

## **Final Report**

### **Xcel Renewable Development Fund Project (RD-56)**

## **Generating Electricity with Biomass Fuels at Ethanol Plants**

### **Chapter/Task 14 – Technology Options and Integration with Dry-Grind Ethanol Plants**

**This chapter develops a model for integrating biomass energy conversion with conventional dry-grind ethanol plants. It describes in detail nine biomass fuel-technology combinations. It was primarily prepared by project participants at the University of Minnesota.**

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## **RD56: Generating Electricity With Biomass Fuels at Ethanol Plants**

### **Report for Task 14, “Technology Options and Integration with Dry-Grind Ethanol Plants”**

#### **Introduction**

The energy required to produce ethanol continues to be an important topic in the bio-fuel industry. Process energy in the form of heat and electricity is the largest energy input into the ethanol production process (Shapouri et al., 2002). Ethanol plants have a choice as to which fuel they will use to supply this energy. The most common source is currently natural gas. Some plants are being designed to use coal. Biomass is an alternative, renewable source of energy for ethanol plants. Dry-grind corn ethanol plants produce biomass co-products which contain a significant amount of energy when used as a fuel. These ethanol plants also are typically located near corn producing areas which have a large amount of corn stover available for use as a fuel. These biomass powered dry-grind ethanol plants could generate the electricity they need for processing as well as surplus electricity to sell to the grid. Using biomass as a fuel replaces a large fossil fuel input with a renewable fuel input which will significantly improve the renewable energy balance of dry-grind corn ethanol (Morey et al., 2006b).

#### ***Objectives***

The main objective of this analysis was to model the technical integration of several biomass energy conversion systems into the dry-grind corn ethanol process. The conceptual system designs must provide the necessary process heat while meeting prevailing air emissions standards.

#### **Methods**

The analysis was performed primarily using Aspen Plus process simulation software. An Aspen Plus model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service (McAloon et al., 2000; McAloon et al., 2004; Kwiatowski et al., 2006) and was used as the basis for the energy conversion system models that followed. This model contains a feature that allows it to be scaled to different annual ethanol outputs. For the purposes of this study all cases were set to produce 190 million liters (50 million gallons) per year of denatured ethanol. The primary components of the process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), thermal oxidation, and co-product drying. Process data from several ethanol plants participating in the project were also taken into account in the modeling process. Several sensitivity analyses were performed on each simulation to ensure good performance.

#### ***Biomass Property Data***

A typical dry-grind corn ethanol plant produces distiller’s dried grains with solubles (DDGS) as a co-product. DDGS is a mixture of two process streams called distiller’s wet grains (DWG) and concentrated distiller’s solubles (also known as “syrup”). The DWG and syrup are mixed and dried together to become DDGS. Property data for these process streams and corn stover was needed in order to build an accurate model. Morey et al. (2006a) provides an analysis of the fuel properties of these streams based on data taken from five dry-grind ethanol plants, as well as a

fuel characterization of corn stover. Table 1 provides a summary of some of the important biomass property data.

Table 1. Selected biomass property data.<sup>1</sup>

<b>Fuel</b>	<b>Moisture content, % wet basis</b>	<b>HHV, MJ/kg dry matter</b>	<b>Nitrogen, % dry matter</b>	<b>Sulfur, % dry matter</b>	<b>Chlorine % dry matter</b>
Corn Stover	13%	17.9	0.7%	0.04%	0.1
Syrup	67%	19.7	2.6%	1.0%	0.35
DDGS	10%	21.8	4.8%	0.8%	0.18
DWG	64%	22.0	5.4%	0.7%	0.17

<sup>1</sup>. Morey et al. (2006a)

In the Aspen Plus modeling environment the ultimate and proximate analysis data for each fuel was used to characterize its composition. The heat of combustion data were also entered for each material. An internal Aspen Plus specific heat model was used for each material which calculates specific heat based on composition. These specific heat models were then validated by comparing them to data presented in a report on a biofuel component physical property database for Aspen Plus from NREL (Wooley and Putsche, 1996).

### *Emissions Estimates*

We worked with RMT, Inc., an engineering consulting firm, to generate predictive emissions estimates from the various thermal conversion technologies and fuel combinations. Computational fluid dynamics modeling was performed for several scenarios with the results focusing mainly on emissions of oxides of nitrogen (NO<sub>x</sub>), oxides of sulfur (SO<sub>x</sub>), and chlorine (HCl). An equilibrium model (minimization of the Gibbs function) is used to simulate the combustion reaction in Aspen Plus. The computational fluid dynamics emissions estimates were used to adjust the emissions output of the Aspen Plus models.

### *Definition of Technology Combinations*

Defining technology combinations was an iterative process of gathering industry data from vendors, ethanol plants, literature, and engineering firms, then modeling certain scenarios to determine their feasibility. We worked with the engineering consulting firms (AMEC and RMT Inc.) to put together suitable technology combinations.

### Thermal conversion

Fluidized bed combustion and gasification were the main thermal conversion options evaluated in the modeling. Fluidized bed combustion was a good candidate because of its capacity to utilize high moisture fuels and the option of adding limestone as a bed material to control SO<sub>x</sub> emissions. Fluidized bed gasification has the added benefits of lower operating temperatures which was important because of the low ash fusion temperatures of DDGS. Gasification also permits greater control of the conversion process through the option of producer gas cleanup before subsequent combustion.

