9.2.1).

Figure 9.2.1. U.S. Coke Production & Consumption

Source: http://www.eia.doe.gov/emeu/aer/txt/ptb0707.html

Coke is the most expensive input into the steel making process and steel remains an industry that is still vital and vibrant in Indiana (at times in 2008 the spot market cost was nearly $400 a ton). It will be a significant benefit for the Indiana steel industry to be able to produce coke from Indiana coal rather than totally rely on imports. Coal transportation costs would be reduced if coke is produced at an Indiana coal mine-mouth facility and then shipped as coke (coal is reduced in volume as much as 25% when made into coke).

CCTR is funding work at Purdue Calumet, for assessing the use of Indiana in the coke-making process [9.4]. The quasi-gasification process during the manufacture of coke also greatly reduces the emissions from the oven which would be an important benefit to the overall air quality of the northwest region of the state. The process being developed proposes to use gas from the volatile material as feed material for production of other product value streams. Initial results indicated that it is possible to use blended coal with up to 40% Indiana coal in a non-recovery oven to produce pyrolysis gas that can be selectively extracted and used for various purposes including the production of electricity, liquid transportation fuels, fertilizer, and hydrogen. Since Indiana coal is less expensive than conventional metallurgic coals, coking coal costs, when made in Indiana, would be significantly reduced. This cost reduction is estimated to be up to 15%.

The Calumet process would increase jobs in the states coal region and reduce the cost of coke in the steel making industry, while reducing air emissions in Indiana's northwest region (Table 9.2.1). The process allows for a third of the coal used to make coke to be

Indiana coal. Currently a total of 6.1 Million tons of eastern coal is shipped into Indiana to produce coke. It is possible for 2.1 Million tons of Indiana coal to substitute for 2.8 Million tons of the expensive imported eastern coal. The Calumet technology/process being developed has potential to:

- Reduce regional air emissions
- Reduce cost of producing steel
- Add employment to both Northwest and Southwest portions of the state
- Connect Port of Indiana at Burns Harbor with the Port of Indiana at Mt. Vernon
- Retain Energy Capital

Table 9.2.1. Increased Indiana Coal Production

Indiana coal to make coke	2.1 Million tons
NiSource coal replacement	6.8 Million tons
TOTAL coal replacement	8.9 Million tons
Coal Mine Employment to produce 8.9 Million tons of coal	742 workers
Ancillary employment	2,967 workers
Total potential annual economic activity	$530.3 Million
Estimated cost of the Indiana/Illinois eastern border rail line	$ 50.0 Million

Source [9.4]

Coke costs have been fluctuating (Figure 9.2.2) and, while in January 2004 it was priced at $60/ton, it then rose to $420/ton in March 2004. In September 2004 it was back to $220/ton.

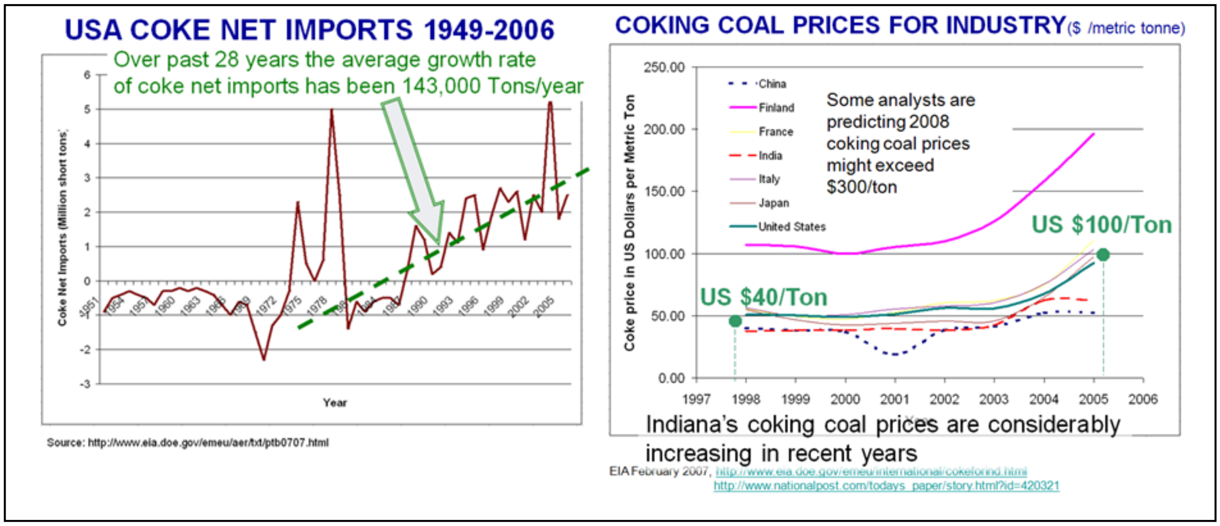
Indiana is home to roughly 22% of the domestic base steel production for the United States. A 2005 forecast indicated that the U.S. would produce 11,500,000 net tons of coke, but would require 17,000,000 net tons for blast furnace, foundry, and related uses. In Indiana at present no state mined coal 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. Essentially all of the coal used for coke production in Indiana's steel industry is imported from outside of Indiana.

The Calumet project considers the suitability of and potential processes for using Indiana coal for the production of coke in a mine mouth or local coking/gasification-liquefaction process. Such processes involve multiple value streams that reduce technical and economic risk. Initial results indicate that it is possible to use blended coal with up to 40% Indiana coal in a non recovery coke oven to produce pyrolysis gas that can be selectively extracted and used for various purposes including the production of electricity and liquid transportation fuels and possibly fertilizer and hydrogen.

The significant shortfall of needed coke has placed an enormous strain on Indiana's steel industries. The initial Calumet project results provide a partial resolution and/or mitigation of this import dependence problem through using Indiana coal in a mine mouth or local, 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.

The general conclusion of this study is that it is possible to use a blend of Indiana and conventional metallurgical coal to produce coke for use in various industrial applications. In addition, there is also potential to also use gas produced in the coking process for a variety of purposes including production of electricity, liquid transportation fuel, fertilizer, and hydrogen. The next steps in this effort entail additional laboratory testing of Indiana coals in conjunction with process design efforts. In addition, computer and process models for the evaluation of coal blending schemes and initial system designs for coking, liquid fuel, and fertilizer production should be further developed.

Figure 9.2.2. Increased U.S. Dependence on Coking Coal Imports & Increasing Prices



One key issue in blast furnace iron making is the strength of the coke (Table 9.2.2). The coke produced from Indiana coal has less strength than coke produced from current metallurgical coal sources and consequently is smaller in size. This means that it will be used in upper portions of the blast furnace.

Preliminary laboratory tests of several Indiana coals were conducted to determine the suitability of Indiana coal for purposes of producing liquid transportation fuels, fertilizer, and hydrogen as part of the coke production process. As the temperature of the coal was increased in the coke production process pyrolysis gas of varying composition was released. It is anticipated that portions of this gas will be gathered from the coke process at specific temperature ranges with the proper composition for the production of liquid transportation fuels, fertilizer, and hydrogen. Figures 9.2.3 and 9.2.4 show the test results of the gas composition from various Indiana coal sample at different temperatures.

Table 9.2.2. 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

Source

Major results from the CCTR sponsored study indicate:

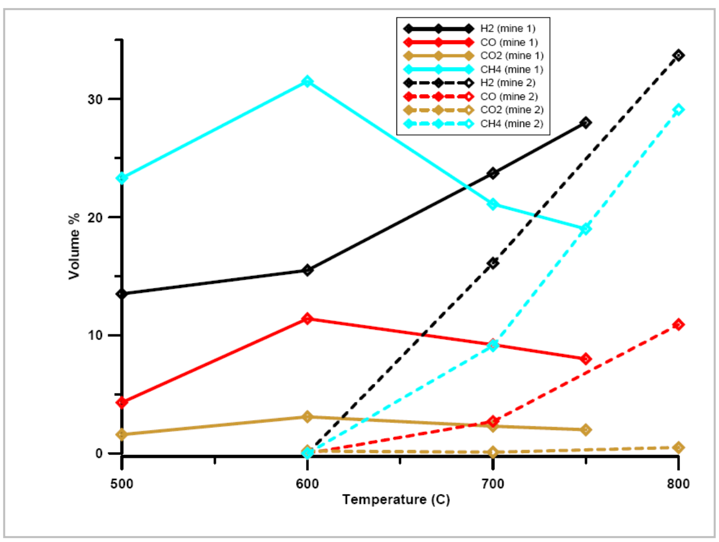
1) A mixture of Indiana Brazil Seam or potentially other Indiana coals, as previously identified by the Indiana Geological Survey, could be blended with other coals to meet metallurgical coke quality and emissions requirements.

