UNIVERSITY OF MINNESOTA

Twin Cities Campus

Department of Biosystems and
Agricultural Engineering

College of Agricultural, Food
and Environmental Sciences
Institute of Technology

Biosystems and Agricultural
Engineering Building
1390 Eckles Avenue
St. Paul, MN 55108-6005

612-625-7733
Fax: 612-624-3005
E-mail: bae@ umn.edu
Web: www.bae.umn.edu

Project Title: Generating Electricity with Biomass Fuels at Ethanol Plants

Contract Number: RD-56 Milestone Number: 2 Report Date: June 1, 2006

Reporting Period: March 1, 2006 to May 31, 2006

Milestone Description: Second three-month reporting period

Principal Investigator: R. Vance Morey
612-625-8775
rvmorey@umn.edu

Contract Contact: Bridget Foss
612-624-0035
foss0134@umn.edu

Congressional District: Minnesota fifth (UofM Sponsored Projects Administration)
Minnesota fourth (UofM Biosystems and Agricultural Engineering)

Executive Summary

- Updated project web site www.biomassCHPethanol.umn.edu with most recent results
- Analyzed and summarized results of samples of feed streams from cooperating ethanol plants
- Defined and evaluated combustion options
- Defined and evaluated fuel processing options
- Developed combustion models and performed preliminary analysis of combustion alternatives
- Performed preliminary emissions analysis using models
- Analyzed power purchase agreements
- Developed preliminary spreadsheet architecture
- Communicated about project activities; conducted a meeting of project participants in Madison, WI in May; carried out project management, accounting, and reporting functions

Technical Progress

Prepared by
R. Vance Morey, Professor, Biosystems and Agricultural Engineering Department
Douglas G. Tiffany, Research Fellow, Applied Economics Department
University of Minnesota
and
Dennis L. Hatfield, Ethanol Team Leader, RMT Inc.

Summary of Tasks Listed under Milestone 2

- **Update website** – added results related to feed stream fuel characteristics, combustion options, power purchase agreements, and ethanol economics

- **Feed stream results** (Mostly complete, a few samples are being rerun in cases where the results could not be explained or indicated that there might be an error.)

Feed streams were sampled at the five partner ethanol plants. Feed streams included distillers dried grains with solubles (DDGS) – 4 plants, distillers dried grains (DDG) – 1 plant, distillers wet grains (DWG) – 5 plants, and syrup – 5 plants. Sample containers with sampling instructions were sent to each of the five plants. Plant personnel obtained the samples then called a delivery service to transport the samples to the laboratory. Two laboratories were used for the various analyses.

A sample of corn stover was also obtained from AURI and submitted for analysis.

Fuel characteristics for ethanol plant coproducts and corn stover are summarized in Table 1. Most results are presented on a moisture free basis for ease of comparison. Since only one plant produced DDG, detailed results are not presented here since we agreed not to identify results from specific plants. However, the DDG results on a moisture free basis are consistent with the DWG results on a moisture free basis from the five plants.

We did not analyze for phosphorus and potassium because a significant amount of information on these two metals is available from other analyses of ethanol coproducts and corn stover. Results from other studies are included in our Milestone 1 report.

Ash characteristics are presented in Table 2. Ash analyses were run for either two or three plants.

Thermogravimetric analyses are presented in Figures 1 through 4 for selected samples. These figures show how the fuels volatilize as a function of temperature.

Table 1. Characteristics of ethanol coproducts and corn stover as fuels.

Parameter	**DDGS**	**DWG**	**Syrup**	**Corn Stover**[7]
As received				
Moisture, %	10.12 (1.38)[1]	64.46 (6.13)[5]	67.29 (6.80)[5]	6.15
Ash, %	3.41 (0.27)[1]	0.97 (0.68)[5]	2.31 (0.77)[5]	6.31
Higher heating value, Btu/lb	8368 (168)[1]	3349 (567)[5]	2765 (418)[5]	7235
Moisture Free				
Ash, %	3.89 (0.29)[2]	2.58 (1.25)[5]	7.02 (1.47)[5]	6.73
Higher heating value, Btu/lb	9349 (88)[2]	9438 (110)[5]	8482 (623)[5]	7709
Lower heating value, Btu/lb	8703 [8]	8819 [8]	7819 [8]	7192 [8]
Proximate				
Volatile matter, %	82.50 (1.32)[2]	83.18 (2.09)[5]	81.71 (0.92)[5]	66.58
Fixed Carbon, %	12.84 (1.61)[2]	13.58 (1.75)[5]	10.32 (1.58)[5]	26.65
Chlorine, µg/g	1757 (89)[3]	1673 (1543)[1]	3459 (807)[1]	984
Mercury, µg/g	<0.010 [4]	<0.10 [6]	<0.012 [6]	<0.010
Ultimate				
Carbon, %	50.24 (0.31)[2]	52.53 (3.24)[5]	43.12 (4.29)[5]	45.48
Hydrogen, %	6.89 (0.05)[2]	6.60 (0.34)[5]	7.07 (0.24)[5]	5.52
Nitrogen, %	4.79 (0.34)[2]	5.35 (0.35)[5]	2.63 (0.59)[5]	0.69
Oxygen, %	33.42 (1.11)[2]	32.28 (2.87)[5]	39.21 (4.31)[5]	41.52
Sulfur, %	0.77 (0.18)[2]	0.66 (0.11)[5]	0.96 (0.31)[5]	0.04
Metals, mg/kg				
Arsenic	<3.20 [4]	<3.10 [6]	<3.20 [6]	2.50
Beryllium	<0.093 [4]	<0.093 [6]	<0.11 [6]	<0.089
Cadmium	<0.046 [4]	<0.50 [6]	<0.53 [6]	<0.45
Chromium	0.50 (0.05)[3]	<0.79 [6]	0.75 (0.20)[1]	<0.45
Lead	<0.046 [4]	<0.50 [6]	<0.53 [6]	0.46
Manganese	15.95 (1.63)[3]	12.05 (4.45)[1]	34.93 (10.63)[1]	23.4
Nickel	0.87 (0.06)[3]	<1.20 [6]	1.97 (0.45)[1]	<0.45
Phosphorus	-	-	-	-
Potassium	-	-	-	-
Selenium	1.80 (0.00)[3]	<1.80 [6]	<1.60 [6]	<1.30

[1] mean (standard deviation) of samples from 3 plants
[2] mean (standard deviation) of samples from 4 plants
[3] mean (standard deviation) of samples from 2 plants
[4] samples from 2 plants
[5] mean (standard deviation) of samples from 5 plants
[6] samples from 3 plants
[7] one sample
[8] calculated using mean higher heating value and mean ultimate analysis

Table 2. Ash characteristics of ethanol coproducts and corn stover.

Parameter	**DDGS**	**DWG**	**Syrup**	**Corn Stover**[3]
Ash Fusion – Oxidizing Atmosphere, °F				
Initial Deformation	1081 (96)[1]	1312 (91)[2]	1912 (1572)[2]	1930
Softening	1099 (100)[1]	1381 (117)[2]	2186 (820)[2]	1984
Hemispherical	1301 (9)[1]	1446 (122)[2]	2595 (146)[2]	2100
Fluid	2027 (805)[1]	2041 (578)[2]	2695 (33)[2]	2205
Ash Fusion – Reducing Atmosphere, °F				
Initial Deformation	1274 (45)[1]	1327 (89)[2]	1898 (377)[2]	1624
Softening	1384 (123)[1]	1467 (148)[2]	2176 (436)[2]	1718
Hemispherical	1493 (231)[1]	1586 (201)[2]	2287 (366)[2]	1909
Fluid	2573 (21)[1]	1978 (62)[2]	2657 (15)[2]	2194
Mineral Analysis, %				
Silicon dioxide	2.89 (0.22)[1]	4.37 (2.16)[2]	<2.42 [5]	54.12
Aluminum oxide	<0.38 [4]	<0.38 [5]	<0.38 [5]	0.78
Titanium dioxide	<0.03 [4]	<0.03 [5]	<0.03 [5]	0.04
Iron oxide	<0.32 [4]	<0.29 [5]	<0.93 [5]	0.45
Calcium oxide	<1.4 [4]	<0.1.4 [5]	<0.1.4 [5]	5.61
Magnesium oxide	13.31 (1.61)[1]	8.85 (1.89)[2]	10.81 (2.71)[2]	4.22
Potassium oxide	30.04 (0.88)[1]	22.40 (6.10)[2]	27.03 (5.66)[2]	20.22
Sodium oxide	3.65 (1.88)[1]	3.05 (1.78)[2]	3.18 (1.01)[2]	1.47
Sulfur trioxide	1.57 (0.35)[1]	2.03 (2.16)[2]	5.87 (1.59)[2]	12.75
Phosphorus pentoxide	43.24 (3.19)[1]	34.77 (5.44)[2]	30.15 (3.59)[2]	1.97
Strontium oxide	<0.02 [4]	<0.02 [5]	<0.02 [5]	<0.02
Barium oxide	<0.02 [4]	<0.02 [5]	<0.02 [5]	0.02
Manganese dioxide	0.06 (0.01)[1]	0.05 (0.02)[2]	0.05 (0.02)[2]	0.06
Nitrogen	2.44 (1.77)[1]	2.35 (1.20)[2]	1.55 (0.64)[2]	-

