Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Summary Chapter

This chapter summarizes the project conclusions, technical and policy recommendations, and benefits. It provides a project overview, summarizes outreach activities and publications, and outlines the individual Chapters/Tasks that comprise the final report.

Project Leaders

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

June 13, 2008

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Summary Chapter for Final Report

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Executive Summary

Biomass can provide electricity and process heat at dry-grind ethanol plants to both reduce costs and improve the renewable energy balance for ethanol production. Ethanol co-products such as distillers dried grains with solubles (DDGS) or the solubles portion (syrup) can potentially be used for energy. Corn stover or corn cobs are also potential biomass energy sources for ethanol plants.

We evaluated nine fuel-technology combinations that take advantage of the available biomass fuels and the higher thermal efficiencies which can be captured with combined heat and power (CHP) at ethanol plants.

Conclusions of Project

- There is enough biomass (coproducts and/or stover/cobs) to provide power and heat at ethanol plants.
- Emissions (NO_x, SO_x, and chlorine) associated with using these biomass fuels need to be addressed.
- Biomass improves the renewable energy balance, which corresponds to reduced life-cycle greenhouse gas (GHG) emissions for ethanol production, ie lowers the carbon foot print.
- Technologies are for the most part “off the shelf”, although not all have been implemented with these specific biomass fuels.
- Applications involving process heat are most likely to be economically feasible.
- Combined heat and power (CHP) applications also are likely to be economically feasible.
- A mixture of syrup and stover or cobs provides the greatest potential for economic feasibility of the fuels studied (stover, DDGS, mixture of syrup and stover or cobs).
- A low carbon foot print incentive for ethanol encourages use of biomass fuels at the plant.
- Other factors that favor biomass over conventional natural gas fired plants include: higher natural gas prices, higher corn prices, lower ethanol prices, and lower DDGS prices.
- Electric power generated with biomass at ethanol plants is renewable and firm, which means it could contribute to the base load of the electric generation system.

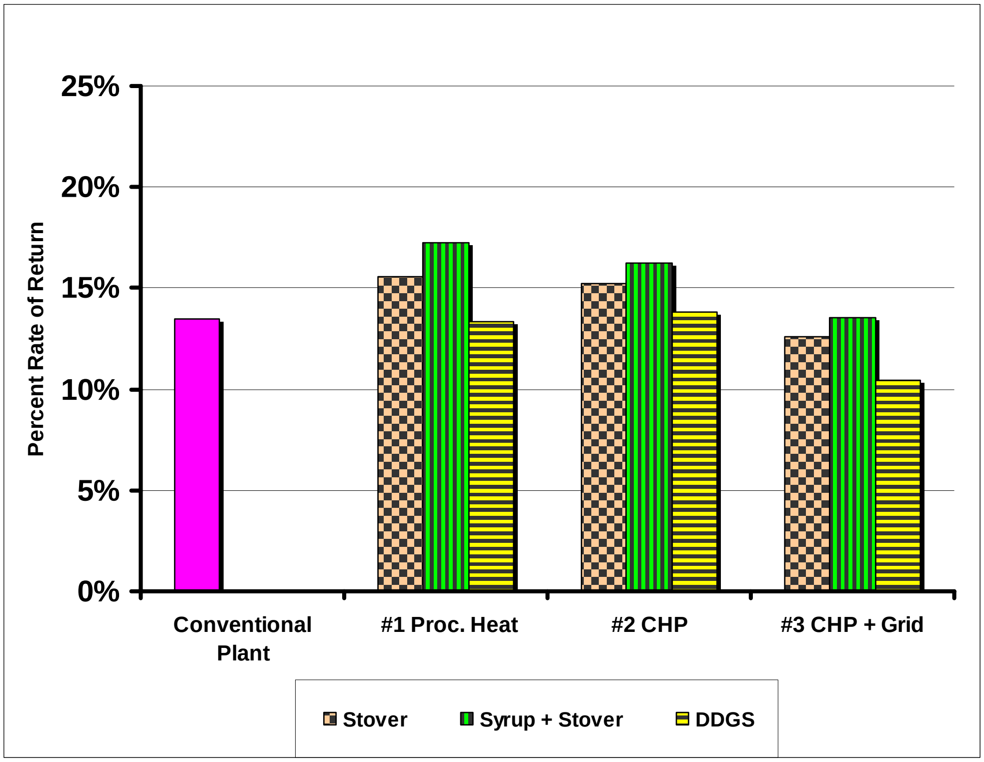
Technical and Policy Recommendations

- Incentives that pay more for low-carbon footprint ethanol, ie ethanol that has a greater green house gas (GHG) reduction potential are needed. The incentives should progressively pay more for greater life-cycle GHG reductions.
- Renewable electricity incentives are needed to make generating electricity to send to the grid economically attractive.

Benefits of Project

- We have evaluated a range of technical and economic issues related to using biomass to generate electricity and process heat at ethanol plants and made that information available to all interested parties – ethanol plants, engineering firms, electric utilities, bankers/lenders, environmental regulators, and legislators and public policy officials. The information is available at www.biomassCHPethanol.umn.edu .
- A workshop entitled "Profitable Use of Biomass at Ethanol Plants" was presented at three locations (Mankato, MN; Norfolk, NE; Des Moines, IA) in February 2008. Approximately 140 people attended and evaluations of the workshops were very strong at all locations. The response to the question "Would you recommend this to others interested in this topic?" was 100% yes for all three locations.
- We have identified systems that generate renewable electricity that potentially are economically feasible under current conditions.
- Using biomass to generate electricity in conjunction with producing biofuels (ethanol) improves the thermodynamic and economic efficiency of the overall process and results in substantial amounts of both renewable biofuel and renewable electricity.
- The biomass technologies such as combustion/gasification, combined heat and power, and handling systems for biomass materials such as corn stover that we are proposing for corn dry-grind ethanol plants also will be essential components of cellulosic ethanol plants. Thus, the results of the project help to lay some of the important ground work for generating renewable electricity in conjunction with producing the next generation of biofuels.

Rates of return for 190 million liter (50 million gallon) ethanol per year capacities for nine biomass fuel/technology combinations compared to a conventional plant. More details are presented in Chapter/Task 16 – Economic Analysis.



Overview of Project

Energy, particularly natural gas for process heat, is one of the major costs in operating an ethanol plant. Although the energy balance for producing ethanol is positive, ethanol conversion (distillation, evaporation, drying) at either dry mill or wet mill plants requires the largest amount of energy in the overall process. Under current technology for ethanol conversion, the process heat is usually supplied by natural gas and the electricity is generated with coal or natural gas. Biomass can provide electricity and process heat at dry-grind ethanol plants to both reduce costs and improve the renewable energy balance for ethanol production. Ethanol co-products such as distillers dried grains with solubles (DDGS) or the solubles portion (syrup) can potentially be used for energy. Corn stover or corn cobs are also potential biomass energy sources for ethanol plants.

We collected co-product samples at five cooperating dry-grind ethanol plants for fuel analysis. 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. We also obtained a corn stover sample for analysis. We determined moisture, ash, sulfur, chlorine, nitrogen, carbon, hydrogen, and oxygen contents of the fuels as well as heating value and ash fusion values. We used these results along with information from the literature for similar biomass fuels in our modeling and analysis.

We evaluated the following technology alternatives:

- Current technology - natural gas for process heat and electricity from coal or natural gas
- Biomass (DDGS, cornstover or combination) to provide process heat (PH) only by combustion or gasification.
- Biomass (DDGS, cornstover or combination) to provide process heat and plant electricity (CHP) - waste heat from electric generation at temperatures sufficient to produce process steam.
- Biomass (DDGS, cornstover or combination) to provide process heat, plant electricity, and electricity to grid (CHPG) - amount based on using all waste heat for process steam.

Based on our analysis of the fuel characteristics and a preliminary review of the available conversion technologies, we settled on the following nine combinations of fuel-conversion technology groupings.

We selected corn stover as one fuel choice and determined that the best alternative for this fuel is combustion in a fluidized bed. We expect to receive corn stover in a 12 to 15% moisture content range. In our analysis we assumed that the corn stover would be delivered in a densified form (briquettes or pellets) at 30 to 35 lbs/ft^3. We evaluated performance for ethanol plants using process heat, CHP, and CHPG for the corn stover combustion alternative.

A combination of syrup and corn stover was selected as another fuel choice. The syrup portion of the co-product appears to be less valuable than the DDG portion and many dry-grind ethanol plants indicate it causes problems in the drying process. The syrup is approximately 65% moisture content, which is too wet to sustain combustion and it does not contain enough energy even if dried to meet the plant needs for process heat. Adding enough corn stover to the syrup to meet the plant process energy needs brings the moisture content of the mixture to around 55%, which is low enough to sustain combustion in a fluidized bed. Additional stover is added to provide sufficient energy for the CHP and CHPG alternatives. The resulting moisture contents are approximately 50% and 45%, respectively. We evaluated performance for ethanol plants using process heat, CHP, and CHPG for the syrup-corn stover combustion alternative.

DDGS were the other fuel choice. The fuel analysis indicated relative low ash fusion temperatures for this material, so we determined that the best alternative for this fuel was gasification followed by ash separation and then combustion. The lower temperatures and a reducing rather than oxidizing environment in the gasification system provided a better option than combustion for dealing with the low ash fusion temperatures. The DDGS moisture content is 10 to 13 %. We evaluated performance for ethanol plants using process heat, CHP, and CHPG for the DDGS gasification-combustion alternative.

The analysis was performed using Aspen Plus process simulation software. An Aspen Plus model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service and was used as the basis for the energy conversion system models that followed. This model contains a feature that allows it to be scaled to different annual ethanol outputs. For the purposes of this study all cases were set to produce 50 million gallons per year of denatured ethanol.

The primary components of the process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), air emissions control, thermal oxidation, and co-product drying. Several variations of steam turbine power cycles were used for the cases involving electricity generation. 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.

Model results include fuel use, fuel energy input rate, power generated, power generation efficiency, and system thermal efficiency. Air emissions (NO_x, SO_x, chlorine) after application of control technologies also are predicted.

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. We developed capital cost estimates for plant capacities of 50 and 100 million gallons per year.

Changes in operating costs using biomass including increased labor as well as potential ethanol price premiums as a result of low-carbon fuel standards were also included in the economic analysis.

Rates of return for each alternative were calculated and compared. 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.

A website www.biomassCHPethanol.umn.edu was established for the project. Information was posted on the website as it became available. Drafts of individual tasks/chapters were posted on the website as they became available.

Project results were presented at various meetings. A workshop entitled "Profitable Use of Biomass at Ethanol Plants" was presented at three locations (Mankato, MN; Norfolk, NE; Des Moines, IA) in February 2008. Evaluations of the workshops were very strong at all locations. The response to the question "Would you recommend this to others interested in this topic?" was 100% yes for all three locations.

Summary and Conclusions of Project

- We evaluated nine fuel-technology combinations that take advantage of the available biomass fuels and the higher thermal efficiencies which can be captured with combined heat and power (CHP) at ethanol plants.
- There is enough biomass (coproducts and/or stover/cobs) to provide power and heat at ethanol plants.
- Emissions (NO_x, SO_x, and chlorine) associated with using these biomass fuels need to be addressed.
- Biomass improves the renewable energy balance, which corresponds to reduced life-cycle greenhouse gas (GHG) emissions for ethanol production.
- Technologies are for the most part "off the shelf", although not all have been implemented with these specific biomass fuels.
- Applications involving process heat are most likely to be economically feasible.
- Combined heat and power (CHP) applications also are likely to be feasible.
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Technical and Policy Recommendations

- Incentives that pay more for low-carbon footprint ethanol, ie ethanol that has a greater green house gas (GHG) reduction potential are needed. The incentives should progressively pay more for greater life-cycle GHG reductions.
- Renewable electricity incentives are needed to make generating electricity to send to the grid economically attractive.

Summary of Outreach Activities – web, workshops, presentations, and papers

The project web site is www.biomassCHPethanol.umn.edu .

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Presentations

"Using Biomass to Enhance Dry-Grind Ethanol Profits" presented by Doug Tiffany at the Fuel Ethanol Workshop, June 21, 2006.

"Economics of Biomass Gasification/Combustion at Fuel Ethanol Plants" presented by Doug Tiffany at the Fifth International Starch Technology Conference held June 3-6, 2007 in Champaign-Urbana, IL. The conference focused on energy issues in starch related industries including ethanol plants.

"Utilization of Biomass for Electrical Generation: Technical and Policy Considerations" presented by Doug Tiffany for the University of Minnesota Electrical Engineering Seminar series at the following utilities: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. The four-hour presentation was made to total of approximately 270 people at the six locations in August 2007.

"Use of Distillers By-Products & Corn Stover as Fuels for Ethanol Plants" presented by Doug Tiffany at a Farm Foundation meeting on February 12, 2008 in Atlanta, GA.

Papers

Morey, R.V., D.G. Tiffany, and D.L. Hatfield. 2006. Biomass for electricity and process heat at ethanol plants. Applied Engineering in Agriculture 22(5): 723-728.

Morey, R.V., D.L. Hatfield, R. Sears, and D.G. Tiffany. 2006. Characterization of feed streams and emissions from biomass gasification/combustion at fuel ethanol plants. ASABE Meeting Paper No. 064180. ASABE St. Joseph, MI 49085.

Tiffany, D.G. and R.V. Morey. 2007. Economics of biomass gasification/combustion at fuel ethanol plants. Proceedings of the Fifth International Starch Technology Conference, Champaign-Urbana, IL. June 3-6.

De Kam, M.J., R.V. Morey, and D.G. Tiffany. 2007. Integrating biomass to produce heat and power at ethanol plants. ASABE Paper No. 076232. St. Joseph, Mich. ASABE.

Tiffany, D.G., R.V. Morey, and M.J. De Kam. 2007. Economics of biomass gasification/combustion at fuel ethanol plants. ASABE Paper No. 076233. St. Joseph, Mich. ASABE.

Tiffany, D.G., R.V. Morey, and M.J. De Kam. 2008. Use of distillers by-products & corn stover as fuels for ethanol plants. Farm Foundation Meeting, Atlanta, GA, February 12.

Outline of Individual Chapters/Tasks (Chapters/Tasks included as appendices or attachments)

Chapter/Task 1 – Applicable Biomass Co-Product Streams
This chapter provides an overview of potential biomass co-product streams (DDGS, syrup, DWG) available at ethanol plants or near plants (corn stover).

Chapter/Task 2 – Analysis of Biomass Co-Product Streams
This chapter describes the sampling and analysis procedures and provides fuel analysis results for dry-grind ethanol plant co-product streams as well as corn stover.

Chapter/Task 3 – Combustion Options
This chapter provides and overview of potential combustion and gasification systems that could be considered for supplying energy to an ethanol plant.

Chapter/Task 4 – Fuel Processing Options
This chapter describes requirements and potential methods for processing co-products to a form suitable for combustion.

Chapter/Task 5 & 6 – Combustion and Emission Modeling Results
This chapter describes a computational fluid dynamics approach to modeling fluidized bed combustion and predicted emissions for the ethanol co-products and corn stover as fuels.

Chapter/Task 7 – Evaluations Relative to Standards
This chapter provides as analysis of environmental regulations that may arise from the use of alternative biomass fuels at dry-grind corn ethanol production facilities.

Chapter/Task 8 – Evaluation of Control Technologies
This chapter describes potential technologies that can be used to control emissions such NO_x, SO_2, and particulates that arise form biomass fuel combustion.

Chapter/Task 9 – Ash Characterization and Evaluation
This chapter describes characteristics and potential uses of ash that arises from the combustion of ethanol co-products as fuels.

Chapter/Task 10 – Capital and Operating Cost Estimates
This chapter describes the development of estimated capital costs that are required for the example systems defined in Chapter/Task 14 and the additional operating costs associated with using these biomass systems.

Chapter/Task 11 – Electricity Producing Options
This chapter outlines potential systems for producing electricity at ethanol plants.

Chapter/Task 12 – Compatibility with Existing Plant Combustion Systems
This chapter outlines potential advantages as well as disadvantages of incorporating biomass energy generation in existing plants.

Chapter/Task 13 – Electric Generation Considerations
This chapter outlines the opportunities and challenges of generating electricity and selling it to the grid.

Chapter/Task 14 – Technology Options and Integration with Dry-Grind Ethanol Plants
This chapter develops a model for integrating biomass energy conversion with conventional dry-grind ethanol plants. It describes in detail nine biomass fuel-technology combinations.

Chapter/Task 15 – Spreadsheet Architecture
This chapter describes development of the architecture of the spreadsheet used to conduct the economic analysis of Chapter/Task 16.

Chapter/Task 16 – Economic Analysis
This chapter presents results of an economic analysis comparing the nine biomass fuel-technology combinations to each other and to a conventional plant using natural gas and purchased electricity.

Chapter/Task 17 – Special Scenarios
This chapter outlines several special scenarios, which all focus on using the syrup since alternatives involving the syrup had the most favorable rates of return in the economic analysis (Chapter/Task 16). The scenarios include syrup and corn cobs in place of corn stover, partial use of biomass (syrup) along with natural gas, and a preliminary evaluation of electricity generation with integrated gasification combined cycle technology using syrup and corn cobs as fuel.

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Chapter/Task 1 – Applicable Biomass Co-Product Streams

This chapter provides an overview of potential biomass co-product streams (DDGS, syrup, DWG) available at ethanol plants or near plants (corn stover). It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 1, "Applicable Biomass Co-Product Streams"

Background of the Task

A wide variety of biomass fuels are potentially available for use in providing energy for the production of fuel-grade ethanol. These potential biomass fuels include wood (virgin chips, waste wood such as harvesting slash and wood from storm damage, wood processing residues such as sawdust and shavings, and such miscellaneous items as pallets and cribbage), distressed grain (excess seed, moldy or wet, contaminated, etc.), agricultural processing residues (hulls, husks, pits, rejects, etc.), and so-called "energy crops" (switch grass, etc.). Also generally classified as biomass fuels are such materials as waste paper and refuse-derived fuel (RDF).

This project focuses on a type of biomass fuel specifically generated at dry grind fuel ethanol plants, namely, the co-products of the ethanol production process itself, and the stover derived from growing the corn that is the dominant feed material for dry grind ethanol plants. These co-products, described in detail below, offer several benefits as fuel for dry grind ethanol plants. The co-products are already located at the ethanol plants, eliminating transportation costs. If the selling price of the co-products is depressed, the plants can potentially derive greater value by extracting the energy content of the co-products rather than selling the co-products themselves. The co-products leaving the process have a high moisture content (about 65%-70%) and a limited shelf life (from days to a few weeks with additives). Drying allows easier handling and a much longer shelf life (months or more), but at a high energy cost. Use of the co-products as fuel may not require as much drying, or may allow more efficient drying. One of the co-products (syrup) is becoming increasingly problematic, and may be most efficiently and effectively dealt with through its use as fuel. Recently, the literature has contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40%-50%, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers. This report therefore does not include further descriptions of such systems, or projections of such systems' effectiveness or utility. However, if such systems are effective and cost effective in reducing the moisture content of the syrup to less than 50 percent, mathematical modeling for this project indicates that stable, self-sustaining combustion of the syrup may be feasible.

The primary products of the fermentation process used to produce fuel ethanol are anhydrous ethanol, carbon dioxide, and solid and soluble stillage. Solid and soluble stillage consists primarily of yeast cells and of the nonstarch portions of the feed stock, as well as whatever starch was not fermented. The nutritional composition of the nonstarch feed stock residues include protein, fat, and fiber.

The solid and soluble residues begin as "whole stillage," which is the material remaining after the ethanol is removed from the mash in distillation columns. The whole stillage is processed in centrifuges to separate a solids-containing portion (distillers wet grains, or DWG) and a solubles-containing portion ("thin stillage"). The DWG can be dried to produce distillers dried grains, or DDG. The thin stillage is further processed through distillation to remove additional water, resulting in a viscous stream referred to as "syrup." The syrup may be sold separately as an animal feed additive, or it may be combined with the solids-containing stream from the centrifuges, a mixture referred to as distillers wet grains with syrup (also sometimes referred to as "solubles"), or DWGS (often also called DWG). The DWGS can be dried, to produce a material referred to as distillers dried grains with syrup, or DDGS.

DDGS has operational and marketing benefits over DWGS, including a much longer shelf life, reduced odor, easier handling, and lower transportation costs. However, the drying of the DWGS is a major user of energy, usually in the form of natural gas, for an fuel ethanol plant. Owing to the high proportion of water in the syrup (typically about 70%) and the syrup's physical characteristics, the drying of the syrup is particularly energy intensive. The DWGS drying operation is also a major source of raw air emissions from fuel ethanol plants.

The distillers grains and solubles have a substantial energy content; indeed, the recoverable energy is projected to be sufficient enough to place substantial electricity from the biomass combustion onto the external electricity grid. Residual steam following electricity generation can replace natural gas in distillers grain drying (depending on equipment), increasing the attractiveness of biomass co-product combustion.

A major potential biomass energy source associated with corn production is corn stover, which is composed of the stalks, leaves, cobs, and husks of the corn plant after the kernels of corn are removed. Corn stover is potentially low cost and is generally generated in the same geographic area and by the same growers as the corn raw material for the ethanol plants. The physical and chemical characteristics of the corn stover may make it a feasible adjunct to the current ethanol plant co-products streams. Corn stover could also represent an economic value-added component for both the farmer and the ethanol plant. However, corn stover has significant challenges in industrial-scale energy applications. It is a seasonal, opportunistic material, and substantial investment would be needed to process and store it for availability as a year-round fuel. The bulk density of corn stover is low, making collection, transportation, storage, and processing costly. The moisture content of typical corn stover is highly variable, and moist corn stover rapidly degrades. Corn stover, especially if collected post-harvest off the ground, may contain considerable contamination, both physical (dirt, rocks, and debris) and biological (both micro- and macro-organisms). Because new technologies are being developed that may overcome some of these drawbacks, this project will include corn stover in the overall evaluation of applicable biomass fuels.

Evaluation of Potential Feed Streams to be Sampled

This project evaluated the fuel characteristics of various feed streams that could potentially be used for combustion. These potential feed streams are listed in Table CS1. These feed streams comprise the components of the ethanol plant co-product streams and their combinations, as well as their combinations with corn stover. These potential feed streams are potentially present in all dry grind fuel ethanol plants, regardless of the plant designer or builder. Operational factors may cause variation in potential feed streams for any particular plant. For example, a plant that burns syrup to produce process steam will therefore produce no DDGS. Plants that do not have dryers will likewise not produce DDGS. However, all feed streams listed in Table CS1 were evaluated because of their wide general applicability and because any given plant may change its process or production needs over time.

Table CS1
Potential Combustion Feed Streams

STREAM #	DESCRIPTION
1	Whole stillage
2	Distillers wet grains without syrup
3	Distillers wet grains with syrup
4	Thin stillage
5	Syrup
6	Distillers dried grains without syrup
7	Distillers dried grains with thin stillage
8	Distillers dried grains with syrup
9	Corn stover
10	Whole stillage with corn stover
11	Distillers wet grains without syrup, with corn stover
12	Distillers wet grains with syrup, with corn stover
13	Thin stillage, with corn stover
14	Syrup, with corn stover
15	Distillers dried grains without syrup, with corn stover
16	Distillers dried grains with thin stillage, with corn stover
17	Distillers dried grains with syrup, with corn stover

Evaluation of Potential Feed Streams for Analytical Testing

The potential combustion feed streams listed in Table CS1 were evaluated to develop a sampling and analytical protocol for execution of feed stream analyses. The protocol was designed to yield the maximum useful data for the lowest cost, thus making efficient use of project funds.

It is not necessary to analyze every potential feed stream for every parameter. Some of the potential feed streams are composed of combinations of component streams that will be analyzed. For example, distillers wet grains with syrup is simply a combination of the syrup with the distillers wet grains without syrup; there is no further processing, and so there is no chemical change in either component. Likewise, all combinations with corn stover can be evaluated by combining the data from corn stover with the data from the other component feed stream, because the combination is not subject to processing that would significantly affect the chemical analyses. On the other hand, when distillers wet grains with syrup are dried to produce DDGS, the high temperature of the drier will produce chemical changes, and the physical action of the drier will cause the loss of some fine particulate, which may in turn change both the physical characteristics and the chemical balance of the final product.

Since the project was proposed, additional relevant data have become available from the literature, from producer plant Internet sites, and from technical and industry conferences. These data will be evaluated for relevance and for general quality, and the data deemed suitable will be used as much as possible to avoid duplication of effort and to allow project funds to be expended on other project pursuits for which such data are not readily available.

Table CS2 presents the evaluation of potential feed streams for analytical testing, including comments relative to potential use as biomass fuel, based on the project team's applicable predictive experience in the ethanol and other industries.

Table CS2
Evaluation of Potential Feed Streams for Analytical Testing

STREAM #	DESCRIPTION	EVALUATION FOR TESTING	TEST?
1	Whole stillage	The water content is judged to be too high for practical burning. Whole stillage is composed of a solids portion that will become DWG and a solubles portion that will become syrup, each through a physical separation. Both DWG and syrup will be analyzed.	No
2	DWG without syrup	The moisture content is judged to be too high for practical self-supporting combustion. However, removal of some of the moisture, or supplementation with other fuel, should allow for such combustion, so the material will be analyzed.	Yes

Table CS2 (continued)
Evaluation of Potential Feed Streams for Analytical Testing

STREAM #	DESCRIPTION	EVALUATION FOR TESTING	TEST?
3	DWG with syrup	The DWG and the syrup will be analyzed separately.	No
4	Thin stillage	The water content is judged to be too high for practical burning. The thin stillage is concentrated into syrup, and the syrup will be analyzed.	No
5	Syrup	Although the moisture content of the syrup is judged to be too high for practical self-supporting combustion, syrup is reportedly being successfully burned for energy at one plant, with the use of auxiliary fuel. Production refinements in the industry may increase the quantity of syrup produced while changing the chemical makeup of the syrup. The resultant change in the economic value of the syrup is uncertain. It is likely that more syrup will be produced than the plants desire, so elimination by energy recovery may become an increasingly attractive option. New systems to significantly reduce the moisture content of the syrup will greatly enhance the syrup's potential use as fuel, but are not expected to change the chemical makeup or the moisture-free heat potential of the syrup.	Yes
6	DDG without syrup	When dried to DDG, chemical changes may take place in the DWG, including minor loss of dry-basis heat value. Comparison of DWG with DDG will allow for an evaluation of the effects of various degrees of drying the DWG prior to combustion.	Yes
7	DDG with thin stillage	The water content of the thin stillage will likely more than negate any additional combustion benefits to be gained through drying the DWG.	No
8	DDG with (undried) syrup	The DDG and the syrup will be analyzed separately.	No
9	DDG with (dried) syrup (DDGS)	Depending on the drying technology and conditions, drying the DWG and syrup may result in chemical changes, including minor loss of dry-basis heat value. Nevertheless, DDGS is expected to have the highest heat value of any material in this project, and is produced by most plants.	Yes
10	Corn stover	Data generated in this project will supplement existing literature data.	Yes
11	Whole stillage with corn stover	The high water content of the whole stillage is judged to make burning impractical.	No

Table CS2 (continued)
Evaluation of Potential Feed Streams for Analytical Testing

STREAM #	DESCRIPTION	EVALUATION FOR TESTING	TEST?
12	DWG without syrup, with corn stover	Data from DWG and corn stover can be combined to allow for an evaluation of this mixture.	No
13	DWG with syrup, with corn stover	Data from the DWG, syrup, and stover can be combined to allow for an evaluation of this mixture.	No
14	Thin stillage, with corn stover	The high water content of the thin stillage is judged to make burning impractical. Data are available for corn stover.	No
15	Syrup, with corn stover	Data from syrup and corn stover can be combined to allow for an evaluation of this mixture.	No
16	DDG without syrup, with corn stover	Data from DDG and corn stover can be combined to allow for an evaluation of this mixture.	No
17	DDG with thin stillage, with corn stover	The high water content of the thin stillage is judged to make burning impractical at any reasonable percent of thin stillage. Data are available for DDG and corn stover.	No
18	DDG with syrup, with corn stover	Data from the separate components can be combined to allow for an evaluation of this mixture.	No
19	DDGS and corn stover	Data from the separate components can be combined to allow for an evaluation of this mixture.	No

Potential Effects of Changes in Raw Material Preprocessing

The dry grind fuel ethanol industry has been in a state of technological change since its inception. Changes have focused on reducing environmental impacts, improving efficiency, lowering costs, enhancing production flexibility, and creating more value-added products and co-products. Raw material preprocessing through fractionation prior to liquefaction, and recovery of certain components following distillation, have gained greater interest. New processes are in development, and have in some cases been installed, to achieve fractionation or biorefining. The primary separated co-products of the preprocessing fractionation are the germ/oil and the fiber (bran), while the primary separated post-fermentation co-product is oil.

The potential effects of germ/oil and fiber removal on the selected co-products feed streams are expected to have both positive and negative impacts on combustion. On the positive side, the removal of fiber could make processing of the feed streams for injection via nozzles into conventional (nonfluidized) combustion units easier, could improve flowability, and could lower the amount of sulfur in the feed. On the negative side, the high heat content of the germ, because of its oil component, is unavailable for combustion, and the fiber, which may aid in dewatering the whole stillage, is also unavailable for combustion. Additional testing will be necessary to quantify these potentials, and the variability inherent in the different fractionation technologies should also be considered. If suitable samples are available in time, limited analyses and data evaluation may be incorporated into the project results.

Partner Ethanol Plants

Table CS3 lists the partner ethanol plants from which samples were obtained. To protect the confidentiality of the plants, the individual samples are not identified by plant name in this report. The analyses performed, and the analytical results, are given in the Feed Stream Analysis section of this report.

Table CS3
Partner Ethanol Plants

PLANT NAME	PLANT LOCATION
Ace Ethanol, L.L.C.	Stanley, Wisconsin
Agri-Energy, L.L.C.	Luverne, Minnesota
Badger State Ethanol, L.L.C.	Monroe, Wisconsin
Chippewa Valley Ethanol Company	Benson, Minnesota
Corn Plus, L.L.C.	Winnebago, Minnesota

A sample of corn stover was obtained from the University of Minnesota Department of Biosystems and Agricultural Engineering.

Analytical results are discussed in the "Analysis of Biomass Co-Product Streams" section of this report.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 2 – Analysis of Biomass Co-Product Streams

This chapter describes the sampling and analysis procedures and provides fuel analysis results for dry-grind ethanol plant co-product streams as well as corn stover. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants Report for Task 2, "Analysis of Biomass Co-Product Streams"

Background of the Task

Five biomass co-product feed streams were selected for analysis in the first task of this project, "Applicable Biomass Co-Product Streams." These potential feed streams are listed in Table ACS1. These feed streams comprise the base components of the ethanol plant co-product streams and their combinations, as well as their combinations with corn stover. Table ACS2 shows the evaluation of each potential feed stream relative to the need for chemical and physical analyses. As discussed in the previous chapter, the literature has recently contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40-50 percent, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers. It was therefore not possible to obtain samples of the reduced-moisture syrup produced by such systems, and this report cannot include further descriptions of such systems, projections of such systems' effectiveness or utility, or specific data regarding the chemical content of such reduced-moisture syrup. However, such systems are not expected to change the chemical composition of the syrup, so the information on the chemical composition included in this report is expected to be applicable to the reduced-moisture syrup.

The project proposal called for sampling from only two partner ethanol plants. To address technical developments in the industry since the proposal was submitted, and to provide broader precision in the statistics of the analytical results, samples were obtained from all five of the current partner ethanol plants. In addition, a sample of corn stover was obtained from the University of Minnesota, Department of Biosystems and Agricultural Engineering. A sampling and analytical protocol was developed for each plant and each parameter. As discussed previously, it is not necessary to analyze every potential feed stream for every parameter, since some of the streams are composed of combinations of component streams that will be analyzed, and since some data are available from the literature. In addition, the limited project analytical funds were devoted to those analyses yielding the most relevant information for the modeling effort.

Table ACS1 below is derived from Table CS2, report for Task 1 "Applicable Biomass Co. – Product Streams," and lists the five feed streams to be analyzed.

Table ACS1
Feed Streams for Analytical Testing

STREAM # (1)	DESCRIPTION
2	Distillers wet grains without syrup (DWG)
5	Syrup
6	Distillers dried grains without syrup (DDG)
8	Distillers dried grains with syrup (DDGS)
9	Corn stover

(1) Referenced in Table CS2, report for Task 1 "Applicable Biomass Co. – Product Streams"

Selection of Parameters

The analytical program provides critical data for subsequent project tasks, and for the modeling effort. As such, the selected analyses include physical characteristics (applicable to storage, handling, combustion feed, and spill management), chemical analyses (applicable to raw material emissions, combustion emissions, combustion chemistry, emission control, material handling, and ash characterization), and thermogravimetric analyses (for combustion assessments and optimization). Much of the data available in the literature pertains to nutritional studies. Although the literature contains some data for some feed streams potentially useful for combustion, these data tend to be limited proximate analyses without the ultimate analyses needed for this project.

Table ACS2 shows the analyses selected for the feed streams from the partner ethanol plants, and for the corn stover from the University of Minnesota. All analyses use standard laboratory procedures, as documented in the individual laboratory reports. RMT selected laboratories for project analyses by comparing capabilities, experience, responsiveness, turnaround time, and cost. If these factors were similar, preference was given to laboratories in Minnesota and Wisconsin.

Table ACS2 also shows analyses performed on the ash generated from the feed streams. The ash was created in the process of performing the analytical testing on the feed streams. Having the same analytical laboratories analyze both the feed streams and the resultant ash is the most cost-effective means by which to obtain the needed ash characterization data. The chemical characteristics of the ash are independent of the method used to generate the ash. The ash data will be discussed in more detail in later chapters.

Table ACS2
Analyses of Feed Streams

ANALYSIS TYPE	LABORATORY	NUMBER OF ANALYSES				
		DWG	DDG	DDGS	SYRUP	STOVER
Whole (Unashed) Sample						
Proximate, ultimate, Btu, S	Twin Ports	5	1	4	5	1
Chlorine	Twin Ports	3	1	2	3	1
Mercury	Twin Ports	3	1	2	3	1
Total select metals	Twin Ports	3	1	2	3	1
Phosphorus	Published data	0	0	0	0	0
Potassium	Published data	0	0	0	0	0
Bulk density/compactibility	Twin Ports	3	1	0	0	0
Sieve distribution	Twin Ports	3	1	0	0	0
Viscosity	Twin Ports	0	0	0	3	0
Specific gravity	Twin Ports	0	0	0	3	0
Subtotal		**20**	**6**	**10**	**20**	**4**
Ash Characterization						
Mineral oxides in ash	Twin Ports	3	1	2	3	1
Nitrogen in ash	Twin Ports	3	1	2	3	1
Ash fusion (oxidizing and reducing)	Twin Ports	3	1	2	3	1
Thermogravimetric analysis	Distillers Grains Technology Council	3	1	2	3	1
Subtotal		**12**	**4**	**8**	**12**	**4**
Total Analyses		**32**	**10**	**18**	**32**	**8**

Sampling

Fuel ethanol plants are complex industrial operations. The products and co-products are contained in vessels and piping, sometimes under pressure, and are generally hot when leaving the process. Samplers must have a thorough knowledge of the production equipment, the processes, and the materials, as well as specific safety training and personal protective equipment. Also important in obtaining samples is that neither the samples nor the product quality be compromised.

It was agreed among the partner plants that plant personnel would obtain the project samples and prepare them for shipment. This is the safest approach, with the least potential disruption to plant schedules and operations. Collecting certain samples is a routine part of the job for many plant staff, and good sampling technique is critical in maintaining good plant operations and good quality products and co-products.

For samples going to Twin Ports Testing, Inc. (Twin Ports), the laboratory prepared sample containers and sent them to the partner ethanol plants, along with prepaid return labels. Once the ethanol plant collected the samples and placed them in the shipping containers, the delivery service came to the ethanol plant, picked up the shipping containers, and returned them to the laboratory. For samples going to the Distillers Grains Technology Council (DGTC), RMT prepared coolers with sample containers and sent them to the ethanol plants, and the ethanol plants, after collecting samples and returning them to the coolers, called the shipper for pickup (prepaid) and shipment to the DGTC.

Analytical Results

As agreed with the partner ethanol plants, the identities of the individual plants are not revealed in this report. For presentation purposes, the plants are referred to in this report numerically as plants 1-5. As a result, the DDG results and the detailed analytical results are not provided in this report.

The feed stream samples received by the analytical laboratory were analyzed "as received," and the results were compiled. These data were then used by the analytical laboratory to calculate results for the same parameters without the moisture component, and the same results were compiled under the heading "moisture free." This procedure is useful in comparing analytical results for feed streams of widely varying moisture content, and for evaluating the operational and economic ramifications of removing moisture from the various feed streams.

For syrup viscosity, RMT instructed the analytical laboratory to perform the test at three different temperatures to more nearly represent actual conditions likely to be encountered at an operating fuel ethanol plant, and to allow graphical examination of the viscosity characteristic for the syrup from each plant. The test was performed at 32°F (0°C), 72°F (22°C), and 210°F (99°C).

The thermogravimetric analyses were begun with samples at essentially room temperature (79°F or 26°C) and a ramp-up rate of 86°F (30°C) per minute. The ending temperature was a minimum of 1,562°F (850°C). Samples of syrup, wet grains, and dried grains from the partner ethanol plants were analyzed, as was one sample of corn stover. The results are shown on Figures ACS1 through ACS9. The left vertical axis, shown in green, depicts the total weight percent of the sample. The right vertical axis, shown in blue, depicts the derivative weight percent of the sample as a function of temperature. The results of the thermogravimetric analyses were generally similar, although some samples exhibited four major transitions and others exhibited only three. All syrup samples exhibited a large transition just beyond 212°F (100°C), representing loss of water. One syrup sample showed three rather distinct transitions (at temperatures of about 536°F [280°C], 662°F [350°C], and 1,112°F [600°C]), another syrup sample showed only two distinct transitions (at temperatures of about 572°F [300°C] and 986°F [530°C]), and the third syrup sample showed a complex pattern of transitions with no major dominant peaks. For DWG, all samples exhibited a large transition at just beyond 212°F (100°C), representing loss of water. Two of the DWG samples showed three subsequent transitions (at temperatures of about 572°F [300°C], 797°F [425°C], and 1,112°F [600°C]), while the third sample exhibited a more complex pattern, with broad dominant peaks in the range of about 572°F-662°F (300°C-350°C) and 1,076°F-1,157°F (580°C-625°C). For dried grains, all the samples exhibited a small peak just above 212°F (100°C), representing loss of water; and the samples exhibited three dominant peaks at temperatures of about 536°F (280°C), 788°F (420°C), and 1,157°F (625°C). Corn stover exhibited three narrow, high peaks (at temperatures of about 140°F [60°C], 572°F [300°C], and 788°F [420°C]); a broader, lower peak at a temperature of about 824°F (440°C); and a very low peak at a temperature of about 1,184°F (640°C).

Summarizing and generalizing the thermogravimetric results, all feed materials except corn stover exhibited a loss of water at a temperature just above 212°F (100°C). While the weight percent of the moisture in the corn stover approximates the derivative weight percent shown on the thermogravimetric graph, and while the initial derivative weight percent peak of the thermogravimetric analysis of the corn stover is presumably the loss of moisture, why the peak is at a temperature substantially below 212°F (100°C) was not determined as part of this analytical program. It may be that the low density and the highly porous nature of the corn stover allowed moisture to rapidly escape at a temperature lower than the ethanol co-products. Whatever the reason, this difference will need to be taken into account in the modeling and design of the combustion system.

Tabulation of Analytical Results

The analytical results were tabulated in two general ways. First, results were tabulated by parameter across the partner ethanol plants, arranged by major parameter group. The tabulated results are presented in Tables ACS3 through ACS34. The major parameter groups for this series of tables are as follows:

- Proximate analyses, as received
- Proximate analyses, moisture free
- Ultimate analyses (including select metals), as received
- Ultimate analyses (including select metals), moisture free
- Ash fusion temperature, oxidizing atmosphere
- Ash fusion temperature, reducing atmosphere
- Ash mineral oxide analyses
- Ash nitrogen content
- Density

- Viscosity, by temperature (syrup only)
- Sieve size distribution (DWG only)

Second, the results were tabulated by parameter across feed streams, arranged by major parameter group. The major parameter groups for this series of tables are shown below. Owing to the wide range of moisture content of the feed streams, especially when comparing syrup with DDGS, only the "moisture free" data were used for these tables. The tabulated results are presented in Tables ACS35 through ACS39.

- Proximate analyses, moisture free
- Ultimate analyses, moisture free
- Ash fusion temperature, oxidizing atmosphere
- Ash fusion temperature, reducing atmosphere
- Ash mineral oxide analyses

The DDG results are not reported in order to not reveal the identity of the individual partner ethanol plants. However, general discussions regarding the DDG results are included.

Utilization Of and Comparison With Literature Values

A key aspect of the analytical program is utilization of applicable data from the literature. This not only is cost-effective for the project, but also provides a broader base of data for evaluation and modeling. The search for literature data was not intended to be exhaustive, but was focused on readily available data from widely available sources believed to be reliable. Sources, which included both government and private entities, are listed in the applicable table. In some instances, readily available literature data were determined to suffice for the purposes of this project, while for other instances, a combination of literature and testing data was desired.

Considerable literature data were found concerning corn stover and DDGS, while applicable data for DWG and syrup were scarce. For DDG, the literature contained a small amount of applicable data.

As a method by which to check on the general comparability of literature data and testing data, a comparison of the partner plant analytical results with comparable values from the literature was performed for selected parameters. Tables ACS40 through ACS52 include both testing data and data from the literature. Comparison of the testing data with the literature data reveals that the two data sets are generally in good agreement, especially considering the differences in source materials, laboratories, and time frames. Some larger differences appear for corn stover, and these may be expected, given the inherent variability of corn stover samples from different locations and at different times. For DDGS, some of the results for partner ethanol plant 4 are considerably different from typical values from other partner ethanol plants and from the literature. These differences appear to be related to the high moisture content of the DDGS sample from partner ethanol plant 4; indeed, the moisture content of the sample, nearly 60 percent, classifies the material more as DWG, although the presence of syrup in the partner ethanol plant 4 samples would be expected to produce analytical results different from other DWG.

Chemical Composition of Combinations of Feed Streams

A key methodology of this project is making the results applicable to the broadest range of dry grind fuel ethanol plants and biomass feed streams. The analyses performed allow for calculation of the chemical composition of any combination of the potential feed streams. The composition of co-product mixtures for both proximate and ultimate analyses is predicted from the laboratory results of the primary co-products using conservation of mass. In general form, the equation for calculating the weight percentage composition for any given chemical parameter from any combination of feed streams is as follows:

$$(w\%)C_m = [(w\%)C_1w_1 + (w\%)C_2w_2 + -\_- - (w\%)C_nw_n]/[w_1 + w_2 + - - - w_n],$$

where

$(w\%)C_m$ = weight percent of chemical compound C in the mixture,
$(w\%)C_1$, $(w\%)C_2$, etc. = weight percent of chemical C in individual feed stream 1, 2, etc.,
w_1, w_2, etc. = the weight of individual feed stream 1, 2, etc., used in the mixture.

For example, the sulfur content of the combination of 100 pounds (45.4 kg) of DDGS with 0.62 weight percent sulfur and 25 pounds (11.3 kg) of corn stover with 0.04 weight percent sulfur can be calculated by using the contribution of sulfur by each of the two feed streams and the weights of the two feed streams. For this example, the mean sulfur weight percentages are used for the feed streams.

$$\text{Wt \% sulfur}_{\text{mixture}} = [(0.62)(100) + (0.04)(25)] / [100 + 25], \text{ or } 0.50$$

If the feed stream mixture consisted of equal weights of corn stover and DDGS, the sulfur weight percent of the feed stream mixture would be 0.33.

This procedure works for any individual chemical component for simple mixtures of any of the feed streams analyzed, or for any other feed streams for which chemical analyses are available. These data can in turn be used in the modeling to predict the chemical composition of the emissions and the ash of simple co-product mixtures. This will allow optimization of mixing of the individual feed stream components to help in meeting emission and ash composition objectives, and in operating emission control and ash management systems.

Conclusions

The feed stream analytical program provided the information needed for the project; indeed, the use of samples from five partner ethanol plants, versus the two plants anticipated at the project proposal stage, provided considerable additional value to the project results.

One general conclusion concerns the comparability of the analytical results among the samples from the different plants. Despite the different geographic locations, ages, process designers, builders, and operators of the plants, in most respects, the samples exhibited similar analytical results. One set of samples from one of the plants exhibited results significantly different from comparable samples at the other plants. Attempts were made to obtain a new set of samples from the plant in question, but such samples were not provided. A review of the processes used at the plant in question revealed no obvious basis for such a difference in the results. The project core team concluded that there must have been some error either in sampling or in labeling the samples, and these aberrant results were not included in the data tabulation.

The heat content of the various materials for energy production should be evaluated on both an "as-received" and a dry basis. This allows for the estimation of the energy potential of the material under the highest net energy conditions (dry, not including the energy needed to achieve the drying), under a scenario of minimal processing (as-received, without drying), and of the degree of drying that will result in optimal energy production (including the energy needed for drying and the net energy derived from combustion or gasification of the partially dried material). On a dry basis, all of the co-product feed streams have a favorable heat content for energy production; the solids portions (DWG and DDG) are in the range of 9,500 Btu per pound (22,050 kJ/kg), while the syrup is in the range of 8,700 Btu per pound (20,193 kJ/kg). Corn stover is in the range of 7,700 Btu per pound (17,872 kJ/kg). For comparison, Powder River Basin coal, a fuel widely used for electric power generation, has a typical energy content of 8,200-8,800 Btu per pound (19,032-20,425 kJ/kg), as received (typically around 30% moisture). The heat content of the ethanol co-product fuels on an as-received (wet) basis is lower than on a dry basis. For DDG and DDGS, with moisture around 10 percent, the difference in heat content between dry and as-received is not significant. Excellent combustion could be maintained with DDG, DDGS, and corn stover. For syrup and DWG, however, there is a significant difference between the heat content of the material if dry, versus the heat content as-received (around 70% moisture). Self-sustaining combustion could not be maintained using only DWG or syrup as received. Some degree of drying of the syrup and DWG will be needed for combustion or gasification if the use of auxiliary fossil fuel is to be avoided. The optimum degree of drying will depend on the combustion or gasification system used and on other details of plant energy system configuration and operations.

The feed streams, like many biomass feed streams, contain considerable nitrogen and phosphorus. The nitrogen content may present challenges regarding the emission of nitrogen oxides (NOx) during combustion. Modeling and control technology evaluations in later portions of this report will shed light on the significance of the nitrogen levels. The phosphorus content may present a challenge in dealing with the ash from the combustion of the co-products, since some agricultural lands already face limitations from an overabundance of applied phosphorus.

The levels of alkaline metals may present challenges regarding ash fusion, and may impact the feasible combustion and gasification technologies. Ash will be considered further in later sections of this report.

DWG

Table ACS3
Analytical Results for Proximate Analyses, DWG As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	65.98	64.67	54.26	70.70	66.71	54.26	70.70	64.46	6.13
Ash	%	0.78	0.72	2.18	0.64	0.54	0.54	2.18	0.97	0.68
Volatile matter	%	27.72	29.42	37.04	25.26	27.94	25.26	29.42	29.48	4.48
Fixed carbon	%	5.32	4.99	6.16	3.17	4.62	3.17	6.16	4.85	1.10
Sulfur	%	0.20	0.20	0.35	0.24	0.19	0.19	0.35	0.24	0.07
Heating value	Btu/lb	3,181	3,298	4,314	2,816	3,151	2,816	4,314	3,352	567
Chlorine	µg/g	--	--	1,580	221	270	221	1,580	690	771
Mercury	µg/g	--	--	<0.005	<0.003	<0.004	<0.003	<0.005	--	--

Notes:

-- = not available/analyzed.

Table ACS4
Analytical Results for Proximate Analyses, DWG Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ash	%	2.28	2.05	4.77	2.17	1.61	1.61	4.77	2.58	1.25
Volatile matter	%	81.48	83.26	80.98	86.22	83.94	80.98	86.22	83.18	2.09
Fixed carbon	%	15.63	14.11	13.49	10.81	13.87	10.81	15.63	13.58	1.75
Sulfur	%	0.60	0.58	0.76	0.80	0.57	0.57	0.80	0.66	0.11
Heating value	Btu/lb	9,351	9,336	9,431	9,609	9,465	9,336	9,609	9,438	110
Chlorine	µg/g	--	--	3,454	753	811	811	3,454	1,673	1,543
Mercury	µg/g	--	--	<0.011	<0.10	<0.012	<0.011	<0.10	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS5
Analytical Results for Ultimate Analyses, DWG As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	65.98	64.67	54.26	70.70	66.71	54.26	70.70	64.46	6.13
Carbon	%	17.36	18.15	23.69	14.72	19.39	14.72	23.69	18.66	3.29
Hydrogen	%	2.31	2.42	2.99	1.99	2.01	1.99	2.99	2.34	0.41
Nitrogen	%	1.90	1.82	2.27	1.54	1.94	1.54	2.27	1.89	0.26
Oxygen	%	11.47	12.02	14.26	10.17	9.23	9.23	14.26	11.43	1.92
Sulfur	%	0.20	0.20	0.35	0.24	0.19	0.19	0.35	0.24	0.07
Ash	%	0.78	0.72	2.18	0.64	0.54	0.54	2.18	0.97	0.68
Metals										
Arsenic	mg/kg	--	--	1.42	<0.29	0.97	<0.29	1.42	1.20	0.32
Beryllium	mg/kg	--	--	<0.043	<0.029	<0.031	<0.029	<0.043	--	--
Cadmium	mg/kg	--	--	<0.021	<0.15	<0.15	<0.021	<0.15	--	--
Chromium	mg/kg	--	--	0.28	0.23	<0.15	<0.15	0.28	0.26	0.04
Lead	mg/kg	--	--	<0.21	<0.15	<0.15	<0.15	<0.21	--	--
Manganese	mg/kg	--	--	7.87	2.75	3.20	2.75	7.87	4.61	2.84
Nickel	mg/kg	--	--	0.55	0.21	<0.15	<0.15	0.55	0.38	0.24
Selenium	mg/kg	--	--	0.82	<0.44	0.47	<0.44	0.82	0.65	0.25

Notes:

-- = not available/analyzed.

