# RESEARCH INVESTIGATION FOR THE POTENTIAL USE OF ILLINOIS COAL IN DRY MILL ETHANOL PLANTS

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ERC
Energy Resources Center
University of Illinois
at Chicago
Established 1973

Energy Resources Center, 1309 South Halsted Street, Chicago, Illinois 60607
Phone (312) 996-4490 • Fax (312) 996-5620 • http://www.erc.uic.edu

# RESEARCH INVESTIGATION FOR THE POTENTIAL USE OF ILLINOIS COAL IN DRY MILL ETHANOL PLANTS

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| Authors: | Steffen Mueller, John Cuttica |
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## ABSTRACT

The objective of this study is to compare a 100 million gallon per year (mgpy) dry mill ethanol plant that employs fluidized-bed coal technologies fueled by Illinois coal to the widely used natural gas fired ethanol plant looking at the differences in equipment, energy flows, costs, environmental permitting, and energy life cycle considerations. The methodology is based on energy and mass flow balances for the key fuel consuming components (boilers, dryers, thermal oxidizers) generated by original equipment manufacturers for this study, personal interviews with regulators and industry experts, and a survey of the published literature.

The present study finds that the integration of fluidized-bed boilers fired by Illinois coal will provide substantial savings to an ethanol plant located in the state. While the capital costs of coal fired fluidized-bed technologies for a 100 mgpy plant are approximately $29 million higher ($41.8 million compared to $12.8 million for a natural gas fired ethanol plant) the $15.7 million annual savings ($18.4 million compared to $34.1 million) result in a 1.8 year payback for this technology, a payback which should well compensate for any perceived technology risk. Additional savings are possible with the use of combined heat and power technologies, which decreases the overall energy cost even more (by an additional $4.7 million annually after financing of the added equipment).

The study also investigates the often cited permitting uncertainties for coal systems and finds that the environmental permitting process for any ethanol plant, regardless of the energy feedstock, needs to be carefully managed. Placing the findings within the context of energy life cycle analysis, the study shows that coal fired ethanol plants will consume slightly more fossil energy for every Btu of energy in ethanol than natural gas fired plants. However, co-firing biomass or the use of combined heat and power technology will likely result in similar or better energy ratios than currently operating natural gas fired plants.

In summary, fluidized-bed boiler technology fueled by Illinois coal provides a financially attractive energy solution for ethanol plants with life cycle fossil fuel consumptions likely similar to natural gas. These findings suggest that Illinois, with ample resources of both coal and corn, stands to reap compound benefits from promoting an increased deployment of fluidized-bed boiler technologies at ethanol plants.

# EXECUTIVE SUMMARY

The ethanol industry is a rapidly growing business with 97 dry mill ethanol plants currently in operation and 37 more under construction in the United States. The construction of an ethanol plant provides substantial investment for a community, while the sale of corn to an ethanol plant provides an opportunity for farmers for added revenue over traditional sales. Besides corn, energy is another major feedstock for an ethanol plant. According to a recent article in Ethanol Producers Magazine, 90% of surveyed ethanol plants in operation use natural gas as their major energy feedstock. While the article states that the majority of new plants under construction still use natural gas as their primary feedstock, “the overall instability of the natural gas market is the likely root of considering other sources” (Niles, 2006). In fact, a higher percentage of surveyed plants under construction use coal than currently operating plants. The article goes on to state that some plants (such as Red Trail Energy in North Dakota) are being sited not according to their proximity to corn but to their proximity to the energy feedstock, in this case coal. Illinois, however, has ample resources of both corn and coal and stands to reap the compound benefit from converting two domestic resources into a value added product.

Recent technical developments in the area of fluidized-bed coal combustion may very well hold the key to realizing these benefits. Rather than burning coal on a grate in a stoker boiler, the coal in fluidized-bed boilers is suspended by blowing high pressure air through a bed of solids. Fluidized-bed combustion technologies can not only significantly reduce sulfur dioxide and nitrogen oxide emissions compared to traditional coal burning technologies (pulverized coal plants), but they can additionally be used for controlling the emissions from other sources at an ethanol plant, such as the thermal oxidation of volatile organic compounds from the fermentation and drying processes.

This study compares a 100 million gallon per year (mgpy) dry mill ethanol plant that employs fluidized-bed coal technologies fueled by Illinois coal (with an average heating value of 10,500 Btu/lb LHV) to the widely used natural gas fired ethanol plant and looks at the differences in:

- the types of equipment needed to operate each type of ethanol plant,
- energy flows,
- capital, operation, and maintenance costs,
- considerations given to environmental permitting of these types of plants, and
- placement within the context of an energy life cycle analysis.

Ethanol plants may produce several by-products. Distillers dried grain with solubles (DDGS) is produced from so-called wet cake leftover from the distillation process. Wet cake as well as DDGS are valuable animal feed products. However, DDGS, which is in essence dried wet cake has a longer shelf life and can be shipped easier. In Illinois DDGS has a relatively high market price, which makes DDGS production, even with the higher energy requirements for the drying process, financially attractive ($75-$87 for DDGS per ton). For the purpose of this study 100% drying of wet cake to DDGS was assumed. While a wide variety of energy systems and equipment configurations exist at ethanol plants, this study looks at the most common types of equipment.

- For coal fired ethanol plants the most common equipment types include a fluidized-bed boiler energy system which generates steam for the ethanol processes (primarily cooking and distillation) and the DDGS drying process utilizing a steam fired dryer. The volatile organic compound (VOC) emissions, which originate primarily from the DDGS drying process are controlled by routing the DDGS drying air through the boiler where the VOCs are substantially reduced through the process of thermal oxidation.
- For natural gas fired-ethanol plants the energy system includes a natural gas fired boiler (generates steam for cooking, distillation) and a natural gas fueled direct fired dryer for DDGS drying. The VOC emissions in a natural gas fired ethanol plant are controlled by a natural gas fired regenerative thermal oxidizer.

Looking at the energy consumption of both types of ethanol plants, the coal fired plant uses more electricity (20% more) than the natural gas fired one. The higher electricity consumption is primarily due to the operation of coal ancillary equipment such as coal crushing, conveying, as well as a substantial electric load for air fans and motors to operate the fluidized-bed system. Several studies also cite higher thermal energy requirements (approximately 25% more) for coal fired systems, which is attributed to a) slightly lower boiler efficiencies of coal fired systems (78% for coal boiler vs. 80+ percent for natural gas fired systems) and b) higher thermal energy requirements associated with the steam fired boilers used at coal plants compared to the direct fired dryers used at natural gas plants. Drying of DDGS consumes about one third of all energy at an ethanol plant.

Besides higher energy requirements coal-fired ethanol plants are also more capital intensive. Looking at the incremental cost to build a coal fired energy system at an ethanol plant compared to a natural gas fired one, a coal fired energy system (just the energy system not the whole ethanol plant) costs about three times as much ($41.8 million compared to $12.8 million): The fluidized-bed boiler system, the steam fired dryers, and the coal transportation systems cost significantly more than standardized gas fired boilers, direct fired dryers, and pipelines to source natural gas. Therefore, using currently prevailing financing of 12 year loans at 10 % interest rates, the annualized loan payments for a coal fired energy system are also more than 3 times higher ($6.1 million compared to $1.9 million) for a coal fired plant.

The annual operating costs, however, are almost half ($18.4 million compared to $34.1 million) for coal fired power plants even under conservative assumption such as forward looking natural gas prices of $8.7/MMBtu rather than currently prevailing prices of greater than $10/MMBtu. The financial bottom line of the present study shows that coal fired ethanol plants of 100 mgpy (with coal prices of $2.63/MMBtu) should provide substantial annual savings over natural gas fired plants of over $11.5 million after loan payments for higher capital costs.

A fuel price sensitivity analysis shows that these savings can vary widely. The analysis shows that if natural gas prices increase by 20% from the baseline $8.7/MMBtu (while coal prices remain unchanged at $2.63 per MMBtu) the owner/operator of a coal fired ethanol plant would save $17.1 million annually. Conversely, the analysis shows that natural gas prices would have to drop by 40% from current levels (to $5.2/MMBtu) for natural gas fired ethanol plants to be competitive with coal fired ones.

Both coal fired as well as natural gas fired ethanol plants can reduce their overall energy requirements by employing combined heat and power technologies. In a coal fired ethanol plant, the conversion to CHP would require the installation of a steam turbine, which increases the capital cost and operation of the boiler at a higher pressure and temperature (increasing coal consumption). However, there is a decrease in overall O&M expenses due to reduced electricity purchases resulting in an overall energy cost reduction of $4.7 million after financing of the added equipment. Combined heat and power is also attractive for natural gas fired power plants (which require the addition of a combustion turbine with heat recovery) decreasing the energy costs by 1 million after financing of added equipment.

Utilizing fluidized-bed coal technology substantially reduces the (primarily sulfur dioxide related) permitting concerns often associated with Illinois coal. Recently, a 37 mgpy plant employing fluidized-bed coal technology using Illinois coal and located in Illinois was permitted as a minor source. However, the permit appears to be a synthetic minor source; the plant size was chosen so that the facility could be permitted as a minor source. This means that substantially larger plants such as a 100 mgpy plant would very likely constitute a major emissions source.

However, while ethanol plants for air emissions permitting purposes are currently considered “petroleum refineries” and therefore fall under the “28 Categories of Source” for which the major source threshold for any pollutant is 100 tons per year, the U.S. Environmental Protection Agency is considering a rule change. The rule change would reclassify ethanol plants into “Other Categories of Source” and limit emissions for any pollutant to 250 tons per year in which case coal fired ethanol plants of close to 100 mgpy may fall within minor source permitting classifications. Regardless, having to obtain a major source permit may not necessarily impede an ethanol plant project. The permitting examples provided in this study show that public challenges to an air permit may be independent of:

- The Size of the Plant: The coal fired Heron Lake Ethanol Plant in Minnesota incurred permitting delays despite its relatively small size (55 mgpy).
- The Fuel Source: An ethanol plant in northeastern Illinois incurred permitting problems despite its natural gas fuel source.

The present study also places the findings in the larger context of Energy Life Cycle Analysis (LCA). The analysis shows that a primarily coal fired ethanol plant will consume approximately 90,000 MWh/year of electricity. A central station power plant with an average efficiency of 33% (EPA eGrid Fossil Energy Only) and assumed Transmission and Distribution losses from the power plant to the ethanol plant of 7.5%

will require about 1,000,000 MMBtu annually to generate this amount of electricity. Added together with the on-site fuel use for the thermal systems of slightly more than 4 million MMBtu annually or 40,000 Btu/gal this results in a total fuel use of approximately 5 million MMBtu annually or 50,000 Btu/gal consumed by the 100 mgpy ethanol process.

In 2004 Argonne National Laboratory conducted an energy life cycle assessment utilizing the Greenhouse gases, Regulated Emissions and Energy use in Transportation (GREET) model. The GREET analysis for the ethanol life cycle found that for every Btu of gasoline, 1.2 Btus of fossil energy are consumed whereas for every Btu of energy in ethanol fuel, 0.74 Btu of fossil energy are consumed. The Argonne LCA was based on data provided by Shapouri, an economist with the U.S. Department of Agriculture. The Shapouri data was primarily based on natural gas fired ethanol plants with an energy consumption of 47,116 Btu/gal, since at the time of data collection there was no dry mill coal fired ethanol plant in operation. The research for the current study, which indicates a total fuel consumption of 50,000 Btu/gal is slightly higher (6%) than the 47,113 Btu/gal provided by Shapouri for the original Argonne LCA. Since the energy requirements at coal fired ethanol plants are slightly higher than the numbers used in the LCA, a coal fired ethanol production process will consume slightly more than the 0.74 Btus of fossil energy for every Btu of energy in ethanol. However, in the CHP case for a coal fired ethanol plant, the total fuel consumption is approximately 45,000 Btu/gal, which is below the number used by Shapouri. Therefore, a coal fired CHP ethanol plant may likely consume less than the 0.74 Btus of fossil fuel for every Btu of energy in ethanol.

While firing coal in ethanol plants increases the overall Btu consumption for the ethanol production process one must consider several key advantages of this technology:

- <u>Btu Adjustments:</u> Fluidized-bed boilers can be co-fired with a wide variety of biomass as long as the biomass conforms to the size requirements for the boiler system. This means that co-firing 6% of biomass will likely result in similar LCA results for coal fired systems than the original GREET analysis which, was based primarily on natural gas.
- <u>Infrastructure Flexibility:</u> A lot of work is currently being done in mapping biomass feedstocks across the U.S. Ultimately, as biomass is concentrated and becomes available coal fired fluidized-bed plants can switch to biomass, which means that coal fired technology provides an intermediate step towards the development of renewable, biomass fired/co-fired ethanol plants with diverse sources of energy feedstocks.
- <u>Complete Cost Accounting:</u> LCA is concerned with counting Btus that go into a final product such as ethanol. However, all fossil fuels are not created equal. In the case of coal, there is an ample domestic resource of coal. Recent studies have allocated some of the defense expenditures to the cost of gasoline as a direct cost in assuring supply (see National Defense Council data quoted in Ethanol Across America, Fall 2004). Coal, however, is free of any social and financial externalities associated with a dependence on a foreign resource.

# OBJECTIVES

The objective of this study is to compare a 100 million gallon per year (mgpy) dry mill ethanol plant that employs fluidized-bed coal technologies fueled by Illinois coal (with an average heating value of 10,500 Btu/lb LHV) to the widely used natural gas fired ethanol plant looking at the differences in

- the types of equipment needed to operate each type of ethanol plant,
- energy flows,
- capital, operation, and maintenance costs,
- considerations given to environmental permitting of these types of plants, and
- placement within the context of an energy life cycle analysis.

The work was divided into the following tasks:

- **Task 1 –** Create a baseline model of a typical state-of-the-art dry mill ethanol plant and identify natural gas consuming equipment.
- **Task 2 –** Research coal technologies applicable to ethanol production. These technologies will be used to modify the base line design to incorporate coal as the preferred fuel in areas of the plant where it makes economic sense.
- **Task 3 –** Perform an economic analysis and model to evaluate and compare the performance and costs between coal and natural gas fired systems in a typical 100 million gallon per year ethanol plant.
- **Task 4 –** Perform a cursory investigation of adding CHP to both the natural gas baseline design and the coal fueled alternative designs. The added costs of incorporating CHP technologies versus the operating savings due to higher efficiencies will be evaluated.
- **Task 5 –** Investigate the current air emissions permitting requirements for coal fired ethanol plants in Illinois.
- **Task 6 –** Place the research findings in the context of energy life cycle analysis.

# INTRODUCTION AND BACKGROUND

The ethanol industry is a rapidly growing business with 97 dry mill ethanol plants currently in operation and 37 more under construction in the United States. The construction of an ethanol plant provides substantial investment for a community, while the sale of corn to an ethanol plant provides an opportunity for farmers for added revenue over traditional sales. Besides corn, energy is another major feedstock for an ethanol plant. According to a recent article in Ethanol Producers Magazine, 90% of surveyed ethanol plants in operation use natural gas as their major energy feedstock. While the article states that the majority of new plants under construction still use natural gas as their primary feedstock, “the overall instability of the natural gas market is the likely root of considering other sources” (Niles, 2006). In fact, a higher percentage of surveyed plants under construction use coal than currently operating plants. The article goes on to state that some plants (such as Red Trail Energy in North Dakota) are being sited not according to their proximity to corn but to their proximity to the energy feedstock, in this case coal. Illinois, however, has ample resources of both corn and coal and stands to reap the compound benefit from converting two domestic resources into a value added product.

