RESEARCH INVESTIGATION FOR THE POTENTIAL USE OF COMBINED HEAT AND POWER AT NATURAL GAS AND COAL FIRED DRY MILL ETHANOL PLANTS

Prepared for:
U.S. Department of Energy

November, 2007

Prepared by:
Steffen Mueller, PhD
John Cuttica
U.S. DOE Midwest CHP Application Center

With Assistance of:
Life Cycle Associates

University of Illinois at Chicago, Energy Resources Center, 1309 South Halsted Street, Chicago, IL 60607

RESEARCH INVESTIGATION FOR THE POTENTIAL USE OF COMBINED HEAT AND POWER AT NATURAL GAS AND COAL FIRED DRY MILL ETHANOL PLANTS

Prepared by:

Steffen Mueller, Ph.D.
John J. Cuttica

The Energy Resources Center
University of Illinois at Chicago

Submitted to:
U.S. Department of Energy

November 2007

LEGAL NOTICE

TABLE OF CONTENT

EXECUTIVE SUMMARY

This study looks at the energy flows and the financial impact resulting from the use of combined heat and power technologies (CHP) at natural gas fired as well as coal fired ethanol plants. Several CHP technologies installed at natural gas fired ethanol plants are configured to displace the traditional boiler system with a combustion turbine and a heat recovery steam generating system. At coal fired ethanol plants, CHP technologies can be employed by adding a steam turbine to the boiler system. In general, adding a CHP system will increase the capital cost requirements for an ethanol plant, but decrease the annual operating costs due to reduced electricity purchases from outside electric provides.

The financial payback for an ethanol plant from a CHP system depends on the fuel costs (coal and natural gas) as well as electricity costs incurred by plants in different areas. Therefore, this study models the payback for CHP systems across eight Midwestern states taking differing fuel and electricity costs into consideration. The eight Midwestern states chosen for this study are home to over 80% of the current ethanol plant capacity (Renewable Fuels Association, 2007). The fuel and electricity cost assumptions are sourced from US DOE Energy Information Administration. All cost assumptions are based on the latest data available for a consistent year, which is 2006. The modeled plant size is a 100 million gallon per year dry mill ethanol plant producing both ethanol and distillers dried grain with solubles. The modeling for this study is based on the BEACCON model developed by Life Cycle Associates. The model can be downloaded at www.lifecycleassociates.com

Using the assumptions detailed in the study, CHP provides relatively attractive paybacks for natural gas fired ethanol plants ranging from 3 years (Wisconsin) to 6 years (South Dakota). It is even more attractive for coal fired ethanol plants to install CHP technologies with paybacks ranging from 1 (Wisconsin) to 1.5 years (Nebraska).

Emerging low carbon incentive structures such as renewable fuel standards and carbon trading mechanisms may further promote CHP since these systems may have the potential to reduce carbon emissions based on their higher efficiencies. Further analyses in this area should be performed.

1) ENERGY FLOWS AT COAL FIRED AND NATURAL GAS FIRED ETHANOL PLANTS

1.1) Natural Gas Fired Ethanol Plants

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 whole stillage leftover from the distillation process. Whole stillage as well as DDGS are valuable animal feed products. However, DDGS, which is in essence dried whole stillage has a longer shelf life and can be shipped easier. In many regions DDGS has a relatively high market price, which makes DDGS production even with the higher energy requirements for the drying process financially attractive (for example, over the last 12 months DDGS prices in Illinois have ranged between $95-$117 per ton per Ethanol Producer Magazine, November 2007). 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.

Table 1, column 1 illustrates 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.). Finally, a regenerative thermal oxidizer (RTO) is used for the destruction of volatile organic compounds (VOC) emitted from the energy system and the drying process. It is assumed that 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).

A natural gas CHP plant will generally add a gas Turbine CHP with a supplementary-fired heat recovery steam generator (HRSG). The steam produced by the HRSG will serve the ethanol process needs in the same way boiler steam in a non-CHP configuration does. Therefore, a CHP system significantly reduces or eliminates the need for a natural gas fired boiler system. 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[1]. 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

[1] 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.

steam requirements supplementary firing was incorporated into the design. Steam generation efficiency for the supplemental burner was assumed to be 90%[2].

Table 1, column 2 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.

1.2) Coal Fired Ethanol Plants

Table 1, column 3 illustrates 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.

Due to the high firing temperature of the boiler the exhaust gases from the dyer can be rerouted back through the boiler for VOC destruction. Therefore, many coal ethanol plants do not require a separate RTO.