[1] mean (standard deviation) of samples from 2 plants
[2] mean (standard deviation) of samples from 3 plants
[3] one sample
[4] samples from 2 plants
[5] samples from 3 plants

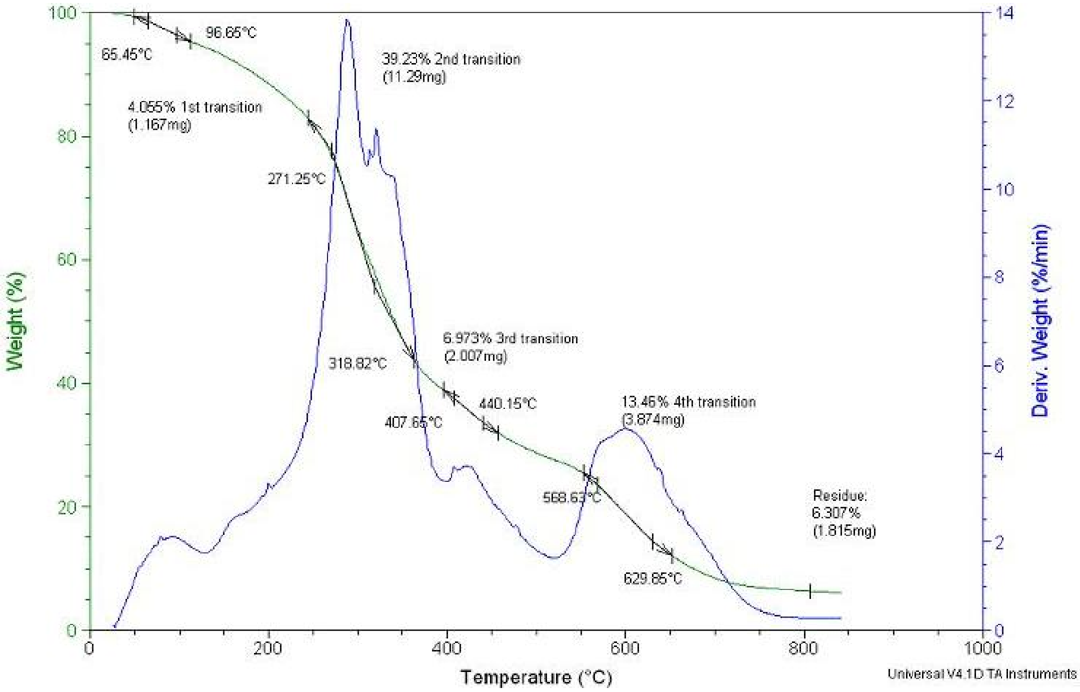

Figure 1. Thermogravimetric analysis for a DDGS sample (9 to 12 % moisture).

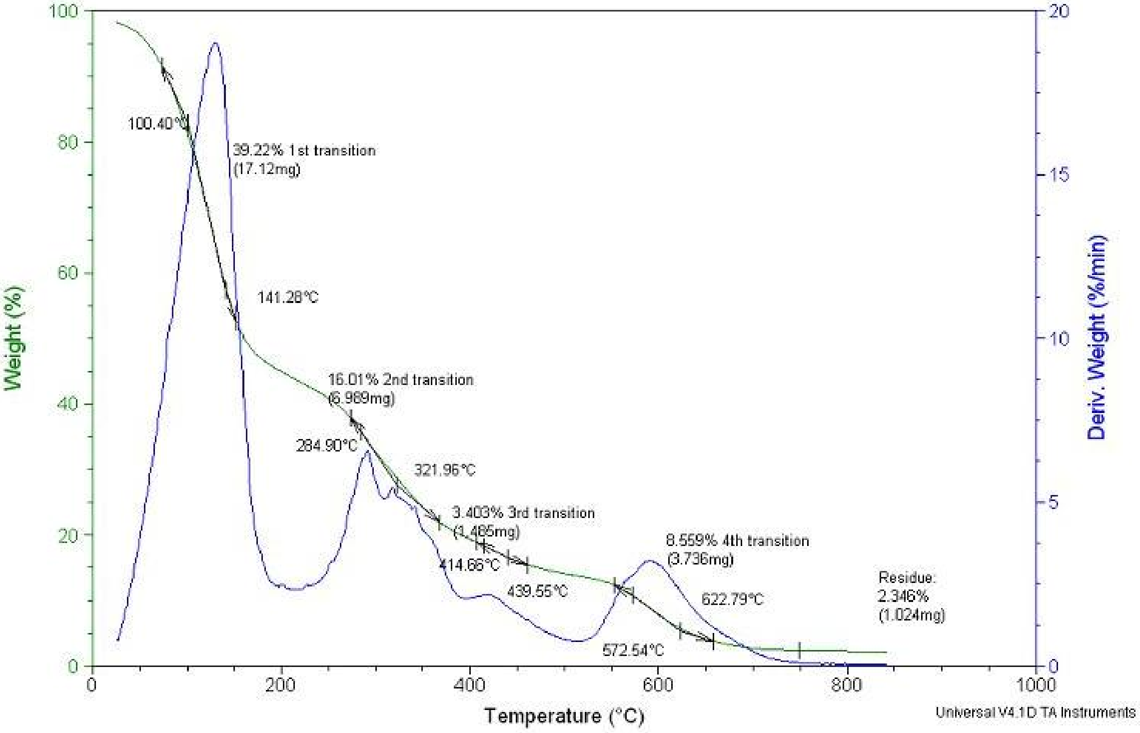

Figure 2. Thermogravimetric analysis for a DWG sample (55 to 70% moisture).

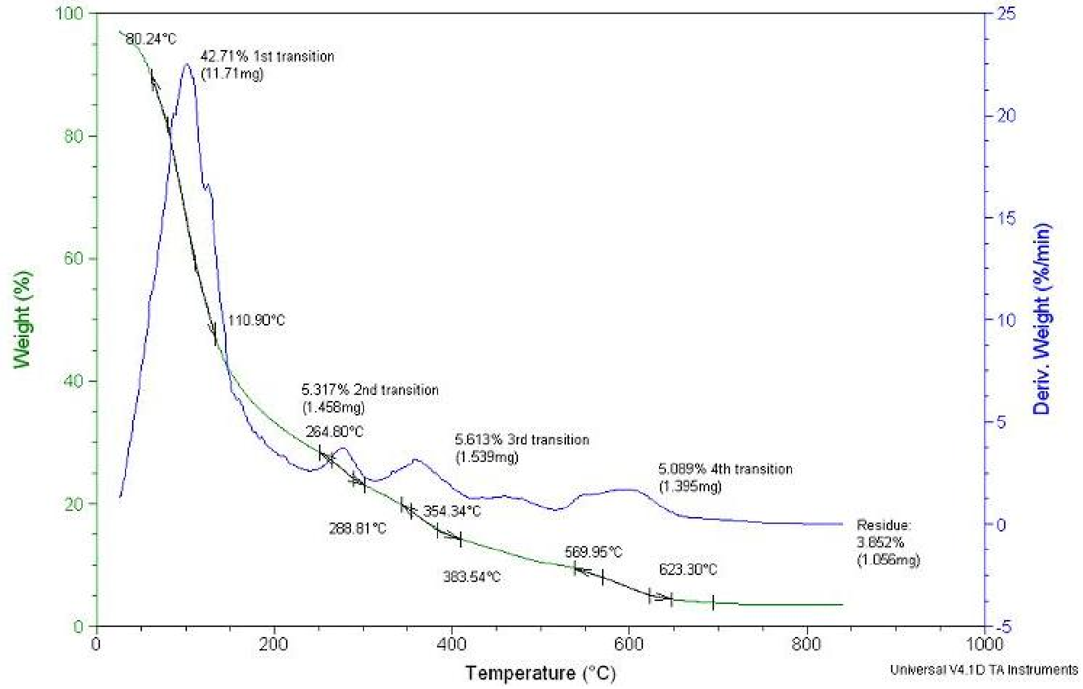

Figure 3. Thermogravimetric analysis for a syrup sample (58 to 77% moisture).

