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Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants

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***Abstract*.** Dry-grind ethanol plants have the potential to reduce their operating costs and improve their net energy balances by using biomass as the source of process heat and electricity. We modeled various technology bundles of equipment, fuels and operating activities that are capable of supplying energy and satisfying emissions requirements for dry-grind ethanol plants of 190 million and 380 million liter (50 and 100 million gallon) per year capacity using corn stover, distillers dried grains and solubles (DDGS), or a mixture of corn stover and “syrup” (the solubles portion of DDGS). Results showed favorable rates of return on investment for biomass alternatives compared to conventional plants using natural gas and purchased electricity over a range of conditions. The mixture of corn stover and syrup provided the highest rates of return in general. Factors favoring biomass included a higher premium for low carbon footprint ethanol, higher natural gas prices, lower DDGS prices, lower ethanol prices, and higher corn prices.

Keywords. Ethanol, Biomass, Economics, CHP, Emissions, Process heat, Electricity production

Introduction

Production of fuel ethanol by the dry-grind process is expanding rapidly in the U.S. and annual production capacity is expected to exceed 12 Billion gallons per year by the end of 2008. (Renewable Fuels Association, 2007). Natural gas has been the fuel typically used to produce process heat at these plants, while coal has sometimes been used for fuel, especially in plants greater than 380 million liter (100 million gallon) per year of capacity. Dry-grind ethanol plants typically yield 0.41 liters of anhydrous ethanol per kg of corn (2.75 gallons/bu) and 8 kg (17.5 pounds) of DDGS. Drying of DDGS requires approximately one-third of the natural gas used by the plant. Consideration of the co-product DDGS as a biomass fuel reveals that there is sufficient energy to supply all needed process heat and electricity for the facility with additional energy available for electrical power generation for sale to the grid.

We have identified the leading methods of thermal conversion of ethanol co-products or field residues that would be technically feasible and financially prudent under a range of economic conditions. We have collected and analyzed technical data related to characteristics of DDGS, syrup, and corn stover in order to model the conversion of energy derived from these biomass fuels (Morey et al., 2006a). We have modeled combustion and gasification performance to help predict emissions of NOx and SOx from the biomass fuels. In addition, issues of ash fusion caused by the alkali metals in the biomass have been studied to help identify combustion/gasification strategies that will have operational reliability. Further details of the systems we modeled are presented in De Kam et al. (2007).

Key Economic Drivers for Adopting Biomass

Natural gas costs are the second largest operating cost for dry-grind ethanol plants, following only the cost of the corn as an operating expense. At this time of expansion of dry-grind ethanol production in the U.S. Corn Belt, demands for natural gas are also expanding rapidly, which exacerbates supply issues on natural gas lines of limited capacity in certain rural areas. Figure 1 shows the history of natural gas prices in Iowa, the heart of the U.S. Corn Belt, with the effects damage to natural gas infrastructure caused by Hurricane Katrina becoming evident in August of 2005.

Electricity costs are not as important to ethanol plant economics in magnitude, but plants have a self -interest in producing enough power on-site in order to maintain uninterrupted operation of computers, process controls, and other vital systems. In some areas, local power providers would welcome the ability of newly established ethanol plants to provide their own power in order to avoid heavy investments to upgrade distribution capacity. In addition, there are improving incentives available to ethanol plants and other facilities to produce power for the grid from biomass as individual states establish goals that increase the renewable percentage of the power used within their borders.

In the years before 2006, revenues from sales of distillers dried grains and solubles (DDGS) often represented 20% of the total revenue stream of dry-grind plants; however, since that time the percent of total revenues from this by-product has fallen to about half of that amount. Given the rapid expansion of ethanol capacity that is underway in the U.S., it will be improbable for U.S. livestock populations to consume the burgeoning production of this by-product. One of the reasons why U.S. livestock can't consume the increased production of DDGS stems from the maximum potential inclusion rates for this mid-level protein feed when fed to certain classes of livestock. DDGS contain nutritional energy, but contain a form of fat that some species of animals can't tolerate at high intake rates while achieving favorable performance. Dairy cows experience milk fat depression when fed diets too high in the fats found in DDGS. Swine and poultry have lower abilities to utilize DDGS in their diets due to adverse effects of the dietary fat on carcass quality and due to the poor balance of amino acids, respectively.

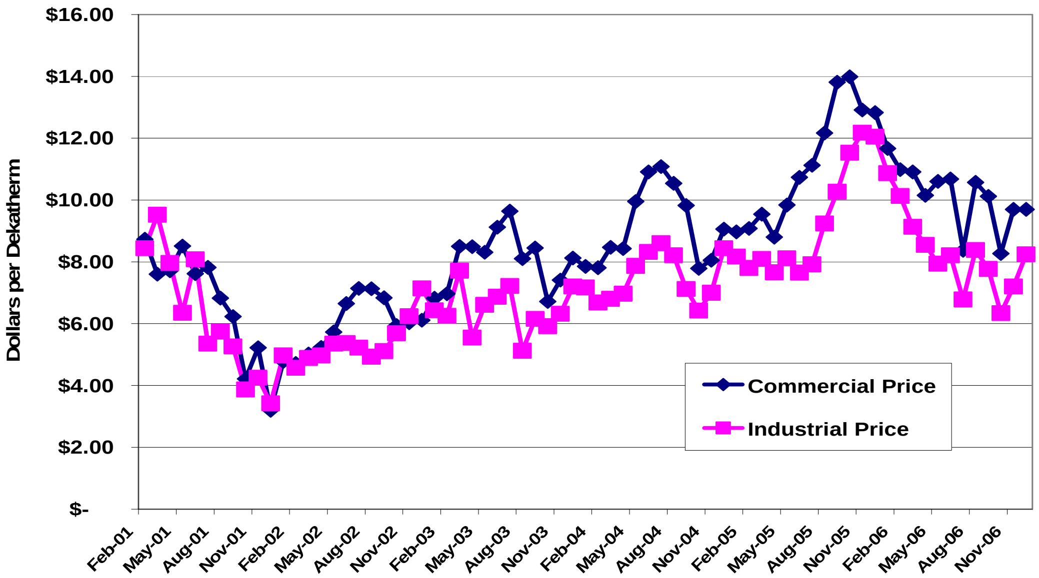

Figure 1. Commercial and industrial natural gas prices in Iowa from 2001-2006 (source: Energy Information Agency, 2007).