2) There is considerable interest in the coal and steel industry to consider establishing a coke production process at an Indiana coal mine or steel facility. 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 could 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. Issues regarding the availability of transportation need to be considered before a final recommendation on location can be made.

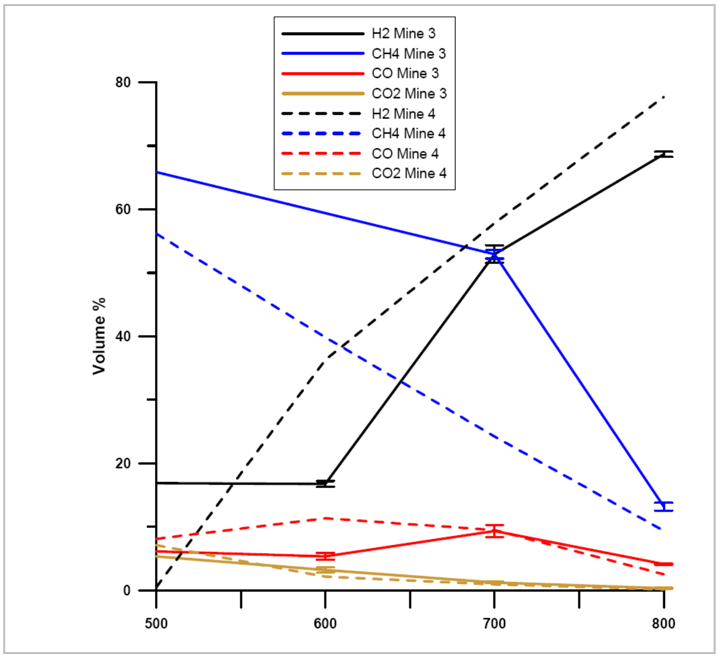
4) Results indicate that it is highly likely that a coking/coal gasification process can be developed that would produce metallurgical grade coke using 20%+ Indiana coal and, at the same time, would produce a byproduct gas stream that would be usable in a cogeneration facility for the production of electricity to be sold in the electric market. By using a new blending approach that optimizes coke properties and pyrolysis gas composition it is possible to increase the percentage of coke produced from Indiana coal blended with coke from other coals in blast furnace operations.

Figure 9.2.3. Gas Composition vs. Temperature



Source [9.4]

Figure 9.2.4. Gas Composition vs. Temperature



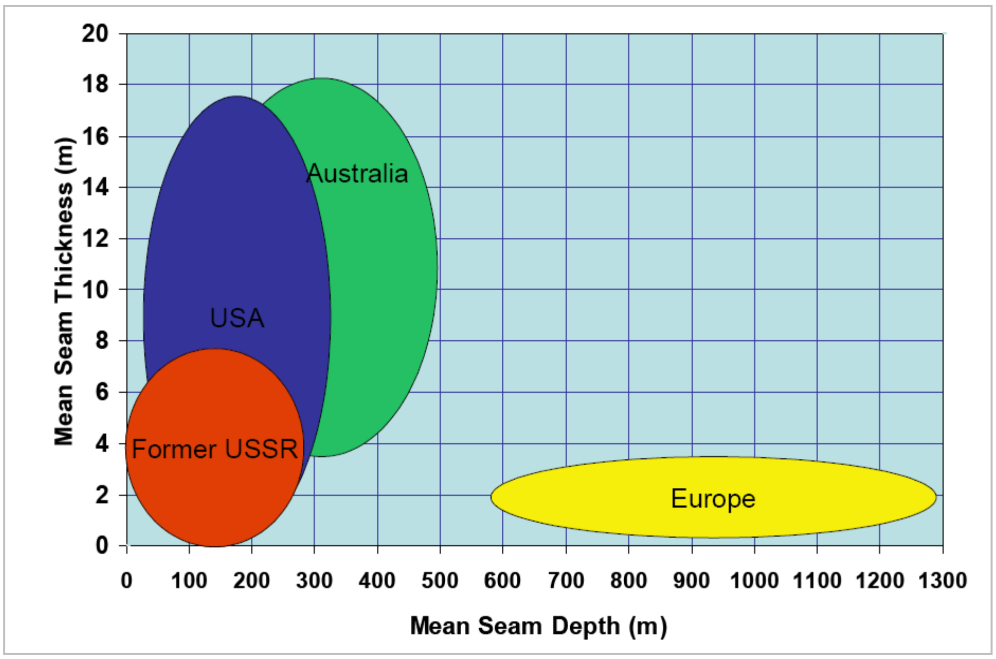
Source [9.4]

Preliminary results indicate that is possible to utilize the pyrolysis gas generated from a coke oven feed with a blend of Indiana and other coal to produce electricity, liquid transportation fuels by means of a Fischer-Tropsch process, fertilizer, and hydrogen. It may be possible to enhance this process with nano catalysis technology. There are also indications that it may be possible to isolate carbon dioxide from the process and use it to produce a marketable chemical product with nano catalysis technology. Indiana's steel and foundry industries are major employers, as well as significant sources of revenue to the state in the form of taxes. The Calumet coke making process will 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 while simultaneously reducing emissions.

9.3 Underground Coal Gasification (UCG)

In 2008 CCTR sponsored a project to identify criteria for potential underground coal gasification (UCG) sites in Indiana. The UCG process has been considered in various countries over recent decades. The two initial variables to be considered in the process are the seam depth and thickness. These two variables fall within various ranges depending on the geographic location. In the U.S. the trend is with shallower depths and a wide range of thicknesses while in Europe the seams are much deeper and the seam thickness much smaller (Figure 9.3.1). The Angren plant in the Former Soviet Union holds the record for being the longest operational UCG site in the world.

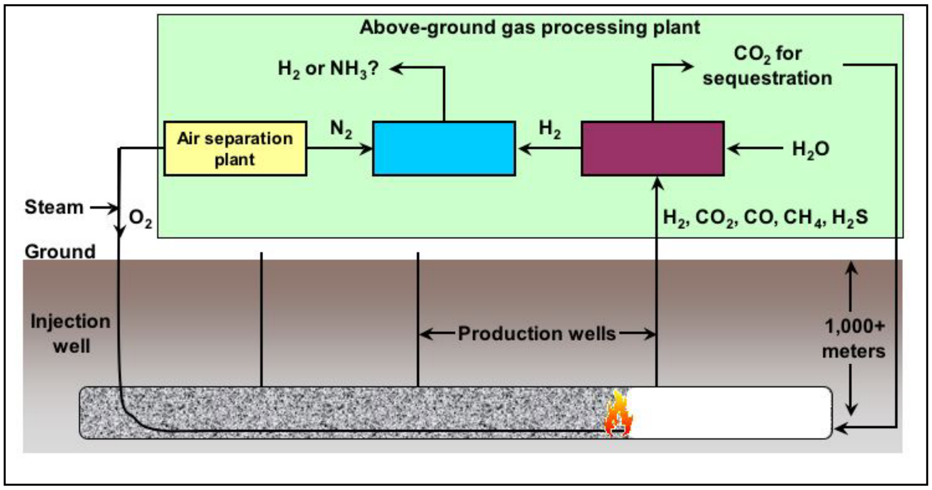
Figure 9.3.1. UCG Test Sites Around the World – Coal Seam Depths & Thicknesses



Taking into account both UCG experience and geological characteristics of Indiana coals, the thickness of coal seam is recommended to be used as the first criterion. After determination of sites with different thickness-based suitability, depth and other criteria will be considered. After selection of potential UCG sites, additional analysis will be required, which may include thermodynamic calculations to estimate composition and heating value of the product gas for different depths and other conditions, as well as estimates of availability for specific applications. Ultimately, an economic analysis, including capital, operational and environmental costs, will need to be conducted; this, however, is beyond the scope of the current project.

