

**Project Title: Generating Electricity with Biomass Fuels at Ethanol Plants**

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**Congressional District: Minnesota fifth (UofM Sponsored Projects Administration)**

**Minnesota fourth (UofM Bioproducts and Biosystems Engineering)**

**Executive Summary**

- Updated project web site [www.biomassCHPethanol.umn.edu](http://www.biomassCHPethanol.umn.edu) with most recent results
- Updated economic analysis – We performed economic analysis for dry-grind ethanol plants of 50 and 100 million gallons per year capacity using corn stover, distillers dried grains and solubles (DDGS), or a mixture of corn stover and “syrup”. 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.
- Performed preliminary analysis on special scenarios.
- Presented project results as part of seven electric power seminars reaching a total of approximately 270 people.
- Developed plans for three workshop meetings on “Profitable Use of Biomass at Ethanol Plants” to be held in Mankato, MN; Norfolk, NE; and Des Moines, IA on February 19<sup>th</sup>, 20<sup>th</sup>, and 21<sup>st</sup>, respectively.
- Communicated about project activities; carried out project management, accounting, and reporting functions.

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## Technical Progress

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## Summary of Tasks Listed under Milestone 7

- **Update website** – Added several papers and presentations made during this reporting period and added information for the upcoming workshops in Mankato, MN; Norfolk, NE; and Des Moines, IA.
- **Updated Economic Analysis** – Update economic results are summarized below.

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<sub>x</sub>) and oxides of sulfur (SO<sub>x</sub>), 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. Cost	% of new	Total Project	F.O.B. Equip.	% of	Total Project Cost	F.O.B. Equip. Cost	% of	Total Project Cost
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
<b>Biomass Powered Ethanol Plant Grand</b>				<b>\$147,120,000</b>			<b>\$162,938,000</b>			<b>\$180,590,000</b>

Syrup and Corn Stover Combustion		Process Heat Only			CHP			CHP plus electricity to the grid		
		F.O.B. Equip. Cost	% of new	Total Project	F.O.B. Equip.	% of	Total Project Cost	F.O.B. Equip. Cost	% of	Total Project Cost
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
<b>Biomass Powered Ethanol Plant Grand</b>				<b>\$136,522,000</b>			<b>\$150,769,000</b>			<b>\$168,372,000</b>

DDGS Gasification		Process Heat Only			CHP			CHP plus electricity to the grid		
		F.O.B. Equip. Cost	% of new	Total Project	F.O.B. Equip.	% of	Total Project Cost	F.O.B. Equip. Cost	% of	Total Project Cost
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
<b>Biomass Powered Ethanol Plant Grand</b>				<b>\$142,465,000</b>			<b>\$156,279,000</b>			<b>\$171,637,000</b>

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)
<b>Conventional</b>	\$112,500,000	\$0.56 (\$2.25)	\$182,756,789	\$0.48 (\$1.83)
<b>Corn Stover</b>				
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)
<b>Corn Stover + Syrup</b>				
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)
<b>DDGS</b>				
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
<b>Debt-Equity Assumptions</b>	
Factor of Equity	40%
Factor of Debt	60%
Interest Rate Charged on Debt	8%
Depreciation Period	15 years
<b>Output Market Prices</b>	
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 <sub>2</sub> Price per liquid unit	\$8.80/tonne (\$8/ton)
Low-Carbon Premium	5.3¢/liter (20¢/gallon)
<b>Government Subsidies</b>	
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
<b>Feedstock Delivered Prices Paid by Processor</b>	
Corn Price	\$138/tonne (\$3.50/bushel)
<b>Energy Prices</b>	
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)
<b>Operating Costs—Input Prices</b>	
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.