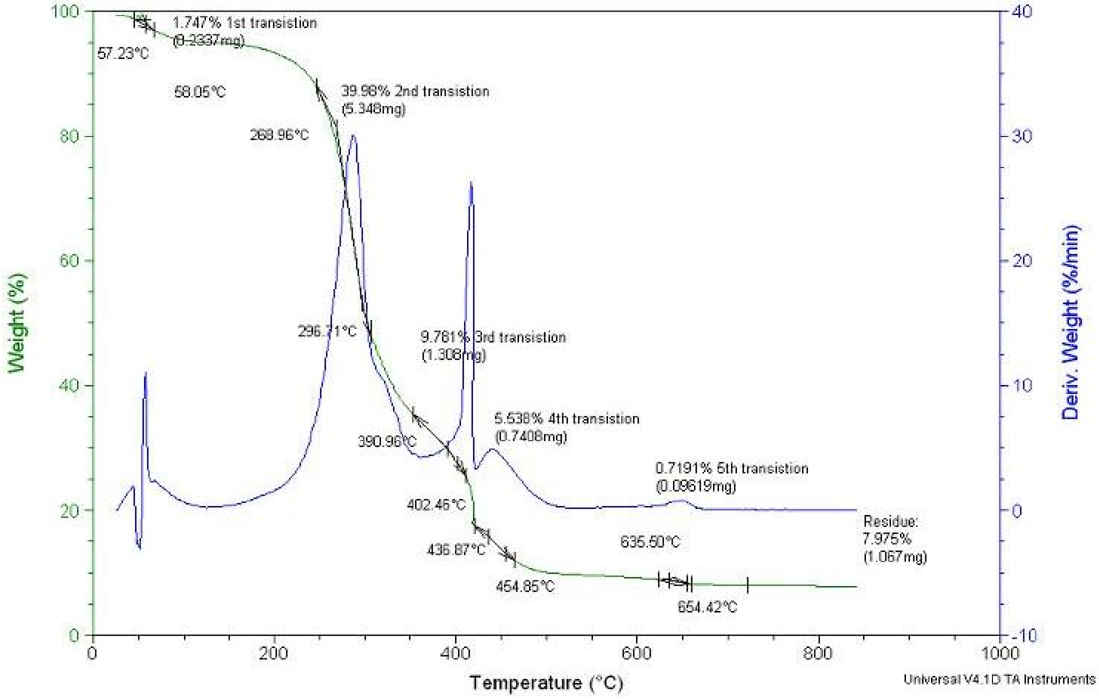

Figure 4. Thermogravimetric analysis for a corn stover sample (6.15% moisture).

- **Combustion options preliminary results**

Four combustion or gasification options were defined for consideration at the proposal stage – fluidized bed combustion, fluidized bed gasification, liquid injection (combustion), and liquid injection with pulverized solids (combustion). More recently updraft, fixed bed gasification has been proposed to meet electricity and process heat needs at ethanol plants, so this option has been added to the analysis. Potential advantages and disadvantages of each are summarized below.

<u>Fluidized bed</u>: Fluidized bed (FB) combustion is a well established technology that has been used in a variety of industries, especially since approximately WWII, although its use in the fuel ethanol industry is only in its initial stages. There are two basic types of fluidized bed combustion systems that will be evaluated for this project: bubbling fluidized bed (BFB) and circulating fluidized bed (CFB). Both types of FB may be designed to operate in a pressurized mode.

In a BFB system, a bed of inert granular material (often silica sand) is agitated with air blown into the bottom of the combustion chamber through an air distributor, at a rate that causes the bed to act like a type of fluid. The fluidized bed has the general appearance of a pot of water at a rolling boil. To initiate the process, the bed is heated to a high temperature (typically around 1500 °F), usually with natural gas, before the biomass fuel is introduced. The combustible biomass fuel is then introduced, either above the level of the bed or directly into the bed, at a rate to make the combustion self-sustaining. The large thermal mass of the bed and the intense shearing action caused by the fluidization of the abrasive bed result in rapid dehydration and rapid and complete combustion. Combustion gasses, along with some fine ash, leave the top of the vessel and enter emission control, steam generation, and heat recovery systems, with the exact sequence and characteristics depending on the particular design of the system. A stream of bed material and ash is continuously removed from the bed for separation of ash and bed material, with bed material returning to the bed. The conceptual system design task of this project will estimate the most efficient and effective biomass feed systems, especially taking into account flexibility to handle biomass fuel, biomass fuel particle size, and feed stream moisture content.

Steam generation may be accomplished by water tubes in the bed itself or, more commonly, in a separate steam generator, either in the combustion vessel or in a dedicated unit. In a variation of the bubbling fluidized bed system, partial combustion occurs in the primary combustion chamber, and is completed in a separate area or chamber of the combustion zone. Additional fuel may be added to the separate area or chamber. This configuration allows flexibility in combustion, and has the potential for higher pressure steam, which is more favorable for generation of electricity.

If the BFB is operated in pressurized mode, the hot, cleaned combustion gasses may be first directed to a turbine for generation of electricity, followed by a heat recovery steam generator (HRSG), and then potentially to further recovery of low grade heat. Such a system produces higher efficiency than an atmospheric system, but with increased capital costs.

There are many advantages of the bubbling fluidized bed combustion system. First, it has the ability to combust a wide variety of fuels, from natural gas to large biomass items, with minimal pre-processing. However, over-bed feed is typically no larger than two inches. Also, because of the aggressive abrasive nature of the bed, it can handle agglomerative materials that would challenge other systems. Further, fuel streams of various moisture and ash content can be handled, and the potential to add auxiliary fuel permits the combustion of materials that have may be problematic for combustion by themselves. This flexibility allows the plant to take advantage of biomass fuels that may become available throughout the year, or that may be available, for whatever reason, sporadically. Because of the large thermal mass of the bed, the bed is resistant to upset. In addition, to address potentially problematic constituents, such as sulfur, of biomass feed streams, chemicals (typically limestone or dolomite) can be added to the bed to allow control of the constituents.

Other advantages of the BFB are efficient combustion and lower emissions. The turbulent nature and scouring effect of the bed provide for complete and uniform combustion. In addition, the relatively low combustion temperature helps reduce the formation of certain emissions such as NO_x.

A substantial advantage of the fluidized bed combustion system relative to this project is that much of the motive power for the system is electrical. This includes the air blowers, the feed pumps, and much of the emission control system. However, this advantage may be a disadvantage if the plant wishes to maximize the sale of electricity to the grid.

The bubbling fluidized bed combustion system has several disadvantages. The capital cost is higher than a conventional steam generator burning natural gas or a conventional system burning coal. Operation and maintenance (O&M) costs are higher than for a conventional natural gas fired system, and may be higher than a conventional coal fired system. The very flexibility of the bed to combust a variety of materials, and the associated “feed anything” tendency, can be problematic, requiring great care to be taken in the variety, rate, heat content, and chemical characteristics of the material fed.

One of the partner ethanol plant for this project, Corn Plus in Winnebago, Minnesota, has operated a bubbling fluidized bed combustion system since 2005, using syrup as a fuel. Results have reportedly been good. System refinements continue to be made.

In the CFB combustion system, the inert bed material and fuel are kept in motion by combustion air and feed material moving the mass around a closed circuit. A high-temperature separation device (usually a cyclone collector) is integral with the combustion vessel. Most solids are removed by the separation device and returned to the circulating bed, while the partially cleaned combustion gasses are sent for steam generation and, potentially, further heat recovery. The advantages and disadvantages of the circulating fluidized bed are similar to those of the bubbling fluidized bed, but the cost of the circulating fluidized bed may be lower, and the potential for fouling by agglomerative materials is even lower. As with the BFB, the CFB can be designed to operate in pressurized mode, making use of a turbine for electricity generation feasible, and improving overall system efficiency.

Fluidized bed gasification. While fluidized bed combustion is operated with excess air at all times, the fluidized bed gasification system operates with both a combustion zone operating with sufficient air and an air-starved gasification zone. The system mechanics are similar to fluidized bed combustion. The large thermal mass of the inert bed material results in rapid dehydration of the feed material and liberation of volatiles, leaving a fixed carbon char for combustion to generate low Btu fuel gas. Sufficient air (oxygen) is allowed into the combustion zone to completely combust the char and so to provide sufficient heat to drive the gasification reaction, while the gasification region is oxygen starved in order to promote the generation of combustible gasses. The fuel gasses are cleaned, with specific systems depending on the design of the overall system, and are then combusted. If combustion is in a conventional steam boiler, little if any cleaning may be needed, since any necessary flue gas cleaning can occur after combustion. If combustion is to be in a combustion turbine, complete removal of particulates will be needed prior to introduction into the turbine.

The advantages and disadvantages of the fluidized bed gasification system mirror those of the fluidized bed combustion system, with additional advantages for gasification. There are three significant additional advantages of the fluidized bed gasification system, however. First, gasification produces a gaseous energy source that can be used, with little equipment modification, in the existing plant systems currently using natural gas. Changing these components to use steam could be quite costly, including potential protracted plant outage for the changeover. Second, temperatures needed for gasification are lower than for fluidized bed combustion systems, reducing the generation of NOx. Third, the fuel gas can be readily used in a combustion turbine for generating electricity, followed by a HRSG to generate steam. Especially if run in pressurized mode, gasification can have high system efficiency.