## Drying and Thermal Oxidation

Conventional dry-grind ethanol plants generally use natural gas direct fired dryers (rotary, or ring type) to dry the DDGS. In a plant powered by solid fuel, a common option is to use steam tube (indirect heat) rotary dryers. In this setup steam from the boiler provides heat to the wet material and air in the dryer through a series of tubes arranged inside the rotating dryer cylinder. One advantage of this method is that less air is required to carry away the moisture than would be used in a direct fired dryer resulting in a lower volume of dryer exhaust needing to be thermally oxidized.

An alternative option that we have observed in practice is the use of hot flue gas from the boiler directed into a rotary dryer to provide the drying energy. This option takes advantage of low grade energy that may have otherwise been vented to the stack, but produces amounts of dryer exhaust similar to direct fired dryers. Depending on the details of the combustion process, the use of hot flue gases for drying DDGS may affect the quality of the dried material.

When gasification is used as the thermal conversion process the option exists to modify a natural gas fired dryer to utilize producer gas as a fuel. This method requires some producer gas cleanup processes.

An additional alternative is superheated steam drying. In this method superheated steam comes into direct contact with the wet material and absorbs moisture. Then, the resulting saturated steam is used to provide heat to another process component. This method has the advantage of being highly energy efficient, and condensing all water vapor produced in the dryer.

All the modeling done to date uses steam tube dryers with the dryer exhaust being routed to the combustion unit where thermal oxidation occurs. The assumption made for modeling purposes in terms of thermal oxidation was that the combustion reactor average temperature had to be greater than 816 °C (1500 °F) (Lewandowski, 2000). Future analyses may include several alternative dryer options.

## Emissions Control

The emissions estimates and technology specifications were made using data from the literature on emissions control technology and suggestions from the partner engineering firms.

Combustion modeling results from RMT and our own calculations indicated that for the chosen system sizes most cases would need to be classified as a major source due to the emissions of NO<sub>x</sub> and/or SO<sub>x</sub> (EPA, 2006). The approach used was to benchmark existing solid fuel consuming facilities in terms of the “Best Available Control Technology” (BACT) determinations in their air quality permits. This information along with emissions modeling was used to develop emissions control equipment specifications for each case. Details of the emissions modeling are found in De Kam (2008).

Emissions of NO<sub>x</sub> were controlled using selective non-catalytic reduction (SNCR). Selective catalytic reduction (SCR) can achieve higher destruction efficiencies, but it has a higher capital cost and requires the flue gas to exit the boiler at fairly high temperatures (the modeling assumed a minimum SCR temperature of 302 °C (575 °F) so it was not considered. For combustion systems with SNCR, ammonia is injected into the flue gases to achieve NO<sub>x</sub> reduction. In the case of gasification, ammonia produced during gasification can assist with NO<sub>x</sub> reduction if the

producer gas is burned in a carefully designed staged combustion reactor. Additional ammonia is injected in the combustion flue gas (SNCR) to further reduce NO<sub>x</sub>.

For the purposes of this paper, SO<sub>x</sub> emission potential was calculated based on the amount of sulfur in the fuel. Destruction efficiencies for each control technology were estimated and used to calculate the resulting air emissions data. A similar procedure was used for calculating HCl emission potential.

Fluidized bed combustors and gasifiers allow for the use of limestone as a bed material which helps to reduce SO<sub>x</sub> and HCl emissions. Flue gas semi-dry scrubbers were also included to further reduce SO<sub>x</sub> and HCL emissions.

Emissions of particulate matter were not simulated in the analysis although the necessary particulate removal equipment was specified in each case. The particulate removal equipment (cyclones, baghouse, etc.) was specified using estimates from similar processes.

### Steam Cycle and Electricity Production

Several variations of steam turbine power cycles were used to generate electricity in this analysis. Each fuel combination and technology scenario was analyzed on three levels of electricity production.

At the first level, the system simply provides the process heat needed to produce ethanol and dry the co-product. No electricity is generated.

The second level system generates steam at an elevated temperature and pressure and uses a backpressure turbine to produce electricity. The limiting factor for electricity production in this case is that all the outlet steam from the turbine needs to be used for ethanol production and co-product drying. Under these constraints the actual amount of electricity produced always exceeds the ethanol plant requirements so some electricity is available to sell to the grid. The second level of electricity production will be referred to as CHP (Combined Heat and Power).

At the third level a surplus of steam is generated at high temperature and pressure and is used to drive extraction type turbines. The steam necessary for ethanol production and co-product drying is extracted after the high pressure turbine stage and the excess steam is sent through the low pressure turbine stage then condensed. The amount of fuel used in this third level is limited to the amount of energy available if all the ethanol co-products at the plant were used as fuel. At this level a portion of the electricity generated is used to meet the plant needs, and a significant amount of electricity is also sold to the grid.

For each case it was assumed that the steam used for ethanol production and co-product drying needed to be 446 kPa (50 psig) saturated steam. This assumption was made based on suggestions from our partner engineering firms, assumptions made in the recent EPA study on CHP for the ethanol industry (EPA, 2005), and discussions with ethanol process design firms.

## Results

Three combinations of fuel and thermal conversion technology were analyzed, each at the three different levels of electricity generation. For each case system performance results are presented.

