State of California
Air Resources Board

Response to Notice of Availability of Modified Text and Availability of Additional Documents Released on September 23, 2009

SUPPLEMENTAL DECLARATION OF JAMES MICHAEL LYONS ON CORN ETHANOL PATHWAYS

I, James Michael Lyons, declare as follows:

1. On August 19, 2009, I provided a Declaration in this proceeding that addressed, among other subjects, the Executive Officer's proposed modifications and additions to proposed section 95486 of title 17, California Code of Regulations. My qualifications to address the issues presented by proposed section 95486 subject are presented in my August 19, 2009 Declaration and Appendix A thereto.

2. This Supplemental Declaration prepared for POET LLC presents the results of an analysis I have performed using the California-Modified GREET pathways for corn ethanol, to determine the appropriate Carbon Intensity ("CI") values that should be assigned to corn ethanol produced using certain processes at Midwest dry mills. The sources cited in this Supplemental Declaration are among the types of sources on which experts in the analysis of the CI intensity of corn ethanol normally and properly rely. If called upon to do so, I would testify in accord with the facts and opinions presented here.

3. As indicated in Table 4.01 of the Corn Ethanol Pathway document in the rulemaking file, the CA-GREET model assumes that the direct energy requirements of a natural gas dry mill ethanol plant producing dry distillers grains (DDGS) are 36,000 btu per gallon of ethanol produced, with 32,330 btu being from natural gas and 3,670 btu being from electricity. According to Wang et al.[1] and Mueller and Cuttica,[2] the primary reference cited by Wang et al., the drying of distillers grains accounts for 10,500 btu of the total of 32,300 btu of natural gas consumed per gallon of ethanol produced. After the GHG emissions associated with natural gas and electricity production are taken into account, the values noted above increase to 34,598 btu and 10,926 btu per gallon of ethanol, respectively. Based on the CA-GREET model, these equate to 25.48 and 12.80 gCO_2eq/MJ, respectively.

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[1] Wang, M. et al., "Life-cycle energy and greenhouse gas emission impacts of different corn ethanol plant types," Environ. Res. Lett. 2, 024001, 2007, attached hereto as Appendix A.

[2] Mueller, S. and Cuttica, J. J. "Research investigation for the potential use of Illinois coal in dry mill ethanol plants," Energy Resources Center, University of Illinois at Chicago, October 2006, attached hereto as Appendix B.

4. According to Mueller,[3] one of the authors of the primary reference used by Wang *et al.* and a source extensively referenced by U.S. EPA in its Draft Regulatory Impact Analysis for Changes to the Renewable Fuel Standard Program, raw starch hydrolysis reduces the process energy requirements for dry mill ethanol production by 5,000 btu per gallon. Similarly, Mueller indicates that the corn fraction reduces process energy by 3,333 btu per gallon and drying energy by 6,667 btu per gallon. However, corn fractionation is also reported to increase electricity consumption by about 10%. In addition to reducing process energy requirements, research reported in an accompanying Declaration from members of the faculty of Iowa State University demonstrates that raw starch hydrolysis is expected to raise the yield for ethanol production by about 0.2 gallons per bushel of corn processed.

5. In reliance on the sources cited above I have calculated CI values for corn ethanol produced at dry mill plants using various combinations of raw starch hydrolysis, corn fractionation, and substitution of biomass for natural gas for process energy requirements. The assumptions I used are summarized in Table 1 in terms of changes from a dry mill plant using natural gas for its process and drying energy requirements, which is shown in Case 1 in Table 1 on the following page. For certain additional pathways, I have also assumed that the use of renewable/biomass fuel can eliminate the use of natural gas for process steam, and that the Executive Officer would not attribute any indirect emissions impacts to the acquisition or use of such renewable/biomass fuel. In addition I have accounted for emissions of methane and nitrous oxide during biomass combustion using values for corn stover fired boilers from the CA-GREET model.

6. The CI values I computed for each case are shown in Table 2 on the following page. The CI values shown in Table 2 are for anhydrous ethanol and would need to each be increased by 0.8 gCO_2eq/MJ to reflect CARB estimates of the additional GHG emissions associated with denaturants and combustion. My calculations are documented in an Excel spreadsheet (Calculations.xls) that is being filed electronically along with this declaration. As shown in Table 2 on the following page, the CI values for all seven of the additional cases are more than 5 gCO_2eq/MJ lower than the CI value for Case 1, which is the dry mill production case in Table B of the Corn Ethanol pathway document in the rulemaking file.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 8th day of October, 2009 at Dearborn, Michigan.

JAMES M. LYONS

[3] Mueller, S., "An analysis of the projected energy use of fuel dry mill corn ethanol plants (2010-2030)," Energy Resources Center, University of Illinois at Chicago, October 2007, attached hereto as Appendix C.

Table 1
Current and Additional Dry Mill Corn Ethanol Pathway Assumptions

Case	Pathway	Change in Process NG (btu/gallon)	Change in Drying NG (btu/gallon)	%Change in Elect.	Change in ETOH Yield (gal/bu)
1	Current CARB Midwest, Dry Mill, Dry DGS, NG	0	0	0	0
2	Midwest, Dry Mill, Raw Starch Hydrolysis, Dry DGS, NG	-5,000	0	0	+0.2
3	Midwest, Dry Mill, Raw Starch Hydrolysis, Dry DGS, Biomass for Process	-21,830	0	0	+0.2
4	Midwest, Dry Mill, Fractionation, Dry DGS, NG,	-3,333	-6,667	+10	0
5	Midwest, Dry Mill, Fractionation, Dry DGS, Biomass for Process	-21,830	-6,667	+10	0
6	Midwest, Dry Mill, Fractionation, Raw Starch Hydrolysis, Dry DGS, NG,	-8,333	-6,667	+10	+0.2
7	Midwest, Dry Mill, Fractionation, Raw Starch Hydrolysis Dry DGS, Biomass for Process	-21,830	-6,667	+10	+0.2
8	CARB Midwest, Dry Mill, Dry DGS, Biomass for Process	-21,830	0	0	0

Table 2
CI Values for Current and Additional Dry Mill Corn Ethanol Pathways
(gCO_2eq/MJ for Anhydrous Ethanol without Denaturant or Combustion)[a]

Cycle Component	Case 1	2	3	4	5	6	7	8
Farming	5.65	5.26	5.26	5.65	5.65	5.26	5.26	5.65
Ag Chem. Prod.	30.20	28.13	28.13	30.20	30.20	28.13	28.13	30.20
Corn Transportation	2.22	2.07	2.07	2.22	2.22	2.07	2.07	2.22
ETOH Production	38.28	31.99	20.54	31.68	18.08	25.84	16.84	22.05
Ethanol T&D	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Co-Products	-11.51	-10.72	-10.72	-11.51	-11.51	-10.72	-10.72	-11.51
Total	67.54	59.43	47.98	60.94	47.34	53.28	44.28	51.31

[a] All values would increase by approximately 0.8 gCO2eq/MJ to account for CARB estimates of GHG emissions associated with denaturants and combustion.

APPENDIX A

Environ. Res. Lett. **2** (2007) 024001 (13pp) doi:10.1088/1748-9326/2/2/024001

Life-cycle energy and greenhouse gas emission impacts of different corn ethanol plant types

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Received 12 March 2007
Accepted for publication 27 April 2007
Published 22 May 2007
Online at stacks.iop.org/ERL/2/024001

Abstract
Since the United States began a programme to develop ethanol as a transportation fuel, its use has increased from 175 million gallons in 1980 to 4.9 billion gallons in 2006. Virtually all of the ethanol used for transportation has been produced from corn. During the period of fuel ethanol growth, corn farming productivity has increased dramatically, and energy use in ethanol plants has been reduced by almost by half. The majority of corn ethanol plants are powered by natural gas. However, as natural gas prices have skyrocketed over the last several years, efforts have been made to further reduce the energy used in ethanol plants or to switch from natural gas to other fuels, such as coal and wood chips. In this paper, we examine nine corn ethanol plant types—categorized according to the type of process fuels employed, use of combined heat and power, and production of wet distiller grains and solubles. We found that these ethanol plant types can have distinctly different energy and greenhouse gas emission effects on a full fuel-cycle basis. In particular, greenhouse gas emission impacts can vary significantly—from a 3% increase if coal is the process fuel to a 52% reduction if wood chips are used. Our results show that, in order to achieve energy and greenhouse gas emission benefits, researchers need to closely examine and differentiate among the types of plants used to produce corn ethanol so that corn ethanol production would move towards a more sustainable path.

Keywords: corn ethanol, life-cycle analysis, greenhouse gas emissions, ethanol plants

1. Introduction

During the second oil crisis in 1979, the US government decided to promote the use of fuel ethanol to help diversify the national transportation fuel supply. The US fuel ethanol programme began in 1980; about 175 million gallons of ethanol were used that year. To encourage fuel ethanol production, the federal government initially provided an incentive of 54 cents per gallon of fuel ethanol used. This incentive was later reduced to the current level of 51 cents. Besides the federal government incentive, various states provided incentives to encourage the construction of ethanol plants.

The 1990 Clean Air Act Amendments established the oxygenated fuel programme and the reformulated gasoline programme to encourage the use of ethanol as an oxygenate in gasoline to help reduce criterion air pollutant emissions, primarily emissions of carbon monoxide and precursors for ozone formation. These provisions helped increase fuel ethanol use to over 1.7 billion gallons per year by 2001.

In 2001 and 2002, the discovery of underground water contaminated with methyl tertiary butyl ether (MTBE), used as an additive in reformulated gasoline, led several states on the west coast and in the Northeast to ban the use of MTBE in reformulated gasoline. Ethanol became the only oxygenate to meet oxygen content requirements for reformulated gasoline. The switch from MTBE to ethanol in states along both coasts caused a significant increase in fuel ethanol use. By 2004, ethanol use reached 3.4 billion gallons per year.

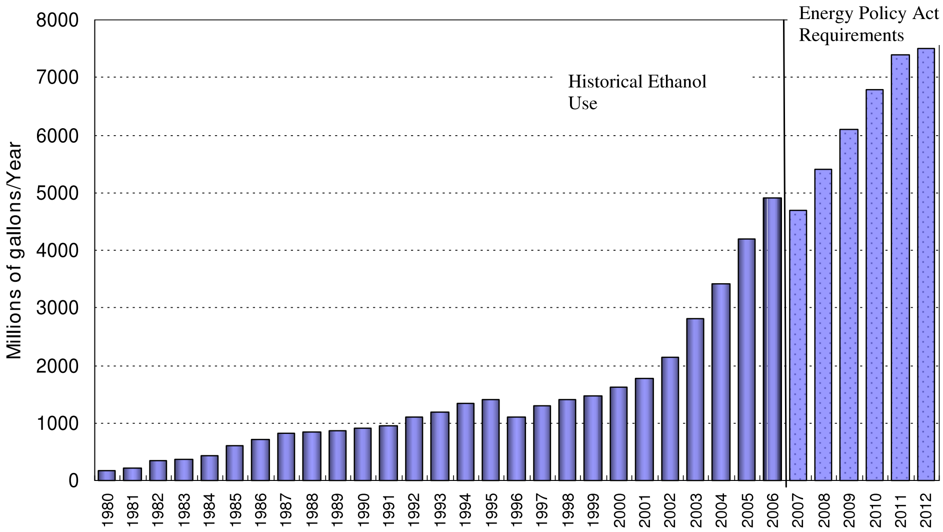

Figure 1. Historical fuel ethanol use and the 2005 Energy Policy Act fuel ethanol use requirements (historical data are from Renewable Fuels Association (2007) and US Congress (2005)).

The 2005 Energy Policy Act established a renewable fuel standard (RFS) that increased the mandated use of renewable fuels—including ethanol and biodiesel—from 4 billion gallons in 2005 to 7.5 billion gallons in 2012. This mandate has spurred the construction of many new ethanol plants and has intensified interest in the research and development (R&D) of technologies to produce ethanol from the cellulose in grass, trees, and other biomass feedstocks. By the end of 2006, fuel ethanol use in the United States had reached 4.9 billion gallons—far exceeding the 4.2 billion gallon mandate in the Energy Policy Act. Figure 1 shows the historical fuel ethanol use in the United States and the Energy Policy Act requirements through 2012. Researchers generally agree that actual fuel ethanol use through 2012 will exceed the volumes required by the Energy Policy Act.

Most corn ethanol plants built in recent years in the United States use natural gas as the process fuel. The average ethanol plant built several years ago had an annual production capacity of about 50 million gallons. By building ethanol plants of this size and installing natural-gas-based boilers, plant owners could obtain state permits on a fast-track basis because such ethanol plants would be classified as minor emission sources. The US corn ethanol industry is undergoing a tremendous expansion. Ethanol plant size has increased significantly; a new ethanol plant could well reach an annual capacity of 100 million gallons. The fuel cost in ethanol plants is the second largest expense after the cost for corn feedstock. Skyrocketing natural gas prices have forced ethanol plant owners to explore ways to reduce plant energy use and find alternatives to using natural gas as a process fuel. The uptrend in ethanol plant sizes makes it feasible for some owners to consider using coal as a process fuel and installing the necessary emission control equipment; unfortunately, this approach would have a detrimental effect on the greenhouse gas (GHG) emission benefits of corn ethanol. Other plant owners have begun to explore other options to reduce energy use in their plants: (1) use of biomass feedstocks or distiller grains and solubles (DGS), (2) production of wet DGS (for animal feedlot use), and (3) use of combined heat and power (CHP) systems. These options can extend the GHG reduction benefits of corn ethanol.