Recent technical developments in the area of fluidized-bed coal combustion may very well hold the key to realizing these benefits. Rather than burning coal on a grate in a stoker boiler, the coal in fluidized-bed boilers is suspended by blowing high pressure air through a bed of solids. Fluidized-bed combustion technologies can not only significantly reduce sulfur dioxide and nitrogen oxide emissions compared to traditional coal burning technologies (pulverized coal plants), but they can additionally be used for controlling the emissions from other sources at an ethanol plant, such as the thermal oxidation of volatile organic compounds from the fermentation and drying processes.

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## EXPERIMENTAL PROCEDURES

The methodology is based on energy and mass flow balances for the key fuel consuming components (boilers, dryers, thermal oxidizers) generated by original equipment manufacturers for this study, personal interviews with regulators and industry experts, and a survey of the published literature.

## RESULTS AND DISCUSSION

### Task 1 – Create a baseline model of a typical state-of-the-art dry mill ethanol plant and identify natural gas consuming equipment

The energy system at a typical state-of-the art natural gas fired ethanol plant includes a natural gas fired boiler (generates steam for cooking, distillation) and a natural gas fueled direct fired dryer for DDGS drying. The VOC emissions in a natural gas fired ethanol plant are controlled by a natural gas fired regenerative thermal oxidizer. Some natural gas fired ethanol plants install heat recovery steam generators (HRSG) at the back-end of the dryer systems and utilize the HRSG as their primary boiler and the HRSG burners for VOC destruction. While this arrangement may seem energy efficient, industry experts interviewed for this study consider the operational inflexibility associated with this arrangement (for example the HRSG always has to be operated when the dryers are operated) not worth the energy efficiency gains. Each component is described in more detail below.

Task 1 is divided into three subtasks:

- Task 1.1: Identify boiler technology/technologies used at natural gas fired ethanol plants.
- Task 1.2: Identify dryer technology/technologies used at natural gas fired ethanol plants.
- Task 1.3: Identify VOC emissions control technology/technologies used at natural gas fired ethanol plants.

### 1.1) Boilers in natural gas-fired ethanol plants

Two commonly used boiler designs are watertube boilers and firetube boilers. In a firetube boiler design the combustion takes place in the furnace section from where the hot gases from combustion are directed along a series of firetubes, or flues, that penetrate the boiler and heat the water, thereby generating steam. Conversely, in a water-tube boiler, water circulates in tubes which are heated externally by fire. Watertube boilers can produce higher pressure steam than firetube boilers; firetube boilers cannot exceed 350 psig. Ethanol processes require relatively low pressure steam (150 psig) which means firetube boilers are more commonly used than watertube boilers. However, in ethanol plants with combined heat and power configurations (i.e steam turbine installations) watertube boilers may be considered.

Packaged firetube boilers are available in sizes from 10 to 3,000 boiler horsepower (American Boiler Manufacturers Association Website, 2006). For a 100 mgpy plant, a leading boiler manufacturer interviewed for this study specified a natural gas fired boiler system consisting of three 2000 hp boilers. This arrangement would best serve the steam requirement and provide a good amount of flexibility for periodic maintenance as well as turndown. The boiler system would produce up to 210,000 lbs/hr of steam at 150 psig.

The specified equipment package includes the boiler, feedwater controls, blowdown valves and piping.

Alternatively, some natural gas fired ethanol plants utilize an alternative configuration where the primary source of process steam is provided by a heat recovery steam generator utilizing heat from the dryers.

### 1.2) Dryers in natural gas fired ethanol plants

A key by-product of the ethanol production process is Distillers Dried Grain with Solubles (DDGS).[1] A 100 mgpy ethanol plant that dries all of its Distillers Wet Grain (DWG) produces about 322,000 tons of DDGS annually. DDGS is produced by reducing the moisture content of DWG from approximately 65% down to 12%. A mass flow balance produced by a leading dryer manufacturer for this study shows that in order to produce 322,000 tons of DDGS in a dryer system a total of 189,000 lbs/hr of wet cake (and syrup combined) are continuously fed to the dryers, which have to remove 113,000 lbs/hr of moisture, resulting in 76,000 lbs/hr of DDGS.

Ethanol plants whose primary fuel is natural gas generally employ direct-fired dryers. In a direct-fired dryer, air, heated by an open flame, passes through the wet cake to evaporate the liquid. Heat transfer, in this case, is by convection and radiation. Co-current dryers are the most widely used type of direct-fired dryers and are particularly suitable for drying materials with high moisture content and which are heat sensitive (Barr-Rosin, 2006).[2] In co-current dryers the wet material is in contact with the gas at its highest temperature, which rapidly evaporates surface moisture.

A natural gas direct-fired dryer consists of the following key parts:

- Natural gas burner and combustion air blower
- Air heating furnace
- Drum dryer section with motor and drum drive
- Cyclone collector
- Induced draft fan
- Control package (thermocouples, sensors, etc.)
- Interconnect ducting and fire suppression system

As mentioned above, the majority of ethanol plants currently use direct fired dryers. However, indirect natural gas fired dryers can also be used. The major advantage of an indirect system is that, like a steam fired dryer, it produces condensable water vapor, which can be more easily recovered for use elsewhere in the plant. Also, the exhaust volume is much less than a comparable direct fired dryer, reducing the size requirements

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[1] The sale of DDGS can provide a significant financial revenue stream for an ethanol plant. A recent US Department of Agriculture Market News quote ranged between $75-$87 for DDGS per ton for Illinois.

[2] In contrast, counter-current dryers are more suitable for materials that must be dried to very low levels of moisture, where the last traces of moisture are difficult to remove.

for the RTO. The disadvantage of indirect fired dryers are increased capital cost requirements.

### 1.3) Thermal oxidizers

Some of the major pollutants of an ethanol plant are Volatile Organic Compounds (VOCs). These type of pollutants are emitted during the boiler operation (both coal and natural gas fired ones), during the fermentation process, and in particularly high concentrations during the drying process. VOCs can be effectively controlled with a thermal oxidizer. At high temperatures (up to 2000 ˚F) VOCs, through the process of thermal oxidation, are converted to carbon dioxide and water vapor. While this process also releases heat, thermal oxidizers have relatively large net energy requirements to heat the gas stream to the temperature necessary for high-efficiency VOC destruction (EPA, Basic Concepts of Environmental Science, www.epa.gov)

In order to save energy costs, heat exchangers are used to recover some of the heat produced to heat the gas stream. Regenerative thermal oxidizers use regenerative beds made of ceramic media for heat exchange with heat recovery efficiencies of up to 95%. A regenerative thermal oxidizer system includes fans, motors, burners, heat exchange media, flow control valves, temperature recorders and exhaust stacks.

A 100 mgpy plant will require thermal oxidizers that can handle air flows of between 80,000 to 100,000 cfm. Most ethanol plants (coal and natural gas fired ones) employ RTO technologies. Alternatively, some natural gas fired ethanol plants utilize thermal oxidizers (without regenerative heat recovery technology) integrated with a heat recovery steam generator (HRSG). The steam from the HRSG then is utilized elsewhere in the plant as process steam.

## Task 2 – Research coal technologies applicable to ethanol production

The energy system at a typical state-of-the art coal fired ethanol plant includes a fluidized-bed boiler energy system, which generates steam for the ethanol processes (primarily cooking and distillation) and the DDGS drying process utilizing a steam fired dryer. The volatile organic compound (VOC) emissions which originate primarily from the DDGS drying process are controlled by routing the DDGS drying air through the boiler where the VOCs are substantially reduced through the process of thermal oxidation. Optionally, a natural gas-fired regenerative thermal oxidizer can be employed for VOC emissions control.

Task 2 is divided into three subtasks.

- Task 2.1: Identify boiler technology/technologies used at coal fired ethanol plants.
- Task 2.2: Identify dryer technology/technologies used at coal fired ethanol plants.
- Task 2.3: Identify VOC emissions control technology/technologies used at coal fired ethanol plants.

## 2.1) Boilers in coal fired ethanol plants

Rather than burning coal on a grate in a stoker boiler, the coal in a fluidized-bed boiler is suspended by blowing high pressure air through a bed of solids (Thompson, March 2006). This allows for a uniform mixture of coal and oxygen with a more complete combustion compared to other coal burning technologies. Furthermore, fluidized-bed boilers can be operated at combustion temperatures between 1,400 and 1,700 degrees F, which is below the 2,500 degrees F where major nitrogen oxide formation occurs (DOE, Fossil Energy Website, Overview of Fluidized-bed Technology, www. Fossil.energy.gov). Furthermore, the tumbling action within the coal bed allows for a uniform injection of limestone powder, which in turn significantly reduces sulfur dioxide emissions from the coal combustion process. Fluidized-bed technology also provides fuel flexibility, since a fluidized-bed boiler can not only burn coal but also biomass from diverse agricultural and municipal waste sources.

Because of these advantages, the majority of coal fired dry-mill ethanol plants currently in construction and operation use fluidized-bed technologies. Due to the complexity of these systems, the boiler as well as ancillary systems are generally supplied and integrated by one qualified engineering and manufacturing company specialized in fluidized-bed technologies. The key components that are integrated and often manufactured by such a firm are the fluidized-bed cell and ancillary components, the forced draft and preheat system, the bed recycle system, the bed additive system, the steam generating system, the gas cleanup equipment, induced draft fan, stack and ducting, fuel metering/feed system, ash handling system, access system, and the instrumentation and control system. In the following each of these components will be described. See also Figure 2.1-1 for more detail.

### Fluidized-bed Cell and Ancillary Components

The fluidized-bed cell is basically a steel vessel where the combustion takes place. For a 350,000 lbs/hr boiler, the size required for a 100 mgpy plant, the vessel would measure approximately 20 feet wide by 30 feet long by 65 feet in height. Ancillary components to the fluidized-bed cell include the underbed air distribution system, a system of air manifolds that extend across the base width of the fluidized-bed cell and supply the air required for fluidization. The manifolds have cooling part ports to reduce the temperature of the bed. Besides the underbed air distribution system, a fluidized-bed cell generally also has nozzles for ovefire air, located in the walls above the active bed allowing for optimization of the thermal oxidation and the temperature profile. Lastly, the fluidized-bed cell contains a bed material of refractory clay.

### Forced Draft and Preheat System

The forced draft preheat system includes the necessary equipment to preheat the fluidized-bed and supply the air required for normal operation. A forced draft fan delivers pressure to force air through the air preheater, fluidizing nozzles, bed material and overfire air nozzles. The preheat burner is generally natural gas fired. A 350,000 lbs/hr boiler requires approximately 15 MBtu/hr of natural gas. In addition, a natural gas fired overbed burner system rated at 40 MBtu per hour is generally located in the upper vessel region of the fluidized-bed cell.

The preheat burner and the overbed burner system provide the energy to heat the bed material and vapor space to approximately 700 degree F for start-up.

### Bed Recycle System

Typically, tramp material consisting of rocks, metal, and other inert material are inadvertently introduced with the fuel coal into the boiler. Accumulation of tramp material increases particle size of the fluidized-bed which can eventually impede bed fluidization. Therefore, tramp material must be regularly removed. In certain boiler designs, a portion of the bed is continuously drawn down through bed recycle gates. Then, bed and tramp material are separated on a vibrating screen conveyor and the bed material is discharged into a bucket elevator that returns it to the boiler vessel while the tramp material is discharged into a hopper for disposal. A bed material storage system (about 4,500 cubic feet for a 350,000 lbs/hr boiler) is also part of the bed recycle system. This storage system allows the vessel to be emptied for inspection or maintenance purposes and it also permits automated refill and makeup to maintain the proper vessel bed material inventory during operation.

### Bed Additive System

A bed additive system is required to introduce limestone, lime, dolomite or other additives (sulfur and other acid gas reduction additives) into the fluidized-bed. The bed additive storage bin has a capacity of approximately 6000 cubic feet (again, for a 350,000 lbs/hr boiler). Filling the storage bin is often accomplished pneumatically from a self-unloading pneumatic capable truck.

### Steam Generating System

The steam generating system is integrated with the fluidized boiler vessel. Steam is generated through heat transfer surfaces in the active fluidized-bed region (tubes immersed in the active fluidized-bed) as well as in the vapor-space area similar to a waste-heat style boiler system. A superheater controls the steam to its final superheated temperature. An economizer heats the feedwater to near steaming conditions before entering the steam drum.

### Gas Cleanup Equipment

- NOx Abatement System. NOx is formed when nitrogen in the fuel and the air is combined with oxygen at high temperatures. Because fluidized-bed coal technologies operate at relatively low temperatures (1,600 to 1,800 degree F), relatively little NOx is formed. The NOx that is formed, however, is generally controlled with a Selective Noncatalytic Reduction (SNCR) system, where ammonia is being injected into the vapor space of the boiler vessel.

- Cyclone System. In a cyclone system ash particles are removed from the flue gas stream with centrifugal force.

- Spray Dryer System. Additional sulfur dioxide and acid control is provided by a spray dryer system, where lime droplets are injected into the acidic flue gas which reacts with the calcium to produce a dry salt.

- Baghouse System. After the spray dryer system, the cooled flue gas is ducted into a baghouse where final acid gas polishing and particulate removal is achieved by passing the gas through a fabric filter media filter. The filter is regularly cleaned with automated compressed air systems.

### Induced Draft Fan, Stack and Ducting

An induced draft fan is located immediately upstream of the stack to create a draft though the gas path of the steam. The fluidized-bed energy system also requires a stack (approximately 100 feet high). All gas ducting is made of carbon steel (with service intended to be less than 800 degrees F).

### Fuel Metering/Feed System

A coal meter and feeder system is located elevated adjacent to the fluidized-bed energy system. The system consists of two basic components, a motorized conveyer to meter the amount of fuel and a rotor to distribute the fuel evenly over the fluidized-bed. Variation of the conveyer's motor speed will regulate the coal flow to match the steam load demand. The rotor RPM is controlled by its own variable speed drive to control longitudinal distribution of the coal from the front to the rear of the bed area. The rotor shaft has to be water cooled. The system also includes a coal feeder, which is separated from the conveyer via an isolation slide gate which closes when the coal feeder conveyer stops.

### Ash Handling System

A pneumatic or vacuum ash collection and transport system constantly removes ash from each discharge point in the fluidized-bed vessel and transports the ash to the storage tank. The storage tank is sized to provide about 12,000 cubic feet of storage (350,000 lbs/hr boiler). An ash wetting system controls fly ash and dust during unloading operations of the storage tank.

### Access System

Access decks and ladders are required throughout the system in areas of frequent access for operation and service.

### Instrumentation and Control System

Local control panels control the operation of specific systems such as the bed change-out system, burner management, fuel metering, ash storage, and the baghouse A central PLC (programmable logic controller) panel can serve as a central management system. A continuous emissions monitoring (CEM) system is generally required to monitor CO O2, NOx, SO2, ammonia slip, and opacity.