### *Corn Stover Combustion*

The first option analyzed was the direct combustion of corn stover in a fluidized bed. The corn stover was assumed to be densified at an off-site facility. Figure 1 shows a simplified process flow diagram of this case. At the heart of the process is the bubbling fluidized bed boiler. The dryer exhaust stream is routed through the combustor to accomplish thermal oxidation of the volatile organic compounds it contains. Oxides of nitrogen are controlled using SNCR at the boiler. Limestone is added in the fluidized bed and the flue gas passes through a semi-dry scrubber to control  $\text{SO}_x$  and  $\text{HCl}$ . Particulate matter is removed from the flue gas by cyclones and a baghouse.

At the first level no electricity is generated. Saturated steam is produced in the boiler at 1136 kPa (150 psig) and then reduced to 446 kPa (50 psig) for use in ethanol processing and co-product drying (see Figure 1).

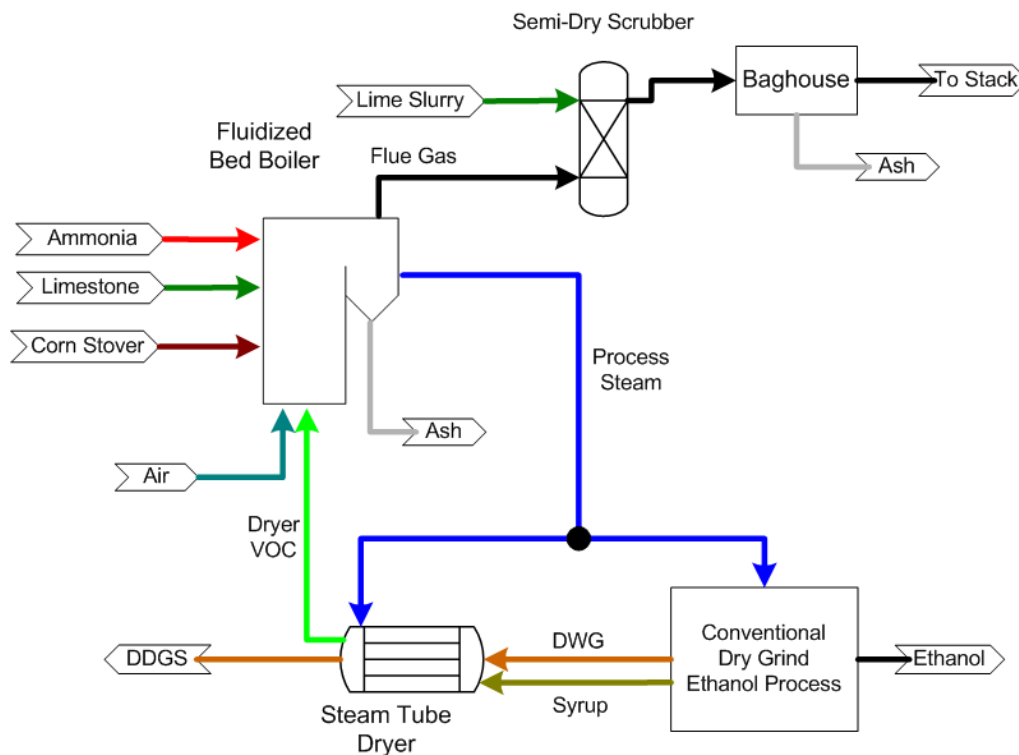


Figure 1. Corn stover combustion, level 1: process heat only.

At the second level electricity is generated using a backpressure turbine. Steam is produced at 6300 kPa (900 psig) and 482 °C (900 °F), then expanded through a backpressure turbine to 446 kPa (50 psig) (see Figure 2). Some de-superheating is then necessary to provide saturated steam to the ethanol process and the co-product dryer.

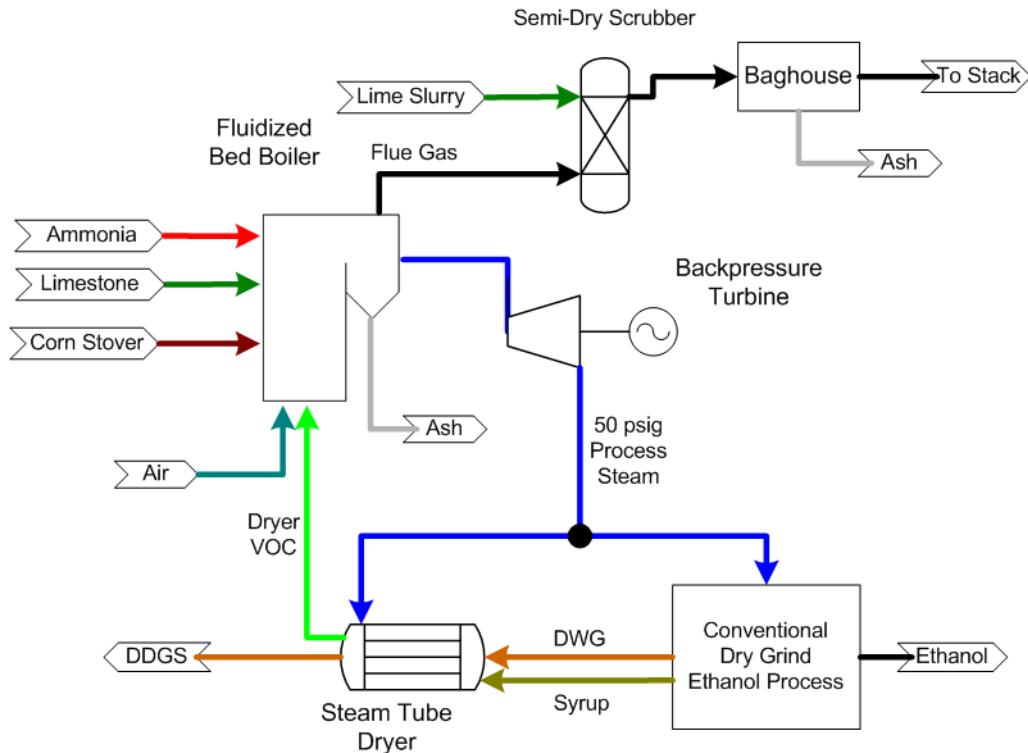


Figure 2. Corn stover combustion, level 2: CHP.