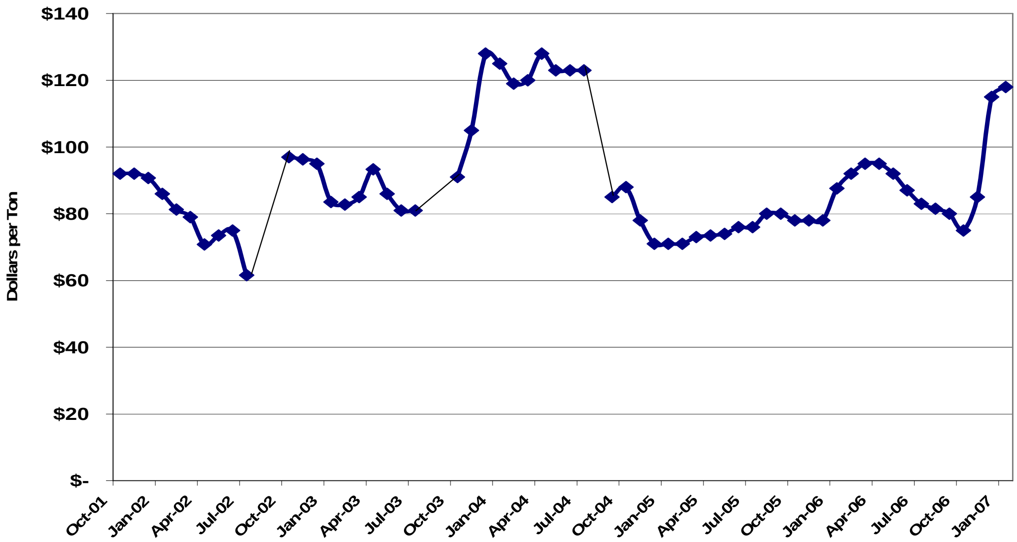

Figure 2. Historical prices of distillers dried grains at Lawrenceburg, Indiana (source: USDA-ERS, 2007).

As a feedstuff, DDGS have been hampered by issues of variability due to differences in corn quality (year to year) as well as ethanol plant operational issues involving the amount of concentrated solubles (syrup) dried with the dry portions of the stillage. The control and management of the DDGS dryers can cause a problem in feed quality when syrup balls are formed in DDGS. The composition of solubles in the DDGS and the manner in which they are dried or handled can also affect issues such as caking when the DDGS are shipped. Figure 2 shows a history of DDGS prices, which have historically been highly correlated with and about equal to corn prices on a per ton basis. Table 1 demonstrates the challenge of feeding the production of U.S. DDGS projected to be produced by 2009 at maximum dietary inclusion rates to the 2006 U.S. livestock population. Based on this table, it will require maximum dietary inclusion rates fed to 75% of the livestock populations to approach consumption of the amount of DDGS produced in 2009.

Table 1. Consumption of available DDGS (28 million metric tons) by percent of market penetration based on annual ethanol production of 38 billion liters (10 Billion gallons) (source: Cooper, Geoff, 2006)

Species	**Millions of Grain-Consuming Animal Units**	**Maximum Rate of Inclusion**	**Millions of Metric tons Market Penetration Percent**		
			50%	**75%**	**100%**
Dairy	10.2	20%	1.9	2.8	3.8
Beef	24.8	40%	9.2	13.8	18.4
Pork	23.8	20%	4.3	6.5	8.7
Poultry	31.1	10%	2.9	4.3	5.8
Total	89.9		18.3	27.4	36.6

Use of by-products of the ethanol plant (DDGS, DDG, or syrup) or use of corn stover as a fuel to operate the plant can improve the net energy balance of the whole process of making fuel ethanol from corn. This occurs because fossil sources of energy are replaced by renewable sources. Morey et al. (2006b) estimated net renewable energy values for corn ethanol with biomass to operate the plant comparable to estimates for cellulosic ethanol based on biochemical processes.

The efforts of California and growing interests on the national level to reduce the carbon footprint of the transportation fuel supply should establish higher prices for ethanol produced by methods that result in lower emissions of greenhouse gases. California's goal is to reduce greenhouse gases from the transportation sector by 10% by 2020. As California's AB-32 Legislation is implemented, firms selling fuels in that state should be willing to pay more for ethanol produced with a low-carbon footprint whether due to the feedstock used, the source of the imbedded energy in the fertilizer used or other factors affecting imbedded energy usage.

Well to wheels studies by Wang et al. (2007) of Argonne National Laboratory reveal that use of biomass as a source of process heat and power in ethanol plants results in nearly a three-fold reduction in greenhouse gas emissions compared to using the current fuel of natural gas and purchased electricity (Figure 3). This data implies that a California fuel supplier would need to purchase and transport one-third as much ethanol to blend in order to achieve equivalent GHG reductions if the ethanol were produced at a plant using biomass for process heat and electricity. Ethanol produced at plants using biomass fuels, with a lower carbon footprint than ethanol produced at plants using natural gas and purchased electricity, should command a price premium in the market related to savings in freight required to move ethanol from the Corn Belt to California.