In this study, we expand the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) model developed at Argonne National Laboratory to examine new designs for corn ethanol plants and their associated energy and GHG emission effects. This paper presents our results for differentiated ethanol plant types; we are hopeful that the information provided here will help the corn ethanol industry select the most energy- and GHG-emission-friendly path forward.

2. Life-cycle analysis methodology

Since 1995, with support primarily from the US Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy (EERE), we have been developing the GREET model at Argonne National Laboratory. Argonne released the first version of the model—GREET 1.0—in June 1996. GREET is a Microsoft® Excel™-based multidimensional spreadsheet model that addresses the well-to-wheels (WTW) analytical challenges associated with transportation fuels (including ethanol) and vehicle technologies. By using the latest version of the model—GREET 1.7—users can analyse more than 90 transportation fuel pathways and 75 vehicle/fuel systems (Wang *et al* 2007). As a licensed software product available free of charge to the public, GREET has more than 3500 registered users worldwide. They include governmental agencies, automotive companies, energy companies, universities and research institutions, and non-governmental organizations. GREET and its documents are available at Argonne's transportation web site at http://www.transportation.anl.gov/software/GREET/index.html.

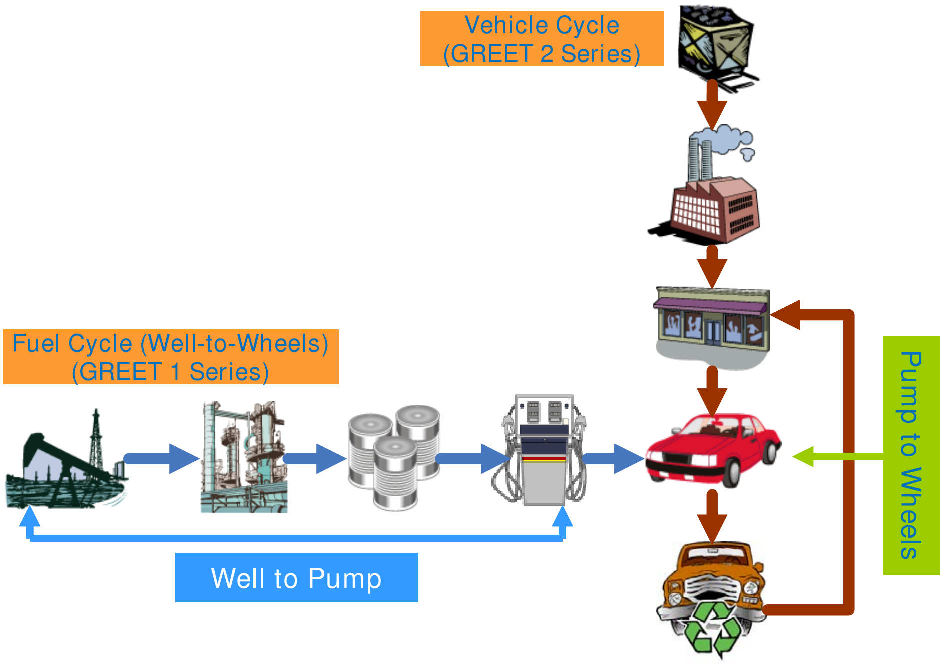

Figure 2. Life-cycle analysis of vehicle/fuel systems with the GREET model.

For a given vehicle and fuel system, GREET separately calculates the following.

- Consumption of total energy (energy in non-renewable and renewable sources); fossil fuels (total of petroleum, natural gas, and coal); natural gas; coal; and petroleum.
- Emissions of GHGs, including carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).
- Emissions of six criterion pollutants: volatile organic compounds (VOCs), carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter measuring less than 10 μm in diameter (PM_{10}), particulate matter measuring less than 2.5 μm in diameter ($PM_{2.5}$), and sulfur oxides (SO_x). These criterion pollutant emissions are further separated into total and urban emissions.

Figure 2 shows the coverage of the GREET model for life-cycle analysis. As the figure shows, the fuel-cycle (or WTW) analysis is conducted by using the GREET 1 series, which covers energy feedstock recovery (e.g. crude oil recovery), energy feedstock transportation (e.g. crude transportation), fuel production (e.g. petroleum refining to gasoline and diesel), fuel transportation, and fuel use in vehicles. The figure also shows the vehicle-cycle analysis, conducted by using the GREET 2 series, which includes raw material recovery (e.g. iron ore mining), material production (e.g. steel production), vehicle part fabrication (e.g. engine production), vehicle assembly, and vehicle disposal and material recycling.

In this study, we used the GREET 1 series model (version 1.7) to examine the life-cycle effects of different corn ethanol production options. For fuel ethanol analysis, GREET begins with production of agricultural chemicals (such as fertilizers and pesticides) and extends to vehicles using ethanol—either in low-level gasoline blends (such as E10 (10% ethanol and 90% gasoline by volume)) or in high-level gasoline blends (such as E85 (85% ethanol and 15% gasoline by volume)). Figure 3 shows the fuel ethanol production pathways that are already included in GREET 1.7. Besides corn ethanol, GREET 1.7 includes cellulosic ethanol with cellulosic biomass feedstocks comprising crop residues (e.g. corn stover and wheat straws), switch-grass, fast-growing trees (e.g. hybrid popular and willow trees), and forest residues. We have recently finished an evaluation of sugar-cane-to-ethanol production in Brazil using the GREET model; this new pathway is not yet included in the public version of GREET.

The focus of this study is corn ethanol produced in plants of varying designs. The GREET 1.7 version differentiates corn ethanol into that produced in wet milling versus dry milling plants. Because all ethanol plants built in recent years and those that will be built in the near future are based on dry milling designs, we examine only the different designs of dry milling corn ethanol plants.

Although GREET can be used to estimate emissions of criterion pollutants, as well as energy use and GHG emissions, criterion pollutant emissions are subject to greater uncertainties. For this reason, we have not included emissions of criterion pollutants in this study.

Of all the activities presented in figure 3 for corn ethanol production, the two that have the most significant effects on energy and emissions are corn farming and ethanol production. We address these two activities in detail in the following two sections.

3. Corn farming

Corn farming requires a significant number of chemical inputs, such as nitrogen fertilizer, phosphate fertilizer, potash

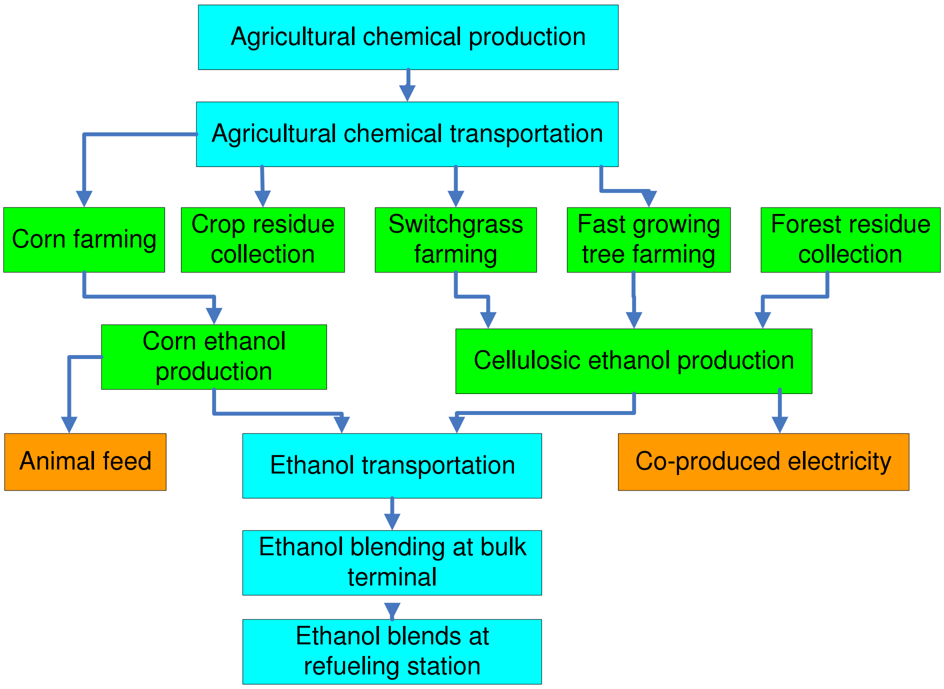

Figure 3. Fuel ethanol production options in GREET 1.7.

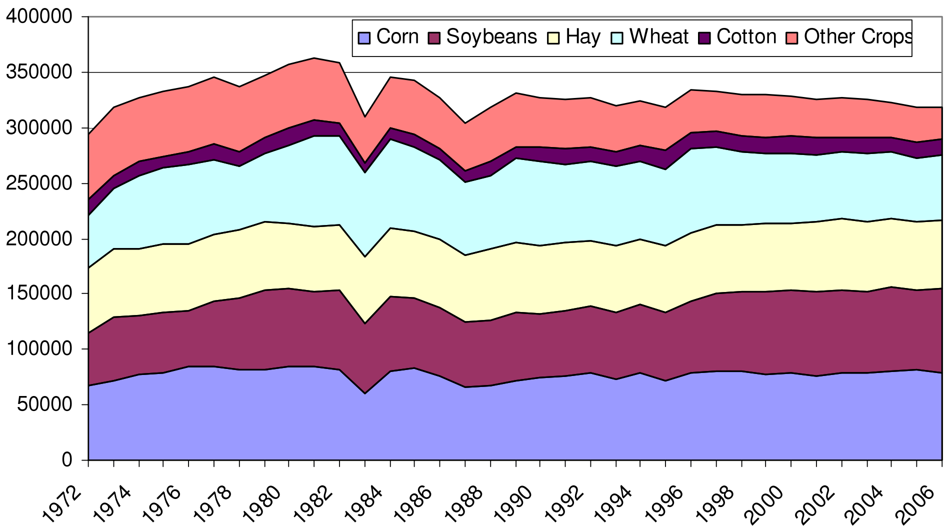

Figure 4. Planted acreage of major crops in the United States (from annual reports of the National Agricultural Statistics Service (US Department of Agriculture, various years); the acreage for hay is harvested acreage).

fertilizer, and lime (for soil conditioning to maintain proper soil acidity). In addition, fossil energy is used to operate farming machinery, to pump water for irrigation, and to dry corn kernels.

The United States has about 80 million acres of corn farms that produce more than 11 billion bushels of corn per year. Figure 4 shows the planted acreage of major crops in the United States. As the figure shows, the total US crop acreage peaked at 360 million acres in 1981. Since then, the number of acres planted for crops has gradually declined to 319 million acres in 2006, thanks to the Conservation Reserve Program (CRP) and other US Department of Agriculture (USDA) environmental protection programs.

It is worth noting that while corn ethanol production increased almost 30-fold between 1980 and 2006, the number of corn farming acres held steady—at around 80 million acres (figure 4). One major reason is that the corn yield per acre has steadily increased. Over the past 100 years, the US corn yield *per acre* has increased nearly eightfold (Perlack *et al* 2005). However, the increase in per-acre corn yields before

Table 1. Historical corn yield and chemical use for US corn farms (three-year moving averages on a per-harvested-acre basis, US Department of Agriculture (2007)).

Year	Corn yield (bushels/acre)	Nitrogen (N) fertilizer (lb/acre)	Phosphorus (P_2O_5) fertilizer (lb of/acre)	Potash (K_2O) fertilizer (lb/acre)	Limestone ($CaCO_3$) (lb/acre)
1970	79	118.2	68.8	66.5	
1971	82	119.8	67.7	65.6	
1972	86	122.6	69.0	67.1	
1973	92	122.8	65.5	65.3	
1974	87	122.5	65.9	69.2	
1975	83	117.8	62.1	67.4	
1976	82	125.3	64.6	71.2	
1977	88	135.1	66.6	73.5	
1978	93	142.1	69.7	76.8	
1979	100	142.1	68.9	76.7	NA
1980	101	141.8	67.5	77.1	
1981	103	146.5	67.7	79.7	
1982	104	147.0	66.2	81.0	
1983	101	150.4	66.1	81.8	
1984	100	150.4	64.5	81.2	
1985	102	151.4	62.1	78.7	
1986	115	146.6	59.2	73.7	
1987	119	143.6	56.8	70.7	
1988	108	144.9	59.0	71.9	
1989	107	145.8	58.5	71.9	
1990	106	146.1	58.5	72.2	365.6
1991	114	140.2	55.4	68.2	299.3
1992	120	138.1	54.1	66.5	305.7
1993	114	137.1	53.1	64.4	274.3
1994	124	136.9	52.1	63.5	294.4
1995	118	137.8	51.6	62.6	324.4
1996	126	138.9	51.4	61.8	377.8
1997	122	140.4	51.7	62.2	416.2
1998	129	142.3	51.6	62.2	420.7
1999	132	142.6	50.2	61.1	410.6
2000	135	144.5	50.2	58.9	411.9
2001	136	141.3	50.1	58.9	414.3
2002	135	143.5	51.9	60.9	NA
2003	137	142.9	51.6	61.9	NA
2004	144	142.9	51.6	61.9	NA
2005	150	144.5	51.5	60.0	NA

the 1970s resulted from increased application of chemicals, especially nitrogen fertilizer, to corn farms. While the high chemical inputs during that period helped increase per-acre corn production, they did not help corn yield per unit of fertilizer input, which is directly related to corn ethanol's energy and emission effects.