Gasification has the ability to process a wide variety of biomass fuels, and can be easily supplemented with fossil fuels. It can handle agglomerative materials that would challenge some other systems, although the fluidized bed gasification system is more sensitive to these types of materials than the fluidized bed combustion system. Fuel streams of various moisture content can be handled, although higher moisture feeds reduce system output and efficiency and can be problematic depending on the end use of the gas. This flexibility allows the ethanol plant to take advantage of biomass fuels that may become available throughout the year, or that may be available, for whatever reason, sporadically. Ash is continuously removed from the bed, and the ash is finely pulverized. The large thermal mass of the bed makes it resistant to upset, although not as resistant as the fluidized bed combustion system. The lower temperature of the gasification system vs. the combustion system lessens the generation of problematic emissions, although this characteristic can be a disadvantage for those constituents, such as sulfur, that can be effectively controlled through addition of simple chemicals to the combustion system.

The fluidized bed gasification system has several disadvantages. The capital cost is higher than a conventional steam generator burning natural gas or a conventional system burning coal. Operation and maintenance (O&M) costs are higher than for a conventional natural gas fired system, and may be higher than a conventional coal fired system. The very flexibility of the bed to handle a variety of materials, and the associated "feed anything" tendency, can be problematic, requiring great care to be taken in the variety, rate, heat content, and chemical characteristics of the material fed.

Liquid injection. Liquid injection into conventional boiler systems of all sizes is a long established technology. The most common liquid injected is some type of petroleum-based fuel oil, ranging from the light home heating oil to the very viscous #6, or Bunker C, residual oils. The paper industry has long burned “black liquor” (typically 60% to 80 % solids by weight), a residual from certain types of wood pulp manufacture, to generate electricity and process steam for the mills. Other non-petroleum fuel liquids that have been used include tar sands, oil shale, and other coal-derived fuels.

Details of the injection vary, depending on the feed material and the type of boiler. For light oils, adequate dispersion into the combustion zone can be achieved by simple pumping through a nozzle at moderate pressure. Somewhat heavier feeds require higher pressures and different nozzles. Feeds that are still heavier require augmentation to achieve adequate dispersion. The augmentation may be accomplished by heating the feed material, and by using special nozzles supplemented with compressed air, steam, or mechanical devices.

For purposes of this project, the term “liquid” will be used for the syrup that is a coproduct of the fuel ethanol production process. The characteristics of the syrup are expected to vary among ethanol plants and, to a lesser extent, within the same ethanol plant over time. The variability of the syrup among the five project partner ethanol plants, along with a review of literature data for syrup from other ethanol plants, will be used for the technical analyses of this project.

Syrup combustion through liquid injection is conceptually a potentially attractive option for ethanol plants because it may be feasible to use existing steam generation equipment with some modifications, rather than replacing existing steam generation equipment with new, and probably costlier, equipment. Even if new steam generation equipment is needed, it may have lower capital and operating cost than fluidized bed approaches. Feed systems may require lower energy input. From a plant reliability standpoint, it may be feasible to have multiple steam generators of a relatively simple nature rather than a single large steam generator using fluidized bed technology.

There are several disadvantages to using liquid injection. Feeding of syrup through pressure nozzles might lead to additional maintenance for the storage, feed system, and nozzles. Syrup contains complex carbon compounds that would not be expected to burn as cleanly as natural gas. Particulates would be generated, some of which might cause fouling of the combustion or steam system. The relatively high levels of alkaline metals in the syrup may cause problems with slagging and ash fusion. A steam generator designed for natural gas may not be able to handle such particulates and ash. The sulfur content of the syrup might pose an emission problem, and, unlike a fluidized bed, adding chemicals to sequester the sulfur may be much more difficult, or even be unfeasible, for conventional systems. System modifications to allow combustion of syrup might not allow combustion of conventional solids, so that the potential for burning of other biomass, including DWG, DDG, or DDGS might be compromised.

Liquid injection with pulverized solids. Liquid injection of pulverized solids is a well established technology, although such solids are usually of low moisture content. This option would allow both syrup and a variety of biomass materials to be burned using essentially conventional technology. The biomass solids would be reduced in size to the consistency necessary for injection through a nozzle, and could be mixed with syrup or with other liquid or gaseous fuel for injection into a conventional steam generator. Material preparation systems could be minimized if the feed was limited to syrup, DWG, DDG, and DDGS.

Problems associated with burning such mixtures are similar to those described above for syrup, but may be exacerbated in this approach unless the combustion system was specifically designed to deal with them. Whether such a specifically designed system would be cost-competitive with the fluidized bed options will be evaluated later in this project.

Specific Evaluation of the Combustion Options Relative to the Analytical Results

While on cursory review it may appear that combustion of syrup alone is likely best accomplished through liquid injection methods due to potentially lower capital costs for equipment and lesser fuel processing needs, a detailed review of the chemical data indicates that certain of the chemical constituents, especially sodium, potassium, organic macromolecules, and water content may adversely affect such systems. The elevated sodium and potassium content as compared with conventional fossil fuels may create slagging and ash fusion problems in the high temperature environment of a standard combustion unit. The relatively short detention time and modest turbulence in the combustion zone of a standard combustion unit may be insufficient for complete combustion of some of the organic macromolecules, resulting in a loss of energy content, production of additional particulates in the emissions, and fouling of equipment downstream of the combustion chamber. The high water content of the syrup may cause flame instability in conventional units, resulting in both operational and safety concerns. Supplemental fuel may be needed to maintain adequate flame stability. For these and other reasons, a fluidized bed is more suitable for combustion of the syrup, and is also amenable to gasification of the syrup.

DWG, DDG, DDGS, and corn stover have similar chemical characteristics to syrup, and DWG has similar water content, so the combustion considerations discussed for syrup also apply to DWG, DDG, DDGS, and corn stover. Given the physical handling challenges of the solid particles in the DWG, DDG, and DDGS, combustion of these feed materials will likely be best accomplished using fluidized bed methods. Fluidized beds also offer the potential for gasification. Corn stover offers particular challenges for conventional systems because of its low density, high alkaline metal content, and variable water content, and because of the potential presence of foreign material (including soil and rocks).

Taking all the chemical data, physical data, and combustion-related data into consideration for the feed streams evaluated in this project, fluidized bed combustion or gasification appear to be preferred over liquid injection or liquid injection with pulverized solids. However, updraft, fixed bed gasification appears to have application for biomass fuels like DDGS and corn stover, so we will further evaluate this alternative.

- **Fuel Processing preliminary results**

The optimal biomass fuel condition and characteristics must be matched with the storage requirements, in-plant transportation and handling requirements, and the selected biomass combustion technology for the individual fuel ethanol plant. An alteration of particle size, viscosity, moisture content, and mixing with materials such as corn stover may affect equipment selection, operating conditions, potential emissions, energy efficiency, and maintenance costs.

The effects of weather must be taken into account when reviewing complete feed systems. In warm weather, biological degradation will be more rapid, especially for the coproducts with higher moisture content. In sub-freezing weather, management of the coproducts with higher moisture content poses additional challenges.

A description of the physical constraints and/or requirements to accommodate the particular biomass fuel component, and an evaluation of applicable capital and operating costs, are presented below, for each combustion option. Results of the laboratory testing of the feed streams have been used to provide input to these evaluations.

<u>Fuel Processing Options for Syrup</u>: Syrup is produced on an ongoing basis by virtually all dry grind fuel ethanol plants. The syrup is produced at an essentially constant rate by any given ethanol plant, and the composition of the syrup is very consistent for that plant. The syrup is stored until it can be processed, usually by adding it to DWG and either selling the mixture in the wet state as DWGS, or after drying to DDGS. Some syrup is sold as-is for mixing with cattle feed at the user's site, but high transportation cost and short shelf life limit this option to particular situations.

A few plants manage the syrup in other ways, such as separately drying some of it to form a high protein animal feed. A few plants process the syrup to separate high-value components, but such processing has little effect on the overall fuel characteristics of the syrup. Some plants are beginning to fractionate the corn to remove germ and fiber prior to fermentation, and this is expected to affect the fuel characteristics of the resulting syrup. None of the partner ethanol plants for this project are yet performing such fractionation, so data are not available to compare the syrup with and without prior fractionation. Also, fractionation is projected to be costly, and so may not be widely retrofitted to the smaller, older ethanol plants that comprise the largest number of operating facilities at the time of this project.

Because of the high moisture content of the syrup, as much of the syrup as possible is sold without drying. Some ethanol plants have considerable storage capacity for syrup to allow scheduling with DWG shipments, or for direct sale, and so to avoid the costs of drying.

Because DWG and DWGS has a short shelf life, does not stack well, requires a large area for storage, may create odors, and is a housekeeping challenge, ethanol plants ship the DWG and DWGS out as soon as possible, especially in warm weather. Financially, both the DWG and the syrup represent inventory carrying costs to an ethanol plant, so the ethanol plant again wants to sell the coproducts as soon as possible.