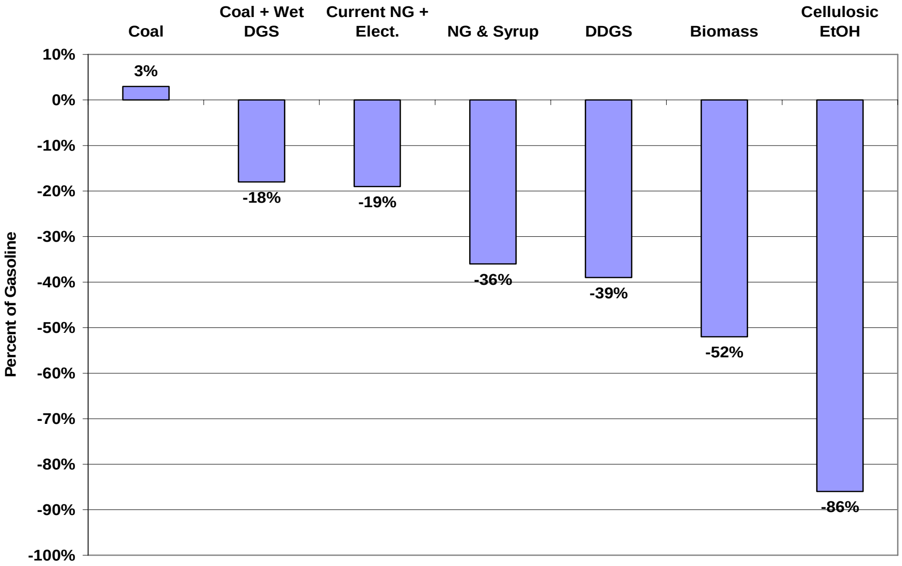

Figure 3. Well to wheels greenhouse gas emissions changes from fuel ethanol produced using various fuels and conversion assumptions at the plant relative to gasoline (source: Wang et al., 2007).

Objectives

The objective of this paper to perform an economic analysis for several biomass energy conversion systems integrated into the dry-grind corn ethanol process as described by De Kam et al. (2007). The economic drivers described above will be reflected in the assumptions related to prices.

Methods

The technical analysis for integrating biomass energy into the dry-grind ethanol process is described in detail in De Kam et al. (2007). Some of the important features are summarized here. 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. Biomass systems that produce 190 million liter (50 million gallon) per year of denatured ethanol were modeled. 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, co-product drying, and emissions control. 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.

Three biomass fuels were included in the analysis – distillers dried gains with solubles (DDGS), corn stover, and a mixture of corn stover and “syrup” (the solubles portion of DDGS). Three levels of technology were analyzed for providing energy at dry-grind plants. They included 1) process heat only, 2) process heat and electricity for the plant – combined heat and power (CHP), and 3) CHP plus additional electricity for the grid. The limit for the third case was defined in terms of the maximum energy available if all of the DDGS were used to provide process heat and electricity. A conventional ethanol plant using natural gas and electricity was also modeled to provide comparison information for the economic analysis.

Fluidized bed combustion was used for corn stover and the mixture of corn stover and syrup. Fluidized bed gasification was used for DDGS to overcome problems with low ash fusion temperatures. Appropriate drying modifications were made to accommodate each fuel/conversion configuration. The necessary emissions control technologies, primarily for oxides of nitrogen (NO_x) and oxides of sulfur (SO_x), were also modeled for each configuration.

Estimating Capital Costs

The Aspen Plus model estimates important material and energy flows which allowed us to specify the capacities of the required capital equipment. Using these capacities, we worked with a consulting engineering firm to specify equipment to meet these requirements. The consulting engineering firm then estimated equipment costs using data from previous projects and by soliciting bids from potential vendors for some items. Cost estimates are categorized according to new equipment and the equipment that would be replaced (avoided cost) compared to a conventional dry-grind plant. We focused on the net change in equipment cost required to construct a dry grind ethanol plant to use biomass rather than natural gas and purchased electricity as energy sources.

In the biomass scenarios, we assumed that a package natural gas boiler would be included for backup and also perhaps to phase in biomass as a fuel source over time, so the cost of that equipment was not deducted from the conventional base case of a natural gas powered plant. However, we were able to eliminate the capital costs of the thermal oxidizer that would be required in the natural gas-fired conventional plants.

Equipment costs for new items were first estimated, and then other costs associated with the project were added. Among these were installation, building, electrical, contractor costs and fees, engineering, contingency, and escalation to arrive at the total project cost for new items. The resulting capital costs for new items for all fuel and technology combinations are shown in Table 2. Total project costs for new items were divided by total equipment costs for new items to yield a project cost/equipment cost factor. The resulting factors ranged from 3.31 to 3.34 for the nine fuel/technology combinations in Table 2.

Avoided equipment costs and corresponding total project costs were also estimated and included in Table 2 for each fuel/technology combination. Recent estimates of total project costs (including operating capital) for conventional (natural gas) dry-grind plants obtained from design-build firms and bankers (Eidman, 2007) also are included in Table 2. Net (new – avoided) project costs for biomass systems are added to the cost of conventional plants to obtain total capital cost estimates for 190 million liters (50 million gallons) per year biomass fueled plants.

Cost estimates for the 380 million liter (100 million gallon) per year plants are developed based on the ratio of the plant sizes (380/190 = 2). The cost estimating factor for the 380 million liter plant is $(2)^{0.7}$ or 1.62. Thus, the cost for 380 million liter plant is estimated to be 1.62 times the cost for a 190 million liter plant for a similar fuel and level. This technique of adjusting costs for scale is commonly used in many chemical and industrial processes. Based on responses from design/builders of ethanol plants, efforts to optimize and de-bottleneck plants can raise capacity 6% in the case of coal or biomass plants and 20% or more in the case of conventional plants (Nicola, 2005). Nameplate installed costs with necessary operating capital are summarized for the nine fuel/technology combinations in Table 3.

Table 2. Total project costs for 190 million liter (50 million gallon) per year plants for nine biomass fuel/technology combinations.