A comparable ethanol plant utilizing CHP technology would add a steam turbine generator utilizing steam from the fluidized bed boiler system; the fluidized bed boiler system, in this case, will be operated at a higher pressure and temperature. 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 2007.[3] 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

---

[2] 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)

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

and 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 1, column 4 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 1: Energy Flow Comparison

	Natural Gas Base Case	Natural Gas CHP Case	Coal Base Case	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

2 FINANCIAL ANALYSIS OF CHP SYSTEMS AT NATURAL GAS AND COAL ETHANOL PLANTS

This section identifies capital as well as O&M costs associated with CHP systems fueled by natural gas and coal at ethanol plants. A properly sized CHP system generally incurs higher capital costs for equipment and higher fuel costs; however, the overall O&M costs are lower due to reduced electric costs. 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.

The financial payback for an ethanol plant from a CHP system depends on the fuel costs (coal and natural gas) as well as electricity costs incurred by plants in different areas. Therefore, this study models the payback for CHP systems across eight Midwestern states taking differing fuel and electricity costs into consideration. The eight Midwestern states chosen for this study are home to over 80% of the current ethanol plant capacity (Renewable Fuels Association, 2007).

2.1) Natural Gas-Fired Ethanol Plants

2.1.1) Capital Cost of Energy Systems at Natural Gas Fired Ethanol Plants

Thermal Systems:

- Non-CHP Plant:
  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).

- CHP Plant:
  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. The steam from the HRSG provides the primary source for process steam eliminating the cost for a natural gas fired boiler (required for a non-CHP plant).

Dryer

A key manufacturer produced a mass flow system for this study, which showed that a 100 mgpy 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 $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.

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.

2.1.2) Operation and Maintenance Cost of Energy Systems at Natural Gas Fired Ethanol Plants

Thermal System Fuel: Natural Gas

Natural gas cost assumptions are based on 2006 Energy Information Administration data of US average costs to industrial customers. The costs are listed in Table 2.

Table 2: Natural Gas Cost Assumptions

	IA	IL	IN	KS	MN	NE	SD	WI
Costs ($/MMBtu)	8.053	8.630	9.049	7.413	7.938	7.723	9.030	8.942

Source: Natural Gas Navigator, Natural Gas Prices, Industrial Price Data Series, 2006. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm

Electricity

Determining the exact electricity costs incurred by ethanol plants is associated with relatively high uncertainties. While ethanol plants are large electricity users, oftentimes, their location at the end of a rural electric feeder results in electricity costs higher than those for comparative industrial customers.[4] Therefore, electricity costs for ethanol plants are assumed to track average bundled costs to commercial customers. The assumed electricity costs are listed in Table 3.

Table 3: Electricity Cost Assumptions

	IA	IL	IN	KS	MN	NE	SD	WI
Costs ($/kWh)	0.073	0.080	0.072	0.070	0.070	0.062	0.065	0.084

Source: US DOE Energy Information Administration, Electric Power Annual with data for 2006, Report Released: October 22, 2007, Prices for "Total Electric Industry" to Commercial Customers.

Annual Permitting Fees

Yearly fees are imposed by many state air quality regulators. These fees are relatively small. In Illinois, for example, a natural gas fired ethanol plants in the 100 mgpy capacity range may often be classified as a minor source and therefore incur annual permitting fees of approximately $2,500. This fee requirement was assumed for the present study.

Personnel

While the staff levels for an ethanol pant are approximately 55-60 employees (Kotrba, 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.

CHP-related O&M Costs

Annual combustion turbine O&M costs are approximately $0.0075 per kWh (Midwest CHP Application Center Guidebook, 2005).

2.1.3) Financing Considerations

The useful life of a dry mill ethanol plant is estimated to be between 30 to 60 years (Jeff Laut with Poet, 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).

Using these assumptions, the capital and O&M costs for an ethanol plant energy system with and without CHP were calculated. The results are listed in Table 4. The detailed spreadsheet summaries are listed in Appendix A. The resulting payback is graphed in Figure 1.

[4] Adkins Energy LLC, a 40 mgpy ethanol plant located in a rural area of ComEd's territory would have had to pay more than $0.1/kWh. As a result Adkins Energy LLC opted for a CHP system. See the Adkins LLC "Fact Sheet" at www.chpcentermw.org.

Table 4: Calculated Natural Gas Plant Capital and O&M Costs

		Natural Gas Non CHP		Natural Gas CHP	
IA	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	31,606,636	$	29,616,522
IL	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	33,966,627	$	31,722,176
IN	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	34,763,942	$	33,046,239
KS	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	29,287,505	$	27,344,640
MN	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	31,030,091	$	29,171,310
NE	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	29,713,005	$	28,289,889
SD	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	34,148,781	$	32,858,729
WI	Capital Cost	$	12,810,000	$	20,610,000
	O&M Cost	$	35,288,670	$	32,869,756

As can be seen, the paybacks for natural gas fired CHP systems range from 3 years (Wisconsin) to 6 years (South Dakota).