Table ACS6
Analytical Results for Ultimate Analyses, DWG Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT 1	2	3	4	5	STATISTICAL ANALYSIS LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbon	%	51.03	51.36	51.79	50.24	58.24	50.24	58.24	52.53	3.24
Hydrogen	%	6.78	6.84	6.54	6.80	6.03	6.03	6.84	6.60	0.34
Nitrogen	%	5.58	5.14	4.96	5.27	5.82	4.96	5.82	5.35	0.35
Oxygen	%	33.72	34.03	31.18	34.72	27.73	27.73	34.72	32.28	2.87
Sulfur	%	0.60	0.58	0.76	0.80	0.57	0.57	0.80	0.66	0.11
Ash	%	2.28	2.05	4.77	2.17	1.61	1.61	4.77	2.58	1.25
Metals										
Arsenic	mg/kg	--	--	3.10	<1.0	2.90	<1.0	3.10	3.00	0.14
Beryllium	mg/kg	--	--	<0.093	<0.10	<0.093	<0.093	<0.10	--	--
Cadmium	mg/kg	--	--	<0.47	<0.50	<0.46	<0.46	<0.50	--	--
Chromium	mg/kg	--	--	0.62	0.79	<0.46	<0.46	0.79	0.71	0.12
Lead	mg/kg	--	--	<0.47	<0.50	<0.46	<0.46	<0.50	--	--
Manganese	mg/kg	--	--	17.20	9.40	9.60	9.40	17.20	12.07	4.45
Nickel	mg/kg	--	--	1.20	0.73	<0.46	<0.46	1.20	0.97	0.33
Selenium	mg/kg	--	--	1.80	<1.5	1.40	<1.5	1.80	1.60	0.28

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS7
Analytical Results for DWG Ash Fusion Temperature, Oxidizing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,226	1,304	1,407	1,226	1,407	1,312	91
Softening	degree F	--	--	1,249	1,432	1,466	1,249	1,466	1,382	117
Hemispherical	degree F	--	--	1,309	1,486	1,544	1,309	1,544	1,446	122
Fluid	degree F	--	--	1,583	2,691	1,849	1,583	2,691	2,041	578

Notes:

-- = not available/analyzed.

Table ACS8
Analytical Results for DWG Ash Fusion Temperature, Reducing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,238	1,327	1,415	1,238	1,415	1,327	89
Softening	degree F	--	--	1,297	1,572	1,531	1,297	1,531	1,467	148
Hemispherical	degree F	--	--	1,358	1,737	1,662	1,358	1,737	1,586	201
Fluid	degree F	--	--	1,912	2,034	1,989	1,912	2,034	1,978	62

Notes:

-- = not available/analyzed.

Table ACS9
Analytical Results for DWG, Ash Mineral Analysis

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Silicon dioxide	wt %	--	--	3.09	3.16	6.87	3.09	6.87	4.37	2.16
Aluminum oxide	wt %	--	--	<0.38	<0.38	<0.38	<0.38	<0.38	--	--
Titanium dioxide	wt %	--	--	<0.03	<0.03	<0.03	<0.03	<0.03	--	--
Iron oxide	wt %	--	--	0.29	<0.29	<0.29	<0.29	0.29	--	--
Calcium oxide	wt %	--	--	<1.4	<1.4	<1.4	<1.4	<1.4	--	--
Magnesium oxide	wt %	--	--	10.25	6.70	9.60	6.70	9.60	8.85	1.89
Potassium oxide	wt %	--	--	26.72	15.42	25.07	15.42	26.72	22.40	6.10
Sodium oxide	wt %	--	--	3.82	1.01	4.31	1.01	4.31	3.05	1.78
Sulfur trioxide	wt %	--	--	1.10	0.50	4.50	0.5	4.50	2.03	2.16
Phosphorus pentoxide	wt %	--	--	41.04	31.93	31.34	31.34	41.04	34.77	5.44
Strontium oxide	wt %	--	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	--
Barium oxide	wt %	--	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	--
Manganese dioxide	wt %	--	--	0.07	0.03	0.04	0.03	0.07	0.05	0.02

Notes:

-- = not available/analyzed.

Table ACS10
Analytical Results for DWG, Ash Nitrogen

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Nitrogen	weight %	--	--	1.38	3.69	1.99	1.38	3.69	2.35	1.20

Notes:

-- = not available/analyzed.

Table ACS11
Sieve Size Analysis Results for DWG, Dry

SIEVE SIZE (US)	NOMINAL SIEVE OPENING		% PASSING					STATISTICAL ANALYSIS			
			PARTNER ETHANOL PLANT								
	NUMBER	UNITS	1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
1/4	6.3	mm	--	--	62.06	65.48	33.38	33.38	65.48	53.64	17.63
1/8	3.15	mm	--	--	19.84	13.33	16.82	13.33	19.84	16.66	3.26
16	1.18	mm	--	--	12.59	14.73	25.03	12.59	25.03	17.45	6.65
20	850	µm	--	--	1.92	2.47	11.04	1.92	11.04	5.14	5.11
30	600	µm	--	--	1.14	1.40	6.46	1.14	6.46	3.00	3.00
40	425	µm	--	--	0.70	0.97	3.90	0.70	3.90	1.86	1.77
<40	<425	µm	--	--	1.75	1.61	3.36	1.61	3.36	2.24	0.97

Notes:

-- = not available/analyzed.

DDGS

Table ACS12
Analytical Results for Proximate Analyses, DDGS As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS*			
		1	2	3	4*	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	8.79	11.55	10.03	59.80	--	8.79	11.55	10.12	1.38
Ash	%	3.51	3.10	3.62	1.68	--	3.10	3.62	3.41	0.27
Volatile matter	%	75.15	72.85	72.88	33.86	--	72.85	75.15	73.63	1.32
Fixed carbon	%	11.87	11.93	12.86	4.24	--	11.87	12.86	12.22	0.56
Sulfur	%	0.68	0.57	0.60	0.42	--	0.57	0.68	0.62	0.06
Heating value	Btu/lb	8,542	8,207	8,354	3,805	--	8,207	8,542	8,368	168
Chlorine	µg/g	--	--	1,638	681	--	NA	NA	NA	NA
Mercury	µg/g	--	--	<0.009	<0.004	--	NA	NA	NA	NA

Notes:

-- = not available/analyzed.

NA = not applicable.

* Data for Partner Ethanol Plant 4 appear to be significantly at odds with data from the other partner plants, and are not included in the statistical analysis.

Table ACS13
Analytical Results for Proximate Analyses, DDGS Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	--	NA	NA	NA	NA
Ash	%	3.85	3.50	4.02	4.17	--	3.50	4.17	3.89	0.29
Volatile matter	%	82.40	82.36	81.01	84.23	--	81.01	84.23	82.50	1.32
Fixed carbon	%	13.02	13.49	14.29	10.55	--	10.55	14.29	12.84	1.61
Sulfur	%	0.74	0.64	0.67	1.04	--	0.64	1.04	0.77	0.18
Heating value	Btu/lb	9,365	9,279	9,285	9,467	--	9,279	9,467	9,349	88
Chlorine	μg/g	--	--	1,820	1,694	--	1,694	1,820	1,757	89
Mercury	μg/g	--	--	<0.010	<0.010	--	<0.010	<0.010	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS14
Analytical Results for Ultimate Analyses, DDGS As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS*			
		1	2	3	4*	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	8.79	11.55	10.03	59.80	--	8.79	11.55	10.12	1.38
Carbon	%	45.73	44.11	45.31	20.34	--	44.11	45.73	45.05	0.84
Hydrogen	%	6.26	6.08	6.16	2.80	--	6.08	6.26	6.17	0.09
Nitrogen	%	4.35	3.83	4.47	2.05	--	3.83	4.47	4.22	0.34
Oxygen	%	30.68	30.77	30.35	12.91	--	30.35	30.68	30.60	0.22
Sulfur	%	0.68	0.57	0.60	0.42	--	0.57	0.68	0.62	0.06
Ash	%	3.51	3.10	3.62	1.68	--	3.10	3.62	3.41	0.27
Metals										
Arsenic	mg/kg	--	--	2.88	<0.33	--	NA	NA	NA	NA
Beryllium	mg/kg	--	--	<0.083	<0.033	--	NA	NA	NA	NA
Cadmium	mg/kg	--	--	<0.41	<0.17	--	NA	NA	NA	NA
Chromium	mg/kg	--	--	0.41	0.21	--	NA	NA	NA	NA
Lead	mg/kg	--	--	<0.41	<0.17	--	NA	NA	NA	NA
Manganese	mg/kg	--	--	15.38	5.95	--	NA	NA	NA	NA
Nickel	mg/kg	--	--	0.74	0.37	--	NA	NA	NA	NA
Selenium	mg/kg	--	--	1.62	0.72	--	NA	NA	NA	NA

Notes:

-- = not available/analyzed.

NA = not applicable.

* Data for Partner Ethanol Plant 4 appear to be significantly at odds with data from the other plants, and are not included in the statistical analysis.

Table ACS15
Analytical Results for Ultimate Analyses, DDGS Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	--	NA	NA	NA	NA
Carbon	%	50.14	49.87	50.36	50.60	--	49.87	51.03	50.24	0.31
Hydrogen	%	6.86	6.88	6.85	6.96	--	6.78	6.96	6.89	0.05
Nitrogen	%	4.77	4.32	4.96	5.11	--	4.32	5.11	4.79	0.34
Oxygen	%	33.63	34.79	33.14	32.12	--	32.12	34.79	33.42	1.11
Sulfur	%	0.74	0.64	0.67	1.04	--	0.64	1.04	0.77	0.18
Ash	%	3.85	3.50	4.02	4.17	--	3.50	4.17	3.89	0.29
Metals										
Arsenic	mg/kg	--	--	3.20	<0.83	--	<0.83	3.20	--	--
Beryllium	mg/kg	--	--	<0.092	<0.083	--	<0.083	<0.092	--	--
Cadmium	mg/kg	--	--	<0.46	<0.42	--	<0.42	<0.46	--	--
Chromium	mg/kg	--	--	0.46	0.53	--	0.46	0.53	0.50	0.05
Lead	mg/kg	--	--	<0.46	<0.42	--	<0.42	<0.46	--	--
Manganese	mg/kg	--	--	17.10	14.80	--	14.80	17.10	15.95	1.63
Nickel	mg/kg	--	--	0.82	0.91	--	0.82	0.91	0.87	0.06
Selenium	mg/kg	--	--	1.80	1.80	--	1.80	1.80	1.80	0.00

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS16
Analytical Results for DDGS Ash Fusion Temperature, Oxidizing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,149	1,013	--	1,013	1,149	1,081	96
Softening	degree F	--	--	1,169	1,028	--	1,028	1,169	1,099	100
Hemispherical	degree F	--	--	1,294	1,307	--	1,294	1,307	1,301	9
Fluid	degree F	--	--	2,596	1,458	--	1,458	2,596	2,027	805

Notes:

-- = not available/analyzed.

Table ACS17
Analytical Results for DDGS Ash Fusion Temperature, Reducing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,242	1,306	--	1,242	1,306	1,274	45
Softening	degree F	--	--	1,297	1,471	--	1,297	1,471	1,384	123
Hemispherical	degree F	--	--	1,329	1,656	--	1,329	1,656	1,493	231
Fluid	degree F	--	--	2,558	2,588	--	2,558	2,588	2,573	21

Notes:

-- = not available/analyzed.

Table ACS18
Analytical Results for DDGS, Ash Mineral Analysis

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Silicon dioxide	wt %	--	--	2.73	3.04	--	2.73	3.04	2.89	0.22
Aluminum oxide	wt %	--	--	<0.38	<0.38	--	<0.38	<0.38	--	--
Titanium dioxide	wt %	--	--	<0.03	<0.03	--	<0.03	<0.03	--	--
Iron oxide	wt %	--	--	0.32	0.30	--	0.30	0.32	0.31	0.01
Calcium oxide	wt %	--	--	<1.4	<1.4	--	<1.4	<1.4	--	--
Magnesium oxide	wt %	--	--	12.17	14.45	--	12.17	14.45	13.31	1.61
Potassium oxide	wt %	--	--	29.41	30.66	--	29.41	30.66	30.04	0.88
Sodium oxide	wt %	--	--	4.98	2.32	--	2.32	4.98	3.65	1.88
Sulfur trioxide	wt %	--	--	1.82	1.32	--	1.32	1.82	1.57	0.35
Phosphorus pentoxide	wt %	--	--	40.98	45.49	--	40.98	45.49	43.24	3.19
Strontium oxide	wt %	--	--	<0.02	<0.02	--	<0.02	<0.02	--	--
Barium oxide	wt %	--	--	<0.02	<0.02	--	<0.02	<0.02	--	--
Manganese dioxide	wt %	--	--	0.06	0.05	--	0.05	0.06	0.06	0.01

Notes:

-- = not available/analyzed.

Table ACS19
Analytical Results for DDGS, Ash Nitrogen Analysis

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Nitrogen	wt %	--	--	1.18	3.69	--	1.18	3.69	2.44	1.77

Notes:

-- = not available/analyzed.

Syrup

Table ACS20
Analytical Results for Proximate Analyses, Syrup As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSES			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	77.17	66.71	58.55	69.32	64.70	58.55	77.17	67.29	6.80
Ash	%	1.39	2.64	3.33	2.50	1.71	1.39	3.33	2.31	0.77
Volatile matter	%	18.98	27.36	33.59	24.82	28.71	18.98	33.59	26.69	5.36
Fixed carbon	%	2.28	3.06	4.07	2.92	4.62	2.28	4.62	3.39	0.94
Sulfur	%	0.19	0.24	0.46	0.44	0.25	0.19	0.46	0.32	0.12
Heating value	Btu/lb	2,100	2,685	3,170	2,818	3,051	2,100	3,170	2,765	418
Chlorine	µg/g	--	--	1,811	870	1,119	870	1,811	1,267	488
Mercury	µg/g	--	--	<0.005	<0.003	<0.004	<0.003	<0.005	--	--

Notes:

-- = not available/analyzed.

Table ACS21

Analytical Results for Proximate Analyses, Syrup Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ash	%	6.09	7.94	8.03	8.16	4.86	4.86	8.16	7.02	1.47
Volatile matter	%	83.10	82.17	81.05	80.89	81.34	80.89	83.10	81.71	0.92
Fixed carbon	%	9.97	9.19	9.82	9.52	13.09	9.19	13.09	10.32	1.58
Sulfur	%	0.84	0.71	1.11	1.43	0.71	0.71	1.43	0.96	0.31
Heating value	Btu/lb	9,198	8,063	7,648	8,859	8,644	7,648	9,198	8,482	623
Chlorine	µg/g	--	--	4,370	2,837	3,169	2,837	4,370	3,459	807
Mercury	µg/g	--	--	<0.012	<0.011	<0.011	<0.011	<0.012	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS22
Analytical Results for Ultimate Analyses, Syrup As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	77.17	66.71	58.55	69.32	64.70	58.55	77.17	67.29	6.80
Carbon	%	10.96	13.22	15.64	14.13	15.56	10.96	15.64	13.90	1.93
Hydrogen	%	1.64	2.46	2.90	2.17	2.38	1.64	2.90	2.31	0.46
Nitrogen	%	0.71	0.54	1.15	0.89	0.97	0.71	1.15	0.85	0.24
Oxygen	%	7.95	14.20	17.97	10.55	14.42	7.95	17.97	13.02	3.86
Sulfur	%	0.19	0.24	0.46	0.44	0.25	0.19	0.46	0.32	0.12
Ash	%	1.39	2.64	3.33	2.50	1.71	1.39	3.33	2.31	0.77
Metals										
Arsenic	mg/kg	--	--	1.24	<0.26	1.13	<0.26	1.24	1.19	0.08
Beryllium	mg/kg	--	--	<0.04	<0.026	<0.039	<0.026	<0.04	--	--
Cadmium	mg/kg	--	--	<0.21	<0.13	<0.19	<0.13	<0.21	--	--
Chromium	mg/kg	--	--	0.39	0.23	0.19	0.19	0.39	0.27	0.11
Lead	mg/kg	--	--	<0.21	<0.13	<0.19	<0.13	<0.21	--	--
Manganese	mg/kg	--	--	9.45	13.07	13.91	9.45	13.91	12.14	2.37
Nickel	mg/kg	--	--	0.99	0.61	0.53	0.53	0.99	0.71	0.25
Selenium	mg/kg	--	--	<0.62	0.46	<0.56	<0.56	0.46	--	--

Notes:

-- = not available/analyzed.

Table ACS23
Analytical Results for Ultimate Analyses, Syrup Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbon	%	47.99	39.72	37.75	46.07	44.06	37.75	47.99	43.12	4.29
Hydrogen	%	7.17	7.39	6.99	7.07	6.73	6.73	7.39	7.07	0.24
Nitrogen	%	3.12	1.61	2.77	2.89	2.75	1.61	3.12	2.63	0.59
Oxygen	%	34.80	42.64	43.35	34.38	40.86	34.38	43.35	39.21	4.31
Sulfur	%	0.84	0.71	1.11	1.43	0.71	0.71	1.43	0.96	0.31
Ash	%	6.09	7.94	8.03	8.16	4.86	4.86	8.16	7.02	1.47
Metals										
Arsenic	mg/kg	--	--	3.00	<0.85	3.20	<0.85	3.20	3.10	0.14
Beryllium	mg/kg	--	--	<0.10	<0.085	<0.11	<0.085	<0.11	--	--
Cadmium	mg/kg	--	--	<0.51	<0.43	<0.53	<0.43	<0.53	--	--
Chromium	mg/kg	--	--	0.94	0.76	0.55	0.55	0.94	0.75	0.20
Lead	mg/kg	--	--	<0.51	<0.43	<0.53	<0.43	<0.53	--	--
Manganese	mg/kg	--	--	22.80	42.60	39.40	22.80	42.60	34.93	10.63
Nickel	mg/kg	--	--	2.40	2.00	1.50	1.50	2.40	1.97	0.45
Selenium	mg/kg	--	--	<1.50	1.50	<1.60	<1.50	1.50	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

Table ACS24
Analytical Results for Syrup Ash Fusion Temperature, Oxidizing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,214	2,708	1,814	1,214	2,708	1,912	752
Softening	degree F	--	--	1,242	2,715	2,602	1,242	2,715	2,186	820
Hemispherical	degree F	--	--	2,435	2,722	2,629	2,435	2,722	2,595	146
Fluid	degree F	--	--	2,682	2,733	2,671	2,671	2,733	2,695	33

Notes:

-- = not available/analyzed.

Table ACS25
Analytical Results for Syrup Ash Fusion Temperature, Reducing Atmosphere

PARAMETER	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSES			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	degree F	--	--	1,544	2,295	1,855	1,544	2,295	1,898	377
Softening	degree F	--	--	1,690	2,305	2,532	1,690	2,532	2,176	436
Hemispherical	degree F	--	--	1,909	2,313	2,639	1,909	2,639	2,287	366
Fluid	degree F	--	--	2,641	2,671	2,660	2,641	2,671	2,657	15

Notes:

-- = not available/analyzed.

Table ACS26
Analytical Results for Syrup, Ash Mineral Analysis

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSES			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Silicon dioxide	wt %	--	--	<2.14	2.42	<2.14	<2.14	2.42	--	--
Aluminum oxide	wt %	--	--	<0.38	<0.38	<0.38	<0.38	<0.38	--	--
Titanium dioxide	wt %	--	--	<0.03	<0.03	<0.03	<0.03	<0.03	--	--
Iron oxide	wt %	--	--	0.93	<0.29	0.90	<0.29	0.93	0.92	0.02
Calcium oxide	wt %	--	--	<1.4	<1.4	<1.4	<1.4	<1.4	--	--
Magnesium oxide	wt %	--	--	9.97	13.84	8.61	8.61	13.84	10.81	2.71
Potassium oxide	wt %	--	--	29.32	31.19	20.59	20.59	31.19	27.03	5.66
Sodium oxide	wt %	--	--	4.11	2.11	3.31	2.11	4.11	3.18	1.01
Sulfur trioxide	wt %	--	--	6.02	7.38	4.22	4.22	7.38	5.87	1.59
Phosphorus pentoxide	wt %	--	--	32.04	32.41	26.01	26.01	32.41	30.15	3.59
Strontium oxide	wt %	--	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	--
Barium oxide	wt %	--	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	--
Manganese dioxide	wt %	--	--	0.04	0.05	0.07	0.04	0.07	0.05	0.02

Notes:

-- = not available/analyzed.

Table ACS27
Analytical Results for Syrup Ash Nitrogen

MINERAL	UNITS	PARTNER ETHANOL PLANT					STATISTICAL ANALYSES			
		1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Nitrogen	wt %	--	--	1.45	0.96	2.23	0.96	2.23	1.55	0.64

Notes:

-- = not available/analyzed.

Table ACS28
Analytical Results for Syrup, Density

	PARTNER ETHANOL PLANT					STATISTICAL ANALYSIS			
	1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
Density (kg/m^3)	--	--	1,131	1,010	1,096	1,010	1,131	1,079	62

Notes:

-- = not available/analyzed.

Table ACS29
Analytical Results for Syrup Viscosity, As Received

TEMPERATURE (degree F)	PARTNER ETHANOL PLANT (units are cP)					STATISTICAL ANALYSIS			
	1	2	3	4	5	LOW	HIGH	MEAN	STD. DEVIATION
32	--	--	18,700	1,240	8,660	1,240	18,700	9,533	8,763
72	--	--	7,130	870	8,020	870	8,020	5,340	3,897
210	--	--	3,660	100	1,060	100	3,660	1,607	1,842

Notes:

-- = not available/analyzed.

Corn Stover

Table ACS30
Analytical Results for Proximate Analyses, Corn Stover

PARAMETER	UNITS	AS RECEIVED	MOISTURE FREE
Moisture	%	6.15	NA
Ash	%	6.31	6.73
Volatile matter	%	62.49	66.58
Fixed carbon	%	25.01	26.65
Sulfur	%	0.04	0.04
Heating value	Btu/lb	7,235	7,709
Chlorine	µg/g	836	984
Mercury	µg/g	<0.010	<0.010

Notes:

NA = not applicable.

Table ACS31
Analytical Results for Ultimate Analyses, Corn Stover

PARAMETER	UNITS	AS RECEIVED	MOISTURE FREE
Moisture	%	6.15	NA
Ash	%	6.31	6.73
Carbon	%	42.68	45.48
Hydrogen	%	5.18	5.52
Nitrogen	%	0.65	0.69
Oxygen	%	38.96	41.52
Metals			
Arsenic	mg/kg	2.35	2.50
Beryllium	mg/kg	<0.084	<0.089
Cadmium	mg/kg	<0.42	<0.45
Chromium	mg/kg	<0.42	<0.45
Lead	mg/kg	0.43	0.46
Manganese	mg/kg	21.96	23.4
Nickel	mg/kg	<0.42	<0.45
Selenium	mg/kg	<0.056	<1.30

Notes:

NA = not applicable.

Table ACS32
Analytical Results for Corn Stover Ash Fusion Temperature, Oxidizing Atmosphere

PARAMETER	UNITS	CORN STOVER
Initial deformation	degree F	1,930
Softening	degree F	1,984
Hemispherical	degree F	2,100
Fluid	degree F	2,205

Table ACS33

Analytical Results for Corn Stover Ash Fusion Temperature, Reducing Atmosphere

PARAMETER	UNITS	CORN STOVER
Initial deformation	degree F	1,624
Softening	degree F	1,718
Hemispherical	degree F	1,909
Fluid	degree F	2,194

Table ACS34
Analytical Results for Corn Stover Ash Mineral Analysis

MINERAL	UNITS	CORN STOVER
Silicon dioxide	wt %	54.12
Aluminum oxide	wt %	0.78
Titanium dioxide	wt %	0.04
Iron oxide	wt %	0.45
Calcium oxide	wt %	5.61
Magnesium oxide	wt %	4.22
Potassium oxide	wt %	20.22
Sodium oxide	wt %	1.47
Sulfur trioxide	wt %	12.75
Phosphorus pentoxide	wt %	1.97
Strontium oxide	wt %	<0.02
Barium oxide	wt %	0.02
Manganese dioxide	wt %	0.06

Feed Stream

Table ACS35
Proximate Analyses, Samples Moisture Free*

PARAMETER	UNITS	FEED STREAM				STATISTICAL ANALYSES (not including Stover)			
		SYRUP	DWG	DDGS	STOVER	LOW	HIGH	MEAN	STD. DEVIATION
Ash	%	7.02	4.77	3.89	6.73	3.89	7.02	5.23	1.61
Volatile matter	%	81.71	83.18	82.50	66.58	81.71	83.18	82.46	0.74
Fixed carbon	%	10.32	13.58	12.84	26.65	10.32	13.58	12.25	1.71
Sulfur	%	0.96	0.66	0.77	0.04	0.66	0.96	0.80	0.15
Heating value	Btu/lb	8,482	9,438	9,349	7,709	8,482	9,438	9,090	528
Chlorine	µg/g	3,459	1,673	1,757	984	1,673	3,459	2,296	1,008
Mercury	µg/g	<0.12	<0.12	<0.10	<0.10	<0.10	<0.12	--	--

Notes:

-- = not available/analyzed.

* All values, except Corn Stover, are the Means from the applicable individual feed stream tables.

Table ACS36
Ultimate Analyses, Samples Moisture Free*

PARAMETER	UNITS	FEED STREAM				STATISTICAL ANALYSES (not including Stover)			
		SYRUP	DWG	DDGS	STOVER	LOW	HIGH	MEAN	STD. DEVIATION
Carbon	%	43.12	52.53	50.47	45.48	43.12	52.53	48.71	4.95
Hydrogen	%	7.07	6.60	6.87	5.52	6.60	7.07	6.85	0.24
Nitrogen	%	2.63	5.35	4.99	0.69	2.63	5.35	4.32	1.48
Oxygen	%	39.21	32.28	33.59	41.52	32.28	39.21	35.03	3.68
Sulfur	%	0.96	0.66	0.77	0.04	0.66	0.96	0.80	0.15
Ash	%	7.02	2.58	3.89	6.73	2.58	7.02	4.50	2.28
Metals									
Arsenic	mg/kg	3.10	3.00	3.20	2.50	3.00	3.20	3.10	0.10
Beryllium	mg/kg	--	--	--	<0.089	--	--	--	--
Cadmium	mg/kg	--	--	--	<0.45	--	--	--	--
Chromium	mg/kg	0.75	0.71	0.5	<0.45	--	--	0.65	0.13
Lead	mg/kg	--	--	--	0.46	--	--	--	--
Manganese	mg/kg	34.93	12.07	15.95	23.4	12.07	34.93	20.98	12.23
Nickel	mg/kg	1.97	0.97	0.87	<0.45	0.87	1.97	1.27	0.61
Selenium	mg/kg	1.50	1.60	1.80	<1.30	1.5	1.8	1.63	0.15

Notes:

-- = not available/analyzed.

* All values, except Corn Stover, are the Means from the applicable individual feed stream tables.

Table ACS37
Ash Fusion, Oxidizing Atmosphere*

PARAMETER	UNITS	FEED STREAM				STATISTICAL ANALYSES (not including Stover)			
		SYRUP	DWG	DDGS	STOVER	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	deg F	1,912	1,312	1,081	1,930	1,081	1,912	1,435	429
Softening	deg F	2,186	1,382	1,099	1,984	1,099	2,186	1,556	564
Hemispherical	deg F	2,595	1,446	1,301	2,100	1,301	2,595	1,781	709
Fluid	deg F	2,695	2,041	2,027	2,205	2,027	2,695	2,254	382

Notes:

* All values, except Corn Stover, are the Means from the applicable individual feed stream tables.

Table ACS38
Ash Fusion, Reducing Atmosphere*

PARAMETER	UNITS	FEED STREAM				STATISTICAL ANALYSES (not including Stover)			
		SYRUP	DWG	DDGS	STOVER	LOW	HIGH	MEAN	STD. DEVIATION
Initial deformation	deg F	1,898	1,327	1,274	1,624	1,274	1,898	1,500	346
Softening	deg F	2,176	1,467	1,384	1,718	1,384	2,176	1,676	435
Hemispherical	deg F	2,287	1,586	1,493	1,909	1,493	2,287	1,789	434
Fluid	deg F	2,657	1,978	2,573	2,194	1,978	2,657	2,403	370

Notes:

* All values, except Corn Stover, are the Means from the applicable individual feed stream tables.

Table ACS39
Ash Mineral Analysis*

PARAMETER	UNITS	FEED STREAM				STATISTICAL ANALYSES (not including Stover)			
		SYRUP	DWG	DDGS	STOVER	LOW	HIGH	MEAN	STD. DEVIATION
Silicon dioxide	wt %	2.42	4.37	2.89	54.12	2.42	4.37	3.23	1.02
Aluminum oxide	wt %	--	--	--	0.78	--	--	--	--
Titanium dioxide	wt %	--	--	--	0.04	--	--	--	--
Iron oxide	wt %	0.92	0.29	0.31	0.45	0.29	0.92	0.51	0.36
Calcium oxide	wt %	--	--	--	5.61	--	--	--	--
Magnesium oxide	wt %	10.81	8.85	13.31	4.22	8.85	13.31	10.99	2.24
Potassium oxide	wt %	27.03	22.40	30.04	20.22	22.40	30.04	26.49	3.85
Sodium oxide	wt %	3.18	3.05	3.65	1.47	3.05	3.65	3.29	0.32
Sulfur trioxide	wt %	5.87	2.03	1.57	12.75	1.57	5.87	3.16	2.36
Phosphorus pentoxide	wt %	30.15	34.77	43.24	1.97	30.15	43.24	36.05	6.64
Strontium oxide	wt %	--	--	--	<0.02	--	--	--	--
Barium oxide	wt %	--	--	--	0.02	--	--	--	--
Manganese dioxide	wt %	0.05	0.05	0.06	0.06	0.05	0.06	0.05	0.01

Notes:

-- = not available/analyzed.

* All values, except Corn Stover, are the Means from the applicable individual feed stream tables.

DWG Literature

Table ACS40
Analytical Results and Literature Values for Ultimate Analyses, DWG Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE		STATISTICAL ANALYSIS*			
		1	2	3	4	5	K	O	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbon	%	51.03	51.36	51.79	50.24	58.24	--	--	50.24	58.24	52.53	3.24
Hydrogen	%	6.78	6.84	6.54	6.80	6.03	--	--	6.03	6.84	6.60	0.34
Nitrogen	%	5.58	5.14	4.96	5.27	5.82	--	--	4.96	5.82	5.35	0.35
Oxygen	%	33.72	34.03	31.18	34.72	27.73	--	--	27.73	34.72	32.28	2.87
Sulfur	%	0.60	0.58	0.76	0.80	0.57	--	--	0.57	0.80	0.66	0.11
Ash	%	2.28	2.05	4.77	2.17	1.61	--	--	1.61	4.77	2.58	1.25
Metals												
Arsenic	mg/kg	--	--	3.10	<1.0	2.90	--	--	<1.0	3.10	3.00	0.14
Beryllium	mg/kg	--	--	<0.093	<0.10	<0.093	--	--	<0.093	<0.10	--	--
Cadmium	mg/kg	--	--	<0.47	<0.50	<0.46	--	--	<0.46	<0.50	--	--
Chromium	mg/kg	--	--	0.62	0.79	<0.46	--	--	<0.46	0.79	0.71	0.12
Lead	mg/kg	--	--	<0.47	<0.50	<0.46	--	--	<0.46	<0.50	--	--
Manganese	mg/kg	--	--	17.20	9.40	9.60	--	--	9.40	17.20	12.07	4.45
Nickel	mg/kg	--	--	1.20	0.73	<0.46	--	--	<0.46	1.20	0.97	0.33
Phosphorus	%	--	--	--	--	--	0.54	0.50 - 0.80	NA	NA	NA	NA
Potassium	%	--	--	--	--	--	0.59	0.50 - 1.00	NA	NA	NA	NA
Selenium	mg/kg	--	--	1.80	<1.5	1.40	--	--	<1.5	1.80	1.60	0.28

Notes:

-- = not available/analyzed.

NA = not applicable.

* Literature values are not included in the statistical analysis.

References:

K = Belyea, R.L., K.D. Rausch, and M.E. Tumbleson. 2004. Composition of corn and distillers dried grains with solubles from dry grind ethanol processing. Bioresource Technology 94:293-298. Mean value of nine samples.

O = Lardy, Greg, Ph.D. 2003. Feeding coproducts of the ethanol industry to beef cattle. North Dakota State University.

DDG Literature

Table ACS41

Analytical Results and Literature Values for Proximate Analyses, DDG

PARAMETER	UNITS	LITERATURE E AS RECEIVED	 E MOISTURE FREE
Moisture	%	13.35	NA
Ash	%	1.96	2.24
Volatile matter	%	--	--
Fixed carbon	%	--	--
Sulfur	%	0.34	0.4
Heating value	Btu/lb	8,473	9,848
Chlorine	μg/g	--	--
Mercury	μg/g	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

References:

E = Agricultural Utilization Research Institute. Fuels initiative. Waseca, Minnesota. Average of multiple samples. Number of samples not reported.

Table ACS42

ure Values for Ultimate Analyses, DDG, Including Select Metals

PARAMETER	UNITS	LITERATURE
		O
Moisture	%	--
Carbon	%	--
Hydrogen	%	--
Nitrogen	%	--
Oxygen	%	--
Sulfur	%	--
Ash	%	--
Metals		
Arsenic	mg/kg	--
Beryllium	mg/kg	--
Cadmium	mg/kg	--
Chromium	mg/kg	--
Lead	mg/kg	--
Manganese	mg/kg	--
Nickel	mg/kg	--
Phosphorus	%	0.40 - 0.80
Potassium	%	0.49 - 1.08
Selenium	mg/kg	--

Notes:

-- = not available/analyzed.

NA = not applicable.

References:

O = Lardy, Greg, Ph.D. 2003. Feeding coproducts of the ethanol industry to beef cattle. North Dakota State University.

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DDGS Literature

Table ACS43
Analytical Results and Literature Values for Ultimate Analyses, DDGS as Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE				STATISTICAL ANALYSIS*			
		1	2	3	4*	5	A	B	I	J	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	8.79	11.55	10.03	59.80	--	9.00	10.78	--	11.70	8.79	11.55	10.12	1.38
Carbon	%	45.73	44.11	45.31	20.34	--	--	--	--	--	44.11	45.73	45.05	0.84
Hydrogen	%	6.26	6.08	6.16	2.80	--	--	--	--	--	6.08	6.26	6.17	0.09
Nitrogen	%	4.35	3.83	4.47	2.05	--	--	--	--	--	3.83	4.47	4.22	0.34
Oxygen	%	30.68	30.77	30.35	12.91	--	--	--	--	--	30.35	30.68	30.60	0.22
Sulfur	%	0.68	0.57	0.60	0.42	--	--	--	--	--	0.57	0.68	0.62	0.06
Ash	%	3.51	3.10	3.62	1.68	--	4.90	5.35	--	4.00	3.10	3.62	3.41	0.27
Metals														
Arsenic	mg/kg	--	--	2.88	<0.33	--	--	--	--	--	NA	NA	NA	NA
Beryllium	mg/kg	--	--	<0.083	<0.033	--	--	--	--	--	NA	NA	NA	NA
Cadmium	mg/kg	--	--	<0.41	<0.17	--	--	--	--	--	NA	NA	NA	NA
Chromium	mg/kg	--	--	0.41	0.21	--	--	--	--	--	NA	NA	NA	NA
Lead	mg/kg	--	--	<0.41	<0.17	--	--	--	--	--	NA	NA	NA	NA
Manganese	mg/kg	--	--	15.38	5.95	--	25	17	--	--	NA	NA	NA	NA
Nickel	mg/kg	--	--	0.74	0.37	--	--	--	--	--	NA	NA	NA	NA
Phosphorus	%	--	--	--	--	--	0.75	0.69	0.79	0.73	NA	NA	NA	NA
Potassium	%	--	--	--	--	--	0.7	0.9	--	0.95	NA	NA	NA	NA
Selenium	mg/kg	--	--	1.62	0.72	--	0.42	--	--	--	NA	NA	NA	NA

Notes:

-- = not available/analyzed.

NA = not applicable.

* Data for Partner Ethanol Plant 4 appear to be significantly at odds with data from the other plants, and are not included in the statistical analysis. Literature values are not included in the statistical analysis.

References:

A = Distillers Grain Technology Council. 2005. Louisville, Kentucky. Typical values.

B = Average of 34 samples. Converted from 100% dry matter basis. University of Minnesota. 2006. Nutrient profiles.

I = Knott, Jeff and Jerry Shurson, University of Minnesota, and John Goihl, Agri-Nutrition Services. Effects of the nutrient variability of distiller's solubles and grains within ethanol plants. Shakopee, Minnesota.

J = Noll, S.L., C. Parsons, C. Abe, and J. Brannon. 2002. Nutrient composition of corn distiller dried grain with solubles. University of Minnesota and Illinois. Average of five samples. Average of 20 samples.

Table ACS44
Analytical Results and Literature Values for Ultimate Analyses, DDGS Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE					STATISTICAL ANALYSIS*			
		1	2	3	4	5	K	L	M	O	P	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	--	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbon	%	50.14	49.87	50.36	50.60	--	--	--	--	--	--	49.87	51.03	50.24	0.31
Hydrogen	%	6.86	6.88	6.85	6.96	--	--	--	--	--	--	6.78	6.96	6.89	0.05
Nitrogen	%	4.77	4.32	4.96	5.11	--	--	--	--	--	--	4.32	5.11	4.79	0.34
Oxygen	%	33.63	34.79	33.14	32.12	--	--	--	--	--	--	32.12	34.79	33.42	1.11
Sulfur	%	0.74	0.64	0.67	1.04	--	--	--	--	--	--	0.64	1.04	0.77	0.18
Ash	%	3.85	3.50	4.02	4.17	--	--	6.00	4.2	--	5.80	3.50	4.17	3.89	0.29
Metals															
Arsenic	mg/kg	--	--	3.20	<0.83	--	--	--	--	--	--	<0.83	3.20	--	--
Beryllium	mg/kg	--	--	<0.092	<0.083	--	--	--	--	--	--	<0.083	<0.092	--	--
Cadmium	mg/kg	--	--	<0.46	<0.42	--	--	--	--	--	--	<0.42	<0.46	--	--
Chromium	mg/kg	--	--	0.46	0.53	--	--	--	--	--	--	0.46	0.53	0.50	0.05
Lead	mg/kg	--	--	<0.46	<0.42	--	--	--	--	--	--	<0.42	<0.46	--	--
Manganese	mg/kg	--	--	17.10	14.80	--	--	--	--	--	--	14.80	17.10	15.95	1.63
Nickel	mg/kg	--	--	0.82	0.91	--	--	--	--	--	--	0.82	0.91	0.87	0.06
Phosphorus	%	--	--	--	--	--	0.86	0.76	0.83	0.40 - 0.80	6.89	NA	NA	NA	NA
Potassium	%	--	--	--	--	--	1.12	1.00	1.19	0.87 - 1.33	--	NA	NA	NA	NA
Selenium	mg/kg	--	--	1.80	1.80	--	--	--	--	--	--	1.80	1.80	1.80	0.00

Notes:

-- = not available/analyzed.

NA = not applicable.

* Literature values are not included in the statistical analysis.

References:

K = Belyea, R.L., K.D. Rausch, and M.E. Tumbleson. 2004. Composition of corn and distillers dried grains with solubles from dry grind ethanol processing. Bioresource Technology 94:293-298. Mean value of nine samples.

L = The value and use of distillers dried grains with solubles (DDGS) in livestock and poultry feeds. University of Minnesota. 2005. Average of 32 plants.

M = Dakota Gold Marketing - Enhanced nutrition distillers products. Dakota Gold. 2005.

O = Lardy, Greg, Ph.D. 2003. Feeding coproducts of the ethanol industry to beef cattle. North Dakota State University.

P = Spiehs, M.J., M.H. Whitney, and G.C. Shurson. 2002. Nutrient database for distiller's dried grains with solubles produced from new ethanol plants in Minnesota and South Dakota. University of Minnesota. Mean value of 118 samples.

Table ACS45
Analytical Results and Literature Values for Proximate Analyses, DDGS As Received

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE	STATISTICAL ANALYSIS*			
		1	2	3	4*	5	E	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	8.79	11.55	10.03	59.80	--	9.27	8.79	11.55	10.12	1.38
Ash	%	3.51	3.10	3.62	1.68	--	4.16	3.10	3.62	3.41	0.27
Volatile matter	%	75.15	72.85	72.88	33.86	--	--	72.85	75.15	73.63	1.32
Fixed carbon	%	11.87	11.93	12.86	4.24	--	--	11.87	12.86	12.22	0.56
Sulfur	%	0.68	0.57	0.60	0.42	--	0.40	0.57	0.68	0.62	0.06
Heating value	Btu/lb	8,542	8,207	8,354	3,805	--	8,459	8,207	8,542	8,368	168
Chlorine	µg/g	--	--	1,638	681	--	--	NA	NA	NA	NA
Mercury	µg/g	--	--	<0.009	<0.004	--	--	NA	NA	NA	NA

Notes:

-- = not available/analyzed.

NA = not applicable.

* Data for Partner Ethanol Plant 4 appear to be significantly at odds with data from the other partner plants, and are not included in the statistical analysis. Literature values are not included in the statistical analysis.

References:

E = Agricultural Utilization Research Institute. Fuels initiative. Waseca, Minnesota. Average of multiple samples. Number of samples not received.

Table ACS46
Analytical Results and Literature Values for Proximate Analyses, DDGS Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE	STATISTICAL ANALYSIS*			
		1	2	3	4	5	E	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	--	NA	NA	NA	NA	NA
Ash	%	3.85	3.50	4.02	4.17	--	4.13	3.50	4.17	3.89	0.29
Volatile matter	%	82.40	82.36	81.01	84.23	--	--	81.01	84.23	82.50	1.32
Fixed carbon	%	13.02	13.49	14.29	10.55	--	--	10.55	14.29	12.84	1.61
Sulfur	%	0.74	0.64	0.67	1.04	--	0.45	0.64	1.04	0.77	0.18
Heating value	Btu/lb	9,365	9,279	9,285	9,467	--	9,422	9,279	9,467	9,349	88
Chlorine	µg/g	--	--	1,820	1,694	--	--	1,694	1,820	1,757	89
Mercury	µg/g	--	--	<0.010	<0.010	--	--	<0.010	<0.010	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

* Literature values are not included in the statistical analysis.

References:

E = Agricultural Utilization Research Institute. Fuels initiative. Waseca, Minnesota. Average of multiple samples. Number of samples not reported.

Table ACS47
Bulk Density Literature Values for DDGS, Dry

LABEL	BULK DENSITY	UNITS	REFERENCE
Control 1	31.0 - 35.5	lb/ft^3	F
Control 2	31.3 - 36.8	lb/ft^3	F
Average	35.7	lb/ft^3	G
Control 1	33.2	lb/ft^3	H
Control 2	34.05	lb/ft^3	H

Notes:
-- = not available/analyzed.
NA = not applicable.

References:
F = Jenike & Johanson, Inc. 2005. Flow properties test report dried distillers' grain. San Luis Obispo, California. Average of four measurements from one sample.
G = Knott, Jeff and Jerry Shurson, University of Minnesota and John Goihl, Agri-Nutrition Services. 2001. Variation in particle size and bulk density of distiller's dried grains with solubles (DDGS) produced by "new generation" ethanol plants in Minnesota and South Dakota. Average of 16 samples.
H = Jenike and Johanson, Inc. 2005. Distiller's dried grains flowability report. San Luis Obispo, California. Results from one sample.

Table ACS48
Sieve Size Literature Values for DDGS, Dry

CONTROL 1, R		CONTROL 2, R	
SIZE (µm)	% PASSING	SIZE (µm)	% PASSING
90.278	0.00	90.278	0.01
106.266	0.00	106.266	0.06
125.085	0.00	125.085	0.13
147.238	0.00	147.238	0.20
173.314	0.00	173.314	0.27
204.008	0.00	204.008	0.32
240.137	0.00	240.137	0.37
282.665	0.00	282.665	0.50
332.725	0.00	332.725	1.01
391.651	0.02	391.651	2.56
461.012	0.78	461.012	5.95
542.656	3.63	542.656	11.96
638.761	9.92	638.761	21.06
751.885	20.57	751.885	33.14
885.043	35.42	885.043	47.41
1,041.784	52.94	1,041.784	62.43
1,226.283	70.55	1,226.283	76.49
1,443.457	85.42	1,443.457	88.03
1,699.092	95.50	1,699.092	96.03
2,000.000	100.00	2,000.000	100.00

References:

R = Jenike & Johanson, Inc. 2005. Flow properties test report dried distillers' grain. San Luis Obispo, California.

Syrup Literature

Table ACS49
Analytical Results and Literature Values for Ultimate Analyses, Syrup Moisture Free

PARAMETER	UNITS	PARTNER ETHANOL PLANT					LITERATURE		STATISTICAL ANALYSIS*			
		1	2	3	4	5	K	O	LOW	HIGH	MEAN	STD. DEVIATION
Moisture	%	NA	NA	NA	NA	NA	--	--	NA	NA	NA	NA
Carbon	%	47.99	39.72	37.75	46.07	44.06	--	--	37.75	47.99	43.12	4.29
Hydrogen	%	7.17	7.39	6.99	7.07	6.73	--	--	6.73	7.39	7.07	0.24
Nitrogen	%	3.12	1.61	2.77	2.89	2.75	--	--	1.61	3.12	2.63	0.59
Oxygen	%	34.80	42.64	43.35	34.38	40.86	--	--	34.38	43.35	39.21	4.31
Sulfur	%	0.84	0.71	1.11	1.43	0.71	--	--	0.71	1.43	0.96	0.31
Ash	%	6.09	7.94	8.03	8.16	4.86	--	--	4.86	8.16	7.02	1.47
Metals												
Arsenic	mg/kg	--	--	3.00	<0.85	3.20	--	--	<0.85	3.20	3.10	0.14
Beryllium	mg/kg	--	--	<0.10	<0.085	<0.11	--	--	<0.085	<0.11	--	--
Cadmium	mg/kg	--	--	<0.51	<0.43	<0.53	--	--	<0.43	<0.53	--	--
Chromium	mg/kg	--	--	0.94	0.76	0.55	--	--	0.55	0.94	0.75	0.20
Lead	mg/kg	--	--	<0.51	<0.43	<0.53	--	--	<0.43	<0.53	--	--
Manganese	mg/kg	--	--	22.80	42.60	39.40	--	--	22.80	42.60	34.93	10.63
Nickel	mg/kg	--	--	2.40	2.00	1.50	--	--	1.50	2.40	1.97	0.45
Phosphorus	%	--	--	--	--	--	1.52	1.30 - 1	NA	NA	NA	NA
Potassium	%	--	--	--	--	--	2.32	1.75 - 2	NA	NA	NA	NA
Selenium	mg/kg	--	--	<1.50	1.50	<1.60	--	--	<1.50	1.50	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

* Literature values are not included in the statistical analysis.

References:

K = Belyea, R.L., K.D. Rausch, and M.E. Tumbleson. 2004. Composition of corn and distillers dried grains with solubles from dry grind ethanol processing. Bioresource Technology 94:293-298. Mean value of nine samples.

O = Lardy, Greg, Ph.D. 2003. Feeding coproducts of the ethanol industry to beef cattle. North Dakota State University.

Corn Stover Literature

Table ACS50
Analytical Results and Literature Values for Proximate Analyses, Corn Stover

				LITERATURE								
		CORN STOVER		C	C	C	D	D	D	E	E	N
PARAMETER	UNITS	AS RECEIVED	MOISTURE FREE	AS RECEIVED	MOISTURE FREE	MOISTURE AND ASH FREE	AS RECEIVED	MOISTURE FREE	MOISTURE AND ASH FREE	AS RECEIVED	MOISTURE FREE	MOISTURE FREE
Moisture	%	6.15	NA	6.1	NA	NA	5.9	NA	NA	9.14	NA	NA
Ash	%	6.31	6.73	4.7	5.1	NA	20.3	21.6	NA	6.81	7.64	5.58
Volatile matter	%	62.49	66.58	76	80.9	85.2	60.1	63.9	81.5	--	--	75.17
Fixed carbon	%	25.01	26.65	--	--	--	--	--	--	--	--	19.25
Sulfur	%	0.04	0.04	0.1	0.11	0.11	0.08	0.09	0.11	0.035	0.04	0.01
Heating value	Btu/lb	7,235	7,709	7,361	7,836	8,253	5,904	6,274	8,000	7,057	7,768	7,588
Chlorine	µg/g	836	984	--	--	--	--	--	--	--	--	--
Mercury	µg/g	<0.010	<0.010	--	--	--	--	--	--	--	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

References:

C = National Renewable Energy Laboratory. 1998. Golden, Colorado. Single corn stover analysis.

D = Evans, R.J., A.R. Knight, M. Onischak, and S.P. Babu. 1988. Development of biomass gasification to produce substitute fuels. Richland, Washington, USA. Pacific Northwest Laboratory (PNL). PNL--6518, 14 p. Single corn stover analysis.

E = Agricultural Utilization Research Institute. Fuels initiative. Waseca, Minnesota. Average of multiple samples. Number of samples not reported.

N = Brown, Robert C. 2003. Biorenewable resources. Iowa State Press. Table 3.3, p. 67.

Table ACS51
Analytical Results and Literature Values for Ultimate Analyses, Corn Stover

				LITERATURE						
		CORN STOVER		C	C	C	D	D	D	N
PARAMETER	UNITS	AS RECEIVED	MOISTURE FREE	AS RECEIVED	MOISTURE FREE	MOISTURE AND ASH FREE	AS RECEIVED	MOISTURE FREE	MOISTURE AND ASH FREE	MOISTURE FREE
Moisture	%	6.15	NA	6.1	NA	NA	5.9	NA	NA	NA
Ash	%	6.31	6.73	4.7	5.1	NA	20.3	21.6	NA	6.26
Carbon	%	42.68	45.48	44	46.8	49.3	35.6	37.8	48.2	43.65
Hydrogen	%	5.18	5.52	5.4	5.74	6	4.6	4.84	6.2	5.56
Nitrogen	%	0.65	0.69	0.62	0.66	0.7	0.61	0.65	0.83	0.61
Oxygen	%	38.96	41.52	38.9	41.4	43.6	33	35	44.7	43.31
Metals										
Arsenic	mg/kg	2.35	2.50	--	--	--	--	--	--	--
Beryllium	mg/kg	<0.084	<0.089	--	--	--	--	--	--	--
Cadmium	mg/kg	<0.42	<0.45	--	--	--	--	--	--	--
Chromium	mg/kg	<0.42	<0.45	--	--	--	--	--	--	--
Lead	mg/kg	0.43	0.46	--	--	--	--	--	--	--
Manganese	mg/kg	21.96	23.4	--	--	--	--	--	--	--
Nickel	mg/kg	<0.42	<0.45	--	--	--	--	--	--	--
Selenium	mg/kg	<0.056	<1.30	--	--	--	--	--	--	--

Notes:

-- = not available/analyzed.

NA = not applicable.

References:

C = National Renewable Energy Laboratory. 1998. Golden, Colorado. Single corn stover analysis.

D = Evans, R.J., A.R. Knight, M. Onischak, and S.P. Babu. 1988. Development of biomass gasification to produce substitute fuels. Richland, Washington, USA. Pacific Northwest Laboratory (PNL). PNL--6518, 14 p. Single corn stover analysis.