However, since the 1970s, the increase in the corn yield per acre has been achieved as the result of an increase in corn productivity through better seed variety, better farming practices, and other agricultural measures. Table 1 shows that between 1970 and 2005 corn yield increased by 90%, while nitrogen fertilizer application increased by only 22%, phosphorus fertilizer application was reduced by 25%, and potash fertilizer application was reduced by 6% (and limestone application was increased by 13% between 1990 and 2001, when statistics for limestone were available). Corn productivity, defined as bushels/lb of three fertilizer types together, has increased by 88%—from 0.312 bushels/lb of three fertilizers to 0.586 bushels/lb between 1970 and 2005.

Nitrogen fertilizer goes through nitrification and denitrification; during this process, a portion of the nitrogen in fertilizer is converted into nitrogen in nitrous oxide (N_2O), a potent greenhouse gas. GREET assumes a conversion rate of 2% from nitrogen in fertilizer to nitrogen in N_2O.

Limestone is applied to the fields to adjust soil pH and to maintain a certain level of buffer necessary for corn and soybean growth. Corn/soybean rotation farms require a soil pH of 6.5–7.0, depending on the soil type and its buffer capacity. Typically, limestone is applied every few years. In soil, limestone is converted into lime (CaO), and 44% of the limestone mass is released to the air as CO_2. We took this CO_2 emission source into account.

Researchers and policymakers have been engaged in a discussion about possible sources of the additional corn that will be needed to meet the demand if the United States significantly increases its corn ethanol production. There are several alternatives. First, the existing 80 million acres of corn farms will continue to increase their per-acre yields. One conservative estimate of corn yield is about 160 bushels/acre, which will be reached in a few years. More optimistic estimates predict a yield of 180 bushels/acre by 2015. Thus, additional corn production from existing corn farms could be 800 to 1600 million bushels of corn per year—providing enough corn for 2.24 to 4.48 billion gallons of ethanol production. Switching from other crops to corn and using some other lands (such as CRP lands) are other alternatives to further increase corn production. For example, the USDA recently maintained that an additional 10 million acres could be available for corn farming by 2010, increasing the total corn farming acreage to 90 million acres by 2010 (Associated Press 2007) and providing at least 1.4 billion bushels of corn production.

In the late 1990s, the USDA conducted a detailed simulation of land use changes to accommodate corn ethanol production of 4 billion gallons per year. The simulation included some crop switches and use of CRP lands. Based on the results from that simulation, we estimated soil CO_2 emissions of 195 g/bushel of corn, and incorporated this estimate into the GREET model. Nevertheless, land use changes need to be simulated for a much greater expansion of corn ethanol production to reflect future corn ethanol production in the United States.

We estimated direct fuel use of 22 500 Btu/bushel of corn harvested on corn farms. The direct fuel use estimate includes diesel for powering farming equipment, liquefied petroleum gas (LPG) and natural gas for drying corn and for other farming operations, and electricity for irrigation (Wang *et al* 2003).

Some have argued that the energy used to produce farming equipment could represent a large energy penalty for the corn ethanol pathway. We have completed a thorough examination of this issue by taking into account the type and lifetime of farming equipment, size of farms to be served by the equipment, material composition of the equipment, and energy intensity of material production and equipment assembly (Wu *et al* 2006). Our thorough examination revealed that farming equipment manufacture contributes a 2% increase in energy use and a 1% increase in GHG emissions to the corn ethanol pathway (on a full fuel-cycle basis); these percentages are well within the uncertainty range for the corn ethanol results.

4. Ethanol production

Historically, corn ethanol plants are classified into two types: wet milling and dry milling. In wet milling plants, corn kernels are soaked in water containing sulfur dioxide (SO_2), which softens the kernels and loosens the hulls. Kernels are then degermed, and oil is extracted from the separated germs. The remaining kernels are ground, and the starch and gluten are separated. The starch is used for ethanol production.

In dry milling plants, the whole dry kernels are milled (with no attempt to remove fractions such as germs). The milled kernels are sent to fermenters, and the starch portion is fermented into ethanol. The remaining, unfermentable portions are produced as DGS and used for animal feed. In general, wet milling plants are much larger than dry milling plants. For example, several wet milling ethanol plants in the United States have an annual production capacity of about 150 million gallons; the annual capacity of dry milling plants has been about 50 million gallons until very recently.

All corn ethanol plants that have come online in the past several years, and those that will come online in the next few years, are dry milling plants (Renewable Fuels Association 2007). The capacity of some of the new dry milling plants is 100 million gallons per year. Dry milling plants have been fuelled primarily with natural gas. Process fuel costs are the second largest expense in ethanol plants (after corn feedstock). Because natural gas prices have skyrocketed in recent years, new plant designs are being developed that will reduce process fuel requirements or allow the use of process fuels other than natural gas. We established a current average and a 2010 average ethanol case to represent ethanol production of the whole industry now and in the future, evaluated nine dry milling ethanol plant types, and examined the aggregate ethanol production from all ethanol plants. Each of the cases and plant types is discussed below.

4.1. Current average and 2010 average ethanol cases

For the current average ethanol case, we used the following assumption: of the 4.9 billion gallons of corn ethanol produced and used in the United States in 2006, 80% was from dry milling plants and 20% from wet milling plants.

We analysed the 2010 average ethanol case so that results for new ethanol plant types could be compared directly with future average ethanol production. In developing the 2010 average ethanol case, we assume that all the new ethanol plants to be built from now until 2010 will be dry milling plants. We also assume that by 2010, total ethanol production in the United States will reach 8 billion gallons. On the basis of these assumptions, we concluded that by 2010 87.5% of ethanol will be produced from dry milling plants and 12.5% from wet milling plants.

4.2. New ethanol plant types

New ethanol plants fuelled with natural gas. A large number of new ethanol plants are still fuelled with natural gas. Natural gas boilers are less expensive than other boiler types, and plants with natural gas boilers are classified as minor emission sources, which helps expedite the process of obtaining emission permits from individual states. These new natural-gas-fuelled ethanol plants have lower natural gas consumption compared with some older natural-gas-fuelled ethanol plants.

New ethanol plants fuelled with natural gas and producing wet DGS. It is estimated that about one-third of the thermal energy used in ethanol plants is consumed by dryers used to dry DGS to about 10% moisture content for long-distance transportation and long shelf life. Some new ethanol plants are sited near animal feedlots so that wet DGS can be moved directly to the feedlots, eliminating the need to dry the DGS and resulting in large energy savings for the ethanol plants.

New ethanol plants fuelled with natural gas and CHP systems. A CHP system produces both steam and electricity for plant operation. Adding CHP systems to ethanol plants can help eliminate or substantially reduce the amount of electricity that must be purchased by ethanol plants, thus decreasing overall plant energy use. The US environmental protection agency (EPA) has been working with several ethanol plants to install CHP systems.

New ethanol plants fuelled with coal. Skyrocketing natural gas prices in recent years have encouraged the use of coal as a process fuel in several ethanol plants under construction or in planning. Because the size of ethanol plants has increased, a large coal-fired boiler—even one equipped with the necessary emission controls—may still be economical relative to a gas-fired boiler. One hurdle to construction of coal-fuelled ethanol plants is that these plants may be classified as major emission sources under the current EPA classification system, requiring plant owners to go through a longer process to obtain emission permits. Ongoing discussions among the ethanol industry, individual states, and the EPA are aimed at encouraging regulators to consider increasing the emission cap—from the current 100 tons of VOCs and NO_x a year to a higher level of emissions (between minor and major emission sources).

New ethanol plants fuelled with coal and producing wet DGS. Similar to the gas-fuelled ethanol plants, this ethanol plant design includes transport of wet DGS to nearby animal feedlots to avoid the need for drying DGS.

New ethanol plants fuelled with coal and CHP systems. Adding CHP systems to coal-fuelled ethanol plants will help reduce overall energy use.

New ethanol plants fuelled with wood chips. Two corn ethanol plants in Minnesota are adding wood chip gasifiers to produce synthesis gas (syngas) from wood chips and then steam from the syngas for ethanol plant operation. So wood chips are replacing natural gas as the process fuel in these two plants. In the long run, crop residues, such as corn stover, could be used as the process fuel in corn ethanol plants located in the US corn belt. This option could well serve as a bridge from production of corn ethanol to production of cellulosic ethanol, because it will help identify and solve the logistical issues associated with the use and transportation of cellulosic biomass such as forest residues or crop residues.

New ethanol plants fuelled with natural gas and producing syrup. Corn syrup (or dewatered distiller solubles) left over from the ethanol distillation process can be burned (instead of being used as DGS) to provide a portion of the steam needed in ethanol plants. The remaining steam requirement can be met by burning natural gas. This technology has already been installed in the Corn Plus ethanol plant located in Winnebago, MN. In that plant, the use of corn syrup as a process fuel accounts for 19% of the total dry mass of DGS (Coil 2006).

New ethanol plants fuelled with DGS. As the corn ethanol industry rapidly grows, there is a concern that the animal feed market could be flooded with DGS from corn ethanol plants. While R&D efforts in the animal feed field are underway to expand the use of DGS as animal nutrients, an alternative is to use DGS as the process fuel for ethanol plant operation. On a dry-matter basis, one ton of DGS has a lower heating value (LHV) of about 17 920 000 Btu. In dry milling ethanol plants, for each gallon of ethanol produced, about 6 lb of dry DGS is produced (Renewable Fuels Association 2007), which has an LHV of about 53 760 Btu. For comparison, a coal-fired ethanol plant requires 40 260 Btu of coal per gallon of ethanol produced. Thus, the amount of energy (in Btu) contained in the DGS is more than the amount of energy that an ethanol plant needs.

We designed this ethanol plant option so that all of the steam needed in a corn ethanol plant is provided through combustion of DGS. There are two advantages to this approach. First, use of DGS as a plant process fuel eliminates the need for drying of DGS as an animal feed. Second, use of the DGS displaces use of fossil fuels (such as natural gas or coal) in ethanol plants, thus helping corn ethanol achieve larger energy and GHG emission reduction benefits.

Table 2 presents energy use in ethanol plants for the nine ethanol plant types, plus the current average ethanol and the 2010 average ethanol cases.

5. Results

On the basis of the assumptions listed in table 2 and on other GREET default assumptions, we simulated energy use and GHG emissions (on a WTW basis) for the nine corn ethanol plant types and the current and 2010 average ethanol cases. To put the results into perspective, we included *current* gasoline production and use and 2010 gasoline production and use. We also included cellulosic ethanol production from switch-grass in the future. GREET default assumptions for current and future gasoline and future cellulosic ethanol were used to simulate these three pathways.

In all the corn ethanol cases simulated in this study, electricity is needed for ethanol plant operation (see table 2). The needed electricity is assumed to be purchased from the electric grid. In GREET simulations, we used the US average electricity generation mix for ethanol plant electricity need. That is, 52% of electricity is generated from coal, 16% from natural gas, 20% from nuclear power, 3% from residual oil, 1% from biomass, and 8% from hydro-power.

In our WTW simulations, we assumed the same fuel economy (on a gasoline-equivalent basis) for all vehicles using ethanol blends and gasoline. Thus, the energy use and emission differences between ethanol and gasoline result from the differences in production of the two fuels. Results are presented for each million Btu of fuel used.

The GREET 1.7 version is capable of estimating energy use by total energy, fossil energy, petroleum, natural gas, and coal separately. The results for each separate energy item are presented. We also present CO_2-equivalent GHG emissions of CO_2, CH_4, and N_2O weighted with their global warming potentials (1 for CO_2, 23 for CH_4, and 296 for N_2O).

Table 2. Energy use in each of the ethanol plant types (per gallon of ethanol produced).

Ethanol plant type	Natural gas (Btu)	Coal (Btu)	Renewable process fuel (Btu)	Electricity (kW h)
Current average production case[a]	26 420	8900	None	0.88
2010 average production case[b]	26 050	7950	None	0.95
1. Plant with NG[c]	33 330	None	None	0.75
2. Plant with NG and wet DGS[d]	21 830	None	None	0.75
3. Plant with NG and CHP[e]	34 600	None	None	0.17
4. Plant with coal[f]	None	40 260	None	0.90
5. Plant with coal and wet DGS[g]	None	26 060	None	0.90
6. Plant with coal and CHP[h]	None	44 310	None	0.06
7. Plant with wood chips[i]	None	None	40 260	0.90
8. Plant with NG and syrup[j]	21 000	None	14 000	0.75
9. Plant with DGS combustion[k]	None	None	40 260	0.75

[a] The values here are based on 80% corn ethanol production from dry milling plants and 20% from wet milling plants. Dry milling plants consume 36 400 Btu of fuel per gallon of ethanol produced, and wet milling plants consume 45 990 Btu. Furthermore, 80% of the process fuel used in dry milling plants is natural gas, and 20% is coal, while 60% of the process fuel used in wet milling plants is natural gas, and 40% is coal.

[b] The values here are for 2010 average ethanol production and are based on corn ethanol production of 87.5% from dry milling plants and 12.5% from wet milling plants. All dry milling plants will consume 36 000 Btu of fuel per gallon of ethanol produced, and all wet milling plants 45 950 Btu. Furthermore, 80% of the process fuel used in dry milling plants is natural gas and 20% is coal, while 60% of the process fuel used in wet milling plants is natural gas and 40% is coal.