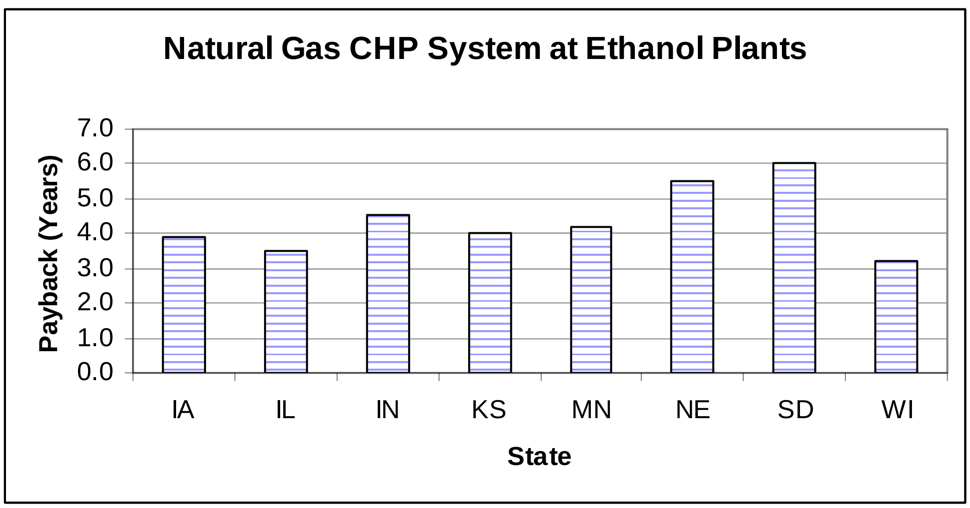

Figure 1: Natural Gas CHP System Payback

2.2) Coal-Fired Ethanol Plants

2.2.1) Capital Cost of Energy Systems at Coal Fired Ethanol Plants

Thermal Systems

- Non-CHP Plant
  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).

- CHP-Plant
  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.

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 particular 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. [5]

[5] 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).

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

Coal Handling Equipment

- 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.

2.2.2) Operation and Maintenance Cost of Energy Systems at Coal Fired Ethanol Plants

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

- Coal Commodity and Transportation:
  Figure 2 and Figure 3 below show the location of the major coal basins (US DOE Energy Information Administration, 2007) and the location of ethanol plants (Renewable Fuels Association, 2007), respectively.