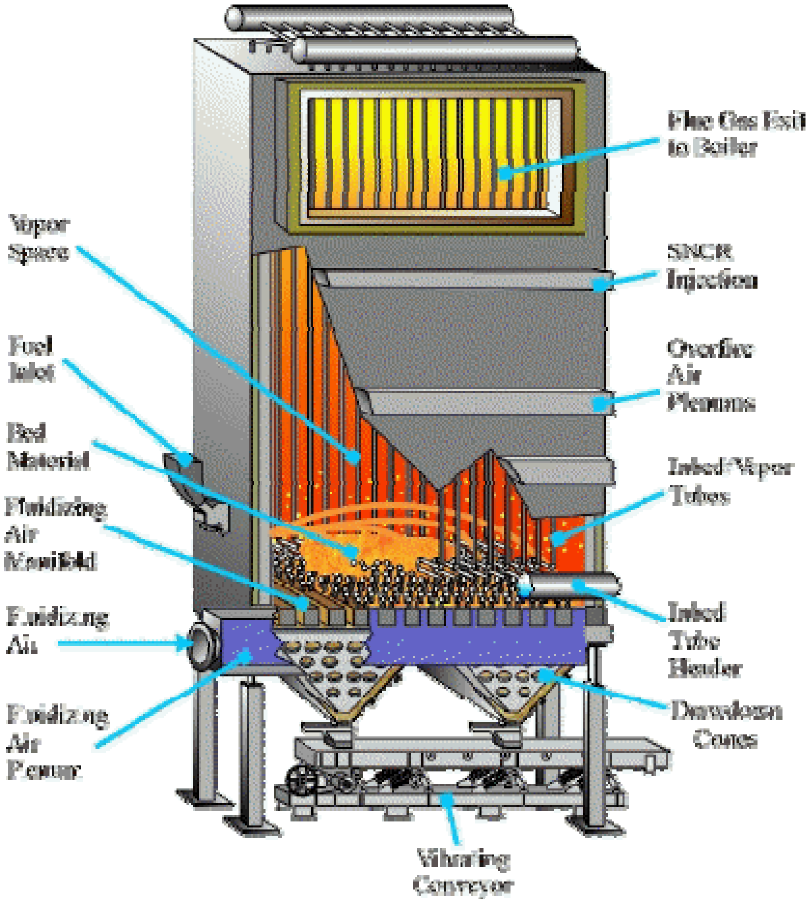


**Figure 2.1-1: Fluidized-bed Boiler (Picture Source: Energy Products of Idaho, 2006)**

## 2.2) Dryers in coal fired ethanol plants

Coal-fired ethanol plants generally utilize excess steam from the fluidized-bed boiler system in an indirect fired dryer. In an indirect-fired dryer there is no direct contact between the wet cake and the drying gas (steam); steam flows through discs, tubes, coils surrounding the wet cake.

In general, steam fired dryers have higher capital cost than natural gas direct-fired dryers (see Section 3) and have higher primary fuel requirements. However, steam fired dryers have generally lower VOC emissions. The reason is two fold: 1) Steam fired dryers often allow to condense the water vapor at the back end of the dryer, which can drastically reduce the water consumption of an ethanol plant. Condensing the water vapor also reduces the exhaust volume. Therefore, steam fired dryers generally require smaller size gas clean-up systems (such as thermal oxidizers) than direct-fired dryers. 2) Steam fired dryers have lower operating temperatures, which also reduces VOC emissions (Kotrba, August 2006, p. 98).

### 2.3) Thermal oxidizers

Fluidized-bed boiler ethanol plants (such as the Canton, Illinois and Goldfied, Iowa plant) can be configured such that the exhaust from the DDGS drying process is routed through a cyclone and a forced draft fan to serve as combustion air to the boiler. This process effectively controls VOC emissions. Since this arrangement may require firing the boiler at a higher temperature, creating at times inefficient operating conditions, some fluidized-bed boiler plants may elect to install separate natural gas fired RTOs. An example of a coal fired fluidized-bed ethanol plant with natural gas fired RTOs is the Heron Lake plant in Minnesota (described in more detail in Section 5)

## Task 3 – Perform an economic analysis to evaluate and compare the performance and costs between coal and natural gas fired systems

Task 3 is divided into four subtasks.

- Task 3.1: Determine the differences in energy flows between the two plant types.
- Task 3.2: Perform an economic comparison.
- Task 3.3: Perform an economic comparison with financing considerations.
- Task 3.4: Perform an economic comparison with fuel price sensitivity considerations.

### Task 3.1 Determine the differences in energy flows between the two plant types

The energy flows discussed in this section are based on a 100 million gallon per year ethanol plant. Ethanol plants may produce several by-products. Distillers dried grain with solubles (DDGS) is produced from so-called wet cake leftover from the distillation process. Wet cake as well as DDGS are valuable animal feed products. However, DDGS, which is in essence dried wet cake has a longer shelf life and can be shipped easier. In Illinois DDGS has a relatively high market price, which makes DDGS production even with the higher energy requirements for the drying process financially attractive ($75-$87 for DDGS per ton per US Department of Agriculture Market News, 2006). For the purpose of this study, 100% drying of wet cake to DDGS was assumed. A second, far less common byproduct is carbon dioxide which is used in the beverage industry. The production process is also energy intensive. No carbon dioxide production was assumed as part of this study.

Figure 3.1-1 and Table 3.1-1 illustrate the general energy flows within a natural-gas fired ethanol plant. A natural gas fired boiler consumes fuel with an annual heating value of 2,150,000 MMBtu. At a boiler efficiency of 80% the natural gas fired boiler generates 1,720,000 MMBtu of steam annually. The steam is used for cooking and distillation. Boiler steam is not used for drying since a direct fired dryer provides a more efficient way to dry the DDGS by-product. A total of 1,050,000 MMBtu of fuel is used in the natural gas direct fired dryer system (information by Henneman Engineering and EEA Inc.). However, this may be a conservative fuel consumption assumption. Fuel consumptions in dryers can vary widely with the boiler fuel requirements. According to a dryer mass flow calculation from a major dryer manufacturer, the actual annual fuel consumption would be around 1,517,000 MMBtu per year compared to the 1,050,000 MMBtu quoted by Henneman/EEA Inc. For this study, the more conservative Henneman/EEA numbers were used, ie. those numbers that are least favorable for coal fired systems in a direct comparison. Finally, an RTO is used for VOC destruction since DDGS drying gases cannot be rerouted through a natural gas fired boiler for VOC destruction (operating at temperatures too low for VOC destruction). The RTO consumes 33,000 MMBtu annually.

Electricity is used in all stages of the ethanol production process since all stages utilize either motors, fans, or other electric components. The ethanol production process consumes about 0.75 kWh/gallon or 75,000 MWh (100 mgpy plant) annually (Roddy, 2006). A relatively small amount of electricity (500 MWh) is required for ancillary boiler operation (i.e. fans).

Figure 3.1-2 and Table 3.1-1 illustrate the general energy flows within a coal-fired ethanol plant. On a yearly basis, coal with a heating value of 4,025,000 MMBtu is combusted in the fluidized-bed boiler system. At a boiler efficiency of 78% the fluidized-bed boiler system generates a total of 3,140,000 MMBtu of steam annually, 1,720,000 MMBtu is used for the combined cooking and distillation process, 1,420,000 MMBtu is used in a steam fired dryer. A coal fired boiler of this type has a nominal capacity of approximately 350,000 lbs/hr of steam (Energy Products of Idaho, 2006).

Electricity use can be grouped into two load sinks:

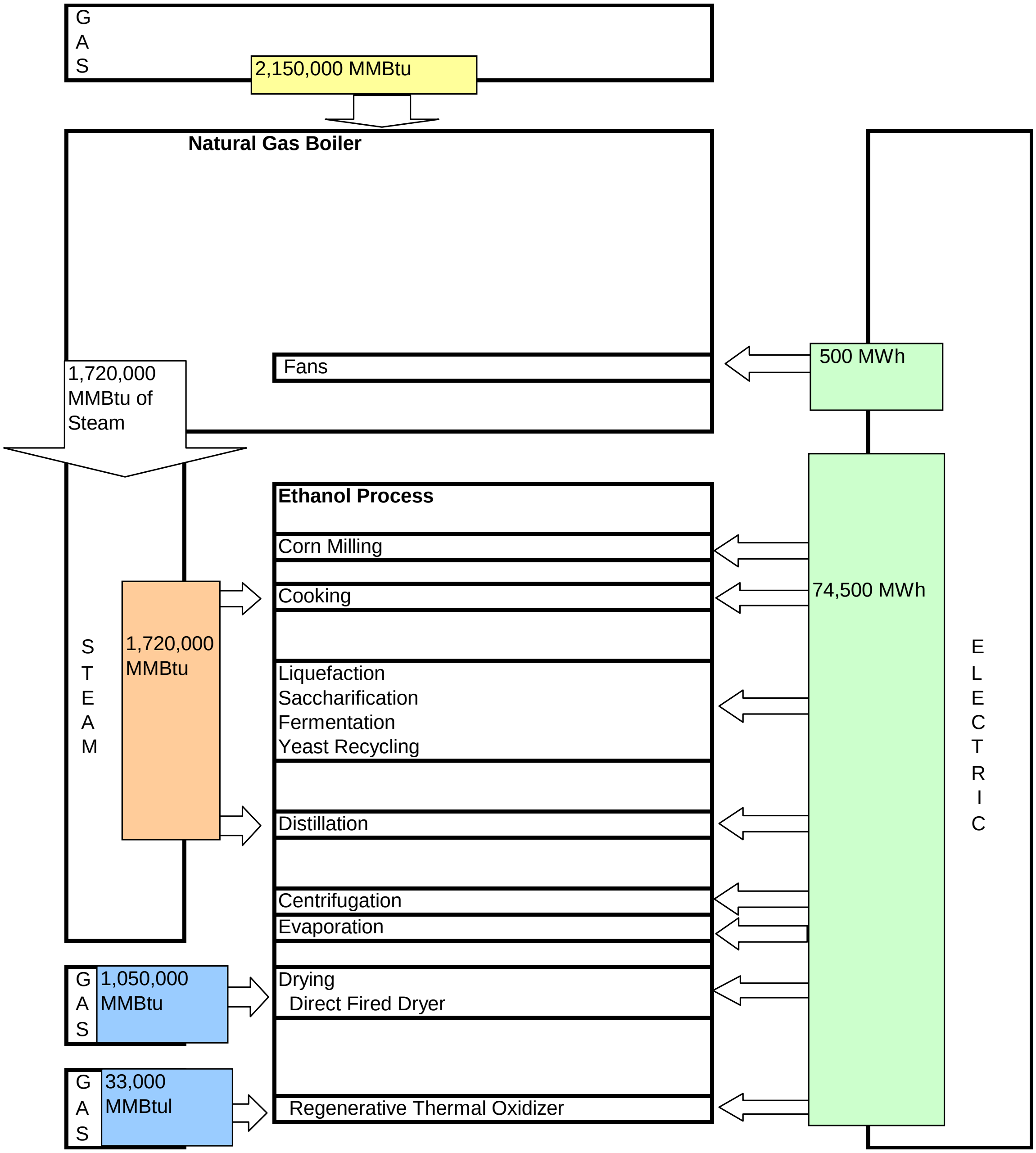
- The ethanol production process: Process electricity consumption totals about 75,000 MWh annually.
- Coal-boiler ancillary equipment: Electricity is used for most ancillary equipment associated with the fluidize bed boiler system. A 350,000 lbs/hr boiler would require approximately 15,000 MWh of ancillary electricity annually.

Finally, natural gas is used to fire the thermal oxidizer system used to clean-up emissions from the DDGS drying process. This may be an optional component, since some coal fired systems reroute the exhaust gases from the dyer for VOC destruction back through the boiler. A regenerative thermal oxidizere system for a 100 mgpy plant consumes approximately 33,000 MMBtu per year of natural gas. Natural gas is also used in small quantities for fluidized-bed start up operations (not shown).

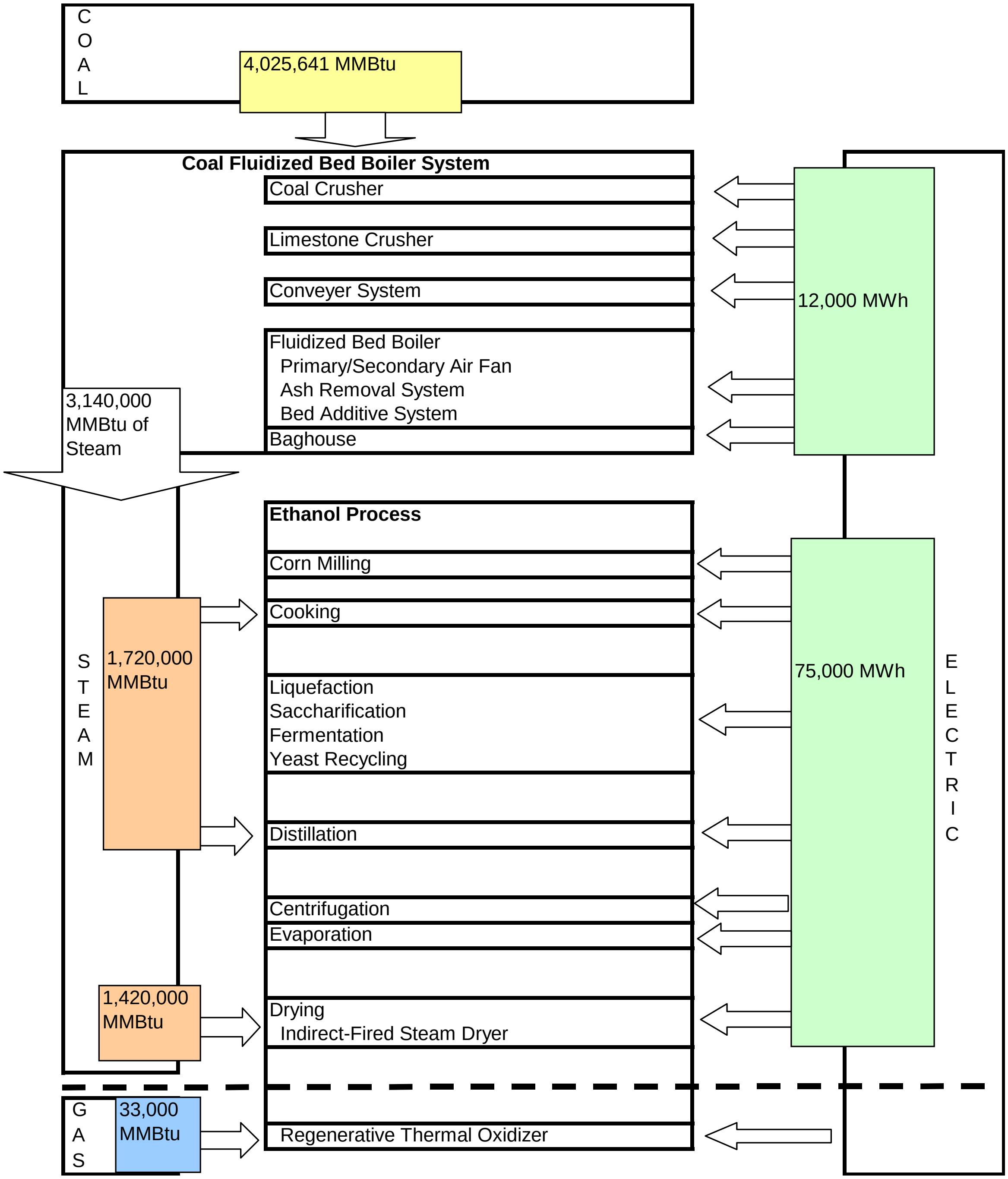
## Table 3.1-1: Energy Flow Comparison – Natural Gas vs. Coal Fired Ethanol Plant

| | **Natural Gas Base Case** | **Fluidized Bed Coal with Integrated VOC Destruction** | **Fluidized Bed Coal with Natural Gas Fired RTO** |
|---|---|---|---|
| Capacity (mgpy) | 100 | 100 | 100 |
| Operating Hours | 8,592 | 8,592 | 8,592 |
| Process Electric Use (MWh/y) | 75,000 | 75,000 | 75,000 |
| Coal Parasitic Electric Use (MWh/y) | | 15,000 | 15,000 |
| Total Electric Use (MWh/yr) | 75,000 | 90,000 | 90,000 |
| Average Electric Demand (MW) | 8.7 | 10.5 | 10.5 |
| Process Energy Use (MMBtu) | 1,720,000 | 1,720,000 | 1,720,001 |
| Steam Dryer Energy Use (MMBtu) | N/A | 1,420,000 | 1,420,000 |
| Total Steam Use (MMBtu) | 1,720,000 | 3,140,000 | 3,140,001 |
| Steam Enthalpy (Btu/lb) | 1,022 | 1,022 | 1,022 |
| Nominal Boiler Capacity (lbs/hr) | 195,877 | 357,589 | 357,589 |
| Boiler Efficiency | 80% | 78% | 78% |
| Required Boiler Fuel (MMBtu) | 2,150,000 | 4,025,641 | 4,025,642 |
| Nat. Gas Dryer Fuel (MMBtu) | 1,050,000 | N/A | N/A |
| RTO Energy (MMBtu) | 33,000 | N/A | 33,000 |
| Total Fuel Use (MMBtu) Thermal Systems | 3,233,000 | 4,025,641 | 4,058,642 |
| Fuel Use (Btu/gal) Thermal Systems | 32,330 | 40,256 | 40,586 |

**Figure 3.1-1: Energy Flow Diagram – Natural Gas Fired Ethanol Plant**



### Figure 3.1-2: Energy Flow Diagram – Coal Fired Ethanol Plant



## Task 3.2 Economic comparison between a coal fired and a natural gas fired ethanol plant

The use of coal in energy systems at dry mill ethanol plants instead of natural gas will result in different up-front investments in equipment and infrastructure (capital costs) as well as different annual expenditures for operation and maintenance. This section identifies these capital as well as O&M costs associated with utilizing a) an energy system fueled by natural gas, and b) an energy system fueled by coal. The study separates the cost and financing aspects associated with the energy plants from the ethanol processes, as if, for illustration purposes, a third party would provide all energy services (thermal and electric) to the ethanol plant. A summary of all cost figures is provided in Table 3.3-1.