This is being done through a partnership between the Purdue University School of Chemical Engineering and the Indiana Geological Survey. For the UCG process to be effective the most critical decision is in site selection. The geology of the coal seam must be just right with an appropriate thickness, depth and rank characteristics. The process consists of an injection well and a production well (Figure 9.3.2). Two major processing issues involve the connection of the two wells and then the control of the UCG process.

Figure 9.3.2. The Underground Coal Gasification Process



The underground coal gasification (UCG) process has great advantages over surface coal gasification such as lower capital investment costs (due to the absence of a manufactured gasifier), no handling of coal and solid wastes at the surface (ash remains in the underground cavity), no human labor underground, minimum surface disruption, and the direct use of water and feedstock "in place". In addition, cavities formed as a result of UCG could potentially be used for CO_2 sequestration. The UCG process, however, has potential problems that must be addressed before commercialization can occur. They include difficulties in linking the injection and production wells, insufficient and varying thicknesses of coal seams, variation of product gas composition, groundwater pollution, potential subsidence and a lower heating value of the produced gas as compared with coal when combusted (which may make it uneconomical to transport over long distances). Several issues will need addressing in designing a UCG facility (Table 9.3.1).

Linking the injection and production wells will be affected by the coal's permeability or fractures in the seam. If the coal seam has low permeability then a linkage technology will be needed. Porosity and permeability of the coal seam are important factors, but difficult to use as factors for site selection because of scarcity of this type of data. Better cleated and more permeable seams make it easier to link the injection and production wells, and this increases the rate of gasification by making reactant transport easier. Conversely higher porosity and permeability increases the influx of water and product gas losses. After testing different methods for linking the injection and production wells, relatively inexpensive technologies could be developed, such as hydraulic fracturing of the coal seam by pressurized air (or water) and the so-called reverse combustion (ignition near the production well and countercurrent flame propagation). It should be noted that in the 1990s, advanced methods for directional underground drilling were developed in the oil and gas industries, which may now successfully compete with these older processes/ technologies.

Table 9.3.1. Factors Affecting UCG Design

- Coal seam geology
  - Thickness, depth and dip
  - Permeability to gas, liquid
- Coal properties
  - Rank (ash, volatile, carbon content)
  - Chemical composition (hydrogen, sulphur)
- Strata/overburden properties
  - Geology
  - Hydrology
  - Geomechanics
  - Drilling properties
- Operating conditions
  - Injection composition and flow rate
  - Operating pressure
  - Well layout
- Product gas
  - Required volume
  - Composition, calorific value
  - Flow rate
- Process efficiency
  - Thermal
  - Chemical
  - Resource recovery
- Interaction with the environment
  - Thermal
  - Chemical
  - Resource recovery
  - Subsidence effects

The thickness, depth, and character of coal seams can be determined from geological data. Available information on the minimum seam thickness for UCG is contradictory. Some reports indicate an optimal thickness should be more than 30 feet, and if working with the thick seams of Wyoming's Powder River Basin then this could be reasonable [3.10]. Other experts claim that UCG can be used at thicknesses as low as 0.5m [3.11]. The UCG work in the Former Soviet Union showed that the heating value of the produced gas decreases significantly with decreasing the coal thickness below 2m (Figure 9.3.3). The literature analysis allows us to make recommendations for selection of Indiana coals based on the coal seam thickness, and are shown in Table 9.3.2.

Figure 9.3.3. Heat Content & Seam Thickness

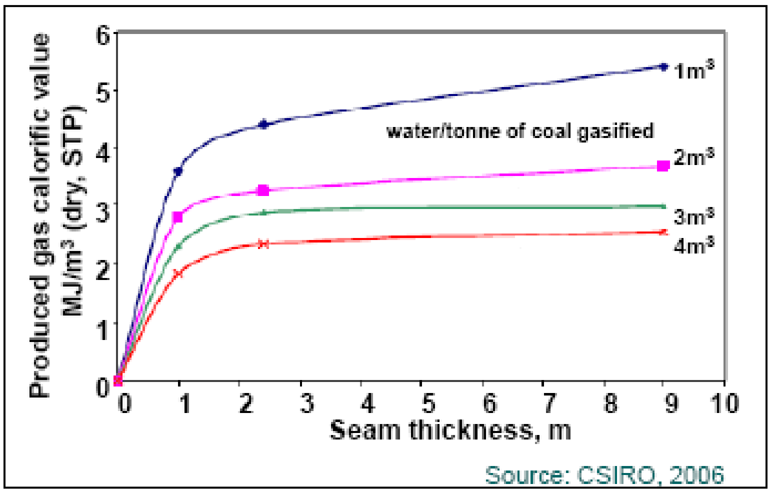


Table 9.3.2. Recommended Seam Thickness Criteria for Selection of Indiana Coals

Thickness	Suitability
> 2.0 m	high
1.5 – 2.0 m	medium
1.0 – 1.5 m	low
< 1.0 m	unacceptable

The coal seams in Indiana are mainly relatively thin (<1.5m). For this reason, thickness is recommended as the first criterion to be used in the selection process. This will significantly reduce the amount of coal that has to be further evaluated using other criteria. Of the seven major coal seams present in Indiana, only the Seelyville and Springfield Coals have a significant quantity of sufficiently thick sites (>1.5 m) to be considered for assessment of UCG potential [3.15]. Thus, the Purdue selection process will focus on these two coal beds. In conjunction with calculating those portions of these two seams that meet the thickness screening criteria, the associated tonnages of these thick contiguous blocks of coal must be determined. Note that the heating value of the produced gas can be increased by oxygen enrichment of the injected air. This was demonstrated in the Lisichansk UCG station where cheap oxygen was available as a byproduct of inert gas production [3.17]. Use of steam and O_2 injection increased the heating value of the fuel gas to 10-12 MJ/m^3 (268-322 Btu/cuft) [3.16]. Although the use of oxygen increases costs, it can remain economically feasible.

The depth varied from 30 to 350 m in the Former Soviet Union (FSU) developments and US experiments, while much deeper coals (600-1200 m) were gasified in Western European trials. The Lawrence Livermore National Laboratory (LLNL) experts indicate that the minimum depth should be 12m [3.14]. The Indiana Geological Survey has used 200 feet (~60 m) as the maximum depth for surface mining. Taking into account the lower cost of surface mining compared with underground mining, and assuming that use of this technology will be continued, it is reasonable to expect that coals with depth in the range from 12 to 60 m have low suitability for UCG in Indiana. Depths more than 300m require more complicated and expensive drilling technologies, but this also has advantages such as minimized risk of subsidence and the possibility to conduct the UCG process at higher pressure, which increases the heating value of the produced gas. Also, deeper seams are less likely to be linked with potable aquifers, thus avoiding drinkable water contamination problems. Finally, if the product gas is to be used in gas turbines, additional compression may not be necessary. To decrease the risk of subsidence it is recommended to go to depths >200 m [3.18]. It is also possible to avoid subsidence at lower depths if the overburden rocks have high yield strength. These considerations are summarized in Table 9.3.3.

Table 9.3.3. Recommended Seam Depth Criteria for Selection of Indiana Coals

Depth	Suitability
> 200 m	high
60-200 m high yield strength of overburden rocks	medium
60-200 m low yield strength of overburden rocks	low
< 60 m	unacceptable

For the coals of the same rank, the higher the heating value of coal, the higher the heating value of the UCG gas. Thus, if other characteristics are identical, coals with higher heating value are advantageous. As ash content increases over 40% there is a steady reduction however in the UCG heat value Indiana coals are characterized by high-volatile bituminous rank and have relatively high heating value, which makes them attractive for UCG (Figure 9.3.4). Although the heating value of Indiana coals is lower than that of the Appalachian Basin, it compares favorably with western coals, for example, Powder River Basin coals which were evaluated recently for UCG [3.13, 3.15].