[c] Based on Mueller and Cuttica (2006). The natural gas consumption value in Mueller and Cuttica is 32 330 Btu per gallon of ethanol. We increased their value by 1000 Btu to account for the uptrend uncertainty in energy use associated with drying of DGS.

[d] Based on Mueller and Cuttica (2006) with the adjustment in footnote c. The difference between total energy need and energy use for drying of DGS is the result here.

[e] From Mueller and Cuttica (2006) and Energy and Environmental Analysis, Inc. (2006).

[f] From Mueller and Cuttica (2006).

[g] From Mueller and Cuttica (2006). The difference between the total energy use need and energy use for drying DGS is the result here.

[h] From Mueller and Cuttica (2006) and Energy and Environmental Analysis, Inc. (2006).

[i] Energy use for coal-fired ethanol plants is assumed here. Carbon neutrality for wood chip combustion is assumed here. Thus, the energy use value here does not affect the carbon emission estimate for wood chip combustion.

[j] Based on Coil (2006) for the Corn Plus ethanol plant in Winnebago, MN. That plant uses about 19% DGS (on a dry-matter basis) to reduce the plant's natural gas usage from 35 000 Btu to 21 000 Btu per gallon of ethanol produced.

[k] The energy use for coal-fired ethanol plants is assumed here. This value does not affect the carbon emission estimate for DGS combustion because the carbon in DGS is ultimately from the air.

5.1. Total energy use

Figure 5 shows WTW total energy use for each million Btu of ethanol (EtOH) and gasoline produced and used. Total energy use includes all energy sources, including fossil energy and renewable energy (i.e. energy embedded in corn kernels and biomass). The chart reveals that ethanol produced from all plant types and cases has higher total energy use than gasoline because of the large amount of total energy use in the WTP stage (the pump-to-wheels (PTW) stage consumes 1 million Btu in all cases because the basis of the chart is 'each million Btu of fuel consumed'). The large increases in the WTP total energy use by all ethanol types are attributable to the fact that a large amount of process energy is consumed in ethanol plants and that a significant energy efficiency loss occurs during the conversion of corn or cellulosic biomass to ethanol.

5.2. Fossil energy use

Figure 6 presents the WTW fossil energy use of 14 fuel production options. Fossil energy use includes petroleum, natural gas, and coal—a subset of the total energy use in figure 5. While the two gasoline options still have 1 million Btu in fossil energy use during the PTW stage, the 12 ethanol options do not have any fossil energy use in the PTW stage because the Btu in ethanol is non-fossil Btu. It should be noted that for the WTP stage, corn-based ethanol options consume much greater amounts of fossil fuel energy than gasoline. The fossil energy consumption for corn ethanol options occurs during fertilizer manufacture, corn farming, and ethanol plant operation. For cellulosic ethanol, the fossil energy use is much lower because switch-grass farming is not chemical and energy intensive and because cellulosic ethanol plants use lignin, instead of fossil fuel, to generate the needed steam.

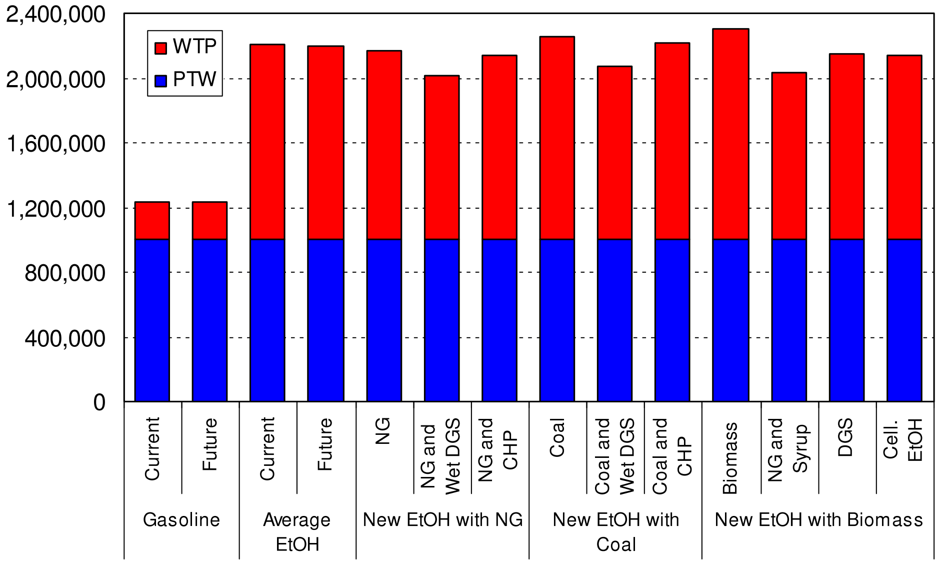

Figure 5. Well-to-wheels total energy use of ethanol and gasoline (Btu per million Btu of fuel produced and used).

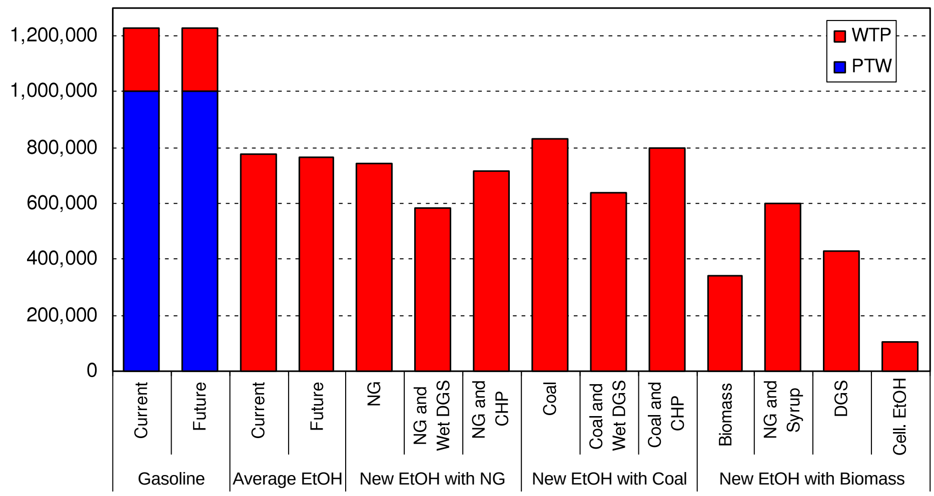

Figure 6. Well-to-wheels fossil energy use of ethanol and gasoline (Btu per million Btu of fuel produced and used).

All ethanol options reduce WTW fossil energy use relative to gasoline. The reductions result from the fact that ethanol itself is a non-fossil fuel. When biomass—such as wood chips, corn syrup, or DGS—is used in corn ethanol plants or when DGS is not dried, corn ethanol can achieve substantial reductions in fossil energy use.

The fossil energy balance of corn ethanol—defined as energy in a fuel minus fossil energy used to produce the fuel and fossil energy embedded in the fuel—is often debated. Figure 7 presents the energy balance of the 12 ethanol options and the two gasoline options, which are derived from the results in figure 6. As the figure shows, gasoline has a negative energy balance because it begins with 1 million Btu of petroleum already embedded in it. On the other hand, all corn ethanol options have positive fossil energy balances. The fossil energy balance values for corn ethanol vary from 170 000 to 660 000 Btu per million Btu of ethanol, depending on the type of process fuels used and ethanol plant designs. Cellulosic ethanol based on switch-grass has an even higher positive energy balance: 900 000 Btu per million Btu of ethanol.

5.3. Petroleum use

Figure 8 shows WTW petroleum use for the 14 fuel options. The WTP stage consumes some petroleum in all 14 options. For the ethanol options, petroleum energy is primarily in the form of diesel fuel for farming equipment and for the trucks and locomotives needed to transport ethanol from plants to bulk terminals and then to refuelling stations.

The significant reductions in petroleum use by all ethanol types relative to gasoline options, as shown in figure 8, result from the fact that gasoline is a petroleum-based product and ethanol is not.

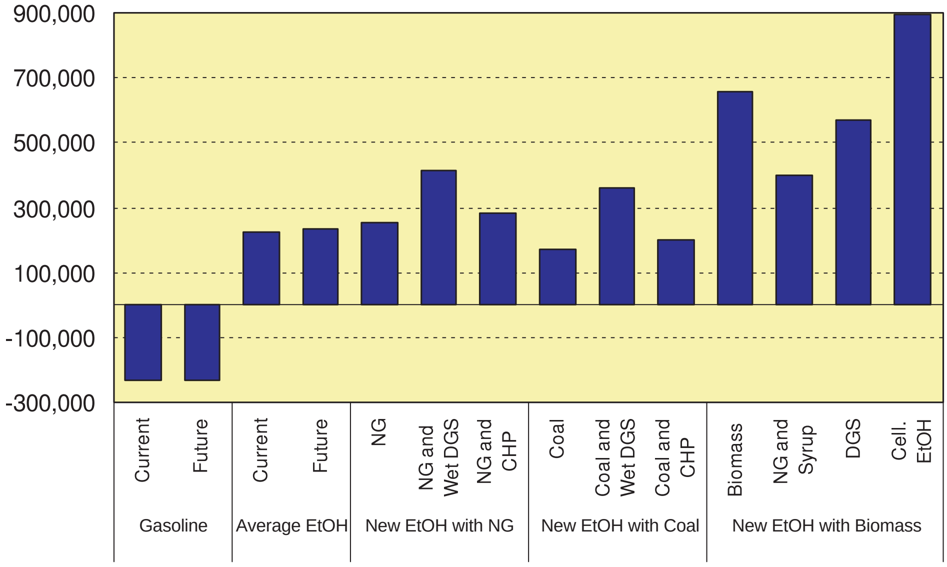

Figure 7. Fossil energy balance per million Btu of ethanol and gasoline (1 million Btu in fuel minus fossil Btu used to produce the fuel and the fossil Btu embedded in the fuel).

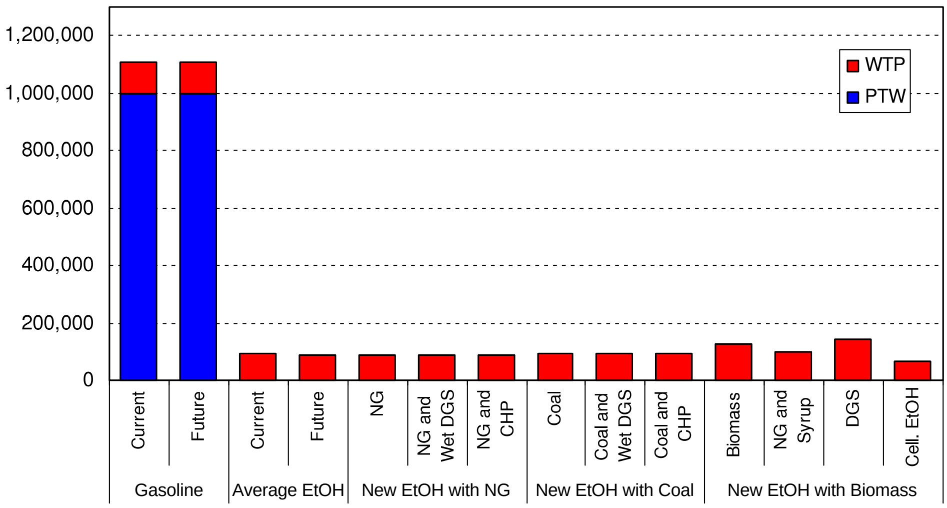

Figure 8. Well-to-wheels petroleum use of ethanol and gasoline (Btu per million Btu of fuel produced and used).

5.4. Natural gas use

Figure 9 presents WTW natural gas use for all of the fuel options. The small amount of natural gas for the two gasoline options is natural gas used in petroleum refineries. For the two average ethanol options (current and 2010), the three natural-gas-powered ethanol options, and the ethanol option with syrup combustion and natural gas supplement, the amount of natural gas is increased significantly because these corn ethanol options rely primarily on natural gas as process fuels in the ethanol plants (see table 2). In the coal-based ethanol options and the cellulosic ethanol option, natural gas is mainly used in production of nitrogen fertilizer.

Figure 9 reveals that the production and use of corn ethanol increases natural gas use compared with the production and use of gasoline. One could argue that this fact shows that ethanol serves as a means to convert gaseous energy into liquid energy for automotive applications. Others could argue that, because the United States will increasingly rely on imported natural gas to meet demand, the increased use of natural gas may offset the energy security benefits achieved through the reductions in petroleum use offered by the ethanol options (see figure 8). It is useful to note that the increase in natural gas use by the ethanol options (up to 600 000 Btu) is considerably smaller than the reduction in petroleum use (about 1 million Btu) achieved by the ethanol options.

5.5. Coal use

Figure 10 presents WTW coal use results. The three coal-based ethanol options significantly increase the use of coal compared with the gasoline options and other ethanol options.