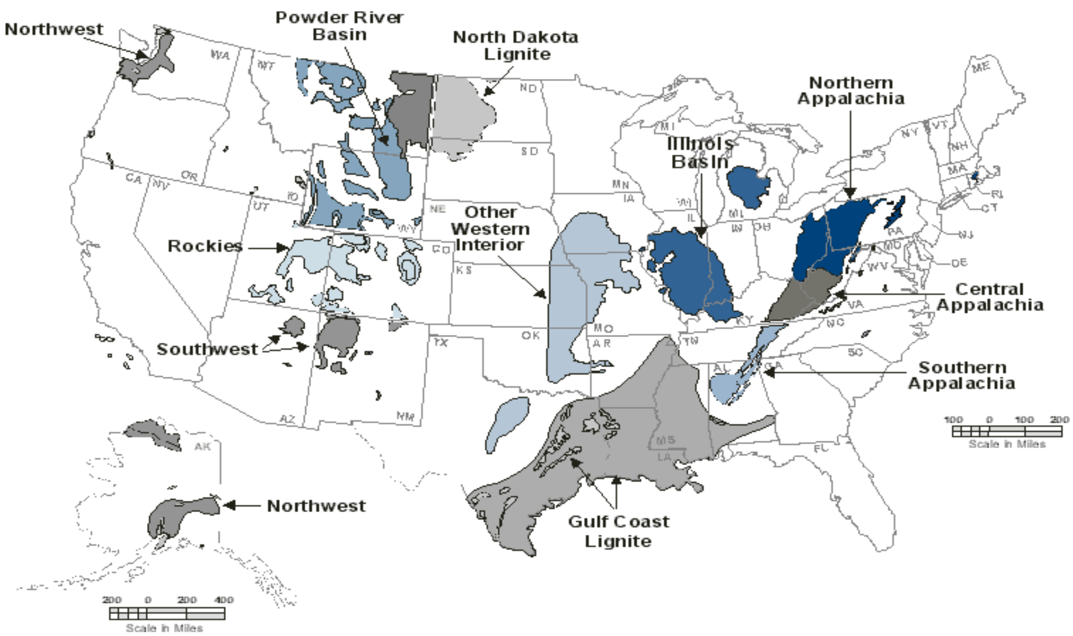

Figure 2: Coal Basins in the United States

Currently, at least three ethanol plants are configured to utilize coal (2 in Iowa and one in Illinois). The Iowa plants utilize Powder River Basin coal (PRB), and the Illinois plant utilizes a mix of Illinois and PRB coal resources. For the purpose of this study it was assumed that ethanol plants in Illinois and Indiana would use a 50/50% percent mix of PRB and Illinois Basin Coal, all other states considered in this study would use PRB coal. Coal commodity costs are based on US DOE Energy Information Administration data, Coal transportation rates are based on a personal conversation with a major rail operator, who quoted a transportation rate of \$0.018/(ton-mile). PRB coal was assumed to be shipped on average for 1,000 miles, IL Basin for 200 miles. For Illinois and Indiana, the coal rates are a weighted average between the different heating values and the different transportation distances. The heating value are listed in Table 5 and the coal costs are listed in Table 6.

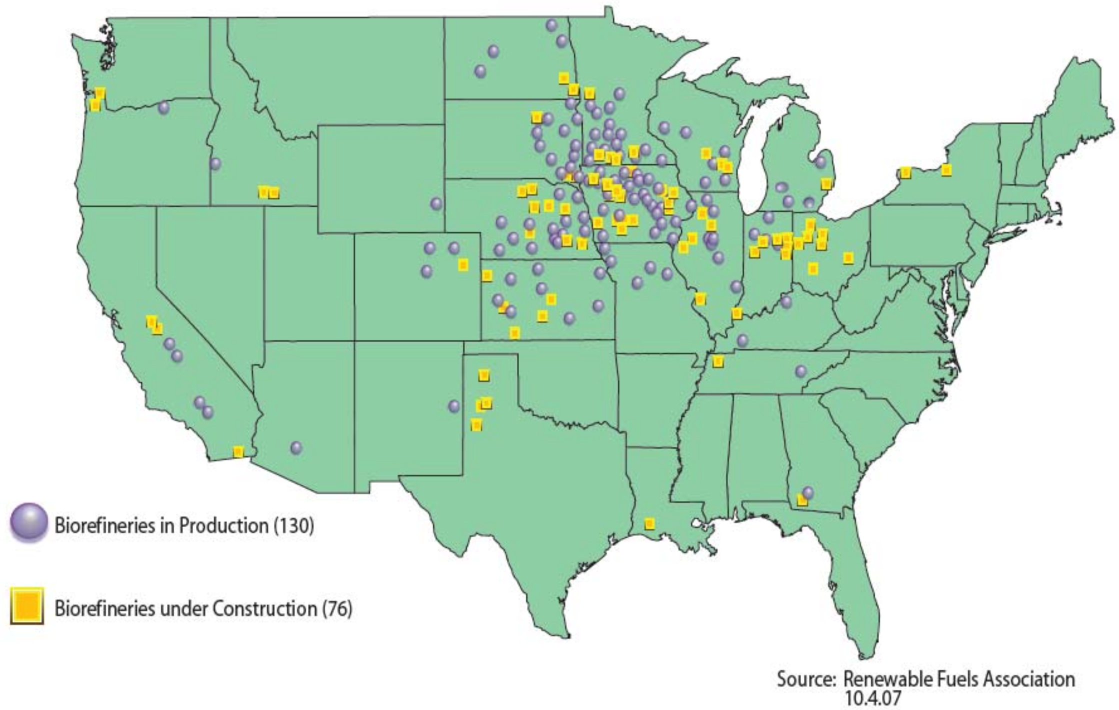

Figure 3: Ethanol Plants in the United States

Table 5: Coal Heating Values

Coal Basin	Coal Type(s)	Avg. Heating Value HHV (Btu/lb)	Avg. Heating Value HHV (MMBtu/ton)
Illinois Basin	Bituminous	11,800	23.6
Powder River Basin (PRB)	Bituminous, Sub-bituminous, Lignite	8,800	17.6

Source: US DOE Energy Information Administration, Coal News and Markets, week of 9/07/07

Table 6: Coal Cost Assumptions

	IA	IL	IN	KS	MN	NE	SD	WI
Coal Mix	PRB	PRB/IL Basin	PRB/IL Basin	PRB	PRB	PRB	PRB	PRB
Costs ($/ton)	25.725	29.563	29.563	25.725	25.725	25.725	25.725	25.725
Costs ($/MMBtu)	1.462	1.435	1.435	1.462	1.462	1.462	1.462	1.462

Source: US DOE Energy Information Administration, Average Open Market Sales Price of Coal by State and Coal Rank, 2006. Includes spot and contract prices which is reflective of ethanol operations.