Corn Stover Combustion		Process Heat Only			CHP			CHP plus electricity to the grid		
		F.O.B. Equip.	% of new	Total Project	F.O.B. Equip.	% of	Total Project	F.O.B. Equip.	% of	Total Project
Biomass Fuel Handling	new	$1,275,000	7%		$1,400,000	6%		$1,750,000	6%	
Fluidized Bed Boiler & Steam System.	new	$9,834,000	50%		$12,389,000	51%		$14,508,000	49%	
Ash Handling	new	$650,000	3%		$650,000	3%		$650,000	2%	
Emissions Control	new	$1,650,000	8%		$1,785,000	7%		$1,709,000	6%	
Steam Turbine Generator & Acc	new	$0	0%		$2,000,000	8%		$4,980,000	17%	
Steam Tube Dryer	new	$6,129,000	31%		$6,129,000	25%		$6,129,000	21%	
Total Cost: new items		$19,538,000	100%	$65,051,000	$24,353,000	100%	$80,868,000	$29,726,000	100%	$98,520,000
Natural Gas Dryer & T.O.	avoided	($9,000,000)	-46%	($30,430,000)	($9,000,000)	-37%	($30,430,000)	($9,000,000)	-30%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$10,538,000	54%	$34,620,000	$15,353,000	63%	$50,438,000	$20,726,000	70%	$68,090,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand				**$147,120,000**			**$162,938,000**			**$180,590,000**

Syrup and Corn Stover Combustion		Process Heat Only			CHP			CHP plus electricity to the grid		
		F.O.B. Equip.	% of new	Total Project	F.O.B. Equip.	% of	Total Project	F.O.B. Equip.	% of	Total Project
Biomass Fuel Handling	new	$1,275,000	8%		$1,400,000	7%		$1,750,000	7%	
Fluidized Bed Boiler & Steam System.	new	$9,037,000	55%		$11,114,000	54%		$13,345,000	51%	
Ash Handling	new	$650,000	4%		$650,000	3%		$650,000	2%	
Emissions Control	new	$1,650,000	10%		$1,785,000	9%		$1,709,000	7%	
Steam Turbine Generator & Acc	new	$0	0%		$2,000,000	10%		$4,853,000	19%	
Steam Tube Dryer	new	$3,700,000	23%		$3,700,000	18%		$3,700,000	14%	
Total Cost: new items		$16,312,000	100%	$54,452,000	$20,649,000	100%	$68,699,000	$26,007,000	100%	$86,302,000
Natural Gas Dryer & T.O.	avoided	($9,000,000)	-55%	($30,430,000)	($9,000,000)	-44%	($30,430,000)	($9,000,000)	-35%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$7,312,000	45%	$24,022,000	$11,649,000	56%	$38,269,000	$17,007,000	65%	$55,872,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand				**$136,522,000**			**$150,769,000**			**$168,372,000**

DDGS Gasification		Process Heat Only			CHP			CHP plus electricity to the grid		
		F.O.B. Equip.	% of new	Total Project	F.O.B. Equip.	% of	Total Project	F.O.B. Equip.	% of	Total Project
Biomass Fuel Handling	new	$790,000	4%		$790,000	4%		$990,000	4%	
Fluidized Bed Gasifier & Steam System.	new	$8,479,000	47%		$10,434,000	47%		$11,837,000	44%	
Ash Handling	new	$350,000	2%		$350,000	2%		$350,000	1%	
Emissions Control	new	$2,373,000	13%		$2,373,000	11%		$2,695,000	10%	
Steam Turbine Generator & Acc	new	$0	0%		$2,250,000	10%		$5,000,000	19%	
Steam Tube Dryer	new	$6,129,000	34%		$6,129,000	27%		$6,129,000	23%	
Total Cost: new items		$18,121,000	100%	$60,396,000	$22,326,000	100%	$74,209,000	$27,001,000	100%	$89,568,000
Natural Gas Dryer & T.O.	avoided	($9,000,000)	-50%	($30,430,000)	($9,000,000)	-40%	($30,430,000)	($9,000,000)	-33%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$9,121,000	50%	$29,965,000	$13,326,000	60%	$43,779,000	$18,001,000	67%	$59,137,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand				**$142,465,000**			**$156,279,000**			**$171,637,000**

Table 3. Nameplate installed costs for conventional and biomass-fueled dry-grind ethanol plants.

Type	190 MM liter (50 MM gallon) Plants		380 MM liter (100 MM gallon) Plants	
	Capital Cost	**Name Plate Cost $/L ($/gal)**	**Capital Cost**	**Name Plate Cost $/L ($/gal)**
Conventional	$112,500,000	$0.56 ($2.25)	$182,756,789	$0.48 ($1.83)
Corn Stover				
Process Heat	$147,120,000	$0.77 ($2.94)	$238,997,145	$0.63 ($2.39)
CHP	$162,938,000	$0.86 ($3.26)	$264,693,562	$0.70 ($2.65)
CHP + Grid	$180,590,000	$0.95 ($3.61)	$293,369,321	$0.77 ($2.93)
Corn Stover + Syrup				
Process Heat	$136,522,000	$0.72 ($2.73)	$221,780,643	$0.58 ($2.22)
CHP	$150,769,000	$0.79 ($3.02)	$244,924,963	$0.64 ($2.45)
CHP + Grid	$168,372,000	$0.89 ($3.37)	$273,521,121	$0.72 ($2.74)
DDGS				
Process Heat	$142,465,000	$0.75 ($2.85)	$231,435,075	$0.61 ($2.31)
CHP	$156.279,000	$0.82 ($3.13)	$253,875,985	$0.67 ($2.54)
CHP + Grid	$171,637,000	$0.90 ($3.43)	$278,825,129	$0.73 ($2.79)

Estimating Operating Costs and Other Baseline Assumptions

Table 4 contains the key baseline assumptions that affect profitability of the dry-grind ethanol plants being evaluated. It includes assumptions about the levels of debt and equity in the plant as well as the overall interest rate charged on the debt. A hurdle rate of return on equity can be established, and the number of years assumed for depreciation can be established.