Ethanol plants handle the syrup by pumping, and are familiar with maintaining the mechanical systems for syrup management. Systems for feeding the syrup to combustion units will be essentially the same as are currently used for syrup management.

For all combustion options, no additional substantive processing will be needed for the syrup. At all times, the syrup is used as fast as possible after production, although a week's or more storage capacity may be present to allow the most cost-effective processing for shipment out of the plant. For most plants, therefore, no additional syrup storage capacity would be needed. The particulate matter in the syrup is very fine, with negligible settling over the time period that the syrup is stored. This fine particulate is not expected to interfere with any fuel feeding mechanism. The syrup as produced is hot, and is stored in insulated tanks. Considering the short time anticipated for the syrup to be stored prior to burning, excessive cooling should not be a problem. Indeed, the sooner the syrup can be burned, the more of the syrup's heat will be recovered.

Depending on the ethanol plant's physical layout, a day tank may be installed for syrup fuel feed. The syrup would go directly from production to the day tank to the combustion unit in the shortest possible time, so conserving heat. Only excess syrup would go to the main syrup storage.

Fuel Processing Options for DWG: The evaluation applied to syrup is equally valid for DWG (with or without the additional of syrup). The material has a short shelf life, does not stack well, requires a large area for storage, may create odors, and is a housekeeping challenge. Ethanol plants ship the DWG out as soon as possible, especially in warm weather. Financially, the DWG represents inventory carrying costs to an ethanol plant, so the ethanol plant again wants to sell the DWG as soon as possible.

Unlike syrup, the DWG are not stored in a vessel, but on a concrete slab, under cover in a large unheated shed or building. Storage capacity is usually quite limited, since the DWG is not suitable for long-term storage and since the ethanol plant ships the DWG out as soon as possible. A front-end loader is usually used to move and load the DWG onto trucks. If DWG is to be used as fuel, a system to collect, store, mix, and meter the material to the combustion device will be needed. Unless all the DWG is to be used as fuel, the system needs to accommodate both fuel feed and outside sale as animal feed.

The physical characteristics of DWG are not substantially dissimilar from other materials that are routinely handled in industry. These materials range from food products to concrete to sewage sludge. The primary systems for managing the DWG as fuel are applicable to all of the selected combustion technologies capable of burning DWG. Depending on the configuration of the particular ethanol plant, the DWG leaving the centrifuge is either split between a feed tank for the combustion system and a DWG storage area on a slab (the most efficient configuration) or only to a storage area on a slab, from where the DWG is moved to the combustion system by a front-end loader or by a separate conveyer.

From the storage tank at the combustion system, the feed into the combustion unit depends on the specifics of the unit. For the fluidized bed systems (both combustion and gasification), no further DWG processing is needed. For the liquid injection with pulverized solids, the DWG solids may be subjected to size reduction sufficient to allow improved injection through a nozzle. The most likely method to achieve the size reduction is mechanical shearing, although pressure shearing (such as through an orifice or constricted throat) or acoustic shearing may be feasible. The method of size reduction may vary depending on whether the syrup is added to the DWG prior to shearing or after shearing. Each of the major potential size reduction methods is described below, along with the advantages and disadvantages of each, and cost estimates for each, assuming the DWG from a 40 million gallon per year ethanol plant.

Shredders and grinders achieve size reduction by direct mechanical shearing of feed material. The shearing may be accomplished with asynchronous roller stacks, hammers, blades, various arrangements of toothed wheels, cage disintegrators, asynchronous disk mills, cone mills, and similar devices. Shredders and grinders are widely used for many materials and applications, from the common household food grinder mounted under the kitchen sink to giant units shredding automobiles. The corn grinders in ethanol plants are another example. Items can be shredded in the dry or wet state; in liquids, high shear mixers may be used.

These types of devices are well established, rugged, reliable, and well understood. Energy consumption depends on the materials and throughput, and on the degree of size reduction desired. Disadvantages include limited application for agglomerative or sticky materials, potentially high energy consumption, mechanical wear, and maintenance safety.

Pressure shearing achieves size reduction by subjecting the feed material to a large, rapid pressure change, typically through some type of nozzle or orifice. The feed material itself may be directly subjected to high pressure, such as through a pump, or may be introduced into another high pressure stream, such as steam, air, or water. The rapid pressure reduction upon leaving the constriction device results in reduction of the particle size of the feed material. The degree of size reduction depends on the materials, type of constriction device, and pressure drop.

Advantages of pressure shearing include small size, the ability to easily vary the degree of size reduction achieved, mechanical simplicity, and the potential to use steam as the energy source. Disadvantages include noise, limited application to abrasive material, limited application to agglomerative or stick material, and clogging.

Fuel Processing Options for DDG and DDGS: The handling characteristics of DDG and DDGS, for the purposes of in-plant use as fuel, can be regarded as the same. The syrup content of DDGS may add a certain tendency for agglomeration upon longer term or higher volume storage, but such storage is not anticipated for in-plant use as fuel.

Like DWG, the DDG and DDGS are typically transported by conveyer from the drier to a concrete slab in a large covered building. A front-end loader then moves the material directly onto trucks or into conveyers and elevators for eventual loading into trucks or rail cars. Some interim storage in tanks may be provided.

Systems for in-plant transfer of the DDG and DDGS can be readily adapted for DWG. With DDG and DDGS, pneumatic transport may also be feasible; however, since pneumatic transport is not practical for DWG, the system constructed at an ethanol plant will likely be one that can transport DWG, DDG, and DDGS.

As with DWG, no additional processing is needed to feed DDG or DDGS into the fluidized bed systems. Also as with DWG, size reduction may be desired prior to using injection with pulverized solids.

- **Combustion tests preliminary results**

As originally proposed, the project would include conducting various combustion tests on selected coproduct streams and combinations. Developments in the industry since then allow a more comprehensive approach that will have wider applicability to more ethanol plants and more biomass streams. This comprehensive approach uses computational fluid dynamics to model the combustion, based on combustion and furnace parameters and on the analytical data generated from the samples collected at the partner ethanol plants in this project. Using this approach, a variety of fuels, including biomass and natural gas, can be modeled. Further, the models can be used to estimate both air emissions and ash characteristics from the various fuel combinations. The methodology is applicable to both existing and new facilities.

Chemistry of Combustion

The chemistry of the combustion depends primarily on the combustion temperature, retention time, and the presence of sufficient oxygen, and will not be significantly different because of the method of combustion. (Turbulence and other parameters affect the rate of combustion and the physical characteristics of the ash, but not the ultimate combustion chemistry, assuming complete combustion. All combustion systems considered in this project will promote complete combustion.) Thus, the chemical characteristics of the combustion process and of the emissions and ash can be determined from the chemical analyses of the feed materials and the residue (ash) remaining after combustion in a laboratory furnace. A mass balance can be calculated for each chemical constituent, as can the proportion of each chemical constituent appearing in the ash and the emissions. The modeling allows estimation of the changes in these proportions based on changes in the feed streams and the combustion parameters.

Ash and Emissions

As described above, an advantage of the modeling approach is that, for any modeled combustion or gasification system, it can be used to estimate the composition and volume of the ash and emissions from any given feed stream or combination of feed streams. This saves time and cost over separate laboratory tests, and is applicable to many plants and many feed streams. Ash and emissions are discussed in detail in the applicable sections of this report

Results of the Modeling

Major components of the software for the models were developed by RMT prior to this project, and are proprietary, but the results of the modeling are part of the output of this project. Key components of the models have been extensively tested and calibrated against actual operating systems in other industries. The opportunity for direct calibration for the ethanol industry presents itself for the bubbling fluidized bed option because of the operating fluidized bed combustion unit at partner ethanol plant Corn Plus.

Fluidized bed combustion: As discussed in the "Combustion Options" section of this report, fluidized bed combustion is a well established technology that has been used in a variety of industries since approximately WWII, although its use in the dry grind fuel ethanol industry began only recently. As described previously, there are two basic types of fluidized bed combustion systems: bubbling fluidized bed and circulating fluidized bed. For the purposes of the combustion modeling for this project, the combustion characteristics of the two types can be regarded as similar. Both types will be operated so that complete combustion will be achieved on a system-wide basis, and the abrasive effects on the feed streams and the ash are expected to be similar. Factors unique to each type of system will be taken into account in the technical evaluation and economic analysis of complete systems, in a separate chapter of this report.

The combination of the detailed chemical, physical, and combustion-related analyses performed in the feed stream analysis portion of this project with the detailed modeling developed as part of this project eliminates the need for combustion testing for fluidized bed combustion.

Fluidized bed gasification. As discussed in the "Combustion Options" section of this report, fluidized bed combustion is operated in aerobic mode at all times, while the fluidized bed gasification system operates with both aerobic and oxygen-starved regions. Sufficient oxygen is allowed into the combustion region to provide for complete combustion of fixed carbon, and so to produce temperatures in the vessel high enough to drive the gasification reaction, while the gasification region is oxygen starved in order to promote the generation of combustible gasses. In modeling such a system, both the aerobic and oxygen-starved regions must be addressed.