- Coal Storage:
  A coal fired ethanol plant consumes between 200,000 and 250,000 tons of coal per year. A rail car holds on average 100 tons. At an average 120 rail cars per unit train this will require at least one coal train to the ethanol plant per months

and a coal yard with approximately 15,000 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.

Electricity

The electricity rates assumed for coal fired ethanol plants are the same rates as the ones assumed for natural gas fired plants in Table 3.

Annual Operating Permitting Fees

Coal fired ethanol plants in the 100 mppy capacity range may often be classified as a major source. For Illinois, for example, an analysis has show that the permitting fees for a 100 mgpy ethanol plant should not exceed $20,000 annually. This fee requirement was assumed for the present study.

Personnel

In general coal-fired energy systems require more and higher-skilled staff than natural gas fired ones (Whelan, 2006). A 100 mgpy 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.

<u>CHP Related O&M Costs:</u>

- 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).

2.2.3) Financing Considerations

Using the same financing assumptions detailed for natural gas fired ethanol plants, the capital and O&M costs for coal fired ethanol plant energy systems with and without CHP were calculated. The results are listed in Table 7. The detailed spreadsheet summaries are listed in Appendix A. The resulting payback is graphed in Figure 4. As can be seen, the paybacks for coal fired CHP systems range from 1 year (Wisconsin) to 1.5 years (Nebraska).

Table 7: Calculated Coal Plant Capital and O&M Costs

		Coal Non CHP	Coal CHP
IA	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 13,191,069	$ 7,891,179
IL	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 13,678,088	$ 7,814,957
IN	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 13,012,088	$ 7,768,381
KS	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 12,894,069	$ 7,870,409
MN	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 12,948,069	$ 7,874,185
NE	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 12,201,069	$ 7,821,945
SD	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 12,453,069	$ 7,829,568
WI	Capital Cost	$ 41,750,000	$ 48,355,000
	O&M Cost	$ 14,163,069	$ 7,959,154

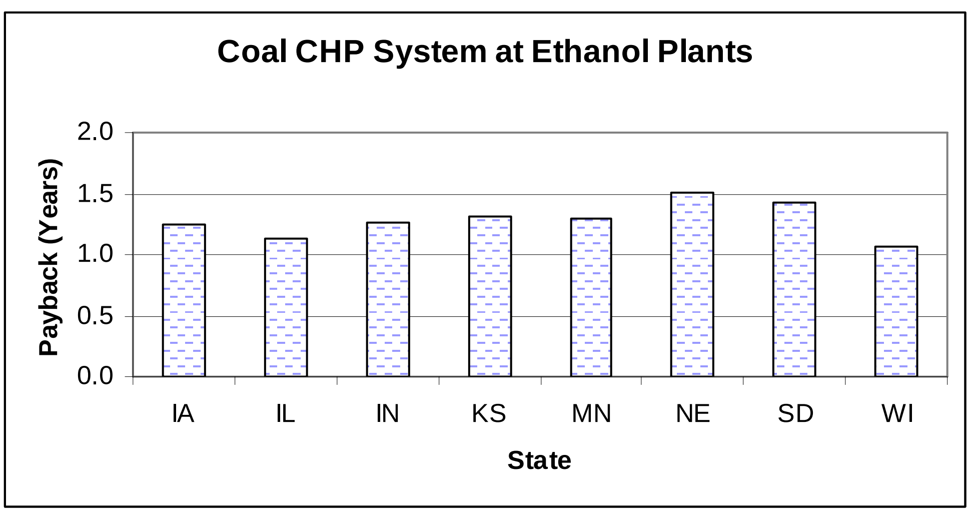

Figure 4: Coal CHP System Payback

CONCLUSION

This study looked at the financial implications of installing combined heat and power systems at coal and natural gas fired ethanol plants located in the key ethanol producing states. Based on the data presented in the study it can be concluded that CHP technologies are very attractive for current coal fired plants with paybacks that do not exceed 1.5 years. For natural gas fired ethanol plants, a more detailed analysis may need to be performed since current paybacks range from 3 years to 6 years. The results show that ethanol plants in Wisconsin, Illinois and Iowa can incur higher savings from CHP than the rest of the studied ethanol producing states. Emerging low carbon incentive structures such as renewable fuel standards and carbon trading mechanisms may further promote CHP since these systems may have the potential to reduce carbon emissions based on their higher efficiencies. Further analyses in this area should be performed.