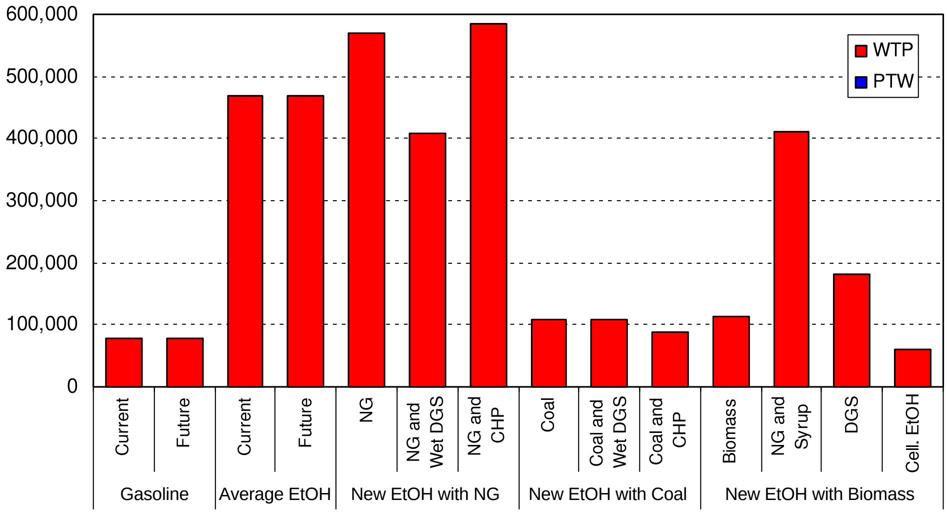

Figure 9. Well-to-wheels natural gas use of ethanol and gasoline (Btu per million Btu of fuel produced and used).

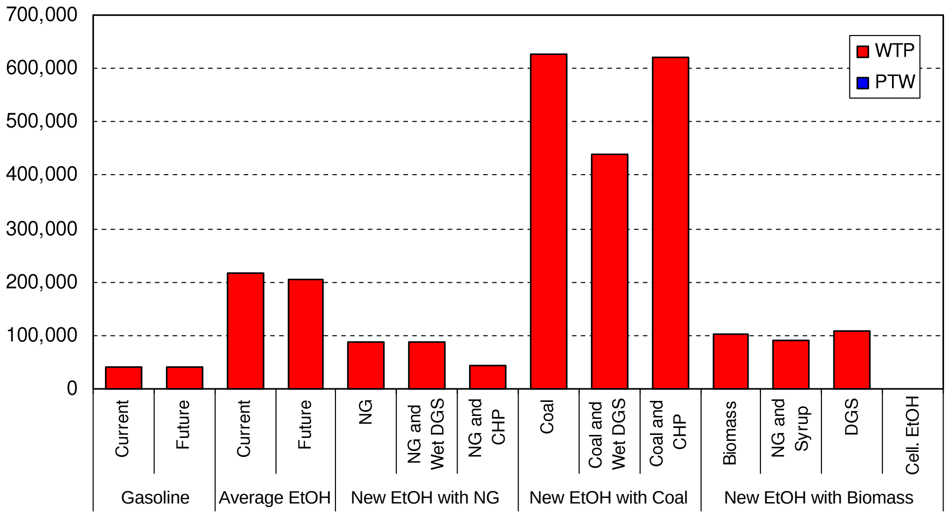

Figure 10. Well-to-wheels coal use of ethanol and gasoline (Btu per million Btu of fuel produced and used).

The two average ethanol cases (current and 2010) consume coal because some ethanol plants are fuelled with coal (see table 2). Coal use for the other fuel options in figure 10 results primarily from electricity use in these options; more than 50% of US electricity is generated from coal.

Some may argue that using coal for ethanol production offers an energy benefit because the United States has a large coal reserve. But burning coal to produce ethanol will certainly reduce the GHG emission benefits offered by corn ethanol (see the following section).

5.6. Greenhouse gas emissions

Figure 11 presents CO_2-equivalent grams of GHGs (CO_2, CH_4, and N_2O) for the 14 fuel options. While GHG emissions for the two gasoline options are dominated by CO_2, N_2O emissions from nitrification and denitrification of nitrogen fertilizer in corn fields are a significant GHG emission source for the corn ethanol options.

To clearly show the effects of different ethanol production options on GHG emissions, figure 12 presents the changes in GHG emissions for the 12 ethanol options relative to the results for future gasoline. The 12 fuel ethanol options are arranged from the worst to the best in terms of GHG emissions. If coal is used as the process fuel in corn ethanol plants, the GHG emission reduction benefits of corn ethanol vanish. If wet DGS is produced in coal-fuelled corn ethanol plants, corn ethanol still offers a GHG reduction of 18%. On average, corn ethanol reduces GHG emissions by 19% now and by 21% in 2010.

For corn ethanol produced in plants fuelled with natural gas, GHG emission reductions vary from 28% to 39%, so natural-gas-fuelled corn ethanol offers distinct GHG emission reduction benefits. Furthermore, if DGS or biomass (such as wood chips) is used as a process fuel, corn ethanol could

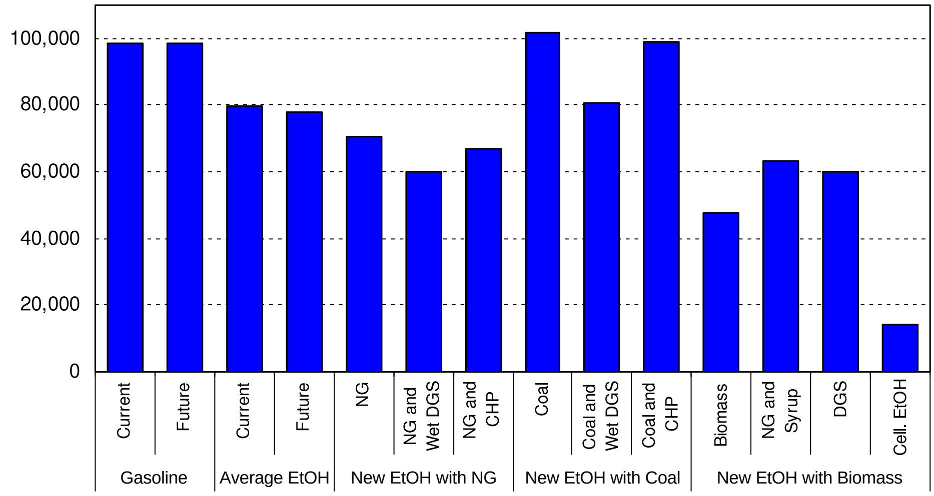

Figure 11. Well-to-wheels GHG emissions of ethanol and gasoline (CO_2-equivalent grams per million Btu of fuel produced and used).

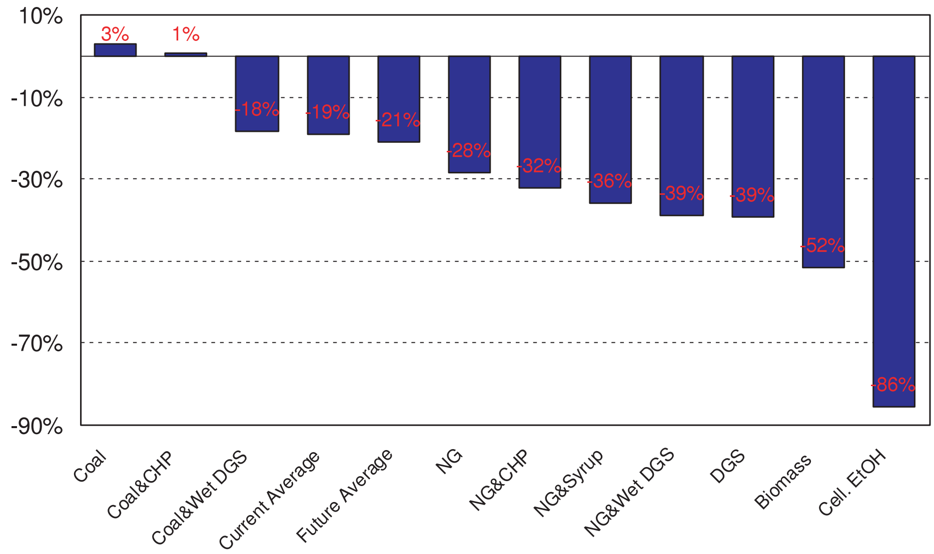

Figure 12. Well-to-wheels GHG emission changes by fuel ethanol relative to gasoline.

achieve 39–52% reductions in GHG emissions. However, cellulosic ethanol is—by far—the best option to reduce GHG emissions. When resource supply (corn versus cellulosic biomass) is taken into account, cellulosic ethanol is certainly the ultimate ethanol option, offering GHG reductions of 86%.

6. Conclusions

Of the corn ethanol production options (nine ethanol plant types plus the current average and 2010 average cases) evaluated in this study, all achieve positive fossil energy balances. A close examination of the energy use associated with each of these ethanol production options shows that all of the options reduce petroleum use relative to gasoline, but at the expense of increasing natural gas use (when natural gas is the process fuel) or coal use (when coal is the process fuel). One may argue that the conversion of gaseous or solid fuel to liquid fuel (i.e. corn ethanol) for automotive applications is indeed an intended benefit.

We found that the ethanol plant types that we examined can have distinctly different energy and GHG emission effects when evaluated on a full fuel-cycle basis. Switching from natural gas to coal as a process fuel in corn ethanol plants may eliminate the GHG reduction benefits of corn ethanol. On the other hand, switching from fossil fuels to biomass-based process fuels (such as wood chips and DGS) significantly increases corn ethanol's energy and GHG benefits. Eliminating the need for drying of DGS in corn ethanol plants can also have a significant positive effect on corn ethanol's energy and GHG emission benefits because the dryers are very energy intensive. Installing CHP systems in ethanol plants offers smaller energy and GHG emission reduction benefits because the amount of electricity used in corn ethanol plants is small.

Our study shows that the GHG emission impacts of corn ethanol could vary from a 3% increase (if coal is used as the process fuel) to a 52% reduction (if wood chips are used). These results suggest that we need to closely examine corn ethanol plant types to identify and promote those that offer the greatest energy and GHG benefits. On the other hand, because cellulosic ethanol produced from switch-grass clearly offers the greatest energy and GHG benefits (by far), this option may represent a long-term, sustainable ethanol production pathway.

Acknowledgments

This work was sponsored by the Office of Biomass Program (under DOE's Office of Energy Efficiency and Renewable Energy). Argonne National Laboratory is a DOE laboratory managed by UChicago Argonne, LLC, under contract No DE-AC02-06CH11357.

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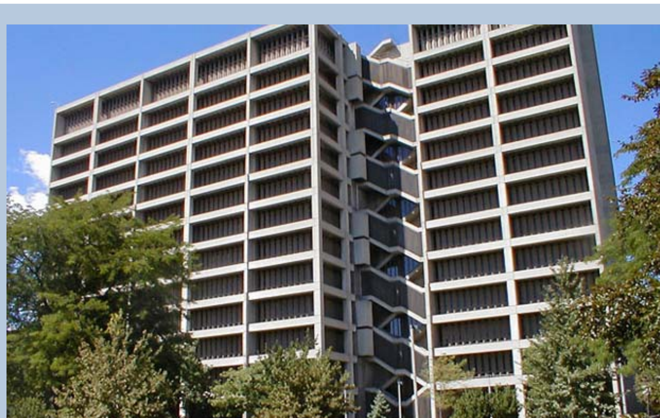
APPENDIX B

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



Prepared for:
Illinois Clean Coal Institute and
Illinois Department of Commerce and Economic Opportunity

October, 2006

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

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Prepared for: Illinois Clean Coal Institute
Date: October 20, 2006

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.

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. 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.

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.

<u>Induced Draft Fan, Stack and Ducting</u>
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).

<u>Fuel Metering/Feed System</u>
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.

<u>Ash Handling System</u>
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.

<u>Access System</u>
Access decks and ladders are required throughout the system in areas of frequent access for operation and service.

<u>Instrumentation and Control System</u>
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.