The third level of electricity production uses an extraction turbine. A surplus of steam is generated in the boiler at 6300 kPa (900 psig) and 482° C (900° F). Process steam is extracted from the turbine at 446 kPa (50 psig) (see Figure 3). The remaining steam continues into the condensing stage where it expands to a final pressure of 10 kPa (13.2 psi lower than atmospheric pressure)

### ***Syrup and Corn Stover Combustion***

The next option analyzed was combustion of the syrup co-product supplemented with corn stover. The process flow diagram for this system (shown in Figure 4) is essentially the same as the corn stover combustion case except that the syrup co-product is not dried, but rather combusted in the fluidized bed boiler along with corn stover. The drying operation in this case is much smaller because only the DWG co-product must be dried. This makes the overall process steam load smaller as well.

The three levels of electricity production for this fuel combination follow the same iterations as the corn stover combustion cases discussed previously. Figure 4 shows a process flow diagram for the second level of electricity production. For all three levels all of the syrup produced at the plant was used as fuel. Figure 5 shows fuel energy input from syrup and corn stover for each level. The amount of fuel used is shown in Figure 6. The average moisture content of the fuel mixture for the process heat, CHP, and CHP + grid scenarios was 55%, 52%, and 44%, respectively.

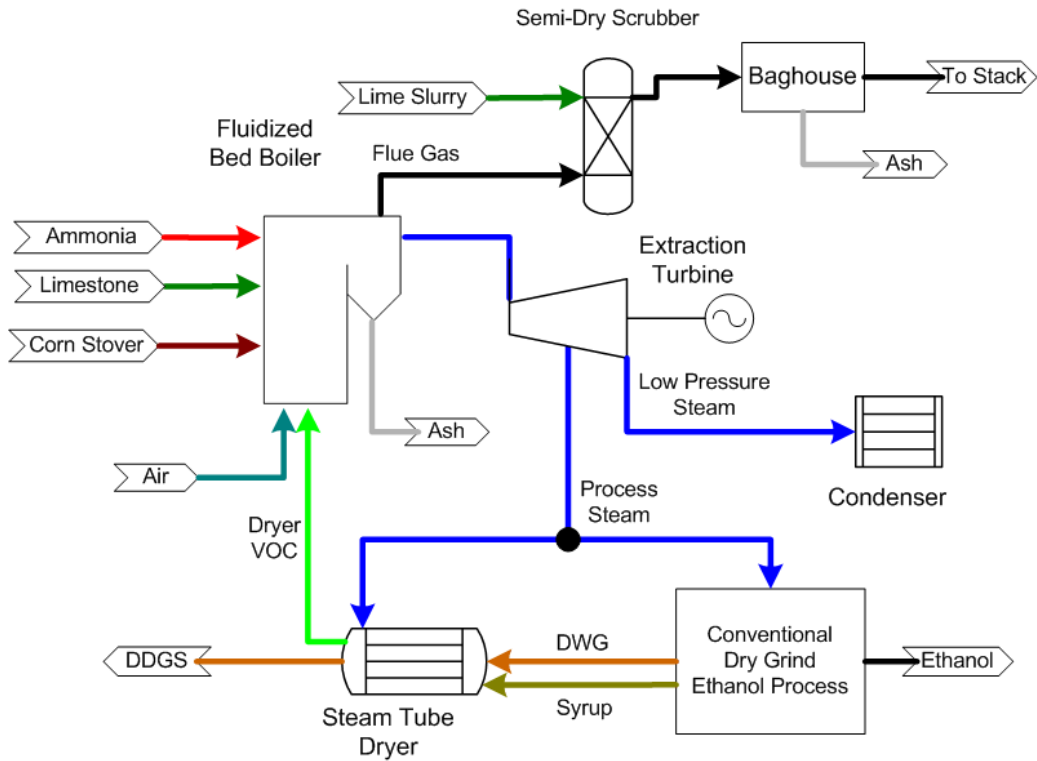


Figure 3. Corn stover combustion, level 3: CHP and electricity to the grid.