Figure 9.3.4. Heat Content & Ash Content

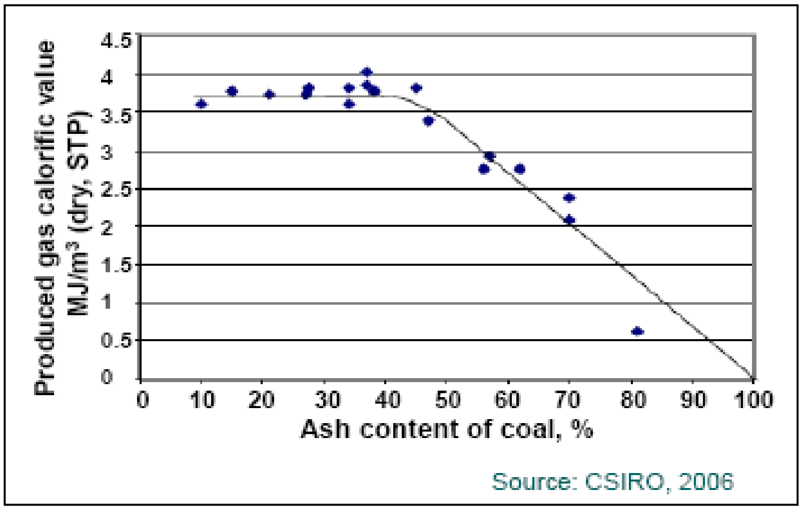
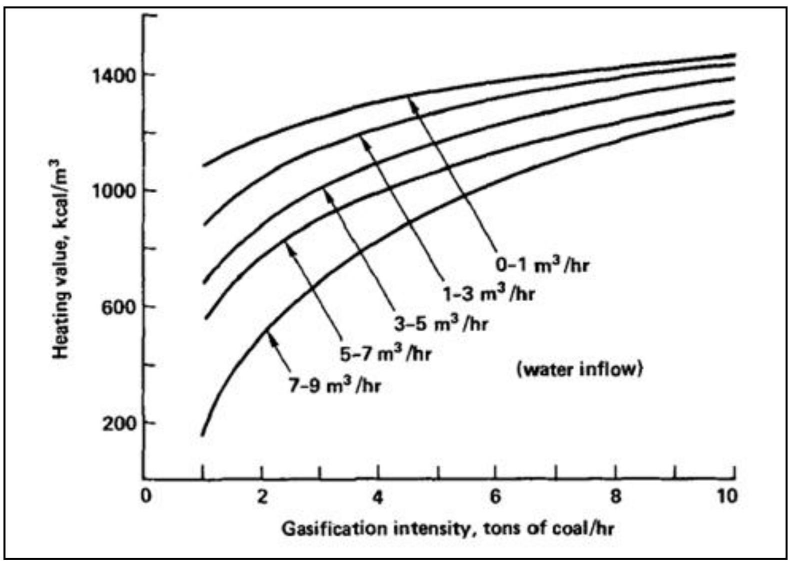


Figure 9.3.5. UCG Product Gas Heating Value, Water Inflows & Gasification Intensity



Source:

Water is an essential component of UCG process, and its presence within a coal seam and its proximity are important characteristics. Groundwater can be protected by conducting the UCG process at pressures below hydrostatic pressure and using the water that exists within the coal seam when total dissolved solids content is greater than 10,000 ppm. The neighboring rocks should contain saline formations (non-potable aquifers). One may think that it is desirable to have a lot of water near the coal seam to provide sufficient water supply to the UCG reactor zone. The UCG experience shows, however, that usually the problem is that there is too much water (in both the coal itself and near the seam), which leads to lower heating value of the produced gas (Figure 9.3.5). Thus, it is desirable to select coals with relatively low moisture content, located far from abundant water reserves. Often, drying is recommended as preparation to UCG and also to use coal seams with no overlying aquifers within a distance of 25 times the seam height [3.12]. Trials have been successfully carried out in seams in closer proximity to aquifers, but the potential risk of contamination is increased.

To control the product gas composition, the process parameters (e.g., injection pressure and flow rate, oxygen concentration) can be adjusted following real-time surface measurements. Probably, the most important result of prior UCG work in the US is the development of the Continuous Retraction Injection Point (CRIP) process by investigators of the Lawrence Livermore National Laboratory (LLNL) [3.18]. In the CRIP process, the production well is drilled vertically, and the injection well is drilled using directional drilling techniques so as to connect to the production well (Figure 9.3.2.). Once the channel is established, a gasification cavity is initiated at the end of the injection well in the horizontal section of the coal seam. The CRIP technique involves the use of a burner attached to coiled tubing. The device is used to burn through the borehole casing and ignite the coal. The ignition system can be moved to any desired location in the injection well. The CRIP technique enables a new reactor to be started at any chosen upstream location after a declining reactor has been abandoned. Once the coal near the cavity is used up, the injection point is retracted (preferably by burning a section of the liner) and a new gasification cavity is initiated. In this manner, a precise control over the progress of gasification is obtained. The CRIP technique has been used in the Rocky Mountain 1 trial and in the later trial in Spain.

It has been suggested that UCG may work better on lower ranks coals because they tend to shrink upon heating, enhancing permeability and connectivity between injection and production wells [3.14]. It has also been suggested that the impurities in lower rank coals improve the kinetics of gasification by acting as catalysts for the burn process. Also, it is often recommended that coals should not exhibit significant swelling upon heating. In general reverse combustion works well in shallow non-swelling coal but this is not recommended at great depths with swelling coals. The FSU methods demonstrated minimum sensitivity to coal swelling. Large dimensioned channels were formed in the linkage process and were not likely to be plugged by coal swelling. Areas of seams that are free of major faulting in the vicinity (>45 m) of the proposed gasifier, and which could potentially provide a pathway for water inflow or gas migration, should be preferentially targeted [3.12].

Some reports indicate shallow dipping seams are preferable [3.12]. Such seams facilitate drainage and the maintenance of hydrostatic balance within the gasifier, and minimize potential damage to the down dip production well from strata movements associated with UCG. Others recommend angles of 0-20 degrees and Indiana coals are placed mainly within this range [3.13]. UCG has been successfully carried out in both shallow and steeply dipping seams and so it appears that the angle of the dip is not such a critical criteria for the selection of a UCG site.

Transportation costs can be decreased by the optimum selection of potential UCG sites and by construction of power-generating or chemical plants near the UCG locations. Long-distance transportation of this gas is economically inefficient. The best way is to use it (for power generation or for conversion to other products) is near the UCG site, preferably not farther that 25-30 km (15-20 miles) [3.17]. This should be an important factor in the selection of UCG sites in Indiana.

There are now a number of sets of selection criteria for UCG: the criteria from the U.S. for 1982 (Table 9.3.4), Australia's CSIRO (Table 9.3.5, Commonwealth Scientific and Industrial Research Organization), and the United Kingdom (Table 9.3.6, National Coal Board 1976).

The U.S. criteria is the most specific of these sets providing minimum distances and specific dimensions for the various factors that affect implementation of the process. The U.S. criteria recommend a seam thickness of at least 0.6m but in the instance of Australia a much greater value of 5m is recommended. Australia recommends using coals with less than 40% ash while the other two criteria sets do not specify ash at all. The US criteria recommend at least 3.5 Million Tons of reserves and in the UK it is 5 Million Tons. These sets of criteria are certainly applicable to specific locations based upon regional experiences. The geology and coal characteristics most similar to those found in Indiana will be the most valued.