Baseline ethanol price is established at $0.48/liter ($1.80/gallon) received at the ethanol plant. Corn price is assumed to be $138/tonne ($3.50/bushel) (for the next ten years) based on the 2007 Baseline Report of the U.S. Department of Agriculture. Natural gas is established at $8 per decatherm (1.06 million kJ or 1 million BTUs). Electricity is assumed to be priced at $0.06 per kWh under baseline conditions, whether the plant is buying or selling.

DDGS are established at the price of $110/tonne ($100/ton). In the scenarios when the syrup is combusted, the resulting by-product is DDG, which we assume has a market value 120% of conventional DDGS. We base this on presumed attributes of greater consistency and the higher inclusion rates that DDG should offer to producers. Corn stover is assumed to be priced at $88/tonne ($80/ton) when it is delivered in a dry, densified form at the plant gate (Sokhansanj and Turhollow, 2004; Petrolia, 2006). The value of ash is assumed to be $220/tonne ($200/ton) based on reported values for the ash collected at Corn Plus Ethanol in Winnebago, MN.

The low-carbon premium is established at 5.3¢/liter (20¢/gallon) for each unit of ethanol produced using biomass, based upon the savings in transportation costs that accrue when California ethanol buyers are able to purchase ethanol having a carbon imprint 1/3 that of ethanol produced at conventional dry-grind plants using natural gas and purchased electricity. In biomass cases that produce only process heat, it is assumed that 90% of the maximum credit is captured when biomass substitutes for process heat. The Federal Renewable Energy Electricity Credit of $.019/kWh is assumed to be received by the ethanol plant (even though it may be necessary for a private or corporate entity with sufficient passive income and tax liability to own the electrical generation equipment). There are additional minor assumptions including the Renewable Fuel Standard tradable credit of 2.6¢/liter (10¢/gallon) that approximates the average transportation and storage cost for the average unit of ethanol that gets produced and used in the U.S.

Table 4. Common assumptions for all systems.

Category	**Baseline Values**
Debt-Equity Assumptions	
Factor of Equity	40%
Factor of Debt	60%
Interest Rate Charged on Debt	8%
Depreciation Period	15 years
Output Market Prices	
Ethanol Price	$0.48/liter ($1.80/gallon)
DDGS Price	$110/tonne ($100/ton)
Electricity Sale Price	$0.06/kWh
Sale Price of Ash	$220/tonne ($200/ton)
CO_2 Price per liquid unit	$8.80/tonne ($8/ton)
Low-Carbon Premium	5.3¢/liter (20¢/gallon)
Government Subsidies	
Federal Small Producer Credit	2.6¢/liter(10¢/gallon)
RFS Ethanol Tradable Credit	2.6¢/liter(10¢/gallon)
Federal Renewable Electricity Credit	$0.019/kWh
Feedstock Delivered Prices Paid by Processor	
Corn Price	$138/tonne ($3.50/bushel)
Energy Prices	
Natural Gas	$8/decatherm
Stover Delivered to Plant	$88/tonne ($80/ton)
Electricity Price	$0.06/kWh
Propane Price	$0.29/liter ($1.10/gallon)
Operating Costs—Input Prices	
Denaturant Price per gallon	$0.48/liter ($1.80/gallon)
Denaturant Rate (volume units per 100 of anhydrous)	5
Ethanol Yield (anhydrous)	0.41 liter/kg (2.75gallon/bushel)

Certain expense items can be considered scale-neutral and are applied equally in 190 million liter (50 million gallon) and 380 million liter (100 million gallon) per year plants. These include per liter (gallon) expenses for enzymes, yeasts, process chemicals & antibiotics, boiler & cooling tower chemicals, water and denaturants. We assumed 1.1¢/liter (4¢/gallon) of enzyme expense, 0.11¢/liter (0.4¢/gallon) of yeast expense, and processing chemicals & antibiotics of 0.53¢/liter (2¢/gallon) (Shapouri and Gallagher, 2005). We also assumed boiler and cooling tower chemical costs of 0.13¢ /liter (0.5¢/gallon) and water costs of 0.08¢/liter (0.3¢/gallon) of denatured ethanol produced. We assumed $120,000 of real estate taxes, $840,000 of licenses, fees & insurance, as well as $240,000 in miscellaneous expenses per year in the 190 million liter (50 million gallon) per year plants, whether powered by natural gas or biomass, with these figures doubled in the case of 380 million liter (100 million gallon) per year plants. We applied the conclusion that management and quality control costs represent one third of labor costs for large and small plants (Nicola, 2005).

Maintenance expenses of biomass plants were established by starting with the costs per (liter) gallon of ethanol produced in a natural gas-fired plant (Shapouri et al., 2005) and then determining maintenance costs of the biomass technology cases in proportion to the capital costs of each biomass bundle. To establish maintenance costs for the 380 million liter (100 million gallon) per year biomass plants, we applied the same scale-up factor as used for capital costs ($(2)^{0.7}$ or 1.62) to the maintenance costs of the 190 million liter (50 million gallon) per year plant.

Labor expenses of biomass plants were established by starting with the costs per gallon of ethanol produced in a natural gas-fired plant (Shapouri, et al., 2005) and then adding the estimates of additional labor needed in the biomass technology cases. A 190 million liter (50 million gallon) per year biomass-powered plant producing process heat can be expected to have $184,000 more in labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $184,000 increase in labor expense for the 190 million liter (50 million gallon) per year biomass cases that generate electricity. For labor costs of 380 million liter (100 million gallon) per year plants, we applied the conclusion that the larger plants spend 75% as much per liter (gallon) produced as the smaller plants (Kotrba, 2006). Thus, a 380 million liter (100 million gallon) per year natural gas-fired plant can be expected to spend $4.5 million per year in labor versus $3 million in a 190 million liter (50 million gallon) per year plant. A 380 million liter (100 million gallon) per year biomass plant producing process heat is expected to have $368,000 greater labor expense than its natural gas-fired counterpart (Nicola, 2005). We assumed an additional $368,000 in labor costs for the larger plants that generate electricity.