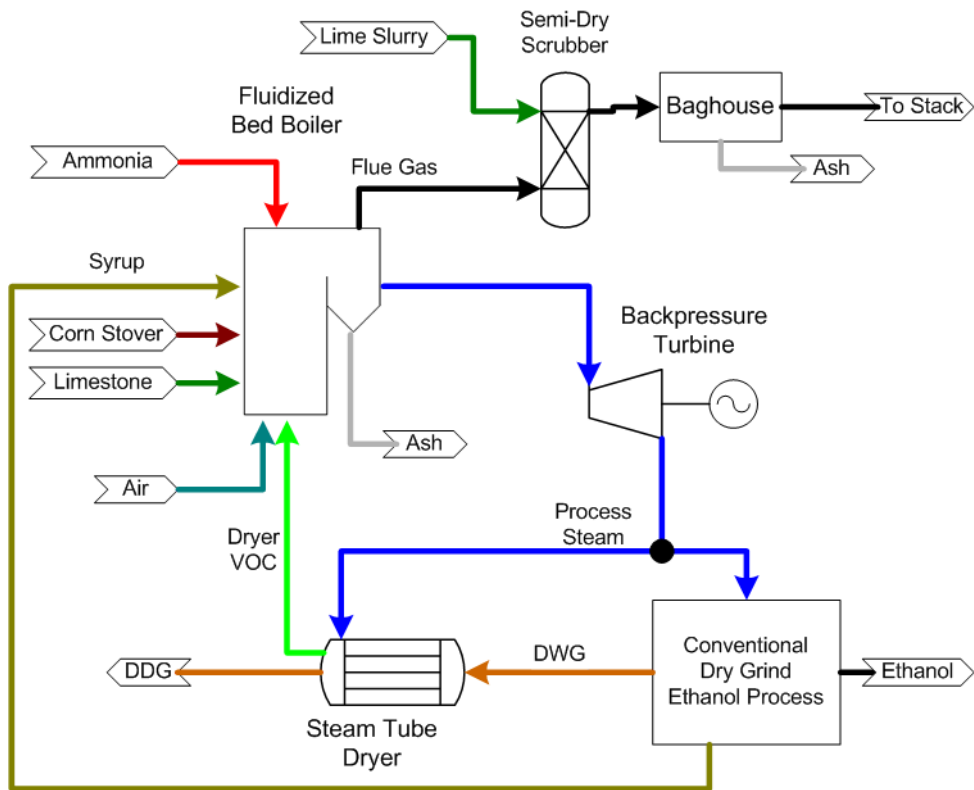


Figure 4. Syrup and corn stover combustion, level 2: CHP.

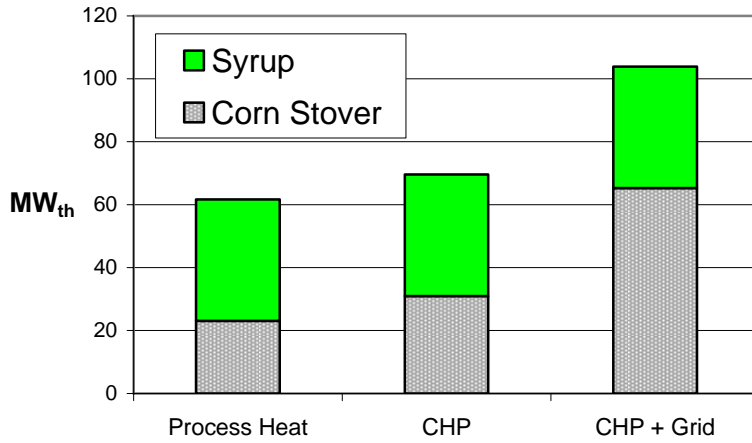


Figure 5. Syrup and corn stover combustion: fuel energy input rate contribution (HHV).

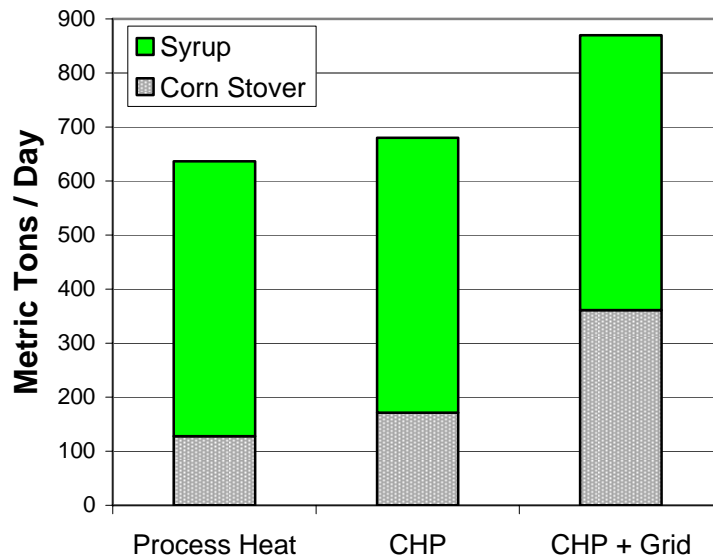


Figure 6. Syrup and corn stover combustion: fuel use.

### *DDGS Gasification*

The last option analyzed was the gasification of DDGS (see Figure 7). The system chosen uses an air-blown fluidized bed gasifier to convert the DDGS into producer gas. Particulates are removed from the gas stream in high-temperature cyclones. The producer gas is not allowed to cool significantly in order to avoid condensation of tars. A staged combustion reactor is used to combust the producer gas. Ambient air and exhaust from the DDGS dryer are added at separate stages. This combustion reactor acts as a thermal oxidizer for the dryer exhaust stream and

eliminates that capital expense. Immediately following the combustor is a heat recovery steam generator (HRSG) where steam is produced for the ethanol process, co-product drying, and electricity production depending on the specific case. The flue gas exiting the HRSG enters an SNCR unit where  $\text{NO}_x$  emissions are reduced. Limestone is added in the fluidized bed gasifier and the flue gas passes through a semi-dry scrubber to control  $\text{SO}_x$  and  $\text{HCl}$ .