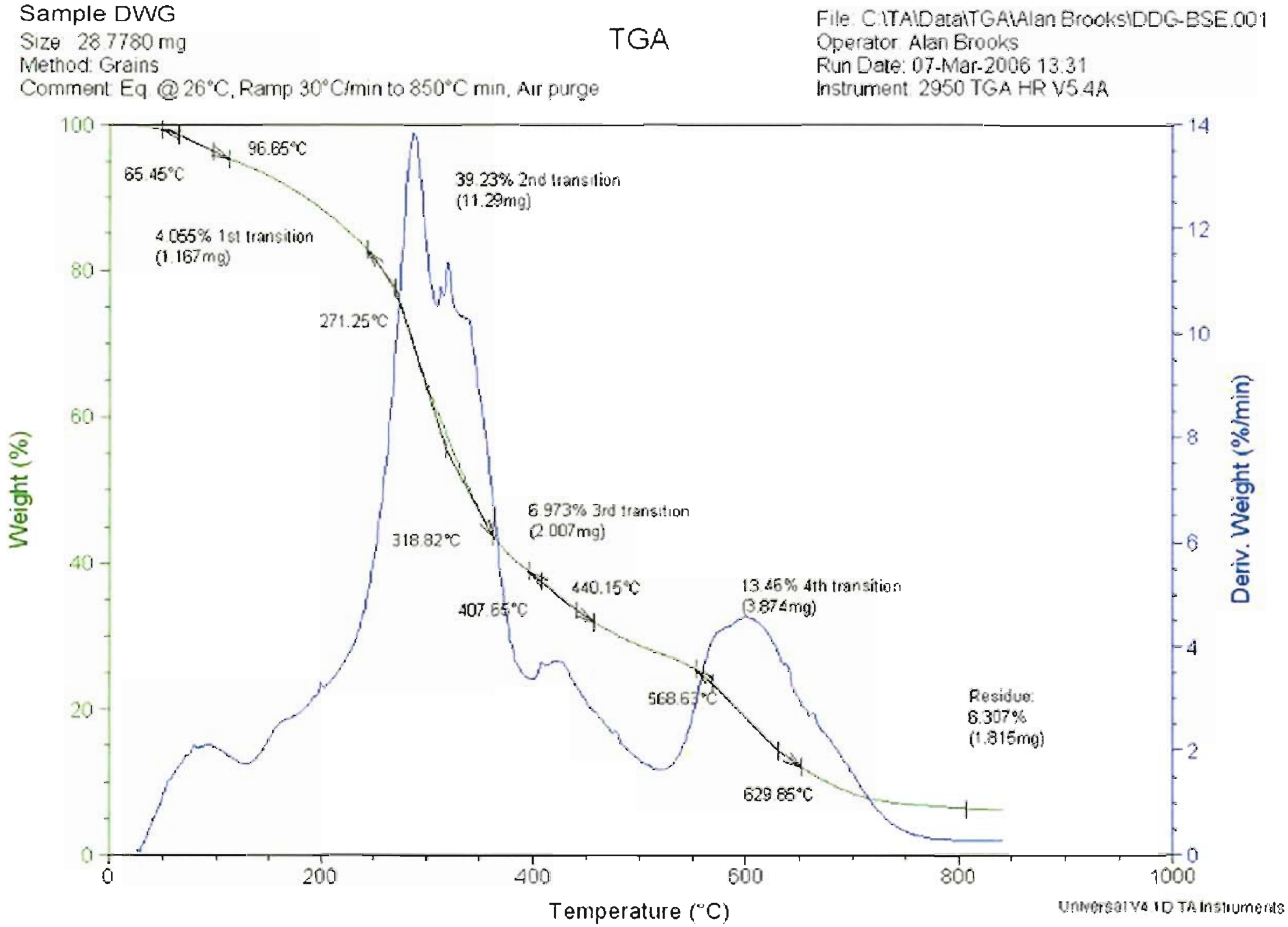
N = Brown, Robert C. 2003. Biorenewable resources. Iowa State Press. Table 3.3, p. 67.

Table ACS52
Analytical Results and Literature Values for Corn Stover, Ash Mineral Analysis

MINERAL	UNITS	CORN STOVER	LITERATURE
			C
Silicon dioxide	wt %	54.12	54
Aluminum oxide	wt %	0.78	2
Titanium dioxide	wt %	0.04	--
Iron oxide	wt %	0.45	--
Calcium oxide	wt %	5.61	8.7
Magnesium oxide	wt %	4.22	6.1
Potassium oxide	wt %	20.22	20.7
Sodium oxide	wt %	1.47	0.2
Sulfur trioxide	wt %	12.75	--
Phosphorus pentoxide	wt %	1.97	8.7
Strontium oxide	wt %	<0.02	--
Barium oxide	wt %	0.02	--
Manganese dioxide	wt %	0.06	--

Notes:
-- = not available/analyzed.

References:
C = National Renewable Energy Laboratory. 1998. Golden, Colorado. Single corn stover analysis.


Sample DWG
Size: 28.7780 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge

TGA

File: C:\TA\Data\TGA\Alan Brooks\DDG-BSE.001
Operator: Alan Brooks
Run Date: 07-Mar-2006 13:31
Instrument: 2950 TGA HR V5.4A

Figure ACS1

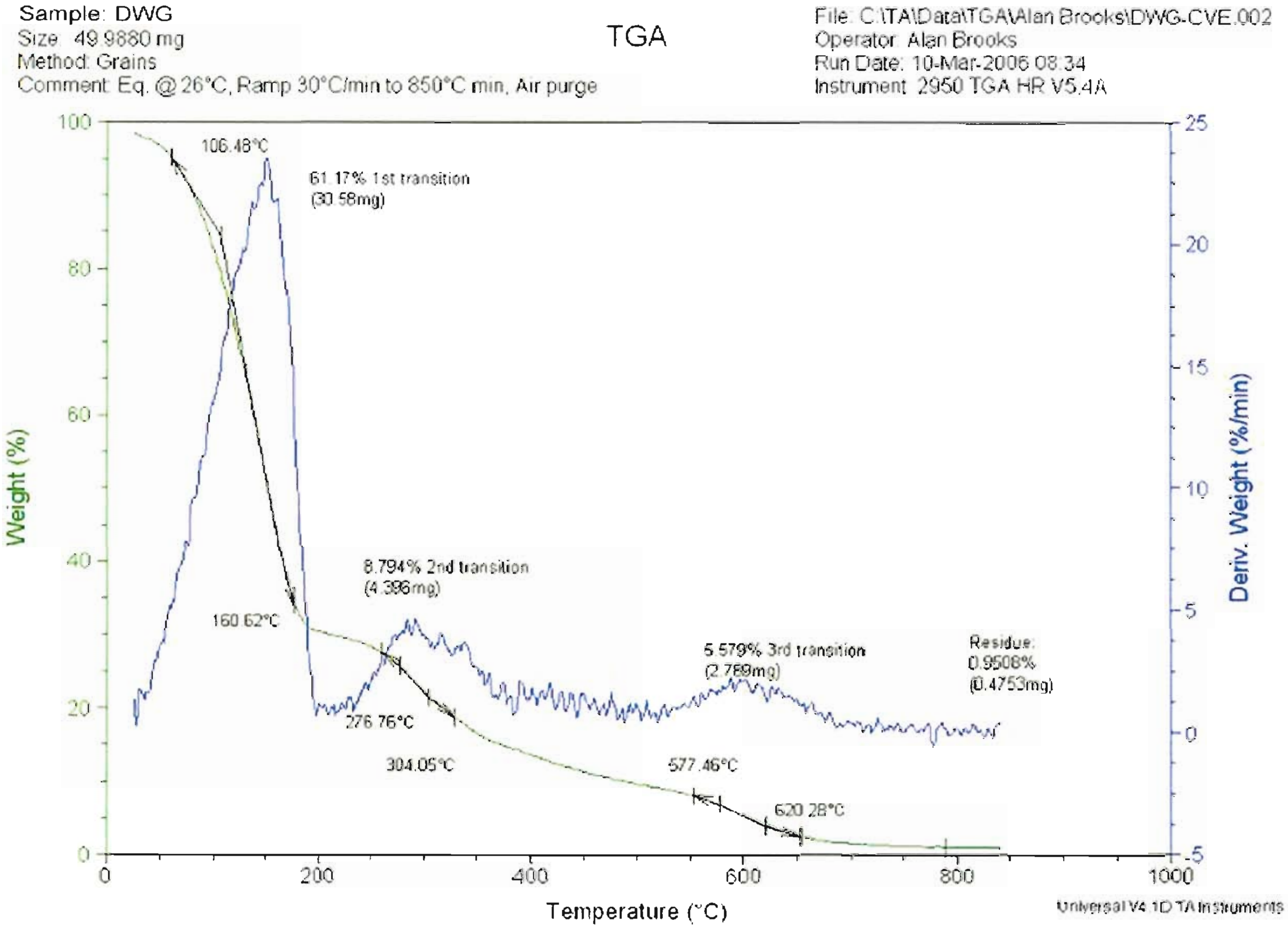

Sample: DWG
Size: 49.9880 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge
TGA
File: C:\TA\Data\TGA\Alan Brooks\DWG-CVE.002
Operator: Alan Brooks
Run Date: 10-Mar-2006 08:34
Instrument: 2950 TGA HR V5.4A
106.48°C
61.17% 1st transition
(30.58mg)
160.62°C
8.794% 2nd transition
(4.396mg)
276.76°C
304.05°C
5.579% 3rd transition
(2.789mg)
577.46°C
620.28°C
Residue:
0.9508%
(0.4753mg)
Weight (%)
0
20
40
60
80
100
Deriv. Weight (%/min)
-5
0
5
10
15
20
25
0
200
400
600
800
1000
Temperature (°C)
Universal V4.1D TA Instruments

Figure ACS2

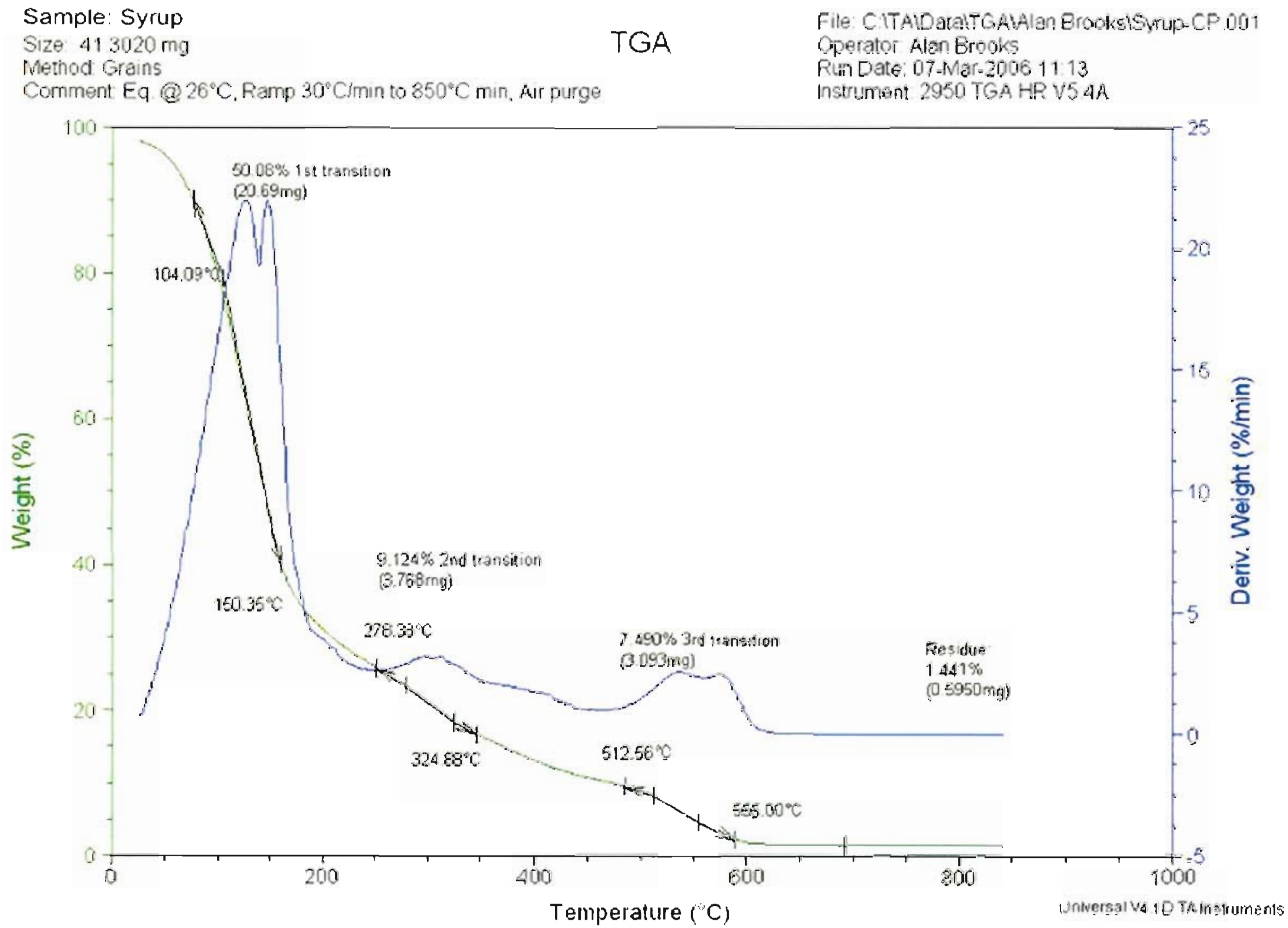
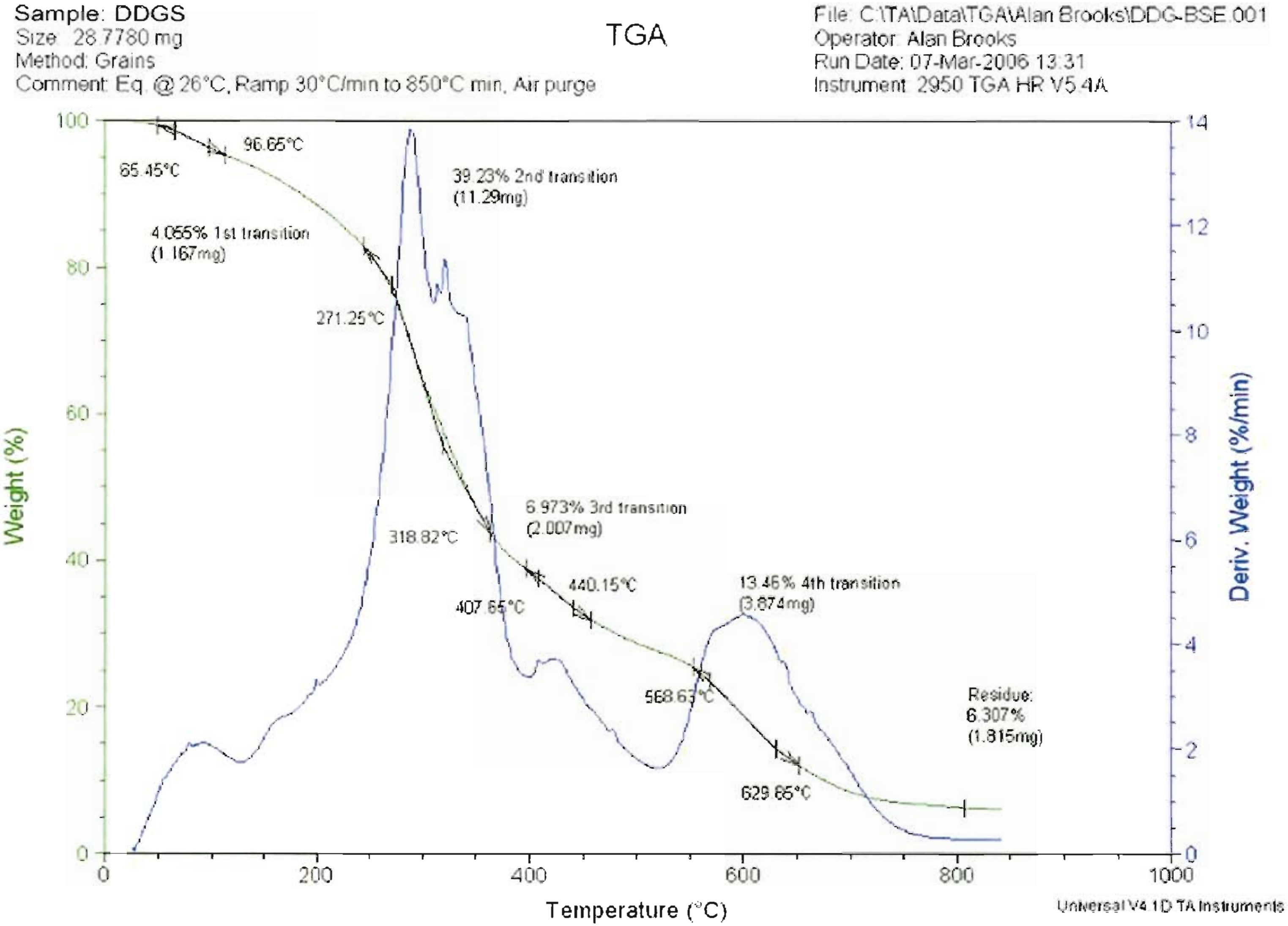

Sample: Syrup
Size: 41.3020 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge
TGA
File: C:\TA\Data\TGA\Alan Brooks\Syrup-CP.001
Operator: Alan Brooks
Run Date: 07-Mar-2006 11:13
Instrument: 2950 TGA HR V5.4A
50.08% 1st transition
(20.69mg)
104.09°C
150.35°C
9.124% 2nd transition
(3.768mg)
278.33°C
324.88°C
7.490% 3rd transition
(3.093mg)
512.56°C
555.00°C
Residue:
1.441%
(0.5950mg)
Weight (%)
100
80
60
40
20
0
Deriv. Weight (%/min)
25
20
15
10
5
0
-5
0
200
400
600
800
1000
Temperature (°C)
Universal V4.1D TA Instruments

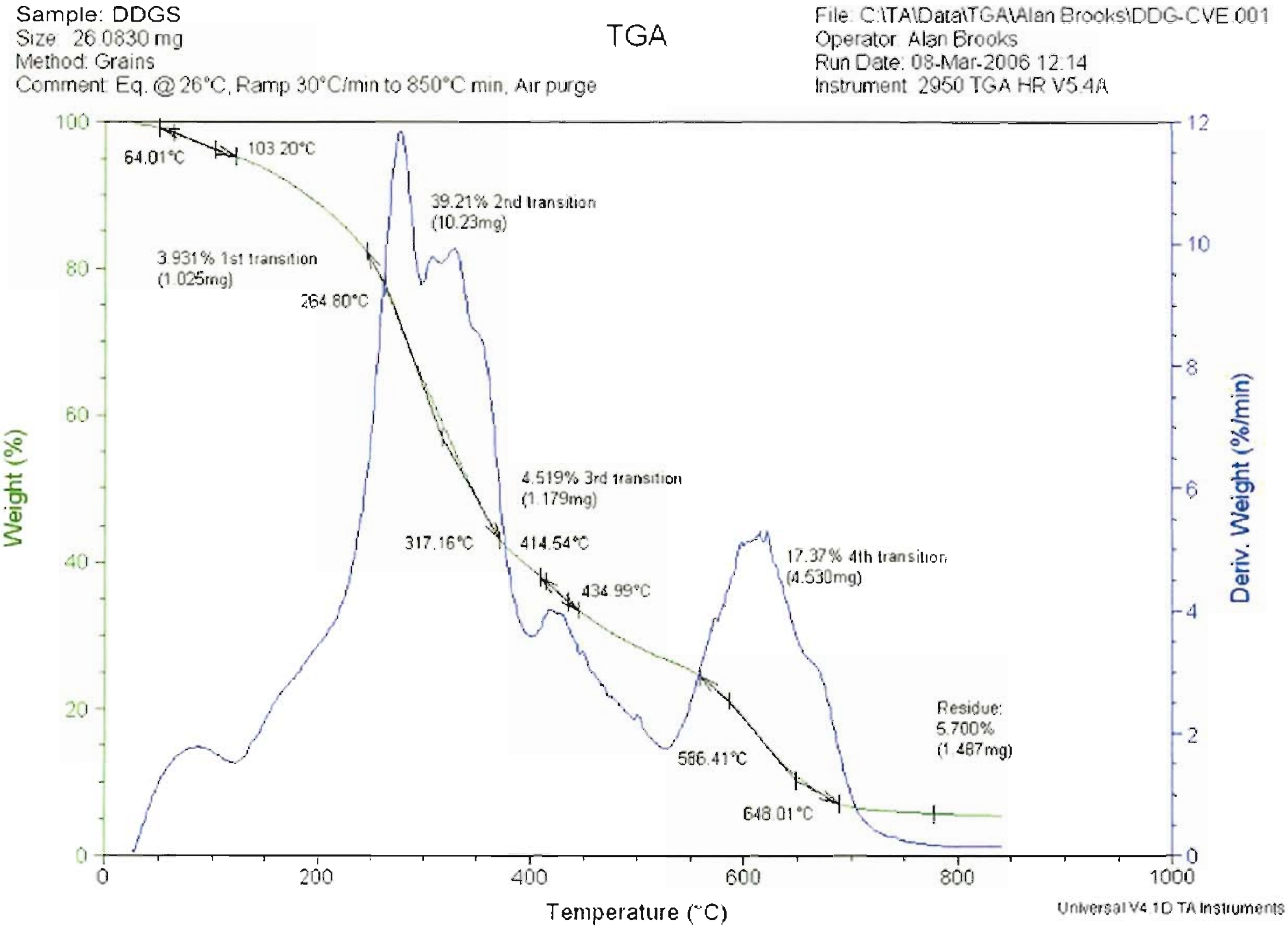
Figure ACS3



Sample: DDGS
Size: 28.7780 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge

File: C:\TA\Data\TGA\Alan Brooks\DDG-BSE.001
Operator: Alan Brooks
Run Date: 07-Mar-2006 13:31
Instrument: 2950 TGA HR V5.4A

Figure ACS4



Sample: DDGS
Size: 26.0830 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge

File: C:\TA\Data\TGA\Alan Brooks\DDG-CVE.001
Operator: Alan Brooks
Run Date: 08-Mar-2006 12:14
Instrument: 2950 TGA HR V5.4A

Figure ACS5

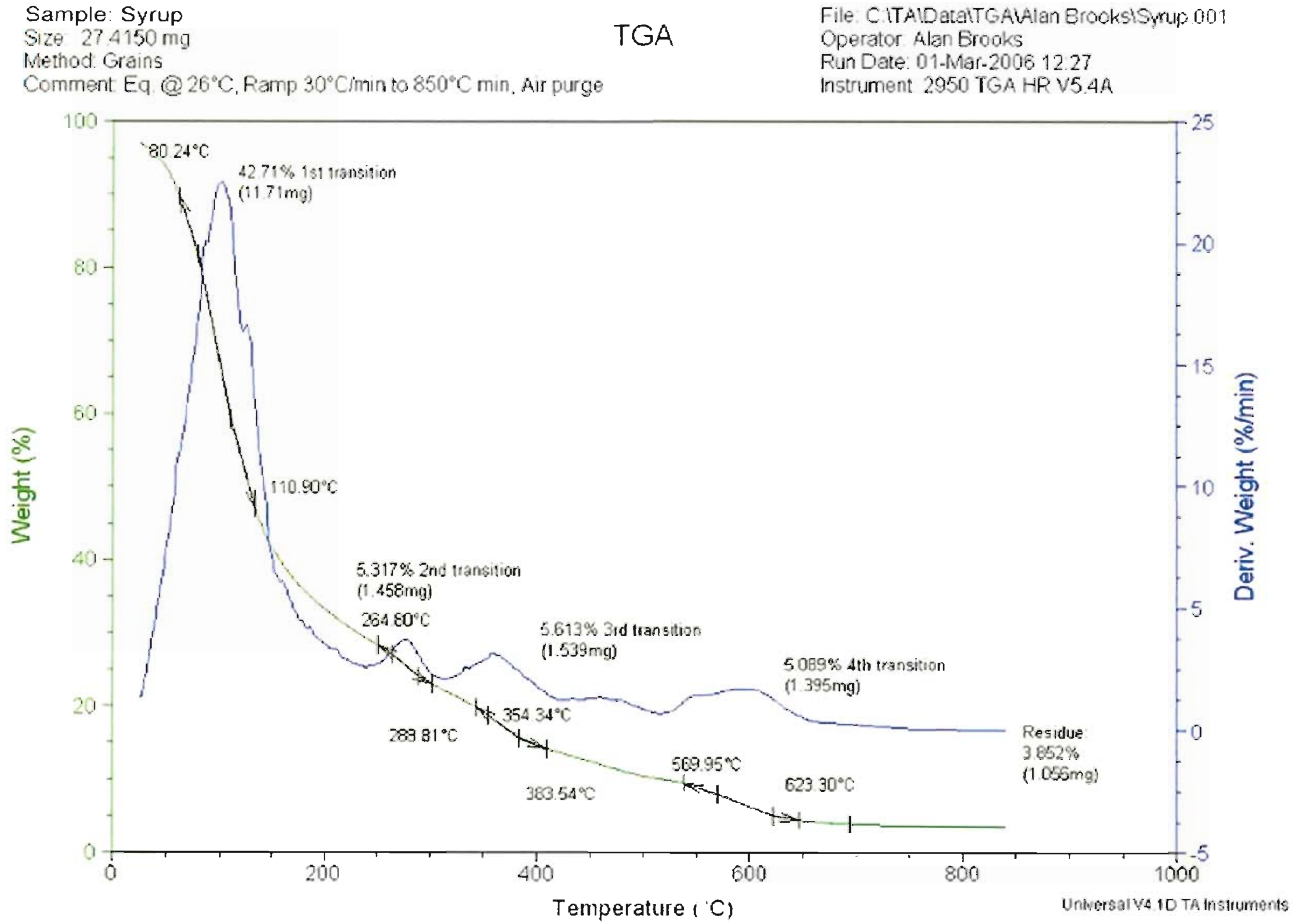
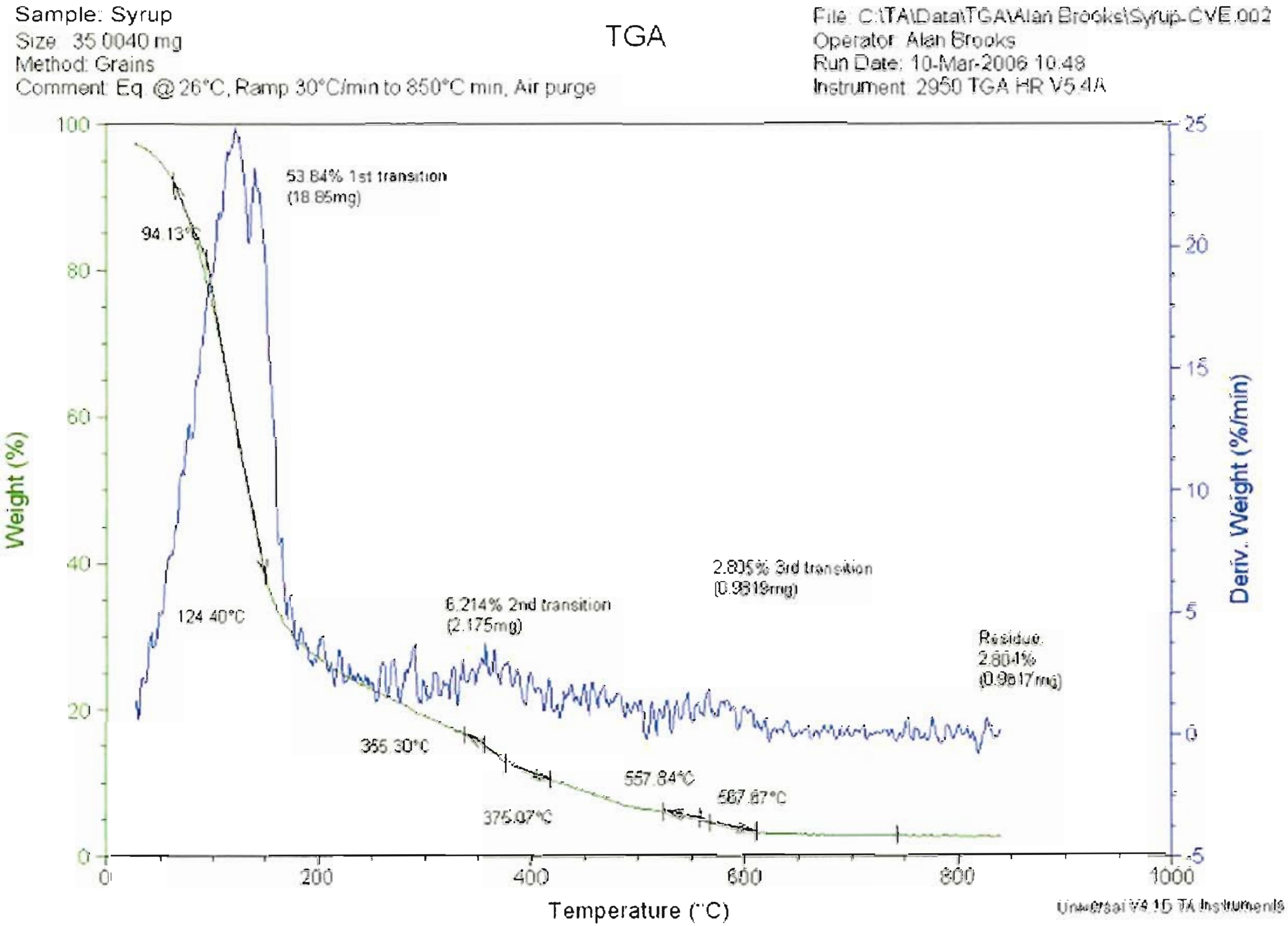

Sample: Syrup
Size: 27.4150 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge
TGA
File: C:\TA\Data\TGA\Alan Brooks\Syrup.001
Operator: Alan Brooks
Run Date: 01-Mar-2006 12:27
Instrument: 2950 TGA HR V5.4A
80.24°C
42.71% 1st transition
(11.71mg)
110.90°C
5.317% 2nd transition
(1.458mg)
264.80°C
288.81°C
354.34°C
383.54°C
5.613% 3rd transition
(1.539mg)
569.95°C
623.30°C
5.089% 4th transition
(1.395mg)
Residue:
3.852%
(1.056mg)
Weight (%)
100
80
60
40
20
0
Deriv. Weight (%/min)
25
20
15
10
5
0
-5
0
200
400
600
800
1000
Temperature (°C)
Universal V4.1D TA Instruments

Figure ACS6



Sample: Syrup
Size: 35.0040 mg
Method: Grains
Comment: Eq @ 26°C, Ramp 30°C/min to 850°C min, Air purge

File: C:\TA\Data\TGA\Alan Brooks\Syrup-CVE.002
Operator: Alan Brooks
Run Date: 10-Mar-2006 10:48
Instrument: 2950 TGA HR V5.4A

Figure ACS7

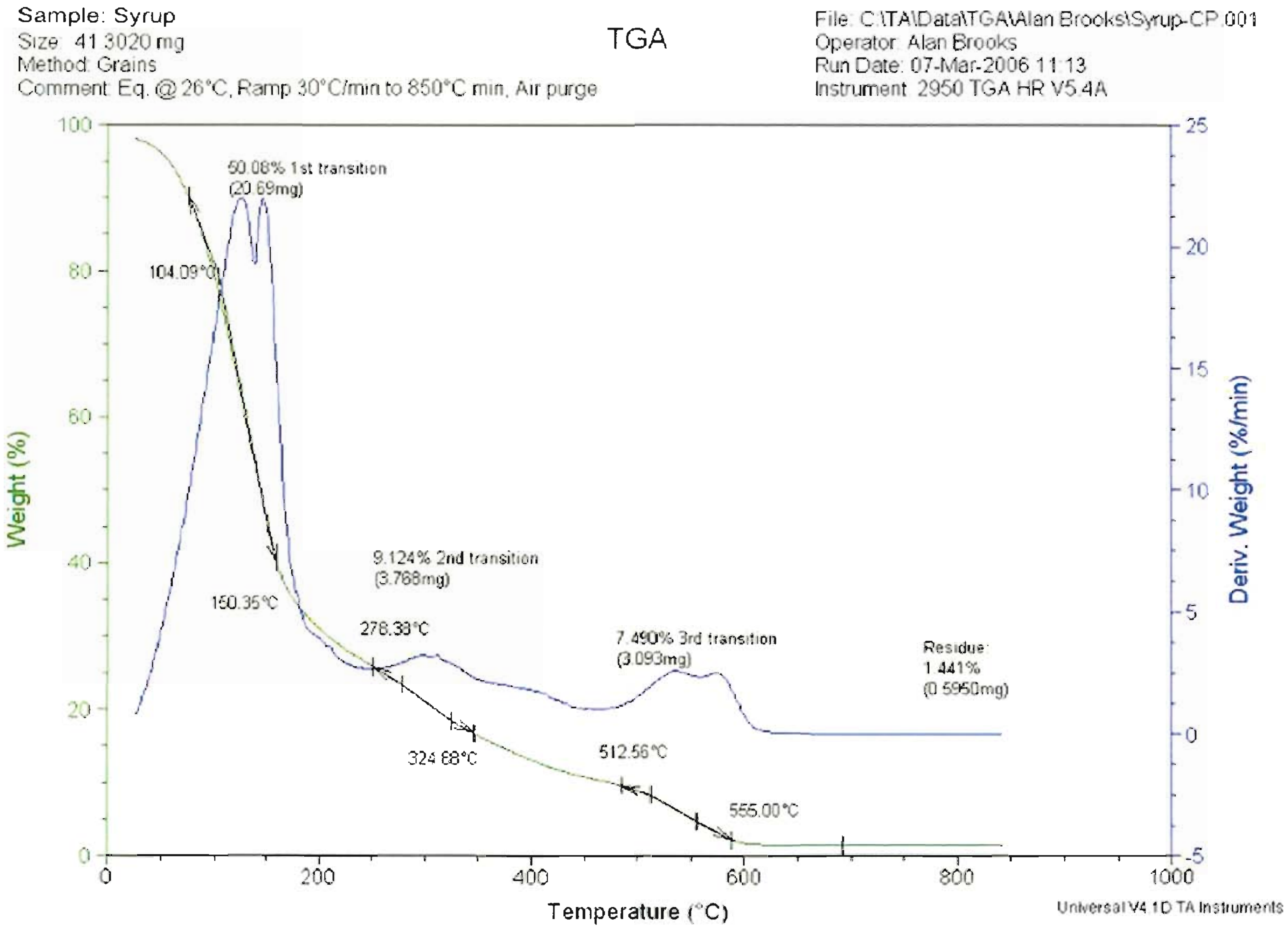

Sample: Syrup
Size: 41.3020 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge
TGA
File: C:\TA\Data\TGA\Alan Brooks\Syrup-CP.001
Operator: Alan Brooks
Run Date: 07-Mar-2006 11:13
Instrument: 2950 TGA HR V5.4A
50.08% 1st transition
(20.69mg)
104.09°C
150.35°C
9.124% 2nd transition
(3.768mg)
278.38°C
324.68°C
7.490% 3rd transition
(3.093mg)
512.56°C
555.00°C
Residue:
1.441%
(0.5950mg)
Weight (%)
100
80
60
40
20
0
Deriv. Weight (%/min)
25
20
15
10
5
0
-5
0
200
400
600
800
1000
Temperature (°C)
Universal V4.1D TA Instruments

Figure ACS8

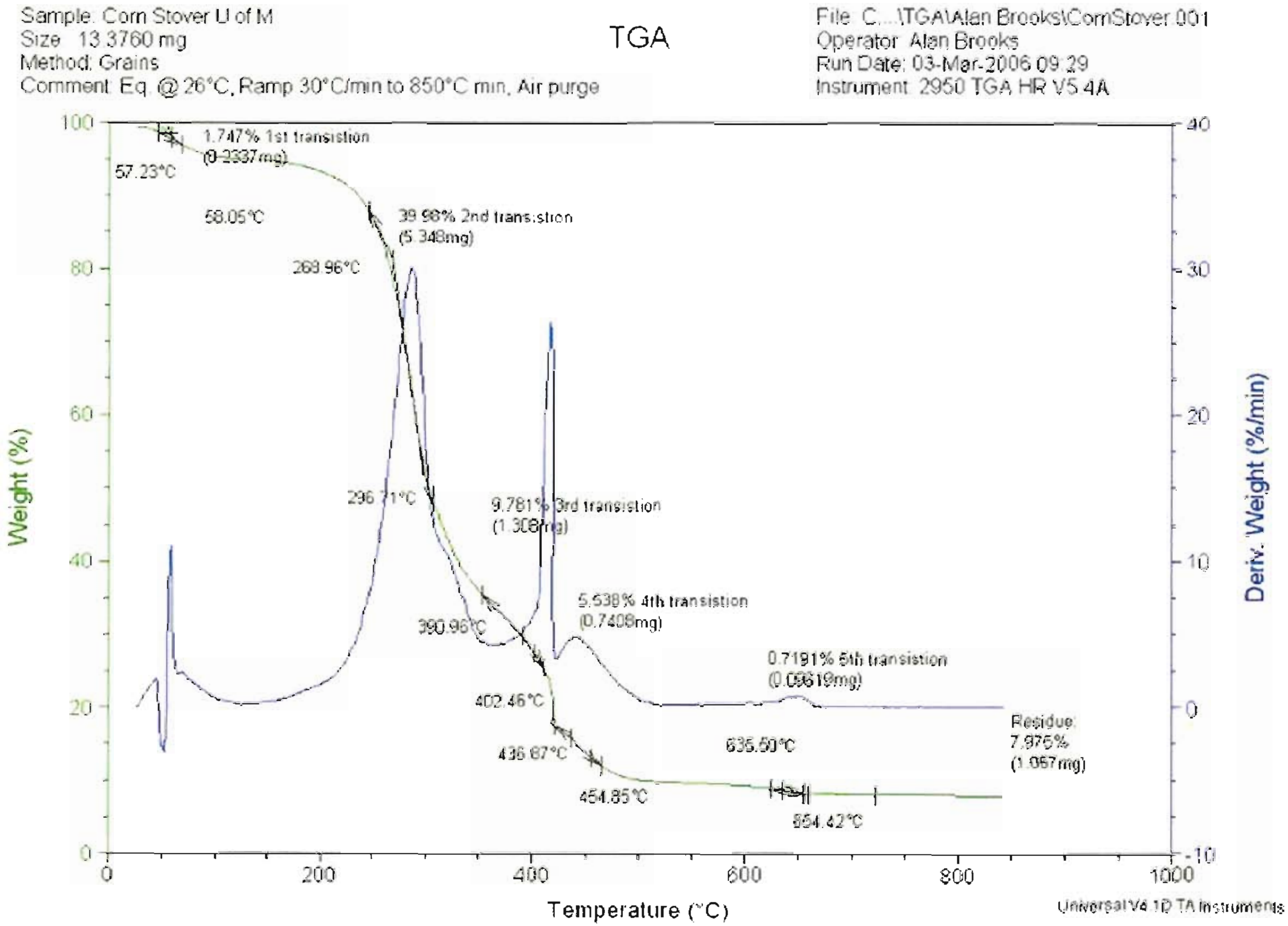

Sample: Corn Stover U of M
Size: 13.3760 mg
Method: Grains
Comment: Eq. @ 26°C, Ramp 30°C/min to 850°C min, Air purge
TGA
File: C:...\TGA\Alan Brooks\CornStover.001
Operator: Alan Brooks
Run Date: 03-Mar-2006 09:29
Instrument: 2950 TGA HR V5.4A
1.747% 1st transistion
(0.2337mg)
57.23°C
58.05°C
39.98% 2nd transistion
(5.348mg)
268.96°C
296.71°C
9.781% 3rd transistion
(1.308mg)
5.538% 4th transistion
(0.7408mg)
390.96°C
402.46°C
436.87°C
454.85°C
0.7191% 5th transistion
(0.09619mg)
635.50°C
654.42°C
Residue:
7.975%
(1.067mg)
Weight (%)
0
20
40
60
80
100
Deriv. Weight (%/min)
-10
0
10
20
30
40
Temperature (°C)
0
200
400
600
800
1000
Universal V4.1D TA Instruments

Figure ACS9

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 3 – Combustion Options

This chapter provides and overview of potential combustion and gasification systems that could be considered for supplying energy to an ethanol plant. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants Report for Task 3, "Combustion Options"

Background

All fuel ethanol plants require process heat. The primary forms of process heat are steam (such as for mash cooking and for evaporators and, for some plants, co-products drying) and hot air (such as for grain and co-products drying). The vast majority of existing plants use on-site fuel combustion to supply both steam and hot air, and have typically used natural gas as fuel. Some new plants intend to use fuels other than natural gas, such as coal, landfill gas, refuse, biomass, and ethanol production co-products. Even for these plants, however, there may still be applications, such as grain drying, where *in situ* combustion of gaseous or atomized liquid fuels is the most efficient means of supplying heat to particular processes. Since the objective of this project is the replacement of as much fossil fuel as possible with biomass fuel, particularly those biomass co-products generated on-site, the following discussions are primarily based on system design and operation that will provide self-sustaining reactions using only biomass. It is recognized that, in the economic analysis of potential systems, there may be instances where the use of some fossil fuel, especially natural gas and/or coal, may be necessary owing to the high water content of some of the feed materials, or there may be instances where its use would be economically advantageous.

Many different combustion options exist for these various alternative fuels. Some of these options are highly specialized or most readily applicable to only certain scales of operation. Evaluating all of these options in detail would not be an efficient use of project funds, nor would the results be very useful to the industry, especially for smaller existing plants. It is understood, however, that new or modified combustion processes may be under development that could contribute to using biomass fuels in the future. For this project, the following four combustion options were selected at the project proposal stage based on their wide potential applicability, their proven track record in other industries, their ability to be effectively integrated into existing plants, their fuel flexibility, the availability of some engineering and test data, and their amenability to economic analysis:

- Combustion in a fluidized bed combustion (FBC) unit, either bubbling (BFBC) or circulating (CFBC)
- Gasification in a BFBC or CFBC
- Combustion of syrup using an injection nozzle in an essentially standard boiler designed for flowable fuel that may produce particulates upon combustion

- Combustion of a combination of syrup and DWG, DDG, or DDGS using a nozzle in an essentially standard boiler designed for flowable/injectable fuel that may produce particulates upon combustion

It should be noted that the moisture content of DWG and syrup are too high for stable self-sustaining combustion or gasification. Some drying of these materials will be necessary. This project, in later sections, examines the optimal degree of drying that balances capital costs, operating costs, energy production, and air emissions. As discussed in previous chapters of this report, the literature has recently contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40%-50%, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers. Anecdotal information indicates that the reduced-moisture syrup will have manageable viscosity as long as the temperature remains at least around 180°F (82°C). Since the temperature of the raw syrup is in this range, and since heat will be conserved if the temperature of the feed material is maintained as high as possible prior to combustion, this constraint is actually a benefit for the energy efficiency of the system. Information is not publicly available regarding the physical characteristics of cooled reduced-moisture syrup, or the effects of cooling, and then reheating, the reduced-moisture syrup. This report therefore doesn't include further descriptions of such systems, or projections of such systems' effectiveness or utility. However, if such systems are effective and cost effective in reducing the moisture content of the syrup to less than 50%, mathematical modeling for this project indicates that stable, self-sustaining combustion of the syrup may be feasible.

Each of the four combustion options is described in more detail below.

Description of the Combustion Options, with Advantages and Disadvantages

Fluidized Bed

Fluidized bed combustion (FBC) 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. Two basic types of FBC systems will be discussed in this report: bubbling fluidized bed combustion (BFBC), and circulating fluidized bed combustion (CFBC). The evaluations in this project will focus on BFBCs and CFBCs, with emphasis on BFBCs because of their demonstrated use for co-product combustion at one of the partner ethanol plants, and therefore the potential availability of data to compare with literature figures and with mathematical modeling. Although both BFBC and CFBC units may be designed to operate in a pressurized mode, such design adds considerable cost and complexity, and the systems are not expected to be applied in dry grind fuel ethanol plant applications. This project will therefore not further evaluate operation of BFBC or CFBC units in pressurized mode.

In a BFBC system (Figure CO1), 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 fluidized, and is then heated to a high enough temperature (typically around 800°F [427°C]), usually with natural gas, to initiate the desired reactions with the biomass fuel. The combustible biomass fuel is then introduced at a rate to make the combustion self-sustaining. The location (top, side, or into the bed itself) of the biomass introduction depends on the system design, the feed material characteristics, and other factors. Considerable moisture removal and combustion/gasification reactions occur in the space above the bed. For materials that enter the bed, the large thermal mass of the bed and the intense shearing action caused by the fluidization of the abrasive bed result in rapid size reduction and mixing, rapid and essentially complete dehydration, and considerable combustion/gasification reaction. Combustion gases, 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 fluidized bed combustion unit requires two ash handling systems, one for the coarse bottom ash and one for the fine fly ash.

Bottom Ash

The coarse bottom ash is removed from the lower furnace by the boiler control system based on differential pressures inside the furnace. Coarse material is removed to maintain proper pressure drop relationships. As the fuel is fed into the furnace for combustion, the ash segregates. Depending on the initial particle size, the final particle size falls somewhere between 100 microns and 1,000 microns. Particles often settle to the fluidized grid level. If they remain there, they are soon joined by other similarly sized particles. This buildup of larger particles needs to be periodically removed from the lower furnace by way of the bottom ash withdrawal system. The fluidized inventory at operating temperatures is very "liquid" in flow characteristics. Some of the inventory that would preferably stay inside the furnace will also be withdrawn, along with some particles of fuel. There is no need to withdraw bottom ash on a time basis, because this would potentially waste fuel and remove inventory unnecessarily. Bottom ash is removed based on pressure differentials set within the furnace. The bottom ash system removes particles at operating temperatures around 1,550°F to 1,600°F (843°C to 871°C).

This is about 40 percent cooler than ash withdrawn from a conventional stoker unit or pulverized coal unit, but the system design still requires careful consideration. The two methods of removing the bottom ash are as follows:

- A ceramic or thermally protected valve opens and closes to allow bottom ash removal to a conventional bottom ash hopper.
- A water-jacketed screw removes bottom inventory.

Fly Ash

Fly ash is removed from the inventory in particle-mass separators. The cutoff point on the particle-mass separators is usually around 100 microns. The fly ash is, therefore, essentially all less than 120 microns, minus material entrained in the flue gas. Flue gas particulate control can be handled with an electrostatic precipitator or a fabric filter with 550°F (288°C) rated material. Fly ash is separated from the flue gas by either slowing it down, turning a sharp corner, and collecting it on a fabric filter, or charging it electrostatically and collecting it on an oppositely charged electrode. The fly ash goes to a hopper, where it can be removed pneumatically by a conventional ash handling system. See Table CO1 for typical BFBC process parameters for both over-bed and in-bed feed systems. 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 for flexibility in combustion, and has the potential for higher pressure steam, which is more favorable for the generation of electricity.

It is theoretically possible that, if the BFBC was operated in a pressurized mode, the hot, cleaned combustion gases could be first directed to a turbine for the generation of electricity, followed by a heat recovery steam generator (HRSG), and then potentially to further recovery of low-grade heat. Such a system might produce higher efficiency than an atmospheric system, but with increased capital costs. Such a system configuration is theoretical at the time of this project, and, as far as the project team knows, such a system has not been implemented in such a configuration.

Table CO1
Typical BFBC Process Parameters[1]

FUEL	OVER-BED FEED	IN-BED FEED
Top size	1 - 2 inches (25 - 50 mm)	0.4 inch (10 mm)
Moisture	--	<6% at surface
Fines	<25% minus 16 mesh	<20% minus 30 mesh
SORBENT		
Top size	0.2 inch (5 mm)	
Diameter at 50% of Rosin-Rammler plot	800 - 1,400 µm	
COMBUSTOR		
Bed temperature	1,560 - 1,650°F (850 - 900°C)	
Bed velocity	4 - 10 ft/sec (1.2 - 3.0 m/sec)	
Bed particle size	500 - 1,200 µm	
Bed depth	24 - 48 inches (0.6 - 1.2 m)	
Bed pressure drop	20 - 50 inches water (0.05 - 0.12 atm)	
Recycle ratio	0 - 5/1	
PERFORMANCE		
Carbon loss	2 - 5%	
Ca/S	2.3 - 3.0	
SO_2	<300 ppm	
CO	250 ppm	
NO_x	<150 ppm	

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 preprocessing. (It has been reported that an entire dead horse was fed to one such unit, with no problems.) However, feed particle sizing is important and over-bed feed is typically no larger than two inches [1]. 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 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 for the control of the constituents.

Other advantages of the BFBC 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 (typically less than 1,650°F [900°C]) helps reduce the formation of certain emissions such as thermal 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. This advantage may be viewed as a disadvantage if the plant wishes to maximize the sale of electricity to the grid, when in fact the fluidized bed combustion system is an effective method to produce steam and electricity.

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

One of the partner ethanol plants for this project has operated a bubbling fluidized bed combustion system since 2005, using syrup as a fuel. Results have reportedly been good. Engineering, operational, and financial details of the system are not publicly available. As reported by plant management, system refinements continue to be made.

In the CFBC system (Figure CO2), 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 gases 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 capital and operating costs of the circulating fluidized bed are generally higher. As a result, CFBCs are usually used in large applications where substantial operation and maintenance staff are available. CFBC systems are expected to provide better performance with a wider variety of fuels than BFBC systems. However, it is unlikely that CFBC systems would find wide application in typical (of the sizes considered in this project) dry grind fuel ethanol plants. See Table CO2 for typical CFBC process parameters.

Fluidized Bed Gasification

While different feed stocks and operating conditions will affect the detailed composition of the gases generated in gasification systems, all such systems have certain common features and characteristics, and generate combustible gases in an essentially similar way. Whereas fluidized bed combustion is operated with excess oxygen at all times, the fluidized bed gasification system operates with both a combustion zone operating with sufficient oxygen to achieve stoichiometric conditions for combustion of fixed carbon, and an oxygen-starved zone with less than stoichiometric amounts of oxygen to promote gasification. The combustible gases produced consist largely of carbon monoxide and hydrogen, and possibly some methane. Necessary oxygen for the reactions may be provided with air, oxygen, or steam. The gases leaving the gasifier are hot, up to 932°F (500°C), or even somewhat higher. The basic system mechanics of fluidized bed gasification are similar to fluidized bed combustion (Figure CO3), although care must be taken owing to the presence of hot, potentially explosive gases. 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 complete combustion to generate the heat necessary to sustain the processes. The fuel gases are cleaned, with specific gas cleaning systems, depending on the design of the overall gasification system, and are then combusted. If combustion is in a conventional steam boiler, little additional cleaning may be needed prior to combustion, thus conserving process heat. Any necessary flue gas cleaning can occur after combustion. If combustion is to be in a combustion turbine, essentially complete removal of particulates will be needed prior to introduction into the turbine, and the system will need to be operated in a manner to minimize the amount of tar reaching the turbine.