APPENDIX A: MODEL RUNS

Plant 1: Natural Gas Non CHP	**Iowa**
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.053398058
Delivered Gas Cost ($)	26,036,636
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	5,467,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	26,036,636
Electric Cost ($)	5,467,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	31,606,636
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	31,606,636
Total Annual Energy Cost ($)	33,486,674
Energy cost per gallon ($)	0.33

Plant 2: Natural Gas CHP	**Iowa**
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.053398058
Delivered Gas Cost ($)	27,863,332
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,212,983
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	27,863,332
Ancillary Electric Cost ($)	1,212,983
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	29,616,522
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	29,616,522
Total Annual Energy Cost ($)	32,641,314
Energy cost per gallon ($)	0.33

Plant 3: Coal Non CHP Plant	**Iowa**
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	6,561,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	6,561,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	13,191,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	13,191,069
Total Annual Energy Cost ($)	19,318,437
Energy cost per gallon ($)	0.19

Plant 4: Coal CHP	**Iowa**
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	458,833
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	458,833
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,891,179
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,891,179
Total Annual Energy Cost ($)	14,987,919
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Illinois
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.6302589
Delivered Gas Cost ($)	27,901,627
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	5,962,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	27,901,627
Electric Cost ($)	5,962,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	33,966,627
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	33,966,627
Total Annual Energy Cost ($)	35,846,665
Energy cost per gallon ($)	0.36

Plant 2: Natural Gas CHP	Illinois
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.6302589
Delivered Gas Cost ($)	29,859,168
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,322,801
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	29,859,168
Ancillary Electric Cost ($)	1,322,801
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	31,722,176
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	31,722,176
Total Annual Energy Cost ($)	34,746,968
Energy cost per gallon ($)	0.35

Plant 3: Coal Non CHP Plant	Illinois
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	195,419
Required Fuel (tons/day)	535
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.44
Delivered Coal Cost ($)	5,777,088
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	7,155,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,777,088
Electric Cost ($)	7,155,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	13,678,088
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	13,678,088
Total Annual Energy Cost ($)	19,805,456
Energy cost per gallon ($)	0.20

Plant 4: Coal CHP	Illinois
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	215,114
Required Fuel (tons/day)	589
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.44
Delivered Coal Cost ($)	6,359,319
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	500,373
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,359,319
Coal Ancillary Electric Cost ($)	500,373
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,814,957
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,814,957
Total Annual Energy Cost ($)	14,911,697
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Indiana
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	9.048543689
Delivered Gas Cost ($)	29,253,942
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	5,407,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	29,253,942
Electric Cost ($)	5,407,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	34,763,942
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	34,763,942
Total Annual Energy Cost ($)	36,643,980
Energy cost per gallon ($)	0.37

Plant 2: Natural Gas CHP	Indiana
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	9.048543689
Delivered Gas Cost ($)	31,306,360
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,199,672
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	31,306,360
Ancillary Electric Cost ($)	1,199,672
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	33,046,239
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	33,046,239
Total Annual Energy Cost ($)	36,071,031
Energy cost per gallon ($)	0.36

Plant 3: Coal Non CHP Plant	Indiana
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	195,419
Required Fuel (tons/day)	535
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.44
Delivered Coal Cost ($)	5,777,088
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	6,489,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,777,088
Electric Cost ($)	6,489,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	13,012,088
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	13,012,088
Total Annual Energy Cost ($)	19,139,456
Energy cost per gallon ($)	0.19

Plant 4: Coal CHP	Indiana
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	215,114
Required Fuel (tons/day)	589
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.44
Delivered Coal Cost ($)	6,359,319
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	453,797
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,359,319
Coal Ancillary Electric Cost ($)	453,797
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,768,381
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,768,381
Total Annual Energy Cost ($)	14,865,121
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Kansas
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.412621359
Delivered Gas Cost ($)	23,965,005
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	5,220,000
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	23,965,005
Electric Cost ($)	5,220,000
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	29,287,505
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	29,287,505
Total Annual Energy Cost ($)	31,167,543
Energy cost per gallon ($)	0.31

Plant 2: Natural Gas CHP	Kansas
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.412621359
Delivered Gas Cost ($)	25,646,358
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,158,074
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	25,646,358
Ancillary Electric Cost ($)	1,158,074
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	27,344,640
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	27,344,640
Total Annual Energy Cost ($)	30,369,432
Energy cost per gallon ($)	0.30

Plant 3: Coal Non CHP Plant	Kansas
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	6,264,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	6,264,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	12,894,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	12,894,069
Total Annual Energy Cost ($)	19,021,437
Energy cost per gallon ($)	0.19

Plant 4: Coal CHP	Kansas
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	438,062
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	438,062
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,870,409
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,870,409
Total Annual Energy Cost ($)	14,967,149
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Minnesota
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.937702265
Delivered Gas Cost ($)	25,662,591
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	5,265,000
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	25,662,591
Electric Cost ($)	5,265,000
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	31,030,091
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	31,030,091
Total Annual Energy Cost ($)	32,910,129
Energy cost per gallon ($)	0.33