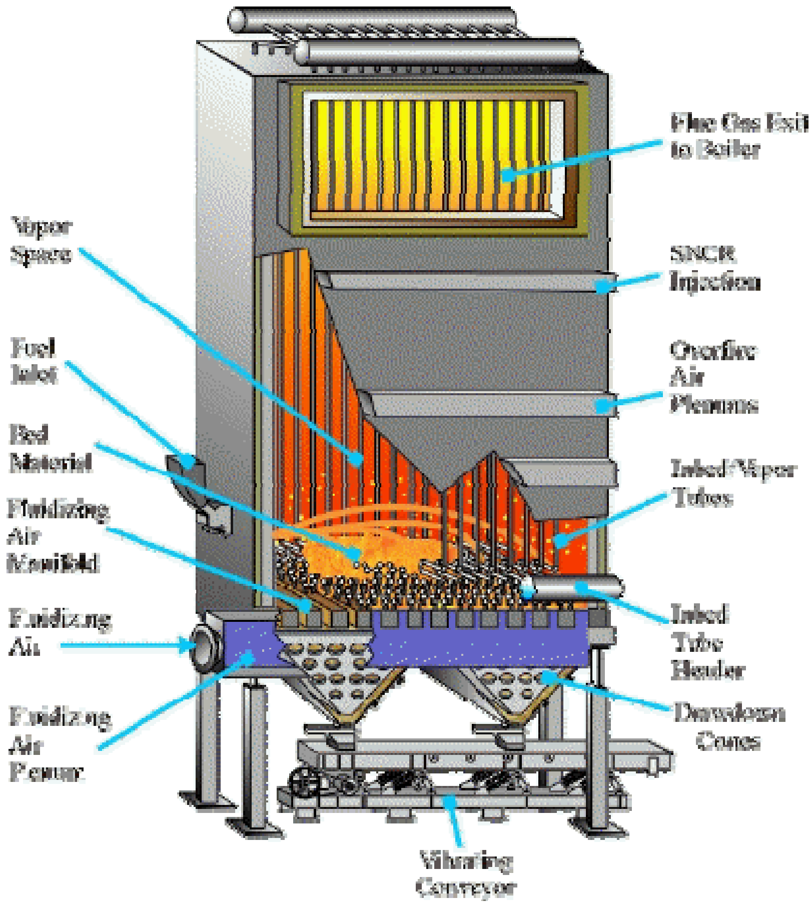


Figure 2.1-1: Fluidized-bed Boiler (Picture Source: Energy Products of Idaho, 2006)

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

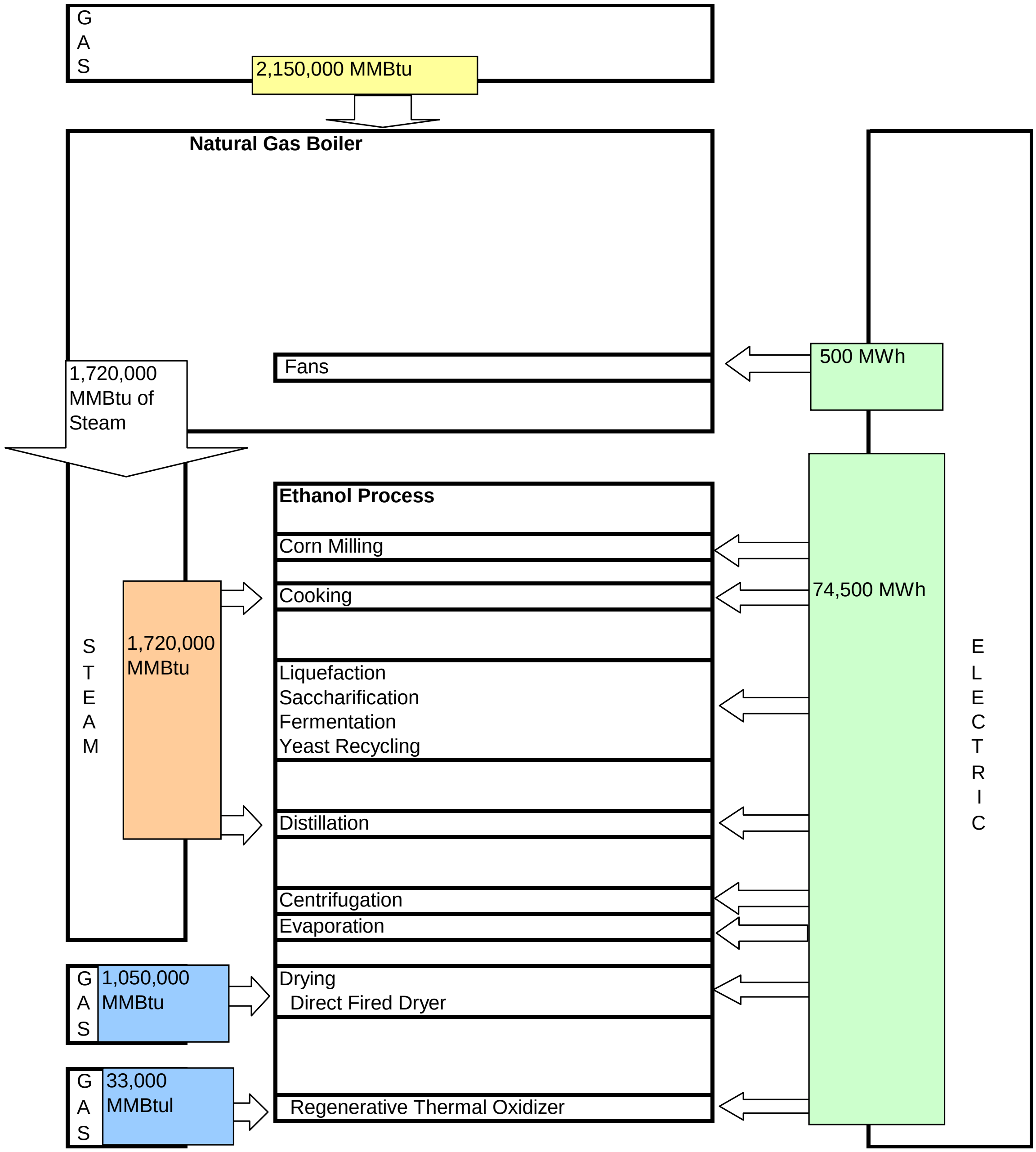
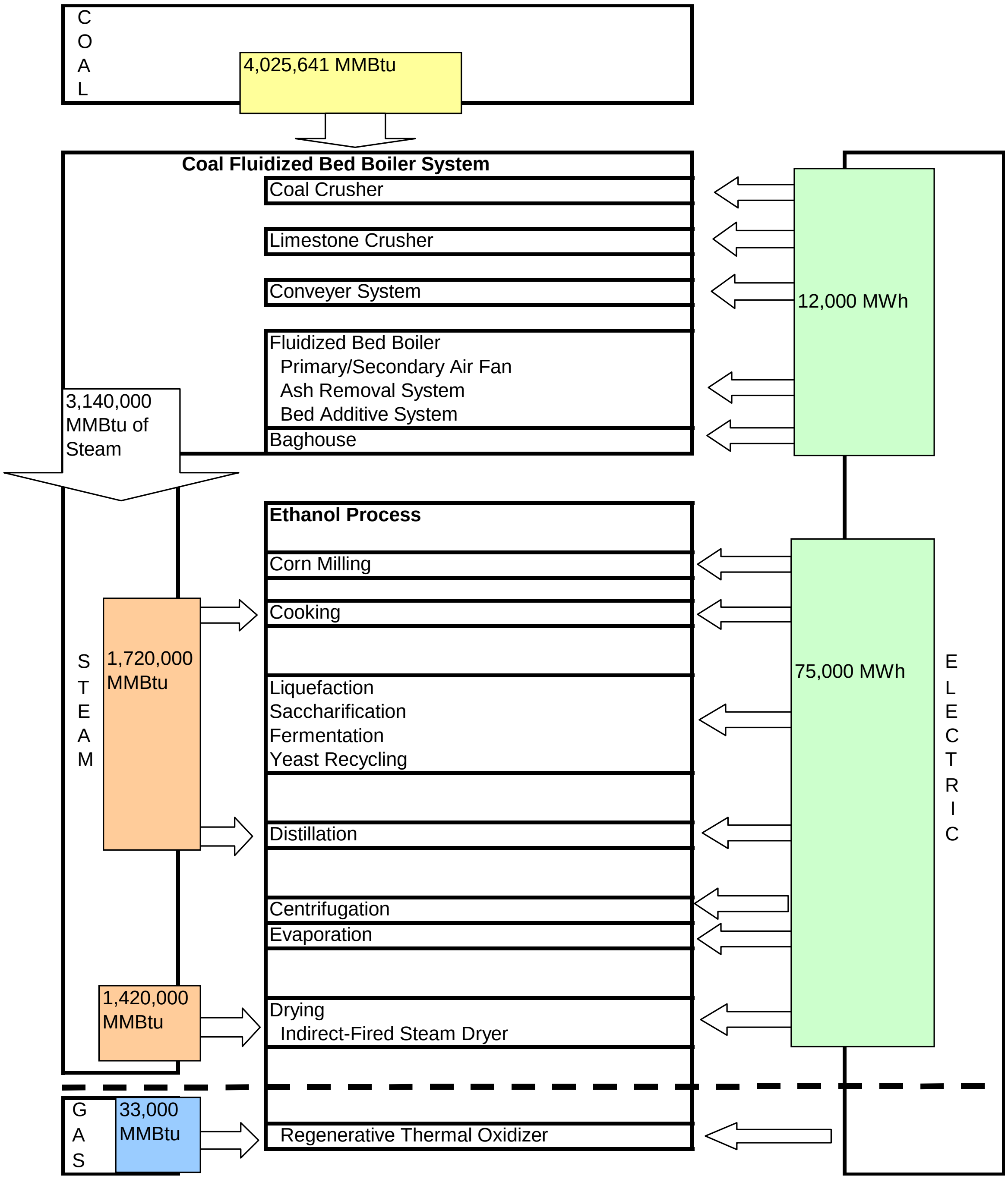


Figure 3.1-2: Energy Flow Diagram – Coal Fired Ethanol Plant



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.

<u>Natural Gas Fuel Handling Equipment</u>

- 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

<u>Thermal System Fuel: Natural Gas</u>
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.

[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.

<u>Other O&M:</u>
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

<u>Boiler</u>
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).

<u>Dryer</u>
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.

<u>Emissions Control Equipment</u>

- 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.

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.

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

Themal System Fuel: Coal

- 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.

<u>Electricity</u>
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.

<u>Annual Operating Permitting Fees</u>
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.

<u>Personnel</u>

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.

<u>Other O&M</u>

- 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

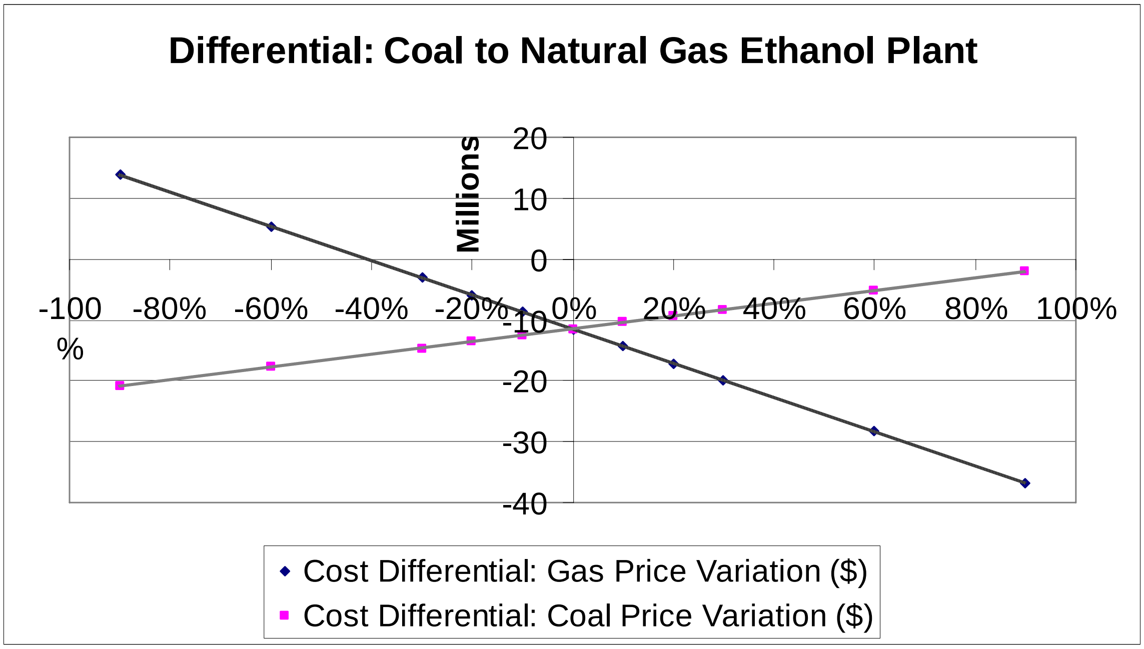

Figure 3.4-1: Sensitivity of Annual Cost Differential to Fuel Prices

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

[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.

<u>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). 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.

<u>a) Geographic Location of the Project</u>

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] 100
	Other Categories of Source 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:

[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]

[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.

[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

<u>Example 2</u>

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 SO_2, 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.

<u>Other Examples</u>

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	
25-100	$1,000	$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.

[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.

[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.