Table 9.3.4. U.S. UCG Site Selection Criteria, Williams 1982

- Seam thickness greater than one metre or 0.6 m for steeply dipping seams
- Avoid variable thickness seams
- Avoid seams with variable partings
- Avoid seams with overlying coal within 15m that is thicker than 0.6 m
- Minimum of 3.5 Mt in resource
- Minimum overburden of 100m
- Minimum of 1.6 km from populated areas (>100 people)
- Minimum distance of 0.8 km from major faults
- Minimum distance to oil and gas recovery development of 1.6 km
- Minimum distance of 0.4 km from major highways and rail
- Minimum distance of 1.6 km from rivers and lakes
- Minimum distance of 3.2 km from active mines
- Minimum distance of 1.6 km from abandoned mines

Other notes

- Steeply dipping (>30°) seams favoured due to lack of mining interest
- Floor and roof conditions need be examined

Table 9.3.5. CSIRO UCG Site Selection Criteria

- Seam thickness greater than five metres
- Coal ash less than 40% (air dried basis)
- Seem dip less than 20°
- Seam depth 200-400 metres
- Minimal faulting and no dips/sills
- Roof thermally stable with minimal permeability, preferably structured to encourage even caving
- Hydraulic head > 200m
- Adjacent aquifers can contain poor quality water and are of minimal permeability

Other notes

- Limited human activities in the vicinity
- No waterways overlying the site
- Subsidence must be acceptable at location
- Coal resource size suitable for long term operation

Table 9.3.6. U.K. UCG Site Selection Criteria
National Coal Board 1976

- 5 Mt of coal in resource to provide 20 years of operation
- Not marked for conventional mining
- Not adjacent to working mines
- Removal will not cause unacceptable subsidence
- Seam thickness at least one metre or banded seam totals over one metre
- Ash content less than 60% including any dirt bands as combustion may be impeded
- Area free of excessive faulting

Other notes

- Leakage may be excessive if adjacent to old mine workings or in a faulted area
- Impact of faulting and roof material on operation largely unknown
- Progress and control of multi-seam operations

9.4 References

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[9.5] Brian H. Bowen, Forrest D. Holland, F.T. Sparrow, Ronald L. Rardin, Douglas J. Gotham, Zuwei Yu, Anthony F. Black. "EXPANDING THE UTILIZATION OF INDIANA COAL." Center for Coal Technology Research, Purdue University, 2004, page 20

[9.6] "A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure", Brady/Pfitzer, Center for Coal Technology Research, Purdue University North Central, March 2007

[9.7] GastTech (2007) Viability of Underground Coal Gasification in the "Deep Coals" of the Powder River Basin, Wyoming, Prepared for the Wyoming Business Council Business and Industry Division State Energy Office, Casper, WY

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Appendix 1

CCTR Research Reports

2008 Final Reports

Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle (IGCC) Performance ~ Maria Mastalerz, Agnieszka Drobniak, John Rupp and Nelson Shaffer, Indiana Geological Survey (November 2008). [Appendices 4, 5, 6, 7, 8 and "FINAL85 Figures" are the six extra files that constitute the IGS CCTR Nov 2008 Final Report. Appendices 1, 2, 3, and 9 are additional files that are not part of this CCTR Nov 2008 Final Report.]

The 2008 Forecast of Indiana Coal Production & Use ~ F.T. Sparrow, F.T. Sparrow & Associates (July 2008)

Coal Gasification and Liquid Fuel - An Opportunity for Indiana ~ Science Applications International Corporation (July 2008)

Evaluation of the Environmental Requirements to Construct and Operate a Coal-To-Liquids Plant ~ Science Applications International Corporation (February 2008)

Synfuel Park/Polygeneration Plant: Feasibility Study for Indiana ~ Paul V. Preckel and Zuwei Yu, Purdue University; John A. Rupp and Fritz H. Hieb, Indiana Geological Survey (Revised June 26, 2008)

2008 Interim Reports

The Potential for Underground Coal Gasification in Indiana, Phase I Report ~ *Shafirovich, Mastalerz, Rupp, and Varma,* August 31, 2008

The Potential for Underground Coal Gasification in Indiana, Phase II Report ~ *Mastalerz, Drobniak, Rupp, Shafirovich, and Varma,* December 1, 2008

2007 Final Reports

Investigating the Production and Use of Transportation Fuels from Indiana Coals ~ *Ribeiro et al., Purdue University*, March 1, 2007

A Feasibility Study for the Construction of a Fischer-Tropsch Liquid Fuels Production Plant with Power Co-Production at NSA Crane (Naval Support Activity Crane) ~ *CCTR, SUFG, and IGS,* May 31, 2007

A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure ~ *Thomas F. Brady and Chad M. Pfitzer*, *Purdue University,* May 2007

Reconnaissance of Coal-Slurry Deposits in Indiana ~ *Denver Harper, Chris Dintaman, Maria Mastalerz, and Sally Letsinger, Indiana Geological Survey, Indiana University,* August 2007

Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke, Liquid Transportation Fuels, Fertilizer, and Bulk Electric Power (Phase II) ~ *Robert Kramer, Purdue University Calumet,* September 30, 2007

2006 Indiana Coal Report

Marty W. Irwin, Brian H, Bowen, Barbara J. Gotham, F.T. Sparrow, Maria Mastalerz, Ronald L. Rardin, Zuwei Yu, Robert Kramer

2006 Interim Reports

Potential for Fine Coal Recovery from Indiana's Coal Settling Ponds ~ *R.E. Mourdock & Associates LLC*

A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure" ~ *Thomas F. Brady and Chad M. Pfitzer*

Investigating the Production and Use of Transportation Fuels from Indiana Coals ~ *F.T. Sparrow, et al.*

2005 Interim Reports

"Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle Performance; Analysis of the existing data and proposal of new research" ~ *Maria Mastalerz, Indiana Geological Survey*

"Factors that Affect the Design and Implementation of Clean Coal Technologies in Indiana" ~ *Ronald L. Rardin, Purdue Energy Modeling Research Groups*

"Development of Coking / Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Bulk Electric" ~ *Robert Kramer, Energy Efficiency & Reliability Center, Purdue Calumet*

2005 Final Reports

"Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle Performance; Analysis of the existing data and proposal of new research" ~ *Maria Mastalerz, Indiana Geological Survey*

"Factors that Affect the Design and Implementation of Clean Coal Technologies in Indiana" ~ *Ronald L. Rardin, Purdue Energy Modeling Research Groups*

"Development of Coking / Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Bulk Electric" ~ *Robert Kramer, Energy Efficiency & Reliability Center, Purdue Calumet*

Special Reports & Papers

CTI & FT Fuels at NSA Crane Feasibility Study ~ Marty W. Irwin and Brian H. Bowen, CCTR

"Sustainable Fuel for the Transportation Sector" ~ Proceedings of the National Academy of Sciences

"Expanding the Utilization of Indiana Coals" ~ Brian H. Bowen, Forrest D. Holland, F.T. Sparrow, Ronald Rardin, Douglas J. Gotham, Zuwei Yu, Anthony F. Black

"Characterization of Indiana's Coal Resource; Availability of the Reserves, Physical, and Chemical Properties of Coal, and Present and Potential Uses" ~ Maria Mastalerz, Agnieszka Drobniak, John Rupp, and Nelson Shaffer - Indiana Geological Survey, Indiana University, 611 North Walnut Grove, Bloomington, IN 47405-2208

Appendix 2

CCTR Guest Speaker Presentations

"Coal Transportation in Indiana," Keith Bucklew, Indiana Department of Transportation, Freight Mobility, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Business, Energy & the Environment: Fighting the Good Fight," Frank Maisano, Bracewell & Giuliani LLP, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Ports of Indiana: Connecting Indiana to the World," Jody Peacock, Ports of Indiana, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal Gasification in Indiana: Solutions for a Low Carbon Footprint Environment," Christopher Peters, CHOREN USA, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal and the Economy," Robert W. Shanks, Arch Coal Inc., presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"CO2 Transportation," Ken Havens, Kinder Morgan Energy Partners, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"Kentucky Carbon Sequestration Activities and the National Research Council Recommendations for Coal Research Priorities," James Cobb, Kentucky State Geological Survey, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"A Regional Concept for a CO2 Pipeline Network," Klaus Lambeck, Ohio Siting Authority, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"EOR: The Economically Viable CCS Solution," Denbury Resources, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"The Anatomy and Evolution of U.S. Climate Change Bills in the U.S. Senate," Ken Richards, School of Public & Environmental Affairs, Indiana University, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"CHOREN Industries Company Presentation," Christopher Peters, CHOREN USA, Houston, TX, seminar at Purdue University hosted by CCTR and the Energy Center, West Lafayette, IN, May 12, 2008.