The combination of the detailed chemical, physical, and combustion-related analyses performed in the feed stream analysis portion of this project with the detailed modeling developed as part of this project eliminates the need for combustion testing for fluidized bed combustion.

Liquid injection. Liquid injection is one of the most widely used combustion techniques, although its modeling is among the most complex. There are many applicable parameters, and many variations for each major system component. Operationally, pumping pressures and rates, orifice sizes, injection points, air feed rate and position, temperature of feed air, and many other factors must be taken into account. Variations in feed material and characteristics will require adjustment of many of these operational parameters in order to maintain optimal combustion, or even to maintain combustion at all.

As shown in the "Feed Stream Analyses" section, the characteristics of the syrup vary somewhat among ethanol plants. While this variation is readily handled by fluidized beds, liquid injection systems are more sensitive to short-term variation, and require more real-time system adjustments to avoid problems. While syrup combustion through liquid injection may be a potential option for ethanol plants, the initial analysis performed for this report indicates that there may be several major operational challenges to doing so; indeed, it may be unfeasible from a practical standpoint to use existing steam generation equipment, even with some modifications, for syrup combustion by liquid injection. Such combustion may be feasible by replacing existing steam generation equipment with new, specially designed equipment, and by incorporating auxiliary fuel feed to compensate for the high moisture content of the syrup, and the resulting flame instability.

Sufficient conclusions can be developed by a combination of data developed in this project, literature data, and experience with liquid injection systems in conventional combustion units so that combustion tests will not be needed for this element of this project. General technical and economic analysis will be performed in evaluating entire systems.

Liquid injection with pulverized solids. Combustion test modeling for injection of pulverized solids along with syrup is similar to that for liquid injection of syrup because the feed stream containing pulverized solids has been modified to approximate the feed stream comprising only syrup. Thus, the primary difference is in the composition of the feed stream. The feed stream contains a higher percentage of solids, and so has a greater potential for fouling of systems not designed to deal with such material. Modeling shows that it is unlikely that a conventional steam generator designed for natural gas could handle the feed mixture including pulverized DWG, DDG, or DDGS. Some thermal oxidizers designed to handle the emissions from the DDG or DDGS drier may be able to handle the pulverized DDG or DDGS feed, but control of the SO_2 originating in the sulfur in the solid feed materials is anticipated to be a major technical concern. Detailed study, beyond the scope of this project, is needed to resolve these issues.

- **Emissions tests preliminary results**

As originally proposed, the project would include conducting emissions tests during laboratory combustion tests on selected coproduct streams and combinations. Developments in the industry since then allow a more flexible and comprehensive approach to predicting emissions, as well as to combustion and ash characterization, through computer modeling. Such models will have wider applicability to more ethanol plants and more biomass streams. The modeling approach uses computational fluid dynamics to model the combustion, the emissions, and the ash characteristics, based on established technical parameters and on the analytical data generated from the samples collected at the partner ethanol plants in this project. Using this approach, a variety of fuels, including biomass and fossil fuels, can be accommodated. The methodology is applicable to both existing and new facilities.

Chemistry of Emissions

The chemistry of the emissions from the combustion process can be directly correlated with the chemistry of the raw materials and of the combustion process. This was described in the "Combustion Tests" section of this report. All combustion systems considered in this project will promote complete combustion in the system as a whole. Thus, the chemical characteristics of the emissions from the combustion process can be determined from the chemical analyses of the feed materials and the residue (ash) remaining after combustion in a laboratory furnace. In a plant combustion system, the ash may appear in the bed (as with a fluidized bed system) or in the raw emissions. For example, sulfur and metals in the feed material that do not appear in the ash will appear in the emissions in the form of oxides. Inclusion of emission control system performance data will allow calculation of remaining emissions into the air. A mass balance can be calculated for each chemical constituent, as can the proportion of each chemical constituent appearing in the ash and the emissions. The modeling allows estimation of the changes in these proportions based on changes in the feed streams and the combustion parameters.

A somewhat different approach is used for nitrogen. Nitrogen is present not only in the feed materials (especially in amino acids), but also in the combustion air. Nitrogen in the combustion air may be thermally converted to nitrogen oxides, depending on the temperature, detention time, and other factors. This conversion is quite well understood, and can be included in the system modeling. The model can be verified and calibrated using data from operating systems.

Combustion of complex mixtures of organics, such as those in the fuel ethanol plant coproducts, can result in the creation of condensation products in the flue gas phase, even in the stack itself, if the combustion temperature, residence time, oxygen levels, and other factors are not carefully controlled. This has been particularly noticeable in relatively low temperature, high moisture applications such as DWG dryers. The combustion modeling approach being developed by RMT will help ensure minimization of the creation of flue gas condensation products, despite anticipated high moisture levels in some feed streams.

Mass of Emissions

As described above, an advantage of the modeling approach is that it can be used to estimate the composition and volume of the ash and emissions from any given feed stream or combination of feed streams. This saves time and cost over separate laboratory tests, and is applicable to many plants and many feed streams. Ash and emissions are discussed in further detail in the applicable sections of this report.

The mass of emissions of refractory materials, such as most metals, can be calculated from the mass of that material in the feed stream, the mass of that material in the ash, and the collection efficiency of the emission control devices. The mass of emissions of non-refractory materials, such as sulfur, carbon. and nitrogen can be calculated based on the feed materials, the combustion conditions, and any emission.

- **Power purchase agreement results**

Electrical Revenue, Rules and Tariffs
The Minnesota Electric Rate Book –MPUC No. 2, contains a section entitled "Technical and Special Terms for Cogeneration and Small Power Production," that identifies a number of rules and definitions needed to determine revenue for co-generation facilities such as an ethanol plant using biomass to generate electricity that can be sold on the grid. Here are two key regulatory definitions for qualified facilities (QF):

Firm Power	Firm power is energy delivered by a QF to the utility with at least 65% on peak capacity factor in the billing period. The capacity factor is based upon a QF's maximum on-peak metered capacity delivered to the utility during the billing period.
On-Peak Period	The on-peak period contains all hours between 9:00 am and 9:00 p.m. Monday through Friday, except the following Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday.

In 2003, capacity payments of $.01 per kWh for Firm Power were offered for on-peak power during the key June-September period by Northern States Power Company (NSP) in Minnesota.[1] In 2005 the published rates per kilowatt hour and for capacity were $.0620 and $.0367, respectively. [2] It must be emphasized that this tariff represents an annual offering, so it would be difficult for a power producer to project earnings at this level for the life of the investment. In fact, discussion with an Xcel employee[3] in 2005 revealed that no QF's were currently receiving such a package of payments. Effective for 2006, Xcel Energy published the following tariff available to the same class of QF's[4]:

Payment Schedule for Energy Delivered to Company	Oct.-May	June-Sept.
On Peak Energy Payment per kWh	$.0584	$.0818
Off Peak Energy Payment per kWh	$.0321	$.0338
Capacity Payment for Firm Power per On Peak kWh	$.0083	$.0432

Based on the tariffs above, attractive rates of $.125 per kWh will be paid for On Peak Firm Power during June-September for a QF, with Off Peak Payments of $.0338 per kWh. This pricing structure shows the importance placed on dependable power from co-generation facilities during the summer months. In contrast, the utility is willing to pay $.0647 per kWh for On Peak

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[1] Northern States Power Company, Minnesota Electric Rate Book-MPUC No.2, Section 9, 5th Revised Sheet No. 3, filed 12/31/02 by Ken T. Larson., with an effective date of 1/01/03.

[2] Xcel Energy Tariff Document, Time of Day Purchase Service, Section No. 9, Rate Code A52 , 7th Revised Sheet No. 4, filed on January 3, 2005.

[3] John Chow, Xcel Energy, phone conversation, August 4, 2005.

[4] Northern States Power Company, Minnesota Electric Rate Book-MPUC No. 2, Section 9, 8th Revised Sheet No. 4, filed on January 3, 2006.

Firm Power during the October through May period and just $.0321 per kWh for Off Peak power during those months.

These appear to be very attractive rates, but one must remember that co-generation situations, while encouraged by PURPA, are not the primary purpose for the investment in that power generation capacity which happens to be available to serve the motives of some other business enterprise.

There are additional advantages for ethanol plants to have electrical power generation capacity on-site. Power outages are very costly when interruptions occur, especially in batch processing. Several plant managers [5] [6] noted the problems encountered and the waste associated with these untimely events. Terry Nixon of Central Minnesota Ethanol expressed satisfaction that sufficient power would be generated on-site to keep critical plant functions progressing in the event of an electrical power outage.