Table CO2
Typical CFBC Process Parameters[1]

FUEL	
Top size	3 - 9 μm
Diameter at 50% of Rosin-Rammler plot	500 - 1,000 μm
SORBENT	
Top size	1,000 μm
Diameter at 50% of Rosin-Rammler plot	200 μm
COMBUSTOR	
Temperature	1,560 - 1,650°F (850 - 900°C)
Velocity	18 - 20 ft/sec (5.5 - 6.1 m/sec)
Particle size	100 - 1,000 μm
Pressure drop	40 - 80 inches water (0.1 - 0.2 atm)
Recycle ratio	10 - 100/1
PERFORMANCE	
Carbon loss	1 - 2%
Ca/S	1.5 - 2.5
SO_2	<100 ppm
CO	<100 ppm
NO_x	<100 ppm

The advantages and disadvantages of the fluidized bed gasification system mirror those of the fluidized bed combustion system. There are three significant additional advantages of the fluidized bed gasification system, however. First, gasification produces a gaseous energy source that may be able to be used, with appropriate equipment modification, in many of 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 (typically 200-400°F [93-204°C] lower) than for fluidized bed combustion systems, potentially reducing the generation of NOx. Third, with proper pretreatment, the fuel gas can be readily used in a combustion turbine for generating electricity, followed by a heat recovery steam generator (HRSG) to generate steam.

Fluidized bed gasification has the ability to process a wide variety of biomass fuels, and can be readily supplemented with fossil fuels. It can handle agglomerative materials of varying sizes 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. The moisture content of DWG and syrup are too high for stable, self-sustaining gasification. As discussed in other chapters of this report, significant moisture reduction would be necessary for the exclusive use of the DWG and syrup as biomass fuels, which is the objective of this project.

The fuel flexibility of fluidized bed gasification 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 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 versus the combustion system may lessen the generation of problematic emissions, although this characteristic can be a disadvantage for those constituents, such as sulfur, that can be effectively controlled through the addition of simple chemicals to the combustion system.

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

Liquid Injection Via Nozzle Into a Conventional (Non Fluidized) Boiler

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 [2]), a residual from certain types of wood pulp manufacture, to generate electricity and process steam for the mills. Other nonpetroleum fuel liquids that have been used include fuel derived from tar sands, oil shale, and other coal-derived fuels. For the ethanol plant co-products, potential success for such combustion depends primarily on the water content of the fuel. DWG and syrup, as received, have too high a water content for stable, self-sustaining combustion. The water content would likely need to be reduced to that comparable to black liquor for successful combustion. As discussed in previous chapters, the literature has recently contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40%-50%, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers. Anecdotal information indicates that the reduced-moisture syrup will have manageable viscosity as long as the temperature remains at least around 180°F (82°C). Since the temperature of the raw syrup is in this range, and since heat will be conserved if the temperature of the feed material is maintained as high as possible prior to combustion, this constraint is actually a benefit for the energy efficiency of the system. Information is not publicly available regarding the physical characteristics of cooled reduced-moisture syrup, or the effects of cooling, and then reheating, the reduced-moisture syrup. This report therefore doesn't include further descriptions of such systems, or projections of such systems' effectiveness or utility. However, if such systems are effective and cost effective in reducing the moisture content of the syrup to less than 50%, mathematical modeling for this project indicates that stable, self-sustaining combustion of the syrup may be feasible.

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 a combination of heating the feed material, by mechanical dispersion, and by using special nozzles supplemented with compressed air, steam, or gaseous fuel.

For purposes of this project, the term "liquid" will be used for the syrup that is a co-product 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.

There are several disadvantages to using liquid injection via nozzles into a conventional combustion unit. As discussed above, the moisture content of the syrup would need to be substantially reduced to allow for stable, self-sustaining combustion. 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 may even be infeasible, for conventional systems. System modifications to allow for the combustion of syrup might not allow for the combustion of conventional solids, so that the potential for burning of other biomass, including DWG, DDG, or DDGS, might be compromised.

Injection Via Nozzle of Liquids and DWG, DDG, or DDGS Into Conventional (Nonfluidized) Boiler Systems

Injection of properly sized solids via nozzles is a well established technology. This option might allow for both syrup and solids-containing portions (DWG, DDG, and DDGS) to be burned using essentially conventional technology. Based on the analyses performed as part of this project, and on the literature, the ethanol plant biomass solids are of a size necessary for injection into a combustion unit through a nozzle, and can be mixed with syrup or with other liquid or gaseous fuel for injection into an essentially conventional steam generator. Material preparation systems could be optimized if the feed was limited to syrup, DWG, DDG, and DDGS. As discussed previously, however, the moisture content of the syrup and DWG, as received, are too high for stable, self-sustaining combustion. A substantial reduction of the moisture content, with associated costs and energy use, would be needed prior to combustion. A new potential technology to accomplish this moisture reduction is described elsewhere in this report.

Problems associated with burning such mixtures of syrup and solids 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 (after necessary moisture reduction) 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 and DWG make stable, self-sustaining combustion infeasible, unless the moisture content is substantially reduced. For these and other reasons, a fluidized bed, with the moisture content of the syrup and DWG adequately reduced, appears to be more suitable for combustion of the syrup and DWG.

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 injection via nozzles in conventional (nonfluidized) 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 information into consideration for the feed streams evaluated in this project, fluidized bed combustion or gasification appear to be the preferred biomass energy technologies meriting substantial further consideration in this project. Further technical developments in conventional combustion methods may call for re-evaluation of this conclusion in the future, but such re-evaluation is beyond the reasonable scope of the current project.

Ramifications for Subsequent Project Tasks

Subsequent project tasks will focus primarily on fluidized bed combustion and fluidized bed gasification. To meet the objectives of this project, some technical and economic evaluation will be performed for conventional systems, and will be pursued in later tasks if merited by the data.

References

1. Combustion Fossil Power, 4th Edition, Combustion Engineering, Inc. 1991.
2. Steam its generation and use, 40th Edition, Babcock & Wilcox Company. 1992.

Typical Bubbling Fluidized-Bed Boiler Schematic

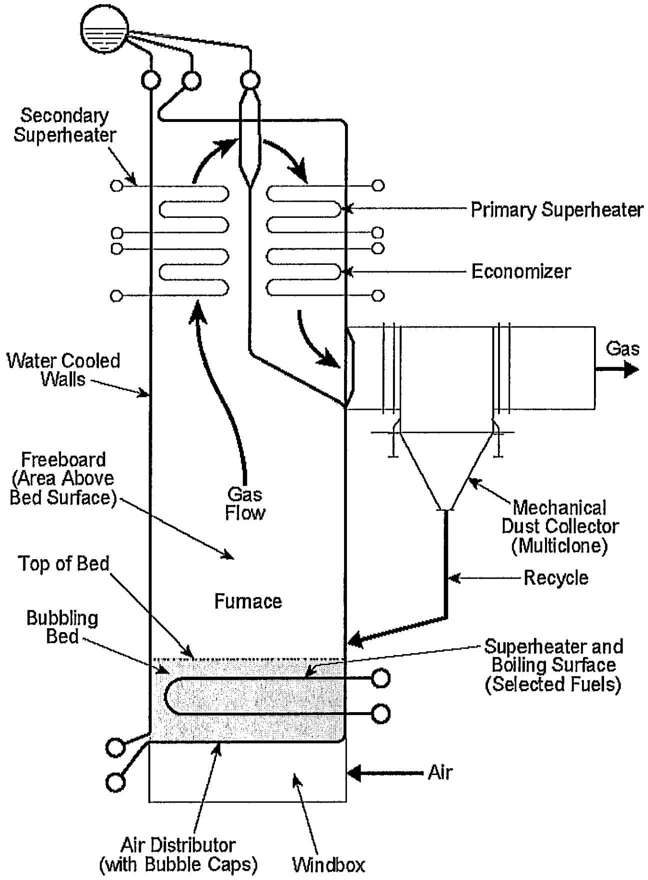


Figure CO1

Note: Courtesy of the Babcock & Wilcox Company

Typical Circulating-Bed Boiler Schematic

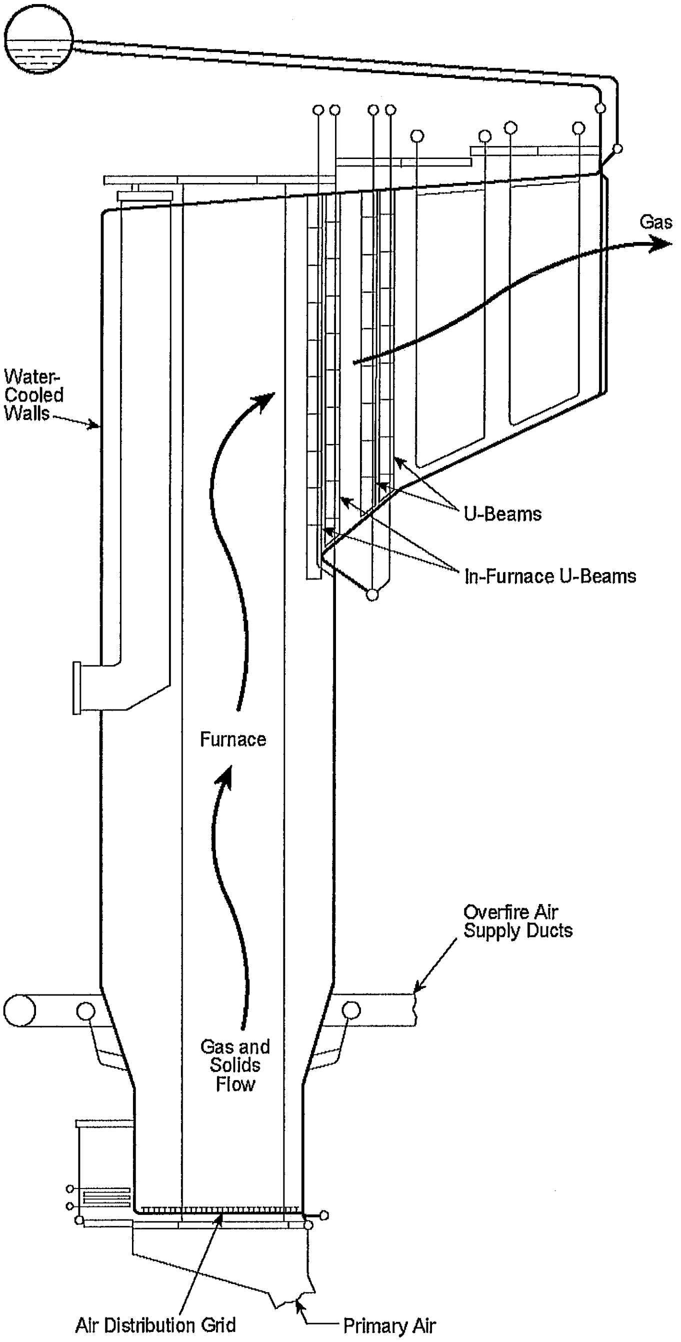


Figure CO2

Note: Courtesy of the Babcock & Wilcox Company

MODULAR FLUIDIZED BED GASIFICATION

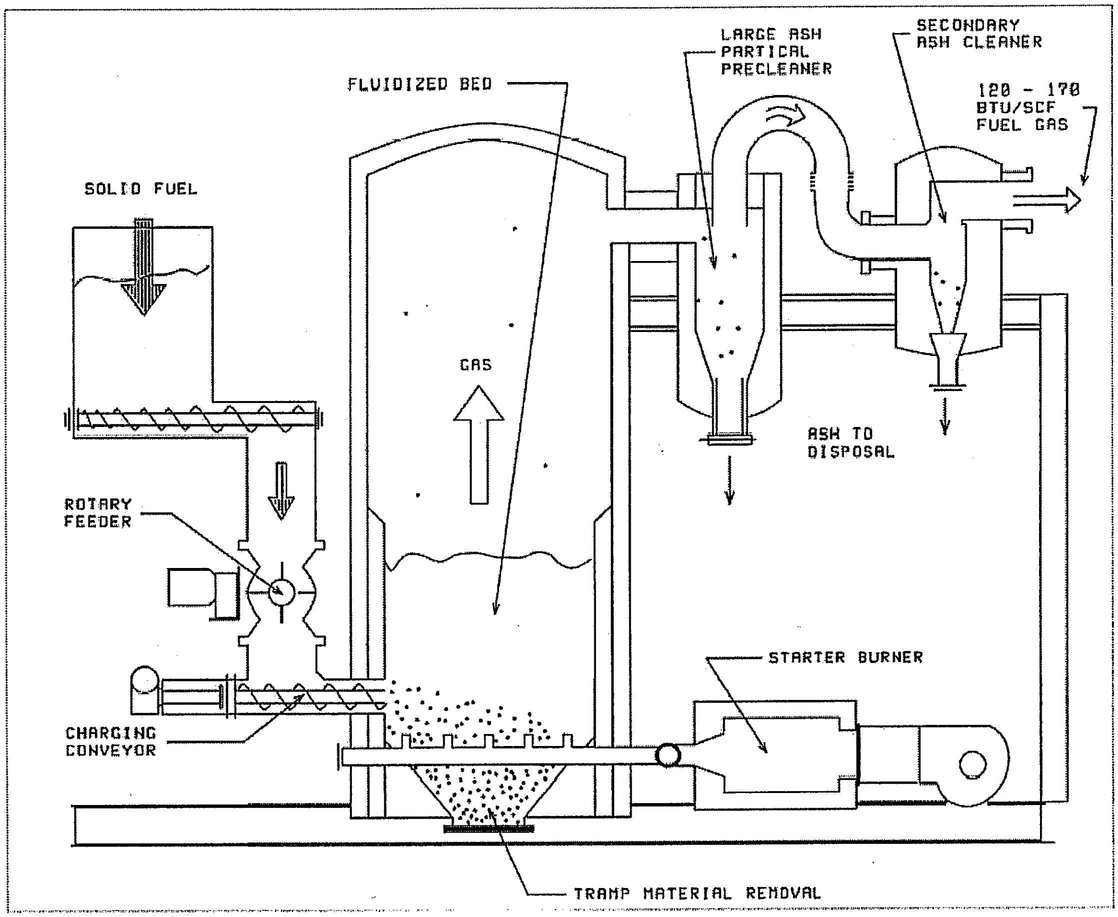


Figure CO3

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 4 – Fuel Processing Options

This chapter describes requirements and potential methods for processing co-products to a form suitable for combustion. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 4, "Fuel Processing Options"

Background

Combustion of biomass feed streams evaluated in this project will require fuel processing. Storage, handling, and fuel processing of biomass fuel is discussed in this section. The optimal biomass fuel conditions and characteristics must be matched with the storage requirements, the 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 will 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 co-products with a higher moisture content. In sub-freezing weather, management of the co-products with a higher moisture content poses additional challenges. Results of the laboratory testing of the feed streams have been used to provide input to these evaluations.

A description of the physical constraints and/or requirements to accommodate the particular biomass fuel component, and a discussion of general capital and operating costs, are presented below, for each combustion option. Although the discussion in this section addresses fuel processing options for each of the selected co-product feed streams, the combustion evaluations performed as part of this project indicate that both the syrup and the DWG contain too much water for practical self-sustaining combustion. Self-sustaining combustion of these two feed streams would require removal of much of the water. In addition, evaluation of the emissions from combustion of the DWG or syrup, described in more detail later in this report, indicates that the high water content exacerbates the potential generation of problematic quantities of nitrogen oxides. Practical combustion of these materials for CHP purposes without removal of much of the water would require blending the syrup or DWG with a large amount of dry biomass material, or adding supplemental fossil fuel, probably coal or natural gas. Such approaches may still be more cost-effective than burning all natural gas, but they do not satisfy one of the primary objectives of this project, the minimization of the combustion of non-coproduct fuels.

Recently, the literature has contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40%-50%, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers.

Anecdotal information indicates that the reduced-moisture syrup will have manageable viscosity as long as the temperature remains at least around 180°F (82° C). Since the temperature of the raw syrup is in this range, and since heat will be conserved if the temperature of the feed material is maintained as high as possible prior to combustion, this constraint is actually a benefit for the energy efficiency of the system. Information is not publicly available regarding the physical characteristics of cooled reduced-moisture syrup, or the effects of cooling, and then reheating, the reduced-moisture syrup. This report therefore doesn't include further descriptions of such systems, or projections of such systems' effectiveness or utility. However, if such systems are effective and cost effective in reducing the moisture content of the syrup to less than 50%, mathematical modeling for this project indicates that stable, self-sustaining combustion of the syrup may be feasible.

Fuel Processing Options for Syrup

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 costs and a short shelf life limit this option to particular situations.

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 have a short shelf life (days in warm weather and weeks in colder weather), they do not stack well, they require a large area for storage, they may create odors, and they present 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 or beneficially utilize the co-products as soon as possible.

Ethanol plants handle the syrup by pumping, and are familiar with maintaining the mechanical systems for syrup management. However, the moisture content of the syrup must be substantially reduced if the syrup combustion is to be stable and self-sustaining (expected to be less than 50% moisture). As described above, the literature has recently contained information concerning a new system to efficiently decrease the moisture content of the syrup to 40%-50%, or less. According to the literature, such systems are currently in trials in ethanol plants, and other systems are on order by other ethanol plants. Information regarding where the trial systems are located, and specific engineering or operational information about the systems, have not been made available by the manufacturers. Anecdotal information indicates that the reduced-moisture syrup will have manageable viscosity as long as the temperature remains at least around 180°F (82° C). Since the temperature of the raw syrup is in this range, and since heat will be conserved if the temperature of the feed material is maintained as high as possible prior to combustion, this constraint is actually a benefit for the energy efficiency of the system. Information is not publicly available regarding the physical characteristics of cooled reduced-moisture syrup, or the effects of cooling, and then reheating, the reduced-moisture syrup. This report therefore doesn't include further descriptions of such systems, or projections of such systems' effectiveness or utility. However, if such systems are effective and cost effective in reducing the moisture content of the syrup to less than 50%, mathematical modeling for this project indicates that stable, self-sustaining combustion of the syrup may be feasible.

For all combustion options, the moisture content of the syrup will need to be substantially reduced prior to combustion. The syrup is used as quickly 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 raw syrup storage capacity would be needed. Storage will need to be provided for the reduced-moisture syrup, unless the moisture reduction is in line with the combustion system. The particulate matter in the syrup is fine, with little settling over the time period during which the syrup is stored. This fine particulate is not expected to unduly interfere with any fuel feeding mechanism. The syrup as produced is hot, and is stored in insulated tanks. Considering the short amount of time anticipated for the syrup to be stored prior to partial drying and burning, excessive cooling is not expected to be a significant challenge.

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 moisture removal to the day tank or the combustion unit in the shortest amount of time possible, thereby conserving heat. Only excess syrup, or syrup destined for a use other than combustion, 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 or otherwise beneficially use the DWG as soon as possible. Like syrup, the moisture content of the DWG is too high for stable, self-sustaining combustion, so moisture reduction will be needed prior to combustion. The literature information concerning the new moisture reduction system for syrup does not include discussion of DWG. If the moisture content of the DWG could be reduced to the same extent as that of the syrup, with a cost-effective technology, both the technical and financial feasibility of using the ethanol plant coproducts for combined heat and power (CHP) would be significantly enhanced.

Unlike syrup, the DWG is 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, remove excess moisture, 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. It should be possible to handle partially dried DWG in a manner similar to the raw DWG, although this should be verified through testing.

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. For example, Figure FPO1 is a typical refuse-to-energy system. The primary systems for managing the DWG as fuel are applicable to all of the selected combustion technologies capable of burning partially dewatered DWG. Depending on the configuration of the particular ethanol plant, the DWG leaving the centrifuge is either split between a feed tank eventually used 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 preparation 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 (after partial drying) is needed, although, as discussed above, removal of much of the water from the DWG will be necessary for stable self-supporting combustion or gasification in the fluidized bed systems. While injection of the DWG via nozzles into conventional combustion units may be feasible, the high water content of the DWG will preclude self-supporting combustion, and forcing the DWG through nozzles, especially if it is only partially dried, may be problematic. Given these two potentially significant drawbacks to the injection of the DWG through nozzles, this combustion option is not further considered in this project. Drying the DWG creates DDG (or DDGS if the syrup has been added to the wet cake), which is discussed below.

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.

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.

Pneumatic transport may be feasible for DDG and DDGS; however, pneumatic transport is not typically used in fuel ethanol plants, so a dedicated system would have to be built.

Unlike the DWG, which requires partial drying, 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 via nozzles into conventional combustion units.

Typical RDF Refuse-To-Energy System

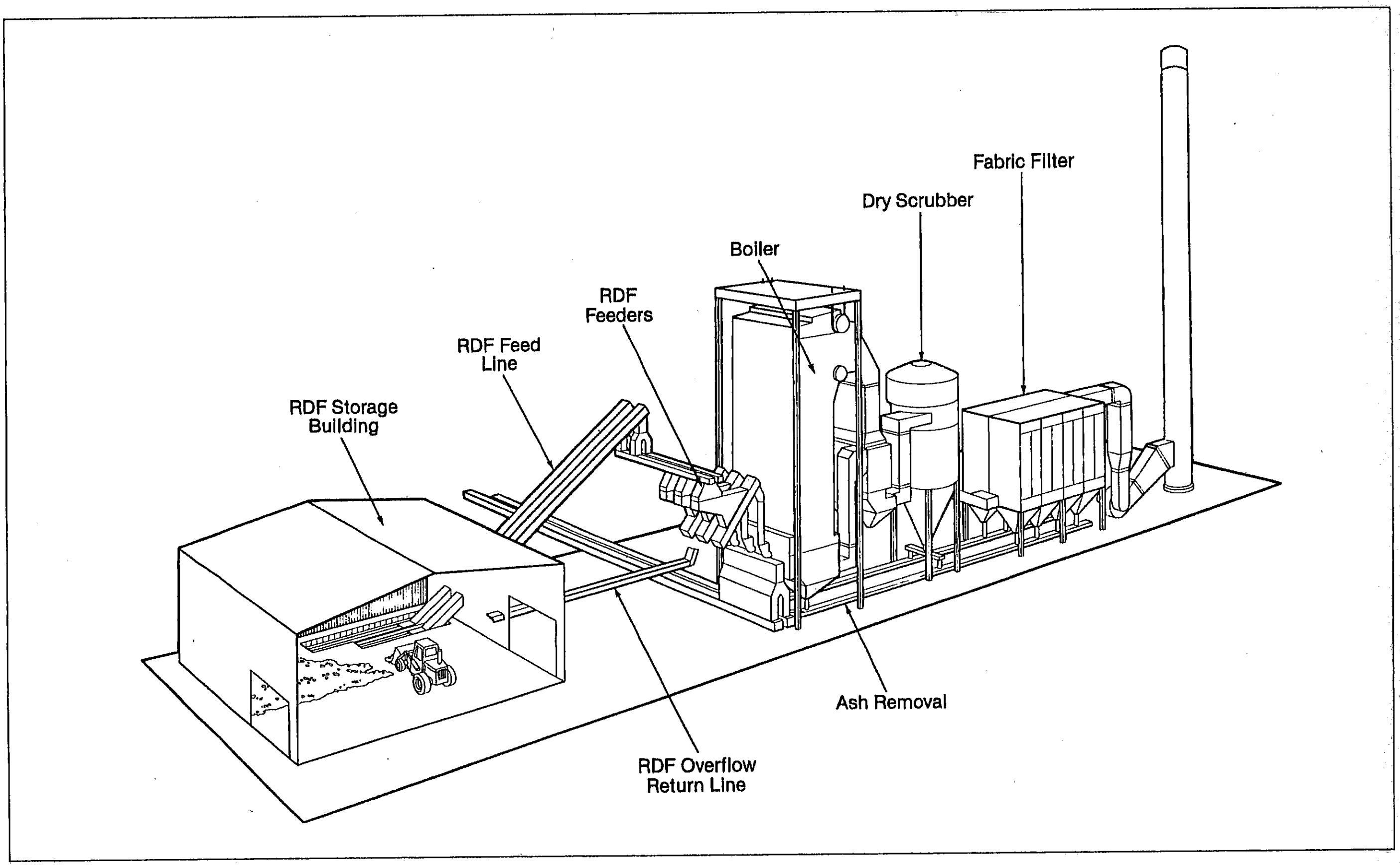

Figure FPO1

Note: Courtesy of the Babcock & Wilcox Company

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 5 & 6 – Combustion and Emission Modeling Results

This chapter describes a computational fluid dynamics approach to modeling fluidized bed combustion and predicted emissions for the ethanol co-products and corn stover as fuels. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants Report for Tasks 5 and 6, "Combustion and Emission Modeling Results"

Background

As originally conceived, the project included conducting various combustion tests on selected co-product streams and combinations. Such combustion tests would provide emissions and ash for analysis, and could potentially be used as a cross-check against possible mathematical modeling of certain aspects of the combustion. In the 2 years from project selection to the signing of the project contract, however, developments in the industry and in mathematical modeling experience present opportunities for an improved approach that will deliver greater value to the project output. Those developments include the following:

- The price of fossil fuels, especially natural gas and electricity, has dramatically increased, increasing the pressure for energy cost solutions for dry grind ethanol plants.
- The potential value of biomass materials as fuel sources has substantially increased, while, simultaneously, the cost of procuring, transporting, and processing the biomass fuels has also substantially increased.
- Other alternative uses for biomass have arisen, especially for biodiesel production.
- One ethanol plant, Corn Plus (a partner plant in this project), began operation of an ethanol co-product combustion system for process steam generation, and made certain information regarding the system and its operations public.
- Two other ethanol plants (one of which is a partner plant for this project) announced construction of biomass gasification systems based on wood residue, potentially providing additional cross-check data.
- Combustion and emission modeling using computational fluid dynamics has improved.
- The cost of laboratory and pilot-scale test burns continues to increase.

On the basis of these factors, the project team, after consultation with the project sponsor, revised the combustion testing and emission testing approach to concentrate on using computational fluid dynamics to model the combustion and emissions, based on available combustion and furnace parameters and on the analytical data generated from the samples collected at the partner ethanol plants in this project. Ash evaluation, described in another section of this report, will be based on testing of the feed materials, testing of ashed samples of the feed materials, and on ash samples obtained from an operating fluidized bed combusting syrup, Corn Plus.

At the most basic level, the ultimate chemistry of combustion in and emissions from any given system depends primarily on the feed material, the combustion temperature, the retention time, and the presence of sufficient oxygen. Turbulence and other parameters affect the rate of combustion and the physical characteristics of the ash, but not the ultimate combustion chemistry, assuming essentially complete (+/- 98%) combustion. All combustion systems considered in this project will promote essentially complete combustion. The moisture content of the feed material can have a significant impact on the efficiency and effectiveness of the combustion process and, for any given system, on the combustion byproducts (emissions and ash). As will be described in greater detail below, the general chemical characteristics of the emissions and ash can be approximated from the chemical analyses of the feed materials and the residue (ash) remaining after combustion of feed material samples in a laboratory furnace. Mathematical calculations can be applied to improve the approximation for certain components, especially nitrogen compounds, that are significantly impacted by the configuration and operating conditions of the combustion system. 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.

Modeling

Modeling for the project was performed by professional modelers with RMT's SmartBurn® Group. 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.

Data evaluation and general experience allowed the modeling to focus on selected key considerations for the combustion systems included in the project. For example, examination of the analytical data for syrup from the five partner plants indicated that combustion by injection via nozzles into conventional (non-fluidized) combustion units could be problematic. The project wanted to definitively answer if that was the case, and, if so, to document the technical reasons. A similar issue arose concerning the elevated nitrogen content of the ethanol co-products, and the high water content of some of the co-products.

After careful consideration, the modeling was conducted to focus on several key issues:

- Is the use of injection of feed materials via nozzles in conventional (non-fluidized) combustion units feasible?
- What are the predicted levels of NO_x, CO, and SO_2 emissions from bubbling fluidized bed systems?
- What are the predicted effects of different feed material moisture content?

- What are the predicted effects of different amounts of excess air in the combustion unit?
- What are the practical differences in potential emissions from combustion versus gasification?

Conclusions from the modeling pertaining to each of these issues are discussed below.

Direct Firing Burners

The feasibility of direct firing the selected dry grind ethanol plant co-products and corn stover was evaluated using computational fluid dynamics (CFD) modeling. The co-products evaluated included condensed distillers solubles (referred to as "syrup"), distillers wet grains (DWG), distillers dried grains (DDG), and distillers dried grains with solubles (DDGS). Corn stover is also included in this study. Analyses of the co-products from the project partner ethanol plants showed that the syrup and the DWG have high (65%-70%) water content and low heat value. Therefore, the CFD modeling for direct firing syrup and DWG was focused on the flame temperature and the flame stability, which are critical for successful combustion in direct-fired systems.

Estimating emissions of criteria air pollutants is necessary for evaluation of the practical feasibility of any combustion option. The CFD model used for this project therefore evaluated potential emissions of carbon monoxide (CO), nitrogen oxides (NOx), and sulfur dioxide (SO_2). Emissions of particulate matter (PM) were not included in the model, because PM mainly depends on the details of the particular combustion system and because a highly efficient particulate control system will be included in any combustion system.

As a baseline for comparison and an approximate validation of the model for the ethanol plant co-products, Powder River Basin (PRB) coal, for which validated modeling results are available, was also modeled under the same conditions.

The IFRF (International Flame Research Foundation) swirl-stabilized burner and furnace, shown on Figure CET 1(1), was selected for the modeling of the direct firing of the ethanol plant co-products. In the IFRF experiments, in-flame temperature, chemical species concentration, and coal burnout were measured at several traverses using standard IFRF sampling probes. The results for coal have been used to validate the combustion model by Peters and Weber [1]. The dimensions of the furnace are shown on Figure CET 1. In this study, the adiabatic boundary condition, which means that the heat transfer rate is set to be zero at the burner wall, was applied to illustrate the impacts of the different fuels on the flame temperature and structure.

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(1) Peter, A.F. and Weber, R. (1997), Mathematical modeling of a 2.4 MW swirling pulverized coal flame, Combustion Science and Technology, 122, p 131.

The total combustion airflow rates for all the fuels are set to be 1,700 lb/s (770 kg/s) based on the airflow rate in the experiments for coal. The modeling results for coal show that the average residence time of the fuel particle is 0.8 ~1.2 second. The fuel flow rate is calculated based on the stoichiometric ratio, which is the ratio of the actual airflow rate to the theoretical combustion airflow rate required for fuel burnout. It is assumed to be 1.2 for all fuels to keep the same excess air level for combustion.

Results for the Direct Firing Burners Modeling

Figure CET 2 shows the temperature distribution inside the IFRF furnace for different fuels. The temperature contours shown on Figure CET 2 are plotted on the cross-sectional surface. Figure CET 2 shows that the flame temperature for syrup and DWG is much lower than the flame temperatures of PRB coal, DDGS, and corn stover. The flue gas temperatures at the outlet of the furnace (location noted as suction pyrometer in Figure CET 1) are also listed in Table CET 1.

For syrup and DWG, the flue gas temperature after combustion is around 1,880 ~ 2,060°F (1,027 ~ 1,127°C). For DDGS and corn stover, this temperature can reach 3,300 ~ 3,500°F (1,816 ~ 1,927°C). The difference in the flame temperature can be explained by the different heat values of the fuels, which are also listed on Figure CET 2. In the industrial furnace, the flame stability is closely related to the adiabatic flame temperature. Fuel with a higher flame temperature has a higher flame stability, because it can offer higher heat flux to heat the fresh fuel particle, which is favorable for devolatilization and solid combustion. Based on the modeling results, DDGS and corn stover have similar flame temperature as that of the PRB coal, which shows that these fuels can be applied to the industrial combustion facilities (*e. g.*, wall-fired unit) for PRB coal. For syrup and DWG, the flame temperatures are ~1,000°F (~ 538°C) lower than that of PRB coal, which implies an unstable combustion condition if the syrup and DWG are used in the same combustion units as for PRB coal.

On Figure CET 2, the flue gas temperature for DDGS is noted as having undergone a slight increase near the outlet of the furnace. This is because of the gradual reaction of char and CO with O_2 in the flue gas across the furnace.

The water mass fraction inside the burner for syrup and PRB coal is shown on Figure CET 3. Since the syrup has a much higher water content than the PRB coal, the water mass fraction in the flue gas can reach 30 percent for syrup combustion compared to the 11 percent of water mass fraction for PRB coal. Although DDGS has less water content than PRB coal, the mass fraction of water in the flue gas from firing DDGS is noted as being slightly higher than that for PRB coal (also shown in Table CET 1). This is because DDGS, like other biofuels, has more hydrogen content than PRB coal, which will generate water during combustion.

The modeling results for the different fuels at the furnace outlet are summarized in Table CET 1. Table CET 1 includes the flue gas temperature and composition at the furnace outlet, along with CO, NO_x and SO_2 emissions evaluated by the CFD model. The O_2 volume fractions at the outlet for all the fuels are very similar, which is due to the same stoichiometric ratio applied for each fuel in the modeling. The modeled CO emission is relatively low for all the fuels in this adiabatic burner. Compared to PRB coal, the results show that firing DDGS and corn stover generates more CO emission. The calculated SO_2 emissions for all biomass fuels are higher than the emission for PRB coal except for corn stover, which has relatively less sulfur content.

Since this study focuses on the fuel feasibility and the adiabatic combustion conditions, the NO_x emissions calculated in the model are derived from the fuel (fuel NO_x). The thermal NO_x and prompt NO_x are mostly related to the combustion process (*e.g.*, flame temperature, excess O_2), which depends on the detailed engineering design of the combustion facility. The modeled NO_x emission for PRB coal (0.63 lb/MMBtu) in this IFRF furnace is relatively high compared to the NO_x emission from the pulverized-coal boiler. This is because the IFRF burner is unstaged, in which no NO_x reduction techniques (*i.e.*, overfire air) were applied. The modeling results show that firing corn stover gives similar NO_x emissions compared to the PRB coal. However, DWG, syrup and DDGS all give higher NO_x emissions than PRB coal. With some combustion optimizations, the NO_x emissions can be reduced from the predicted value. Post combustion treatment (*i.e.*, selective noncatalytic reduction) may also be necessary for firing some fuels with high predicted NO_x emissions.

Explanations of the Predicted NO_x from Direct Firing

The NO_x generation mechanism used in modeling the biomass combustion includes three reactions, which can be summarized for the nitrogen component as follows:

$$\begin{tikzcd}
Fuel\ N \arrow[r] & NH_3 \arrow[r, "1{:}+O_2"] \arrow[d, "3{:}+NO"] & NO \arrow[r, "2{:}+Char"] & N_2 \\
& N_2 & &
\end{tikzcd}$$

Reaction 1: $NH_3 + O_2 \text{ --> } NO + H_2O$;
Reaction 2: $NO + C \text{ --> } CO + N_2$;
Reaction 3: $NH_3 + NO \text{ --> } N_2 + H_2O$.

Figures CET 4 and CET 5 illustrate the different NO_x conversion rates for fuel nitrogen in DDGS and DWG. Basically, the difference is due to the water content of the fuel. Figure CET 2 shows that the flames of the DWG and the syrup are shorter than the flames of the DDGS and coal, as evidenced by the O_2 fraction on Figure CET 1. The IFRF burner is a swirling burner with primary air (fuel + carrying air) in the center of the burner, which is surrounded by the rotational combustion air. For DWG and syrup with a high water content, the rapid evaporation of the moisture from the fuel will make the primary air quickly expand near the inlet of the furnace. This will disturb the rotation of the combustion airflow and intensify the mixing of the gas. As a result, the fuel nitrogen in DWG is rapidly released as ammonia(NH_3) near the furnace inlet (shown on the Figure CET 4). The ammonia then contacts and reacts with O_2 (Reaction 1) from the rotational air to generate NO, as shown on Figure CET 4. The early mixing of the NH_3 and O_2 causes a higher NO, and less NH_3 left for the NO reduction reaction (Reaction 3).

For DDGS, as show on Figure CET 4, the swirling flow has longer penetration without the disturbance caused by the high moisture, and the NH_3 is gradually mixed with O_2 to generate lower NO. Furthermore, the longer NH_3 region in the flue gas is also favorable to the NO reduction reaction (Reaction 3). The comparison of the NOx reduction rate for DDGS and DWG is shown on Figure CET 5.

These results show that additional drying of the wet fuel (DWG and syrup) will not only benefit the combustion stability, it will also be helpful in optimizing the fuel/air mixing, and thus in reducing overall NOx generation.

Conclusion Regarding Direct Firing

CFD modeling results using the IFRF furnace show that self-sustaining direct firing is probably not feasible for either syrup or DWG. For syrup and DWG, the predicted flame temperatures are approximately 1,000°F (538°C) lower than that of PRB coal, which implies the potential instability of the flame. Results show that DDGS and corn stover have a similar flame temperature as that of the PRB coal. The results show that firing DDGS and corn stover generates more CO emissions than PRB coal does. Except for corn stover, modeling shows that all ethanol co-products yield higher NO_x and SO_2 emissions in direct firing than the PRB coal.

Fluidized Bed Combustion

Fluidized bed combustion (FBC) of the selected dry grind ethanol plant co-products, and of a mixture with corn stover, was evaluated using CFD modeling. The co-products evaluated included condensed distillers solubles (referred to as “syrup”) and distillers dried grains with solubles (DDGS). A combination of 70 % syrup and 30% corn stover was also evaluated. This mixture results in a feed material with a moisture content that previous modeling indicates will be stable and self-sustaining, while maximizing the combustion of the syrup. The CFD model evaluated potential emissions of carbon monoxide (CO), nitrogen oxides (NO_x), and sulfur dioxide (SO_2). Emissions of particulate matter (PM) were not included in the model, because PM mainly depends on the details of the particular combustion system and because a highly efficient particulate control system will be included in any combustion system.

Modeling

The direct-firing CFD model and certain data from an existing fluidized bed reactor combusting syrup were used for comparison and an approximate validation of the model.

The fluidized bed setup is shown on Figure CET 6. The basis for the model is 150,000 Btu/hr (158 MJ/hr) fuel with biomass fuel and limestone feed from the top of the bed. Sand is the fluidizing media. In this study, an adiabatic boundary condition, which means that the heat transfer rate is set to be zero at the burner wall, was used. The total combustion airflow rates for all the fuels are set to be 155,000 lb/hr (70,300 kg/hr).

Additional model setup parameters for syrup, DDGS, and the syrup/corn stover mixture are shown in Table CET 2, and are based on data obtained from co-product analyses and operating fluidized bed combustion units.

Results for the Fluidized Bed Combustion Modeling

The modeling results for syrup, DDGS, and the syrup/corn stover mixture at the furnace outlet are summarized in Table CET 3. Table CET 3 includes the flue gas temperature and composition at the furnace outlet, along with the CO, NO_x, and SO_2 emissions evaluated by the CFD model. The O_2 volume fractions at the outlet for both fuels are very similar, which is due to the similar stoichiometric ratio applied for each fuel in the modeling.

The percent water in the emissions is more than three times greater combusting syrup than DDGS because of a much higher moisture content in the syrup fuel. As a result, the temperature is lower when combusting syrup. Results for the syrup/corn stover mixture are intermediate between the syrup alone and the DDGS.

The NO_x and NO_2 emissions from DDGS are higher than syrup because of the high nitrogen content in DDGS. The mixture of syrup and corn stover shows the lowest NO_x and NO_2 emissions; the reasons for this are not clear. Modeling shows the SO_2 emissions from syrup as higher than DDGS, despite about twice the sulfur in DDGS fuel than syrup. The mixture of syrup and corn stover shows the lowest SO_2, at least partially because of the very low sulfur content of the stover.

Additional modeling was completed to show the effects of moisture (Table CET 4) and excess air (Table CET 5) for DDGS. As expected, the percent water in the flue gas increases and the temperature decreases as the moisture in DDGS increases. Both NO_x and SO_x emissions generally decrease with an increase in moisture. Increasing excess air decreases the temperature, moisture, CO, NO_x, and SO_x.

Figures CET 7 to CET 11 show various predicted conditions, including gas phase temperature, solid volume fraction, gas phase pressure drop, CO mass fraction, and NO concentration within the fluidized bed reactor for syrup and DDGS. It should be noted that the fluidized bed combustion CFD model is a dynamic system and that Figures CET 7 to CET 11 only capture a snapshot in time of the model.

Conclusion Regarding Fluidized Bed Combustion

FBC CFD modeling results combusting syrup, DDGS, and a syrup/corn stover mixture using a fluidized bed reactor show that syrup and DDGS have similar NO_x and SO_2 emissions that may require post-combustion treatment. Increasing moisture content in the DDGS generally decreases the NO_x, SO_x, and CO. However, energy content will be lower with increasing moisture. Likewise, increasing excess air will decrease the energy content. Additional FBC configurations may yield different results, but are expected to be generally the same.

Fluidized Bed Gasification

Modeling

The biomass gasification modeling was conducted using RMT's engineering biomass gasification model to estimate the product fuel gas from a fluidized bed gasifier using partial oxidation. The engineering model provides a high-level approximation of the fluidized bed biomass gasification process based on results reported in the literature. Partial oxidation gasification with air is considered the simplest gasification technology with the lowest capital cost. The modeling looked at the feasibility of gasification for distillers dried grains with solubles (DDGS) to produce a fuel gas that could be used to provide energy for the dry grind ethanol plant. The gasification modeling focused on DDGS only as other co-products, syrup and distillers wet grains (DWG), contained a high (65%-70%) water content and have a low heating value that would not make them suitable feed materials for gasification. Corn Stover was viewed as not being economical compared to ethanol plant co-products due to harvesting and handling.

The gasification model evaluated the conversion of the DDGS into a product fuel gas and the composition of the product fuel gas. The modeling investigated both the effects of gasification bed temperature and moisture content of the DDGS feed at a nominal atmospheric pressure of 1.05 atm. Based on industry experience, the gasification temperature was limited to 1,472°F (800°C) due to the low ash fusion temperature under reducing conditions that could potentially cause bed agglomeration at higher gasification temperatures. The product gas composition included the percent of carbon monoxide (CO), carbon dioxide (CO_2), hydrogen (H_2), methane (CH_4), nitrogen (N_2), ammonia (NH_3), hydrogen sulfide (H_2S), and water (H_2O). The model also estimated the tar yield from the gasification of DDGS, which typically occurs from the partial pyrolysis reactions during biomass gasification at lower temperatures. Emissions of particulate matter (PM) were not included in the model as this type of information is not readily available in the literature. A key simplifying assumption of the model is that all of the nitrogen in the fuel will be converted to NH_3 and all of the sulfur will be converted to H_2S. The estimated amounts of NH_3 and H_2S in the product gas will be important in determining the level of gas cleanup required to utilize the product fuel gas in conventional gas combustion systems.

Results of the Modeling for Fluidized Bed Gasification

The modeling investigated three operating temperatures, 1,292°F (700°C), 1,382°F (750°C), and 1,472°F (800°C). The feed rate was based on the same DDGS feed thermal input to the fluidized bed combustion model at 19,742 lb/hr (8,963 kg/hr) for each temperature range. The results of the gasification modeling at different operating temperatures are shown in Table CET 6. The product gas compositions at the different operating temperatures on both a wet and a dry basis are shown in Table CET 7. As the gasification temperature increases, more air is required to maintain the higher operating temperature. The amount of feed air more than doubled over the range of 1,292°F (700°C) to 1,472°F (800°C). This increase in feed air increases the percentage of nitrogen and carbon dioxide, and reduces the carbon monoxide and methane, in the product gas with increasing temperatures. This results in a lower heating value for the product gas produced at higher gasification temperatures. The chemical energy in the dry product gas decreased from 173.7 Btu/SCF (6.47 MJ/Nm^3) at 1,292°F (700°C) to 72.8 Btu/SCF (2.71 MJ/Nm^3) at 1,472°F (800°C).

The amount of carbon in the DDGS that is converted to product gas increases with increasing temperature. Carbon conversion increased from 80 percent at 1,292°F (700°C) to over 98 percent for 1,472°F (800°C). The increase in carbon conversion with temperature corresponds with a decrease in tar yield with increasing temperature. As mentioned previously, at lower gasification temperature, pyrolysis reactions can produce tars in the product gas. As the gasification temperature increases these tars are cracked to gaseous components. The estimated tar yield went from 0.000929 lb/scf (14.9 g/Nm^3) at 1,292°F (700°C) to 0.0000692 lb/scf (1.11 g/Nm^3) at 1,472°F (800°C). Although biomass gasification of the DDGS at lower temperatures can produce a higher chemical energy in the product gas, the gasification system will have to be able to handle the tar produced from the system.

The effect of different feed moistures for DDGS gasification at 1,382°F (750°C) is shown in Tables CET 8 and CET 9. Table CET 8 shows the operating effects and Table CET 9 shows the product gas composition effects. The DDGS feed rate for the feed moisture cases was based on the same dry feed rate in the temperature cases, but adjusted to reflect the increase in moisture content in the as-received DDGS feed.

As the moisture content of the DDGS feed increases, the feed air increases to maintain the gasification temperature. This is illustrated by the increase in the oxygen to a DDGS feed stoichiometric ratio that goes from 0.404 at 10 percent moisture to 0.802 at 25 percent moisture. This degrades the dry product gas heating value from 116.5 Btu/SCF (4.34 MJ/Nm^3) at 10 percent moisture down to 59.3 Btu/SCF (2.21 MJ/Nm^3) at 25 percent moisture. The carbon converted to gas declines at greater than 15 percent moisture content to below 90 percent conversion for 25 percent moisture.

The product gas composition increases in nitrogen content with higher moisture contents due to the higher amount of feed air required to maintain gasification temperature. Increases in moisture content reduces the amount of carbon monoxide but increases the percentage of hydrogen in the product gas. This is due to the water-gas shift reaction ($H_2O + CO = H_2 + CO_2$) in the gasification process. The percentage of methane is reduced with increasing moisture content due to steam-reforming of the methane at higher moisture contents with water to produce hydrogen and carbon monoxide. Although the increase in moisture content has some beneficial effects to increase hydrogen it is offset by the decrease in carbon monoxide and the high nitrogen in the product gas.

As the dry feed rate is the same for all of the cases, the amount of ammonia and hydrogen sulfide that result in the product gas are the same for all cases. Table CET 10 shows the estimated amount of ammonia and hydrogen sulfide produced in the product gas and the estimated emissions after combustion in conventional systems without pretreatment of the product gas or staging of the combustion for NO_x control. The estimated NO_x and SO_2 emissions are based on the thermal input of the DDGS feed to the gasifier. Emissions for NO_x are estimated at 2.52 lb/MMBtu (1.08×10^{-3} kg/MJ) and for SO_2 at 1.44 lb/MMBtu (6.22×10^{-4} kg/MJ). The NO_x emissions can be reduced from the estimated value with some combustion optimization. The removal of ammonia and hydrogen sulfide prior to combustion can also reduce the NO_x and SO_2 combustion emissions. However, in the event that sufficient amounts of ammonia can not be economically removed, some post-combustion treatment (*i.e.*, selective noncatalytic reduction) may be necessary for reducing the NO_x emission.

Conclusion Regarding Fluidized Bed Gasification

The gasification modeling of DDGS indicated that lower gasification temperatures will produce a higher quality of product gas. However, this comes with the tradeoff of higher yields of tar that will need to be taken in consideration in development of the overall gasification system. Moreover, increasing moisture content of the DDGS has a detrimental effect on product gas quality. As the quantity of air required to maintain the gasifier temperature increases, the subsequent dilution of the product gas with nitrogen results in a lower product gas heating value. Therefore, the moisture content of the DDGS feed should remain as low as possible.

Product gas cleanup prior to combustion would help to reduce both NO_x and SO_2 emissions and minimize or eliminate post-combustion treatment if at all possible.

Synthesis Gas Conditioning

The product gas exiting the fluidized bed contains particulates, tars, and other constituents that may interfere with gas utilization. The type and degree of gas conditioning required will depend on its use. For example, co-firing applications may not require as extensive a gas cleanup as for gas turbines or internal combustion engines. For co-product fluidized bed gasification, we discuss the need for reductions in both nitrogen-containing compounds and sulfur in more detail. Insufficient data are available to discuss tar formation and its related gas conditioning in this study.

The main nitrogen-containing compound in the product gas is ammonia. Ammonia is formed from the protein and other nitrogen-containing components in the co-products, and is undesirable because it leads to the formation of NO_x emissions when the product gas is burned. Both ammonia and NO_x emissions must meet regulatory requirements.

Catalytic destruction of ammonia and wet scrubbing to remove ammonia are the two most feasible systems to reduce ammonia concentrations. Wet scrubbing is effective and can be used when the product gas is first cooled. Catalytic destruction of ammonia is more advantageous because it occurs at higher temperatures (near 1,650°F or 900°C) and has the potential to remove both ammonia and tars from the product gas. Typically, greater than 99 percent destruction of ammonia is possible. However, the use of catalytic destruction for biomass applications has been limited to date, and wet scrubbing applications have been more widely used for biomass.

Sulfur from the co-products can be converted to hydrogen sulfide or sulfur oxides during gasification. The average sulfur content in the co-products is relatively low, and ranges from 0.04 percent in corn stover to 0.96 percent in syrup. However, sulfur oxide emissions and the potential poisoning of certain catalysts can be significant problems. Sorbents can be used to remove sulfur from the product gas. Metal oxide sorbents such as zinc ferrite, titanate, copper oxide, and iron oxide are used in regenerable systems, or limestone or dolomite can be used as throwaway sorbents.