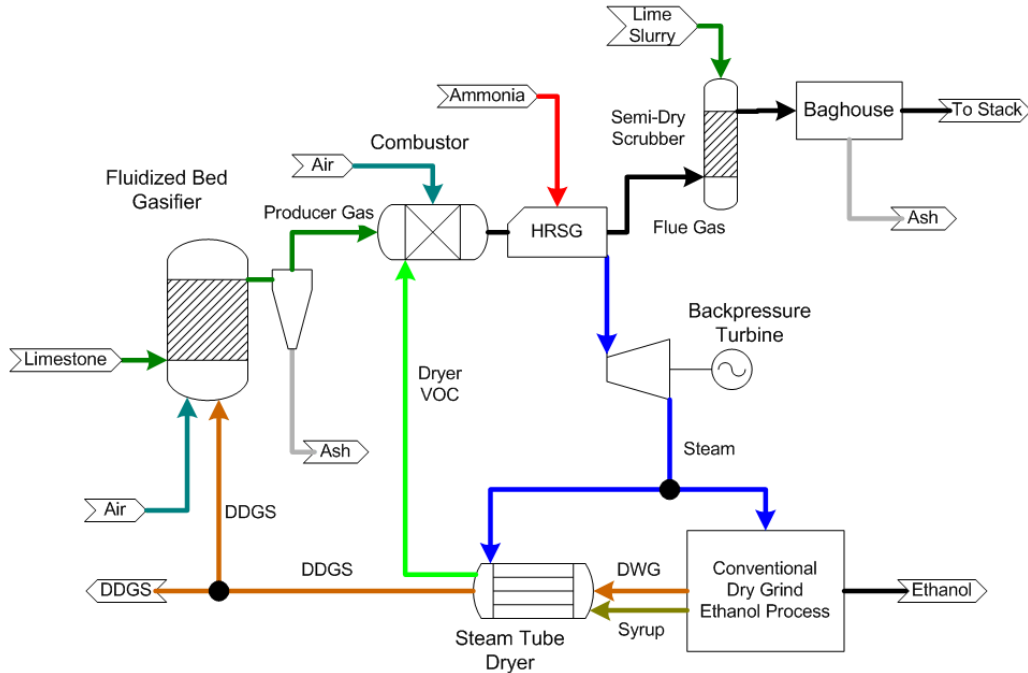


Figure 7. DDGS gasification, level 2: CHP.

The second level of electricity production for the DDGS gasification option is shown in Figure 7. The other levels of electricity production have system changes similar to the previously mentioned cases of corn stover combustion.

Gasification of DDGS is an attractive option because of relatively low temperature ash fusion characteristics of DDGS. The gasification reaction occurs at lower temperature than combustion and much of the ash is removed before the gas is combusted. This decreases the chance of fouling the boiler tubes with alkali deposits.

### *System Performance Comparison*

Table 2 presents some of the performance data of interest from each case. In general the combustion of corn stover makes most efficient use of the fuel energy input due to its simplicity and relatively low fuel moisture content. However, in the syrup and corn stover combustion cases the energy for drying the syrup co-product is effectively hidden in the lower system thermal efficiency. This is because the syrup moisture is vaporized in the combustor where it decreases the boiler efficiency rather than being evaporated in the dryer via process steam where the energy would be counted as a useful output of the system. This dynamic also explains why less electricity is generated in level 2 of the syrup and corn stover combustion cases. Less process steam is required for drying the co-product since only DWG is being dried. This limits the amount of steam flowing through the backpressure turbine since all of the output steam must be used to meet process needs.

Table 2. System performance results for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.<sup>1</sup>

	Biomass Fuel Use <sup>2</sup> (Wet Basis) t/day	Fuel Energy Input Rate MW <sub>th</sub>	Power Generated (Gross) MW <sub>e</sub>	Power To Grid (Net) <sup>3</sup> MW <sub>e</sub>	Power Generation Efficiency	System Thermal Efficiency <sup>4</sup>
<b><i>Corn Stover Combustion</i></b>						
Level 1: Process Heat Only	355	64.1	0	-6.0	-	77.1%
Level 2: CHP	431	77.9	10.9	4.6	14.0%	77.0%
Level 3: CHP & Elec. to Grid	575	103.9	17.4	10.7	16.7%	63.6%
<b><i>Syrup &amp; Corn Stover Combustion</i></b>						
Level 1: Process Heat Only	647	63.6	0	-5.7	-	62.4%
Level 2: CHP	709	74.8	8.8	2.8	7.8%	64.5%
Level 3: CHP & Elec. to Grid	870	103.9	16.0	9.6	12.4%	53.0%
<b><i>DDGS Gasification</i></b>						
Level 1: Process Heat Only	307	69.6	0	-5.4	-	71.9%
Level 2: CHP	374	84.5	8.8	5.2	12.9%	71.7%
Level 3: CHP & Elec. to Grid	459	103.9	15.4	9.6	14.8%	62.5%

<sup>1</sup> All energy and power values in this table are based on the fuel Higher Heating Value (HHV).

<sup>2</sup> Moisture contents: Corn stover – 13%; Syrup & corn stover – 55%, 52%, 44% for levels 1, 2, 3, respectively; DDGS – 10%.

<sup>3</sup> Negative values refer to power purchased from the grid by the ethanol facility.

<sup>4</sup> Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity).