Economic Model

Biomass fuel/technology combinations along with a convention natural gas plant are compared in a workbook, with each assigned a specific worksheet. Pro forma budgets are constructed for each combination and a common menu page is established to orchestrate various economic conditions to determine the economic viability of various options. The format of the pro forma budgets used to analyze ethanol plant economic sensitivity was originally developed at the University of Minnesota (Tiffany and Eidman 2003).

The nine biomass fuel technology combinations and the conventional plant are compared on the basis of rates of return on investment (ROR) using the base line assumptions for 190 million liter (50 million gallon) and 380 million liter (100 million gallon) per year capacities. Sensitivities of rates of return to changes in some of the key variables are then evaluated.

Results

Baseline Cases

Rates of return on investment (ROR) for 190 million liter (50 million gallon) per year capacities are shown in Figure 4. Rates of return of biomass plants producing process heat only exceed the natural gas-fired plant in the cases of stover and syrup plus stover. Syrup and stover utilization in a plant producing CHP also provides a higher ROR than the natural gas plant. Under baseline assumptions, natural gas-fired plants have higher RORs than any of the three biomass plants producing CHP plus sales of electricity to the grid.

Similar comparisons are shown for the 380 million liter (100 million gallon) per year plant in Figure 5. Rates of return are higher for the larger capacity, but the relative effects between biomass and conventional plants remain the same as for the smaller capacity.

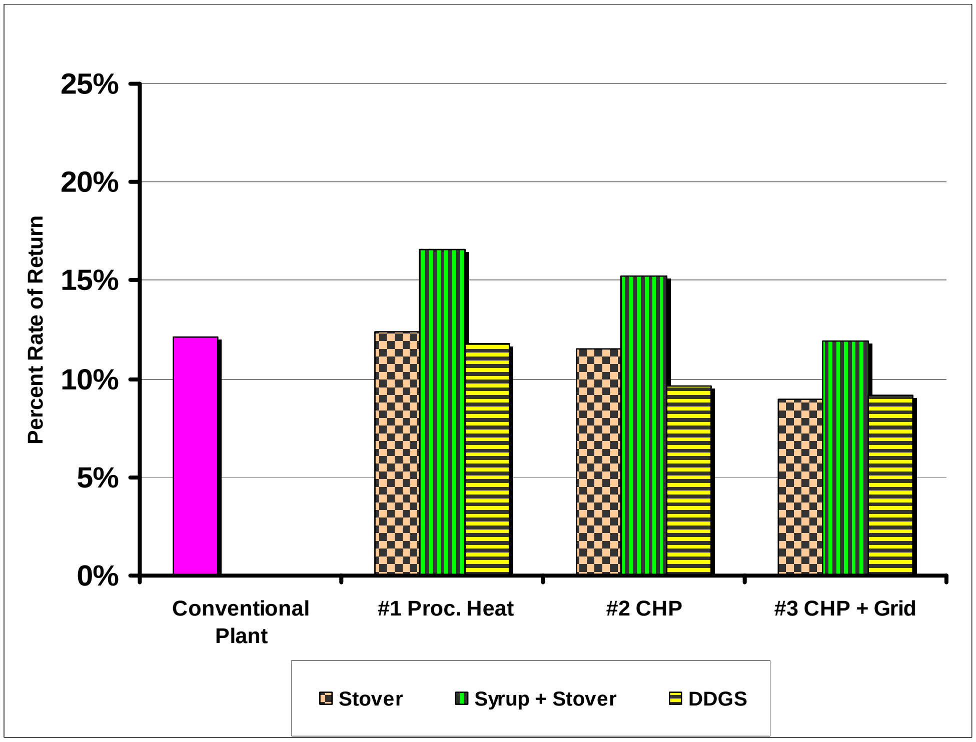

Figure 4. Baseline rates of return for 190 million liter (50 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

Sensitivity to Changes in Key Variables

Sensitivities of rates of return to changes in key variables are compared in Tables 5 and 6 for 190 million liter (50 million gallon) and 380 liter (100 million gallon) per year plants, respectively. Shaded values indicate higher rates of returns on investment (RORs) for biomass alternatives than for the corresponding conventional plant. In general, RORs are higher for the larger plants; however, cases which favor biomass alternatives over conventional plants are the same for both plant sizes.

An exogenous rise in natural gas prices from $8 to $12 per decatherm would affect a conventional ethanol plant with no effects shown on the biomass plants when all plants are at baseline conditions. The issue of natural gas prices is very sensitive to ethanol plants, and despite the higher capital costs to implement the biomass options, higher rates of return will be captured by plants utilizing biomass.