Tables

Table CET 1
Direct Firing Burner Modeling Results Summary

		COMPOSITION AT FURNACE OUTLET					
FUEL TYPE	**TEMPERATURE °F (°C)**	**O_2 (% vol)**	**H_2O (% vol)**	**CO_2 (% vol)**	**CO (% vol)**	**NO_x lb/MMBtu (kg/MJ)**	**SO_x (lb/MMBtu) (kg/MJ)**
PRB coal	3,280 (1,804)	4.3	11.4	14.9	0.005	0.63 (2.70×10^{-4})	0.5-0.7 (2.15×10^{-4} - 3.00×10^{-4})
Syrup	1,948 (1,064)	3.7	30.3	10.6	0.008	0.94 (4.03×10^{-4})	2.31 (9.91×10^{-4})
DWG	2,168 (1,187)	3.8	30.1	13.8	0.0004	3.02 (1.30×10^{-3})	1.43 (6.13×10^{-4})
DDGS	3,398 (1,870)	3.7	12.9	14.9	1.14	1.09 (4.68×10^{-4})	1.48 (6.35×10^{-4})
Corn stover	3,482 (1,917)	3.5	12.2	16.9	0.41	0.56 (2.40×10^{-4})	0.10 (4.29×10^{-5})

Table CET 2
FBC CFD Model Setup: Syrup and DDGS

FUEL TYPE	Syrup	DDGS	70% Syrup + 30% Corn Stover
MOISTURE	67.6%	10.1%	49.2%
ASH	2.31%	3.4%	3.5%
VOLATILE	26.7%	74.3%	37.4%
FIX CARBON	3.39	12.2	9.88
HIGH HEAT VALUE	2,765 Btu/lb (6.424 MJ/kg)	8,368 Btu/lb (19.44 MJ/kg)	Not determined
NITROGEN IN FUEL	0.85%	4.22%	0.78%
SULFUR IN FUEL	0.32%	0.62%	0.23%
FUEL FLOW RATE	59,749 lb/hr (27,160 kg/hr)	19,742 lb/hr (8,974 kg/hr)	40,234 lb/hr (18,288 kg/hr)
AIRFLOW RATE	155,000 lb/hr (70,300 kg/hr)	155,000 lb/hr (70,300 kg/hr)	155,000 lb/hr (70,300 kg/hr)
HEAT INPUT	$1.65 x 10^8$ Btu/hr (1.74×10^{-5} MJ/hr)	$1.65 x 10^8$ Btu/hr (1.74×10^{-5} MJ/hr)	$1.65 x 10^8$ Btu/hr (1.74×10^{-5} MJ/hr)
STOICHIOMETRIC RATIO	1.4	1.3	1.38
REACTOR VOLUME	21,500 ft^3 (609 m^3)	21,500 ft^3 (609 m^3)	21,500 ft^3 (609 m^3)
REACTOR DIAMETER	25 ft – 32 ft (7.6 m - 9.8 m)	25 ft – 32 ft (7.6 m - 9.8 m)	25 ft – 32 ft (7.6 m - 9.8 m)
REACTOR HEIGHT	40 ft (12 m)	40 ft (12 m)	40 ft (12 m)
LIMESTONE FLOW RATE	503 lb/hr (229 kg/hr)	503 lb/hr (229 kg/hr)	503 lb/hr (229 kg/hr)

Table CET 3
Summary of FBC CFD Modeling Results at Furnace Outlet

	SYRUP	DDGS	70% Syrup + 30% Corn Stover
Temperature	1,430°F (777 °C)	1,700°F (927 °C)	1,580°F (859 °C)
H_2O	24.6 % (mass)	7.40 % (mass)	16.1 % (mass)
O_2	4.88 % (mass)	4.73 % (mass)	5.04 % (mass)
CO_2	14.2 % (mass)	18.7 % (mass)	17.1 % (mass)
CO	9.6 ppm	9.2 ppm	8.4 ppm
NO_X	404 ppm	748 ppm	194 ppm
NO_2	0.86 lb/MMBtu (3.7 x 10^{-4} kg/MJ)	1.20 lb/MMBtu (5.2 x 10^{-4} kg/MJ)	0.30 lb/MMBtu (1.3 x 10^{-4} kg/MJ)
SO_X	502 ppm	413 ppm	258 ppm
SO_2	1.62 lb/MMBtu (7.0 x 10^{-4} kg/MJ)	0.96 lb/MMBtu (4.1 x 10^{-4} kg/MJ)	0.71 lb/MMBtu (3.1 x 10^{-4} kg/MJ)

Table CET 4
FBC CFD Modeling Results - DDGS With Different Moisture Content

FLUE GAS AT OUTLET	DDGS Moisture Content				
	10%	15%	25%	35%	50%
Temperature (°F)	1,700	1,682	1,628	1,588	1,520
H_2O (mass %)	7.40%	8.00%	9.43%	11.25%	15.04%
O_2 (mass %)	4.73%	4.69%	4.61%	4.52%	4.33%
CO_2 (mass %)	18.70%	18.59%	18.30%	17.93%	17.16%
CO (ppm)	9.2	9.2	8.9	7.9	4.9
NO_x (ppm)	748	760	745	739	699
SO_x (ppm)	413	409	399	386	361

Table CET 5
FBC CFD Modeling Results - DDGS Combustion With Different Excess Air

Flue gas at outlet	EXCESS AIR		
	20%	30%	40%
Temperature (°F)	1,880	1,700	1,520
H_2O (mass %)	7.92%	7.40%	6.93%
O_2 (mass %)	3.43%	4.73%	6.93%
CO_2 (mass %)	20.02%	18.705	17.52%
CO (ppm)	48	9.2	5.6
NO_x (ppm)	1,095	748	689
SO_x (ppm)	443	413	387

Table CET 6
Biomass Gasification Modeling for DDGS at Different Operating Temperatures

GASIFICATION OPERATING TEMPERATURE ˚F (°C)	1,292 (700)	1,382 (750)	1,472 (800)
DDGS feed rate, as recorded lb/hr (kg/hr)	19,742 (8,963)	19,742 (8,963)	19,742 (8,963)
Total feed air scf/hr (nm^3/hr)	343,816 (9,730)	511,484 (14,475)	729,081 (20,633)
Total feed air lb/hr (kg/hr)	7,748 (3,522)	10,987 (4,994)	14,934 (6,788)
Product gas, dry scf/hr (nm^3/hr)	475,124 (13,446)	633,463 (17,927)	791,767 (22,407)
O_2/DDGS stoichiometric ratio	0.270	0.404	0.572
Gas yield, dry product gas scf/lb (nm^3/kg)	24.06 (1.50)	32.08 (2.00)	40.10 (2.50)
Gas higher heating value, dry Btu/scf (mJ/nm^3)	173.7 (6.47)	116.5 (4.34)	72.8 (2.71)
Product gas chemical energy, dry mmBtu/hr (mJ/hr)	82.54 (86,998)	73.80 (77,781)	57.65 (60,762)
Carbon conversion %	80.1	96.1	98.3

Table CET 7
Product Gas Composition for DDGS at Different Operating Temperatures

Temperature	**°F (°C)**	**1,292 (700)**		**1,382 (750)**		**1,472 (800)**	
PRODUCT GAS COMPOSITION		**WET**	**DRY**	**WET**	**DRY**	**WET**	**DRY**
N_2	Vol %	33.3	52.2	40.1	57.2	48.0	64.4
CO_2	Vol %	9.0	14.1	11.6	16.5	13.4	18.0
CO	Vol %	13.7	21.5	11.9	17.0	7.9	10.6
H_2	Vol %	2.3	3.5	2.4	3.5	2.4	3.3
CH_4	Vol %	2.7	4.2	1.7	2.4	0.7	1.0
NH_3	Vol %	2.7	4.2	2.2	3.2	1.9	2.5
H_2S	Vol %	0.2	0.2	0.1	0.2	0.1	0.2
H_2O	Vol %	36.2	--	29.9	--	25.6	--
Total	**Vol %**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Tar yield	lb/SCF (g/Nm^3)	--	9.28x10^{-4} (14.89)	--	4.84x10^{-4} (7.77)	--	6.92x10^{-5} (1.11)
	lb/MMBtu (g/MJ)	--	5.35 (2.30)	--	4.16 (1.79)	--	0.954 (0.410)

Note:
Conditions for standard cubic feet (SCF) and normal cubic meter (Nm^3) are 60°F (16°C) and 14.73 psia (1 atm).

Table CET 8
Biomass Gasification Modeling for 1,382°F (750°C) Operating Temperature at Different DDGS feed Moisture Contents

DDGS FEED MOISTURE, %	10	15	20	25
DDGS feed rate, as-recorded* lb/hr (kg/hr)	19,742 (8,963)	20,896 (9,487)	22,203 (10,080)	23,682 (10,752)
Total feed air scf/hr (nm^3/hr)	511,484 (14,475)	797,279 (22,563)	920,212 (26,042)	1,021,767 (28,916)
Total feed air lb/hr (kg/hr)	10,987 (4,994)	17,125 (7,784)	19,765 (8,984)	21,947 (9,976)
O_2/DDGS stoichiometric ratio	0.404	0.625	0.722	0.802
Product gas, dry scf/hr (nm^3/hr)	633,463 (17,927)	964,523 (27,296)	1,081,060 (30,594)	1,177,350 (33,319)
Gas yield, dry product gas scf/lb (nm^3/kg)	32.08 (2.00)	46.20 (2.88)	48.76 (3.04)	49.72 (3.10)
Gas higher heating value (HHV), dry Btu/scf (mJ/nm^3)	116.5 (4.34)	74.9 (2.79)	65.5 (2.44)	59.3 (2.21)
Product gas chemical energy, dry mmBtu/hr (mJ/hr)	73.8 (77,781)	72.3 (76,216)	70.9 (74,761)	69.8 (73,559)
Carbon conversion %	96.1	99.2	94.0	89.4

Notes:
Conditions for standard cubic feet (SCF) and normal cubic meter (Nm^3) are 60°F (16°C) and 14.73 psia (1 atm).
* DDGS feed rate based on same dry feed rate, adjusted for moisture content for as-recorded rate.

Table CET 9
Product Gas Composition for DDGS Gasification at 1,382°F (750°C) at Different Feed Moisture

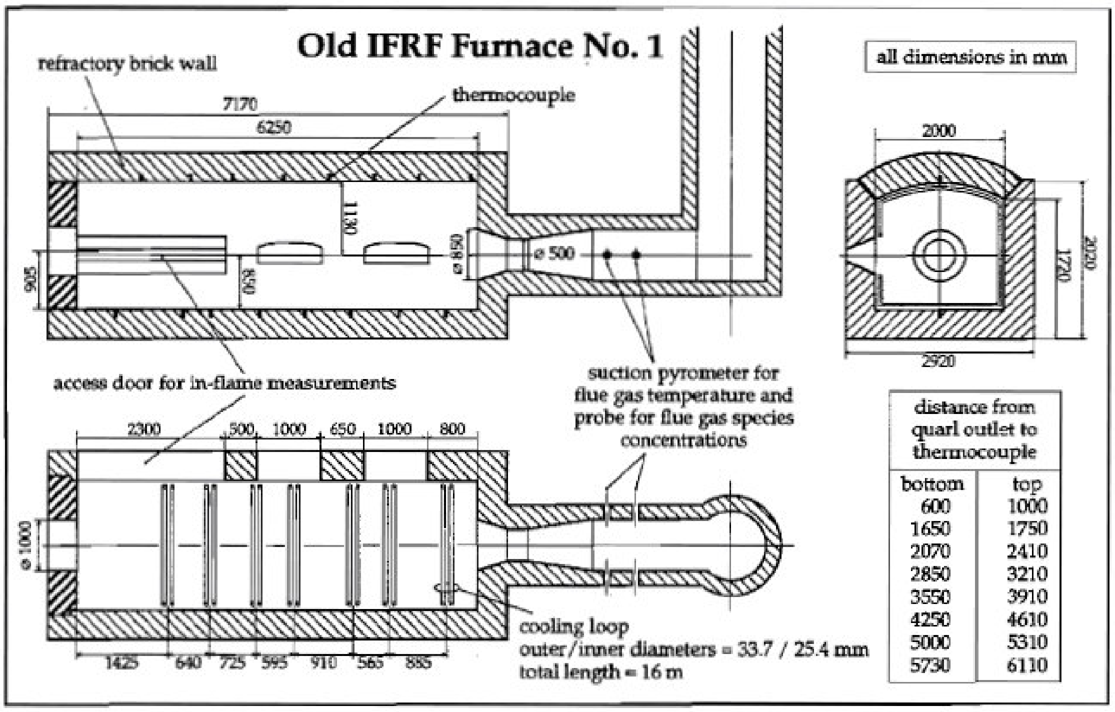
MOISTURE, %	10		15		20		25	
PRODUCT GAS COMPOSITION, VOLUME %	WET	DRY	WET	DRY	WET	DRY	WET	DRY
N_2	40.1	57.2	45.7	61.6	46.3	62.6	46.2	62.9
CO_2	11.6	16.5	12.4	16.7	12.2	16.5	12.0	16.3
CO	11.9	17.0	7.1	9.6	5.1	6.9	3.6	4.8
H_2	2.4	3.5	5.7	7.7	7.4	10.0	9.1	12.4
CH4	1.7	2.4	1.4	1.9	1.2	1.6	0.9	1.3
NH_3	2.2	3.2	1.8	2.4	1.7	2.2	1.6	2.1
H_2S	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
H_2O	29.9	-	25.8	-	26.0	-	26.5	-
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Table CET 10
Ammonia and Hydrogen Sulfide Production and Resulting Emissions Estimates Without Gas Treatment

NH_3 PRODUCTION	lb/hr (kg/hr)	1,070 (485.7)
NH_3 per DDGS fuel thermal input	lb/mmBtu (kg/mJ)	6.49 (2.79×10^{-3})
NO_x emission estimate* without gas treatment	lb/mmBtu (kg/mJ)	2.52 (1.08×10^{-3})
H_2S Production	lb/hr (kg/hr)	126.6 (57.5)
H_2S per DDGS fuel thermal input	lb/mmBtu (kg/mJ)	0.767 (3.31×10^{-4})
SO_2 emissions estimate without gas treatment	lb/mmBtu (kg/mJ)	1.44 (6.22×10^{-4})

Note:
* NOx emissions as NO.

Figures



distance from quarl outlet to thermocouple	
bottom	top
600	1000
1650	1750
2070	2410
2850	3210
3550	3910
4250	4610
5000	5310
5730	6110

Figure CET 1
IFRF Furnace(1)

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(1) Peter, A.F. and Weber, R. (1997), Mathematical modeling of a 2.4 MW swirling pulverized coal flame, Combustion Science and Technology, 122, p 131.

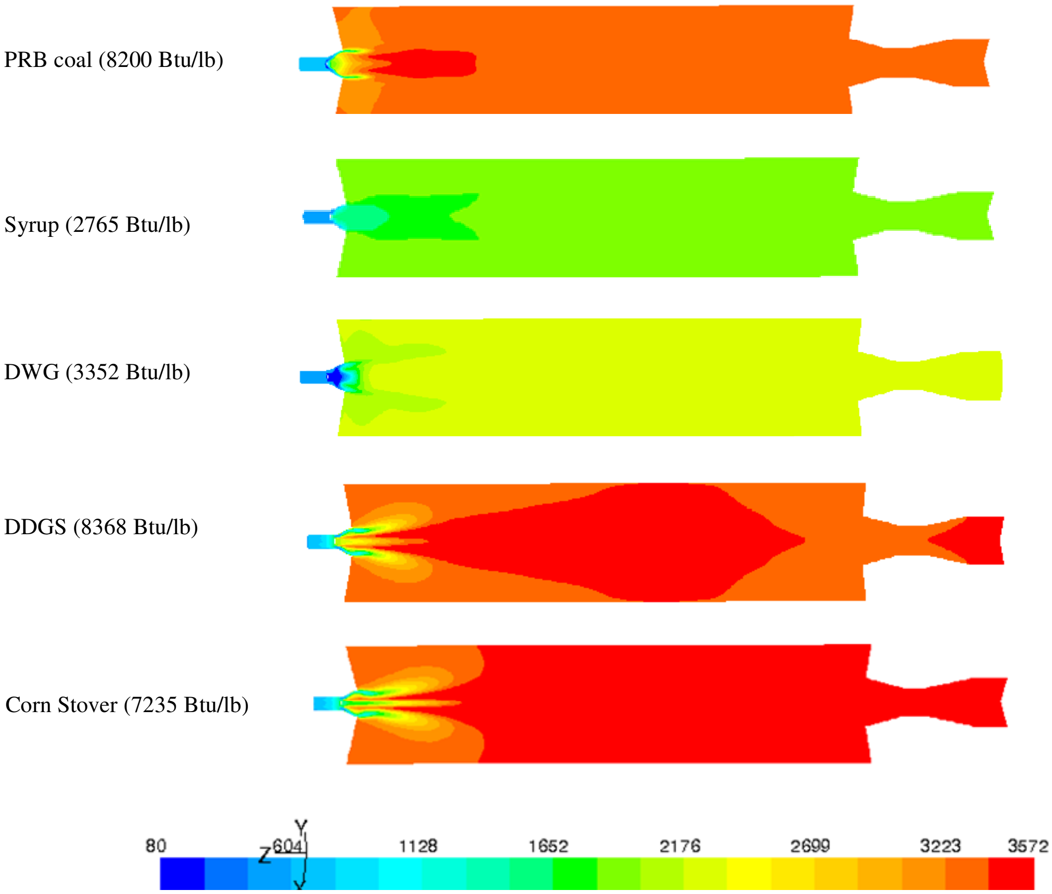


Figure CET 2
Direct Firing Burner Simulated Temperature Distribution (°F)

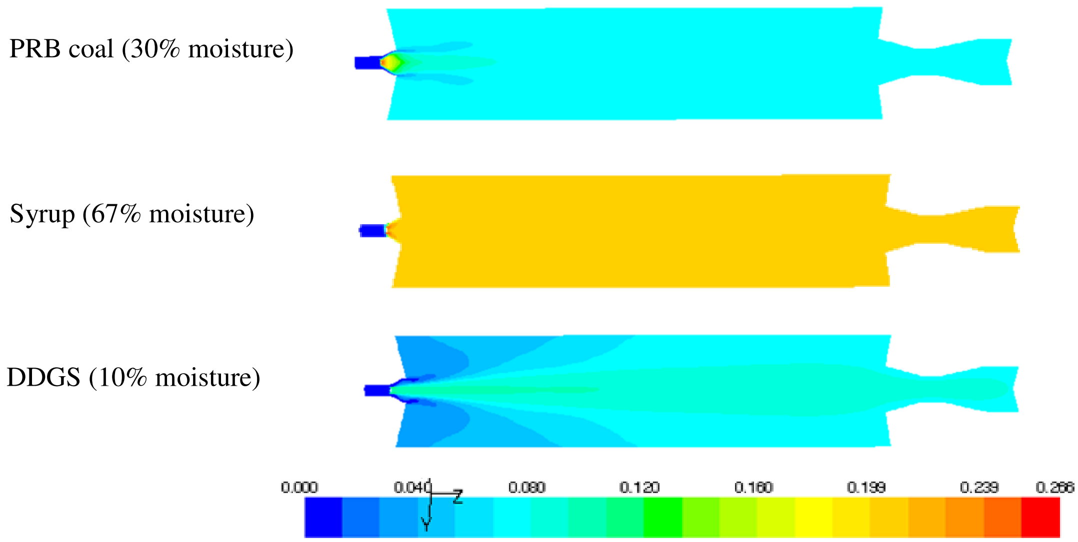


Figure CET 3
Simulated Water Mass Fraction in the Burner for Direct Firing

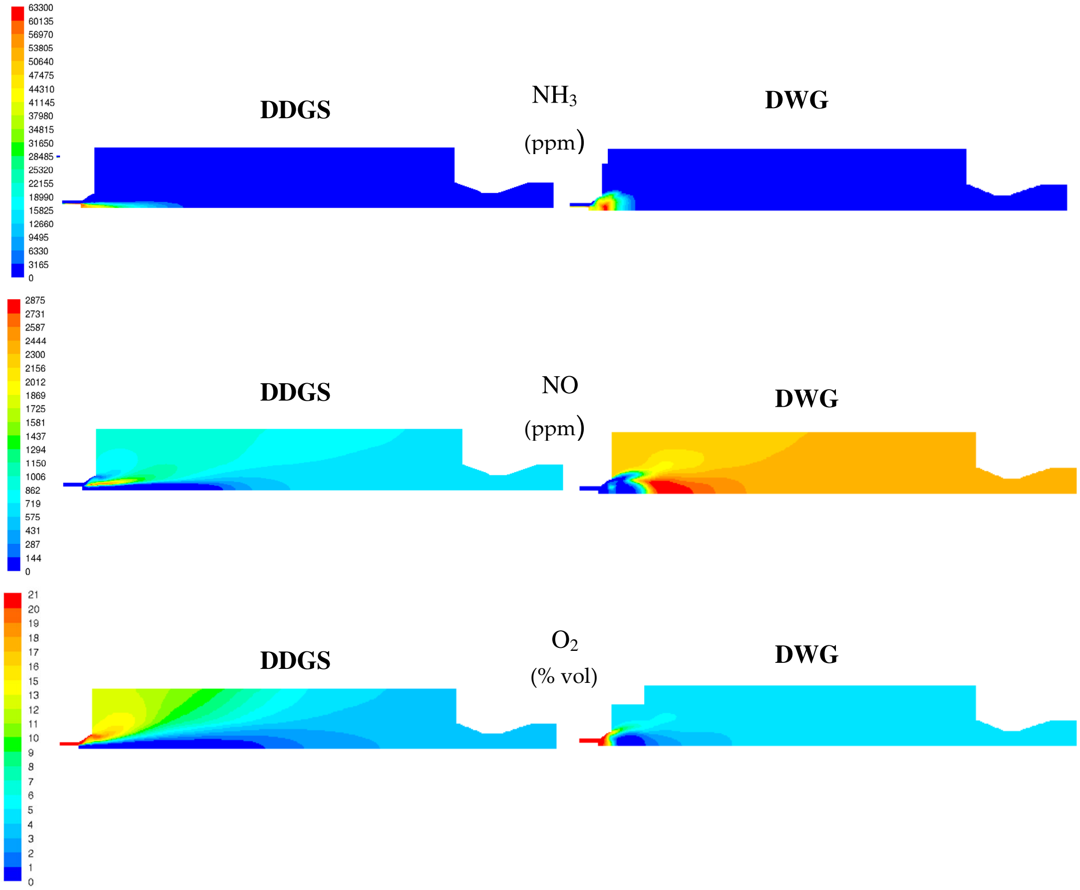


Figure CET 4
IFRF Direct Firing Conditions

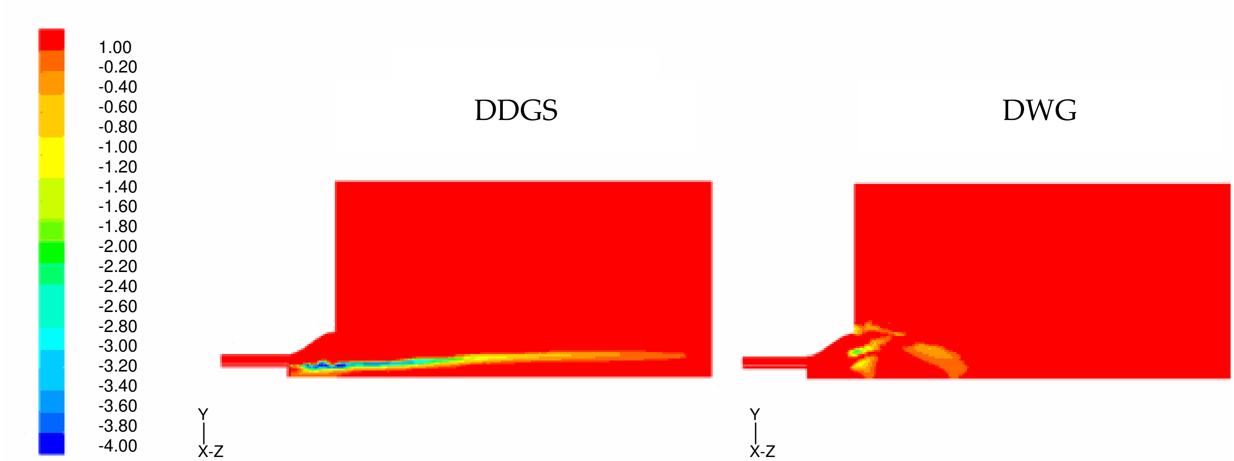


Figure CET 5
NO_x Reduction Reaction for Direct Firing DDGS and DWG

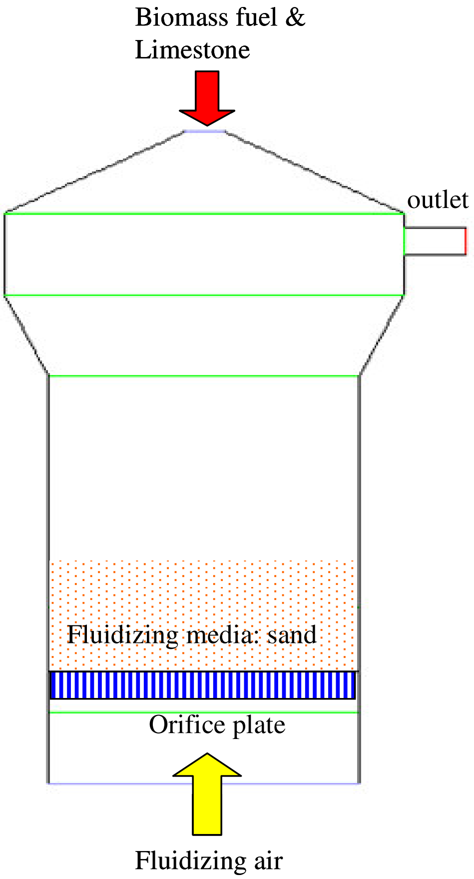
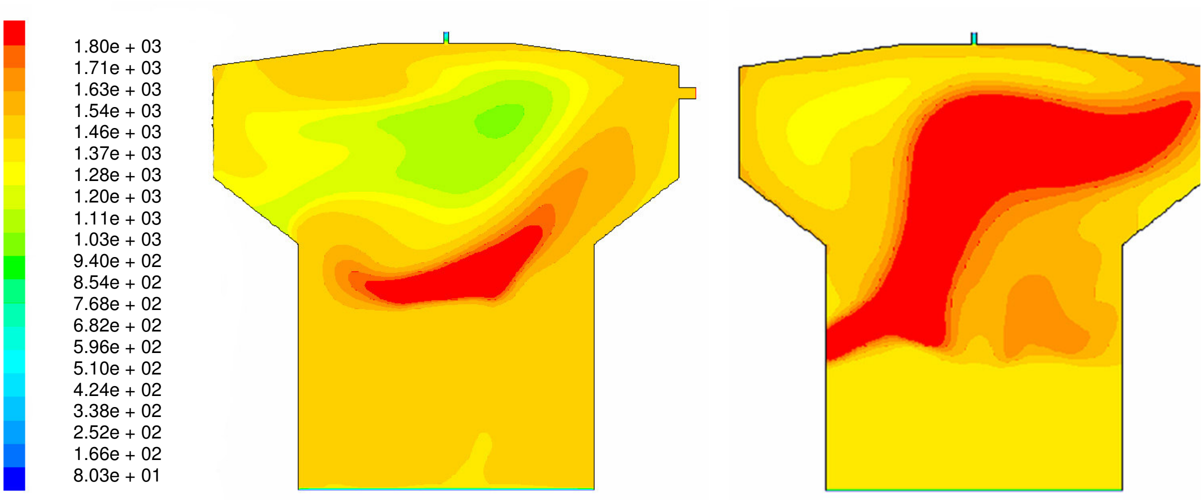
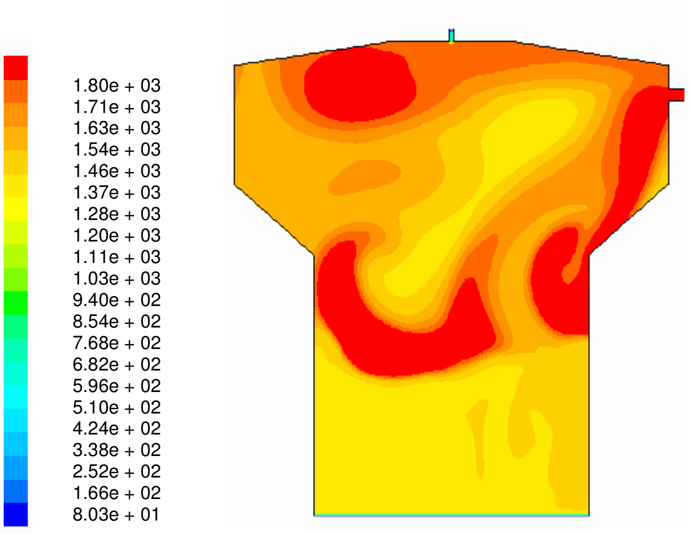


Figure CET 6
Fluidized Bed Configuration



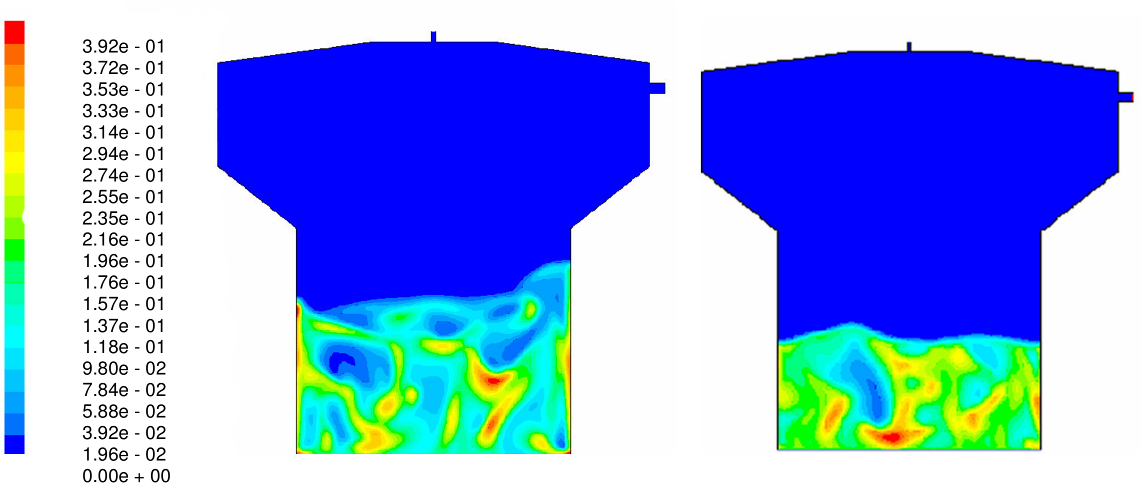
Syrup

DDGS



70% Syrup + 30%
Corn Stover

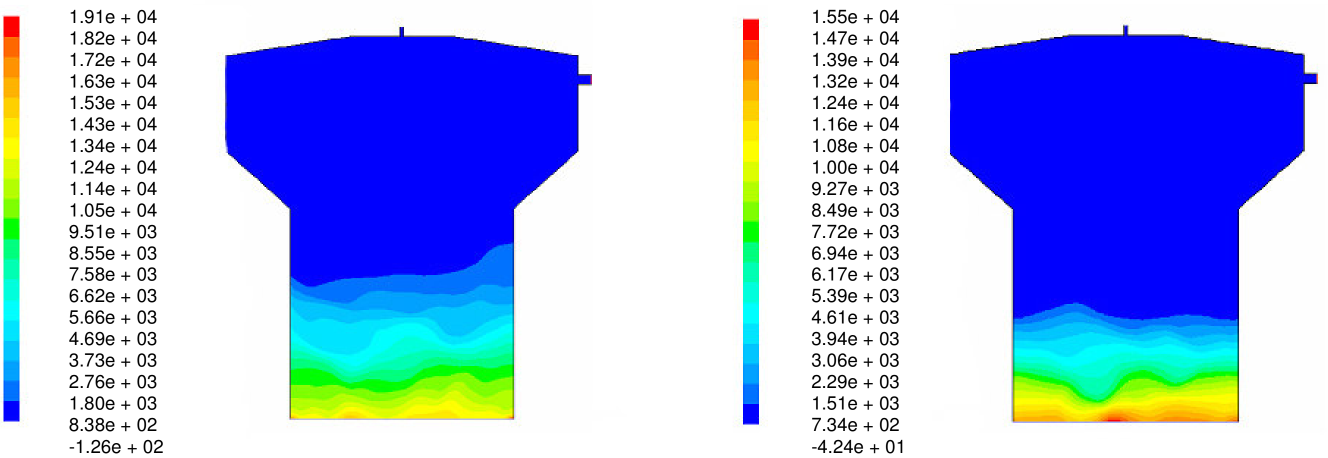
Figure CET 7
FBC CFD Modeling For Syrup, DDGS, and 70% Syrup + 30% Corn Stover - Gas Phase Temperature (°F)



Syrup

DDGS

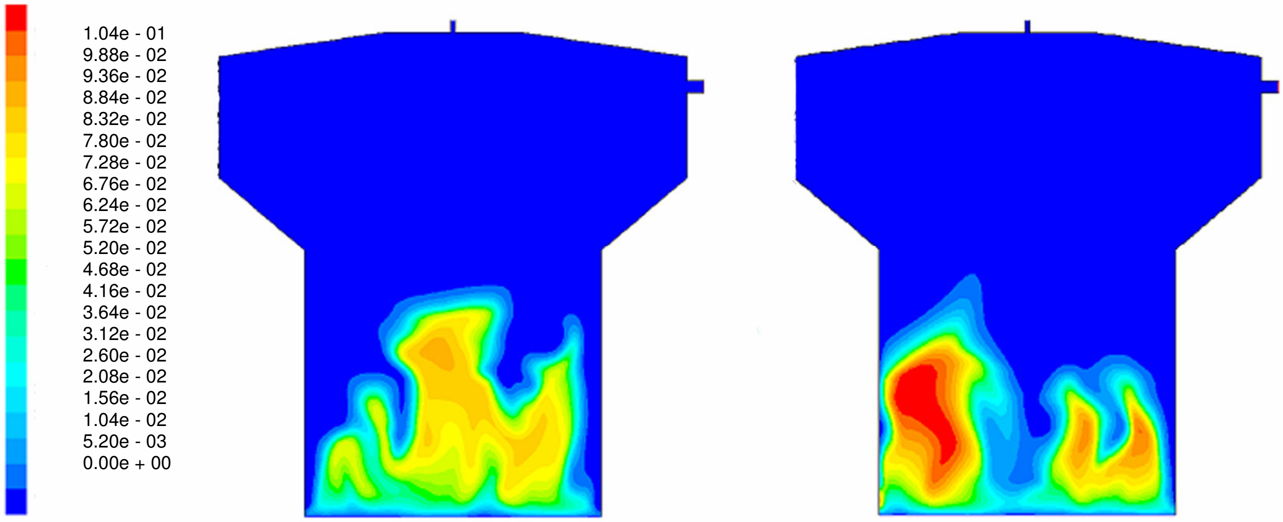
Figure CET 8
FBC CFD Modeling For Syrup and DDGS - Solid Volume Fraction



Syrup

DDGS

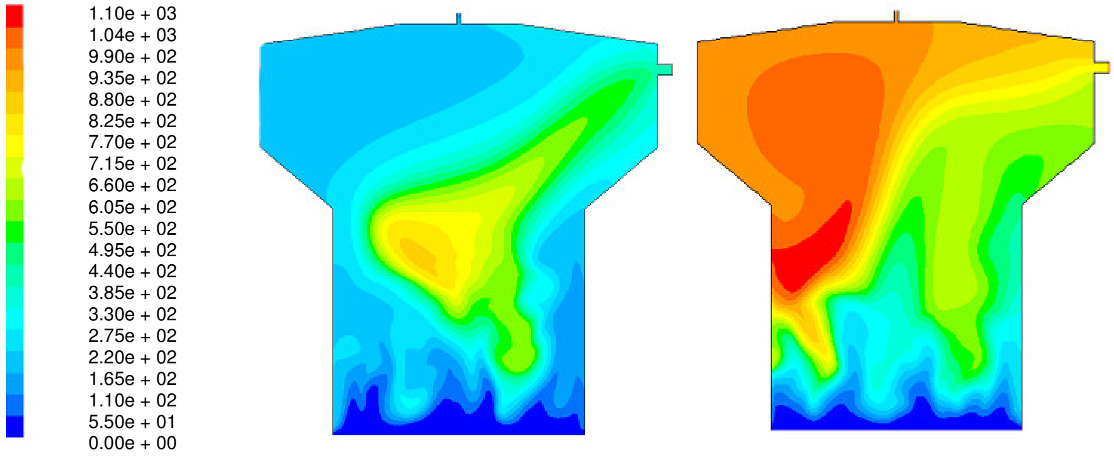
Figure CET 9
FBC CFD Modeling For Syrup and DDGS - Gas Phase Pressure Drop (Pa)



Syrup

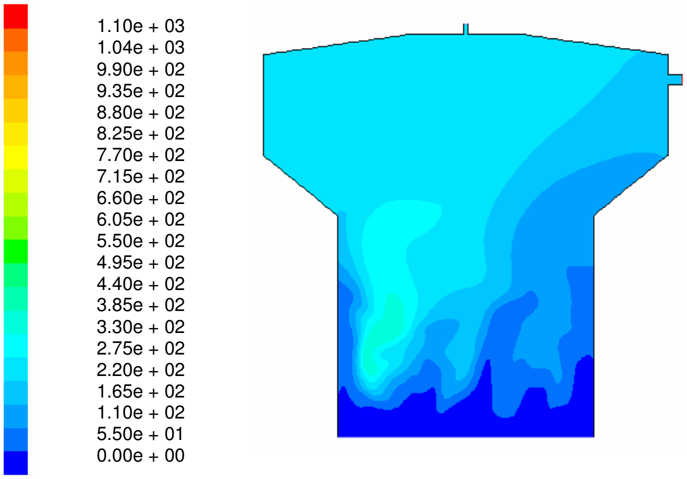
DDGS

Figure CET 10
FBC CFD Modeling For Syrup and DDGS - CO Mass Fraction



Syrup

DDGS



70% Syrup +
30% Corn Stover

Figure CET 11
FBC CFD Modeling For Syrup, DDGS, and 70% Syrup + 30% Corn Stover - NO_x (ppm)

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 7 – Evaluations Relative to Standards

This chapter provides as analysis of environmental regulations that may arise from the use of alternative biomass fuels at dry-grind corn ethanol production facilities. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants Report for Task 7, "Evaluations Relative to Standards"

Background

This chapter presents an analysis of environmental regulatory issues that may arise from the use of alternative biomass fuels at dry grind, corn-based fuel ethanol production facilities. Because the environmental regulations with the greatest potential impact on the use of biomass fuels are emissions-related, this chapter focuses on emissions considerations. Combustion of ethanol plant co-products and/or corn stover present new emission profiles that may trigger regulations different from the air quality regulations governing an ethanol plant burning natural gas. These regulatory differences, and hazardous waste and health and safety issues, are reviewed and summarized below.

Process Descriptions

To highlight the differences in the air quality compliance profiles for ethanol plants that burn alternative biomass fuels versus natural gas, we first consider a general fuel-related process description of a typical ethanol plant using natural gas and a general fuel-related process description for a plant using the types of biomass fuels and the type of combined heat and power (CHP) systems being evaluated in this project.

Plant Using Natural Gas

The example fuel ethanol plant considered in this project receives whole corn and then grinds, processes, and ferments it to produce "beer." The ethanol is separated from the beer by distillation, and is then dehydrated to produce fuel-grade ethanol. The stillage is separated into two components, thin stillage and wet cake. The thin stillage is concentrated via evaporation to produce "syrup." The syrup may be sold as-is, may be dried and sold, may be mixed with the wet cake and the combined wet product sold as-is, or it may be mixed with the wet cake and the combined components dried and sold. Drying is usually accomplished with a rotary kiln fired with natural gas, although steam may be used as a heat source for the kiln. The exhaust from the drying operation is routed to a device, sometimes a thermal oxidizer, to control emissions of volatile organic compounds (VOCs). The exhaust from the thermal oxidizer can be routed through a waste heat recovery boiler to provide plant steam. A baghouse, or fabric filter control device, controls particulate matter (PM) in the exhaust from the waste heat recovery boiler.

Because of the rising and unpredictable cost of natural gas and the generally low cost of utility-provided electricity to ethanol plants, few ethanol plants burning natural gas generate their own electricity. However, at least one ethanol plant burns natural gas in a combustion turbine connected to an electric generator, with steam provided via a heat recovery steam generator behind the turbine.

This typical manufacturing process contains numerous air contaminant emission sources, creating significant emissions of particulate matter, fine particulate matter—or particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) - carbon monoxide (CO), VOCs, nitrogen oxides (NO_x), and other pollutants, including hazardous air pollutants listed under Section 112(b)(1), 42 U.S.C. § 7412(b)(1), of the Clean Air Act. The primary sources of these emissions are co-product dryers, fermentation units, steam boilers, co-product cooling cyclones, ethanol truck load-out systems, and the fugitive dust emissions[1] generated from facility operations.

The unit emission sources generally do not change as the capacity of the ethanol plant increases, but the quantity of emissions will increase as plant production increases.

Plant Using Ethanol Production Co-products as Fuel

The general production process for a plant using co-products as fuel is the same as for the plant using natural gas, with the major exception being the primary plant energy source. That energy source will change from natural gas to biomass co-products. The biomass can be combusted, likely in a fluidized bed unit, in which case the natural gas-fired steam generators would be replaced with biomass combustion units. Alternatively, the biomass can be gasified, typically in a fluidized bed unit, in which case the existing burners and material handling equipment may be modified so that the biogas would replace the natural gas. A separate thermal oxidizer may or may not be needed, depending on energy and dryer system design. Electricity could be generated with a steam turbine or, in the case of gasification, with either a combustion turbine or a steam turbine operated from a conventional boiler or from a heat recovery steam generator. For purposes of this project, the maximum electricity output is assumed to be less than 25 megawatts (MW).

Overview of Air Quality Regulations

The federal Clean Air Act, and numerous state air quality control statutes, regulate air quality using a variety of strategies. Broadly, there are two primary strategies applicable to new manufacturing facilities or to manufacturing facilities undergoing major changes: (1) air quality control regulations, or emission standards, apply design or performance standards to defined categories of newly constructed emission sources (e.g., the New Source Performance Standards, the National Emission Standards for Hazardous Air Pollutants); and (2) new source review programs allow the regulating agency to ensure that air contaminant emission controls are considered and applied—on a site-specific basis—to newly constructed emission sources.

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[1] "Fugitive emissions" are emissions that do not pass through a stack or vent, capable of a control device.

Generally, new source review serves as the procedure through which regulators ensure that all categorical emission standards are properly interpreted and applied and that site-specific considerations, such as the quality of the air shed and regional air quality goals, dispersion characteristics, and local nuisance requirements, are also addressed.

Air quality control rules are promulgated by both federal and state agencies, and sometimes by local agencies. In this chapter, we review federal rules and state rules, using Minnesota and Wisconsin as model states. This review focuses on the differences in regulation between a plant using natural gas as fuel and a plant using biomass co-products as fuel. The addition of electricity generation also impacts what regulations are applicable. All other air quality compliance obligations for the project conceptual plant are likely to remain the same as for a natural gas–fired plant.

Federal Emission Standards

New Source Performance Standards

Section 111 of the Clean Air Act authorizes the United States Environmental Protection Agency (USEPA) to develop "New Source Performance Standards" (NSPSs) for newly constructed (or modified or reconstructed) emission sources in certain defined categories. These emission standards were originally intended as design or performance standards that reduce pollution from the heaviest polluting emission sources. One category of sources subject to NSPSs are industrial, commercial, and institutional steam generating units (*e.g.*, boilers) with a heat input capacity greater than 100 million British thermal units (Btu) per hour. A USEPA memorandum entitled Applicability of New Source Performance Standards at 40 CFR Part 60, Subpart Db, to a Thermal Oxidizer/Waste Heat-Recovery Boiler at an Ethanol Production Facility and dated January 8, 2003, states that thermal oxidizers and heat recovery steam generators used at fuel ethanol plants are subject to 40 CFR Part 60, Subpart Db. Subpart Db applies to sources constructed, modified, or reconstructed after June 19, 1984.

The Wisconsin Department of Natural Resources (WDNR) implements Subpart Db through its own rule at s. NR 440.205. The Minnesota Pollution Control Agency (MPCA) follows the federal rule, and does not implement Subpart Db through its own rule.

Subpart Db is focused on fossil fuel-fired units, in particular coal- and oil-fired units. Nevertheless, except with regard to PM, it regulates units firing "other solid fuels," when such fuels are co-fired with natural gas.[2] Subpart Db provides emission standards

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[2] Subpart Db also regulates units firing "byproducts/wastes." However, byproduct/waste is specifically defined in 40 CFR 60.41b as a liquid or gaseous substance. Thus, the associated emission limits would not apply to units firing the biomass products under consideration.

for PM, sulfur dioxide (SO_2), and NO_x. A unit that fires natural gas with "any other fuel" must limit NO_x emissions to 0.20 lb/MMBtu, unless the unit is subject to a permit condition limiting the "annual capacity factor" of natural gas to ten percent or less.[3] This review presumes that both the baseline and project conceptual plants will use natural gas only to start up the units, rendering the annual capacity factor for natural gas well below 10%. Thus, the units will be exempt from Subpart Db NO_x emission standards. PM emission standards apply only to facilities that co-fire coal, oil, or wood. Subpart Db standards as applied to the baseline and project conceptual plants are summarized in Table ERS 1.

No other NSPSs apply to the fluidized bed boiler combusting biomass fuels. The following NSPSs apply to other non–combustion-related emission units at both a plant burning natural gas and a plant burning biomass fuels:

- 40 CFR Part 60, Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.
- 40 CFR Part 60, Subpart VV: Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

National Emission Standards for Hazardous Air Pollutants (NESHAPs)

Section 112 of the Clean Air Act authorizes the USEPA to develop "National Emission Standards for Hazardous Air Pollutants" for newly constructed (or reconstructed) emission sources in certain defined categories. These emission standards were originally intended as health-based standards. With the Clean Air Act Amendments of 1990, the regulatory approach was changed to providing performance standards that reduce hazardous air pollution from a defined list of source categories responsible for the heaviest toxic air pollution. This more recent approach results in the application of Maximum Available Control Technology, or MACT, standards for major hazardous air pollutant (HAP) sources.

The Subpart DDDDD MACT standards establish HAP emission limits and work practice requirements for all new, reconstructed, and existing industrial, institutional, and commercial boilers and process heaters that are a major source of HAPs. Major sources of HAPs are those facilities with a potential to emit 10 tons per year (tpy) of any single HAP, or 25 tpy of any combination of HAPs.

Under Subpart DDDDD, several important definitions are used to establish fuel type and capacity subcategories. A facility burning syrup would fall under the liquid fuel subcategory and would be defined as a large unit. Liquid fuel includes distillate oil,

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[3] *See* 40 CFR 60.44b(l)(1).

residual oil, waste oil, and process liquids. Large units are defined as boilers and process heaters with heat input capacities greater than 10 million Btu/hr and having annual capacity factors greater than 10 percent. The annual capacity factor refers to the ratio of the actual heat input to a boiler or process heater from fuels burned during a calendar year to the heat input to the boiler or process heater had it operated at the maximum time of 8,760 hours per year. For large units burning liquid fuel, emission limits have been established for hydrochloric acid (HCl), mercury (Hg), PM (as a surrogate for non-mercury metallic HAPs), and carbon monoxide (CO). These limits are summarized in Table ERS 1.

A facility burning solid biomass co-products, such as DDGS, would fall under the solid fuel subcategory and would be defined as a large unit. Solid fuel includes coal, wood, biomass, tires, plastics, and other nonfossil solid materials (see 40 CFR 63.7575). For large units burning solid fuel, emission limits have been established for HCl, Hg, PM and CO. These limits are summarized in Table ERS 1.

No other NESHAPs apply to a fluidized bed boiler combusting biomass fuels. The following NESHAPs apply to other non–combustion-related emission units at a plant burning natural gas and a plant burning biomass fuel:

- 40 CFR Part 60, Subpart Q: National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.
- 40 CFR Part 60, Subpart FFFF: National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

Clean Air Market Programs

Acid Rain Program

The USEPA's Acid Rain Program, created with the Clean Air Act Amendments of 1990, is credited with implementing one of the most successful emission reduction strategies ever. Emission data show that power plants subject to the first phase of the program reduced emissions more than 40 percent below the required level, primarily through the SO_2 emission allowance trading system. The program was created to reduce emissions of SO_2 and NO_x, the precursors of acid rain.

The program focuses on coal-burning power plants, but it can also apply to utility plants that use fuels with high sulfur and nitrogen content. The typical dryer/RTO configuration of an ethanol plant used as a baseline plant for this project is not subject to the Acid Rain Program because it is not a "utility unit," *i.e.*, it does not serve a generator of electricity with a nameplate capacity of more than 25 MWe, producing electricity for sale. Although the project conceptual plant is intended to generate electricity, it is assumed that the amount of electricity generated will not reach the 25 MWe threshold necessary for applicability of this program. If the plant design were to exceed this threshold, the plant would be responsible for complying with the following Acid Rain Program requirements:

- Obtaining an Acid Rain permit
- Providing for continuous emission monitoring systems in compliance with 40 CFR Part 75
- Ensuring that the plant holds (through the allowance trading system) sufficient SO_2 emission allowances at the end of each year
- Complying with NO_x emission reduction requirements

Federal NO_x Budget Trading Program

In 2005, the USEPA finalized rules to implement the NO_x Budget Trading Program. This program provides NO_x reductions from fossil fuel–fired utility units in a manner similar to the Acid Rain Program. The goal of the program is to address NO_x "transport" from upwind regions that contribute to nonattainment with the ozone standards in the eastern half of the country.

Similar to the Acid Rain Program, the NO_x Budget Trading Program focuses on large, fossil fuel–fired utility units. Because the project conceptual plant configurations are more akin to small cogeneration facilities, they will not be subject to this program.

Minnesota and Wisconsin are not affected states in the NO_x Budget Trading Program.

Clean Air Interstate Rule

The Clean Air Interstate Rule (CAIR) is a clean air market program intended to reduce NO_x and SO_2 emissions from electric generating units (EGUs) in 28 eastern states, including Minnesota and Wisconsin, and the District of Columbia. CAIR offers states two compliance options: (1) requiring power plants to participate in a USEPA cap-and-trade program, under which states will be allocated an emission cap proportional to historical electric utility NO_x and SO_2 emissions, or (2) implementing measures of the state's choosing to meet the state's emission allocation. At the end of each accounting period (*i.e.*, year or ozone season), each affected facility must hold sufficient emission allowances to cover its emissions.

Under the federal cap-and-trade program, CAIR applies to “stationary fossil-fuel–fired boilers or stationary fossil-fuel-fired combustion turbines serving at any time, since the startup of a unit’s combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.” See 40 CFR 96.104(a). “*Fossil fuel–fired* means … combusting any amount of fossil fuel in any calendar year.” “*Fossil fuel* means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.” See 40 CFR 96.102. The typical dryer/RTO ethanol plant used as a baseline plant for this study is not subject to CAIR because the boiler or RTO does not serve a generator of more than 25 MWe in capacity. Although the project conceptual plant is intended to generate electricity, the biomass fuels we are considering for these plants are not fossil fuels, nor are they derived from fossil fuels. Biomass combustion projects are not the intended focus of this emission reduction program. Consequently, CAIR will not apply to the NO_x and SO_2 emissions of ethanol plants combusting biomass fuels, an advantage for these potential electricity generators.

Clean Air Mercury Rule

The Clean Air Mercury Rule (CAMR) is a clean air market program related to CAIR. It attempts to control mercury emissions from the power sector utilizing the cap-and-trade program created under CAIR for SO_2 and NO_x emissions. See 70 Federal Register (FR) 28606. CAMR will not apply to ethanol plants that use biomass fuels to generate steam or electricity, unless the plants also fire coal. Although the CAMR standards apply to “electric utility steam generating units,” a utility unit for purposes of CAMR is limited to “a stationary coal-fired boiler or a stationary coal-fired combustion turbine.” See 40 CFR 60.4102.

Summary

All of the clean air market programs to date focus on fossil fuel–fired electricity-generating units. In all of these programs, biomass combustion units are not intended to be regulated. This is evident in the exemptions these programs provide for cogeneration facilities, which are typically smaller, distributed utility units. Thus, either because biomass combustion will produce too little electricity or because biomass is not a fossil fuel, the project conceptual plant will avoid the clean air market programs and maintain an advantage over other utility units in avoiding such complex regulations.

State Emission Standards

Many states regulate emission sources with air quality control programs that go beyond the federal requirements. This analysis reviews additional state requirements in Wisconsin and Minnesota as representative state programs.

Each state is required by the Federal CAA to adopt and implement a state implementation plan, or SIP. The state's SIP shapes its air quality control plan, and contains all requirements for controlling air contaminant emissions, according to federal requirements and according to additional state requirements chosen to attain federal requirements. The SIP comprises permitting, nonattainment area, hazardous air pollutant, mobile source, and numerous other air-related programs. Because each state has some latitude within which to choose how to comply with federal standards, SIPs vary from state to state.