Federal Production Tax Credit

A business tax credit of 1.9 cents per kWh is available for biomass projects that are installed by December 31, 2007 for ten years. IRS tax form 8835 is used to determine elgibility and to claim this credit, which is offered at the same rate as the Production Tax Credit for wind. [7] This credit, if available to the business producing the power, would provide very favorable project economics in many cases. In addition, federal tax law permits the use of five-year depreciation for biomass or biogass equipment, which is another favorable incentive if it can be used.

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[5] Kramer, Gary. General Manager of Badger State Ethanol, Personal Interview January 27, 2006.

[6] Nixon, Kerry. General Manager of Central Minnesota Ethanol, Personal Interview May 8, 2006.

[7] Minnesota Department of Commerce. "Renewable and Efficiency Incentives" Website: http://www.state.mn.us/portal/mn/jsp/content.do?id=-536881350&subchannel=-536881511&contentid=536885915&contenttype=EDITORIAL&programid=536885394&sp2=y&agency=Commerce#Biomass . Viewed May 8, 2006.

- **Spreadsheet architecture results**

Testing of biomass sources as potential fuels for ethanol plants has occurred and is continuing on the project to determine likely methods of combustion as well as the likely costs of capital equipment and operating expenses of appropriately sized equipment. A key consideration is that of determining if a biomass system can comply with prevailing standards of emissions. Because most dry-grind ethanol plants are fuelled with natural gas, which is a very clean-burning fuel, it is easy to predict emissions from a plant using that fuel. Similarly, a vast amount of experience is available on proper methods to combust coal in order to capture operating efficiencies and also comply with emissions standards.

In order to compare the economics of plants using by-products such as DDGS, syrup, and cornstover as fuels versus conventional, natural gas-powered plants, spreadsheets have been designed. Starting from spreadsheets designed to analyze the profitability of dry-grind plants using natural gas, a template has been prepared that also captures some of the unique elements of systems using biomass fuels. This will allow fair comparisons of various alternatives to power the plants and reflect the three principal options:

1) provide process heat for the plant's use
2) provide process heat and electricity for the plant's use
3) provide process heat and electricity for plant use and electricity to sell to grid

Other criteria for the spreadsheets' designs include the ability to change various cost categories to represent the various biomass fuels. Depending upon the fuel being considered, it is likely that there will be additional capital costs for the equipment to burn the biomass. Few systems can be as cheap as natural gas in terms of natural gas.

Capital Costs

Depending upon the fuel and combustion system chosen, we shall search for appropriate capital costs. With biomass fuels there are likely to be additional capital costs for the following:

1) stover harvest equipment and trucks to bring in the biomass
2) storage structures for biomass
3) feed mechanisms for the biomass
4) the combustion unit, itself
5) emissions control equipment
6) ash storage costs
7) etc.

Operating Costs—the Fuel

One operating cost is the cost of biomass fuel, itself. We are preparing to analyze the total cost of using various biomass fuels, and in some cases that may include the need to purchase the biomass from others. In other instances, the biomass is produced concurrently with other production at the plant, so the transaction is really internal to the ethanol plant. An example in this regard is the combustion of DDGS to provide process heat. If DDGS is combusted by a plant, then the plant has less revenue from the sale of DDGS and hopefully, lower natural gas costs. A plant combusting syrup made from concentrated wet stillage is reducing the dry-matter mass it has to sell in DDGS, but it is also reducing the amount of natural gas needed to dry the DDGS under conventional processing. A plant using cornstover must purchase this material from local farmers and be competitive versus farmers' valuation of the cornstover as a nutrient source and groundcover. An ethanol plant would probably need to establish contracts to ensure that it has adequate supplies available from nearby farms. Depending upon whether or not the ethanol plant would become directly involved in stover harvest and storage, there may be more or less operating expenses.

Operating Costs Associated with Combustion Technology Used

Once a fuel and combustion technology combination have been chosen, then it is possible to estimate the additional expenses associated with that system. **We certainly don't know the answers to all these questions at this time. And we don't know all the questions, but here are some important ones that we look for in each technology-feedstock combination:**

1) How many additional workers will be needed?
2) Will there be greater needs for electricity to grind, agitate, dry or in some other way pre-process the fuel so that it will perform consistently?
3) What will be the requirements for media such as sand for a fluidized bed?
4) Will chemicals or minerals such as ground limestone be needed to capture sulfur?
5) Will the additional capital equipment require substantially more repairs?
6) Will more testing of batches of biomass fuel be needed before use?
7) Will more periodic testing be needed of emissions levels?
8) What operating costs will be associated with disposal of ash materials?
9) Will there be landfill charges?
10) Will the ash from biomass have value as a nutrient source on farm fields?

Spreadsheet for Dry-Grind Plant Using Natural Gas

On the following page one can see a spreadsheet that can be used to calculate profits for a conventional dry-grind ethanol plants under a variety of operating conditions. Cells that are masked in yellow and pink in **Column C** can be changed in order to model the conditions for various ethanol plants and various situations. For example, it is possible to see the impact of higher ethanol prices , DDGS prices, CO2 prices and Minnesota Producer Payments on annual revenues for the plant. The spreadsheet allows one to readily calculate the **Gross Margin** between the products sold and the cost of corn purchased for processing.

Similar detail is allowed with respect to **Operating Expenses**, where natural gas is the major expense item. It is possible to specify the price of natural gas as well as the BTU's of heat needed by the plant as well as the kiloWatthours and the cost per kWh purchased.

As far as results, this spreadsheet shows the ethanol plant profits for the established levels of **corn cost**, **ethanol price**, **DDGS price**, **natural gas cost**, and the lesser factors. The number of bushels of corn ground in a year and the number of denatured gallons are summarized. A high degree of volatility in plant returns can occur because of the volatility of the four key factors. Profits can change drastically based on changes in any of the four, but especially ethanol price, corn price, and natural gas price.

1	B	C	D	E	F	G	H	I
2	**Conventional Ethanol Dry Mill**		**by Douglas G. Tiffany,**		**University of Minnesota**			
3	**5/21/2006 19:30**	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**					**Plant Totals**
4	**Nameplate Ethanol Prod. (Denat. Gal.)**	**40,000,000**						
5	**Investment per Nameplate Gallon**	**$1.5000**	$1.00- $2.00				**Plant Cost**	**$ 60,000,000**
6	**Factor of Nameplate Capacity**	**1.2000**	(80%- 150%)					
7	**Debt-Equity Assumptions**							
8	Factor of Equity	**0.40**						
9	Factor of Debt	**0.60**					**Initial Debt**	**$ 36,000,000**
10	Interest Rate Charged on Debt	**0.07**						
11	Rate of Return Reqd. by Investors on Equity	**0.12**						
12								
13	**Conversion Efficiency Assumptions**				**Annual Production**			
14	Anhydrous Ethanol Extracted (Gal. per Bu.)	**2.75**	2.5-2.85 gal/bu		**Bushels Ground**		**Denat. Gallons**	
15	DDGS per Bushel (lb. per Bu.)	**17.5**	15-22 lb./bu		**17,118,881**		**48,000,000**	
16	CO2 extracted per Bushel (lb. per Bu.)	**17.5**	15-22 lb./bu					
17								
18	**Establishment of Gross Margin**	**Price per Unit**			**Revenue/Bu. Ground**		**Revenue/Gal. Denatured Sold**	**Plant Totals**
19	Ethanol Price (denatured price) $/gal.	**$2.00**	$.80 to $1.60		$5.6078		2.0000	$ 96,000,000
20	DDGS Price $/T	**$75.00**	$60-$120		$0.6563		0.2340	$ 11,234,266
21	CO2 Price ($ per Ton liq. CO2)	**$8.00**	$2- $12 / liq.Ton		$0.0700		0.0250	$ 1,198,322
22	MN Prod. Subsidy/gal.Denat. Ethanol	**$0.00**			$0.0000		0.0000	$ -
23	Federal Small Producer Subsidy							$ -
24	CCC Bioenergy Credit							$ -
25	Revenue per Unit				$6.3341		$2.2590	**$ 108,432,587**
26	Corn Price Paid by Processor ($ per bu.)	**$2.00**	$1.70---$3.25		$2.0000		$0.7133	**$ 34,237,762**
27	Gross Margin				**$4.3341**		**$1.5457**	**$ 74,194,825**
28								
29	**Operating Expenses Per Bushel**	**Price per Unit**			**Cost /Bushel Ground**		**Cost /Gal. Denatured Sold**	**Plant Totals**
30	Natural Gas Price ($ 1,000,000 Btu)	**$8.00**	($1.50-$9.00/Dtherm)					
31	LP (Propane) Price ($ per gallon)	**$1.10**	$.55-$.72 / gal.					
32	Factor of Time Operating on Propane	**0.02**	0-.12					
33	BTU's of Heat fr Fuel Req./ Denat. Gal.	**35,000**	28,500-55,000					
34	Combined Heating Cost				$0.7930		$0.2828	$ 13,574,693
35	Electricity Price ($ per kWh)	**$0.06**	$.025-$.090/kwh					
36	Kilowatt Hours Required per Denat.Gal.	**1.090**	(.85-1.2 kWh/denat. gal.)					
37	Electrical Cost				$0.1834		$0.0654	$ 3,139,200
38	Total BTU's of Fuel and Electricity	45,900						
39	**Total Energy Cost**				**$0.9763**		**$0.3482**	**$ 16,713,893**
40		**Cost/Denat. Gal. Ethanol**						
41	Enzymes	**$0.0480**			$0.1346		$0.0480	$ 2,304,000
42	Yeasts	**$0.0220**			$0.0617		$0.0220	$ 1,056,000
43	Other Proc.Chemicals & Antibiotics	**$0.0200**			$0.0561		$0.0200	$ 960,000
44	Boiler & Cooling Tower Chemicals	**$0.0050**			$0.0140		$0.0050	$ 240,000
45	Water	**$0.0060**	$.005-.010		$0.0165		$0.0060	$ 282,462
46	Denaturant Price per Gal.	**$1.8000**	Rate per 100 gal anhydrous	2.00	$0.0990000		$0.03529412	$ 1,694,769
47	**Total Chemical Cost**				**$0.3819**		**$0.1363**	**$ 6,537,231**
48								
49	Depreciation based on C49 asset life	**15**	Years		$0.2337		$0.0833	$ 4,000,000
50	Maintenance & Repairs	**$0.0125**			$0.0350		$0.0125	$ 600,000
51	Interest Expense				$0.1472		$0.0525	$ 2,520,000
52	Labor	**$0.0450**	$.04--$.06		$0.1262		$0.0450	$ 2,160,000
53	Management & Quality Control	**$0.0136**	$.010-$.022		$0.0381		$0.0136	$ 652,800
54	Real Estate Taxes	**$0.0020**			$0.0056		$0.0020	$ 96,000
55	Licenses, Fees& Insurance	**$0.0040**	.0030-.0050		$0.0112		$0.0040	$ 192,000
56	Miscellaneous Expenses	**$0.0135**	$.01-$.03		$0.0379		$0.0135	$ 648,000
57	**Total of Other Processing Costs**				**$0.6349**		**$0.2264**	**$ 10,868,800**
58	**Total Processing Costs**				**$1.9931**		**$0.7109**	**$ 34,119,924**
59	**Net Margin Achieved Per Unit**				**$2.3410**		**$0.8348**	**$ 40,074,901**
60	**Farmer-Investor Reqd. Return on Equity**	12.00%			**$0.1682**		**$0.0600**	$ 2,880,000
61	**Increment of Success/Failure to Meet Required Return**				**$2.1727**		**$0.7748**	$ 37,194,901
62								
63	**Ethanol Plant Profits for Shareholders and Principal Reduction**				**$40,074,901**		**$40,070,014**	**$ 40,074,901**