"CO2 Capture from Existing Coal-Fired Power Plants," Jared Ciferno, National Energy Technology Laboratory, Pittsburgh, PA, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Carbon Management & Underground Coal Gasification," S.J. Friedmann, Lawrence Livermore Laboratory, Livermore, CA, presented at the CCTR Advisory Panel Meeting, West Lafayette, IN, December 11, 2007.

"An Overview of Clean Coal Research at CAER," Donald Challman, Center for Applied Energy Research (CAER), University of Kentucky, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Illinois Clean Coal Research," R.H. Carty, Illinois Clean Coal Institute, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Indiana's New Air Quality Rules for Utilities," Kathryn Watson, Office of Air Quality, IDEM, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Indiana Coal to SNG," John Clark, Director, Indiana Office of Energy and Defense Development, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"The Role of Fischer Tropsch Fuels for the US Military," William E. Harrison III, Air Force Research Laboratory, Wright-Patterson AFB, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"The Case for IGCC," Kay Pashos, President, Duke Energy Indiana, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Clean Coal Gasification, F.T. Process Design and Implementation," Michael Reed, Systems Analyst, Office of Systems, Analyses, and Planning, Office of Fossil Energy, National Energy Technology Laboratory, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Clean Coal and Co-Production Potential," Tom Lynch, Chief Engineering, ConocoPhillips, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"OSD Clean Fuel Initiative and the Air Force," Theodore K. Barna, Assistant Deputy Under Secretary of Defense, Advanced Systems and Concepts, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Air Pollution Implications of Coal Based Gas-To-Liquid Transportation Fuels," Evan J. Ringquist, School of Public and Environmental Affairs, Indiana University, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Ohio Coal Research Consortium," David J. Bayless, Ohio University, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"Ohio ... A Leader in Clean Coal Research, Development & Deployment," Bob Brown, Ohio Coal Development Office, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"The Illinois Clean Coal Institute, ICCI - Mission, Organization, Priorities, and Future Activities," Ronald H. Carty, ICCI Director, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

"Illinois Coal Research Program," Francois Botha, ICCI, presented to CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Appendix 3

CCTR Staff Presentations

"A Review & Future of Underground Coal Gasification," Brian H. Bowen, CCTR, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"CO2 and Indiana's Infrastructure: Turning Problems into a Resource," Marty W. Irwin, CCTR, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Underground Coal Gasification (UCG)," Brian H. Bowen, presented to Heritage Research Laboratory, Indianapolis, October 21, 2008.

"Now Is the Time, Indiana Is the Place," Marty W. Irwin, Director, CCTR, presented to the Indiana State Department of Agriculture, July 15, 2008.

"Now Is the Time, Indiana Is the Place," Marty W. Irwin, Director, CCTR, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"Coal Gasification ... Now is the Time ... Indiana is the Place," B. Bowen and M. Irwin, Indiana Center for Coal Technology Research, presented at the TATA Chemicals Innovation Centre Visit, Purdue University, West Lafayette, IN, May 22, 2008.

"Indiana's Stake in the CO2 Control Debate," M. Irwin, Director, Indiana Center for Coal Technology Research, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"CCTR & Indiana's Clean Coal Initiative," B. Bowen, Indiana Center for Coal Technology Research, presented at the ASME Central Indiana Section meeting, Indianapolis, IN, January 16, 2008.

"Center for Coal Technology: Why We Are Here," M. Irwin, Director, Indiana Center for Coal Technology Research, presented at the CCTR Advisory Panel Meeting, West Lafayette, IN, December 11, 2007.

"Indiana Coal is Economic Development," M. Irwin, CCTR, presented at the Indiana Society of Mining and Reclamation (ISMR) meeting, Jasper, IN, December 4, 2007.

"Project Development in Indiana," Brian H. Bowen, Purdue University, presented at The Promise of Coal Gasification Conference, John A. Logan College, Carterville, IL, September 18, 2007.

"Indiana Coal is Economic Development," M. Irwin, CCTR, presented at the Energy Summit for Southwestern Indiana, Evansville, IN, August 30, 2007.

"Indiana's Growth and Coal Development: Minerals matter," M. Irwin, CCTR, presented at the National Minerals Education Conference, Bloomington IN, June 25, 2007.

"Synfuel Park for NSA Crane Feasibility Study," M. Irwin and B. Bowen, CCTR, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Challenges of U.S. Energy Goals: Determinism, Stewardship, Technology," Brian Bowen, presented at The Richard G. Lugar Symposium for Tomorrow's Leaders, University of Indianapolis, December 9, 2006.

"Indiana Coal is Economic Growth," Marty W. Irwin, presented to the Indiana Coal Council, Indianapolis, December 7, 2006.

"The Future of Illinois Basin Coal Feedstock," F.T. Sparrow, presented to the Indiana Society of Mining and Reclamation, Jasper IN, December 5, 2006.

"Future U.S. Energy Supplies," Brian H. Bowen, presentation at Huntington University, Huntington IN, November 21, 2006.

"Coal Essentials for the Future," Marty W. Irwin, Director, CCTR, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"2006 Activities Update," Marty Irwin, CCTR Director, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"CCTR Activities in 2006," Marty Irwin, Director, CCTR, Energy Center at Discovery Park, Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

"The 2005 Energy Policy Act Illinois Basin Coal Indiana Perspective," Marty W. Irwin, Director, Center for Coal Technology Research, Purdue University, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"The Future of Indiana Coal," F.T. Sparrow presentation to the Indiana Chamber of Commerce, Energy Committee, Indianapolis IN, October 30, 2005.

"Indiana Center for Coal Technology Research, Round 2 Research Topics, 2005," CCTR Staff Presentation, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

"Activities of the Center Technology Research; 2002 to Present," F.T. Sparrow presentation to the Indiana Energy Association, Indianapolis IN, November 30, 2004.

Appendix 4

CCTR Presentations by Topic

Clean Technology and Economics

"Steel Production and the Industrial Economy," Eric Knorr, ArcelorMittal, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Development of a Multipurpose Coke Plant for Synthetic Fuel Production," Robert Kramer, Purdue University Calumet, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal Opportunities, Economic Strength and Environmental Protection," Robert Kramer, Purdue Calumet, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Business, Energy & the Environment: Fighting the Good Fight," Frank Maisano, Bracewell & Giuliani LLP, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal Gasification in Indiana: Solutions for a Low Carbon Footprint Environment," Christopher Peters, CHOREN USA, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Oxy-Fuel Coal Combustion," Steve Son et al., Purdue School of Mechanical Engineering, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Measuring the Contribution of Coal to Indiana's Economy," F.T. Sparrow, F.T. Sparrow & Associates, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Indiana/Crane Energy Project," Steven Gootee, SAIC, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"CO2 Capture from Existing Coal-Fired Power Plants," Jared Ciferno, National Energy Technology Laboratory, Pittsburgh, PA, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Clean Coal Technologies," Paul Preckel and Zuwei Yu, Purdue University, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"CO_2 Sequestration and Indiana Site Selection," John A. Rupp, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)," John A. Rupp, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)," John A. Rupp, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Synfuel Park Feasibility Study," Ronald L. Rardin, Purdue Energy Modeling Research Groups, Purdue University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"The Case for IGCC," Kay Pashos, President, Duke Energy Indiana, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Factors that Affect the Design & Implementation of Clean Coal Technologies in Indiana: Phase 2 - Feasibility Studies," Ronald L. Rardin and Zuwei Yu, Purdue Energy Model Research Groups, Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

"Clean Coal Gasification, F.T. Process Design and Implementation," Michael Reed, Systems Analyst, Office of Systems, Analyses, and Planning, Office of Fossil Energy, National Energy Technology Laboratory, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Clean Coal and co-Production Potential," Tom Lynch, Chief Engineering, ConocoPhillips, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Factors that Affect the Design & Implementation of Clean Coal Technologies in Indiana," Ronald L. Rardin, Purdue Energy Modeling Research Groups, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"Factors that Affect the Design & Implementation of Clean Coal Technologies in Indiana," Ronald L. Rardin, Purdue Energy Modeling Research Groups, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Coal Bed Methane