Wisconsin

The WDNR is authorized to implement and enforce Wisconsin's air quality control regulations according to Wisconsin's SIP.

Toxic Air Contaminants Emission Control

The WDNR regulates several hundred toxic air contaminants under NR 445. People exposed to these toxic chemicals at sufficient concentrations and durations can suffer acute and chronic effects, including an increased risk of developing cancer, or neurological, reproductive, respiratory, development, or other health problems. Emission thresholds for HAPs are given under Chapter NR 445, Wisconsin Administrative Code. Under NR 445, Best Available Control Technology requirements (BACT) are triggered. For both the project conceptual plants and a plant burning natural gas, a threshold analysis would need to take place to determine if any threshold would be exceeded.
Table ERS 1 below provides a summary of HAPs known to be emitted from a baseline and the project conceptual plants.

Nonattainment Areas

A nonattainment area is a geographic area, typically a county, that does not meet the federal ambient air quality standards applicable to criteria air pollutants.[4] Wisconsin currently has nonattainment areas for ozone and no nonattainment areas for sulfur dioxide. The nonattainment areas for ozone include Door, Kewaunee, Manitowoc, Kenosha, Milwaukee, Ozaukee, Racine, Washington, Waukesha, and Sheboygan Counties. On June 14, 2007, the

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[4] CO, NO_2, PM_{10}, Pb, SO_2, and ozone.

WDNR submitted a request to the USEPA to redesignate all of these counties, except Door and Sheboygan, as attainment areas.

Minnesota

The Minnesota Pollution Control Agency (MPCA) is authorized to implement and enforce Minnesota's air quality control regulations according to Minnesota's SIP.

Air Emissions Risk Analysis (AERA)

The MPCA uses a process called the Air Emission Risk Analysis (AERA) to identify potential human health impacts, risks, or hazards to the public as a result of chemical emissions to the air. Results of the AERA process help inform the MPCA in making recommendations for permitting and environmental review. The AERA also generates a risk estimate based on emission rates and stack parameters compared with toxicity characteristics of each chemical. This risk estimate number can then be compared with a threshold value designed to characterize the potential amount of excess risk.

Not all ethanol facilities may need an AERA. The MPCA has developed a checklist to help potential ethanol facilities determine if an AERA will be required for their project. A copy of the checklist is included in Appendix B. If a facility answers "No" to any of the seven characteristics listed on the checklist, an AERA will be required. One characteristic states that a facility will be using only natural gas as fuel and no solid fuels (e.g., coal and biomass) or liquid fuels will be used. Since syrup is considered a liquid fuel, an AERA would be required for the project conceptual plant.

As part of the AERA process, an estimation of the additional lifetime cancer risks and hazard indices is made using the Risk Assessment Screening Spreadsheet (RASS). First, a list of chemicals potentially emitted at the facility is generated. Next, the emissions are estimated for the potentially emitted chemicals that have at least one inhalation health benchmark value (IHB) in the RASS. Dispersion factors for estimating air concentrations must then be selected, and using the IHBs and multimedia factors in the RASS, potential risks are estimated. At the request of the MPCA, the Minnesota Department of Health (MDH) has also developed Ethanol Sector Specific Interim Exposure Values (ESSIEVs) that can be used as screening tools for the environmental review of ethanol facilities.

As a result of the AERA process, four possible courses of action could occur:

1. Further refined and focused risk assessment of the issues identified through the screening process

2. No further analysis
3. Consideration of implementing additional pollution prevention and/or mitigative measures to reduce or better disperse emissions
4. Recommendation that the issue of risk be evaluated within an environmental impact statement, if AERA is part of the Environmental Review process

Standards of Performance

The project conceptual plant is not subject to the Minnesota Standards of Performance for Stationary Sources (Minn. R. ch. 7011) or the Standards of Performance for Industrial Process Equipment (Minn. R. 7011.0700 – 7011.0735). The Standards of Performance for Stationary Sources apply to combustion equipment that burns fossil fuels. Fossil fuels include natural gas, petroleum, coal, wood, peat, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of generating useful heat.

Permitting

Preconstruction Review

Any person proposing to construct or install a stationary source of emissions must apply for a construction permit, or permit-to-install, unless the proposed project falls within a permit exemption. The agency process of reviewing the construction permit application, determining applicable requirements under the Clean Air Act, and approving the use of emission control technology is called a "preconstruction review." A fuel ethanol production facility is a stationary source of emissions that is not exempt from this permit requirement. Preconstruction review can take from several months to a year to complete, depending on site-specific issues and agency schedules.

The Clean Air Act requires states like Minnesota and Wisconsin to implement pre-construction review programs for both major and minor sources. There is an increased level of scrutiny for major sources, which are defined for facilities producing ethanol through a natural fermentation process as sources that have the potential to emit 250 tons per year or more of a regulated pollutant. "Potential-to-emit," or PTE, for this category does not include fugitive emissions.[5] Major stationary sources are subject to

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[5] The United States Environmental Protection Agency (USEPA) recently promulgated a change to its interpretation of the "chemical process plant" source category definition to exclude fuel-grade ethanol production facilities from the list of source categories subject to greater scrutiny. This change moves the major source threshold for fuel-grade ethanol production facilities from 100 to 250 tons per year and removes the requirement to account for fugitive emissions in PTE. The rule renders many ethanol plants minor sources for preconstruction review. Based on the values provided by this analysis in

the Prevention of Significant Deterioration, or PSD, Program, or the Nonattainment Area New Source Review Program, depending on the location of the proposed plant site.

The Prevention of Significant Deterioration (PSD) Program

The PSD Program is the major source preconstruction review program that applies to all "attainment areas." An area (typically a county) is designated attainment if it meets certain criteria for achieving compliance with the National Ambient Air Quality Standards, or NAAQSs, which are concentration limits for the criteria pollutants in ambient air. (Nonattainment Area New Source Review (NAA NSR) is the analogous major source preconstruction review program applying to all nonattainment areas.) The PSD Program attempts to allow economic growth in attainment areas within specific air quality goals, *i.e.*, to avoid all "clean" areas from degrading to the limit of a NAAQS for a regulated pollutant.

To achieve this goal, the PSD Program implements two review elements not typically found in minor source preconstruction review: (1) an ambient air quality impact analysis, and (2) a control technology analysis. The ambient air quality impact analysis, usually performed through dispersion modeling, ensures that added emissions to an air shed do not, in combination with other newly constructed facilities, exceed a defined "increment" of air pollution. The control technology analysis ensures that Best Available Control Technology (BACT), the control standard applicable to major sources, is properly applied to new emission units. Both analyses will limit emissions on a site-specific basis.

Ambient Air Quality Analysis

The ambient air quality impact analysis may result in emission limits more stringent than federal and state emission control standards. The site-specific plant configuration, surrounding terrain, and meteorological conditions may combine to cause adverse ambient air impacts beyond the fence line. Anticipating modeling issues that might arise from the project conceptual plants is beyond the scope of this project. However, our experience indicates that typical ethanol plants, such as the baseline plant, may have problems with modeling PM_{10} emissions without an adverse impact to ambient air quality, especially if other emission units with poor dispersion (*e.g.*, low exhaust velocities or low stacks) and high hourly PM_{10} emissions are present, such as diesel-fired emergency generators. Biomass combustion will likely contribute to the PM_{10} emissions inventory for the project conceptual plant. Consequently, it is imperative that a new facility considering this design perform dispersion modeling early in the design process.

Table ERS 4, the project conceptual plants would likely remain major sources for preconstruction permitting. *See* 72 FR 24060; May 1, 2007.

Depending on the many site-specific factors for dispersion modeling, changes to stack height, stack location, or the level of control may be necessary.

BACT Demonstration

The control technology analysis may result in emission limits more stringent than federal and state emission control standards because these emission control standards are static, whereas BACT is designed to increase in stringency over time with improvements in control technology. The federal definition of BACT is as follows:

An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under [the Clean Air Act] emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant (see 42 U.S.C. 7479[3]).

BACT must be applied to every emission unit that emits a pollutant for which the source is considered a major source. Here, the emission unit at issue is the fluidized bed combustion unit,[6] the most significant source of NO_x and SO_2 emissions at the study plant.[7]

Following USEPA guidance for determining BACT for an emission unit, the applicant must do the following:

1. Identify all available control options (*i.e.*, control options that have been demonstrated in practice and have a practical potential for application).
2. Eliminate technically infeasible options.
3. Rank available, technically-feasible options by overall control effectiveness.
4. Evaluate the most effective controls, and document the results of the evaluation.

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[6] Note that the fluidized bed unit itself is the subject of a BACT demonstration. The USEPA has not required applicants to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. The source must simply consider demonstrated control technologies for the proposed design, which is, in this case, a fluidized bed unit fired with biomass fuels. See In re SEI Birchwood, Inc., 5 E.A.D. 25 (1994); In re Old Dominion Electric Cooperative, 3 E.A.D. 779 (1992); and Memorandum from Mr. Stephen Page (OAQPS) to Mr. Paul Plath (E3 Consulting) re: Best Available Control Technology Requirements for Proposed Coal-Fired Power Plant Projects (December 13, 2005).

[7] The fluidized bed unit serves as a VOC control device for the dryer. The fluidized bed unit may be part of the BACT demonstration for the dryer, if the source has the potential to emit a significant amount of VOCs.

5. Select BACT.

Emission limits based on BACT are approved as a part of a major source's construction permit. Each state agency forwards approved BACT limits to the USEPA, which enters them into a database that allows the public to track them. We have reviewed the "RACT/BACT/LAER Clearinghouse," or RBLC, to determine the most recent BACT determinations for fluidized bed boilers. The results are presented in Tables ERS 2 and ERS 3. Because it is not a widely applied technology, a BACT determination for biomass fuel combustion in a fluidized bed unit is not yet available. However, the results of BACT determinations for coal-fired fluidized bed boilers provide an indication of NO_x and SO_2 BACT emission levels from fluidized bed technology burning biomass.

The Nonattainment Area New Source Review (NAA NSR) Program

The NAA NSR Program is the major source preconstruction review program that applies to all "nonattainment areas." An area (typically a county) is designated nonattainment if it fails to meet certain criteria for achieving compliance with the NAAQSs. The NAA NSR Program attempts to allow economic growth in nonattainment areas within specific air quality goals, *i.e.*, to reduce overall criteria pollutant emissions within the area and meet "rate of progress" requirements within the Clean Air Act for attaining the NAAQS.

To achieve this goal, the NAA NSR Program implements two review elements not typically found in minor source preconstruction review: (1) emission offsets, and (2) a control technology analysis. Emission offsets ensure that net emissions added to a nonattainment area are below zero, thus not only avoiding any increase in emissions but also ensuring that emissions continue to decrease despite economic development. The control technology analysis ensures that the Lowest Achievable Emission Rate (LAER), the control standard applicable to major sources in nonattainment areas, is properly applied to new emission units. Both analyses will limit emissions on a site-specific basis.

Emission Offsets

Emission offsets are required at varying ratios, depending on the degree of nonattainment of the air shed. Larger offsets are required for more polluted areas. Offsets may be purchased as shutdown credits or other emission reduction credits claimed by other sources in the area.

LAER Demonstration

The control technology analysis will likely result in emission limits more stringent than federal and state emission control standards because, similar to BACT, LAER is a "technology-forcing" standard that increases in stringency over time with improvements in control technology. LAER is more stringent than BACT, in that cost is not a consideration. The federal definition of LAER is as follows:

1. The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or
2. The most stringent emission limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the Lowest Achievable Emission Rate for the new or modified emission units within (the) stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable New Source Performance Standard. See 42 U.S.C. 7501(3).

It is unlikely that NAA NSR will be an issue for the project conceptual plant. We know of no ethanol plants, similar to the baseline plant, which have been successfully sited in a nonattainment area. Nonattainment areas are typically large population centers. Beyond the stringent air quality control requirements that would accompany such a location, there are logistical and public relations reasons for avoiding a nonattainment area site. Consequently, this review does not consider NAA NSR obligations any further.

Operating Permits

Major Source Operating Permits

The purpose of Title V of the Clean Air Act Amendments of 1990, codified as 40 CFR Part 70, is to create a uniform vehicle for administering the various programs of the Clean Air Act. A "Title V Operating Permit" collects all air quality control requirements applicable to a source into one document. Such a permit will inform company officials and agency inspectors alike of all the source's compliance obligations. Ideally, increased compliance and more thorough enforcement will follow. If company officials comply with existing rules, states are less likely to create new rules for increased environmental cleanup.

40 CFR Part 70, or Part 70, provides regulations governing state operating permit programs that implement the Title V Program. As the implementing authorities, states must promulgate their own rules to require and issue Part 70 Permits and subsequently receive EPA approval of their Part 70 Permit Programs. Minnesota's Part 70 Permit Program follows the federal provisions and is governed by Chapter 7007.0100 to 7007.1850 of the Minnesota Regulations. Wisconsin's Part 70 Permit Program also

follows the federal program and is codified at NR 407 of the Wisconsin Administrative Code.

Applicability

In general, the Part 70 Permit Program applies to "major stationary sources." A major stationary source is

- the group of emission units located within a contiguous area and under common control that has the potential to emit 100 tons per year or more of any regulated air pollutant;
- any stationary source defined as major for the PSD or NAA NSR pre-construction review programs; or
- a stationary source of hazardous air pollutants that has the potential to emit 10 tons per year or more of a single HAP, or 25 tons per year or more of a combination of HAPs.

The Part 70 Permit Program also applies in most cases to sources regulated by a New Source Performance Standard, a National Emission Standard for Hazardous Air Pollutants, the Acid Rain Program, or other source category designated by the USEPA.

Typically, an ethanol plant with a capacity to produce 50 million gallons per year (MMGY) or more has a potential to emit 100 tons per year or more of a regulated pollutant and is consequently a major source subject to the Part 70 Program.[8] Sources subject to Part 70 permitting requirements must submit a permit application within 1 year of applicability, annually certify compliance with all applicable requirements, and provide semiannual monitoring reports demonstrating compliance with permit conditions. In Wisconsin and Minnesota, a new source may apply for its Part 70 Operating Permit simultaneously with its application for a Construction Permit, thus streamlining the process to some extent.

Based on our review of potential emissions from the project conceptual plant, a Part 70 Permit would be required.

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[8] USEPA's recent change in the definition of "chemical process plant," discussed above, means that ethanol facilities will not have to include fugitive emission sources in their source status determinations. Fugitive emissions are primarily emitted from leaky fittings on the back end of the plant (VOC) and from truck traffic kicking up dust (PM). Although combustion controls have been improving in recent years, NO_x and CO typically remain the pollutants emitted closest to the 100 tpy threshold. Consequently, the change in the treatment of fugitive emissions is not likely to provide room for larger minor sources.

Synthetic Minor Permits

In general, the Part 70 Permit Program brings additional liability to a source. For example, the Clean Air Act authorizes third parties to bring suit against a source for failing to comply with Part 70 Permit conditions. Combined with the Part 70 requirement to semiannually report "deviations" from permit conditions, this authorization creates a scheme whereby third parties—not regulatory agencies—may enforce air quality regulations. Also, the Clean Air Act increases enforcement penalties considerably for major sources. For these reasons, and others, many owners of new ethanol plants try to avoid the Part 70 Program. The USEPA allows sources to accept "federally-enforceable" limitations on operation or schedule to artificially limit capacity, or to accept federally-enforceable requirements for control technology performance to limit potential emissions, and thereby maintain PTE below 100 tons per year. While there are some additional requirements for the permit review, such as public notice and comment, an applicant would use the minor source operating permit procedure to obtain such limits. A minor source permit issued with such limitations is referred to as a Synthetic Minor Permit, or Federally-enforceable State Operating Permit.

A Synthetic Minor Permit may be a good choice for facilities that will not have a PTE approaching the 100 tpy threshold. Nevertheless, it is generally inadvisable to create artificial limitations to avoid major source status, if it means the limitations constrain production, and if actual facility emissions will approach the 100 tpy threshold. Such a constraint provides little value in return for the increased risk of exceeding the threshold. Generally, a plant should be designed and permitted to provide the best long-term economic return, and to use the Best Available Control Technology, and should not be designed on the basis of avoiding permit programs. While the Part 70 Program may be a frustrating process, a facility can usually get this regulatory process behind them without excessive effort and impact to schedule, if regulatory affairs are approached with the proper planning.[9]

Both Minnesota and Wisconsin provide permitting procedures for Synthetic Minor Permits. For example, Wisconsin rules for permitting synthetic minor sources are similar to permitting major sources in that they require annual certification of compliance and annual submittal of monitoring reports. Consequently, the benefits of a Synthetic Minor Permit in Wisconsin are somewhat reduced.

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[9] Many new sources are eager to construct, and believe that the added permit review scrutiny (*e.g.*, ambient air quality impact modeling and control technology analyses) and schedule will impede construction. Nevertheless, many states require this additional scrutiny for minor sources (*e.g.*, Wisconsin requires air quality impact modeling and control technology analyses in some cases) anyway.

Typically, a 50 MMGY ethanol plant utilizing a natural gas–fired RTO can be permitted as a synthetic minor source. However, a similar 100 MMGY plant is likely to be a major source on account of CO emissions. See attached Table ERS 4 for a summary of major source determinations. Based on the evaluation of potential emissions from the project conceptual plants, permitting as a synthetic minor would not be recommended, and might not be feasible. As shown in Table ERS 4, potential emissions of NOx and SO2 are likely to exceed the 100 tpy threshold.

Environmental Review

Wisconsin

The Wisconsin Environmental Policy Act (WEPA) establishes a policy to ensure governmental consideration of the short- and long-term environmental and economic effects of policies, plans, and programs upon the environment. These procedures are detailed in Chapter NR 150 of the Wisconsin Administrative Code.

Under NR 150, air pollution control permits issued by the state may require an environmental review for new sources or modifications or relocations of existing sources resulting in a potential for increased emissions of particulate matter, sulfur dioxide, carbon monoxide, oxides of nitrogen, volatile organic compounds, and lead or lead compounds:

- 100 tons or more per year after controls
- 100 tons or more per year before controls
- Less than 100 tons per year before controls unless analysis is required under s. 285.63 (2) (d), Stats.

Minnesota

Environmental Assessment Worksheet (EAW)

The Environmental Quality Board (EQB) issues the rules governing the environmental review process in Minnesota. The actual review process is carried out by a local government or state agency, which is termed the "responsible government unit" or RGU. For ethanol plant projects, the RGU is the MPCA. An EAW is used to gather and disclose information about potential environmental effects from a proposed project, and about ways to avoid or minimize those effects. An EAW is required when air emissions from a facility increase by more than 100 tpy. Environmental reviews are also mandatory for electric generating units over 25 MWe, petroleum refineries, ethanol plants, metallic mineral mining and processing, paper or pulp processing mills, and solid waste incineration (Minn. R. 4410.4300).

Once an EAW is completed, there is a 30-day public comment period. The amount of time it takes to complete the EAW process varies from project to project, but generally it takes roughly 6 months from start to finish.

Environmental Impact Statement (EIS)

If the EAW finds that a project has a "potential for significant environmental effects," an EIS is required. An EIS is much more detailed than an EAW, and provides information about the extent of the potential environmental impacts of a project, and suggests ways to minimize those potential impacts.

Summary

The Minnesota rules apply to both a plant burning natural gas and a plant burning biomass fuel. Emission limits typically are not applied through environmental review.

Review of Solid and Hazardous Waste Regulations

In 1976, Congress enacted Subtitle C of the Resource Conservation and Recovery Act, or RCRA. Subtitle C established a program for managing hazardous wastes from "cradle to grave." Consequently, hazardous waste generators must comply with rigorous waste management requirements.

As discussed in Chapter 9 below, the biomass fuels under consideration will generate quantities of ash in the fluidized bed unit and as fines collected in the fabric filter. To determine RCRA hazardous waste management requirements for a solid waste, three steps must be followed to determine whether the waste is hazardous:[10]

1. Determine whether the waste is excluded from regulation under 40 CFR 261.4. A review of these rules shows that the ash is not listed as excluded from regulation. Although fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste are listed at 40 CFR 261,4(b)(4), only such ash generated primarily from the combustion of coal or other fossil fuels is excluded.
2. Determine whether the waste is a "listed waste." Review of listed wastes in 40 CFR 261.30 through 261.38 shows that this ash is not a listed hazardous waste.
3. Apply generator knowledge of the waste, or test the waste, to determine whether the waste exhibits any hazardous characteristics, as defined in 40 CFR 262.21 through 262.24. Of the four characteristics defined in the regulations, the most directly applicable characteristic is

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[10] See 40 CFR 262.11.

> based on the potential of the ash to leach specified quantities of certain metals. A sample of ash from an operating fluidized bed unit burning syrup was shown through the Toxicity Characteristic Leaching Procedure not to exhibit any hazardous characteristics. Mineral analyses performed on corn stover and DDGS show that these biomass fuels do not have any constituents that would result in an ash with hazardous characteristics.[11]

Because the fluidized bed unit ash is not a listed waste and does not exhibit a hazardous characteristic, it will not require management under Subtitle C rules as a hazardous waste.

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[11] See Chapter 9 for details regarding ash analysis.

Table ERS 1

Summary of Clean Air Act Applicable Requirements

Standard/Program	Applicability Summary	Pollutant	Emission Standard	Units	Baseline Plant (natural gas)		Operating Plant (syrup)		Project Conceptual Plant (syrup)		Project Conceptual Plant (DDGS)	
					Emissions	Compliance Method	Emissions	Compliance Method	Emissions	Compliance Method	Emissions	Compliance Method
Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR Part 60, Subpart Db)	Applies to "affected facilities," which are steam generating units constructed after 1984 and that have a heat input capacity greater than 100 MMBtu/hr. The baseline plant, operating plant, and the project conceptual plants all operate steam generating units that are affected facilities. NOx, PM, and SO_2 standards apply only if the biomass fuel is burned in combination with a fossil fuel, such as natural gas. NOx standards apply only if the annual capacity factor of natural gas is 10% or more, which this review presumes is not the case. PM standards apply only to affected facilities co-fired with coal, oil, or wood. APPLICABLE.	NO_x (natural gas constitutes < 10% of fuel at full capacity)	---	---	0.0736	NG < 10% of fuel feed	0.0350	Low NO_x burners	0.8600	Combustion controls	1.2000	Combustion controls
		PM	---	---	---	---	---	---	---	---	---	---
		SO_2 (natural gas assist)	0.2	lb/MMBtu	0.0250	Pipeline quality NG	0.2390	Limestone injection	1.6200	Limestone injection	0.9600	Limestone injection
		SO_2 (natural gas assist)	1.2 after 92% reduction (alternative)	lb/MMBtu	0.0250	Pipeline quality NG	0.2390	Limestone injection	1.6200	Limestone injection	0.9600	Limestone injection
National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR Part 63, Subpart DDDDD)	Applies to boilers and process heaters, located at major HAPs sources, with a capacity greater than 10 MMBtu/hr and an annual capacity factor greater than 10%. The ethanol plants under review have, or will likely have, "large" units. Standards depend on whether a large unit fires gaseous, liquid or solid fuel. Alternative standards are available for PM emissions from large, solid fuel units, either a PM emission standard or a total selected metals (TSM) emission standard. Total selected metals are the combination of arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. APPLICABLE.	PM (solid fuel)	0.025 or 0.0003 (TSM)	lb/MMBtu	---	---	---	---	---	---	NA	NA
		PM (liquid fuel)	0.03	lb/MMBtu	---	---	0.3260	Fabric filter	NA	NA	---	---
		HCl (solid fuel)	0.02	lb/MMBtu	---	---	---	---	---	---	NA	NA
		HCl (liquid fuel)	0.0005	lb/MMBtu	---	---	0.0379	None	NA	NA	---	---
		Hg (solid fuel)	0.000003	lb/MMBtu	---	---	---	---	---	---	NA	NA
		CO (all fuels)	400	ppm (@ 7% O2 for solid fuels and @ 3% O2 for other fuels)	69	Thermal oxidizer	28	Combustion controls	9.6	Combustion controls	9.2	Combustion controls
Acid Rain Program (40 CFR Parts 72 through 78)	Focuses on coal-burning power plants, but it can also apply to utility plants that use fuels with high sulfur and nitrogen content. Applies to power plants serving electricity generators with a nameplate capacity of more than 25 Mwe, producing electricity for sale. NOT APPLICABLE.	---	---	---	---	---	---	---	---	---	---	---
Clean Air Interstate Rule (40 CFR Part 96)	Applies to "stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine serving at any time, since the start up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 Mwe producing electricity for sale." NOT APPLICABLE.	---	---	---	---	---	---	---	---	---	---	---
Clean Air Mercury Rule (CAMR) (70 FR 28606; 40 CFR 60.4102)	Applies to "electric utility steam generating units." A utility is defined as "a stationary coal-fired boiler or a stationary coal-fired combustion turbine." NOT APPLICABLE.	---	---	---	---	---	---	---	---	---	---	---
Federal NOx Budget Trading Program (40 CFR Part 97)	Applies to large, fossil fuel-fired utility units. Fossil fuel comprises coal, natural gas, and petroleum products, as well as derivatives. NOT APPLICABLE.	---	---	---	---	---	---	---	---	---	---	---
BACT, as determined through major source new source review (40 CFR Part 52)	Applies to major sources of listed pollutants through the new source review program. A major source is a source with the potential to emit more than 100 tons per year of the listed pollutant. APPLICABLE.	CO	0.1 to 0.27	lb/MMBtu	0.09	Combustion controls	0.03	Combustion controls	0.01	Combustion controls	0.01	Combustion controls
		NO_x	0.07 to 0.42	lb/MMBtu	0.07	Combustion controls	0.04	Low NO_x burners	0.86	Combustion controls	1.20	Combustion controls
		PM	0.01 to 0.03	lb/MMBtu	0.02	Pipeline quality NG	0.33	Fabric filter	NA	NA	NA	NA
		SO_2	0.11 to 1.08	lb/MMBtu	0.03	Pipeline quality NG	0.24	Limestone injection	1.62	Limestone injection	0.96	Limestone injection
		VOC	0.0025 to 0.03	lb/MMBtu	0.03	Thermal oxidizer	0.01	Fluidized bed unit	NA	Fluidized bed unit	NA	Fluidized bed unit
Control of Hazardous Pollutants (Wisconsin Air Toxics Rule NR 445, Wis. Administrative Code)	Applies to all HAP and toxic air contaminant stationary sources. Provides control technology standards for sources with HAPs or toxic air contaminant emissions that exceed thresholds listed in NR 445. APPLICABLE.	Acetaldehyde	62.952	lb/hr	0.035	Thermal oxidizer	NA	Fluidized bed unit	NA	Fluidized bed unit	NA	Fluidized bed unit
		Acrolein	0.0864	lb/hr	0.0008		NA		NA		NA	
		Formaldehyde	250	lb/hr	0.0003		NA		NA		NA	
		HCl	9.15	lb/hr	NA		6.7		NA		NA	
Minnesota Air Emissions Risk Analysis (AERA)	The MPCA has developed the AERA - 13 Ethanol Determination Checklist to help potential ethanol facilities determine if an AERA is required. Ethanol facilities burning biomass are required to conduct an AERA. APPLICABLE.	---	---	---	---	---	---	---	---	---	---	---

Notes:

1. --- = not applicable.
2. NA = not available

Table ERS 2
BACT Determinations for Fluidized Bed Units

SOURCE	FUEL	THROUGHPUT (MMBtu/hr)	CO (lb/MMBtu)	NO_x (lb/MMBtu)	PM (lb/MMBtu)	SO_2 (lb/MMBtu)	VOC (lb/MMBtu)
RBLC Determinations (Limits) for CFB Boilers	Coal, coke	550 to 2,800	0.1 to 0.27	0.07 to 0.42	0.01 to 0.03	0.11 to 1.08	0.0025 to 0.03
Fluidized Bed Unit in Operation	Syrup	177	0.0339	0.0350	0.3260	0.2390	0.0053
Project Conceptual Plant	Syrup	165	0.0068	0.8600	---	1.6200	---
	DDGS	165	0.0074	1.2000	---	0.9600	---

Notes:

1. --- = not available

2. All BACT determinations are as reported on the USEPA's RACT/BACT/LAER Clearinghouse database and detailed in Table ERS 3.

Table ERS 3
BACT Determinations for Fluidized Bed Units

FACILITY NAME	RBLC ID	PERMIT DATE	PROCESS DESCRIPTION	FUEL	THROUGHPUT (MMBtu/hr)	CO LIMIT (Lb/MMBtu)	NO$_x$ LIMIT (Lb/MMBtu)	PM LIMIT (Lb/MMBtu)	SO$_2$ LIMIT (Lb/MMBtu)	VOC LIMIT (Lb/MMBtu)
Cargill, Inc.	NE-0037	9/8/2006	Circulating fluidized bed boiler (CFB)	Coal	1,500.00	0.1200	0.0800	0.0120	0.1100	0.0070
Southern Illinois Power Cooperative	IL-0093	5/16/2001	Boiler (Marion Power Station), CFB	Coal	1,400.00	0.1500	NR	NR	NR	NR
Kentucky Mountain Power, LLC	KY-0079	5/4/2001	Boiler, CFB Units 1 & 2	Coal	2,550.00	0.2700	0.0700	0.0150	0.1300	0.0072
JEA Northside Generating Station (2)	FL-0178	7/14/1999	Boiler, CFB	Coal, coke	2,764.00	0.1266	0.0900	0.0110	0.200	0.0051
Archer Daniels Midland Company	IL-0060	12/24/1998	Boiler (Decatur 9 & 10), fluidized bed	Coal	1,500.00	0.1000	0.1200	0.0250	0.7000	0.0320
Archer Daniels Midland Company	IA-0046	6/30/1998	Boiler (Cedar Rapids Unit 5), CFB	Coal	1,500.00	0.1500	0.0700	0.0300	0.36	0.0072
Archer Daniels Midland Company	IA-0051	6/30/1998	Boiler (Cedar Rapids Unit 6), CFB	Coal	1,500.00	0.1500	0.0700	0.0150	0.36	0.0072
Toledo Edison Co - Bayshore Plant (3)	OH-0231	6/20/1997	Boiler, CFB	Coal, coke	1,764.00	0.1579	0.3001	0.0250	1.0757	0.0025
Northampton Generating Co.	PA-0134	4/14/1995	Boiler, CFB	Coal	1,146.00	0.1500	0.1000	0.0100	0.1290	0.0050
Archer Daniels Midland Company (4)	IL-0058	8/11/1994	Boiler, fluidized bed, modified, #6	Coal	700.00	0.1500	0.4200	0.0250	0.7000	0.0320
AES Warrior Run, Inc. (5)	MD-0022	6/3/1994	Atmospheric CFB boiler	Coal	2,070.00	0.1500	0.1000	0.0150	0.2100	0.0050
Archer Daniels Midland Company (6)	IA-0025	8/3/1993	Boiler, fluidized bed steam generator/co-gen	Coal	551.50	0.2000	0.0700	0.0300	NR	NR
North Branch Energy Partners LP	PA-0058	1/25/1993	Boiler, CFB, 2 EA	Coal	563.50	0.1500	0.1500	0.0200	0.4900	0.0100

Notes:

1. All BACT determinations are as reported on the USEPA's RACT/BACT/LAER Clearinghouse database; NR = not reported.
2. The CO and VOC limits were reported in lb/hr. These values were converted as follows: Limit (lb/MMBtu) = Limit (lb/hr) / Throughput (MMBtu/hr).
3. The CO, NO$_x$, SO$_2$, and VOC limits were reported in lb/hr. These values were converted as follows: Limit (lb/MMBtu) = Limit (lb/hr) / Throughput (MMBtu/hr).
4. The CO and NO$_x$ limits were reported in lb/hr. These values were converted as follows: Limit (lb/MMBtu) = Limit (lb/hr) / Throughput (MMBtu/hr).
5. The SO$_2$ limit for this unit has a 3-hour averaging period.
6. The CO limit for this unit is based on a 3-hour averaging period; the NO$_x$ limit for this unit is based on a 30-day average.

Table ERS 4
Major Source Determination

POLLUTANT	MAJOR SOURCE THRESHOLD (ton/yr)	BASELINE PLANT (natural gas)		OPERATING PLANT (syrup)		PROJECT CONCEPTUAL PLANT (syrup)		PROJECT CONCEPTUAL PLANT (DDGS)	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
CO	100/250	22.0	96.5	6.0	26.3	1.12	4.9	1.21	5.3
NO$_x$	100/250	18.5	80.9	6.2	27.2	142	621.5	198	867.2
PM	100/250	5.3	23.1	57.7	252.7	---	---	---	---
SO$_2$	100/250	6.3	27.5	42.3	185.3	267	1,170.8	158	693.8
VOC	100/250	6.8	29.7	0.94	4.1	---	---	---	---

Notes:

1. --- = not available.
2. Emissions, ton/yr = Emissions, lb/hr x 8,760 hr/yr x 1 ton/2,000 lb.
3. Baseline Plant pollutant data is taken from the preliminary determination for a construction permit for United Ethanol in Milton, WI, a 50 MMGY facility.
4. Operating Plant emission data is taken from stack testing performed on 9/15/05 (Comprehensive Emission Test Report from MPCA project file).
5. Project Conceptual Plant data is taken from the "Modeling Evaluation of Bubbling Fluidized Bed Reactor for Combustion of Syrup and DDGS" completed by RMT on 8/28/06.
6. Major Source Thresholds are listed as 100 ton/yr, as currently in effect in "SIP-approved" states like Wisconsin, and 250 ton/yr, as currently in effect in "delegated states" like Minnesota. With the USEPA's change in its interpretation of "chemical process plant" on May 1, 2007 (see 72 FR 24060), states implementing and enforcing their own, USEPA-approved, state implementation plans must amend state rules before the 250 ton/yr threshold becomes effective. This process could take at least a year from the effective date of the rule change, July 2, 2007. States delegated to implement and enforce USEPA's PSD and Title V programs must implement the 250 ton/yr threshold as of July 2.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 8 – Evaluation of Control Technologies

This chapter describes potential technologies that can be used to control emissions such NO_x, SO_2, and particulates that arise form biomass fuel combustion. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants Report for Task 8, "Evaluation of Control Technologies"

Background of the Task

Combustion or gasification of biomass co-products feed streams using any of the technologies considered in this project have the potential to produce emissions of criteria pollutants such as particulate matter (PM), sulfur dioxide (SO_2), oxides of nitrogen (NO_X), carbon monoxide (CO), and volatile organic compounds (VOCs). Depending on feed material composition, combustion/gasification technology, combustion/gasification conditions, and operating procedures, small amounts of hazardous air pollutants (HAPs) which are a subcomponent of the total VOC emissions, may also be produced. These emissions must comply with local, state, and federal requirements at the eventual exhaust point from the combustion/emission control system, as well as with local, state, and federal requirements applicable to the ambient air surrounding the fuel ethanol facility.

Raw emissions can be affected by the feed materials, the combustion/gasification technology, and the combustion/gasification operating conditions, while final emissions can be affected by the post-combustion/gasification controls applied to the raw emissions. Designing and implementing overall systems to maximize fuel utilization, minimize capital cost, minimize maintenance cost, and achieve stringent emissions requirements is challenging. It is especially challenging if the fuel mix and composition are variable and contain potentially problematic components.

Effects of Feed Materials on Raw Emissions

(For a more detailed discussion, see the "Combustion Tests/Emissions Tests" chapter of this report.)

The most obvious effect that feed materials have on raw emissions results from the chemical makeup of the feed material. For any given combustion/gasification system, careful management of feed materials can have a significant impact on raw emissions, and hence on post-combustion/gasification units and on ultimate emissions. For example, syrup has a much higher sulfur content than corn stover, so combusting syrup will result in raw emissions with a much higher SO_2 content. The comparative nitrogen content of the feed materials will have a similar effect. A combustion/gasification system can only be designed for a certain latitude in the chemical composition of the feed material, and diligent management is needed to keep emissions within acceptable ranges.

The physical characteristics of the feed material can affect raw emissions. For example, corn stover has very low density in the unprocessed state. Adding corn stover to a system not specifically designed to handle it may result in the entrainment of the corn stover in a combustion-poor area of the unit, and so result in excessive PM in the raw emissions. A similar effect could occur with distillers dried grains (DDG) or distillers dried grains with solubles (DDGS) fines. Densification would change the bulk density of these feed materials, and so change the projected PM in the raw emissions. As with chemical composition, a system design can accommodate only a certain range of variability in the physical characteristics of the feed material.

A more subtle effect of feed material composition emerged in the computational fluid dynamics (CFD) modeling performed for this project. CFD modeling showed that the moisture content of the feed material has a significant impact on the NO_X content of the raw emissions. (For a more detailed discussion of the effects of moisture content, see the "Combustion Tests/Emission Tests" chapter of this report.) Higher moisture content also significantly affects the design and operation of the post-combustion/gasification emission control systems.

Effects of Combustion/Gasification Technology on Raw Emissions

(For a more detailed discussion, see the "Combustion Tests/Emissions Tests" chapter of this report.)

Achieving the required characteristics of ultimate emissions is a controlling factor in the selection of combustion/gasification technology. For example, a combustion turbine can only combust essentially clean gaseous fuels, so a gasification system with gas cleaning before the combustion turbine is needed for use of biomass as fuel. This reduces the potential emissions from most feed materials; however, the high temperatures developed in a combustion turbine may result in higher generation of thermal NO_X.

Gasification operates at lower temperatures than combustion, and so generation of thermal NO_X is lessened. On the other hand, if the syngas is directly combusted without cooling for gas cleaning, PM may increase, and thermal NO_X may result from the combustion.

A major advantage of fluidized bed combustion or gasification is that materials can be added, usually limestone, to sequester the sulfur that is present at a high concentration in the feed materials. This may preclude the need for additional sulfur removal after combustion/gasification.

Effects of Combustion/Gasification Operating Conditions on Raw Emissions

(For a more detailed discussion, see the "Combustion Tests/Emissions Tests" chapter of this report.)

Four primary operating factors affect raw emissions. First, a general rule (assuming the same cold leg temperature) for a combustion process is that the higher the combustion temperature, the more efficient the combustion process. However, thermal NO_X increases with temperature. Especially considering the high nitrogen content of the ethanol plant co-products, NO_X generation in the raw emissions is an important factor. Capital cost also increases for systems designed for increasing temperature and pressure.

Second, combustion of biomass produces ash. The ash will soften and melt at different temperatures, depending on the oxygen content and the chemical composition of the ash. The alkaline metal content of the ash is the most important factor. Both the ethanol co-products and the corn stover have high alkaline metal content, and exhibit ash fusion beginning at low (around 1,100°F [590°C])to medium (around 1,600°F-1,800°F [870°C-980°C] temperatures, with the highest temperature for fluid ash being around 2,700°F [1,480°C]). Unplanned ash fusion can cause plant shutdown and high repair costs.

Third, various chemicals can be added to the combustion/gasification system to impact raw emissions. As described above, limestone (calcium carbonate [$CaCO_3$]) is often added to sequester sulfur. Ammonia may be added to impact NO_X. Other chemicals may be added to impact ash thermal characteristics, or to alter the chemical makeup of the ash. These chemical additions may have a significant impact on raw emissions.

Fourth, the configuration of the combustion chamber, burner, air feeds, fuel inlets, and chamber outlets can all significantly affect the composition of raw emissions. Indeed, a specialized area of combustion expertise utilizing computational fluid dynamics (CFD) has arisen to impact raw emissions, especially NO_X, from combustion units. Chemical inputs can be incorporated into the CFD data set. CFD can also be used to estimate raw emissions from a combination of feed materials.

Modeling of Raw Emissions

The CFD modeling described in the "Combustion Tests/Emissions Tests" chapter of this report predicted raw emissions for the critical criteria pollutants except PM. The results are shown in the tables in that chapter. Engineering development of a specific combustion/gasification system, and refinement of the modeling to predict the minimum raw emissions for such a configuration for each pollutant, are beyond the scope of this project. However, the techniques applied in this project may be beneficially applied to an actual system.

Post-Combustion/Gasification Emission Control Techniques

Based on the results of emission predictions performed as part of this project, and the identification of the expected emission rate(s) and regulatory limitations generally applicable to each source of criteria and hazardous air pollution emissions, emission scenarios were established for which a review of potential emission control technologies was conducted.

For each emission scenario and pollutant, potential emission control options were identified, including both demonstrated and likely potential techniques, and certain add-on or process modifications. Technically feasible control options and combinations were evaluated and ranked based on potential emission reduction.

The energy, environmental, and economic impact of each control option was reviewed in accordance with procedures developed by the United States Environmental Protection Agency (USEPA) Office of Air Quality and Planning Standards (OAQPS) and the Office of Management and Budget (OMB). The energy and economic impacts were evaluated through an estimate of the total capital investment for purchase and installation, and the total annual costs for operation, maintenance, and ownership of the control technology option.

The results of the emission control technology assessment were then summarized to help determine the optimal emission control alternative(s).

Methodology

The United States Environmental Protection Agency (USEPA) has developed a methodology commonly used in evaluating the technical and economic feasibility of emission control technology. This methodology was described in the October 1990 *New Source Review Workshop Manual*, and consists of a five-step analysis, as follows:

1. Identify all available emission control technologies, both demonstrated and proposed, as well as add-on or process modifications, applicable to the proposed source and pollutant.
2. Eliminate technically infeasible control technology options. Technical infeasibility may be determined based on the ability of a given control technology to control a particular pollutant, or based on the ability of the technology to effectively control the pollutant.
3. Rank the remaining control technology options by pollutant control effectiveness.
4. Evaluate control technology options to determine the most effective option, considering energy, environmental, and economic impacts. The energy and economic impacts are evaluated through a determination of the total capital investment for purchase and installation, and the total annual costs for operation, maintenance, and ownership of the control technology option.
5. Select the "best" emission control options for the proposed source.

This methodology was applied in this project in reviewing the control technology options described in the following section.

Control Technologies Evaluated

The methodology described in the previous section was applied in this project to the control technology options identified in Table CTXX below, to determine which option(s) would likely be necessary and the energy, environmental, and economic impact of the emission control technology option(s) needed to comply with local, state, and federal requirements at the exhaust point from the combustion/gasification system and in the ambient air surrounding the fuel ethanol facility.

The project proposal included an evaluation of potential alternative control technologies for the pollutants identified in Table CTXX. However, no demonstrated or proposed alternative control technologies for these pollutants have come to light in the course of this project. Table CTXX identifies the available emission control technologies that may be applicable to regulated pollutants at ethanol plants. Regarding pollutant control effectiveness, the listed technologies are generally capable of producing acceptable levels of pollutant control if properly designed and operated. The selection of the "best" pollutant control option will be impacted by economic, environmental, and energy considerations, and by site-specific factors.

Table CTXX
Summary of Potentially Applicable Emission Control Technology Options, by Pollutant

PM	SO_2	NO_x	CO	VOCs/HAPs
Demonstrated Control Technologies				
▪ Combustion conditions ▪ Cyclones ▪ Electrostatic precipitation ▪ Fabric filtration ▪ Wet scrubbing	▪ Combustion additives ▪ Dry scrubbing ▪ Fuel selection ▪ Wet scrubbing	▪ Combustion conditions or controls ▪ Fuel selection ▪ Low NO_x Burners ▪ Selective catalytic reduction (SCR) ▪ Selective noncatalytic reduction (SNCR)	▪ Catalytic oxidation ▪ Combustion conditions or controls	▪ Adsorption ▪ Catalytic oxidation ▪ Condensation ▪ Thermal oxidation

A brief description of the potentially applicable emission control technologies listed in Table CTXX is provided below, organized by type of pollutant.

PM Control

PM in emissions is generally divided into two categories by size. PM with a diameter of less than or equal to 10 μm is referred to as PM10, and is regarded as coarse, whereas PM with a diameter of less than or equal to 2.5 μm is referred to as PM2.5, and is regarded as fine. PM of certain types and within certain size ranges can be controlled by devices treating the flue gas, as described below. The combustion conditions impact the nature and quantity of PM created during combustion, and so also impact the selection, the operation, and the efficiency of downstream control devices.

Combustion Conditions

Combustion conditions are described in more detail in the "NO_X Control" section below. The discussion here will briefly describe PM control as influenced by combustion conditions.

In all the analyses performed for this project, complete combustion of feed material is assumed. Given this condition, the primary factors influencing PM generation, and thus PM control, are combustion temperature, flue gas volume, and ash particle size.

Lower combustion temperatures may be desired to help control NO_X, to prevent ash fusion, or to allow less costly materials of construction (such as bags in a baghouse) in the PM emission control system capital costs. Lower combustion temperature can be achieved by changing the fuel to air ratio, generally by additional excess air. This results in a larger flue gas volume, and therefore in larger (and so more costly) PM emission control devices. Combustion systems generally become more efficient with higher combustion temperatures, accompanied by PM emission control considerations the opposite of those for lower combustion temperatures. The overall design of the combustion and emission control system is a tradeoff among these factors. Given the generally lower ash fusion temperatures and the generally higher nitrogen content of the ethanol co-products, combustion systems using the co-products will tend to operate at a temperature lower than for a coal- or natural gas–fired system.

Ash particle size is influenced by several factors, but for this project, the primary factor is the type of combustion or gasification unit and the operating conditions. Fluidized bed units tend to produce a very fine ash. Samples analyzed as part of this project showed all ash particles passing a #40 sieve and 83 percent passing a #200 sieve. The ash is relatively benign, as long as it is kept dry, and is readily collected by the several types of PM control devices described below. If significant imbalance were to occur in the bed, or if short circuiting were to occur, larger, possibly agglomerative, particulate could leave the unit and cause problems in the PM collector.

Cyclones

Cyclones are used to reduce the inlet loading of particulate matter (PM) to other downstream collection devices by removing larger, abrasive particles. Cyclones, themselves, are generally not adequate to meet stringent air pollution regulations, but serve as precleaners for more expensive control devices, such as fabric filters or electrostatic precipitators (ESPs). Removal of PM is by centrifugal and inertial forces, induced by forcing particulate-laden gas to change direction. Cyclones are used to control PM, primarily PM greater than 10 micrometers (μm) and smaller than 200 μm. They are unable to handle sticky or tacky materials.

The collection efficiency of cyclones varies as a function of particle size and cyclone design. Cyclone efficiency generally increases with the following operational characteristics:

- Particle size and/or density
- Inlet duct velocity size of cyclone
- Number of gas revolutions during residence in the cyclone
- Dust loading
- Smoothness of the cyclone’s inner wall

A common factor contributing to decreased control efficiencies in cyclones is the leakage of air into the dust outlet. Cyclone efficiency will decrease with increases in the following operational characteristics:

- Flue gas viscosity
- Flue gas density
- Flue gas exit diameter
- Flue gas inlet duct area

Cyclones perform more efficiently with higher pollutant loadings, provided that the device does not become choked. Higher pollutant loadings are generally associated with higher flow designs. Typical gas flow rates for a single cyclone unit are 0.5 to 12 cubic meters/second (m^3/s) or 1,060 to 25,400 standard cubic feet per second (scfm). Flow rates higher than approximately 10 m^3/s (21,200 scfm) usually employ multiple cyclones operating in parallel (often referred to as multiclones) up to approximately 50 m^3/s or 106,000 scfm. Inlet gas temperatures are limited by the materials of construction of the cyclone, and have been operated at temperatures as high as 540°C (1000°F). The density of PM in the flue gas prior to precleaning typically ranges from 2.3 to 230 grams per standard cubic meter (g/m^3) and as high as 16,000 g/m^3 for specialized applications.

Cyclones have relatively low collection efficiencies for PM less than 10 μm in size. The control efficiency range for conventional single cyclones is estimated to be 30 to 90 percent for PM 10 , and 0 to 40 percent for PM 2.5. High-efficiency single cyclones are 60 to 95 percent efficient for PM 10, and 20 to 70 percent for PM 2.5 and come with higher pressure drops, which require more energy to move the waste gas. Cyclone design is generally driven by meeting a specified pressure-drop limitation, rather than a specified control efficiency. High throughput cyclones are 10 to 40 percent for PM 10, and 0 to 10 percent for PM 2.5, and may require a multiclone design.

Cyclones have a low capital cost in comparison to other pollution control technologies and require a relatively small space. As a rule, smaller units controlling a waste stream with a low PM concentration will be more expensive (per unit of gas flow rate and per quantity of PM controlled) than a large unit controlling a waste stream with a high PM concentration.

The capital cost (2002 dollars) for a single conventional cyclone under typical operating conditions ranges from \$4,600 to \$7,400 per m^3/s (\$2.20 to \$3.50 per scfm).

Except for the fan providing the gas throughput, cyclones have no moving parts, and therefore few maintenance requirements and low operating costs. Waste management costs are lower than for wet devices, as the collected waste is dry and is collected in a hopper.

Pressure drop is an important parameter because it relates directly to operating costs and control efficiency. Higher control efficiencies for a given cyclone can be obtained by higher inlet velocities, but this also increases the pressure drop. When both high-efficiency (which requires a small cyclone diameter) and large throughput are desired, a multiclone with a number of parallel cyclone units with a common gas inlet and outlet can be used. Higher pressure drops translate to higher energy usage and operating costs. Several designs can be considered to achieve the optimum combination of collection efficiency and pressure drop.

Typical annual O&M costs (2002 dollars) are $1,500 to $18,000 per m^3/s ($0.70 to $8.50 per scfm) of gas treated.

Fabric Filtration

Fabric filtration is usually accomplished in devices called baghouses. A baghouse has compartments containing rows of fabric bags or pleated cartridges. The gas stream to be cleaned is forced through the baghouse (usually by means of an induced draft fan located downstream of the baghouse), and PM above a certain size is retained on the upstream face of the bags. The cleaned gas stream goes to additional treatment or, if sufficiently cleaned, is vented to the atmosphere. The bag banks in the baghouse are operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning, during which collected dust is removed from the bags and deposited in a hopper for subsequent disposal. Cleaning can be accomplished by shaking, by using pulsed jet cleaners, or by reversing the airflow.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9 percent. Gas temperatures up to about 500°F can be accommodated in some configurations and with specialized fabrics. Most of the energy used to operate the baghouse system is to maintain the specified pressure drop across the bags and ducting.

Limitations are imposed by gas characteristics (especially temperature, combustibility, and corrosivity) and particle characteristics (such as stickiness and abrasiveness) that affect the fabric or the removal of the captured PM from the fabric. An important design parameter is the gas-to-cloth ratio; i.e., the ratio of the volume of flue gas to the surface area of the cloth comprising the bags. The typical controlling operating parameter is the pressure drop across the filter system, which affects energy use, collection efficiency, and the physical condition of the system.

The capital cost of a baghouse system depends on many factors, including the gross area of the cloth, the choice of fabric material, the structure of the baghouse, and the choice of cleaning method. Cloth area is primarily determined by the flue gas volumetric flow rate, PM loading, and the emission limits imposed on the system. Fabric material choice is impacted by the temperature of the flue gas; the material's resistance to chemicals, acids, or alkali; the need to withstand abrasion; the agglomerative characteristics of the PM; and the cost. Fabric costs vary significantly, ranging from (about $1/ft^2 for cotton to about $30/ft^2 for specialized synthetic fibers. The cost of the bags varies from less than 15 percent to more than 100 percent of the cost of the bare baghouse. The baghouse structure and cleaning method, and therefore the cost, is site specific and application specific, and depends on many of the same factors as for the bags.