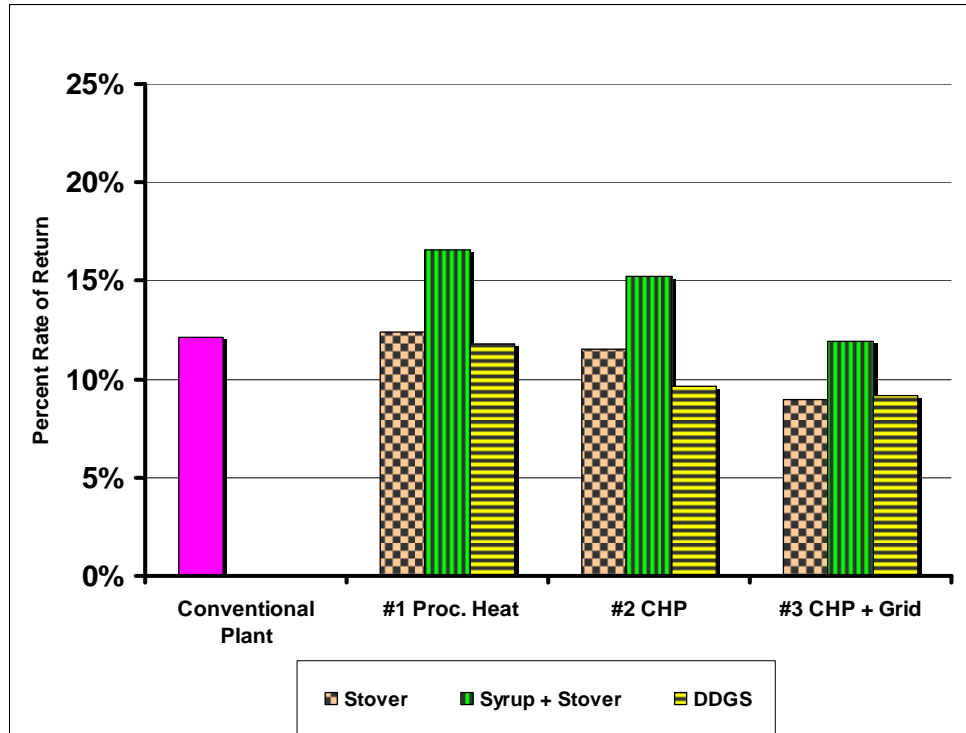


Figure 4. Baseline rates of return for 190 million liter (50 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

***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.

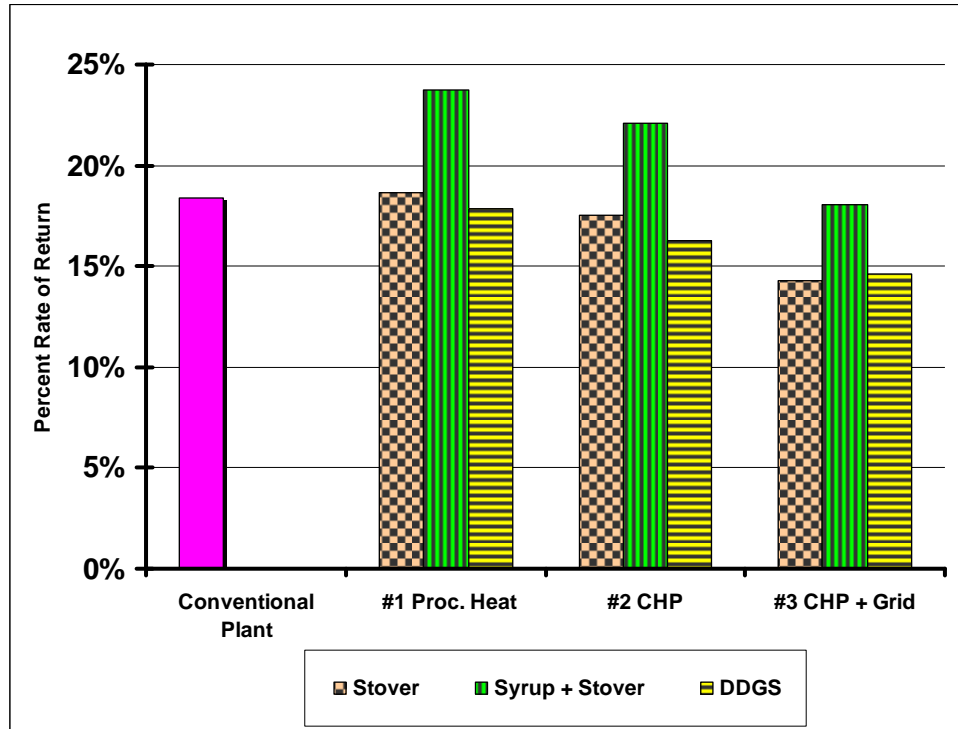


Figure 4. Baseline rates of return for 380 million liter (100 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