Stack emissions results with control technologies in place for NO<sub>x</sub>, SO<sub>x</sub>, and HCl are presented in Tables 3, 4, and 5 respectively. None of the cases emit a pollutant at a rate above the current regulatory threshold of 227 metric tons (250 tons) per year which would put them in the major source category. However, if plant capacities were expanded to 380 million liters (100 million gallons) per year, a number of the cases would exceed the major source regulatory threshold for NO<sub>x</sub> and/or SO<sub>x</sub>.

The relatively high nitrogen content of DDGS contributes to potentially high NO<sub>x</sub> emissions in the gasification cases; however, the control technologies that are modeled suggest that it is possible to significantly reduce these emissions. The sulfur content of syrup and DDGS contribute to potentially high SO<sub>x</sub> emissions that require significant control technologies to achieve suitable reductions.

Table 3. Emissions of NO<sub>x</sub> after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.<sup>1</sup>

	NO <sub>x</sub> Emissions		NO <sub>x</sub> Annual Emissions	
	Reduction Efficiency <sup>2</sup>	NO <sub>x</sub> Emissions Rate <sup>3</sup> g/MJ (lb/MMBtu)	t/yr	(tn/yr)
<b><i>Corn Stover Combustion</i></b>				
Level 1: Process Heat Only	40%	0.05 (0.11)	86	(106)
Level 2: CHP	47%	0.05 (0.12)	128	(142)
Level 3: CHP & Elec. to Grid	53%	0.05 (0.12)	263	(179)
<b><i>Syrup &amp; Corn Stover Combustion</i></b>				
Level 1: Process Heat Only	60%	0.06 (0.13)	113	(124)
Level 2: CHP	61%	0.05 (0.13)	127	(140)
Level 3: CHP & Elec. to Grid	62%	0.05 (0.12)	163	(179)
<b><i>DDGS Gasification</i></b>				
Level 1: Process Heat Only	48%	0.06 (0.14)	131	(144)
Level 2: CHP	61%	0.07 (0.16)	181	(199)
Level 3: CHP & Elec. to Grid	70%	0.07 (0.15)	214	(236)

<sup>1</sup> All NO<sub>x</sub> emissions are calculated as NO<sub>2</sub>.

<sup>2</sup> Emissions controls include selective non-catalytic reduction (SNCR) in all cases plus staged combustion for DDGS gasification.

<sup>3</sup> Values are based on the fuel Higher Heating Value (HHV).

Table 4. Emissions of SO<sub>x</sub> after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.<sup>1</sup>

	SO <sub>x</sub> Emissions		SO <sub>x</sub> Annual Emissions	
	Capture Efficiency <sup>2</sup>	SO <sub>x</sub> Emissions Rate <sup>3</sup> g/MJ (lb/MMBtu)	t/yr	(tn/yr)
<b><i>Corn Stover Combustion</i></b>				
Level 1: Process Heat Only	86%	0.006 (0.015)	13	(14)
Level 2: CHP	87%	0.006 (0.014)	14	(16)
Level 3: CHP & Elec. to Grid	88%	0.005 (0.012)	17	(19)
<b><i>Syrup &amp; Corn Stover Combustion</i></b>				
Level 1: Process Heat Only	90%	0.059 (0.14)	119	(134)
Level 2: CHP	89%	0.056 (0.13)	131	(144)
Level 3: CHP & Elec. to Grid	87%	0.050 (0.12)	163	(179)
<b><i>DDGS Gasification</i></b>				
Level 1: Process Heat Only	91%	0.065 (0.15)	144	(159)
Level 2: CHP	91%	0.065 (0.15)	173	(191)
Level 3: CHP & Elec. to Grid	91%	0.065 (0.15)	213	(235)

<sup>1</sup> All SO<sub>x</sub> emissions are calculated as SO<sub>2</sub>.

<sup>2</sup> Emission controls include limestone sorbent in the fluidized bed (combustion and gasification) plus flue-gas semi-dry scrubbers in all cases.

<sup>3</sup> Values are based on the fuel Higher Heating Value (HHV).

Table 5. Emissions of chlorine after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.<sup>1</sup>

	HCl Emissions		HCl Emissions Rate <sup>3</sup>		HCl Annual Emissions	
	Capture Efficiency <sup>2</sup>		g/MJ	(lb/MMBtu)	t/yr	(tn/yr)
<b><i>Corn Stover Combustion</i></b>						
Level 1: Process Heat Only	97%		0.002	(0.005)	4.0	(4.4)
Level 2: CHP	97%		0.002	(0.004)	4.3	(4.8)
Level 3: CHP & Elec. to Grid	97%		0.002	(0.004)	5.0	(5.6)
<b><i>Syrup &amp; Corn Stover Combustion</i></b>						
Level 1: Process Heat Only	97%		0.004	(0.010)	8.3	(9.2)
Level 2: CHP	97%		0.004	(0.009)	9.0	(9.9)
Level 3: CHP & Elec. to Grid	97%		0.003	(0.008)	10.7	(11.8)
<b><i>DDGS Gasification</i></b>						
Level 1: Process Heat Only	89%		0.009	(0.21)	20.5	(22.5)
Level 2: CHP	89%		0.009	(0.21)	24.6	(27.1)
Level 3: CHP & Elec. to Grid	89%		0.009	(0.21)	30.2	(33.3)

<sup>1</sup> All chlorine emissions are calculated as HCl.