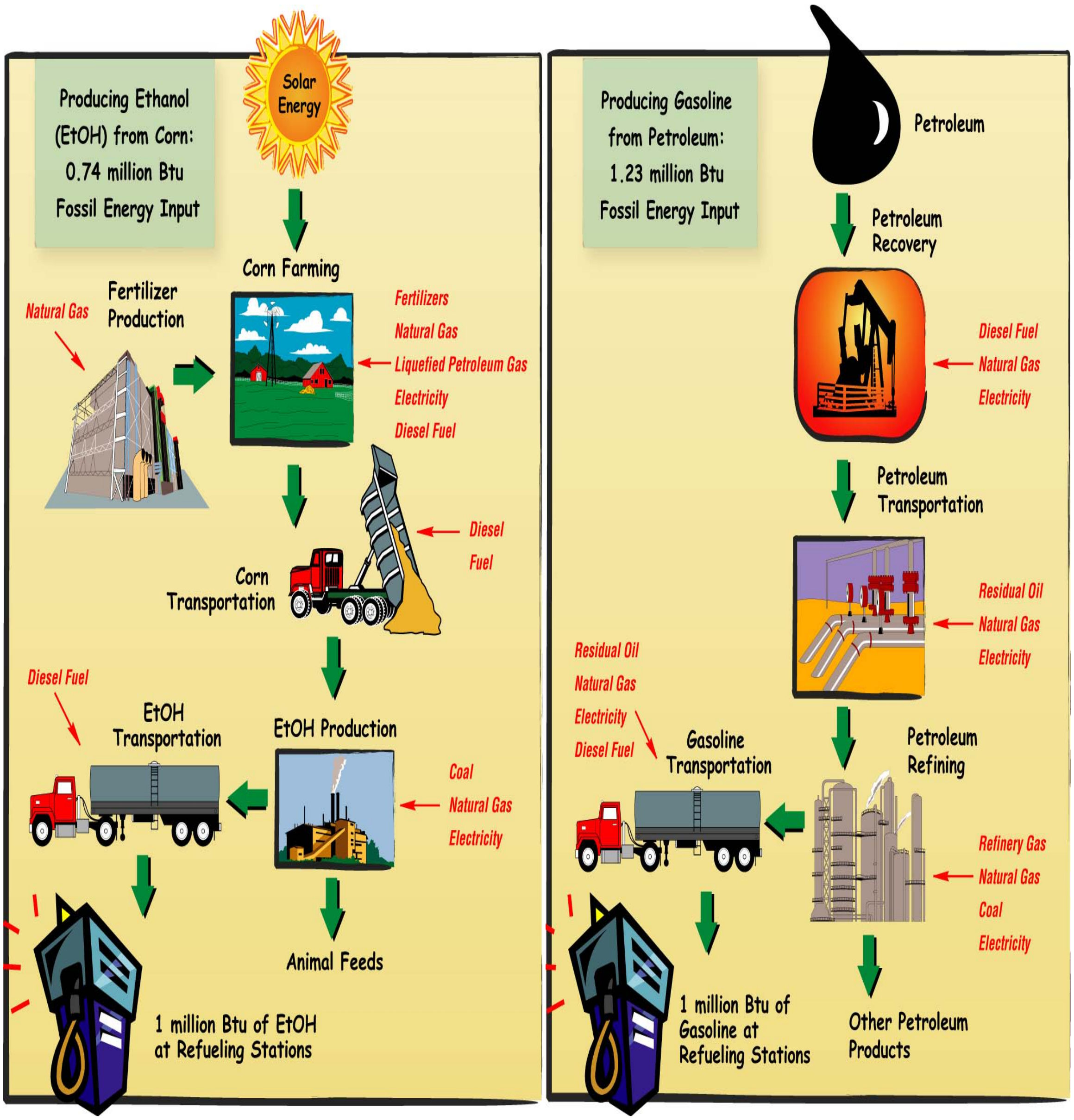

Figure 6-1: Ethanol versus Gasoline LCA (Source: Michael Wang, Argonne National Laboratory)

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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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

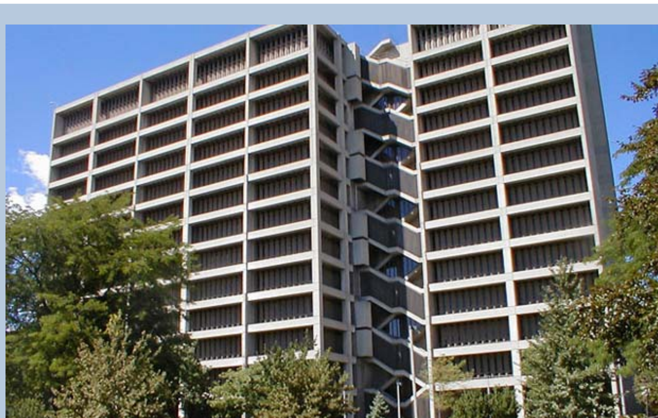
Southern Illinois Railcar

US Energy Services

DISCLAIMER STATEMENT

APPENDIX C

AN ANALYSIS OF THE PROJECTED ENERGY USE OF FUTURE DRY MILL CORN ETHANOL PLANTS (2010-2030)



Prepared for:
Illinois Corn Marketing Board
ProExporter Network

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October 10, 2007

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Introduction

The Illinois Corn Marketing Board and the ProExporter Network have retained the University of Illinois at Chicago to conduct an analysis of the energy use of future dry mill corn ethanol plants operating between the years 2010 through 2030. This report details the results of this effort. This analysis, combined with data on agricultural efficiency improvements compiled by the ProExporter Network will form the basis to study changes in the global warming intensity of corn ethanol resulting from future production practices.

Several sources provide a good indication of current ethanol plant energy conversion efficiencies. ICM, Inc. a major ethanol plant process developer currently provides process guarantees for new natural gas fired ethanol plants in the range of 32,000-34,000 Btu/gal (thermal energy) and 0.75 kWh/gal (electricity) with 100% DDGS drying and 22,000 to 24,000 Btu/gal without DDGS drying.[1] Mueller and Cuttica (2006) as well as Energy and Environmental Analysis Inc. (2006) expect the current coal fired ethanol plant conversion efficiency to be around 40,000 Btu/gal (thermal) and 0.9 kWh/gal (electricity). Data by Life Cycle Associates (2007) expects certain biomass conversion technologies to be in the same range as coal fired ethanol plants.[2] Looking at the time frame of this study (2010-2030), these conversion efficiencies will experience an adjustment based on ethanol plants choosing different primary energy feedstocks (coal, natural gas, biomass), different energy system configurations (adoption of combined heat and power technologies), improvements to energy equipment (boilers, motors, etc.), and adjustments to the dry mill processes. The various adjustments to ethanol plant conversion efficiencies will be discussed followed by an analysis of their impact on the currently prevailing thermal and electricity requirements at ethanol plants.

Projected Fuel Feedstocks and Plant Energy System Configurations

Based on projected cost reductions for biomass based energy systems as well as a likely valuation of carbon in the fuel, more ethanol plants are expected to switch to this energy source. Biomass-based fuel is either provided as solid fuel for boilers or gasifiers or converted to biogas in integrated biogas energy systems using wet cake or manure from animal feedlots as a biomass source. For example, E3 BioFuels in Nebraska produces biomethane from digested manure and thin stillage. Panda Ethanol Inc. plans to gasify cattle manure for process heat at its Hereford, Texas, facility that is currently under construction. Existing producers are retrofitting their plants to gasify wood waste or combust syrup, like Central Minnesota Ethanol Co-op and Corn Plus, respectively. Some

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[1] A by-product of the ethanol process, distillers wet grain (DWG) or distillers wet grain with solubles (DWGS, thin stillage left from the centrifugation process is added back in) may be used as animal feed. In order to increase the shelf life of DWG(S), many ethanol plants currently elect to dry DWG(S) to produce an animal feed called distillers dried grain with solubles (DDGS).

[2] Certain biomass plants use similar equipment as coal fired plants (use of fluidized bed boilers, solid fuel handling systems, etc.)

of these companies are already replicating these biomass technologies in plants under development.

In addition to the type of primary feedstock used at the ethanol plant, energy systems can also differ by configuration. The majority of plants currently employ natural gas boiler technologies. However, several plants utilize combined heat and power technologies (chp). These technologies allow ethanol plants to generate a significant part of the plant's electricity needs onsite and utilize the otherwise wasted heat from electricity generation to meet process (thermal) energy requirements.

Table 1 shows the projected changes to the primary energy feedstock and energy system configuration at ethanol plants over time. The base year (2007) numbers are taken from an industry survey conducted by Ethanol Producers Magazine (June 2006) adjusted by ethanol plant construction data provided by the Renewable Fuels Association and a study by Mueller and Cuttica (2006).[3,4,5] For example, while currently 88% of ethanol plants utilize natural gas fired boiler technologies, the relative use of natural gas boiler technology is expected to decline by 2030 and natural gas boiler plants will constitute only 31% of the total stock of plants. The decline in natural gas boilers is expected to be due to increased use of biomass (combustion, gasification, integrated biogas systems) as well as increased deployment of natural gas chp plants. The diffusion rates over time are largely estimated from the rates at which projects get announced in each category. For example, Panda Energy announced this year that it is in development of four manure fueled ethanol plants, which, together with another company's (Prime BioSolutions) indication of future joint ventures (www.e3biofuels.com) in this field resulted in a relatively high diffusion rate of integrated biogas energy systems.

Table 1: Projected Diffusion of Primary Energy Feedstocks and Energy System Configurations

	2007	2010	2015	2020	2025	2030
Natural Gas Boiler	88%	77%	65%	54%	42%	31%
Natural Gas CHP	4%	6%	8%	11%	13%	15%
Coal Boiler	0%	0%	0%	0%	0%	0%
Coal CHP	4%	4%	4%	4%	4%	4%
Biomass Boiler*	2%	5%	7%	10%	12%	15%
Biomass CHP*	1%	4%	7%	9%	12%	15%
Integ. Biogas Energy System	1%	5%	9%	12%	16%	20%
Sum:	100%	100%	100%	100%	100%	100%

[3] "Process Heat and Steam Alternatives Rising"; Dave Nilles, Ethanol Producer Magazine, June 2006.
[4] Renewable Fuels Association. Ethanol Industry Overview. http://www.ethanolrfa.org/industry/statistics/#EIO
[5] "Research Investigation for the Potential Use of Illinois Coal in Dry Mill Ethanol Plants"; Report to the Illinois Clean Coal Institute, Mueller and Cuttica, October 2006.

Projected Energy Equipment Technologies

Technologies that are currently in various stages of the commercialization process will increase the efficiency of currently utilized energy generating and conversion equipment such as natural gas and coal boilers, combustion turbines, motors, fans, and pumps. For example, significant boiler improvements may come from technology programs such as the US DOE Super Boiler Program and the development of new combustion control technologies (tunable diode laser sensors, new high efficiency burners, and others), whereas efficiency improvements of motors will come from increased deployment of technologies like NEMA Premium efficient motors and advanced motor monitoring and diagnostic systems (i.e. sensors that measure current and voltage and integrate with advanced energy management systems).[6]

Table 2 below shows the expected improvement of current energy equipment technologies. Data for boilers are based on an assessment of the success of DOE's Super Boiler program, which is expected to produce a "family of future generation Super Boilers" with 94% efficiency by 2020.[7] The data in the table takes the expected diffusion and commercialization of this technology into account. Expected efficiency improvements to electrical equipment used at ethanol plants is expected to track the diffusion of NEMA Premium Efficiency motors. Ethanol plants utilize a significant amount of high horsepower motors (in excess of 100 hp) for induced draft fans, dryer motors etc. and NEMA Premium Efficiency motors are expected to be adopted widely and thus reduce electricity consumption of ethanol plants.[8] The efficiency of distributed electricity generating equipment (10 MW Industrial Turbine, the size that would be installed in a 100 mgpy plant) is taken from US DOE projections available through 2020 and held conservatively constant during the outer years.[9] Central power plant efficiencies are taken from EPA eGrid data and efficiency improvements are expected to track improvements projected for the 10 MW turbine.

Table 2: Projected Energy Equipment Efficiencies

	2007	2010	2015	2020	2025	2030
Boiler, Efficiency (HHV)	82.0%	83.0%	86.0%	90.0%	94.0%	94.0%
Energy Savings rel. to Base Year		1.2%	4.7%	8.9%	12.8%	12.8%
Motor, Efficiency	90.0%	91.0%	92.0%	93.0%	95.0%	95.0%
Energy Savings rel. to Base Year		1.1%	2.2%	3.2%	5.3%	5.3%
10 MW Industrial Turbine, Efficiency (HHV)	31.0%	32.0%	33.0%	34.0%	34.0%	34.0%
Energy Savings rel. to Base Year		3.1%	6.1%	8.8%	8.8%	8.8%
Central Power Plant, Efficiency (HHV)	30.5%	31.5%	32.5%	33.5%	33.5%	33.5%
Energy Savings rel. to Base Year		3.1%	6.1%	8.8%	8.8%	8.8%

[6] US Department of Energy Industrial Technologies Program. "US DOE Energy Technology Solutions: Public Private Partnerships Transforming Industries"; June 2006
[7] US Department of Energy Industrial Technologies Program. "Super Boiler – First Generation, Ultra-High Efficiency Firetube Boiler"; June 2007.
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Projected Dry Mill Corn Ethanol Processes

The traditional dry mill ethanol process consists of the following steps: Corn is ground and slurried with water and enzymes (alpha amylase), followed by cooking of the slurry to gelatinize and liquefy the starch (liquefaction). After liquefaction, the mash is cooled, and another enzyme is added (gluco amylase) to convert the liquefied starch into fermentable sugars. The yeast is added to ferment the sugars to ethanol and carbon dioxide, followed by distillation and dehydration.[10] As mentioned above, a by-product of the ethanol process, distillers wet grain is often dried to produce distillers dried grain with solubles (DDGS). Expected process improvements will enhance both the ethanol as well as the by product production process. The following process adjustments have been identified and considered in this study.