Typical baghouse capital costs (2002 dollars) are $13,000 to $55,000 per sm^3/s ($6 to $26 per scfm).

The filter bags have a typical operating life of 2 to 4 years. Other operating materials are generally not required for baghouses, with the exception of precoat materials for sticky or corrosive particles, which would not be expected in the ethanol plant applications considered in this project. Adsorbents may be injected when the baghouse is used for simultaneous removal of PM and gaseous pollutants. Maintenance labor typically varies from 1 to 2 hours per shift for major baghouses.

Electricity is needed to operate baghouse system fans and cleaning equipment. Pulsed jet cleaners additionally require compressors. Fuel costs may be associated with the heating of the baghouse to avoid condensation.

Typical annual O&M costs (2002 dollars) are $11,000 to $50,000 per m^3/s ($5 to $24 per scfm).

Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particulate control device that uses electrical forces to move particles entrained within an exhaust stream onto collector plates. ESPs are applicable to PM 10, PM 2.5, and HAPs that are in particulate form, such as many metals (except mercury, which emits as a vapor).

The two basic operational types of ESPs are "dry" and "wet." As the terms imply, the dry type operates in gas stream environments without condensation or added water, while the wet type can operate in condensing environments, and water is often added for effectiveness or safety purposes. Dry ESPs are not suitable for sticky particles. Wet ESPs can collect sticky particles and mists, as well as highly resistive or explosive dusts. Wet ESPs are often used to control acid mists and can provide incidental control of some volatile organic compounds.

ESPs in general are not well suited for use in processes that are highly variable because they are sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also not well suited for sites that have limited space, as the units must be relatively large to obtain the low gas velocities necessary for efficient PM collection. ESPs are capable of operating under high pressure to 1,030 kPa (150 psi) or under vacuum conditions.

ESPs can handle large volumetric gas flow rates, with typical gas flow rates for dry ESPs ranging from 100 to 500 standard cubic meters per second (m^3/s) (200,000 to 1,000,000 scfm). Typical gas flow rates for wet ESPs range from 50 to 250 m^3/s (100,000 to 500,000 scfm).

Pollutant inlet concentrations to an ESP are typically from 2 to 110 g/m^3. It is common to pretreat a waste stream, usually with a water spray or scrubber, to bring the temperature and pollutant concentration into a manageable range. Highly toxic flows with concentrations below 1 g/m^3 are also sometimes controlled with ESPs. When much of the pollutant loading consists of relatively large particles, mechanical collectors such as cyclones or spray coolers may be used to reduce the load on the ESP, especially at high inlet concentrations.

ESP size is related to many design parameters. Higher collection areas relative to gas flow lead to better removal efficiencies. Collection areas normally are in the range of 40 to 160 m^2/m^3 /s of gas flow (200-800 ft^2/1000 scfm). ESP size is an important factor in determining particle collection efficiency, as size determines particle residence time. Maximizing electric field strength will also maximize ESP collection efficiency. Collection efficiency is affected by dust electrical resistivity (for dry ESPs), gas temperature, effluent chemical composition, and particle size distribution. Typical design efficiencies for new ESPs are between 99 and 99.9%.

In dry ESPs, mechanical rapping is used to dislodge the accumulated dust layer. The rapping also projects some of the particles (up to 12% for coal fly ash) back into the gas stream with some of the re-entrained particles processed again by later sections of the ESP. Particles re-entrained in the last section of the ESP are not recaptured and escape. Captured dust is removed through a valve into a dust-handling system, such as a pneumatic conveyor, to a hopper for disposal.

For dry ESPs, care must be taken in measuring resistivity because it is affected by operating temperature, moisture, gas composition, particle composition, and surface characteristics. Gas conditioning equipment that injects an agent into the gas stream ahead of the ESP to improve performance by changing dust resistivity may be used. The conditioning agent most used is sulfur trioxide (SO_3). Dry ESPs can operate at high temperatures, up to 700°C (1,300°F). The operating gas temperature and the chemical composition of the dust are key factors influencing dust resistivity and must therefore be carefully considered in the design of an ESP.

In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water, eliminating the re-entrainment of particles found in dry ESPs. The humid atmosphere that results from the washing in a wet ESP enables the ESP to collect high-resistivity particles, absorb gases, or cause pollutants to condense, and cools and conditions the gas stream. The frequent washing of the plates also limits particle buildup on the collectors. The collection hoppers used by dry ESPs are replaced with a drainage system. The wet effluent is collected, and often treated on-site. The spray water may be recirculated after treatment. Wet ESPs are limited to operating at stream temperatures under approximately 80 to 90°C (170 to 190°F), and generally must be constructed of noncorrosive materials.

ESPs generally have high capital costs. The cost ranges for ESPs of conventional design under typical operating conditions are shown below. Costs can be substantially higher than shown for pollutants that require an unusually high level of control, or that require the ESP to be constructed of special materials such as stainless steel or titanium. In general, smaller units controlling a low concentration waste stream will not be as cost effective as a large unit cleaning a high-pollutant load flow.

For dry ESPs, typical capital costs (2002 dollars) range from $21,000 to $70,000 per m^3/s ($10 to $33 per scfm).

For wet ESPs, capital and operating costs are generally higher due to noncorrosive material requirements, increased water usage, and treatment and disposal of wet effluent.

Typical capital costs (2002 dollars) range from $42,000 to $85,000 per m^3/s ($20 to $40 per scfm).

ESPs minimally hinder flue gas flow and have very low pressure drops, so energy requirements for air handling and operating costs tend to be low. ESPs are capable of very high efficiencies, even for very small particles.

Relatively sophisticated maintenance personnel are required for ESPs, and special precautions and equipment are needed to safeguard personnel from the high voltage and from ozone that is produced by the negatively charged electrode during gas ionization.

For dry ESPs, the annual O&M costs (2002 dollars) typically range from $6,400 to $74,000 per m^3/s ($3 to $35 per scfm).

For wet ESPs, the annual O&M costs (2002 dollars) typically range from $11,000 to $85,000 per m^3/s ($5 to $40 per scfm).

Wet Scrubbers

Wet scrubbers can be used to control materials that are soluble in the scrubbing fluid (usually water, sometimes with additives), and can also be used to control certain particulates, especially those that are problematic to other control technologies because of their physical (such as sticky) or chemical (such as highly acidic or basic) characteristics. In an ethanol plant, wet scrubbers are commonly used on the fermentation vessels, where they capture ethanol and certain other organic vapors, as well as mists. The term flue gas desulfurization (FGD) applies when a wet scrubber is used to control sulfur dioxide (SO_2). For PM applications, wet scrubbers usually generate waste in the form of a slurry, creating the need for both wastewater treatment and solid waste disposal.

Various techniques of wet scrubbing exist, and their applicability to the control of VOC, PM, and SO_2 varies as follows:

- Venturi - Typically, venturi scrubbers are applied where it is necessary to obtain high collection efficiencies for fine PM. The waste gas stream accelerates in a "throat" section, where the gas contacts atomized scrubbing liquid. After the throat section, the mixture decelerates, and further impacts occur causing the droplets to agglomerate. Once the particles have been captured by the liquid, the wetted PM and excess liquid droplets are separated from the gas stream by an entrainment section, which usually consists of a cyclonic separator and/or a mist eliminator. PM collection efficiencies range from 70 percent to greater than 99 percent.
- Spray water tower - Spray scrubbers consist of chambers in which the gas stream contacts liquid droplets generated by spray nozzles that are usually

arranged in successive banks. The gas-liquid contact is driven by a combination of liquid pressure and flow rate. Collection efficiencies for PM range from 70 percent to greater than 99 percent. Spray tower scrubbers generally are not used to control fine PM because of the high liquid-to-gas ratio needed. SO_2 removal efficiencies vary from 80 percent to greater than 99 percent, depending upon the type of reagent used and the spray tower design. For VOC, the typical collection efficiency ranges from 50 percent to 95 percent, with efficiencies greater than 99 percent for spray tower absorbers.

- Impingement-plate/tray-tower - This type of scrubber has a chamber with plates mounted horizontally, wherein the scrubbing liquid flows down the tower while the gas stream flows upward (countercurrent) and gas-liquid contact occurs on the plates. Like a sieve, the plates are equipped with openings that allow the gas to pass through. PM collection efficiencies range from 50 percent to 99 percent, depending upon the application. As collection is via inertial impaction, efficiency decreases as particle size decreases. Short residence times will also lower scrubber efficiency for small particles. For SO_2 control, removal efficiencies vary from 90 percent to greater than 99 percent, depending upon the type of reagent used and the plate tower design.
- Packed bed - Chambers with layers of variously-shaped packing material provide a large surface area for liquid-particle contact. Scrubbing liquid is evenly introduced above the packing and flows down through the bed with the gas stream either countercurrent or crosscurrent to the liquid. Packed-bed wet scrubbers are limited to applications in which dust loading is low, and collection efficiencies range from 50 percent to 90 percent.
- Orifice - Used to control PM, orifice scrubbers pass the particle-laden waste gas stream over a pool of scrubbing liquid at a high velocity, entraining the stream as droplets as it enters an orifice. The entrained liquid droplets then atomize as they flow through the orifice and agglomerate essentially in the same manner as a venturi scrubber. Orifice scrubber collection efficiencies range from 80 percent to 99 percent.
- Fiber bed - In fiber-bed scrubbers, moisture-laden waste gas passes through beds or mats of packing fibers, such as spun glass, fiberglass, or steel. These scrubbers are used to collect fine and/or soluble PM or are used as mist eliminators to collect liquid aerosols, including inorganic (e.g., sulfuric acid mist) and VOC. Insoluble and/or coarse PM will clog the fiber bed with time, and VOCs that are difficult to condense will not be collected efficiently. Fiber-bed scrubber collection efficiencies for PM and VOC mists generally range from 70 to greater than 99 percent, depending upon the size of the aerosols to be collected and the design of the scrubber and the fiber beds.

Operational procedures for the removal of the captured pollutants from wet scrubbers vary. For PM applications, wet scrubbers generate waste in the form of a slurry, creating the need for both wastewater treatment and solid waste management. In some cases, the collected solids may have value and can be sold or recycled. For FGD applications, the slurry or sludge is removed from the scrubber and, depending upon the liquid used to react with the SO_2, the waste-reacted sludge is disposed, recycled, or regenerated. For slurries that produce calcium sulfate and sulfite, the waste can be oxidized and sold as gypsum. For VOC absorption, the water or other solvent must be treated to remove the captured pollutant from the solution. The recovered solvent may be treated and recycled back into the system.

A summary of the common pollutant applications of each technique is found in the table below, along with estimated capital costs (in 1999 dollars). Costs are for wet scrubbers of conventional design under typical operating conditions, and are given per unit of waste gas flow rate.

Common Pollutant Applications of Wet Scrubbers, With Costs (1999 dollars)

SCRUBBING TECHNIQUE	PM CONTROL	SO_2 CONTROL	VOC CONTROL	CAPITAL COSTS ($/scfm)	ANNUAL O&M ($/scfm)
Venturi	PM10 - PM2.5 or less	Yes	Incidental	2.5 to 21	5 to 120
Spray tower	PM10 - PM2.5	Yes	Yes	2 to 6	2 to 30
Impingement	PM10 - PM2.5	Yes	No	4 to 11	3 to 44
Packed bed	No	Yes	Yes	11 to 55	15 to 49
Orifice	PM10 - PM2.5 or less	No	No	5 to 17	4 to 70
Fiber bed	PM 2.5 or less	No	Yes	1 to 3	2 to 36

Wet scrubbing is likely not the preferred means of particulate or SO_2 control for the combustion and gasification processes considered in this project. Other control technologies produce good control with less potential maintenance and lower energy use. Many ethanol plants are located in geographic areas with cold winters, where freezing is a concern with wet emission control systems. Wet scrubbers produce a wastewater stream and a solid residue that must be managed. Wet scrubber systems to control SO_2 are complex, require high maintenance, and produce a potentially troublesome sludge.

SO_2 Control

In general, acceptable SO_2 emissions can be obtained by one or more of the following overall techniques: limiting the amount of sulfur in the feed material; adding sulfur capturing chemicals to the combustion process; or removing SO_2 from the flue gas.

All of the ethanol plant co-products contain sufficient sulfur, generally from around 0.4 to 0.8 percent, to be problematic for uncontrolled emission. Corn stover generally contains about an order of magnitude less sulfur than the co-products. Since a primary objective of this project is the maximum utilization of the ethanol plant co-products, and since the co-products contain so much more sulfur than does corn stover, controlling SO_2 emissions by the choice of feed materials is impractical.

Adding sulfur-capturing chemicals (typically limestone) to the combustion chamber or to the hot flue gases is a well established technique for SO_2 emission control. The technique works especially well for fluidized beds. Project partner plant Corn Plus adds limestone to the fluidized bed combustion unit in which its syrup is burned. The sulfur is captured in the form of calcium sulfate, or gypsum, which is removed in a flue gas baghouse. The exact process and the exact amount of limestone used are proprietary to Corn Plus. However, typical application rates for coal are in the range of XX pounds of limestone for each YY pounds of sulfur to be sequestered. The valuable nutrient and excess lime content of the co-product combustion ash make the ash a potential source of revenue for the plant.

SO_2 can be removed from flue gas by several methods, but the most common are wet scrubbing or dry scrubbing. Wet scrubbing is described in the “PM Control” section above. In dry scrubbing, the chemical used to capture the SO_2, usually powdered limestone, is added to hot flue gases. The resultant calcium sulfate is captured in a PM control device, often a baghouse. It may be possible to beneficially reuse the collected PM, although the volume of collected PM at a typical ethanol plant (as opposed to, say, a coal-fired power plant) may be insufficient for economic reuse in any but basic (such as agricultural liming) applications.

NO_X Control

Various oxides of nitrogen (NO_X) may be formed during any combustion. The quantity and types of NO_X formed depend primarily on the fuels used and the combustion conditions. These factors are discussed below.

Three general types of NO_X may be formed during combustion: thermal NO_X, prompt NO_X, and fuel NO_X. Thermal NO_X is formed from nitrogen and oxygen present in air, and forms at combustion temperatures of approximately 2,400°F (1,315°C) or greater. The longer the time that the combustion remains above the thermal NO_X formation temperature, the greater the amount of thermal NO_X that will form. Thermal NO_X thus is not dependent on the fuel type, but on the combustion temperature and retention time at that temperature. Prompt NO_X is formed from nitrogen in the air that combines with fuel in fuel-rich conditions during combustion, and subsequently oxidizes along with the fuel to form NO_X. The production of prompt NO_X thus is influenced by the fuel type. Fuel NO_X is formed when the nitrogen inherent in the fuel oxidizes during combustion. Since the sole source of fuel NO_X is the fuel, production of fuel NO_X depends completely on the fuel type. Ethanol plant co-products are high in nitrogen, and thus have high fuel NO_X potential.

Six primary methods of controlling NO_X are used, with the seventh method being a combination of the six:

- Reducing combustion temperature
- Reducing residence time at peak temperature of combustion
- Reducing the NO_X
- Oxidating the NO_X
- Lowering the nitrogen content of the combustion air prior to combustion
- Injecting adsorbents and absorbents

Reducing combustion temperature avoids the temperatures at which nitrogen in the air becomes ionized and generates higher concentrations of thermal NO_X. At lower temperatures, the stoichiometric ratio (i.e., the exact mix that fully completes a reaction) of compounds that enter into the NO_X reaction is not present, either through dilution via an excess of fuel, air, flue gas, or steam, or combustion control of the fuel/air ratio. The usual control methods of reducing combustion temperature are as follows:

- Flue gas recirculation
- Fuel reburning
- Low NO_X burners
- Combustion optimization
- Less excess air
- Injection of water or steam
- Overfire air

- Air staging
- Reduced air preheat
- Catalytic combustion

These techniques can generally be used for different combustion systems, including fluidized bed systems.

Cooled oxygen-depleted flue gas can be added into the combustion air to dilute energy and lower temperature, or can be added with additional fuel. This flue gas recirculation control method reduces the oxygen content of combustion air and causes heat to be diluted in a greater mass of flue gas, lowering the NO_X concentration that is generated. If combustion temperature is held to below 1,400°F, the thermal NO_X formation will be negligible.

Low NO_X burners reduce the temperature of combustion products with an excess of fuel, air, flue gas, or steam. Low NO_X burners cost about $150 per ton (1999 dollars) of NO_X prevented, and produce up to 80 percent reduction in NO_X generation. They provide a stable flame that has several different zones, and can operate with many variations. For example, the first zone can be primary combustion, the second zone can be fuel reburning with fuel added to chemically reduce NO_X, and the third zone can be final combustion in low excess air to limit the temperature.

The amount of excess airflow for combustion correlates to the amount of NO_X generated. Limiting the net excess airflow to under 2 percent can strongly limit the NO_X content of flue gas. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.

When primary combustion uses a fuel-rich mixture, the use of overfire air completes the combustion. Because the fuel-air mixture is always non-stoichiometric when combustion is occurring, the temperature is held down. After all other stages of combustion, the remainder of the fuel is oxidized in the overfire air.

Water or steam can be added to dilute the NO_X combustion reaction. Fuel-rich mixtures limit the amount of oxygen available, whereas fuel-lean mixtures limit temperature by diluting energy input. However, since the typical ethanol co-product contains substantial water, adding water or steam is an unlikely control technique.

While lowering combustion temperature with the above control methods lowers NO_X formation, it can also decrease combustion efficiency. Combustion control measures seek to find an optimum combustion efficiency and to control emissions at that efficiency.

Reduction of the residence time of combustion air at high temperatures can be accomplished by restricting the area of highest temperature to a small region in which the combustion air becomes flue gas, immediately followed by injection of fuel, steam, more combustion air, or recirculating flue gas. This short residence time at peak temperature keeps the majority of nitrogen in the air from becoming ionized. Therefore, the control methods of reducing combustion air residence time at peak temperatures are as follows:

- Design of the combustion region
- Injection of fuel
- Injection of steam
- Injection of air
- Recirculation of flue gas

While some low- NO_X burners are based partially on the principle of NO_X reduction (as opposed to the oxidation of NO_X), the usual methods of NO_X control through chemical reduction are as follows:

- Fuel reburning
- Selective catalytic reduction
- Selective non-catalytic reduction

The reduction of NO_X employs a substance to remove oxygen from nitrogen oxides and reduce the number of electrons available for chemical reaction (the “valence”) of nitrogen to zero. Types of reducing technologies include selective catalytic reduction (SCR), which uses ammonia; selective non-catalytic reduction (SNCR), which uses ammonia or urea; and fuel reburning. An emerging technology is based on the use of non-thermal plasma, along with a reducing agent.

SCR is capable of NO_X reduction efficiencies in the range of 70 to 90 percent on NO_X concentrations as low as 20 parts per million (ppm), which is generally greater than low-NO_X burners and SNCR. Higher reductions are possible, but generally not cost-effective. The NO_X reduction reaction is effective within a given temperature range, which depends on the type of catalyst used and the flue gas composition. SCR operates at temperatures from 480°F to 800°F (250°C to 427°C), which is a lower and broader range than for SNCR. Capital costs are significantly higher than for other types of NO_X controls due to the large volume of catalyst that is required. The cost of the catalyst is approximately \$10,000 /m^3 (\$2830 /ft^3) in 1999 dollars. The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage.

The O&M cost and the cost per ton of pollutant removed are greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

NO_X reduction levels by SNCR, alone, range from 30 to 50 percent. For SNCR applied in conjunction with combustion controls, such as low NO_X burners, reductions of 65 to 75 percent can be achieved. The waste gas stream must be within a temperature range of from 1,600°F to 2,100°F (870°C to 1,150°C). SNCR is less effective at lower levels of uncontrolled NO_X, which are typically from 200 ppm to 400 ppm. SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR. The capital costs of SNCR for industrial boilers greater than 100 MMBtu/hr ranges from $900 to $2,500 /MMBtu/hr (1999 dollars), and are among the lowest of all NO_X reduction methods. Annual O&M costs are approximately $100 to $500 /MMBtu/hr (1999 dollars).

For both SCR and SNCR, excess or unreacted ammonia may require cleaning downstream equipment to lessen plugging and corrosion, and the plume visibility and resale or disposal of ash may be affected.

NO_X control through oxidation consists of the following methods:

- Injection of oxidant
- Non-thermal plasma reactor

As NO_X has a greater solubility in water at a higher valence, the oxidation of NO_X involves raising the valence of the nitrogen ion to allow water to absorb it. This is accomplished either by using a catalyst, injecting hydrogen peroxide (H_20_2), creating ozone (O_3) within the airflow, or injecting ozone into the airflow. Non-thermal plasma (used without a reducing agent) can be used to oxidize NO_X. A scrubber must be added to the process to absorb N_2O_5 (the anhydride of nitric acid) emissions to the atmosphere. Any resultant nitric acid (HNO_3) can be collected for commercial sale or first neutralized and then sold (usually as a calcium or ammonia salt).

Lowering the nitrogen content present during combustion is accomplished by using oxygen instead of air (or reducing the air in excess of that needed for combustion) used in the combustion process, or by using a low-nitrogen fuel to form less fuel NO_X. Use of oxygen produces an intense flame that must be diluted to lower the temperature, though if air is the quench medium, thermal NOx will still be formed as the air is heated by hot flue gas. Use of oxygen also has a high capital and operating cost. For some applications, using ultra-low-nitrogen content fuels with oxygen can nearly eliminate fuel and prompt NO_X. This is impractical for ethanol co-products, as the intrinsic nitrogen content is quite high, and even considerable blending with alternative low-nitrogen fuels (such as corn stover) will not yield a reduction in NO_X to levels that do not require emission control by other means. Control of NOx through lower nitrogen during combustion is therefore relegated to the following methods:

- Using oxygen instead of air
- Reducing the net excess air
- Using auxiliary low-nitrogen fuel

Treating flue gas by injecting adsorbents and absorbents, such as ammonia, powdered limestone, aluminum oxide, or carbon, can remove NOx and other pollutants (principally sulfur). The sorbent control methods are based on the area of application:

- In the combustion chambers
- In the flue gas ducts
- In the flue gas baghouse

Sorbent treatment can be applied in the combustion chamber, flue, and baghouse. The sorption method most commonly employs a dry sorbent, but slurries also have been used. NOx control by sorption is followed by fabric filtration and/or electrostatic precipitation to remove the sorbent, and in some cases, the spent product is a saleable commodity.

No single NOx control technology is superior for all combustion systems, boilers, or fuels. Low NOx burners are among the least expensive emission control technologies. SCR is more expensive, but can obtain up to 94 percent control efficiency. Many of the methods can be combined to achieve a lower NOx concentration than can be achieved by any one method, alone. Low NOx burners can be used in conjunction with SCR or SNCR, and water or steam injection can be used with SCR. Fuel reburning and SCR can be used together.

Other control technologies intended to primarily reduce concentrations of sulfur can also strongly affect NOx. Selective catalytic reduction of NOx can utilize the N_2 that is formed in the selective oxidation of sulfur dioxide to sulfur trioxide. Tandem application of NOx control techniques, such as SNCR followed by SCR in the duct and then sorption before an ESP, can achieve an overall reduction of 90 percent in NOx and 80 percent in SOx without lowering NOx generation with low NOx burners.

In practice, reduction in NOx emissions can be complex. The choice of NOx control technology depends on the type of combustion system, the type of boiler or other energy conversion device, and the type of fuel used. Available technologies will be narrowed by consideration of turndown ratio (range of firing positions between full capacity and shutdown), stability of combustion, applicability of low NO_X burners to the system, air supply controls, fuel impurities, and cost, among other factors.

The design of the boiler or gas turbine has a major effect on NO_X formation. Larger combustors tend to have more intense combustion with higher combustion temperatures and longer residence time for flue gases, though designs that incorporate staging of the combustion can lessen the formation of NO_X. The ethanol co-products under consideration for combustion have a high moisture content, which drives boiler design for thermal efficiency as well as emission control.

CO Control

Catalytic Oxidation

Catalytic oxidation is described in detail in the "VOCs Control" section below.

Combustion Conditions or Controls

The "Combustion Conditions and Controls" discussion in the "NO_X Control" section above also applies to CO control. In optimizing the combustion conditions and controls for NO_X control, optimization can also be achieved for CO. Since post-combustion CO control is typically less costly than NO_X control, achievement of the NO_X requirement usually takes precedence. Key factors in achieving CO minimization in the combustion zone are sufficient excess oxygen, sufficiently high temperature, sufficient turbulence, and sufficient retention time.

VOC Control

Adsorption

Emissions of volatile organic compounds (VOCs) and organic hazardous air pollutants (HAPs) can be controlled, recovered, recycled, or concentrated for additional treatment by adsorption technology. In the adsorption process, pollutants are physically held (adsorbed) onto the surface of the absorption material. This differs from the absorption process, in which materials are trapped in pores and interstitial spaces throughout the bulk of the absorption material. Adsorption is generally used for processes that generate VOC emissions at relatively low concentrations (as low as 20 parts per million [ppm]) at relative high airflows (greater than 5,000 scfm) to concentrate VOCs prior to final treatment, recycling, or destruction. Adsorbed pollutants are generally released (desorbed) by washing, heat, vacuum, or pressure.

Adsorbers are typically used to reduce VOC concentrations from between 400 and 2,000 ppm to under 50 ppm. Lower or higher influent concentrations may be handled, but the process may become technically difficult or uneconomical using adsorbents. Higher VOC influent concentrations may be more economically controlled by technologies such as incinerators, membrane separators, and condensers. An adsorber system can achieve 95-98 percent control efficiency at influent concentrations between 500 and 2,000 ppm in air.

Adsorption systems may typically use carbon, zeolite, or polymer adsorbents. Zeolite is a naturally occurring alumino-silicate crystal. De-aluminizing zeolite creates an adsorbent material that has an affinity for nonpolar substances, such as many VOCs. Polymer adsorbents are plastic granules or beads. Polymers generally desorb faster than carbon. Like carbon, polymers are not highly selective as to which VOC they will adsorb. The adsorption operating characteristics, including concentration, temperature, and pressure, are different for each type of adsorbent and each type of pollutant. Some vapors are best controlled by a mixture of adsorbents. Adsorption is exothermic, so adsorption gives off heat and causes a temperature rise in the adsorber bed. Carbon or metals on the carbon have been known to catalyze the oxidation of some pollutants, which can result in bed temperatures high enough to cause fires in the bed, consuming part or all of the carbon. Some polymers and zeolites are less sensitive to humidity and less subject to fire, crumbling, or powdering than carbon. Therefore, they require less frequent replacement. Carbons are lower in cost per unit (at least initially). The cost per pound of carbon is about $2.00 (1998 dollars), while the cost per pound of polymers or zeolite up to 20 times higher. However, zeolites and polymers need to be changed out infrequently, whereas carbon needs to be replaced more frequently, including when a bed fire has occurred.

After as few as five cycles of adsorption and regeneration, the adsorption capacity of carbon decreases by about 50% of its original capacity, while zeolites maintain about 90% of their original adsorption capacity, and polymers maintain about 50% to 90% of their original adsorption capacity. This “working capacity” can have a significant effect on the cost of installing, operating, and maintaining an adsorber.

Regeneration of the adsorbent (desorbing) needs to occur before all of the absorbent has become saturated. Regeneration is often accomplished by raising the temperature (often with steam), by applying vacuum, or by applying pressure. The desorbed VOCs are sometimes purified and then recovered for reuse or for sale. Otherwise, the VOCs are destroyed, typically by flameless oxidation, thermal incineration, or catalytic incineration. A vapor concentrator can be use with the desorbed VOCs to provide more economical treatment in either combustion or condensation devices.

An important design parameter is the emission residence time in the adsorption system, and therefore the physical size of the system. While shorter adsorption times result in smaller adsorber systems and lower capital costs, higher annual costs may result because the adsorbent must be regenerated more frequently. Also, the system size must be compatible with the production facility's schedule, including the schedule of the individual unit processes contributing the VOCs to the emissions. Unless redundancies are built in, the system needs to be sized to avoid regeneration in the midst of a production run.

Adsorber system costs depend on a variety of facility, operational, regulatory, sizing, and cost parameters. For that reason, accurate generic system cost estimates are essentially infeasible. Facility and sizing parameters include the exhaust gas volumetric flow rate, temperature, pressure, VOC composition, VOC loading, moisture content, and particulate characteristics. Operational factors include production schedules, planned outages, and raw material variability. Regulatory factors include the required degree of VOC control, provisions for operation during regeneration, O&M requirements in permits, and the ambient air quality status of the area. The cost of retrofitting an adsorption system at an existing facility will usually be higher than the cost of installing a new facility.

Capital costs increase with both increasing gas flow rate and VOC emission rate. Larger flow rates require larger and more costly adsorber vessels, decanters, condensers, and other equipment. As the emission rate increases, more adsorbent is needed. As a general example, Table 1 shows estimated capital costs (1998 dollars) for two differing gas flow rates and two emission rates for toluene, using a carbon adsorption system.

Table 1
Cost of Thermal Swing ("regenerative") Carbon Adsorption Systems

GAS FLOW RATE (scfm)	TOLUENE EMITTED (lb/hr)	CAPITAL COSTS (1988 $)	
		1,000 $	$/scfm
5,000	50	240	48
	250	430	87
50,000	250	1,100	22
	1,250	1,700	3

Operation costs for adsorption systems include the cost of replacement adsorbent, electricity for the air movers, energy for bed regeneration, and labor. If there is a favorable market value to the recovered VOC, the current market price of a reusable or marketable VOC can significantly offset the cost of emission control.

Catalytic Oxidation

VOCs, CO, and for some applications, PM can be destroyed by oxidation via use of a catalyst. Catalytic incinerators operate similarly to thermal incinerators. Hot gas with pollutants pass through a catalyst bed, where the pollutants are oxidized with oxygen from the air. The catalyst enables oxidation at lower reaction temperatures than in thermal incinerators, and therefore allows for smaller incinerator size.

Catalysts are of various types, but the most common are metals. Single or mixed metal oxide catalysts can tolerate almost any organic compound. Most of these catalysts are supported by a mechanically strong carrier such as alumina. Catalysts such as chromia/alumina, cobalt oxide, and copper oxide/manganese oxide have been used for oxidation of gases containing chlorinated compounds. Platinum-based catalysts are active for oxidation of sulfur-containing VOCs, although such catalysts are rapidly deactivated by the presence of chlorine.

Catalytic incinerators can be used to reduce pollutants from a variety of stationary sources. In an ethanol plant, the most common use is for oxidation of CO from thermal oxidizer systems. Catalytic oxidation is most suited to systems with moderate exhaust volumes, when there is little variation in the type and concentration of pollutant emission, and where catalyst poisons or other fouling contaminants such as silicone, sulfur, heavy hydrocarbons, and certain particulates are not present.

Destruction efficiency is dependent upon pollutant composition and concentration, operating temperature, oxygen concentration, catalyst characteristics, and the volumetric flow of gas entering the catalyst per volume of the catalyst. Increases in temperature and catalyst volume increase pollutant destruction efficiency. A catalytic unit operating at about 450°C (840°F) with a catalyst bed volume of 0.5 to 2 cubic feet (ft^3) per 1,000 scfm of offgas passing through the device can achieve 95 percent VOC destruction efficiency. Higher destruction efficiencies of 98 to 99 percent are achievable, but require larger catalyst volumes and/or higher temperatures, and are usually designed on a site-specific basis. The maximum design exhaust temperature of the catalyst is typically 1,000° to 1,250°F (540° to 675°C) .

Catalytic incinerators can be used effectively at very low inlet loadings, as low as 1 part per million by volume (ppmv) or less. For safety considerations, as with thermal incinerators, the maximum concentration of the organics in the gas must be well below the lower explosive limit (LEL) of the compound being controlled. The level of CO in the thermal oxidizer exhaust from an ethanol plant is well below the LEL.

Because of the sensitivity of catalytic incinerators to inlet stream flow conditions, which may cause catalyst deactivation, some pretreatment, such as removal of particulate matter (PM), may be required. The amount of PM in the thermal oxidizer exhaust from an ethanol plant is usually low enough to not be a problem.

Catalytic oxidizers have a relatively high initial cost. Typical costs for packaged catalytic incinerators of conventional design with fixed beds under typical operating conditions and referenced to the volumetric flow rate of the waste stream treated are shown below. Costs for a gas pretreatment and any post-oxidation acid gas treatment system are not included. Costs can be substantially higher than the ranges shown when used for low-pollutant concentration streams (less than around 100 ppmv).

Capital costs (2002 dollars) are estimated to range from \$47,000 to \$191,000 per m^3 /s (\$22 to \$90 per scfm).

Costs would likely be lower for an ethanol plant application, because no separate firing would likely be needed if the catalytic oxidizer system treated the flue gas from the thermal oxidizer. However, efficient heat recovery upstream of the catalytic oxidation system may require reheat for efficient operation.

Operation costs are dominated by the cost of supplemental fuel required in the incinerator, if such supplemental fuel is required. Compared to thermal incineration, alone, catalytic oxidation has fewer fuel requirements and lower operating temperatures with reduced fire hazards. Spent catalyst that cannot be regenerated or recycled will need to be disposed.

Typical annual O&M costs (2002 dollars) are estimated to range from \$8,500 to \$53,000 per m^3/s (\$4 to \$25 per scfm).

Condensation

Some VOCs can be recovered in some circumstances by condensation, and in some cases it is possible to recycle or reuse the recovered material. The ethanol production process includes extensive use of condensation to capture the distilled ethanol product. Regarding the use of condensation as an emission control technology for combustion systems, however, condensation is essentially infeasible. Condensation systems can be costly and can consume considerable water and energy. Good candidates for condensation are small-volume, moderate-temperature, clean, uncomplicated emission streams with a high content of one or a few VOCs with recoverable value. None of these conditions apply to the biomass combustion emission streams considered in this project. Therefore, condensation is not further considered.

Thermal Oxidation

Thermal oxidation, or incineration, is the process of oxidizing combustible materials by raising the temperature of the material above the point where it will spontaneously ignite in the presence of oxygen for sufficient time to complete the conversion to oxides, ash, and water. VOCs and certain PM are commonly destroyed by incineration. PM formed as a result of partial combustion (such as in product driers operating at higher temperatures) can also be destroyed in various degrees, depending on the specific design of the thermal oxidation unit. Time, temperature, turbulence (for mixing), and the availability of oxygen all affect the rate and efficiency of the combustion process.

Thermal oxidizers can be used to reduce emissions from many VOC sources. They can handle certain fluctuations in influent flow, but are generally not suited to influent streams with highly variable flow because of altered residence time and inadequate mixing, which decrease the completeness of combustion. Thermal oxidizers are a proven method for destroying VOCs, with efficiencies up to 99.9999 percent possible.

There are four basic types of thermal oxidizers. One type is a flare, which may be either open or enclosed. A flare uses auxiliary fuel (usually natural gas) to initiate combustion of a pollutant gas stream. For most flare applications, the quantity and concentration of the combustible pollutant gas are sufficient to contribute major thermal input to the flare, even to the point of being self-sustaining, after combustion is initiated. Flares are typically used in an ethanol plant for incinerating the off gases from product loading, since the off gases are low volume with relatively high concentrations of ethanol or denaturant (gasoline).

A second type of thermal oxidizer uses a combustion chamber with auxiliary fuel (usually natural gas), and exhausts the products of combustion. Fuel consumption of such systems is high. However, the capital costs of such systems are low, and the effectiveness of pollutant destruction is high. Because more efficient and effective thermal oxidizer systems are now available, large systems without heat recovery are rare.

A third type of thermal oxidizer is essentially a modified boiler. The waste gas stream enters the unit either as a component of the makeup air or as a separate stream. Thermal oxidation of the waste components occurs incidental to the combustion process, which is usually fired with natural gas or coal. The thermal oxidizer serves as a steam generation unit, either directly or with the use of a heat recovery steam generator (HRSG). While these designs have certain advantages, especially for small plants, they have three main drawbacks. First, combustion of the pollutants may result in conditions, such as acid gases, agglomerative combustion products, clogging, and corrosion from excessive moisture, detrimental to the thermal oxidizer system. Second, the introduction of the pollutant stream likely lowers the overall efficiency of the steam generator, because of the components of the waste gas stream, the variability of the waste gas stream, and the inability to optimize the steam generation system for the primary fuel supply. Third, such arrangements may result in an inconsistent elimination of the pollutants, and may even create additional pollutants (such as carbon monoxide and condensable PM).

The fourth basic type of thermal oxidizer is regenerative or recuperative, often referred to as an RTO. These systems contain multiple beds of (usually) ceramic material. To initiate the process, auxiliary fuel (usually natural gas) is used to heat one of the beds to a sufficiently high temperature to combust the pollutants. The pollutant stream is introduced into the heated bed, where combustion of the pollutants raises the temperature of the bed further. Additional natural gas may be introduced to increase the temperature. The hot gases leaving the active bed pass through another bed, which absorbs heat. When the second bed reaches a sufficiently high temperature, the waste gas flow is reversed; i.e., the waste gas (and sometimes additional natural gas) is combusted in the second bed, and the hot gases flow through the first bed, maintaining its temperature. The cycle is then repeated. Bed switching may occur as often as every minute. Multiple beds are often used to maintain consistent operation and to perform O&M on the system without bypassing.

RTOs are very fuel efficient, often exceeding 95 percent thermal efficiency, and are also very effective, producing pollutant destruction of 98 percent or more.

Using a separate system to incinerate pollutants allows the plant steam generation system to be optimized. RTOs are now widely used at fuel ethanol plants.

For all thermal oxidizers, key operational parameters are combustion temperature and retention time in the combustion zone. The shorter the retention time, the higher the reactor temperature must be. Design of systems involves striking a balance between larger size (which increases retention time but also increases capital cost) and higher operating temperature (which allows for a smaller size, but adds some additional cost). Thermal destruction of most organic compounds occurs between 590°C and 650°C (,1100°F and 1,200°F). To balance retention time and temperature, many RTOs are designed to provide around 1 second of residence time to the waste gas, with typical operating temperatures of around 730 to 790°C (1,350 to 1,450°F). Steam generator type thermal oxidizers tend to operate at a higher temperature, which increases the efficiency of the unit.

Flare type thermal incinerators can be used over a fairly wide range of organic vapor concentrations. Except for flares, for safety reasons the concentration of the organics in the waste gas is kept well below the lower explosive limit (LEL) of the specific compound being controlled. For operational reasons, the concentrations of VOCs in the waste gas must remain in the range that the equipment was designed to handle; too high of concentrations can result in overheating and severe damage to equipment. If needed, the waste gas may be diluted with ambient air to lower the concentrations.

The following are cost ranges (expressed in 2002 dollars) for packaged thermal incinerators of conventional design under typical operating conditions. Costs can be substantially higher than in the ranges shown when used for low to moderate VOC concentration streams (less than around 1,000 to 1,500 ppmv). Thermal incinerators are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Capital costs (2002$) range from $53,000 to $190,000 per m^3/s ($25 to $90 per scfm).

Thermal incinerator operating costs are relatively high owing to supplemental fuel costs. Recuperative incinerators recover waste heat energy from the exhaust gases and operate at a lower cost.

Annual O&M costs (2002 dollars) range from $11,000 to $160,000 per m^3/s ($5 to $75 per scfm).

Results of Control Technology Evaluation

The control technologies were evaluated considering relative energy, economic, and environmental impacts. The results are based on information from the literature and on the experience of the technical team with such systems. The summary results of the control technology evaluations are presented in tables CTXX through CTXX.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 9 – Ash Characterization and Evaluation

This chapter describes characteristics and potential uses of ash that arises from the combustion of ethanol co-products as fuels. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 9, "Ash Characterization and Evaluation"

Background of the Task

Combustion of any of the biomass co-product feed streams evaluated in this project, by any of the combustion methods evaluated, will result in the production of ash. This project examined the quantities of ash produced in the combustion of the biomass fuels, the mineral composition of the ash, the chemical and physical characteristics of the ash, the fusion temperature of the ash, the equipment needed to handle the ash, the ash disposal options, and the potential for beneficial use of the ash or the ash components.

The ash content of the co-product streams (DWG, syrup, DDG, and DDGS) and corn stover were determined through laboratory testing of the samples obtained at the partner ethanol plants. Samples were ashed in laboratory furnaces at a maximum temperature of 1,382°F (750°C) for 2 hours. The ash was weighed and then subjected to chemical and physical analyses. This procedure yielded valid data for most purposes; but, for the physical and handling characteristics of ash from a fluidized bed unit, ash samples were obtained and tested from an operating fluidized bed burning syrup.

Quantities of Ash

The ash content of the co-products ranges from less than 2% to over 8%, while the ash content of corn stover is typically around 6% to 7%. One datum for corn stover ash, 21.6%, is regarded by this project as an outlier, and is not included in the further evaluation of corn stover ash. Data from the analyses performed as part of this project and data from the literature are listed in Table Ash-1.

The maximum total quantity of ash that an ethanol plant could produce can be estimated from the ash content of the dried distillers grains with syrup (DDGS), since the DDGS contains the solid components of both the syrup and the distillers wet grains (DWG) without syrup. Some of the ash will come directly from the combustion process, while the remainder will have been captured in the emission control system. We assume that emissions of particulate to the atmosphere will be negligible. An ethanol plant with a nominal capacity of 40 million gallons per year (mgy) (150 million liters per year) of ethanol is usually estimated to produce about 130,000 tons (118,000 metric tons) per year of DDGS. Assuming that the DDGS is 10% moisture, this amounts to about 120,000 tons (109,000 metric tons) of DDGS per year on a moisture-free basis. Using the project data and the range of values in the literature for the ash content of DDGS, 3.50% to 6.00%, this calculates to an annual ash production of 4,200 tons to 7,200 tons (3,810 to 6,530 metric tons).

As a crosscheck, we can calculate the maximum potential ash based on the feed material (corn) and on the literature values for the ash content of the corn, approximately 1.4%. We assume here that negligible ash-forming material (such as neutralizing acid) is added during the production process, and that negligible ash-forming components are present in the ethanol. However, substantial amounts of ash-forming materials may come into the process from the process water, especially since the process water is often well water. Therefore, the calculation of ash based on the input corn is expected to be low. A 40 million gallon (150 million liter) per year fuel ethanol plant will use about 15 million bushels of corn annually. At 56 pounds (25 kg) per bushel, this is 420,000 tons (381,000 metric tons) of corn per year. At 1.4% ash in the corn, the maximum ash production is calculated to be 5,900 tons (5,350 metric tons) per year.

These estimates of ash quantity do not include materials, such as limestone for SO_2 suppression, that may be added to the combustion process. Data are not publicly available regarding the exact identification or quantities of such materials, but they may be expected to contribute significantly to the quantity of ash produced.

Ash Mineral Analysis

Ash samples from syrup, DWG, DDG, DDGS, and corn stover were subjected to a standard analysis (in oxidizing environment per ASTM D 3682-01) of mineral content. Results, as shown in Table Ash-2, are expressed in terms of the mineral oxides. The ash mineral analyses are used in evaluating the behavior of the ash in the combustion unit, the disposal alternatives and costs, and the potential for beneficial reuse of the ash. The ash mineral analyses of the individual feed streams are discussed below.

For corn stover, results from the literature were compared with the sample analyzed as part of this project. The dominant component from both sources is silicon, comprising about 54% of the ash in both sources. There was good agreement between the sources for the alkaline metals, comprising about 27.3 % of the project sample and 29.6% of the literature source. The dominant metal is potassium at about 20%, with calcium at about 7%, and sodium at about 1%. The literature source had no data for sulfur, while the project sample showed sulfur at about 12%. Magnesium was at about 5% in both sources, and aluminum was at about 1%. The figures for phosphorus differ substantially, with the literature value at 8.7% and the project sample value at 1.97%. Overall, considering the inherent expected variability in corn stover from different areas and different soil types, and subject to different applications of chemicals, and also considering the inherent inconsistent nature of corn stover samples (especially when the corn stover has been collected off the ground), good comparability was found between the literature data and the project sample data.

Literature data were not available for ash analysis of the co-product streams, so all data are from project samples. The ash mineral composition of the co-product streams differs substantially from that of the corn stover. The dominant metal is phosphorus, the content of which is very much higher than in the corn stover, with a mean of about 35%. The silicon content is much lower, ranging from less than 2.14% to 6.87%, with a mean of less than 3%. For the alkaline metals, while the total content, at about 30%, was similar to corn stover, the distribution of the alkaline metals is substantially different, with calcium consistently below the level of quantification (1.4%); potassium ranging from about 15% to about 31%, with a mean of about 26%; and sodium ranging from about 1% to nearly 4%, with a mean of about 3%. The magnesium content is substantially higher than in the corn stover, with a mean of about 10.7%. The aluminum content is consistently below the level of quantification (0.38%). Sulfur is much lower, with a mean of about 3.4%.

These ash analyses do not include materials, such as limestone for SO_2 suppression, that may be added to the combustion process. Data are not publicly available regarding the exact identification or quantities of such materials, but they may be expected to significantly affect the ash chemical composition of operating ash combustion or gasification units.

Physical Characteristics of the Ash

Ash samples from an operating fluidized bed combusting syrup were analyzed for physical characteristics, including sieve distribution, bulk density, and specific gravity. These values are not included in this report, but are generally discussed further. The ash used for physical characteristics analyses includes materials that are be added to the combustion process. Data are not publicly available regarding the exact identification or quantities of such materials, but they may be expected to contribute significantly to the physical characteristics of the ash produced. The literature indicates that limestone is added to the combustor for SO_2 suppression. The project team believes that the ash sample characterized for this project is representative of ash that will be produced by combusting any of the biomass co-products, and that will require management for reuse or disposal.

The sieve distribution indicates that the ash particle size is very fine, with all particles passing the #40 sieve or <425 µm. The bulk density of the ash is similar to that of the co-products except syrup.

Literature data were not available for the physical characteristics of ash. However, publicly-available documents from the operating fluidized bed combusting syrup indicate that the physical characteristics are similar to typical dry fertilizers applied to cropland.

Ash Fusion Characteristics

The ash fusion characteristics are critical to the proper design and operation of a combustion system. Because this project evaluates both biomass combustion (operating in an oxidizing atmosphere) and biomass gasification (operating in an oxygen-starved atmosphere), ash fusions for the various feed streams were evaluated (ASTM D 1857-04) under both oxidizing and reducing conditions. The data are presented in Table Ash-3, and are depicted graphically on Figures Ash-1 and Ash-2.

For the oxidizing atmosphere, the ash fusion temperatures differed widely among partner ethanol plants and among co-product feed streams. However, examination of the data allow for certain preliminary conclusions to be drawn regarding the use of these feed streams for combined heat and power (CHP) purposes. For DWG and DDGS, although two of the samples exhibited a sharp rise in the temperature needed to progress from a hemispherical stage to a fluid stage, overall, the temperature at which ash handling in the combustion unit becomes problematic is generally quite low. Combustion systems, especially those designed for CHP applications, need to be operated at as high a temperature as possible to promote both fuel efficiency and generation of the energy density needed for the CHP process. These temperatures are usually well above the approximately 1,200°F-1,500°F (650°C-815°C) at which the tested ash samples demonstrated problematic behavior. This may result in material buildup or fouling of the combustion system components and the ash handling equipment. These issues need to be addressed in the design of the combustion and ash handling systems.

The situation is different for the syrup samples. With the exception of the softening temperature at one partner ethanol plant, the temperatures at which the syrup ash would become problematic are above those needed for either gasification or combustion. Although no literature data were found regarding syrup ash fusion temperatures under oxidizing conditions, one of the project partner ethanol plants is combusting its syrup to generate process steam, thus verifying the conclusions drawn from the data from this project.

For reducing conditions, the temperatures at which the ash from all of the feed streams becomes problematic are well above those required for efficient operation of a gasification system, which typically generates combustible gasses in the 800°F-1,200°F (427°C-650°C) range. The temperature in the non–oxygen-starved portion of the bed, where the fixed carbon is completely oxidized, will be somewhat higher, but can be maintained at a level below which the ash may become problematic. This will be less of a concern for syrup, for which ash fusion temperatures are typically several hundred degrees higher than the other feed streams.

These data on ash fusion characteristics do not include materials, such as limestone for SO_2 suppression, that may be added to the combustion process. Data are not publicly available regarding the exact identification or quantities of such materials, but they may be expected to substantially impact the ash behavior in an operating system.

Chemical Characteristics of Ash

Ash samples from a fluidized bed burning syrup were analyzed for pH, calcium, and TCLP metals to provide additional information regarding the chemical characteristics of ash. These values are not included in this report, but are generally discussed further. The results indicate that significant fluidized bed material (limestone) is mixed with the ash, affecting both physical and chemical characteristics. Information is not publicly available on what, if any, additional materials may be added to the combustor. However, the project team believes that the sample is representative of ash that will be produced by combustion of biomass co-products, and that will require management for reuse or disposal.

The laboratory results indicate very little potential for metals to leach from the ash. Also, both the calcium concentration and the pH are elevated due to the limestone portion of the ash.

Literature data were not available for the chemical characteristics of ash. However, publicly-available data for the chemical characteristics of fluidized bed ash from the combustion of syrup were reviewed. The following is a summary of those results:

- No PAHs were detected.
- Various inorganic compounds were detected in the ash sample. However, the concentrations do not appear to be at significant levels.
- The MPCA Tier 1 Generic Soil Reference Value (SRV) for copper (11 mg/kg) was compared and exceeded, but the copper concentration was well below the Tier 2 industrial SRV. These exceedences are not expected to prohibit the reuse of ash. However, specific restrictions on the reuse of ash are expected.
- The MPCA Tier 1 Generic Soil Leaching Values (SLVs) for molybdenum (6.0 mg/kg), selenium (1.5 mg/kg), and silver (3.9 mg/kg) were compared and exceeded. However, the co-products themselves typically contain greater than 1.5 mg/kg selenium. These exceedences are not expected to prohibit the reuse of ash. However, specific restrictions on the reuse of ash are expected.

Ash Beneficial Reuse

Co-products from dry grind ethanol production contain about 3-7 percent ash. If all co-products were to be used as fuel, a 40 mgy (150 million liters per year) ethanol plant would produce about 4,000-7,000 tons (3,630-6,350 metric tons) of ash annually, while a 100 mgy (375 million liters per year) plant would produce about 2 ½ times as much. Co-product ash can potentially be put to multiple productive uses in civil engineering, manufactured products, and agricultural applications in ways that are technically sound, environmentally benign, and commercially competitive. Both Minnesota and Wisconsin have active state-sponsored programs to reuse combustion ash and to avoid disposal in landfills (except for use as daily cover). The Wisconsin Department of Administration reported that 72 percent of coal combustion ash and slag was beneficially used in the year 2000. The primary beneficial uses of the ash from the industrial and institutional coal boilers were as an unbonded surface course for roads, as a cold weather road abrasive, as a confined structural fill, and as a daily cover at landfills.