<sup>2</sup> Emission controls include limestone sorbent in the fluidized bed (combustion and gasification) plus flue-gas semi-dry scrubbers in all cases.

<sup>3</sup> Values are based on the fuel Higher Heating Value (HHV).

The renewable energy ratio for each case was calculated following the assumptions presented in a previous study (Morey et. al. 2006b). The renewable energy ratio is defined as follows:

$$\text{(Energy in Ethanol + Co-product Energy + Electricity to Grid Energy) / (Fossil Energy Input)}$$

The energy use and credit assumptions made by Morey et. al. (2006b) use data from Shapouri et al. (2002) as a basis for these calculations. In our analysis, electricity used in a conventional natural gas ethanol plant was updated to 0.20 kWh/L (0.75 kWh/gal). We used our models to estimate electricity generation, use, and amount to the grid for biomass plants (Table 6).

Table 6. Electricity generation, use, and amount to the grid for conventional and biomass fueled plants [kWh/L (kWh/gal)].

	Electricity Generated, kWh/L (kWh/gal)	Electricity Used, kWh/L (kWh/gal)	Electricity to Grid, kWh/L (kWh/gal)
<b><i>Conventional Natural Gas</i></b>			
Level 1: Process Heat Only	0	0.20 (0.75)	0
<b><i>Corn Stover Combustion</i></b>			
Level 1: Process Heat Only	0	0.25 (0.94)	0
Level 2: CHP	0.45 (1.72)	0.26 (1.00)	0.19 (0.72)
Level 3: CHP & Elec. to Grid	0.73 (2.75)	0.28 (1.06)	0.45 (1.69)
<b><i>Syrup &amp; Corn Stover Combustion</i></b>			
Level 1: Process Heat Only	0	0.24 (0.91)	0
Level 2: CHP	0.37 (1.39)	0.25 (0.96)	0.12 (0.44)
Level 3: CHP & Elec. to Grid	0.67 (2.54)	0.27 (1.02)	0.40 (1.52)
<b><i>DDGS Gasification</i></b>			
Level 1: Process Heat Only	0	0.22 (0.85)	0
Level 2: CHP	0.46 (1.73)	0.24 (0.90)	0.22 (0.83)
Level 3: CHP & Elec. to Grid	0.64 (2.44)	0.25 (0.93)	0.40 (1.51)

The amount of electricity needed in biomass-powered plants increases as a result of the additional equipment, such as fluidized beds and semi-dry scrubbers, required to successfully use these fuels.

Figure 8 shows the comparison of renewable energy ratio between the modeled cases and a conventional dry-grind corn ethanol plant. It can be seen that using biomass as a fuel can greatly increase the renewable energy balance of ethanol production. Electricity generation further increases the renewable energy balance.

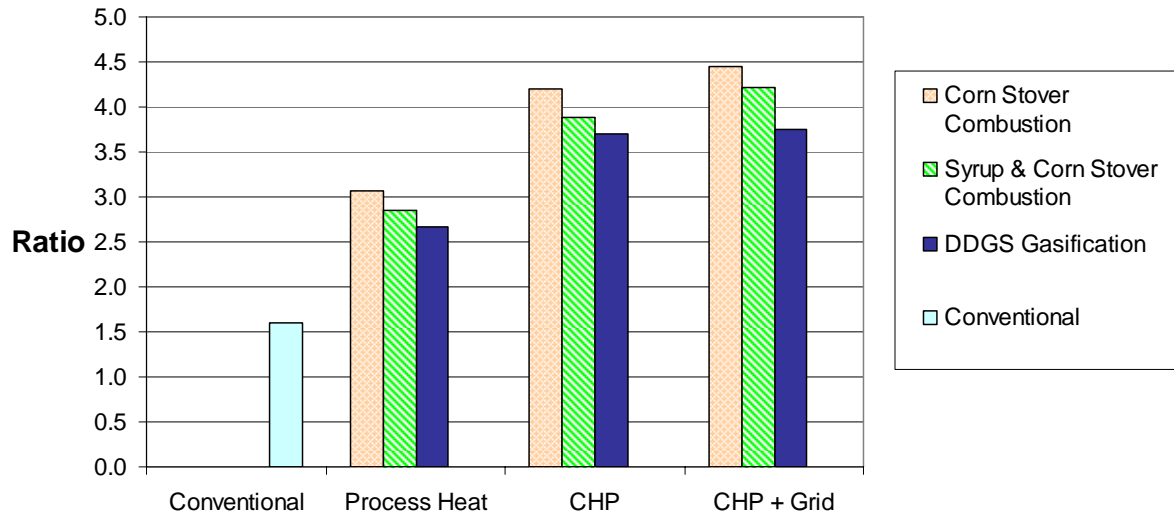


Figure 8. Renewable energy ratio (LHV).

## Conclusion

The results show that there are several methods which could be used to generate electricity and process heat using biomass at ethanol plants. These technologies can produce renewable electricity for the grid and improve the renewable energy balance of ethanol. These systems will need to be designed with close attention to the ash fusion characteristics of the biomass fuels and with appropriate emissions technology in place.

There is opportunity for much future study on this subject. Several alternative co-product drying scenarios could be modeled. A system utilizing superheated steam drying holds promise for increased efficiency and decreased water use. Electricity production could be significantly increased with the use of biomass integrated gasification combined cycle (BIGCC) technology. A full study on the application of BIGCC in the ethanol industry would be useful.

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