"Coal Bed Methane (CBM) in Indiana," Tom Hite, Hite CBM Operating, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

Coal Characteristics

"Assessment of the Quality of Indiana Coals for Integrated Gasification of IGCC Performance," Maria Mastalerz et al., Indiana Geological Survey, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal and the Economy," Robert W. Shanks, Arch Coal Inc., presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Demonstrating Geological Carbon Sequestration in the Mt. Simon Sandstone of the Illinois Basin," Robert J. Finley, Illinois State Geological Survey, Champaign, IL, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Assessing the Geological Sequestration Potential in the Illinois Basin – Successes and Challenges," John A. Rupp, Indiana Geological Survey, Bloomington, IN, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Indiana Coal Characteristics," Maria Mastalerz, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)," John A. Rupp, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)," John A. Rupp, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Assessment of the Quality of Indiana Coal for Integrated Gasification Combined Cycle Performance (IGCC)," M. Mastalerz, A. Drobniak, J. Rupp, and N. Shaffer, Indiana Geological Survey, Indiana University, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"Coal Cost Reduction Using Low Rank Coals," Hardarshan S. Valia, Coal Science Inc., Highland, IN, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Assessment of the Quality of Indiana Coals for Integrated Gasification Combined Cycle (IGCC) Performance; Analysis of the Existing Data and Proposal of New Research," Maria Mastalerz, Indiana Geological Survey, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"Assessment of the Quality of Indiana Coal for IGCC Performance," Maria Mastalerz, Indiana Geological Survey, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Coal Gasification

"Coal Gasification in Indiana: Solutions for a Low Carbon Footprint Environment," Christopher Peters, CHOREN USA, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Indiana/Crane Energy Project," Steven Gootee, SAIC, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"Indiana Energy Project – CCTR Status Update," Steve Gootee, Science Applications International Corporation (SAIC), presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Clean Coal Technologies," Paul Preckel and Zuwei Yu, Purdue University, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Synfuel Park for NSA Crane Feasibility Study," M. Irwin and B. Bowen, CCTR, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Factors That Affect the Design of Clean Coal Technologies: Synfuel Park Feasibility Study," Marty W. Irwin, Paul V. Preckel, Zuwei Yu, Brian H. Bowen, and Ron L. Rardin, Energy Center at Discovery Park, Purdue University, presented at Crane Naval Weapons Support Center, Crane IN, April 12, 2007.

"Investigating the Production and Use of Transportation Fuels from Indiana Coals," Fabio Ribeiro, Chemical Engineering, Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Investigating the Production and Use of Transportation Fuels from Indiana Coals," Fabio Ribeiro, Chemical Engineering, Purdue University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Indiana Coal to SNG," John Clark, Director, Indiana Office of Energy and Defense Development, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Synfuel Park Feasibility Study," Ronald L. Rardin, Purdue Energy Modeling Research Groups, Purdue University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Synfuel Park Feasibility Study," Ronald L. Rardin, Purdue Energy Modeling Research Groups, Purdue University, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"Clean Coal Gasification, F.T. Process Design and Implementation," Michael Reed, Systems Analyst, Office of Systems, Analyses, and Planning, Office of Fossil Energy, National Energy Technology Laboratory, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

Coal Prep and Coal Fines

"Reconnaissance of Coal-Slurry Deposits in Indiana," Denver Harper, Indiana Geological Survey, Bloomington, IN, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Potential for Fine Coal Recovery from Indiana's Coal Settling Ponds," Richard E. Mourdock, R.E. Mourdock & Associates, LLC, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Development Strategies for the Utilization of Indiana's Coal Settling Ponds," Richard Mourdock, R.E. Mourdock & Associates, LLC, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

Coal for Transportation Fuels

"Coal, Steel, and the Industrial Economy: Railroads & Coal Transportation Enhancements," Thomas F. Brady, Purdue North Central, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Indiana/Crane Energy Project," Steve Gootee, Science Applications International Corporation (SAIC), presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"Indiana Energy Project – CCTR Status Update," Steve Gootee, Science Applications International Corporation (SAIC), presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Status of Liquid Fuels for the U.S. Military," M. Thom, Baere Aerospace Consulting, Inc., West Lafayette, IN, presented at the CCTR Advisory Panel Meeting, West Lafayette, IN, December 11, 2007.

"Synfuel Park for NSA Crane Feasibility Study," M. Irwin, B. Bowen, CCTR, presented at the CCTR Advisory Panel Meeting, Westville, IN, June 5, 2007.

"Investigating the Production and Use of Transportation Fuels from Indiana Coals," Fabio Ribeiro, Chemical Engineering, Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Investigating the Production and Use of Transportation Fuels from Indiana Coals," Fabio Ribeiro, Chemical Engineering, Purdue University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"The Role of Fischer Tropsch Fuels for the US Military," William E. Harrison III, Air Force Research Laboratory, Wright-Patterson AFB, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"Investigating the Production and Use of Transportation Fuels from Indiana Coals," F.T. Sparrow, Coal Transformation Laboratory, Energy Center at Discovery Park, Purdue University, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"Transportation Fuels from Coal," F.T. Sparrow, Coal Transformation Laboratory, Energy Center at Discovery Park, Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Policy Incentives to Stimulate Investment in Conversion of Coal to Liquid Fuels," Wally Tyner, Department of Agricultural Economics, Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Production Issues and Fischer-Tropsch Commercialization," Fabio Ribeiro, School of Chemical Engineering, College of Engineering; and Hilkka KenttÃ¤maa, Department of Chemistry, College of Science, Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Usage Issues and Fischer-Tropsch Commercialization," Diesel Engine Research: John Abraham (ME), Jim Caruthers (CHE); Gas Turbine Research: Steve Heister (AAE), Bill Anderson (AAE), Jay Gore (ME), Yuan Zheng (ME), Bob Lucht (ME), Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Environmental Issues and Fischer-Tropsch Commercialization," Linda S. Lee, Department of Agronomy, Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"OSD Clean Fuel Initiative and the Air Force," Theodore K. Barna, Assistant Deputy Under Secretary of Defense, Advanced Systems and Concepts, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"Planning the Coal Fuel Alliance (CFA) Response to the Obama/Lugar Amendment," Jay Gore (Interim Director, The Energy Center) and Tom Sparrow (Executive Director, Coal, The Energy Center), Purdue University, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

Coking Coal

"Development of a Multipurpose Coke Plant for Synthetic Fuel Production," Robert Kramer, Purdue University Calumet, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal Opportunities, Economic Strength and Environmental Protection," Robert Kramer, Purdue Calumet, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coking Processes with Indiana Coal," Robert Kramer, Purdue University-Calumet, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Coking/Coal Gasification Using Indiana Coal for the Production of Metallurgical Coke, Liquid Transportation Fuels, and Electric Power," R. Kramer, Purdue University, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Coking/Coal Gasification Using Indiana Coal for the Production of Metallurgical Coke, Liquid Transportation Fuels, and Electric Power," Robert Kramer, Energy Efficiency and Reliability Center, Purdue University Calumet, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Coking/Coal Gasification Using Indiana Coal for the Production of Metallurgical Coke, Liquid Transportation Fuels, and Electric Power," Robert Kramer, Energy Efficiency and Reliability Center, Purdue University, Calumet, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"Coal Cost Reduction Using Low Rank Coals," Hardarshan S. Valia, Coal Science Inc., Highland, IN, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Bulk Electric Power," Robert Kramer, Director, Energy Efficiency and Reliability Center, Purdue University Calumet, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

"Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke and Bulk Electric Power," Robert Kramer, Energy Efficiency & Reliability Center, Purdue Calumet, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"Development of Coking/Coal Gasification Concept to Use Indiana Coal for the Production of Metallurgical Coke & Bulk Electric Power," Robert Kramer, Energy Efficiency & Reliability Center, Purdue Calumet, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Emissions and Environment