Spreadsheets for Dry-Grind Plants Using Biomass for Process Heat and Power

Additional lines are added to the format of the spreadsheet to accommodate the additional capital costs, potential revenue increases for electricity sold, potential revenue decreases for reduced sales of DDGS, additional operating expenses for using biomass associated with labor, maintenance, ash disposal, etc. A key element to include is the “capital cost” legal services of negotiating a power purchase agreement with a utility. Additional power lines and substations may also be necessary are capital costs that are easier to identify and quantify.

A key calculation that the spreadsheets in the workbook are set up to make is that of determining the amount of biomass needed for the various biomass options based on the BTU ‘s that can effectively be extracted from the biomass by an appropriate technology that complies with emissions standards. The spreadsheet on the following page has the BTU density in the biomass fuel DDGS. Formulas reduce the amount of DDGS that can be sold for the options selected, which on the next page is that of producing process heat.
Process heat has one set of efficiency, but electric power production will perhaps have a range of efficiencies, depending upon the generation equipment purchased. A factor for efficiency of conversion will likely be added to the spreadsheets in the workbook that conform to the following:

1) natural gas fired plant
2) biomass used to provide process heat
3) biomass to provide process heat and on-site power
4) biomass to provide process heat, on- site power, and power for sale to grid

Once heat or power has been generated from a biomass fuel, the processes of ethanol production are expected to be quite similar to conventional plants with respect to the usage of enzymes, yeasts, boiler and cooling tower chemicals, denaturant used, and water usage associated with fermentation.

The spreadsheet on the following page has some trial figures entered to test the formulas, but is included to show the concept of the workbook containing spreadsheets of the various options.

1	B	C	D	E	F	G	H	I
2	**Biomass Utilization Alternative:**	**DDGS**	**Process Heat Only**					
3		**Cost/Denat. Gal. Ethanol**						**Plant Totals**
4	**Plant Production Capacity (Denat. Gal.)**	40,000,000						
	Investment per Nameplate Gallon	$1.50						
5	**Addl. Capital Investment for Biomass**	$ 20,000,000					**Plant Cost**	**$ 80,000,000**
6	**Factor of Nameplate Capacity**	1.20						
7	**Debt-Equity Assumptions**							
8	Factor of Equity	0.40						
9	Factor of Debt	0.60					**Initial Debt**	**$ 48,000,000**
10	Interest Rate Charged on Debt	0.07						
11	Rate of Return Reqd. by Investors on Equity	0.12						
12								
13	**Conversion Efficiency Assumptions**				Annual Production			
14	Anhydrous Ethanol Extracted (Gal. per Bu.)	2.75			Bushels Ground		Denat. Gallons	
15	DDGS per Bushel (lb. per Bu.)	17.50	8559	BTU/lb	17,118,881		48,000,000	
16	CO2 extracted per Bushel (lb. per Bu.)	17.50						
17								
18	**Establishment of Gross Margin**				**Revenue/Bu. Ground**		**Revenue/Gal. Denatured Sold**	**Plant Totals**
19	Ethanol Price (denatured price) $/gal.	$ 2.00			5.607843137		$2.00	$96,000,000
20	DDGS Price $/T	$ 75.00			0.65625		$0.0807	$3,873,593
21	CO2 Price ($ per Ton liq. CO2)	$ 8.00			0.07		$0.0250	$1,198,322
22	Electricity Sale Price to Grid	$ -			0			
23	MN Prod. Subsidy/gal.Denat. Ethanol	0.00						
24	Federal Small Producer Subsidy	0.00						
25	CCC Bioenergy Credit	0.00						
26	Revenue per Unit				$6.33			
27	Corn Price Paid by Processor ($ per bu.)	2.00			2.00			
28	Gross Margin				4.33			
29								
30	**Operating Expenses Per Bushel**	**Price per Unit**			**Cost /Bushel Ground**		**Cost /Gal. Denatured Sold**	**Plant Totals**
31	Natural Gas Price ($ 1,000,000 Btu)	8.00			0			
32	LP (Propane) Price ($ per gallon)	1.10			0			
33	Factor of Time Operating on Propane	0.02						
34	BTU's of Heat fr Fuel Req./ Denat. Gal.	35,000						
35	Combined Heating Cost							
36	Electricity Price ($ per kWh)	0.06						
37	Kilowatt Hours Required per Denat.Gal.	1.3625						
38	Electrical Cost							
39	Total BTU's of Fuel and Electricity	48,625.00						
40	**Total Energy Cost**							
41		Cost/Denat. Gal. Ethanol						
42	Enzymes	$0.0480						
43	Yeasts	$0.0220						
44	Other Proc.Chemicals & Antibiotics	$0.0200						
45	Boiler & Cooling Tower Chemicals	$0.0050						
46	Water	$0.0060						
	Ground Limestone							
47	Denaturant Price per Gal.	$1.8000	Denat.Rate/ 100 gal :	2.00				
48	**Total Chemical Cost**							
49								
50	Depreciation based on C49 asset life	15	Years					
51	Maintenance & Repairs	$0.0125						
52	Interest Expense							
53	Labor	$0.0450						
54	Management & Quality Control	$0.0136						
55	Real Estate Taxes	$0.0020						
56	Licenses, Fees& Insurance	$0.0040						
57	Miscellaneous Expenses	$0.0135						
58	**Total of Other Processing Costs**							
59	**Total Processing Costs**							
60	**Net Margin Achieved Per Unit**							
	Farmer-Investor Reqd. Return on Equity	12.00%						
	Increment of Success/Failure to Meet Required Return							
	Ethanol Plant Profits for Shareholders and Principal Reduction							

- **Summary of project management activities, travel, etc. for period (RMT)** – activities supported progress on tasks described above. RMT hosted a meeting of project participants at their offices in Madison, WI on May 9 and 10.

- **Summary of project management activities, travel, etc. for period (UofM) –** activities supported progress on tasks described above. UofM personnel traveled to Madison for a meeting of project participants on May 9 and 10. Doug Tiffany and Vance Morey participated in a meeting hosted by AURI in Redwood Falls, MN on May 16 related to "Managing High Energy Cost: Discussion of Alternatives and Opportunities". The meeting focused on the fuel ethanol industry and other agricultural processing industries.