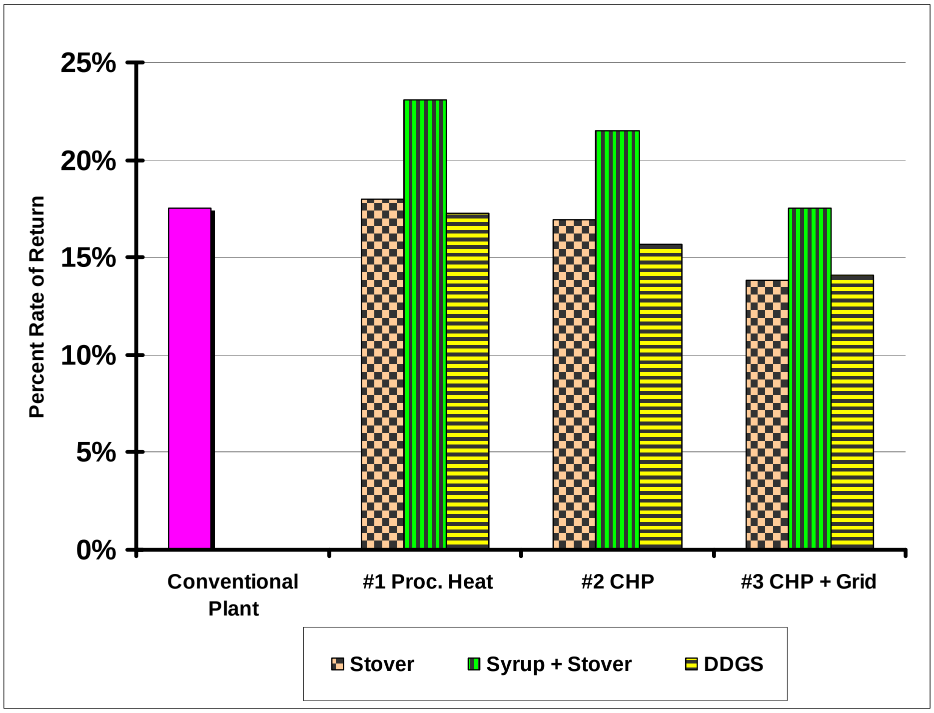

Figure 4. Baseline rates of return for 380 million liter (100 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

Declines in DDGS prices from $110 to $77 per tonne ($100 to $70 per ton) have a more pronounced effect on the conventional plant using natural gas. Plants using stover as fuel have substantial declines as well, for they are producing as much DDGS as the conventional plant. The plants using syrup and stover are less affected and have less DDGS to sell in all cases because the syrup represents 40% of the dry matter in DDGS. The plants combusting DDGS have the least effect with the drop in DDGS price; and in the case of level #3 (CHP plus sales of electricity to the grid), no effect is noted because all of the DDGS are combusted. Higher DDGS prices as shown in case 4 result in higher RORs for the conventional plants and are exceeded only by the cases of plants using stover and syrup for process heat as well as combined heat and power (CHP).

Higher ethanol prices would remove much of the economic attraction for designing and building ethanol plants capable of using biomass. Higher ethanol prices experienced when moving from the price of $0.48/liter ($1.80/gallon) at baseline to $0.53/liter ($2.00/gallon) result in a favorable rate of return on investment (ROR) in the case of the conventional plant. This effect occurs because of the lower capital costs associated with a plant built to run on natural gas and purchased electricity. The shift to lower ethanol prices is similar to conditions experienced by plants in the summer and early fall of 2007, with ethanol prices dropping from the baseline level of $0.48/liter ($1.80/gallon) to $0.42/liter ($1.60/gallon). With this exogenous shift, we observe that the biomass-powered plants have their rates of returns trimmed much less than the conventional plants. This aspect may be comforting to boards of directors and possibly their bankers when considering the capital costs to implement a biomass option.

Changes in the premium price for ethanol produced with a low carbon footprint can have substantial impact on the rates of return of the biomass-powered plants. If the price premium increases from 5.3 to 10.6¢/liter (20 to 40¢/gallon), the biomass-powered plants at all fuel/technology combinations are favored over conventional ethanol plants. If the price premium is zero instead of the 5.3 ¢/liter (20 ¢/gallon) assumed in the baseline, the RORs of the biomass-powered plants are trimmed and are less than those of the conventional plants, which are unaffected.

In instances where electricity can be sold at a favorable price of 10¢/kWh versus 6¢/kWh, the CHP plus grid cases experience higher rates of return. This would reflect a situation of a utility making a strong response to a state mandate for renewable energy. Such a shift, with other levels at baseline, results in a higher rate of return for the CHP plus grid option for the syrup plus stover case versus the conventional natural gas-fired plant.

A rise in corn price from the $138/tonne ($3.50/bushel) baseline to $157/tonne ($4.00/bushel) reduces the rates of returns of all the plants. However, it is interesting to note that the biomass-powered plants possess a degree of economic resiliency due to their control of the second highest operating cost of natural gas versus the conventional plant in this shift from baseline levels. This effect of greater economic resiliency for the biomass plants should offer some comfort for boards of directors of plants and bankers financing plants. Despite higher capital costs than the conventional plants, biomass plants offer greater stability in their RORs and may be more successful in the face of corn prices substantially above the baseline of $138/tonne ($3.50 per bushel).

A shift to higher stover prices from $88 to $110/tonne ($80 to $100/ton) results in minor shifts in the RORs of the options that use stover and no effect on the plants that use DDGS as a fuel. In any case, process heat and CHP applications, still maintain higher rates of return than the conventional plant in the case of the syrup plus corn stover fuel. These results offer some assurance that additional expenses that may be required to densify and process corn stover can be economically justified by plants using corn stover. However, if corn stover were available as cheap as $66/tonne ($60/ton), then three additional biomass options would exceed the natural gas fired plant, including the syrup plus stover option producing CHP and electricity for the grid.

Case 13 in Tables 5 and 6 shows the effects of two exogenous factors on RORs of the competing technology bundles. If the price of DDGS were to drop from baseline at $110 to 77/tonned ($100 to $70/ton) and natural gas were to rise from baseline at $8 to $12 per decatherm, the ROR of a conventional plant would be reduced to zero for the 190 million liters (50 million gallons) per year case, while all plants using biomass would be producing favorable rates of return. Although, all rates of return are higher for the larger plant, biomass alternatives produce much higher RORs than the conventional plant under these assumptions.

Table 5. Sensitivity of rates of return on investment to changes in key economic parameters for 190 million liter (50 million gallon) per year plants – shaded values indicate higher rates of return for biomass alternative than for corresponding conventional plant.