### 3.2.1) Energy systems at natural gas fired ethanol plants

### 3.2.1.1) Capital cost of energy systems at natural gas fired ethanol plants

Boiler

A key manufacturer interviewed for this study stated that three 2,000 hp natural gas fired boilers would best serve the steam requirement of a 100 mgpy plant and provide a good amount of flexibility for periodic maintenance as well as turndown. These systems would produce up to 210,000 lbs/hr of steam (150 psig). The complete package with boiler, feedwater controls, blowdown valves and piping would cost approximately $ 1.2 million (for three boiler systems combined). The electric requirements of a boiler for the blower and compressor motors are approximately 500 MWh per year.

Dryer

A key manufacturer produced a mass flow system for this study, which showed that a 100 mpgy plant with 100% DDGS drying (approximately 320,000 tpy of DDGS) would require 4 natural gas direct fired dryer systems of that particular manufacturer’s systems at a cost of $7.4 million. This system includes the natural gas burners, furnaces, drums, cyclones, fans, controls, and ducting.

Emissions Control Systems

- VOC Emission Control:
  A 100 mgpy plant will require thermal oxidizers that can handle air flows of between 80,000 to 100,000 cfm. Natural gas-fired Regenerative Thermal Oxidizers (RTO) for a 100 mgpy plant cost between US$ 2.5-3 million (Eisenmann, 2006, personal conversation). RTOs will add about 330 Btu/gal to the energy needs of the plant.

- Dust Particulate Control:
  There are no baghouse structures for dust/particulate control directly associated with the natural gas fired energy systems; baghouse structures are primarily

associated with the ethanol processes (i.e. for corn dumping, corn grinding, and DDGS drying) but not with the natural gas fired energy system.

- Permitting Costs:
  Ethanol plants initially require a construction permit and once constructed an annual operating permit. Any fees associated with the construction permitting process fall under capital cost considerations while annual operating permit fees fall into O&M expenses. In Illinois, however, there are no fees associated with the construction permitting process administered by the Illinois Environmental Protection Agency (IEPA). Additional costs for permitting consultants were not considered as part of this study.

Natural Gas Fuel Handling Equipment

- Feedwater controls, Blowdown Valves and Piping:
  These systems are integrated and supplied with the natural gas fired boiler system.

- Pipeline:
  Pipeline construction cost have historically ranged between $30,000 to $58,000 per inch-mile with costs of around $40,000 per inch-mile quoted in the most recent numbers (Crump, 2003). A 12 inch pipeline required for the natural gas fired system of a 100 mgpy plant therefore costs approximately $480,000 per mile to construct. For the purpose of this study costs for a 3 mile pipeline were assumed costing approximately 1.4 million dollars.

#### 3.2.1.2) Operation and maintenance cost of energy systems at natural gas fired ethanol plants

Thermal System Fuel: Natural Gas

Table 3.2.1.2-1 below indicates that in Illinois natural gas costs delivered to industrial customers over the last four years have risen significantly (EIA Natural Gas Monthly, June 2006):

**Table 3.2.1.2-1: Annual Average Natural Gas Prices Delivered to Industrial Customers in Illinois**

| Year | $/MMBtu |
|---|---|
| 2002 | 4.97 |
| 2003 | 7.23 |
| 2004 | 8.07 |
| 2005 | 9.97 |

While natural gas prices are not expected to keep rising at the same rate, the prices are expected to fluctuate around the current, high levels. A recent article in Ethanol Producer Magazine quotes natural gas prices over the next one to three years to "average around $9/MMBtu (Jessen, July 2006). A more in depth analysis for the present study looked at the NYMEX Futures contract for natural gas Northern Illinois Hub. Averaging all monthly quotes through August 2011 will result in an average futures price of $8.69/MMBtu. This price was selected for the analysis performed in the present study.

The natural gas consumption of a 100 mgpy ethanol plant is approximately 3,233,000 MMBtu. At $8.69 per MMMBtu this results in annual fuel costs of $28.1 million. However, this may be a conservative fuel consumption assumption. Fuel consumptions in dryers can vary widely with the boiler fuel requirements. According to a dryer mass flow calculation from a major dryer manufacturer, the actual annual fuel consumption would be around 1,517,000 MMBtu per year compared to the 1,050,000 MMBtu (per Henneman/EEA Inc.) embedded in the 3,233,000 MMBtu used in the present study.

### Electricity

For natural gas fired power plants ICM, a major ethanol plant builder, guarantees electrical usage per gallon of 0.75 kWh/gal or 75,000 MWh for a 100 mgpy plant (Roddy, 2006). Electricity price forecasts are based on an analysis of NYMEX electricity future contracts. This type of forward looking analysis was chosen over a historical electricity price analysis since new regulatory changes starting January 2007 will alter electricity rates in Illinois. This study uses the average of the monthly NYMEX electricity future settlements (Northern Illinois Hub) for January 2007 through December 2008 and added 30% for Transmission and Distribution. This approach results in an electricity rate of $0.078 per kWh.[3] The 75,000 MWh consumed annually by a 100 mgpy plant therefore will result in annual electricity cost of $5.9 million.

### Annual Permitting Fees

Yearly fees are imposed by IEPA for operating permits depending on the combined project emissions of NOx, SOx, PM, VOC, and Hazardous Air Pollutants (in tons per year) . In general, if a facility was permitted as a minor source during construction (see Section 5) the facility has to obtain a Yearly State operating permit, whereas, if the facility was permitted as a major source, the facility has to obtain a Yearly CAAP operating permit. Natural gas fired ethanol plants in the 100 mgpy capacity range may often be classified as a minor source and therefore operate under a State Operating Permit. The annual fees for State Operating Permits are capped at $2,500. However, these are permitting fees for the whole ethanol plant and not all emissions are attributable to the operation of the natural gas fired plant. Therefore, attributing $2,500 to the natural gas fired plant is conservative.

### Personnel

While the staff levels for an ethanol pant are approximately 55-60 employees (Yancey, May 2006), the dedicated staff required to operate the natural gas-fired energy systems are estimated to be 2 person per year at a combined annual cost of $100,000.

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[3] In fact, these electricity rates may be low considering that many ethanol plants are located at the end of rural feeders. Adkins Energy LLC located in a rural area of ComEd's territory would have to pay more than $0.1/kWh but decided on a combined heat and power system. See the Adkins LLC "Fact Sheet" at www.chpcentermw.org.

Other O&M:
As a conservative assumption no additional maintenance cost (beyond personnel cost) were assumed for natural gas fired systems.

### 3.2.2) Energy systems at coal fired ethanol plants

#### 3.2.2.1) Capital cost of energy systems at coal fired ethanol plants

Boiler
Fluidized-bed and Ancillary Components
As detailed in Section 1, a fluidized-bed energy system is highly integrated which means that one engineering/manufacturing company will supply the majority of components including the fluidized-bed cell and ancillary components, the forced draft and preheat system, the bed recycle system, the bed additive system, the steam generating system, the gas cleanup equipment, induced draft fan, stack and ducting, fuel metering/feed system, ash handling system, access system, and the instrumentation and control system. As a first approximation, for a 350,000 lbs/hr boiler these system components cost approximately $20 million (Energy Products of Idaho, 2006).

Dryer
A key manufacturer produced a mass flow system for this study, which showed that a coal fired 100 mpgy plant with 100% DDGS drying (approximately 320,000 tpy) would require 10 steam fired disc dryers of that parrticular manufacturer's systems with each system requiring 16,000 lbs/hr of steam. The total dryer system size to produce the approximately 320,000 tons of DDGS per year will cost approximately $17.25 million including condensers.

Emissions Control Equipment

- VOC Control:
  Fluidized-bed boiler ethanol plants (such as the Canton, Illinois and Goldfied, Iowa plant) are commonly configured such that the exhaust from the DDGS drying process is routed through a cyclone and a forced draft fan to serve as combustion air to the boiler. This process effectively controls VOC emissions. Therefore, no additional costs for a RTO were assumed. [4]

- Dust Particulate Control:
  Coal-fired energy systems at ethanol plants will require baghouse structures for dust/particulate control for coal dumping and coal flue gas control. Additional baghouse structures are primarily associated with the ethanol processes and include corn dumping, corn grinding, and DDGS drying. The baghouse structures

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[4] Under certain conditions destroying VOCs in the boiler may require firing the boiler at a higher temperature, which may at times create inefficient operating conditions. Therefore, some fluidized-bed boiler plants may elect to install separate natural gas fired RTOs (like the Heron Lake, MN plant). A 100 mgpy plant will require thermal oxidizers that can handle air flows of between 80,000 to 100,000 cfm. RTOs of this size will add about 330 Btu/gal to the energy needs of the plant and cost between US$ 2.5-3 million (Eisenmann, 2006).

associated with the coal energy plant operation are included in the integrated fluidized boiler package.

- Permitting Cost:
  There are no permitting fees associated with obtaining an air emissions construction permit. However, consultant fees may apply.

<u>Coal Handling Equipment</u>

- Fuel Metering/Feed Systems, Bed Additive Systems, Ash Removal System:
  These systems are integrated and supplied with the fluidized-bed and ancillary components and included in the cost detailed above.

- Rail:
  Absent access to water and the potential for coal delivery by barge, coal-fired ethanol plants need access to the rail system. The costs of constructing new rail tracks are approximately $300 per foot (across agricultural land) or approximately US$ 1.5 million per mile (personal conversation with LB Foster Company, 2006). For the purpose of this study a dedicated rail line of 3 miles was assumed costing approximately 4.5 million dollars to construct. However, once constructed, the rail system can also be used for ethanol and corn shipments. Therefore, attributing the rail costs solely to fuel procurement is a conservative assumption.

#### 3.2.2.2) Operation and maintenance cost of energy systems at coal fired ethanol plants

<u>Themal System Fuel: Coal</u>

- Coal Commodity:
  Coal commodity prices are based on historical data since Illinois coal is lacking an index similar to the NYMEX listings for Illinois natural gas. Since September 2004 the spot price for Illinois coal has been consistently above $35 per ton (with few exceptions) and averages around $37 per ton (EIA Coal News and Markets, 2006).

- Coal Transportation:
  A 100 mgpy coal fired plant (350,000 lbs/hr steam) requires approximately 470 tons of coal per day. A standard rail car holds about 90 tons of coal, aluminum made rail cars hold about 100 tons of coal. Western coal is generally delivered on Union Pacific or Burlington Northern Santa Fee (BNSF) lines with trains ranging between 90 to 135 cars. Transporting Illinois coal within the state, however, would generally be accommodated on trains ranging from 75 to 100 cars, transported on Union Pacific or Norfolk Southern lines. Transportation costs are generally estimated at $30/ton for Western coal from mine moth to generator and $25/ton for Illinois coal delivered within the state. Coal transportation costs have significantly increased over the last several years (approximately 30% increase over the last 3 years) with the rail system currently operating at full capacity (personal conversation with Southern Illinois Railcar). While recent reports point

to supply shortages of coal due to rail transportation logistics, the investment into rail infrastructure by the seven Class I railroad companies (defined as freight hauling railroads with operating income in excess of 289.4 million each) has increased by 21% over the last year and is the largest in history (Clair, August 2006). This investment should provide some needed stability to coal transportation arrangements.

- Delivered Coal:
  Including transportation, the total cost of delivered coal is $62 per ton ($37 commodity plus $25 transportation).

- Coal Storage:
  As discussed above a coal rail car holds on average 95 tons. At an average 83 rail cars per unit train this will require one coal train to the ethanol plant every 17 days and a coal yard with approximately 8,000 tons of coal storage capacity on site (personal conversation with LB Foster Company, 2006). The costs associated with rail yard operation are difficult to quantify with the majority of the cost considered in the personnel category. However, Illinois coal, which is the focus of this study, is less susceptible to spontaneous combustion when stored than Power River Basin Coal (Pircon, July 2006) thus requiring relatively low risk management costs.

### Electricity

A coal fired ethanol plant has a higher electricity demand than a natural gas fired one. The key loads of additional electricity are conveyer belts, crushers, dust collector fans, boiler tube cleaning, fluidized-bed air fans, induced draft fan, ash removal system (pneumatic/vacuum systems), and the bag house (compressed air) (Henneman Engineering, 2006, personal conversation).

Several sources estimate the electricity uses to be between 15% to 20% higher for a coal fired ethanol plant than for a natural gas fired one (Whelan, 2006; EEA Inc., 2006). For natural gas fired power plants ICM guarantees electrical usage per gallon of 0.75 kWh/gal (Roddy, 2006). This study assumes an incremental 0.15 kWh/gal electricity consumption for a coal fired plant or a total of 0.9 kWh/gal. At an electricity rate of $0.078 per kWh the 90,000 MWh consumed annually by a 100 mgpy plant will result in electricity cost of $7 million.

### Annual Operating Permitting Fees

Coal fired ethanol plants in the 100 mppy capacity range may often be classified as a major source and therefore have to obtain a CAAP permit. The annual fees for CAAP Permits are capped at $100,000. However, as the permitting example in Section 5.4 shows, the permitting fees for a 100 mgpy plant should not exceed $20,000 Further, these are permitting fees for the whole ethanol plant and not all emissions are attributable to the operation of the coal fired energy plant. Therefore, attributing $20,000 to the coal plant is conservative.

Personnel

In general coal-fired energy systems require more and higher-skilled staff than natural gas fired ones (Whelan, 2006). A 100 mpgy natural gas-fired ethanol plant requires approximately 55-60 employees (Kotrba, May 2006, p. 64) with an estimated 2 person dedicated to running the natural gas fired energy system at $50,000 salary per employee. With coal, this study assumes an additional 2 operators annually (Diego Nicola, quoted in Ethanol Producer Magazine by Dave Niles, August, 2006, p. 110). The cost of so-called start-up advisors, which are sometimes recommended by coal energy system providers are not considered (Energy Products of Idaho recommends a start-up advisor of 6 man months) since this is an optional component.

Other O&M

- Coal System Maintenance:
  Other O&M fees considered in this study include coal system and boiler system maintenance fees not covered by personnel (parts replacements, etc.). For a 100 mgpy coal fired ethanol plant these costs were estimated to be $360,000 annually (Diego Nicola for a biomass fired ethanol plant, quoted in Ethanol Producer Magazine, August, 2006).

- Limestone Supply:
  Another O&M component are limestone requirements for sulfur control. The costs were assumed to total $166,000 (Diego Nicola for a biomass fired ethanol plant, quoted in Ethanol Producer Magazine by Dave Niles, August, 2006).