"Coal Gasification in Indiana: Solutions for a Low Carbon Footprint Environment," Christopher Peters, CHOREN USA, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Oxy-Fuel Coal Combustion," Steve Son et al., Purdue School of Mechanical Engineering, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"CO2 Transportation," Ken Havens, Kinder Morgan Energy Partners, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"A Regional Concept for a CO2 Pipeline Network," Klaus Lambeck, Ohio Siting Authority, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"EOR: The Economically Viable CCS Solution," Denbury Resources, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"The Anatomy and Evolution of U.S. Climate Change Bills in the U.S. Senate," Ken Richards, School of Public & Environmental Affairs, Indiana University, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"Kentucky Carbon Sequestration Activities and the National Research Council Recommendations for Coal Research Priorities," James Cobb, Kentucky State Geological Survey, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"Demonstrating Geological Carbon Sequestration in the Mt. Simon Sandstone of the Illinois Basin," Robert J. Finley, Illinois State Geological Survey, Champaign, IL, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"CO2 Capture from Existing Coal-Fired Power Plants," Jared Ciferno, National Energy Technology Laboratory, Pittsburgh, PA, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Oxy-Fuel for Indiana," S. Son, Purdue University, presented at the CCTR Advisory Panel Meeting, West Lafayette, IN, December 11, 2007.

"Oxy-Fuel Combustion: Clean Coal," S. Son, K. Cramer, Purdue University, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Coal Transformation: Clean Coal," Steve Son, Multiphase Combustion Laboratory, Mechanical Engineering , Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"Synfuel Park Feasibility Study," Ronald L. Rardin, Purdue Energy Modeling Research Groups, Purdue University, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Potential for Fine Coal Recovery from Indiana's Coal Settling Ponds," Richard E. Mourdock, R.E. Mourdock & Associates, LLC, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"Environmental Issues and Fischer-Tropsch Commercialization," Linda S. Lee, Department of Agronomy, Purdue University, presented at the CCTR Advisory Panel Meeting, Terre Haute IN, June 1, 2006.

"Air Pollution Implications of Coal Based Gas-To-Liquid Transportation Fuels," Evan J. Ringquist, School of Public and Environmental Affairs, Indiana University, presented at the Clean Coal for Transportation Fuels Workshop, Purdue University, December 2, 2005.

"CO2 Sequestration in Indiana - IGS Status Report," John Rupp, Indiana Geological Survey, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Indiana's Coal Forecast

"Measuring the Contribution of Coal to Indiana's Economy," F.T. Sparrow, F.T. Sparrow & Associates, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 12, 2008.

"Forecasting Indiana Coal Use," F.T. Sparrow, F.T. Sparrow & Associates, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"Electricity Price Impacts from CO2 Restrictions," Douglas J. Gotham, State Utility Forecasting Group, Purdue University, West Lafayette, IN, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Forecasting Indiana Coal Production & The Midwest Coal Fuel Alliance," F.T. Sparrow, Executive Director, Coal Transformation Laboratory, Energy Center at Discovery Park, Purdue University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

Infrastructure Development

"Coal, Steel, and the Industrial Economy: Coal Transportation," Thomas F. Brady, Purdue North Central, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal, Steel, and the Industrial Economy: Railroads & Coal Transportation Enhancements," Thomas F. Brady, Purdue North Central, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal Transportation in Indiana," Keith Bucklew, Indiana Department of Transportation, Freight Mobility, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"CO2 and Indiana's Infrastructure: Turning Problems into a Resource," Marty W. Irwin, CCTR, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Steel Production and the Industrial Economy," Eric Knorr, ArcelorMittal, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Ports of Indiana: Connecting Indiana to the World," Jody Peacock, Ports of Indiana, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"CO2 Transportation," Ken Havens, Kinder Morgan Energy Partners, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"A Regional Concept for a CO2 Pipeline Network," Klaus Lambeck, Ohio Siting Authority, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"EOR: The Economically Viable CCS Solution," Denbury Resources, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 5, 2008.

"Coal Transportation, Next Phase," Thomas F. Brady, Jr., Purdue University-North Central, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," T. Brady, C. Pfitzer, K. Sinha, Purdue University, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," Tom Brady, Purdue North Central, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, March 1, 2007.

"A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," Tom Brady, Purdue North Central, presented at the CCTR Advisory Panel Meeting, Hammond IN, December 6, 2006.

"A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," Tom Brady (Purdue North Central, Chad Pfitzer (Purdue Extension), and K. Sinha (JTRP, School of Civil Engineering), Purdue University, presented at the CCTR Advisory Panel Meeting, West Lafayette IN, August 30, 2006.

"A Prescriptive Analysis of the Indiana Coal Transportation Infrastructure," Tom Brady, Purdue University North Central; Chad Pfitzer, Purdue Extension-Daviess County; K. Sinha, Purdue University, School of Civil Engineering, JTRP; Tom Beck, Steve Smith, INDOT; and Dr. Black, Indiana University, presented at the CCTR Advisory Panel Meeting, Indianapolis IN, February 28, 2006.

Midwest Collaboration

"Steel Production and the Industrial Economy," Eric Knorr, ArcelorMittal, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Coal and the Economy," Robert W. Shanks, Arch Coal Inc., presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Measuring the Contribution of Coal to Indiana's Economy," F.T. Sparrow, F.T. Sparrow & Associates, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Demonstrating Geological Carbon Sequestration in the Mt. Simon Sandstone of the Illinois Basin," Robert J. Finley, Illinois State Geological Survey, Champaign, IL, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Energy Research for a Cleaner Environment – 2008 Program," Ron Carty, Illinois Clean Coal Institute, Carbondale, IL, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"Status of the Coal Projects in Illinois," Dan Wheeler, Office of Coal Development, State of Illinois, Champaign, IL, presented at the CCTR Advisory Panel Meeting, Indianapolis, IN, March 6, 2008.

"An Overview of Clean Coal Research at CAER," Donald Challman, Center for Applied Energy Research (CAER), University of Kentucky, presented at the CCTR Advisory Panel Meeting, Vincennes University, Vincennes IN, September 6, 2007.

"Illinois Clean Coal Research," R.H. Carty, Illinois Clean Coal Institute, presented at the CCTR Advisory Panel Meeting, Purdue North Central, Westville IN, June 5, 2007.

"Ohio Coal Research Consortium," David J. Bayless, Ohio University, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"Ohio ... A Leader in Clean Coal Research, Development & Deployment," Bob Brown, Ohio Coal Development Office, presented at the CCTR Advisory Panel, West Lafayette IN, November 17, 2005.

"The Illinois Clean Coal Institute, ICCI - Mission, Organization, Priorities, and Future Activities," Ronald H. Carty, ICCI Director, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

"Illinois Coal Research Program," Francois Botha, ICCI, presented at the CCTR Advisory Panel Meeting, Bloomington IN, June 10, 2005.

Underground Coal Gasification

"A Review & Future of Underground Coal Gasification," Brian H. Bowen, CCTR, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"The Potential for Underground Coal Gasification in Indiana," Evgeny Shafirovich and Arvind Varma, Purdue School of Chemical Engineering, presented at the CCTR Advisory Panel Meeting and Briefing, Hammond, IN, December 11-12, 2008.

"Underground Coal Gasification (UCG)," Brian H. Bowen, presented to Heritage Research Laboratory, Indianapolis, October 21, 2008.

"The Potential for Underground Coal Gasification in Indiana: Phase I Report," E. Shafirovich (Purdue), M. Mastalerz (IGS), J. Rupp (IGS), and A. Varma (Purdue), presented to M. Irwin, CCTR, September 16, 2008.

"The Potential for Underground Coal Gasification in Indiana," Evgeny Shafirovich, School of Chemical Engineering, Purdue University, presented at the CCTR Advisory Panel Meeting, Bloomington, IN, June 5, 2008.

"Carbon Management & Underground Coal Gasification," S.J. Friedmann, Lawrence Livermore Laboratory, Livermore, CA, presented at the CCTR Advisory Panel Meeting, West Lafayette, IN, December 11, 2007.