Corn Oil Extraction (after ethanol distillation):

In an adjustment to the traditional dry mill ethanol process, corn oil is removed after the ethanol distillation process from the syrup using centrifuges. With this adjustment a 100 mgpy plant can produce an additional 7 million gallons of corn oil (biodiesel) and thus increase a plant's fuel production by 7 %. Since the corn oil is removed after the distillation process, the extraction process has no impact on the ethanol yield. Furthermore, the deoiled DDGS is believed to be of higher value as a feed particularly for cattle operations and have lower energy requirements and VOC emissions during the drying process. GS Cleantech Corp. is currently implementing the process in 4 ethanol plants.[11]

According to GS Cleantech Corp. the process increases dryer efficiency by about 20% (2000-2500 Btu/gal) resulting in overall savings of about 8% (2,500/32,000 Btu/gal). The National Corn to Ethanol Research Center (NCERC) estimates the energy savings to be slightly lower. NCERC assumes that the reduction in the dryer load is proportional to the reduction in the mass of the oil content in the whole stillage, which is approximately 10% resulting in overall savings of about 1,200/32,000 Btu/gal or 4%. The more conservative assumptions by NCERC were assumed for this study. However, electricity needs will increase by about 9% to operate the centrifuges for oil extraction.[12]

Raw Starch Hydrolysis, also known as cold cooking or cold hydrolysis:

Raw starch hydrolysis allows producers to eliminate the cooking step. The cold cook process (which occurs at 86 to 104 degrees F) skips the liquefaction and saccharification steps. The ground corn is slurried with water and both gluco amylase and alpha amylase are added, followed directly by fermentation. Skipping the cooking process reduces both water and energy consumption. Nine Poet managed companies have implemented the BPX cold cook process. Critics argue that the process needs significantly more enzymes (20% more) and reduces yield in fermentation.[13] In a personal conversation with an industry insider, the energy savings from cold cooking were estimated to be about 5,000

[10] Ethanol Producer Magazine. "Break it Down."; January 2006.
[11] Distillers Grains Quarterly. "GS Cleantech to install corn oil extraction for four ethanol producers." Third Quarter 2007, BBI International.
[12] Personal conversation with Chris Kennedy from GS Cleantech Corp.
[13] Ethanol Producer Magazine. "Break it Down", January 2006.

btu/gal (5,000/32,000 Btu/gal) or 16%. Electricity consumption is likely similar to current dry mill ethanol plants; no increase or decrease in electricity consumption was assumed.

Dry Mill Corn Fractionation (germ/oil is removed at the front end):
The objective of this process adjustment is to remove the fermentable components from the non fermentable components as a first step in the ethanol production process. Fractionation separates the endosperm from the kernel. The endosperm contains 98% of the starch (the germ, another part of the kernel, in contrast contains the oil, protein and enzymes that start the germination process). By removing non fermentable components at the front end, the percentage of starch in the slurry is higher, requiring less enzymes. Also, the removal of non-fermentable compounds reduces the drying load and thus the energy requirements. Furthermore, the removed germ (with the oil) can be more easily processed into corn oil. Similar to corn oil extraction, about 7-8% by volume of additional corn oil (convertible to biodiesel) can be produced with this process. Critics argue that fractionation results in a loss of starch and reduced ethanol yields.[14] Fractionation is expected to be often adopted in conjunction with the corn kernel fiber to ethanol process (see below).

The energy savings from dry mill fractionation/corn kernel fiber to ethanol are around 10,000 Btu/gal or (10,000/32,000) 31%. About 2/3rd of the savings are from reduced drying requirements, 1/3rd of the savings from reduced process energy needs. The process does require about 10% more electricity.[15]

Corn Kernel Fiber to Ethanol (adopted with fractionation):
Corn kernel fiber to ethanol is another often cited near term possible technology improvement for dry grind ethanol plants. The technology utilizes specific enzymes which can convert corn kernel fibers into fermentable sugars. The technology can increase the ethanol yield from a bushel of corn by 10-20%.[16] The challenges are to develop affordable enzymes, and create process streams which are concentrated enough for ethanol recovery. According to NCERC, this technology will likely be adopted with corn fractionation. While the technology increases yield, the energy conversion efficiency is expected to remain constant.

Table 3 below details the expected adoption rate for each process adjustment as a percentage of the total ethanol plant stock in that year. For example, in year 2030 it is expected that 30% of all operating ethanol plants will utilize raw starch hydrolysis. Please note the use of the corn oil extraction process and dry mill corn fractionation is mutually exclusive, since both processes remove oil from the corn. In contrast, combined adoption of an oil extraction process and raw starch hydrolysis could be possible. For the purpose of this study it is assumed that almost every ethanol plants built in 2030 will make use of one process improvement, hence a total of 90% combined diffusion rate.

[14] Ethanol Producer Magazine. "Corn Fractionation for the Ethanol Industry"; November 2005 Issue.
[15] Personal conversation with Ehanex Energy Inc. representative.
[16] Rodney J. Bothast. "New Technologies in Biofuels Production"; Presented at the Agricultural Outlook Forum, February 2005, available at www.ethanolresearch.com, and Illinois Department of Commerce and Economic Opportunity.

Table 3 also details the expected thermal energy and electricity reductions that can be expected from each process relative to current production practices. As a conservative assumption, only slight additional gains for each process improvement are assumed over time.

Table 3: Projected Adoption Rates and Energy Savings from Ethanol Process Improvements

Percent of all Plants Adopting Process						
Process Improvement	**2007**	**2010**	**2015**	**2020**	**2025**	**2030**
Corn Oil Extraction	5%	10%	15%	20%	25%	30%
Raw Starch Hydrolysis	5%	10%	15%	20%	25%	30%
Dry Mill Corn Fractionation	1%	7%	13%	18%	24%	30%
Energy Reduction from Base Process (Thermal)						
	Btu/gal	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**
Corn Oil Extraction	4%	4%	4%	4%	5%	5%
Raw Starch Hydrolysis	16%	16%	16%	16%	17%	17%
Dry Mill Corn Fractionation	31%	31%	31%	31%	31%	32%
Weighted Average Savings from Process Adjustments (Thermal)	1.3%	4.1%	6.9%	9.7%	13.1%	16.2%
Energy Reduction from Base Process (Electric)						
	kWh/gal	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**
Corn Oil Extraction	-9%	-9%	-9%	-9%	-8%	-8%
Raw Starch Hydrolysis	0%	0%	0%	0%	0%	0%
Dry Mill Corn Fractionation	-10%	-10%	-9%	-9%	-8%	-8%
Weighted Average Savings from Process Adjustments (Electric)	-0.6%	-1.6%	-2.5%	-3.5%	-3.9%	-4.8%

Note: Negative numbers indicate increased energy consumption

Summary of Projected Dry Mill Ethanol Plant Conversion Efficiencies

Table 4 below shows the currently prevailing ethanol plant conversion efficiencies. As discussed above, these numbers are based on current process guarantees from ethanol process developers (ICM), a study by Mueller and Cuttica (2006), Energy and Environmental Analysis Inc (2006), data provided by NCERC, and data summarized in the BEACCON model developed by Life Cycle Associates.[17,18,19,20,21] The weighted average in Table 4 is the sum of the product of the currently prevailing energy consumption for each energy technology and configuration multiplied by the diffusion rates listed in Table 1.

Table 4: Current Dry Mill Ethanol Plant Energy Conversion Efficiencies

Thermal	**2007**
	Btu/gal
Natural Gas Boiler	32,000
Natural Gas CHP	34,500
Coal Boiler	40,000
Coal CHP	44,000
Biomass Boiler	40,000
Biomass CHP	44,000
Integ. Biogas Energy System	14,500
Weighted Average Efficiency	32,685
Electric	**kWh/gal**
Natural Gas Boiler	0.75
Natural Gas CHP	0.17
Coal Boiler	0.90
Coal CHP	0.06
Biomass Boiler	0.90
Biomass CHP	0.06
Integ. Biogas Energy System	0.06
Weighted Average Efficiency	0.69

[17] ICM, Inc. "ICM Performance Guarantees – We Put Them in Writing"; Revision 6/01/06, www.icminc.com

[18] Mueller and Cuttica. "Research Investigation for the Potential Use of Illinois Coal in Dry Mill Ethanol Plants"; Report to the Illinois Clean Coal Institute, October 2006.

[19] Energy and Environmental Analysis, Inc. "An Assessment of the Potential for Energy Savings in Dry Mill Ethanol Plants from the Use of Combined Heat and Power (CHP)"; prepared for the US Environmental Protection Agency Combined Heat and Power Partnership, July 2006.

[20] Life Cycle Associates. "Biofuels Emissions and Cost Connection (BEACCON) model"; www.lifecycleassociates.com

[21] NCERC provided comments on the energy consumption of an integrated biogas energy system. For example, a 100 mgpy plant which anaerobically digests wet cake can produce 20,000 Btu/gal of biogas, and thus reduce the energy needs of chp based ethanol plant from 34,500 Btu/gal to 14,500 Btu/gal. Other sources show that integrated biogas energy systems can be almost self sufficient, see "Bioconversion of Thin Stillage – A business case for ethanol plants"; New Bio E Systems, Inc., 2007, available at www.newbio.com

Table 5 shows the expected decrease of ethanol plant energy consumption due to expected improvements to current energy equipment. Efficiency improvements to the thermal energy equipment are approximated by efficiency improvements to boiler systems.[22] For example, in year 2030 the average natural gas boiler plant is expected to utilize only 27,915 Btu/gal of thermal energy (as opposed to the current 32,000 Btu/gal) due to the expected 12.8% boiler efficiency improvements listed in Table 2. Weighted by the diffusion rate of the various plant energy system primary fuel uses and configurations in Table 1, the average ethanol plant will consume 28,225 Btu/gal.

On the electricity side, energy consumption for boiler based ethanol plants are expected to decrease by the product of efficiency improvements for electric equipment (largely improvements to large motors, see Table 1) and efficiency improvements to central power stations (see Table 1) since boiler plants purchase all of their electricity from central power plants. Electricity consumption for chp-based ethanol plants is expected to decrease by the product of efficiency improvements in electric equipment (again, largely improvements to large motors, see Table 1) and projected efficiency improvements approximated by small combustion turbines (see Table 1), a common equipment type utilized by chp plants to produce onsite electricity.

Table 5: Projected Conversion Efficiencies with Efficiency Gains from Energy Equipment Improvements

	2007	2010	2015	2020	2025	2030
Thermal	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**
Natural Gas Boiler	32,000	31,614	30,512	29,156	27,915	27,915
Natural Gas CHP	34,500	34,084	32,895	31,433	30,096	30,096
Coal Boiler	40,000	39,518	38,140	36,444	34,894	34,894
Coal CHP	44,000	43,470	41,953	40,089	38,383	38,383
Biomass Boiler	40,000	39,518	38,140	36,444	34,894	34,894
Biomass CHP	44,000	43,470	41,953	40,089	38,383	38,383
Integ. Biogas Energy System	14,500	14,325	13,826	13,211	12,649	12,649
Weighted Average Efficiency	32,685	32,226	31,039	29,599	28,282	28,225
Electric	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**
Natural Gas Boiler	0.75	0.72	0.69	0.66	0.65	0.65
Natural Gas CHP	0.17	0.16	0.16	0.15	0.15	0.15
Coal Boiler	0.90	0.86	0.83	0.79	0.78	0.78
Coal CHP	0.06	0.06	0.06	0.06	0.05	0.05
Biomass Boiler	0.90	0.86	0.83	0.79	0.78	0.78
Biomass CHP	0.06	0.06	0.06	0.06	0.05	0.05
Integ. Biogas Energy System	0.06	0.06	0.06	0.06	0.05	0.05
Weighted Average Efficiency	0.69	0.60	0.53	0.46	0.40	0.35

[22] Note that chp plants also benefit from boiler efficiency improvements. Coal-fired chp ethanol plants generally utilize a larger boiler and a steam turbine to produce thermal and electric energy. Natural gas fired ethanol plants generally utilize a combustion turbine with a heat recovery steam generator (essentially a boiler) for thermal and electricity generation.

Table 6 shows the expected decrease of ethanol plant energy consumption due to both improvements to current energy equipment and adjustments to the current corn dry mill process. The weighted average adjusts the conversion efficiency improvements by the diffusion rate of each plant type listed in Table 1. As can be seen by 2030, on average, an ethanol plant will consume about 23,652 Btu/gal of thermal energy and 0.37 kWh/gal of electricity taking into account:

a) adjustment based on ethanol plants choosing different primary energy feedstocks (coal, natural gas, biomass) and energy system configurations (adoption of combined heat and power technologies),

b) expected improvements to energy equipment (more efficient boilers, motors, etc.), and

c) adjustments to the current dry mill processes (adoption of corn fractionation, cold cook, etc.).

Table 6: Projected Conversion Efficiencies with Efficiency Gains from Energy Equipment Improvements and Dry Mill Process Improvements

	2007	2010	2015	2020	2025	2030
Thermal	**Btu/gal***	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**	**Btu/gal**
Natural Gas Boiler	31,581	30,316	28,395	26,326	24,272	23,393
Natural Gas CHP	34,048	32,684	30,614	28,383	26,168	25,220
Coal Boiler	39,476	37,895	35,494	32,908	30,340	29,241
Coal CHP	43,424	41,684	39,044	36,199	33,374	32,165
Biomass Boiler*	39,476	37,895	35,494	32,908	30,340	29,241
Biomass CHP*	43,424	41,684	39,044	36,199	33,374	32,165
Integ. Biogas Energy System	14,310	13,737	12,867	11,929	10,998	10,600
Weighted Average Efficiency	32,257	30,902	28,886	26,727	24,591	23,652
Electric	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**	**kWh/gal**
Natural Gas Boiler	0.75	0.73	0.71	0.68	0.67	0.68
Natural Gas CHP	0.17	0.17	0.16	0.16	0.15	0.15
Coal Boiler	0.90	0.88	0.85	0.82	0.81	0.81
Coal CHP	0.06	0.06	0.06	0.06	0.06	0.06
Biomass Boiler*	0.90	0.88	0.85	0.82	0.81	0.81
Biomass CHP*	0.06	0.06	0.06	0.06	0.06	0.06
Integ. Biogas Energy System	0.06	0.06	0.06	0.06	0.06	0.06
Weighted Average Efficiency	0.69	0.61	0.54	0.47	0.41	0.37

*Higher Heating Value