- Coal Combustion Products:
  In the US approximately 40% of coal combustion production such as fly ash and bottom ash are used in, primarily, construction. This means coal combustion products can provide a net revenue stream for coal fired power plants (Hansen, July 2006). However, the ability to sell CCPs depends on a variety of factors such as the surrounding transportation infrastructure and construction activity. While prices paid for fly ash can be as high as $65 per ton, for the purpose of this study, no additional revenues from selling CCPs were assumed. Conversely, no disposal cost for CCPs were assumed either.

### 3.3) Perform an economic comparison with financing considerations

The useful life of a dry mill ethanol plant is estimated to be between 30 to 60 years (Jeff Laut with Broin, quoted in Ethanol Producers Magazine, May, 2006, p. 69). More conservatively, the useful life of energy producing equipment is rated at 20 years (ASHRAE Handbook, HVAC Applications, 1995). Financing assumptions detailed by BBI international for dry mill ethanol plants are as follows: 10 to 15 year loans with 35 % to 40% equity. The loan interest rates are 2% to 2.5% over prime rate (BBI Ethanol Plant Handbook). For the purpose of this study the loan duration is assumed to be 12 years with an interest rate of 10% (2% over an 8% prime rate). These assumptions result in annualized capital cost payments of $6.1 million for coal fired energy systems and $1.9 million for natural gas fired energy systems (see Table 3.3-1 below). However, the annual O&M cost (including fuel) for coal fired systems are lower for coal with $18.4 million compared to natural gas O&M cost of $34.1 million. Adding the annualized capital cost to the O&M costs for each energy system shows net annual savings of $11.5 million for the coal fired energy system.

## Table 3.3-1: Cost Comparison Coal fired Ethanol Plant vs. Natural Gas fired Ethanol Plant

| Coal | | Natural Gas | |
|---|---|---|---|
| Plant Capacity (gpy) | 100,000,000 | Plant Capacity (gpy) | 100,000,000 |
| **Fuel Quantity:** | | **Fuel Quantity:** | |
| Required Fuel (MMBtu) | 4,025,641 | Required Fuel (MMBtu) | 3,233,000 |
| Coal Heating Value (MMBtu/ton) | 23.6 | | |
| Required Fuel (tons/y) | 170,578 | | |
| Required Fuel (tons/day) | 467 | | |
| **Fuel Cost:** | | **Fuel Cost:** | |
| Price of Coal at Mine Mouth ($/ton) | 37 | | |
| Transportation Cost ($/ton) | 25 | | |
| Delivered Coal cost ($/ton) | 62 | | |
| Delivered Coal cost ($/MMBtu) | 2.63 | Delivered Gas Cost ($/MMBtu) | 8.7 |
| Delivered Coal Cost ($) | 10,587,436 | Delivered Gas Cost ($) | 28,127,100 |
| **Electric Cost:** | | **Electric Cost:** | |
| Electricity Consumption (kWh) | 90,000,000 | Electricity Consumption (kWh) | 75,000,000 |
| Electric Rates for Indust. Plants ($/kWh) | 0.078 | Electric Rates for Indust. Plants ($/kWh) | 0.078 |
| Electric Cost ($) | 7,020,000 | Electric Cost ($) | 5,850,000 |
| **Rail Logistics:** | | **Pipeline Logistics:** | |
| Railcar capacity (tons/rail car) | 95 | | |
| Number of cars per train | 83 | | |
| Delivered coal per train (tons) | 7885 | | |
| Number of days between trains | 16.87 | Construction Cost per Inch-Mile ($) | 40,000 |
| Rail Track Construction Cost ($/mile) | 1,500,000 | Pipeline Diameter (inches) | 12 |
| Number of Required Rail Miles | 3 | Number of Required Rail Miles | 3 |
| Rail Cost ($) | 4,500,000 | Pipeline Costs ($) | 1,440,000 |
| **Regenerative Thermal Oxidizer:** | | **Reg. Thermal Oxidizer (RTO):** | |
| Fuel Requirements (Btu/gal) | N/A | Fuel Requirements (Btu/gal) | 330 |
| Total Fuel Requirements (MMBtu/y) | N/A | Total Fuel Requirements (MMBtu/y) | 33,000 |
| Cost ($) | N/A | Cost ($) | 2,750,000 |
| **Financing:** | | **Financing:** | |
| Equipment Life (years) | 20 | Equipment Life (years) | 20 |
| Loan Duration (years) | 12 | Loan Duration (years) | 12 |
| Interest Rate | 10% | Interest Rate | 10% |

| | | | |
|---|---|---|---|
| **Capital Cost:** | | **Capital Cost:** | |
| Fluidized Bed Boiler Cost ($) | 20,000,000 | Firetube Boiler Cost ($) | 1,200,000 |
| Dryer ($) | 17,250,000 | Dryer ($) | 7,420,000 |
| RTO ($) | N/A | RTO ($) | 2,750,000 |
| Rail Cost ($) | 4,500,000 | Pipeline Cost ($) | 1,440,000 |
| Emissions Construction Permitting Fees ($) | 0 | Emissions Construction Permitting Fees ($) | 0 |
| Total Capital Cost ($): | 41,750,000 | Total Capital Cost ($): | 12,810,000 |
| **O&M Cost:** | | **O&M Cost:** | |
| Total Annual Fuel Cost ($) | 10,587,436 | Total Annual Fuel Cost ($) | 28,127,100 |
| Electric Cost ($) | 7,020,000 | Electric Cost ($) | 5,850,000 |
| Personnel Cost ($) | 200,000 | Personnel Cost ($) | 100,000 |
| Emissions Operating Permitting Fees ($) | 20,000 | Emissions Operating Permitting Fees ($) | 2,500 |
| Other O&M: | | Other O&M: | |
| Coal System Maintenance ($) | 360,000 | Boiler System Maintenance ($) | incl. in personnel |
| Limestone Cost ($) | 166,000 | | |
| Coal Combustion Product Costs ($) | 0 | | |
| Total O&M ($) | 18,353,436 | Total O&M ($) | 34,079,600 |
| **Financing:** | | **Financing:** | |
| Annualized Loan Payments ($) | 6,127,368 | Annualized Loan Payments ($) | 1,880,038 |
| Add: O&M Cost ($) | 18,353,436 | Add: O&M Cost ($) | 34,079,600 |
| Total Annual Energy Cost ($) | 24,480,804 | Total Annual Energy Cost ($) | 35,959,638 |
| Differential: Coal to Gas ($) | -11,478,834 | | |

## 3.4) Fuel price sensitivity considerations

Table 3.3-1 above has shown that building and operating a coal fired ethanol plant compared to a natural gas fired one should, under the stated assumptions, save approximately $11.5 million annually. The capital cost assumptions embedded in these savings (i.e. different equipment prices for coal boilers etc.) have to be expended now and the uncertainties associated with these expenses are largely related to different price points for different types of equipment and vendors. However, significantly higher uncertainties exist for operating expenses and in particular the fuel costs for the thermal systems, coal and natural gas. The following analysis shows how an increase/decrease in coal and natural gas costs affects the differential costs of owning/operating a coal fired ethanol plant vs. owning/operating a natural gas fired ethanol plant.

The starting point for this analysis is the $11.5 million annual savings that are the results of owning and operating a 100 mgpy coal-fired ethanol plant that sources coal at $2.63/MMBtu over a natural gas fired ethanol plant that sources natural gas at $8.7/MMBtu. For illustration purposes this is the point where the two trend lines cross at the y-axis at -$11.5 million in the graph below. Now, this analysis shows that if natural gas prices increase by 20% from the baseline $8.7/MMBtu to $10.44/MMBtu, the owner/operator of a coal fired ethanol plant would save $17.1 million annually (at a constant coal price of $2.63/MMBtu). Conversely, if coal prices decrease, for example by 30% from the baseline $2.63/MMBtu to $1.84 MMBtu, then the savings from owning/operating a coal fired ethanol plant increase to $14.7 million annually (at a constant natural price of $8.7/MMBtu). The analysis also shows that if natural gas prices were to drop to $3.48/MMBtu the owner/operator of a natural gas fired plant would actually save $5.4 million annually over a coal fired ethanol plant. The actual break-even point in this analysis is around $5.2/MMBtu of natural gas, or a 40% drop from current prices (this is also where the natural gas line crosses the x axis in the graph). Further, the analysis shows that even at $5 per MMBtu for coal (a 90% increase from the current baseline) the owner/operator still saves almost 2 million over a natural gas fired plant.

**Table 3.4-1: Sensitivity of Annual Cost Differential to Fuel Prices**

| | Gas | | Coal | |
|---|---|---|---|---|
| Price Variation | Gas Price ($/MMBtu) | Cost Differential: Gas Price Variation ($) | Coal Price ($/MMBtu) | Cost Differential: Coal Price Variation ($) |
| 90% | 16.53 | -36,793,224 | 5.00 | -1,950,142 |
| 60% | 13.92 | -28,355,094 | 4.21 | -5,126,372 |
| 30% | 11.31 | -19,916,964 | 3.42 | -8,302,603 |
| 20% | 10.44 | -17,104,254 | 3.16 | -9,361,347 |
| 10% | 9.57 | -14,291,544 | 2.89 | -10,420,090 |
| 0% | 8.70 | -11,478,834 | 2.63 | -11,478,834 |
| -10% | 7.83 | -8,666,124 | 2.37 | -12,537,577 |
| -20% | 6.96 | -5,853,414 | 2.10 | -13,596,321 |
| -30% | 6.09 | -3,040,704 | 1.84 | -14,655,065 |
| -60% | 3.48 | 5,397,426 | 1.05 | -17,831,295 |
| -90% | 0.87 | 13,835,556 | 0.26 | -21,007,526 |

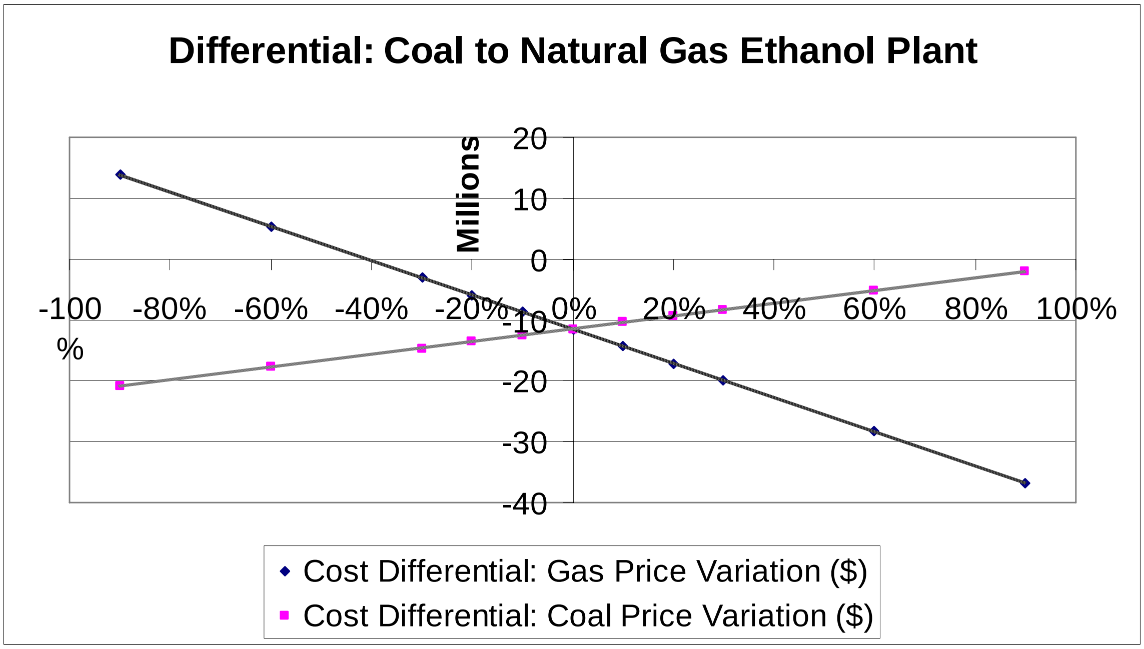

**Figure 3.4-1: Sensitivity of Annual Cost Differential to Fuel Prices**

## Task 4 – Perform a cursory investigation of adding CHP to both the natural gas baseline design and the coal fueled alternative designs

Task 4 is divided into two subtasks.

- Task 4.1: Determine the differences in energy flows between CHP and non-CHP plants.
- Task 4.2: Perform an economic comparison with financing considerations.

### 4.1) Difference in energy flows between CHP and non-CHP plants

In previous sections several methods of efficient waste heat utilization have been mentioned, such as the utilization of recuperative or regenerative heat exchangers for thermal oxidizers or the use of HRSGs coupled with DDGS dryers for process steam generation. Combined heat and power (CHP) constitutes another way of waste heat utilization.[5] The relatively large and coincident electricity and steam demands of dry mill ethanol plants make them ideal candidates for application of CHP systems. By generating a portion of the plant's power needs on-site and recovering the heat normally wasted in the generation process as process steam, CHP can increase the efficiency of energy use in the ethanol production process. A preliminary analysis was conducted of the relative energy consumption of dry mill ethanol plants incorporating CHP compared

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[5] The majority of the energy flow calculations presented in this section were performed by Energy Environmental Analysis, Inc. Contributions were also provided by the U.S. Environmental Protection Agency's Combined Heat and Power Partnership. Any errors in applying these calculations are strictly the errors by the authors of the present study.

to conventional non-CHP boiler plant designs. The analysis was based on the energy profiles of the state-of-the-art 100 million gallons/year natural gas- and coal-based ethanol plants as described in Section 2. Two CHP plant designs were evaluated:

- Natural Gas CHP - Gas Turbine CHP with a supplementary-fired heat recovery steam generator (HRSG), natural gas-fired DDGS dryer, and a natural gas-fired regenerative thermal oxidizer.

- Coal CHP - High pressure fluidized-bed coal boiler with a backpressure steam turbine generator, with exhaust from steam-heated DDGS dryer integrated into the boiler intake for combustion air and VOC destruction.

There are currently four gas turbine CHP systems similar to the natural gas CHP system described above operating at dry mill ethanol plants in the United States[6]. The gas turbine system considered was sized to ensure that all generated power would be used on-site. Gas turbine size and performance was based on a Solar Turbines Taurus 70 rated at 7.2 MW. Since a 7.2 MW gas turbine will not produce enough steam in an unfired HRSG to meet the plant steam requirements supplementary firing was incorporated into the design. Steam generation efficiency for the supplemental burner was assumed to be 90%[7].

Table 4.1-1 provides detailed performance and output characteristics of the gas turbine based CHP system and similarly compares purchased electricity use and fuel use with the base case non-CHP natural gas ethanol plant. Based on the system performance assumptions outlined above, the gas turbine CHP system produces about 78% of the plant's total annual electricity needs and 95% of the plant's steam needs. While the CHP system displaces 2,042,500 MMBtu/yr of natural gas in the boiler, it consumes 677,307 MMBtu/yr in the gas turbine and an additional 1,592,016 MMBtu/yr in the HRSG supplemental burner. Overall natural gas use at the plant (including dryer and thermal oxidizer as well) increases from 3,233,000 MMBtu/yr in the non-CHP base case to 3,459,823 MMBtu/yr with CHP. Process fuel consumption per gallon of ethanol product increases from 32,330 Btu/gallon to 34,598 Btu/gallon. However, the CHP system displaces 58,361 MWh/yr of purchased electricity.