Plant 2: Natural Gas CHP	Minnesota
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.937702265
Delivered Gas Cost ($)	27,463,045
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,168,058
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	27,463,045
Ancillary Electric Cost ($)	1,168,058
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	29,171,310
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	29,171,310
Total Annual Energy Cost ($)	32,196,102
Energy cost per gallon ($)	0.32

Plant 3: Coal Non CHP Plant	Minnesota
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	6,318,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	6,318,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	12,948,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	12,948,069
Total Annual Energy Cost ($)	19,075,437
Energy cost per gallon ($)	0.19

Plant 4: Coal CHP	Minnesota
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	441,839
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	441,839
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,874,185
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,874,185
Total Annual Energy Cost ($)	14,970,925
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Nebraska
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.722859665
Delivered Gas Cost ($)	24,968,005
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	4,642,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	24,968,005
Electric Cost ($)	4,642,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	29,713,005
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	29,713,005
Total Annual Energy Cost ($)	31,593,043
Energy cost per gallon ($)	0.32

Plant 2: Natural Gas CHP	Nebraska
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	7.722859665
Delivered Gas Cost ($)	26,719,727
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,029,954
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	26,719,727
Ancillary Electric Cost ($)	1,029,954
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	28,289,889
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	28,289,889
Total Annual Energy Cost ($)	31,314,681
Energy cost per gallon ($)	0.31

Plant 3: Coal Non CHP Plant	Nebraska
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	5,571,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	5,571,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	12,201,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	12,201,069
Total Annual Energy Cost ($)	18,328,437
Energy cost per gallon ($)	0.18

Plant 4: Coal CHP	Nebraska
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	389,599
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	389,599
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,821,945
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,821,945
Total Annual Energy Cost ($)	14,918,685
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	S. Dakota
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	9.029935275
Delivered Gas Cost ($)	29,193,781
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	4,852,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	29,193,781
Electric Cost ($)	4,852,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	34,148,781
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	34,148,781
Total Annual Energy Cost ($)	36,028,819
Energy cost per gallon ($)	0.36

Plant 2: Natural Gas CHP	S. Dakota
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	9.029935275
Delivered Gas Cost ($)	31,241,978
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,076,543
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	31,241,978
Ancillary Electric Cost ($)	1,076,543
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	32,858,729
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	32,858,729
Total Annual Energy Cost ($)	35,883,520
Energy cost per gallon ($)	0.36

Plant 3: Coal Non CHP Plant	S. Dakota
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	5,823,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	5,823,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	12,453,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	12,453,069
Total Annual Energy Cost ($)	18,580,437
Energy cost per gallon ($)	0.19

Plant 4: Coal CHP	S. Dakota
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	407,222
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	407,222
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,839,568
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,839,568
Total Annual Energy Cost ($)	14,936,308
Energy cost per gallon ($)	0.15

Plant 1: Natural Gas Non CHP	Wisconsin
Fuel Quantity	
Required Fuel (MMBtu)	3,233,000
Btu/gal EtOH, HHV	32,330
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.941747573
Delivered Gas Cost ($)	28,908,670
Electric Cost	
Purchased Power (kWh)	75,000,000
Electric Cost ($)	6,277,500
Capital Cost	
Firetube Boiler Cost ($)	1,200,000
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	12,810,000
O&M Cost	
Total Annual Fuel Cost ($)	28,908,670
Electric Cost ($)	6,277,500
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	N/A
Boiler System Maintenance ($)	incl. in personnel
Total O&M ($)	35,288,670
Financing	
Annualized Loan Payments ($)	1,880,038
Add: O&M Cost ($)	35,288,670
Total Annual Energy Cost ($)	37,168,708
Energy cost per gallon ($)	0.37

Plant 2: Natural Gas CHP	Wisconsin
Fuel Quantity	
Required Fuel (MMBtu), HHV	3,459,823
Btu/gal EtOH, HHV	34,598
Fuel Cost	
Delivered Gas Cost ($/MMBtu)	8.941747573
Delivered Gas Cost ($)	30,936,864
Electric Cost	
Purchased Power (kWh)	16,639,000
Electric Cost ($)	1,392,684
Capital Cost	
Firetube Boiler Cost ($)	N/A
Dryer ($)	7,420,000
RTO ($)	2,750,000
Pipeline Cost ($)	1,440,000
Gas Turbine with Heat Recovery Boiler ($)	9,000,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	20,610,000
O&M Cost	
Total Annual Fuel Cost ($)	30,936,864
Ancillary Electric Cost ($)	1,392,684
Personnel Cost ($)	100,000
Emissions Operating Permitting Fees ($)	2,500
Other O&M:	
Gas Turbine O&M ($)	437,708
Boiler System Maintenance ($)	N/A
Total O&M ($)	32,869,756
Financing	
Annualized Loan Payments ($)	3,024,792
Add: O&M Cost ($)	32,869,756
Total Annual Energy Cost ($)	35,894,548
Energy cost per gallon ($)	0.36