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	12.2%	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	7.2%	9.0%	14.0%	10.8%	8.5%	12.9%	9.0%	6.2%	9.9%	9.2%
4. DDGS: \$100 to \$130/ton	17.2%	15.8%	19.2%	12.9%	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	12.2%	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	12.2%	6.2%	9.9%	5.4%	5.3%	8.5%	3.2%	3.3%	6.0%	3.3%
9. Electricity sale price: 6¢ to 10¢/kWh	12.2%	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	12.2%	10.5%	15.9%	11.8%	9.5%	14.4%	9.6%	6.5%	10.3%	9.2%
12. Corn stover price: \$80 to \$60/ton	12.2%	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%	10.8%	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	18.4%	18.6%	23.8%	17.9%	17.5%	22.1%	16.2%	14.3%	18.1%	14.6%
2. Natural gas: \$8 to \$12/decatherm	9.6%	18.6%	23.8%	17.9%	17.5%	22.1%	16.2%	14.3%	18.1%	14.6%
3. DDGS: \$100 to \$70/ton	12.2%	14.5%	20.6%	16.6%	13.8%	19.2%	15.5%	10.9%	15.5%	14.6%
4. DDGS: \$100 to \$130/ton	24.5%	22.8%	26.9%	19.2%	21.3%	25.0%	17.0%	17.7%	20.6%	14.6%
5. Ethanol: \$1.80 to \$2.00/gallon	31.5%	27.5%	33.3%	27.0%	25.5%	30.8%	24.6%	21.5%	25.8%	22.2%
6. Ethanol: \$1.80 to \$1.60/gallon	5.2%	9.8%	14.2%	8.7%	9.5%	13.4%	7.9%	7.1%	10.3%	7.0%
7. Low carbon premium: 20¢ to 40¢/gallon	18.4%	26.3%	32.0%	25.8%	25.2%	30.4%	24.2%	21.2%	25.5%	21.9%
8. Low carbon premium: 20¢ to 0¢/gallon	18.4%	11.0%	15.6%	10.0%	9.9%	13.8%	8.3%	7.4%	10.7%	7.4%
9. Electricity sale price: 6¢ to 10¢/kWh	18.4%	18.6%	23.8%	17.9%	17.6%	22.1%	16.5%	15.8%	19.6%	16.2%
10. Corn price: \$3.50 to \$4.00/bu.	7.0%	10.9%	15.5%	9.9%	10.6%	14.6%	9.0%	8.0%	11.3%	8.0%
11. Corn stover price: \$80 to \$100/ton	18.4%	16.3%	22.9%	17.9%	15.1%	21.0%	16.2%	11.3%	16.0%	14.6%
12. Corn stover price: \$80 to \$60/ton	18.4%	21.0%	24.7%	17.9%	19.9%	23.2%	16.2%	17.3%	20.1%	14.6%
13. Natural gas: \$8 to \$12/dekatherm and DDGS: \$100 to \$70/ton	3.5%	14.5%	20.6%	16.6%	13.8%	19.2%	15.5%	10.9%	15.5%	14.6%

## 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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- **Preliminary Analysis of Special Scenarios** – Based on our analysis so far we have identified several special scenarios or cases that deserve additional consideration.

One special scenario is to use a combination of syrup and natural gas to provide process heat at ethanol plants. One plant, Corn Plus in Winnebago, MN, is already doing this. Although this alternative does not reduce fossil energy use as much as the full biomass options or provide for renewable electricity generation, it may be a bridge strategy for some plants because it takes advantage of the biomass source at the plant without having to supplement it with a biomass source external to the plant, for example corn stover. We are modeling the technical and economic performance of this alternative.