There is at least one coal-based ethanol plant that includes a steam turbine CHP system similar to the system described above due to come on line in 2006.[8] The size of the coal-based steam turbine CHP system is set by the steam demand of the plant; the CHP system for the studied 100 mgpy plant consists of a 358,000 lbs/hr fluidized-bed boiler producing steam at pressures and temperatures higher than the process requirements (575 psig and

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[6] Gas turbine CHP systems are installed at Adkins Energy LLC, Lena, IL; U.S. Energy Partners, Russell, KS; Northeast Missouri Grain, Macon, MO; and Otter Creek Ethanol, Ashton, IA. The Midwest Combined Heat and Power Application Center has compiled "Project Profiles" on the CHP systems installed at the ethanol plants in Lena, Russell, and Macon. The information is available at www.chpcentermw.org.

[7] The steam generating efficiencies of duct burners are typically above 90% because the combustion air (turbine exhaust) is already at an elevated temperature (800 to 1000 F)

[8] Central Illinois Energy Canton, IL – a 37 mgpy plant fueled by coal fines and coal incorporates a fluidized-bed boiler/steam turbine CHP system.

615 F). The boiler outlet steam conditions were selected to ensure that all power generated by the steam turbine generator would be used on-site. The entire steam output of the boiler enters a back pressure steam turbine where 10.3 MW of electricity is generated before the steam exits the turbine at the 150 psig pressure required for the process. The output of the steam turbine generator assumes a combined gearbox and generator efficiency of 95%. The availability of the steam turbine generator was conservatively assumed to be 95%.

Table 4.1-1 also provides detailed performance and output characteristics of the coal boiler/steam turbine based CHP system and compares purchased electricity use and fuel use with the non-CHP base case coal ethanol plant. Based on the system performance assumptions outlined above, the steam turbine CHP system produces about 93% of the plant's total annual electricity needs. While the steam flows are the same in terms of lbs/hr of boiler output, the CHP system uses 10.1% additional coal over the non-CHP base case in order to provide higher pressure and temperature steam for the turbine generator. Overall coal use at the plant increases from 4,025,641 MMBtu/yr in the non-CHP base case to 4,431,356 MMBtu/yr with CHP, for a total increase in coal consumption of 405,715 MMBtu/yr. In-plant fuel consumption per gallon of product increases from 40,256 Btu/gallon in the non-CHP base case to 44,314 Btu/gallon in the CHP case. However, the CHP system displaces 83,706 MWh/yr of purchased electricity.

## Table 4.1-1: Natural Gas and Coal-Based CHP System Energy Flow Comparison

| | Natural Gas Base Case | Natural Gas CHP Case | FB Coal Base Case | FB Coal CHP Case |
|---|---|---|---|---|
| Capacity (mgpy) | 100 | 100 | 100 | 100 |
| Operating Hours | 8,592 | 8,592 | 8,592 | 8,592 |
| **Electric:** | | | | |
| Process Electric Use (MWh/y) | 75,000 | 75,000 | 75,000 | 75,000 |
| Coal Parasitic Electric Use (MWh/y) | | | 15,000 | 15,000 |
| Total Electric Use (MWh/y) | 75,000 | 75,000 | 90,000 | 90,000 |
| Average Electric Demand (MW) | 8.7 | 8.7 | 10.5 | 10.5 |
| Gas Turbine Electric Capacity (MW) | N/A | 7.2 | N/A | N/A |
| Steam Turbine Electric Capacity (MW) | N/A | N/A | N/A | 10.3 |
| CHP Power Generated (MWh/y) | N/A | 58,361 | N/A | 83,706 |
| Purchased Power (MWh/y) | 75,000 | 16,639 | 90,000 | 6,294 |
| **Thermal:** | | | | |
| Process Energy Use (MMBtu/y) | 1,720,000 | 1,720,000 | 1,720,000 | 1,720,000 |
| Steam Dryer Energy Use (MMBtu/y) | N/A | N/A | 1,420,000 | 1,420,000 |
| Steam Turbine Energy Use (MMBtu/y) | N/A | N/A | N/A | 316,458 |
| Total Steam Energy Use (MMBtu/y) | 1,720,000 | 1,720,000 | 3,140,000 | 3,456,458 |
| | | | | |
| Total Steam Provided by Boiler (MMBtu/y) | 1,720,000 | 86,000 | 3,140,000 | 3,456,458 |
| Steam Enthalpy (Btu/lb) | 1,022 | 1,022 | 1,022 | 1,125 |
| Nominal Boiler Capacity (lbs/hr) | 195,877 | 9,794 | 357,589 | 357,589 |
| | | | | |
| Boiler Efficiency | 80% | 80% | 78% | 78% |
| Required Boiler Fuel (MMBtu/y) | 2,150,000 | 107,500 | 4,025,641 | 4,431,356 |
| Nat. Gas Dryer Fuel (MMBtu/y) | 1,050,000 | 1,050,000 | N/A | N/A |
| RTO Energy (MMBtu/y) | 33,000 | 33,000 | N/A | N/A |
| Gas Turbine Fuel Input (MMBtu/y) | N/A | 677,307 | N/A | N/A |
| HRSG Fuel Input (MMBtu/y) | N/A | 1,592,016 | N/A | N/A |
| Total Fuel Use (MMBtu) Thermal Systems | 3,233,000 | 3,459,823 | 4,025,641 | 4,431,356 |
| Fuel Use (Btu/gal) Thermal Systems | 32,330 | 34,598 | 40,256 | 44,314 |

## 4.2) Economic comparison with financing considerations

A properly sized CHP system generally requires higher capital costs for equipment and higher fuel costs; however, the overall O&M costs are lower due to reduced electric costs. Table 4.2.2-1 summarizes the financial considerations associated with CHP at ethanol plants.

### 4.2.1) Natural gas fired ethanol plant

Capital Cost:
Converting a natural gas fired ethanol plant to combined heat and power requires the investment into a combustion turbine and a heat recovery boiler with supplemental firing capabilities. Combustion turbines with heat recovery in the 7 MW range cost between $1,000 to 1,500 per kW (Midwest CHP Application Center Combined Heat and Power Resource Guide, September 2005). Assuming the midpoint of $1,250 per kW a 7.2 MW CHP system costs approximately $9 million.

O&M Costs:
Annual combustion turbine O&M costs are approximately $0.0075 per kWh. Therefore, the 58,000 MWh generated onsite by the CHP system will require O&M costs of $438,000 per year.

The fuel cost of a natural gas fired ethanol plant are also higher than the comparable base case plant without CHP since the fuel consumption increases from 3.2 million MMBtu to 3.5 million MMBtu increasing fuel expenses from $28.1 million to $30.1 million. However, electricity purchases are much lower (16,600 MWh vs. 58,300 MWh) reducing the electricity cost from $5.9 million to $1.3 million.

Taking financing considerations of the capital cost into considerations, a natural gas fired CHP system results in annual total energy savings of $1 million ($35 million vs $36 million) over the non CHP base case after payment for the added equipment.

### 4.2.2) Coal fired ethanol plant

Capital Cost:
Converting a coal fired fluidized-bed ethanol plant to combined heat and power requires the investment into a backpressure steam turbine. Backpressure steam turbines cost between $300-400 per kW (Midwest CHP Application Center Combined Heat and Power Resource Guide, September 2005). Assuming $350 per kW steam turbine capital cost, a 10.3 MW steam turbine (required for a 100 mgpy ethanol plant) costs approximately $3.6 million.

O&M Costs:
Annual steam turbine O&M costs are approximately $0.0015-0.0035 per kWh (Midwest CHP Application Center Combined Heat and Power Resource Guide, September 2005). Taking the midpoint of the cost range ($0.0025 /kWh) the 83,000 MWh generated onsite by the CHP system will require O&M cost of $209,000 per year.

The fuel cost of a coal fired ethanol plant are also higher than the comparable base case plant without CHP since the fuel consumption increases from 4.0 million MMBtu to 4.4 million MMBtu increasing fuel expenses from $10.6 million to $11.7 million. However, electricity purchases are much lower (6,300 MWh vs. 83,700 MWh) reducing the electricity costs from $7 million (non CHP) to $491,000 per year for the CHP plant.

Taking financing of the capital cost into considerations, a coal fired CHP system results in savings of $4.7 million ($19.8 million vs. $24.5 million) in total annual energy cost over the non CHP base case after payment for the added equipment.

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## Table 4.2.2-1: Cost Comparison Coal fired CHP vs. Natural Gas fired CHP Ethanol Plant

| **Coal CHP** | | **Natural Gas CHP** | |
|---|---|---|---|
| Plant Capacity (gpy) | 100,000,000 | Plant Capacity (gpy) | 100,000,000 |
| **Fuel Quantity:** | | **Fuel Quantity:** | |
| Required Fuel (MMBtu) | 4,431,356 | Required Fuel (MMBtu) | 3,459,823 |
| Coal Heating Value (MMBtu/ton) | 23.6 | | |
| Required Fuel (tons/y) | 187,769 | | |
| Required Fuel (tons/day) | 514 | | |
| **Fuel Cost:** | | **Fuel Cost:** | |
| Price of Coal at Mine Mouth ($/ton) | 37 | | |
| Transportation Cost ($/ton) | 25 | | |
| Delivered Coal cost ($/ton) | 62 | | |
| Delivered Coal cost ($/MMBtu) | 2.63 | Delivered Gas Cost ($/MMBtu) | 8.7 |
| Delivered Coal Cost ($) | 11,654,466 | Delivered Gas Cost ($) | 30,100,460 |
| **Electric Cost:** | | **Electric Cost:** | |
| Purchased Power (kWh) | 6,294,000 | Purchased Power (kWh) | 16,639,000 |
| Electric Rates for Indust. Plants ($/kWh) | 0.078 | Electric Rates for Indust. Plants ($/kWh) | 0.078 |
| Electric Cost ($) | 490,932 | Electric Cost ($) | 1,297,842 |
| **Rail Logistics:** | | **Pipeline Logistics:** | |
| Railcar capacity (tons/rail car) | 95 | | |
| Number of cars per train | 83 | | |
| Delivered coal per train (tons) | 7885 | | |
| Number of days between trains | 15.33 | Construction Cost per Inch-Mile ($) | 40,000 |
| Rail Track Construction Cost ($/mile) | 1,500,000 | Pipeline Diameter (inches) | 12 |
| Number of Required Rail Miles | 3 | Number of Required Rail Miles | 3 |
| Rail Cost ($) | 4,500,000 | Pipeline Costs ($) | 1,440,000 |
| **Regenerative Thermal Oxidizer:** | | **Reg. Thermal Oxidizer (RTO):** | |
| Fuel Requirements (Btu/gal) | N/A | Fuel Requirements (Btu/gal) | 330 |
| Total Fuel Requirements (MMBtu/y) | N/A | Total Fuel Requirements (MMBtu/y) | 33,000 |
| Cost ($) | N/A | Cost ($) | 2,750,000 |
| **Financing:** | | **Financing:** | |
| Equipment Life (years) | 20 | Equipment Life (years) | 20 |
| Loan Duration (years) | 12 | Loan Duration (years) | 12 |
| Interest Rate | 10% | Interest Rate | 10% |

| | | | |
|---|---|---|---|
| **Capital Cost:** | | **Capital Cost:** | |
| Fluidized Bed Boiler Cost ($) | 20,000,000 | Firetube Boiler Cost ($) | N/A |
| Dryer ($) | 17,250,000 | Dryer ($) | 7,420,000 |
| RTO ($) | N/A | RTO ($) | 2,750,000 |
| Rail Cost ($) | 4,500,000 | Pipeline Cost ($) | 1,440,000 |
| Steam Turbine ($) | 3,605,000 | Gas Turbine with Heat Recovery Boiler ($) | 9,000,000 |
| Emissions Construction Permitting Fees($) | 0 | Emissions Construction Permitting Fees($) | 0 |
| Total Capital Cost ($): | 45,355,000 | Total Capital Cost ($): | 20,610,000 |
| **O&M Cost:** | | **O&M Cost:** | |
| Total Annual Fuel Cost ($) | 11,654,466 | Total Annual Fuel Cost ($) | 30,100,460 |
| Coal Ancillary Electric Cost ($) | 490,932 | Ancillary Electric Cost ($) | 1,297,842 |
| Personnel Cost ($) | 200,000 | Personnel Cost ($) | 100,000 |
| Emissions Operating Permitting Fees ($) | 20,000 | Emissions Operating Permitting Fees ($) | 2,500 |
| Other O&M: | | Other O&M: | |
| Steam Turbine O&M ($) | 209,265 | Gas Turbine O&M ($) | 437,708 |
| Coal System Maintenance ($) | 360,000 | Boiler System Maintenance ($) | N/A |
| Limestone Cost ($) | 166,000 | | |
| Coal Combustion Product Costs ($) | 0 | | |
| Total O&M ($) | 13,100,663 | Total O&M ($) | 31,938,510 |
| **Financing:** | | **Financing:** | |
| Annualized Loan Payments ($) | 6,656,450 | Annualized Loan Payments ($) | 3,024,792 |
| Add: O&M Cost ($) | 13,100,663 | Add: O&M Cost ($) | 31,938,510 |
| Total Annual Energy Cost ($) | 19,757,113 | Total Annual Energy Cost ($) | 34,963,302 |
| Differential: Coal to Gas ($) | -15,206,188 | | |

## Task 5 – Investigate the current air emissions permitting requirements for coal fired ethanol plants in Illinois

Task 5 is divided into five subtasks.

- Task 5.1: Provide an introduction to air emissions permitting regulations.
- Task 5.2: Provide an overview of ethanol plant air permitting considerations.
- Task 5.3: Provide ethanol plant air permitting examples.
- Task 5.4: Provide a sample calculation for an ethanol plant air emissions permitting fee.
- Task 5.5: Provide an overview of ethanol plant air permitting time requirements.

### 5.1) Introduction to air emissions permitting regulations

Besides a lack of familiarity with coal technologies, uncertainty associated with obtaining air emission construction permits is often cited as a reason not to implement coal fired technologies at an ethanol plant. For example, the construction of the Heron Lake fluidized-bed coal fired ethanol plant was delayed for several months because the final air permit from the Minnesota Pollution Control agency was held up over public objections (Thomson, USDA March 2006). This section provides an overview of air emissions permitting regulations applicable to ethanol plants.

Two of the key concepts of air permitting are that the requirements differ based on a) the geographic region where the ethanol plant project is located and also on b) the emission levels of each regulated pollutant.

a) Geographic Location of the Project

The Clean Air Act as amended in 1990 sets standards for the permissible levels of certain pollutants in the air on a pollutant by pollutant basis. Geographic regions where the level of such a pollutant is below the standard are called attainment areas for the specific pollutant; regions where the level of a pollutant is above the standard are called non-attainment areas for the specific pollutant. As a result, a certain region may be in attainment for one pollutant while being a designated non-attainment area for another pollutant. In Illinois certain areas are designated non-attainment for ground level ozone, which forms when sunlight combines with nitrogen oxides (NOx) and volatile organic compounds (VOCs) such as the chemicals released from gasoline, hairspray, charcoal lighter fluids and, in the case of ethanol plants, in particular from the DDGS drying process. Other areas in Illinois are designated non-attainment for particulate matter (PM), which is a general term for solid particles or liquid droplets found in the air. These particles can be large enough to be seen as soot or smoke. Example sources of PM emissions at coal-fired ethanol plants include flue gas and ash handling.

The following areas are currently designated non-attainment areas for the ozone precursor VOC in Illinois:

**Table 5.1-1: Illinois Non-attainment Areas for VOC**

| **County/Township** | **Name of Area** |
|---|---|
| Cook | Chicago Non-Attainment Area |
| DuPage | Chicago Non-Attainment Area |
| Kane | Chicago Non-Attainment Area |
| Lake | Chicago Non-Attainment Area |
| Will | Chicago Non-Attainment Area |
| McHenry | Chicago Non-Attainment Area |
| Kendall OswegoTownship | Chicago Non-Attainment Area |
| Grundy: Aux Sable Township | Chicago Non-Attainment Area |
| Grundy: Goose Lake Township | Chicago Non-Attainment Area |

The following areas are currently designated non-attainment areas for the ozone precursors VOC and NOx in Illinois:

**Table 5.1-2: Illinois Non-Attainment Areas for VOC and NOx**

| **County** | **Name of Area** |
|---|---|
| Madison | Metro-East Non-Attainment Area |
| Monroe | Metro-East Non-Attainment Area |
| St. Clair | Metro-East Non-Attainment Area |

Furthermore the following areas are currently designated non-attainment for particulate matter (PM): McCook, Lake Calumet and Granit City.