Plant 3: Coal Non CHP Plant	Wisconsin
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,025,641
Btu/gal EtOH, HHV	40,256
Required Fuel (tons/y)	228,730
Required Fuel (tons/day)	627
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	5,884,069
Electric Cost	
Purchased Power (kWh)	90,000,000
Electric Cost ($)	7,533,000
Capital Cost	
Fluidized Bed Boiler Cost ($)	20,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	N/A
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	41,750,000
O&M Cost	
Total Annual Fuel Cost ($)	5,884,069
Electric Cost ($)	7,533,000
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	N/A
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	14,163,069
Financing	
Annualized Loan Payments ($)	6,127,368
Add: O&M Cost ($)	14,163,069
Total Annual Energy Cost ($)	20,290,437
Energy cost per gallon ($)	0.20

Plant 4: Coal CHP	Wisconsin
Fuel Quantity	
Required Fuel (MMBtu), HHV	4,431,356
Btu/gal EtOH, HHV	44,314
Required Fuel (tons/y)	251,782
Required Fuel (tons/day)	690
Fuel Cost	
Delivered Coal cost ($/MMBtu)	1.46
Delivered Coal Cost ($)	6,477,081
Electric Cost	
Purchased Power (kWh)	6,294,000
Electric Cost ($)	526,808
Capital Cost	
Fluidized Bed Boiler Cost ($)	23,000,000
Dryer ($)	17,250,000
RTO ($)	N/A
Rail Cost ($)	4,500,000
Steam Turbine ($)	3,605,000
Ethanol Process Improvements ($)	0
Total Capital Cost ($)	48,355,000
O&M Cost	
Total Annual Fuel Cost ($)	6,477,081
Coal Ancillary Electric Cost ($)	526,808
Personnel Cost ($)	200,000
Emissions Operating Permitting Fees ($)	20,000
Other O&M:	
Steam Turbine O&M ($)	209,265
Coal System Maintenance ($)	360,000
Limestone Cost ($)	166,000
Coal Combustion Product Costs ($)	0
Total O&M ($)	7,959,154
Financing	
Annualized Loan Payments ($)	7,096,740
Add: O&M Cost ($)	7,959,154
Total Annual Energy Cost ($)	15,055,894
Energy cost per gallon ($)	0.15

.

REFERENCES

ASHRAE Handbook, 1995. "HVAC Applications," American Society of Heating, Refrigerating and Air-Conditioning Engineers.

Crump, Bill and Andy Foley, R.W. Beck Inc., 2003. "Natural Gas Transmission – Pipeline Construction Cost," Oil and Gas Bulletin

Energy and Environmental Analysis, Inc., July 2006. "An Assessment of the Potential for Energy Savings in Dry Mill Ethanol Plants from the Use of Combined Heat and Power," prepared for: U.S. Environmental Protection Agency Combined Heat and Power Partnership

Energy Products of Idaho, Process Flow Diagram for a 100 mgpy dry mill ethanol plant, prepared for University of Illinois at Chicago Energy Resources Center

Ethanol Plant Development Handbook, 2001. Third Edition. Researched and Published by BBI International

Ethanol Producers Magazine, November 2007. Commodities Report, DDGS Prices.

Hansen, Teresa, July 2006. "Coal Combustion Products: Trash or Treasure?" Power Engineering Magazine

Kotrba, Ron, May 2006. "Larger Scale, Relative Economics," Ethanol Producer Magazine

Kotrba, Ron, August 2006. "Ethanol Producers Talk Shop," Ethanol Producer Magazine

Midwest CHP Application Center and Avalon Consulting, Inc. "Combined Heat and Power (CHP) Resource Guide," September, 2005.

Niles, Dave, August 2006. "Control Your Energy Destiny," Ethanol Producer Magazine

Roddy, Bill, "Dry Mill Ethanol Plants, Environmental Impacts and Future Growth," ICM, presented at the Governor's Ethanol Coalition, February 10, 2006

Renewable Fuels Association Website, www.ethanolrfa.org

Whelan, Casey D, June 20, 2006 "Thermal Requirements: Coal vs Natural Gas," presented at the Fuel Ethanol Workshop

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

Center Oil / Center Ethanol

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