Another special scenario is to use corn cobs in place of corn stover. Corn cobs are part of the corn residue, but most cobs would normally not be captured in corn stover harvest. Corn cobs have physical characteristics that might allow them to be utilized with out as much processing, for example densification, as corn stover. They also have lower ash content than corn stover. We are modeling the technical and economic performance of this alternative.

We are also evaluating the option of supplying process heat needs at ethanol plants at steam pressures of 50 psi rather than 150 psi as previously modeled. Although it is common to generate steam at 150 psi, many process applications only require steam at 50 psi. Using 50 psi for

process applications will allow greater electricity generation with modest increases in biomass fuel required. We are modeling the technical and economic performance of this alternative.

Our economic analyses show that rates of return on investment for biomass applications are very sensitive to assumptions about low-carbon fuel premiums for ethanol like those proposed for adoption in California. We are further evaluating the assumptions and analysis related to the impact that electricity generation at ethanol plants has on the carbon foot print, which in turn impacts the magnitude of the low-carbon fuel premiums that can be assigned to the ethanol produced. This involves further technical as well as economic analysis.

We are planning to undertake preliminary analysis of integrated gasification combined cycle systems to produce electricity at ethanol plants. The greater levels of electricity production with this technology will provide increased revenue for ethanol plants and potentially justify a greater low-carbon fuel premium for the ethanol produced.

● **Preparation for Workshops** – Workshops were part of the original project proposal. We have scheduled a series of workshop meetings entitled “Profitable Use of Biomass at Ethanol Plants” to be held in Mankato, MN; Norfolk, NE; and Des Moines, IA on February 19<sup>th</sup>, 20<sup>th</sup>, and 21<sup>st</sup>, respectively. Details of those workshops including registration information is included on our website: [www.biomassCHPethanol.umn.edu](http://www.biomassCHPethanol.umn.edu) .

The workshop objective is to learn about opportunities to use biomass at ethanol plants to:

- reduce energy costs
- generate renewable electricity
- improve the renewable energy balance (reduce carbon footprint)
- improve profit margins

The target audience includes ethanol plant managers and board members, bankers financing ethanol projects, regulators, utilities, engineering companies, and policy makers.

An agenda for the workshops is shown on the next page.



- **Summary of project management activities, travel, etc. for period (RMT)** – Dennis Hatfield of RMT attended the lecture/seminar presented by Doug Tiffany for Alliant Energy at Dubuque, IA as described below. After the seminar Dennis Hatfield and Doug Tiffany discussed project activities.

- **Summary of project management activities, travel, etc. for period (UofM)** – Doug Tiffany presented preliminary conclusions of this project and described the opportunities that may be available to ethanol plants and electric power utilities with ethanol plants in their service areas in a series of seven lectures held at power utilities in Minnesota, Iowa, and Wisconsin. The lecture series was sponsored by the Electrical Engineering Department at the University of Minnesota as a service to a regional consortium of power utilities who support scholarships in that department. He presented a 3-4 hour lecture entitled “Utilization of Biomass for Electrical Generation: Technical and Policy Considerations” to a total audience of around 270, primarily in August, at the following locations:

Great River Energy	Elk River, MN
Xcel Energy	Minneapolis, MN
Minnesota Power	Duluth, MN
Ottertail Power	Fergus Falls, MN
Alliant Energy	Dubuque, IA
Dairyland Power	La Crosse, WI
Southern Minnesota Municipal Power Agency	Rochester, MN

Staff of Great River and others expressed interest in helping ethanol plants within their service areas in developing CHP because this development would obviate the need for substantial investment in upgrades to distribution capacity. The audiences at all locations were interested in the material presented on scenarios developed by Steven Taff and others in their regional carbon model. The local availability of biomass supplies offer opportunities for power utilities in this part of the country. The Center for Energy and the Environment (CEE) study of biomass supplies was also discussed with these audiences. The production economics of ethanol, biodiesel, and bio-oil produced by pyrolysis were also discussed.

Doug Tiffany, Matt De Kam, and Vance Morey met with Nick Cave of AMEC and Larry Schedin of LLS Resources on August 24 in Minneapolis to discuss project activities.