Ethanol plants whose potential emissions would exceed certain thresholds (see Section "b" below) and which are installed in non-attainment areas have to obtain "Non-Attainment New Source Review" (Non-Attainment NSR) permits. Ethanol plants whose potential emissions exceed certain thresholds (see Section "b" below) but are installed in attainment areas obtain Prevention of Significant Deterioration (PSD) permits. Generally speaking Non-Attainment NSR rules have stricter requirements than PSD rules, which result in the following key differences in emissions control requirements for potential ethanol plant projects:

Ethanol plants subject to Nonattainment-NSR permits have to employ Lowest Achievable Emission Rate (LAER) technologies. This means that the ethanol plant has to utilize equipment, which achieves the most stringent emission limitations by such class or category of source regardless of cost. Equipment achieving LAER requirements only needs to be applied for emissions of pollutants subject to Nonattainment-NSR permits.

Ethanol plants subject to PSD permits have to employ Best Available Control Technology (BACT). This means that the ethanol plant project has to utilize the best technically feasible technology for emissions of pollutants subject to PSD taking into account energy, environmental, and economic impacts as well as costs.

b) Emission Levels

Depending on the amount of pollution emitted an ethanol plant project can be classified as i) a minor source, ii) a new major source or iii) a major modification at an existing major source. Only ethanol plant projects classified as a major source or a major modification have to obtain a PSD permit or a non-attainment NSR permit. A new major source refers to ethanol plants constructed on greenfield sites or at facilities which are not already classified as a major source. A major modification at an existing source refers to ethanol plants constructed at sites which are already classified as a major source. The threshold levels, which determine whether or not a project constitutes a major source or a major modification depend on whether or not the project is located in an attainment or a non-attainment area.

An ethanol plant located in a non-attainment area will be classified as a major source for the nonattainment area pollutant(s) if its emissions levels for any pollutant exceed the following thresholds in tons per year (tpy):

**Table 5.1-3: Nonattainment Major Source Thresholds**

| Pollutant by Non Attainment Area | Non Attainment - Major Source Thresholds (tpy) |
|---|---|
| PM - McCook, Lake Calumet, Granite City | 100 |
| VOC - Metro-East | 100 |
| NOx - Metro East | 100 |
| VOC – Chicago | 25 |

The EPA classifies Ozone, Particulate Matter and Carbon Monoxide nonattainment areas into five severity levels corresponding to different emission levels, which trigger a major source classification. For example, Chicago is currently classified as a severe non-attainment area for ozone, which means that new projects emitting 25 tons or more of VOC (a precursor to ozone) constitute a major source and require a Nonattainment-NSR permit. Metro East is currently classified as a marginal non-attainment area for ozone, which means that new projects emitting 100 tons of either VOC or NOx require a Nonattainment-NSR permit.

An ethanol plant project located in a non-attainment area will be classified as a major modification at an existing major source if the facility is already classified as a major source for the nonattainment area pollutant(s) and if its emissions levels for the nonattainment area pollutant exceed the following thresholds:

**Table 5.1-4: Nonattainment Major Modification Thresholds**

| Pollutant by Non Attainment Area | Non Attainment - Major Modification Thresholds (tpy) |
|---|---|
| PM – McCook, Lake Calumet, Granite City | 15 |
| VOC - Metro-East | 40 |
| NOx - Metro East | 40 |
| VOC– Chicago | 25 |

An ethanol plant project located in an attainment area will be classified as a major source if its emissions levels for any pollutant exceed the following thresholds:

**Table 5.1-5: Attainment Major Source Thresholds**

| Attainment – Major Source Thresholds (tpy) | | |
|---|---|---|
| | Individual Pollutant | 28 Categories of Source[9]<br>100 |
| | | Other Categories of Source<br>250 |

As discussed above, the applicable permitting requirements depend primarily on the location of the project (attainment/non-attainment area) and on the size of the project (amount of emissions). However, the major source thresholds for projects located in an attainment area depend on a third factor: the type of facility ("Categories of Source"). Currently, ethanol plants are considered "petroleum refineries" and therefore fall under the "28 Categories of Source" for which the major source threshold for any pollutant is 100 tons per year. However, the U.S. Environmental Protection Agency is currently considering a rule change that would reclassify ethanol plants into "Other Categories of Source" and limit emissions for any pollutant to 250 tons per year.

An ethanol plant project located in an attainment area will be classified as a major modification at an existing major source if the facility is already classified as a major source and if its emissions levels for a pollutant exceed the following thresholds:

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[9] These 28 categories are: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), kraft pulp mills, portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants.

**Table 5.1-6: Attainment Major Modification Thresholds**

| Pollutant | Attainment – Major Modification Thresholds (tpy) |
|---|---|
| Ozone (VOC) | 40 |
| CO | 100 |
| PM | 15 |
| Sox | 40 |
| NOx | 40 |

Note that the major modification thresholds in an attainment area do not depend on the Categories of Source (unlike the major source thresholds).

In addition to the above detailed pollutants, ethanol plants may also emit so called Hazardous Air Pollutants (HAPs). The major source threshold for HAP's is 10 tpy for any one HAP and 25 tpy for combined HAP. Key HAPs in coal ethanol plants are Acetaldehyde, Methanol, and Hydrochloric Acid emitted during DDGS drying and fermentation.

## 5.2) Ethanol plant permitting considerations

Table 5.2-1 shows the major emission sources of fluidized-bed coal fired ethanol plants by ethanol production process stage (see Canton, IL Ethanol Plant Air Permit). The table shows that coal-fired boilers and the DDGS drying process emit the most complex emission patterns.

**Table 5.2-1: Major Emission Sources of Coal Fired Ethanol Plants**

| Process | VOC | PM | NOx | CO | SO2 | HAP |
|---|---|---|---|---|---|---|
| Coal-fired Boiler | X | X | X | X | X | X |
| Natural gas fired Boiler (backup) | X |  | X | X |  |  |
| Raw Grain Dryer |  | X | X | X |  |  |
| Fuel Handling |  | X |  |  |  |  |
| Grain Handling |  | X |  |  |  |  |
| Fermentation | X |  |  |  |  | X |
| Distillation/DDGS Drying | X | X |  | X |  | X |
| Loading Rack | X |  |  |  |  |  |
| Ethanol Loading | X |  |  |  |  |  |
| Leaking Components | X |  |  |  |  |  |
| Flu Ash Processing |  | X |  |  |  |  |

An ethanol plant which is significant enough in size to trigger the need for a PSD permit or a Nonattainment-NSR permit (which means having to install BACT or LAER equipment) can avoid obtainment of these permits by giving consideration to the following:

- Netting:
  Netting means that projects, under certain conditions, can claim credit for the actual emission reductions from emission sources replaced by the project. For example, a dry mill ethanol plant is added to a wet mill plant where an oversized new fluidized-bed boiler system provides energy to the combined wet and dry mill plant. Under certain conditions the project can claim credit for the displaced emissions of the now shut-down natural gas fired energy system at the wet mill.

- Plant Size and Plant Location:
  In general, the least stringent emissions control requirements apply to new ethanol plants constructed in an attainment area, whereas the most stringent emissions control requirements apply to major modifications at an existing major source in a nonattainment area. Therefore, the nonattainment area plant can be sized larger relative to the attainment area plant and still be considered a minor source (Pinto, June 2006). In fact many plants are sized such that their emissions stay below the major source threshold, which makes them a so-called synthetic minor source.

- Fuel Source:
  The choice of fuel source may also depend on the attainment/nonattainment status of an area. If, for example, an area is designated nonattainment for sulfur dioxide, then the plant developers may be reluctant to consider coal, which has a much higher sulfur content than natural gas (Pinto, June 2006). In Illinois, however, there are no nonattainment areas for sulfur dioxide.

- Technology:
  Grain drying at an ethanol plant emits volatile organic compounds and nitrogen oxides (both ozone precursors). If an area is designated nonattainment for ozone, it may be impractical to operate a plant with grain dryers and the plant may be better off selling wet cake to surrounding farmers (Pinto, June 2006). Alternatively, the plant developer may select an indirect fired dryer over a direct fired dryer to reduce VOC exhaust volumes.[10]

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[10] However, employing this technology may result in higher VOC contents in the effluent water, which then may create a water discharge issue.

## 5.3) Ethanol plant permitting examples

This section details several actual air emissions permitting examples of ethanol plants. The examples are based on published air permitting records filed with the air permitting agencies[11].

Example 1

A 37 mgpy ethanol plant is currently under construction near Canton, Illinois and developed by Central Illinois Energy Cooperative. The plant is scheduled to enter commercial operation in spring 2007. The plant will have a primary fluidized-bed boiler fueled by coal refuse and coal and a secondary natural gas-fired boiler as back-up. The exhaust from the DDGS drying process will be routed through a cyclone and a forced draft fan to serve as combustion air to the boiler. The emissions of the primary boiler will be controlled by addition of limestone in the bed, a selective noncatalytic reduction system (SNCR), dry scrubber and baghouse. The maximum amount of coal burned each year is limited to 120,000 tons. The maximum firing rate of the fluidized-bed boiler is also limited to 211 MMBtu/hr.

The following permitting considerations apply to this facility. The facility is located in an attainment area. Since this is a new construction and not a modification to an existing emission source, the emissions limits in Table 5.1-5 "Attainment Major Source Thresholds apply." As can be seen the threshold at which an ethanol facility will be classified as a major source are 100 tpy for each VOC, PM, NOx, SO2, and CO. The above described ethanol plant does in fact emit close to these allowable emission limits. The facility wide maximum operating scenario allowed under the air permit produces emissions of:

**Table 5.3-1: Emission Limits of Canton Ethanol Plant**

| Pollutant | | Emission Limits (TPY) |
|---|---|---|
| VOC | < | 99.38 |
| PM | < | 92.90 |
| Sox | < | 96.10 |
| SO2 | < | 96.27 |
| CO | < | 99.92 |

The Canton ethanol plant is, however, a fairly standard, fluidized-bed boiler plant and therefore provides a good indication that a much larger plant that employs this technology fired by Illinois coal (i.e. 60 or 70 mgpy) may probably not be permitted as a minor source.

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[11] US EPA Region 5 and Region 7 Air Permitting Database, http://www.epa.gov/ARD-R5/permits/ and http://www.epa.gov/region7/programs/artd/air/title5/petitiondb/petitiondb.htm

Example 2
The following example indicates that the requirement to obtain a major source permit does not impede a project's viability. Aventine Renewable Energy, Inc. is currently constructing a 56.5 mgpy ethanol plant in Peking, Illinois. The plant is fueled by natural gas. The DDGS dryer system is equipped with cyclones and gas fired oxidizer systems. The oxidizer also functions as the furnace for the boiler to supply steam to the dry mill facility. Besides emissions from the DDGS drying process the oxidizer also controls the emissions from certain units in the fermentation and distillation area.

The following permitting considerations apply to this facility. The facility is located in an attainment area. However, the facility is a fuel ethanol expansion project at an existing facility that is already existing major source. Therefore the emission limits in Table 5.1-6 "Attainment Major Modification Thresholds" apply. As can be seen the threshold at which an ethanol facility will be classified as a major modification are 40 tpy for VOC, SOx, and NOx, 100 tpy for CO, and 15 tpy for PM. The above described ethanol plant, however, has the potential to emit the following levels of pollutants: 94.41 tpy of VOC, 34.31 tpy of PM, 54.8 tpy of NOx, 37.3 tpy of SO2, and 96.2 tpy of CO. This means that the ethanol plant project is subject to PSD review as a major modification because it is significant for emissions of PM, VOC, and NOx (i.e. the plant's emissions levels for these pollutants are above the major source thresholds). The facility has to employ Best Available Control Technologies (BACT) for emissions of PM, NOx, and VOC from the various units in the dry mill facility. With that the final air permit was issued in January 2005.

Other Examples
Outside Illinois several ethanol plants utilizing coal-fired fluidized-bed technologies are in operation or construction. The Central Iowa Renewable Energy in Goldfield, Iowa is an operating, coal-fired fluidized-bed ethanol plant. The air emissions permit specifies low sulfur Powder River Basin coal with a heating value of 8,800 Btu/lb, which, combined with the plant's location in an attainment area allowed this 55 mgpy plant to be permitted as a minor source. Similar to the Canton, Illinois plant, the exhaust from the DDGS drying process is routed through the boiler for VOC control. The emissions limits for key pollutants according to the plant's air emissions permit are:

**Table 5.3-2: Emission Limits of Goldfield Ethanol Plant**

| Pollutant | | Emission Limits (TPY) |
|---|---|---|
| VOC | < | 18.56 |
| PM | < | 43.00 |
| Sox | < | 95.36 |
| SO2 | < | 99.20 |
| CO | < | 91.54 |

An identical plant (same capacity, same coal-fired fluidized-bed boiler technology) is currently under construction by for Lincolnway Energy LLC in Nevada, Iowa. This plant’s air emissions permit specifies the same emissions than the Goldfield plant. The plant is also permitted as a minor source.

Another coal-fired fluidized-bed ethanol plant is currently under construction in Heron Lake Minnesota for Bioenergy LLC. This 55 mgpy plant utilizes a separate natural gas fired thermal oxidizer for VOC emissions control from the drying process. The plant is located in an attainment area and permitted as a minor source. The following emission limits apply according to the air emissions permit filed for the plant:

**Table 5.3-3: Emission Limits of Nevada Ethanol Plant**

| Pollutant | | Emission Limits (TPY) |
|---|---|---|
| VOC | < | 95.00 |
| PM | < | 95.00 |
| Sox | < | 95.00 |
| SO2 | < | 95.00 |
| CO | < | 95.00 |
| Hydrochloric Acid, a Hazardous Air Pollutant (HAP) is limited to 9.2 tpy. | | |

## 5.4) Annual fee for an ethanol plant air permit – sample calculation

According to the air permit filed for the ethanol plant in Canton, Illinois the plant emits at most 400 tons of combined NOx, SOx, PM, and VOC and at most 25 tons of HAPs. Table 5.4-1 below shows that the annual permitting fees for plants with total emissions greater 100 tpy are \$13.50 per ton, which should result in yearly operating permitting cost of 425tpy *\$13.50 < \$5,750 per year. Since the Canton plant is classified as a minor source the yearly fees are capped at \$2,500.

Extrapolating from these fees, a 100 mgpy plant which is about three times as large as the Canton plant and permitted as a major source (where the maximum permitting fee is not \$2,500 but \$100,000) should not exceed annual permitting fees of \$20,000, i.e three times as high. Furthermore, these fee assumptions are additionally conservative since these are permitting fees for the whole ethanol plant and, hence, the permitting portion attributable to the coal component is even lower.

**Table 5.4-1: Annual Air Emissions Permit Fees**

| **Project Total Emissions in tons per year** | **Yearly State Operating Permit Fees (corresponding to Minor Source Construction Permit)** | **Yearly CAAP Operating Permit Fees (corresponding to Major Source Construction Permit)** |
|---|---|---|
| < 25 | $100 | $1,000 |
| 25-100 | $1,000 | |
| > 100 | $13.50 per ton up to a maximum of $2,500. | $13.50 per ton up to a maximum of $100,000. |

## 5.5) Air permitting time requirements for ethanol plants

Depending on the permitting requirements, IEPA may (by law) take the following processing time after receipt of the initial filing of a complete application:

- An ethanol plant project where the emissions are well within the minor source emission limits (i.e. it is clearly not a major Source or a major modification to an existing major source for any pollutant) will require at least 3 months of processing time by IEPA for the construction permit.