Economic Parameters	**Convent. Plant Nat. gas Electric.**	**Biomass Process Heat**			**Biomass CHP**			**Biomass CHP + Grid**		
		Corn Stover	**Stover & Syrup**	**DDGS**	**Corn Stover**	**Stover & Syrup**	**DDGS**	**Corn Stover**	**Stover & Syrup**	**DDGS**
1. Baseline case	12.1%	12.4%	16.6%	11.8%	11.5%	15.2%	9.6%	8.9%	12.0%	9.2%
2. Natural gas: $8 to $12/decatherm	5.0%	12.4%	16.6%	11.8%	11.5%	15.2%	9.6%	8.9%	12.0%	9.2%
3. DDGS: $100 to $70/ton	7.1%	9.0%	14.0%	10.7%	8.5%	12.9%	9.0%	6.2%	9.9%	9.2%
4. DDGS: $100 to $130/ton	17.1%	15.8%	19.1%	12.8%	14.6%	17.6%	10.3%	11.7%	14.1%	9.2%
5. Ethanol: $1.80 to $2.00/gallon	22.8%	19.6%	24.3%	19.2%	18.0%	22.3%	16.4%	14.8%	18.3%	15.4%
6. Ethanol: $1.80 to $1.60/gallon	1.5%	5.2%	8.8%	4.4%	5.0%	8.2%	2.8%	3.1%	5.7%	3.0%
7. Low carbon premium: 20¢ to 40¢/gallon	12.1%	18.6%	23.2%	18.2%	17.7%	21.9%	16.1%	14.5%	18.0%	15.1%
8. Low carbon premium: 20¢ to 0¢/gallon	12.1%	6.2%	9.9%	5.4%	5.3%	8.5%	3.1%	3.3%	6.0%	3.3%
9. Electricity sale price: 6¢ to 10¢/kWh	12.1%	12.4%	16.6%	11.8%	11.6%	15.2%	9.8%	10.1%	13.2%	10.4%
10. Corn price: $3.50 to $4.00/bu.	2.9%	6.2%	9.8%	5.3%	5.9%	9.1%	3.7%	3.8%	6.5%	3.8%
11. Corn stover price: $80 to $100/ton	12.1%	10.5%	15.8%	11.8%	9.6%	14.3%	9.6%	6.5%	10.3%	9.2%
12. Corn stover price: $80 to $60/ton	12.1%	14.3%	17.3%	11.8%	13.5%	16.1%	9.6%	11.4%	13.6%	9.2%
13. Natural gas: $8 to $12/dekatherm and DDGS: $100 to $70/ton	0.0%	9.0%	14.0%	10.7%	8.5%	12.9%	9.0%	6.2%	9.9%	9.2%

Table 6. Sensitivity of rates of return on investment to changes in key economic parameters for 380 million liter (100 million gallon) per year plants – shaded values indicate higher rates of return for biomass alternative than for corresponding conventional plant.

Economic Parameters	**Convent. Plant Nat. gas Electric.**	**Biomass Process Heat**			**Biomass CHP**			**Biomass CHP + Grid**		
		Corn Stover	**Stover & Syrup**	**DDGS**	**Corn Stover**	**Stover & Syrup**	**DDGS**	**Corn Stover**	**Stover & Syrup**	**DDGS**
1. Baseline case	17.6%	18.0%	23.1%	17.2%	16.9%	21.5%	15.7%	13.8%	17.5%	14.1%
2. Natural gas: $8 to $12/decatherm	8.8%	18.0%	23.1%	17.2%	16.9%	21.5%	15.7%	13.8%	17.5%	14.1%
3. DDGS: $100 to $70/ton	11.4%	13.9%	19.9%	15.9%	13.2%	18.6%	14.9%	10.4%	14.9%	14.1%
4. DDGS: $100 to $130/ton	23.7%	22.2%	26.3%	18.5%	20.7%	24.4%	16.4%	17.2%	20.1%	14.1%
5. Ethanol: $1.80 to $2.00/gallon	30.7%	26.9%	32.7%	26.4%	25.0%	30.1%	24.0%	21.0%	25.3%	21.7%
6. Ethanol: $1.80 to $1.60/gallon	4.4%	9.1%	13.5%	8.1%	8.9%	12.8%	7.3%	6.6%	9.7%	6.5%
7. Low carbon premium: 20¢ to 40¢/gallon	17.6%	25.6%	31.3%	25.1%	24.6%	29.7%	23.6%	20.7%	24.9%	21.4%
8. Low carbon premium: 20¢ to 0¢/gallon	17.6%	10.4%	14.9%	9.4%	9.3%	13.2%	7.7%	6.9%	10.1%	6.8%
9. Electricity sale price: 6¢ to 10¢/kWh	17.6%	18.0%	23.1%	17.2%	17.1%	21.5%	15.9%	15.3%	19.1%	15.6%
10. Corn price: $3.50 to $4.00/bu.	6.2%	10.3%	14.8%	9.3%	10.0%	14.0%	8.4%	7.5%	10.8%	7.5%
11. Corn stover price: $80 to $100/ton	17.6%	15.7%	22.2%	17.2%	14.5%	20.4%	15.7%	10.8%	15.5%	14.1%
12. Corn stover price: $80 to $60/ton	17.6%	20.4%	24.0%	17.2%	19.4%	22.6%	15.7%	16.8%	19.5%	14.1%
13. Natural gas: $8 to $12/dekatherm and DDGS: $100 to $70/ton	2.6%	13.9%	19.9%	15.9%	13.2%	18.6%	14.9%	10.4%	14.9%	14.1%

Conclusions

We modeled various technology bundles of equipment, fuels and operating activities that are capable of supplying energy and satisfying emissions requirements for dry-grind ethanol plants of 190 million and 380 million liter (50 and 100 million gallon) per year capacity using corn stover, distillers dried grains and solubles (DDGS), or a mixture of corn stover and “syrup” (the solubles portion of DDGS).

We estimated capital and operating costs for plants using biomass fuels. Although plants using biomass have higher capital costs, they may offer increased economic resiliency to changes in some of the key operating variables. Results showed favorable rates of return on investment for biomass alternatives compared to conventional plants using natural gas and purchased electricity over a range of conditions. The mixture of corn stover and syrup provided the highest rates of return in general. Factors favoring biomass included a higher premium for low carbon footprint ethanol, higher natural gas prices, lower DDGS prices, lower ethanol prices, and higher corn prices.

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