- An ethanol plant where the emissions are close to the major source thresholds or the major modification thresholds, longer processing times with a minimum of 6 months will be required by the IEPA. If a project’s emissions are higher than 80% of the major source or major modification threshold limits then the IEPA may determine that public notice is necessary. This could prolong the permitting process substantially since this process includes an additional 45 day comment period.

- An ethanol plant project, where the emissions are definitely above the threshold for a major source or a major modification will take at least 12 months to permit.

Public opposition to an ethanol plant may trigger public hearings.  However, one should keep in mind that public opposition to an ethanol plant may be independent of:

- The Size of the Plant: The Heron Lake Ethanol Plant incurred permitting delays despite its relatively small size 55 mgpy and its anticipated minor source classification.
- The Fuel Source: Adkins Energy LLC in Lena Illinois incurred permitting problems despite its natural gas fuel source.

## Task 6 – Place the research findings in the context of energy life cycle analysis

This section places the results from the energy flow analysis (Section 3) in the broader context of energy life cycle analysis. Energy life cycle analysis (LCA) looks at the total energy requirements of a product's life cycle from "cradle to grave" including its production, distribution, use and recycling, treatment or disposal. LCA allows researchers to evaluate various energy and fuel combinations with a consistent methodology. For ethanol, for example, LCA looks at all the energy requirements that go into the conversion of corn into ethanol at the ethanol plant as well as the energy requirements that go into corn agriculture, fertilizer production, corn transportation, and other energy components.

Looking more closely at the energy requirements at an ethanol plant, a partial LCA may look at the Btus utilized by the thermal systems, the MWhs consumed by the electric systems and additionally at the Btus required to produce the MWhs for the electric systems.

The analysis in Section 3 has shown that a primarily coal fired ethanol plant will consume approximately 90,000 MWh/year. A central station power plant with an average efficiency of 33% and assumed Transmission and Distribution losses from the power plant to the ethanol plant of 7.5% will require about 1,006,000 MMBtu to generate this amount of electricity (see Table 6.1).[12] Added together with the on-site fuel use for the thermal systems of slightly more than 4 million MMBtu or 40,000 Btu/gal this results in a total fuel use of approximately 5 million MMBtu or 50,000 Btu/gal consumed by the 100 mgpy ethanol process. Adding CHP to a coal fired ethanol plant significantly reduces the overall energy requirements to 45,000 Btu/gal.

A primarily natural gas fired ethanol plant will consume approximately 75,000 MWh/year. A central station power plant will require about 839,000 MMBtu to generate this amount of electricity. Added together with the on-site fuel use for the thermal systems of 3.23 million MMBtu or 32,000 Btu/gal this results in a total fuel use of approximately 4.1 million MMBtu or 41,000 Btu/gal consumed by the 100 mgpy ethanol process. Adding CHP to a natural gas fired ethanol plant, again, reduces the overall energy requirements to 36,000 Btu/gal.

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[12] The quoted average power plant efficiency is based on data derived from the US Environmental Protection Agency's eGrid database which lists performance parameters for the majority of electric generating facilities installed in the US.

**Table 6-1: Energy Use Life Cycle Considerations**

| **Life Cycle Considerations:** | **Natural Gas Base Case** | **Natural Gas CHP Case** | **FB Coal Base Case** | **FB Coal CHP Case** |
|---|---|---|---|---|
| Total Electric Use (MWh/y) | 75,000 | 75,000 | 90,000 | 90,000 |
| Central Station Electric Use (MWh/y) | 75,000 | 16,639 | 90,000 | 6,294 |
| CHP Electric Generation (MWh/y) | N/A | 58,361 | N/A | 83,706 |
| Average Central Station Efficiency (%) | 33.0% | 33.0% | 33.0% | 33.0% |
| Transmission and Distribution Losses (%) | 7.5% | 7.5% | 7.5% | 7.5% |
| Net Central Station Efficinecy (%) | 30.5% | 30.5% | 30.5% | 30.5% |
| Central Stat. Fuel for Electr. Gen. (MMBtu/y) | 838,575 | 186,041 | 1,006,290 | 70,373 |
| Total Fuel Use (MMBtu) Thermal Systems | 3,233,000 | 3,459,823 | 4,025,641 | 4,431,356 |
| Total Fuel Use (MMBtu/y) | 4,071,575 | 3,645,864 | 5,031,931 | 4,501,730 |
| Fuel Use (Btu/gal) Thermal Systems | 32,330 | 34,598 | 40,256 | 44,314 |
| Fuel Use (Btu/gal) Total (Thermal&Electric) | 40,716 | 36,459 | 50,319 | 45,017 |

These energy consumption values reflect recent improvements/optimizations in process energy needs. Shapouri et al. (2004) using 2001 data performed an ethanol LCA which was primarily based on natural gas fired power plants, since in 2001 there was no dry mill coal fired ethanol plant in operation. The study uses 47,116 Btu/gal for the ethanol conversion process at a dry mill ethanol plant compared to the 41,000 Btu/gal researched for the present study. Shapouri's numbers reflect electricity need assumptions of 1.09 kWh/gal and 34,700 Btu/gal of thermal energy compared to the 0.75 kWh/gal and 32,000 Btu/gal of thermal energy researched for the present study.

Using Shapouri's numbers a comprehensive LCA for ethanol was developed by Argonne National Laboratory utilizing the Greenhouse gases, Regulated Emissions and Energy use in Transportation (GREET) model (Michael Wang, 2006). The GREET analysis for the ethanol life cycle found that it takes about 0.74 MMBtu of fossil energy to deliver 1 MMBtu of ethanol (see Figure 6.1). In contrast, it takes only about 0.23 MMBtu of fossil fuel to deliver 1 MMBtu of gasoline taking into account energy for crude oil recovery from the well, refining, transportation. However, the important difference is that the Btus in ethanol are renewable (Oregon Renewable Resources, The Ethanol Forum). When consuming ethanol in a car, one only consumes the fossil energy that went into making ethanol. In contrast, when consuming gasoline in the car, one consumes the fossil energy contained in gasoline plus the fossil energy that went into gasoline production. Therefore, the correct comparison should be that for every Btu of energy in gasoline fuel 1.23 Btu of fossil energy are consumed whereas for every Btu of energy in ethanol fuel about 0.74 Btu of fossil energy are consumed.

As pointed out above, the energy requirements at natural gas fired ethanol plants have been further decreasing since the Shapouri-based LCA was performed by Argonne. It follows that at present even less than 0.74 Btus of fossil energy should be consumed for every Btu of energy in ethanol. For coal fired plants, as discussed above, the research for the current study indicates a total fuel consumption of 50,000 Btu/gal, which is slightly higher than the 47,113 Btu/gal provided by Shapouri for the original Argonne LCA (again, since Shapouri's numbers were based on natural gas fired plants). Since the energy requirements at coal fired ethanol plants are slightly higher than the numbers used in the LCA a coal fired ethanol production process may likely consume slightly more than the 0.74 Btus of fossil energy for every Btu of energy in ethanol.[13] However, in the CHP case for a coal fired ethanol plant the total fuel consumption is approximately 45,000 Btu/gal, which is below the number used by Shapouri. Therefore, a coal fired CHP ethanol plant may likely consume less than the 0.74 Btus of fossil fuel for every Btu of energy in ethanol.

While firing coal in ethanol plants, when compared to natural gas fired plants, increases the overall Btu consumption for the ethanol production process one must consider several key advantages of this technology:

- Btu Adjustments:
  A personnel interview conducted for this study with a major fluidized-bed manufacturer confirmed that these boilers can relatively easily be co-fired with a wide variety of biomass as long as the biomass conforms to the size requirements for the boiler system (i.e. less than 4" fuel particle size for certain systems). This means that co-firing 6% of biomass will likely result in similar LCA results for coal fired systems than the original GREET analysis which was based primarily on natural gas (0.74 Btus of fossil energy are consumed for every Btu of energy in ethanol); any additional co-firing will further reduce this ratio.

- Infrastructure Flexibility:
  A lot of work is currently being done in mapping and assessing biomass feedstocks in various states (see Washington Biomass Feedstock tool, ORNL tool). Ultimately, as biomass is concentrated and becomes available coal fired fluidized-bed plants can switch to biomass which means that coal fired technology provides an intermediate step towards the development of renewable, biomass fired ethanol plants with diverse sources of energy feedstocks.

- Complete Cost Accounting:
  LCA is concerned with counting Btus that go into a final product such as ethanol. However, all fossil fuels are not created equal. In case of coal, there is an ample domestic resource of coal. Recent studies have allocated some of the defense expenditures to the cost of gasoline as a direct cost in assuring supply (see National Defense Council data quoted in Ethanol Across America, Fall 2004). Coal, however, is free of any social and financial externalities associated with a dependence on a foreign resource.

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[13] As pointed out above a complete LCA should also look at the energy consumption that goes into producing the fuel feedstock. In this case, similar energy needs were assumed for coal mining/transportation and natural gas drilling/transportation. Further research in this area is required.

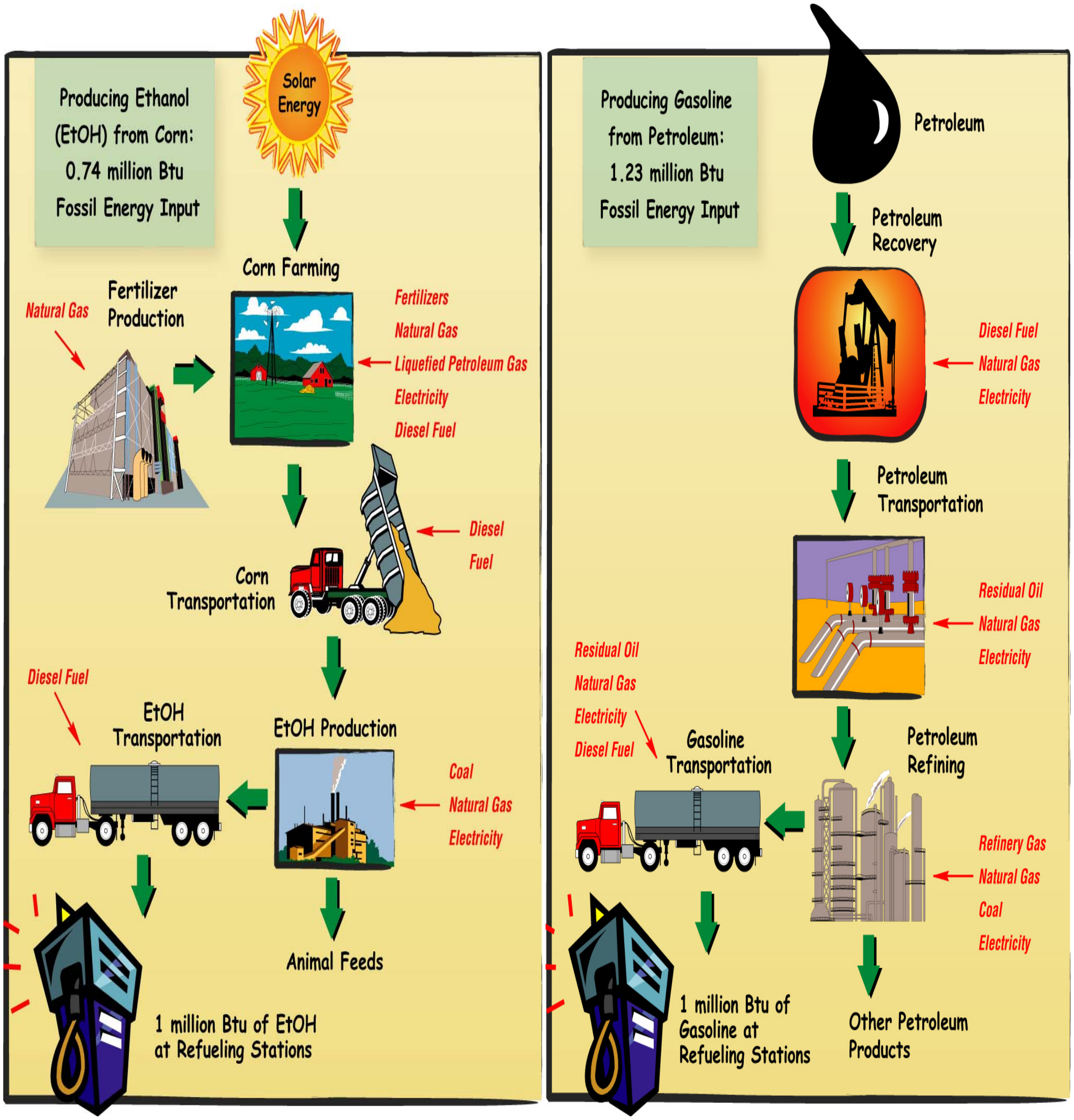

**Figure 6-1: Ethanol versus Gasoline LCA (Source: Michael Wang, Argonne National Laboratory)**

# CONCLUSIONS AND RECOMMENDATIONS

This study looked at the potential use of Illinois coal at dry mill ethanol plants with a focus on fluidized-bed technology. In several interviews conducted for this study technology uncertainties and permitting uncertainties were cited as the major reasons for some reluctance to adopt coal. However, as with many adoption processes of new technologies in the market place such as fluidized-bed coal systems, this study concludes that public policy makers may be called upon to close the information gap and promote the benefits of this technology and consider the following:

1) The recent developments in fluidized-bed coal fired technologies have resulted in the availability of a relatively clean source of energy. Despite the availability of this new technology and relatively low Illinois coal feedstock prices (compared to natural gas), adoption of this technology has been slow. This study shows that the integration of fluidized-bed boilers fired by Illinois coal will provide substantial savings to an ethanol plant located in the state. While the capital costs of coal fired fluidize bed technologies for a 100 mgpy plant are approximately $29 million higher ($41.8 million compared to $12.8 million for a natural gas fired ethanol plant), the 15.7 million annual savings ($18.4 million compared to $34.1 million) result in a 1.8 year payback for this technology, a payback which should well compensate for any perceived technology risk. Therefore, the use of fluidized-bed technology needs to be promoted.

2) While the use of fluidized-bed technology is financially attractive, utilizing combined heat and power technologies decreases the overall energy cost even more (by an additional $4.7 million annually after financing of the added equipment). Therefore, combined heat and power applications should be promoted.

3) Looking at the often cited permitting uncertainties for coal systems, the study shows that the environmental permitting process for any ethanol plant regardless of the energy feedstock needs to be carefully managed. Therefore, guidance on the environmental permitting process associated with fluidized-bed technology permitting needs to be provided to ethanol project developers.

4) This study indicates that coal fired ethanol plants will consume slightly more than 0.74 Btus of fossil energy for every Btu of energy in ethanol, while coal fired ethanol plants with CHP will consume slightly less than this ratio. More work should be done to include coal fired ethanol plants in full LCA analyses.

5) Finally, sites located close to Illinois coal, including potential mine mouth locations, should be identified and promoted. Some industry experts see a trend towards ethanol plants being located closer to fuel sources than corn sources.

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**Personal conversations as part of the research for this study were conducted with representatives of the following companies:**

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Dupps Company

Eisenmann – Clean Air Technology

Energy Products of Idaho

Energy Environmental Analysis Inc.

Henneman Engineering

Iowa Department of Natural Resources

Illini Bio Energy

Illinois Clean Coal Institute

Illinois Department of Commerce and Economic Opportunity

Illinois Environmental Protection Agency

Johnston Boiler Company

LB Foster Company

National Corn to Ethanol Research Center

Southern Illinois Railcar

US Energy Services

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