Ethanol co-product ash has the potential for beneficial reuse in several ways. Based on known applications for coal ashes from like combustion technologies and the results of laboratory analyses of co-product ash composition and physical characteristics, the potential applications include the following:

- Agricultural applications, including liming, soil amendment, and nutrient recovery
- Construction applications, including cement substitute, concrete products production, and soil stabilizer
- Self-cementing ash for oil field grouting
- Selected roadbase and subbase applications, including as a component of structural fill and synthetic aggregates
- Waste stabilization, including acidic waste, sludge, and heavy metals
- Landfill daily cover

Ash chemical composition varies somewhat by co-product burned, although for all of the co-products, the ash retains a high mineral content with 30 to 45% phosphorus (in the form of pentoxide) by weight. Potassium oxide is 20 to 30% by weight, while magnesium oxide is about 10% and silica is about 2%. Co-products contain about 0.5 to 1% sulfur by weight, with the highest measured sulfur level found in syrup.

Federal and state regulations place stringent limits on the amounts of pollutants that can be emitted from combustion processes. For combustion of ethanol plant co-products, the most potentially problematic emissions will likely be SO_2 and NO_x. SO_2 is usually controlled by material that reacts with the sulfur oxide and produces nongaseous sulfur compounds that remain with the ash. The most commonly used material is limestone, which reacts with the SO_2 to form gypsum ($CaSO_4$). In a typical application, about 25-30 percent excess limestone is added, which results in a strongly alkaline ash. The addition of the limestone changes both the chemical and physical nature of the ash. The high alkaline content and very small particle size necessitate careful management of the ash and the use of appropriate personal protective equipment for personnel involved in ash management. Particular care will need to be taken if the ash is handled by individuals who have not had applicable training in handling such material, and who may not possess applicable personal protective equipment. If corn stover is part of the feed material, the high silica content of the resultant ash will also need to be taken into account in ash management.

Unlike ash from coal combustion, which may contain heavy metals of several types, the ash from combustion of the ethanol plant co-products is low in mercury and other heavy metals of concern. Biomass ash is intrinsically more environmentally benign than coal ash, and may be beneficially reused in additional ways.

Ash Use As Fertilizer and Soil Amendment

Co-product ash may be suitable to improve soil chemical and physical properties. An evaluation of the soil is needed to determine crop requirements, and how the character of the ash may improve soil. The evaluation would include application rates to meet crop needs.

Studies have shown that combustion ash added to topsoil mixtures improves porosity, increases seed germination rates, and improves plant yields for a variety of crops.

Co-product ash can be used to treat soil pH and provide soil nutrients. The unreacted lime present in the ash will raise the pH of acidic soil, while the reacted lime (gypsum) is a source of calcium. Magnesium, phosphorus, potassium, and other minerals are also added to soil. The ash also improves physical soil properties, such as soil porosity, which improves aeration and water penetration for acidic soil, and increases moisture retention.

When used as agricultural liming materials, uncontaminated co-product limes can be distributed in accordance with Minnesota Statutes, sections 18C.531 to 18C.575, and Wisconsin Statutes, sections 94.65 to 94.66. Greenhouse studies demonstrated that ash-amended soil resulted in higher plant productivity than typical ag-lime–amended soil. These results possibly are due to pH and nutritional issues, but root penetration due to improved soil porosity was also probably a factor. Application rates for byproduct limes must be based on the lime recommendations of the University of Minnesota Extension Service and cannot cause the soil pH to exceed 7.1 after application. Site-specific application rates for byproduct lime must be determined by an individual, such as a crop consultant, who has a background and understanding of crop nutrient management. Recommended rates for lime can be obtained from the University of Minnesota Extension Service publication "Fertilizer Recommendations for Agronomic Crops in Minnesota" BU-06240-S, and the Minnesota Department of Agriculture publication "Ag-Lime Recommendations in Pounds ENP per acre" available on their Web site (www.mda.state.mn.us/lime). Similar recommendations for Wisconsin can be found at the University of Wisconsin-Extension Web site (learningstore.uwex.edu/Soil-Fertility).

Co-product ash is high in phosphorus, a nutrient commonly added to soil to increase crop yields. The addition of phosphorus to the soil depends on the total phosphorus already present and the amount of organic and inorganic acid extractables available in the ash. The rate of organic phosphorus is applied based on the soil nitrogen content. New regulations may limit the rate of ash co-product application based on the phosphorus soil test and runoff risk, the phosphorus content of co-product ash, and the phosphorus removal rate of the crop.

Co-product ash also contains significant amounts of potassium, calcium, magnesium, and sulfur. Most potassium in the ash is considered available, while the other mineral cations are available to varying degrees. High levels of sulfate may leach in the soil.

Trace metals such as boron, copper, zinc, iron, manganese, and molybdenum are present in the ash and serve as micronutrients, low amounts of which are required for plant growth.

Some sodium is present in the ash, which is detrimental to soil structure, as high levels of sodium are toxic to plants.

In the past (1940s through about 1980), agricultural research raised some concern about the proper soil calcium to magnesium ratio. The popular thinking was that high levels of magnesium cause soil to be "hard," with a drop in crop yields. More recent research, as highlighted on the Minnesota Extension Web site, has demonstrated that neither magnesium soil nor the calcium/magnesium ratio has any effect on crop growth and production. The calcium to magnesium ratio is an outdated concept and should be not used in making fertilizer recommendations.

A case-specific beneficial use determination (CSBUD) was made by the MPCA for the use of ash generated from the project partner ethanol plant combusting syrup. The ash is land-applied as a fertilizer or an alternative liming agent. The ash is bundled, stored, tested, and reused according to the requirements of the CSBUD. Specific reporting and record keeping also apply. Soil testing is completed to verify the site suitability and application rates.

The very fine particle size of the co-products ash from fluidized bed combustion, combined with the chemical composition of the ash, pose handling and application challenges for agricultural reuse. Slurrying is likely impractical owing to the chemical nature of the ash, the large amount of weight added to the ash, the high pH of the slurry, and the need for ongoing agitation to avoid settling or plugging of piping or nozzles. The literature reports that pelletization is being tested. Pellitization would avoid the problems associated with slurrying, and makes the ash amenable to use in standard agricultural equipment, albeit likely with some minor modifications to equipment and/or procedures. Cost data for pelletization are not available.

Little information is available regarding detailed, long-term field experience with the agricultural reuse of ash generated from combustion of dry grind co-products, although such reuse is ongoing. Specific studies on the ash from the gasification of alfalfa stems indicate the following:

- Potassium concentrations increased and magnesium concentrations decreased significantly in corn.
- Little effect was noted for phosphorus or other trace elements.
- Ash application significantly increased salinity chlorine, extractable phosphorus, exchangeable potassium, calcium, magnesium, and sodium in soil.

- Although some PAH compounds were detected in ash, its application will not cause a major environmental concern when applied at reasonable agronomic rates.

Ash Use in Construction

Coal ash is used as structural fill material in constructing highway embankments and road bases. Marketable uses for bottom ash include replacements for sand, gravel, and crushed stone; aggregate for concrete products; soil amendments; structural fills; base and sub-base pavements; anti-skid material for roads; roofing shingle granules; chip seal road topping; blasting grit; and material for snow and ice removal.

When ash is present with free lime, it reacts chemically to form cementitious materials, the type of which depends on the properties of the ash. Pulverized coal units, which are the most common type of coal combustion technology, produce both a bottom ash and a fly ash, which differ in chemical composition and physical properties. Bottom ash is coarser than fly ash due to larger fuel particle size and increased combustion residence time. Fly ash has properties that are acceptable for use as a high-strength concrete (Portland cement), while bottom ash has use as described above. The free lime, carbon content, and sulfate content of co-product ashes can limit their utilization to moderate-strength concrete products production, as free lime in ash will form water-soluble calcium hydroxide, resulting in some weakening of the concrete from contact with moisture. Such materials may not be preferred for heavy construction applications. When used as an aggregate, the bottom ash product has a lower unit weight than many naturally occurring aggregates, thus reducing the weight of the finished product.

Coal ash can be used either mixed with or in the place of conventional backfill materials, such as soil, sand, or gravel, and to alleviate problems and restrictions generally associated with the placement of these materials. As the result is more cement-like, less compaction is required.

Data are not available regarding the use of dry grind ethanol co-products ash as compared with coal ash for construction applications. Coal ash has been used in large quantities for many years, with a great deal of research and established market channels, while dry grind ethanol co-products ash is relatively new in the marketplace, has limited available applications research, and limited local marketing channels. Construction applications for dry grind co-products ash will likely be minimal until additional research is performed, and the performance of applications and products incorporating the ash withstand the test of time.

Ash for Treatment of Certain Waste Streams; Landfill Disposal

Co-product ash can likely be used to stabilize certain waste streams from both industrial processing operations and municipal sludge. The ash may help to solidify certain waste materials for landfilling and to neutralize acidic wastes. For each of these applications, the suitability of co-product ash is enhanced by its free lime content.

In the case that a practical beneficial use is not found for the ash, landfill disposal is an option, based on the nontoxic characteristics of the ash. The primary challenge for landfill disposal is the potential for the ash to become airborne during unloading and spreading. The ash may be suitable for use as daily cover for other landfilled materials. It may also be possible to send the ash to a monofill. Ash monofills generally have a lower tipping price than regular landfills, as the ash can be retrieved at a later date for use in road building, etc. Considerations for ash monofill disposal include the location of the monofill, whether some amount of ash will be stored on-site prior to pickup, and dust handling.

Regulatory Beneficial Use Determination

States regulate beneficial reuse of solid waste. For Minnesota, beneficial use determination (BUD) has been made for specific solid waste, including coal combustion slag for the manufacture of roofing shingles, ceiling tiles or asphalt products; coal combustion slag for use as a sand blast abrasive; coal combustion fly ash when used as a pozzolan or cement replacement; coal combustion fly ash for aggregate in concrete; and uncontaminated byproduct lime used as agricultural liming material. The co-product ash will require a case-specific BUD prior to its reuse. In Wisconsin, similar beneficial use requirements apply to industrial byproducts.

Economic Value

In addition to the avoided cost of ash disposal, there is an economic value to the beneficial reuse of co-product ash. The chemical and physical composition of co-product ash, its (and its potential user's) market location, and seasonal aspects all contribute to determining the value of co-product ash. These market factors and pricing are explored below.

Chemical and Physical Composition of Co-product Ash

If the quality of the co-product ash meets engineering standards, its use can lower the costs of construction. For example, the substitution of ash as a cementing agent reduces the cost of the finished product. If the co-product ash can be used as a synthetic gypsum for use in wallboard, then the processing required of natural mined gypsum is avoided.

Ash used to stabilize soil or waste makes this process less expensive.

Market Location

The marketplace in which the co-product ash is produced has a substantial impact on its value. The co-product ash may be competing with large quantities of coal ash from utilities' plants. The most economically attractive reuse applications may be geographically remote. Transportation distance and method (truck, rail, barge, ship) are major factors in the cost of using co-product ash. Loading and unloading methods impact the cost of handling, which is reflected in the transportation price. Local and state regulations regarding transportation of the ash, permitting of the application, reporting, and possibly waste fees may have a significant impact on the desire and ability of a potential buyer to use the ash.

Seasonal Factors

The time of year may also contribute to pricing, depending on the application. In the Midwest, the production of coal ash is highest during both the coldest and hottest months of the year, during the heating and cooling seasons. These same periods of the year may represent the slowest times for construction and other applications that beneficially use the ash. This sort of imbalance in the production and demand for ash can contribute to highs and lows in pricing. Many utilities and ash marketing firms work to overcome this seasonal imbalance by using storage silos and sometimes large distribution networks. A dry grind ethanol plant seeking to beneficially reuse co-products ash will need to take these factors into account for its particular ash, location, and potential ash buyer.

Per the American Coal Ash Association (www.acaa-usa.org), some of the typical 2003 price ranges found for various coal combustion ash products are as follows.(2) These prices will likely change over time and, considering the differences of the dry grind ethanol co-products ash and the coal ash, may not be comparable to the former.

- Concrete quality ash - $20 to $45 a ton ($22 to $49 metric ton)
- Self-cementing ash for soil stabilization - $10 to $20 a ton ($11 to $22 metric ton)
- Snow and ice control - $3 to $6 a ton ($3 to $7 metric ton)
- Flowable fill - $1 a ton and up
- Road base - $4 to $8 a ton ($4 to $9 metric ton)
- Self-cementing ash for oil field grouting or waste stabilization - $15 to $25 a ton ($16 to $22 a metric ton)

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(2) American Coal Ash Association, "Frequently Asked Questions," www.acaa-usa.org.

Tables

Table Ash-1
Summary of Ash Content From Laboratory Results and Literature Values

SOURCE/ REFERENCE	AS RECEIVED		MOISTURE FREE
	% ASH	% MOISTURE	% ASH
Corn Stover			
LAB	6.31	6.15	6.73
C	4.7	6.1	5.1
D	20.3	5.9	21.6
E	6.81	9.14	7.64
N	--	--	5.58
DDG			
E	1.96	13.35	2.24
DDGS			
1	3.51	8.79	3.85
2	3.10	11.55	3.50
3	3.62	10.03	4.02
4*	1.68	59.80	4.17
5	--	--	--
A	4.90	9.00	--
B	5.35	10.78	--
E	4.16	9.27	4.13
J	4.00	11.70	--
L	--	--	6.00
M	--	--	4.2
P	--	--	5.80
DWG			
1	0.78	65.98	2.28
2	0.72	64.67	2.05
3	2.18	54.26	4.77
4	0.64	70.70	2.17
5	0.54	66.71	1.61
Syrup			
1	1.39	77.17	6.09
2	2.64	66.71	7.94
3	3.33	58.55	8.03
4	2.50	69.32	8.16
5	1.71	64.70	4.86

Notes:

-- = not available/analyzed.

1, 2, 3, 4, and 5 = samples collected from partner ethanol plant.

Lab = laboratory analysis of sample collected.

* The DDGS results from Partner Ethanol Plant #4 appear to be at odds with other DDGS values.

References:

A = Typical values. Distillers Grain Technology Council. 2005. Louisville, Kentucky.

B = Average of 34 samples. Converted from 100% dry matter basis. University of Minnesota. 2006. Nutrient profiles.

C = Single corn stover analysis. National Renewable Energy Laboratory. 1998. Golden, Colorado.

D = Single corn stover analysis. Evans, R.J., A.R. Knight, M. Onischak, and S.P. Babu. 1988. Development of biomass gasification to produce substitute fuels. Richland, Washington, USA. Pacific Northwest Laboratory (PNL). PNL--6518, 14 p.

E = Average of multiple samples. Number of samples not reported. Agricultural Utilization Research Institute. Fuels initiative. Waseca, Minnesota.

J = Average of 20 samples. Noll, S.L., C. Parsons, C. Abe, and J. Brannon. 2002. Nutrient composition of corn distiller dried grain with solubles. University of Minnesota and Illinois.

L = Average of 32 plants. The value and use of distillers dried grains with solubles (DDGS) in livestock and poultry feeds. University of Minnesota. 2005.

M = Dakota Gold Marketing - Enhanced nutrition distillers products. Dakota Gold. 2005.

P = Mean value of 118 samples. Spiehs, M.J., M.H. Whitney, and G.C. Shurson. 2002. Nutrient database for distiller’s dried grains with solubles produced from new ethanol plants in Minnesota and South Dakota. University of Minnesota.

Table Ash-2
Results for Ash Mineral Analysis

MINERAL	CORN STOVER		DDGS						DWG			SYRUP		
	LAB	C	1	2	3	4	4*	5	3	4	5	3	4	5
Silicon dioxide (wt%)	54.12	54	<2.14	<2.14	2.73	3.04	<2.14	--	3.09	3.16	6.87	<2.14	2.42	<2.14
Aluminum oxide (wt%)	0.78	2	<0.38	<0.38	<0.38	<0.38	<0.38	--	<0.38	<0.38	<0.38	<0.38	<0.38	<0.38
Titanium dioxide (wt%)	0.04	--	<0.03	<0.03	<0.03	<0.03	<0.03	--	<0.03	<0.03	<0.03	<0.03	<0.03	<0.03
Iron oxide (wt%)	0.45	--	<0.29	0.33	0.32	0.30	0.40	--	0.29	<0.29	<0.29	0.93	<0.29	0.90
Calcium oxide (wt%)	5.61	8.7	<1.4	<1.4	<1.4	<1.4	<1.4	--	<1.4	<1.4	<1.4	<1.4	<1.4	<1.4
Magnesium oxide (wt%)	4.22	6.1	11.92	11.45	12.17	14.45	13.20	--	10.25	6.70	9.60	9.97	13.84	8.61
Potassium oxide (wt%)	20.22	20.7	28.37	26.50	29.41	30.66	30.07	--	26.72	15.42	25.07	29.32	31.19	20.59
Sodium oxide (wt%)	1.47	0.2	1.32	2.35	4.98	2.32	3.01	--	3.82	1.01	4.31	4.11	2.11	3.31
Sulfur trioxide (wt%)	12.75	--	0.62	1.65	1.82	1.32	1.02	--	1.10	0.50	4.50	6.02	7.38	4.22
Phosphorus pentoxide (wt%)	1.97	8.7	44.76	36.32	40.98	45.49	42.85	--	41.04	31.93	31.34	32.04	32.41	26.01
Strontium oxide (wt%)	<0.02	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Barium oxide (wt%)	0.02	--	<0.02	<0.02	<0.02	<0.02	<0.02	--	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Manganese dioxide (wt%)	0.06	--	0.05	0.05	0.06	0.05	0.05	--	0.07	0.03	0.04	0.04	0.05	0.07
Nitrogen (wt%)	<0.20	--	--	--	1.18	3.69	--	--	1.38	3.69	1.99	1.45	0.96	2.23

Notes:

Lab = laboratory analysis of sample collected.

1, 2, 3, 4, and 5 = samples collected from partner ethanol plant.

* = resampled to confirm previous results.

-- = not available/analyzed.

Reference:

C = Single corn stover analysis. National Renewable Energy Laboratory. 1998. Golden, Colorado.

Table Ash-3
Summary of Laboratory Results and Literature Values for Ash Fusion Temperature

	OXIDIZING ATMOSPHERE																REDUCING ATMOSPHERE															
	CORN	DDGS							DWG				SYRUP				CORN	DDGS							DWG				SYRUP			
PARAMETER	STOVER	1	2	3	4	4*	5	AVG	3	4	5	AVG	3	4	5	AVG	STOVER	1	2	3	4	4*	5	AVG	3	4	5	AVG	3	4	5	AVG
Initial deformation (°F)	**1,930**	1,510	1,423	1,149	1,013	1,407	--	**1,300**	1,226	1,304	1,407	**1,312**	1,214	2,708	1,814	**1,912**	**1,624**	1,350	1,316	1,242	1,306	1,390	--	**1,321**	1,238	1,327	1,415	**1,327**	1,544	2,295	1,855	**1,898**
Softening (°F)	**1,984**	1,514	1,443	1,169	1,028	1,546	--	**1,340**	1,249	1,432	1,466	**1,382**	1,242	2,715	2,602	**2,186**	**1,718**	1,386	1,425	1,297	1,471	1,580	--	**1,432**	1,297	1,572	1,531	**1,467**	1,690	2,305	2,532	**2,176**
Hemispherical (°F)	**2,100**	1,543	1,555	1,294	1,307	2,414	--	**1,623**	1,309	1,486	1,544	**1,446**	2,435	2,722	2,629	**2,595**	**1,909**	1,476	1,566	1,329	1,656	2,516	--	**1,709**	1,358	1,737	1,662	**1,586**	1,909	2,313	2,639	**2,287**
Fluid (°F)	**2,205**	1,747	2,044	2,596	1,458	2,639	--	**2,097**	1,583	2,691	1,849	**2,041**	2,682	2,733	2,671	**2,695**	**2,194**	1,742	2,603	2,558	2,588	2,707	--	**2,440**	1,912	2,034	1,989	**1,978**	2,641	2,671	2,660	**2,657**

Notes:

1, 2, 3, 4, and 5 = samples collected from partner ethanol plant.

* = resampled to confirm previous results.

-- = not anlayzed.

Figures

Figure Ash-1
Ash Fusion Temperatures by Co-Product, Oxidizing Atmosphere

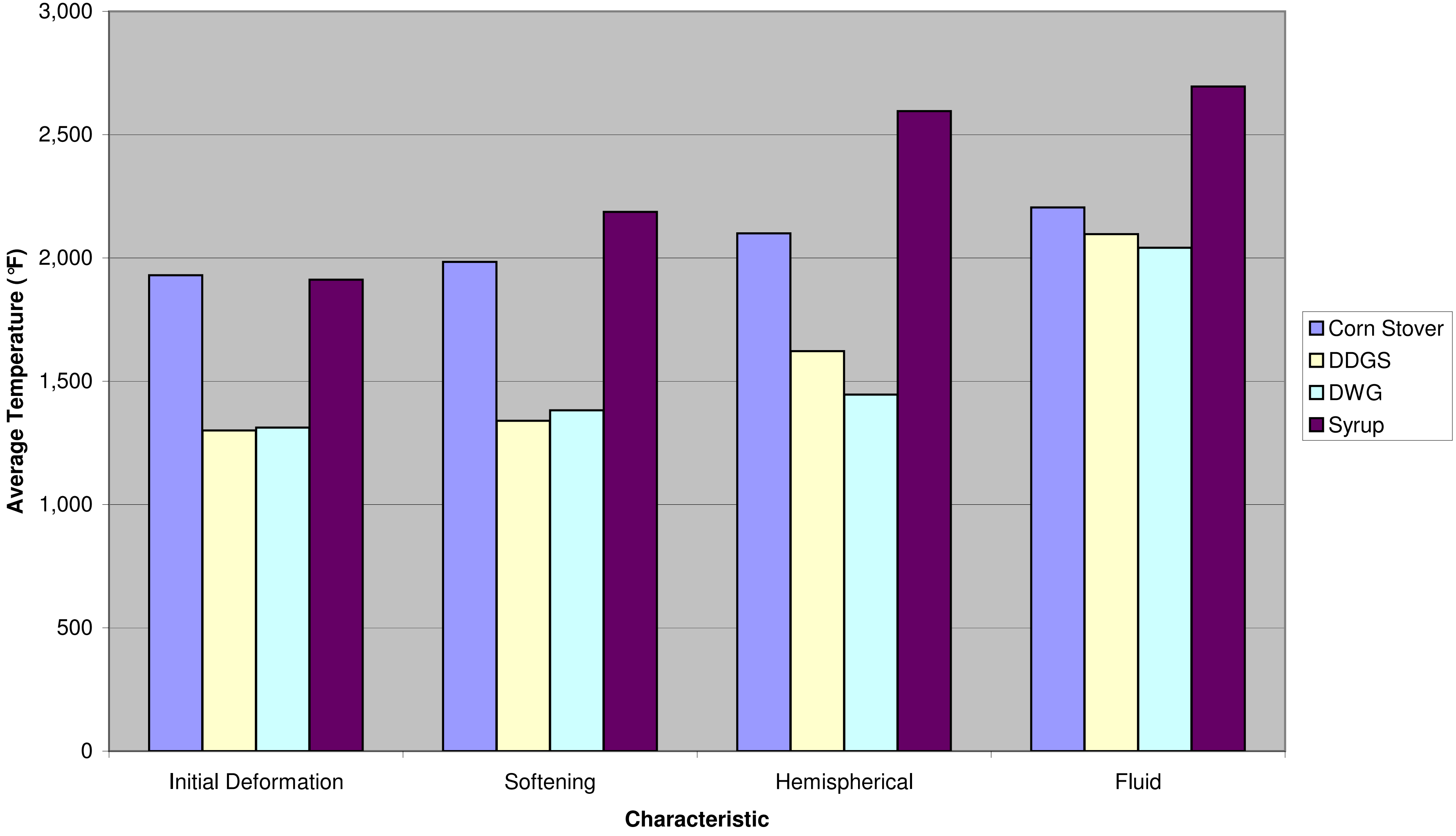
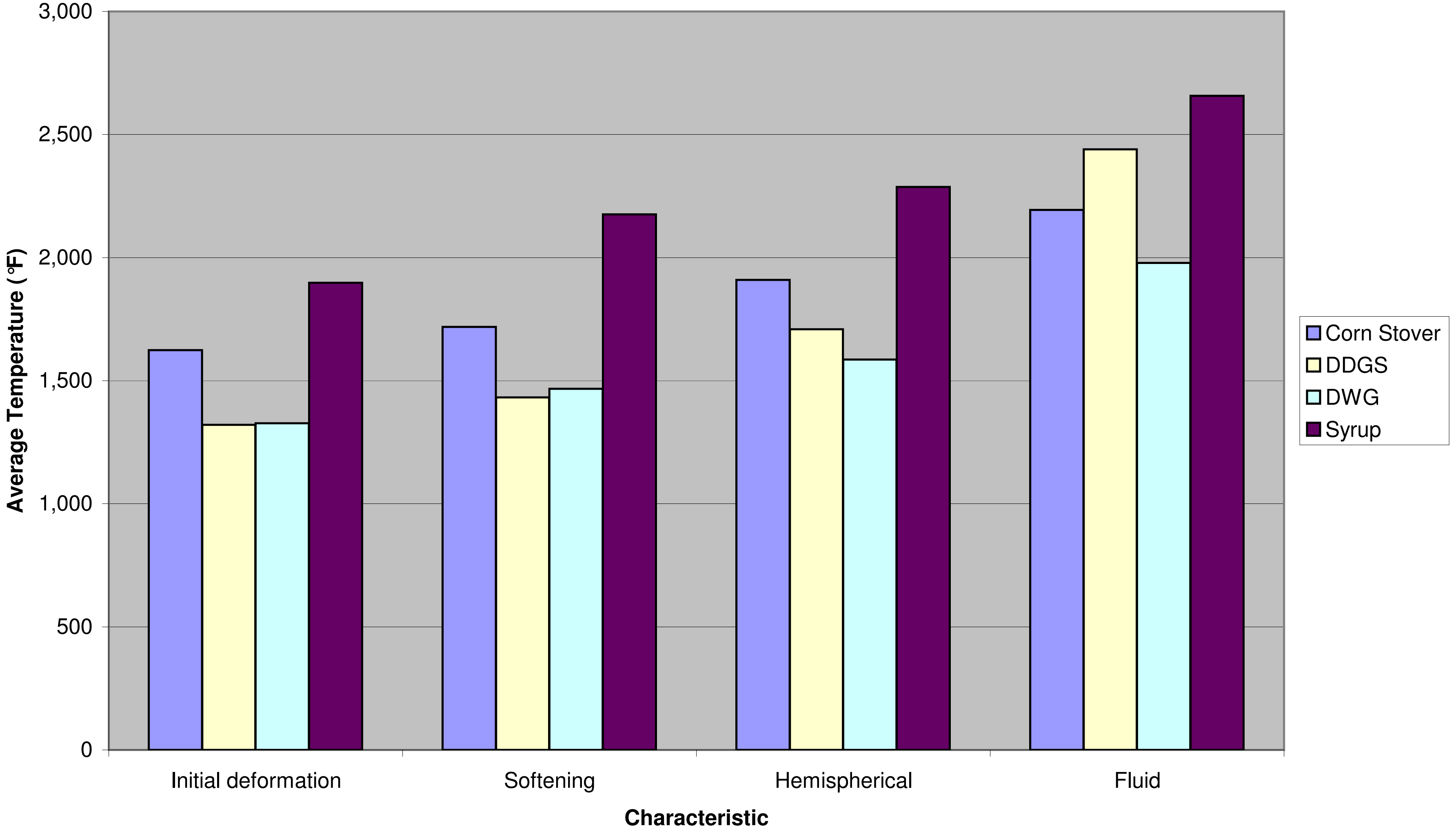


Figure Ash-2
Ash Fusion Temperatures by Co-Product, Reducing Atmosphere



Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 10 – Capital and Operating Cost Estimates

This chapter describes the development of estimated capital costs that are required for the example systems defined in Chapter/Task 14 and the additional operating costs associated with using these biomass systems. It was primarily prepared by project participants at the University of Minnesota in cooperation with AMEC E&C Services.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 10, “Capital and Operating Cost Estimates”

Background of the Task

The technical analysis for integrating biomass energy into the dry-grind ethanol process is described in detail in Chapter/Task 14 – Technology Options and Integration with the Dry-Grind Ethanol Plant. 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 configuration. The necessary emissions control technologies, primarily for oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and chlorine (HCl) 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, because the dryer exhaust was routed to the combustion unit in the biomass systems, 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 1. 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 3.33 for the nine fuel/technology combinations in Table 1.

Avoided equipment costs and corresponding total project costs were also estimated and included in Table 1 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 1. 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 1.6245. Thus, the cost for 380 million liter plant is estimated to be 1.6245 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 2.

Table 1. 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**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$1,275,000	6%		$1,400,000	5%		$1,750,000	5%	
Fluidized Bed Boiler & Steam System.	new	$10,394,000	50%		$13,203,000	49%		$15,314,000	47%	
Ash Handling	new	$650,000	3%		$650,000	2%		$650,000	2%	
Emissions Control	new	$2,520,000	12%		$2,575,000	10%		$2,950,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,900,000	11%		$5,566,000	17%	
Steam Tube Dryer	new	$6,129,000	29%		$6,312,000	23%		$6,312,000	19%	
Total Cost: new items		$20,968,000	100%	$69,749,000	$27,040,000	100%	$89,697,000	$32,542,000	100%	$107,773,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-43%	($30,430,000)	($9,000,000)	-33%	($30,430,000)	($9,000,000)	-28%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$11,968,000	57%	$39,319,000	$18,040,000	67%	$59,267,000	$23,542,000	72%	$77,343,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$151,819,000**			**$171,767,000**			**$189,843,000**

Syrup and Corn Stover Combustion		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	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	$9,264,000	53%		$11,731,000	52%		$13,867,000	49%	
Ash Handling	new	$650,000	4%		$650,000	3%		$650,000	2%	
Emissions Control	new	$2,481,000	14%		$2,517,000	11%		$2,565,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,600,000	11%		$5,497,000	20%	
Steam Tube Dryer	new	$3,700,000	21%		$3,810,000	17%		$3,810,000	14%	
Total Cost: new items		$17,370,000	100%	$57,928,000	$22,708,000	100%	$75,465,000	$28,139,000	100%	$93,308,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-52%	($30,430,000)	($9,000,000)	-40%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$8,370,000	48%	$27,498,000	$13,708,000	60%	$45,035,000	$19,139,000	68%	$62,878,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$139,998,000**			**$157,535,000**			**$175,378,000**

DDGS Gasification		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$790,000	4%		$890,000	4%		$990,000	4%	
Fluidized Bed Gasifier & Steam System.	new	$9,054,000	49%		$10,586,000	45%		$12,216,000	43%	
Ash Handling	new	$350,000	2%		$350,000	1%		$350,000	1%	
Emissions Control	new	$2,300,000	12%		$2,414,000	11%		$2,673,000	10%	
Steam Turbine Generator & Acc	new	$0	0%		$2,870,000	12%		$5,556,000	20%	
Steam Tube Dryer	new	$6,129,000	33%		$6,312,000	27%		$6,312,000	22%	
Total Cost: new items		$18,623,000	100%	$62,045,000	$23,422,000	100%	$77,811,000	$28,097,000	100%	$93,170,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-48%	($30,430,000)	($9,000,000)	-38%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$9,623,000	52%	$31,615,000	$14,422,000	62%	$47,381,000	$19,097,000	68%	$62,740,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$144,115,000**			**$159,881,000**			**$175,240,000**

Table 2. Nameplate installed costs for conventional and biomass-fueled dry-grind ethanol plants.

Type	190 MM liter (50 MM gallon) Plants		380 MM liter (100 MM gallon) Plants	
	Capital Cost	Name Plate Cost $/L ($/gal)	Capital Cost	Name Plate Cost $/L ($/gal)
Conventional	$112,500,000	$0.59 ($2.25)	$182,757,000	$0.48 ($1.83)
Corn Stover				
Process Heat	$151,819,000	$0.80 ($3,04)	$246,631,000	$0.65 ($2.47)
CHP	$171,767,000	$0.90 ($3.44)	$279,036,000	$0.73 ($2.79)
CHP + Grid	$189,843,000	$1.00 ($3.80)	$308,401,000	$0.81 ($3.08)
Corn Stover + Syrup				
Process Heat	$139,998,000	$0.74 ($2.80)	$227,427,000	$0.60 ($2.27)
CHP	$157,535,000	$0.83 ($3.15)	$255,916,000	$0.67 ($2.56)
CHP + Grid	$175,378,000	$0.92 ($3.51)	$284,902,000	$0.75 ($2.85)
DDGS				
Process Heat	$144,115,000	$0.76 ($2.88)	$234,116,000	$0.62 ($2.34)
CHP	$159,881,000	$0.84 ($3.20)	$259,727,000	$0.68 ($2.60)
CHP + Grid	$175,240,000	$0.92 ($3.50)	$284,678,000	$0.75 ($2.85)

Estimating Operating Costs and Other Baseline Assumptions

Table 3 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 $0.61/liter ($2.30/gallon) received at the ethanol plant. Corn price is assumed to be $197/tonne ($5.00/bushel) (for the next ten years) based on the 2007 Baseline Report of the U.S. Department of Agriculture. Natural gas is established at $10 per decatherm (1.06 million kJ or 1 million BTUs). Electricity is assumed to be priced at 6¢/kWh under baseline conditions, whether the plant is buying or selling.

DDGS are established at the price of $160/tonne ($145/ton). In the scenarios when the syrup is combusted, the resulting by-product is DDG, which we assume has a market value 110% 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 2¢/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 1.8¢/liter (7¢/gallon) based on recent sales of Renewable Identification Number (RIN) certificates.

Table 4. Common assumptions for all systems.

Category	**Baseline Values**
Debt-Equity Assumptions	
Factor of Equity	40%
Factor of Debt	60%
Interest Rate Charged on Debt	8%
Depreciation Period	15 years
Output Market Prices	
Ethanol Price	$0.61/liter ($2.30/gallon)
DDGS Price	$160/tonne ($145/ton)
Electricity Sale Price	6¢/kWh
Sale Price of Ash	$220/tonne ($200/ton)
CO_2 Price per liquid unit	$8.80/tonne ($8/ton)
Low-Carbon Premium	5.3¢/liter (20¢/gallon)
Government Subsidies	
Federal Small Producer Credit	2.6¢/liter(10¢/gallon)
RFS Ethanol Tradable Credit	1.8¢/liter(7¢/gallon)
Federal Renewable Electricity Credit	2¢/kWh
Feedstock Delivered Prices Paid by Processor	
Corn Price	$197/tonne ($5.00/bushel)
Energy Prices	
Natural Gas	$10/decatherm
Stover Delivered to Plant	$88/tonne ($80/ton)
Electricity Price	6¢/kWh
Propane Price	$0.40/liter ($1.50/gallon)
Operating Costs—Input Prices	
Denaturant Price per gallon	$0.79/liter ($3.00/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 and Gallagher, 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 1.6245) 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 and Gallagher, 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.

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Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 11 – Electricity Producing Options

This chapter outlines potential systems for producing electricity at ethanol plants. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants
Report for Task 11, "Electricity-Producing Options"

Background of the Task

This project concerns the use of biomass as the proximate energy source for producing electricity. Electricity-producing technologies based on a proximate energy source other than biomass, such as photovoltaics, geothermal, hydro, wind, etc., are therefore not within the scope of this project, and will not be evaluated.

There are, at present, two applicable technologies for using biomass to produce electricity on a commercial scale: rotating generators and fuel cells. By far the predominant means of producing commercial-scale electricity is with rotating generators. The generators are similar in operation (although differing in design details and control systems), regardless of the motive force used to spin them (steam turbines, combustion turbines, wind turbines, water turbines, etc.). The primary differences in the electricity-producing systems are thus in the components used to supply and support the rotating generator. Likewise, fuel cells are similar in operation (although differing in design details, especially regarding fuel pretreatment), regardless of the source of the fuel. It is primarily the supply and support systems that differ. Because the electricity-producing component of the energy systems is essentially independent of the motive force and/or fuel, this chapter examines the relevant details of the different supply/support systems as they relate to generating electricity using biomass fuel at ethanol plants.

Steam Turbine–Based Systems

In a steam turbine–based system, high-pressure steam is used to power a turbine, which is in turn connected to an electric generator. There are two primary means of producing the steam for such systems (direct-fired or heat recovery), and two major modes of operation of steam turbines (letdown and condensing). All of these means are applicable to the use of biomass fuel in ethanol plants.

The steam-producing units can be either of the direct-fired or of the heat recovery type. In a direct-fired unit (whether it is conventional or fluidized bed), fuel is combusted within the unit, and the steam-generating components are integral with the combustion unit. Direct-fired units may be of the "fire tube" or "water tube" configuration. In the fire tube configuration, the hot combustion gases pass through a series of tubes immersed in a vessel of water. In the water tube configuration, water passes through a series of tubes, located inside the combustion chamber and/or in an adjacent chamber directly connected to the combustion chamber. Especially for larger units, the water tube configuration is more efficient and can produce higher steam pressures and temperatures, and is by far the predominant configuration. Direct-fired units are widely used in fuel ethanol plants, for both steam generation and for pollutant incineration.

In a heat recovery type steam-producing unit, usually referred to as a heat recovery steam generator, or an "HRSG", the steam generation unit is separate from the combustion unit, although usually located in proximity to it. HRSGs are almost always of the water tube design. While an HRSG can be designed to meet essentially any steam-producing need, in practice, they are often used to recover somewhat lower grade heat from systems in which higher grade heat has been used for some other purpose (such as turning a combustion turbine or incinerating pollutants). HRSGs are therefore more common in lower (up to 150 psi or so) to medium (several hundred psi) pressure applications. HRSGs are widely used in fuel ethanol plants.

While steam turbines are of a similar basic design, with details dependent on specifics of the system being served, there are two basic operational modes. In a "letdown" steam turbine, only a portion of the available steam pressure is used to rotate the turbine (and thus generate electricity for the purposes of this project), with steam exiting the turbine at sufficient pressure to perform some other function. In a typical fuel ethanol plant, process steam is generated at around 150 psi. If a letdown turbine were used to generate electricity, the steam might enter the turbine at 600 psi and leave it at 150 psi, with the pressure reduction used to generate electricity.

The second basic turbine operational mode is "condensing," where the maximum pressure drop is achieved across the turbine by condensing the exiting steam. This mode of operation is more efficient than the letdown mode because, by condensing the exiting steam, an actual vacuum can be created at the discharge side of the turbine, thus maximizing the differential pressure drop across the turbine. In addition, because the pressure on the exiting side of the turbine is as low as possible and is uniform, and because this mode of operation can readily handle varying conditions, the condensing turbine can enhance the stability of the entire steam system, can aid in handling transient loads, and can help avoid process disruptions. However, to achieve the condensing requires considerable amounts of cooling water, and the lower the temperature of the cooling water, the better the system works. If a facility cannot be located near a large supply of clean, low-temperature water, an evaporative cooling tower may be needed. Although most fuel ethanol plants have cooling towers, the cooling towers are probably not sized to provide cooling for a condensing turbine, and additions or changes in operation of the cooling tower may be needed to accommodate the condensing turbine.

The most efficient overall system design may be to use both a letdown and a condensing turbine. Steam feed to the letdown turbine would be constant, resulting in a constant stream of process steam out of the letdown turbine, and a constant generation of electricity. This also allows for a uniform and highly efficient use of the steam-generating unit. Steam exiting the letdown turbine would go to both process and the condensing turbine, with any excess process steam going to the condensing turbine. Variations in the use of process steam would be handled by the condensing turbine, helping the management of the process. Figures EPO-1 and EPO-2 show conceptual fluidized bed combustion and gasification systems with both letdown and condensing turbines.

Combustion Turbine–Based Systems

In a combustion turbine system, the combustion unit and the rotating turbine are a single unit. Combustion of fuel inside the unit produces the power needed to operate and rotate the turbine. The turbine is connected to an electric generator through a speed reducer. The typical large combustion turbine is similar to the jet engines that power aircraft.

Only gaseous or liquid fuels can be used in combustion turbines. The fuels must be free of particulates, agglomerative materials, and any component that would cause undue wear on system components, especially turbine blades. Liquid fuels can be injected into the combustion chambers, whereas gaseous fuels must be compressed before injection. Compression of the gaseous fuels can require considerable energy, especially if the heat content of the fuel is low.

In a simple-cycle system, the exhaust gases from the combustion turbine are discharged to a stack. This is a common configuration for electric "peaking" plants that operate intermittently, for short periods. For continuous operations, much higher efficiency is achieved if the combustion turbine is combined with an HRSG, as described in the next section. Such a configuration also produces process steam.

Combined Combustion Turbine and Steam Turbine Systems

The hot exhaust gases from the combustion turbine can be directed into an HRSG to generate steam. Such a system is called a combined-cycle system. Once the steam is generated in the HRSG, the rest of the steam turbine and electric generator systems are the same as for the steam turbine systems described above. If more energy is needed from the HRSG (for example, if it is desired to generate larger quantities of high-pressure steam), the system can be designed to introduce additional fuel into the HRSG. Figure EPO-3 shows a conceptual fluidized bed gasification system with a combined-cycle system.

The overall efficiency of combined-cycle systems is much higher than that of simple-cycle systems. In addition, the combined-cycle system generates process steam that the plant needs.

Sterling Engine – Based Technology

Sterling engines produce energy from external heat based on temperature differences causing the expansion and contraction of gases. The external heat source could be generated from a variety of fuel sources, including biomass. Sterling engines have proved effective for small-scale energy production (up to 150 kw). However, because of their high capital costs and size, sterling engines are not suitable for large-scale industrial applications.

Water Considerations

Water is consumed in the ethanol production process, both as a chemical component and as cooling water for various processes. These production processes are essentially independent of the plant energy center, and are not included in this analysis.

The simple-cycle combustion turbine uses little water, and is not considered further in this analysis of water use. Likewise, the electricity generators do not use water.

All of the steam-based energy systems use water for boiler feed. The boiler feed water is treated to remove as much sediment and problematic dissolved solids as possible by using industrial feed water pretreatment systems. These processes generate a wastewater stream containing the removed material and any water treatment chemicals. This wastewater stream is either discharged from the plant or returned to the ethanol production process. The treated boiler feed water becomes steam in the steam generator. After being used in the process (primarily for low-level process heat and for distillation), most of the steam is returned to the steam generator in the form of condensate. The buildup of sediment and dissolved solids in the boiler water limits the number of times the sequence of water-steam-water (called a "cycle") can continue. To maintain acceptable levels of sediment and dissolved solids in the boiler, there is a purge (called blowdown) of boiler water from the boiler, and an equal input of pretreated boiler feed water into the boiler. All else being equal, the purer the boiler feed water, the greater the number of cycles that can be maintained. Because the blowdown is hot, energy can be saved if the blowdown can be recycled to the production process or sometimes additional heat recovery is implemented.

The amount of water used to produce boiler feed water is primarily a function of the amount of steam used, the quality of the available raw water supply, and the ethanol production process details. The type of steam generator used will have little impact on the amount of boiler feed water needed.

For one of the technologies included in this project, fluidized bed gasification, the syngas conditioning step may include syngas cooling. As much as possible, the syngas cooling would be done in a manner promoting the maximum recovery of heat from the raw syngas. If additional cooling is needed, or if maximization of heat recovery from the raw syngas is not feasible, cooling water may be needed to achieve the desired degree of cooling. The cooling water would likely be taken as a side stream from the main plant cooling tower, although additional capacity may have to be added to the cooling tower to accommodate the syngas heat load. Since the cooling tower uses evaporation as the means of cooling, such a heat load would result in consumptive use of water.

Of the two types of steam turbines considered in this project, the letdown turbine does not use cooling water. The steam discharging from the letdown turbine enters the production process, from which it is returned to the steam generator as condensate. Cooling water is used for the production process, the same as if there was no letdown turbine in the system. If excess steam entered the letdown turbine (such as to attempt to generate an amount of electricity greater than the amount corresponding to the process steam needs of the plant), the resultant excess steam discharging from the letdown turbine would either have to be vented or routed to the process. In the latter event, however, since the amount of steam needed for the production process is carefully balanced, and since most plants do not have significant excess production cooling capacity or excess production condensate handling capacity, a serious imbalance, or even a process shutdown, would occur.

The second type of steam turbine, the condensing turbine, requires substantial quantities of cooling water to achieve condensation of the steam discharging from the turbine, and thus provide the maximum pressure drop across the turbine. Most ethanol plants would not have sufficient excess cooling capacity to accommodate the condensing turbine. Additional cooling capacity would need to be added, by either once-through (if the plant had access to a suitable source of cooling water) or recirculating evaporative cooling (cooling tower) systems. To offset the disadvantage of needing this additional cooling water, and as described above, the condensing turbine offers significant advantages to a combined heat and power (CHP) system by providing both highly efficient operation and the ability to smoothly handle variations in steam load. This in turn allows for stable, efficient operation of the remainder of the system.

Ash Considerations

The ash from the combustion or gasification units is not affected by the type of steam turbine used, or by the electricity generator. The ash (or total residue) from the gasification system will be affected by the type of steam generator used. If the syngas is directly burned in a boiler, little if any pretreatment will be needed, and little if any residue will be generated in the pretreatment step. The ash from the boiler will be essentially the same chemically as the ash from the gasification unit itself, although the particle size distribution will likely be affected, with the ash from the boiler likely being finer.

For use in a combustion turbine, or for use as a general replacement for natural gas in various systems in the plant, the syngas will need to be pretreated, and the pretreatment will produce additional and different residues. Typical pretreatment begins with cooling. The cooling helps remove moisture, and allows for additional pretreatment using lower cost, conventional devices such as fabric filters. The cooling step may produce tarry condensates and potentially, depending on the degree of cooling, a liquid waste stream containing organic condensables, water, and water-soluble components. This material would need to be processed before either reintroduction into the gasifier (for the organics phase) or discharge from the plant (for the aqueous phase). The material captured in the post-cooling step, such as in the fabric filter, would be expected to differ chemically from the ash from the gasifier itself, in that the captured material would likely be only partially oxidized. Managing this material would depend on the detailed design of the overall system.

Maintenance Considerations

As a general rule, the simpler the system and the fewer the components, the lower the maintenance. A simple boiler, fueled with natural gas, and generating only medium-pressure (about 150 psi) process steam usually requires little maintenance, and will be used as the base case for this project.

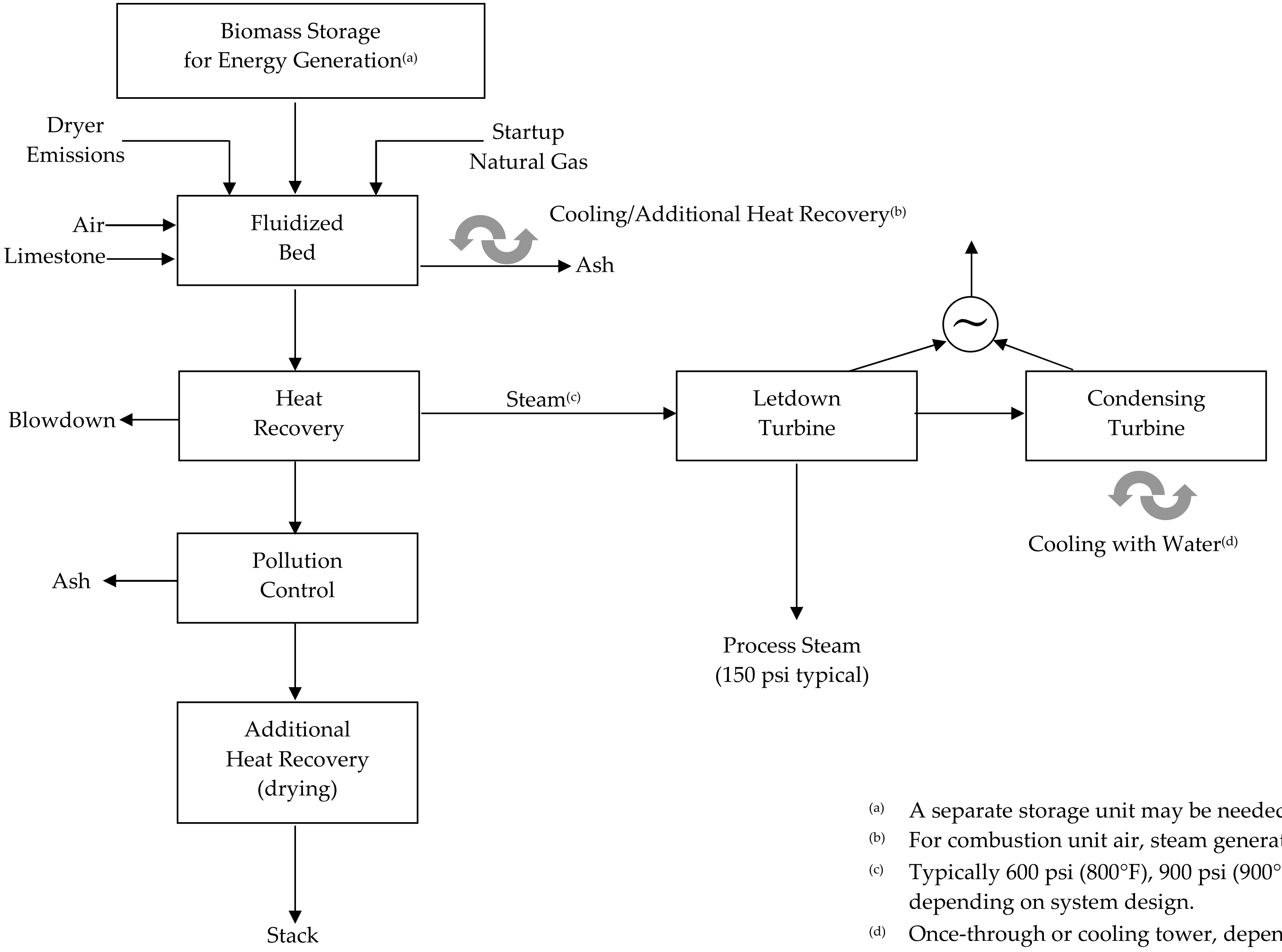
The types of electricity generators that will likely be used for the CHP systems considered in this project require very little maintenance, and will not be considered further in this analysis of maintenance considerations. Likewise, assuming proper boiler feed water and condensate treatment, the types of steam turbines that will likely be used for the CHP systems considered in this project require little but routine maintenance of a type that can likely be performed by plant maintenance staff, and therefore will not be considered further in this analysis of maintenance considerations.

Because of the physical characteristics of the biomass fuels, their biodegradability, and their being subject to freezing, the biomass fuel storage, handling, and feed systems may be quite complex, and will likely require considerable maintenance. A severe incident, such as freezing up of feed materials, with associated damage to piping, pumps, and other system components, could be very costly. And, the indirect cost of the interruption of plant operations, and possibly the need to discard batches, could result in even higher costs. Such costs could be lowered somewhat if an alternative fuel supply (likely natural gas) was readily available and if the CHP systems could be rapidly switched to the alternative fuel, but the possible demand charges for such alternative fuels could be substantial. Also, if plant systems were set up for near "real-time" use of the biomass materials as fuels, the limited storage capacity for the coproducts would limit the amount of production the plant could continue. Additional biomass storage may not be feasible, both because of cost and because of the material handling challenges. The design of individual plant systems would have to take these considerations into account.

Fluidized bed systems require additional maintenance, with gasification systems requiring somewhat more maintenance than combustion systems.

Figures

Figure EPO-1
Fluidized Bed Combustion with Electricity Generation and Process Heat



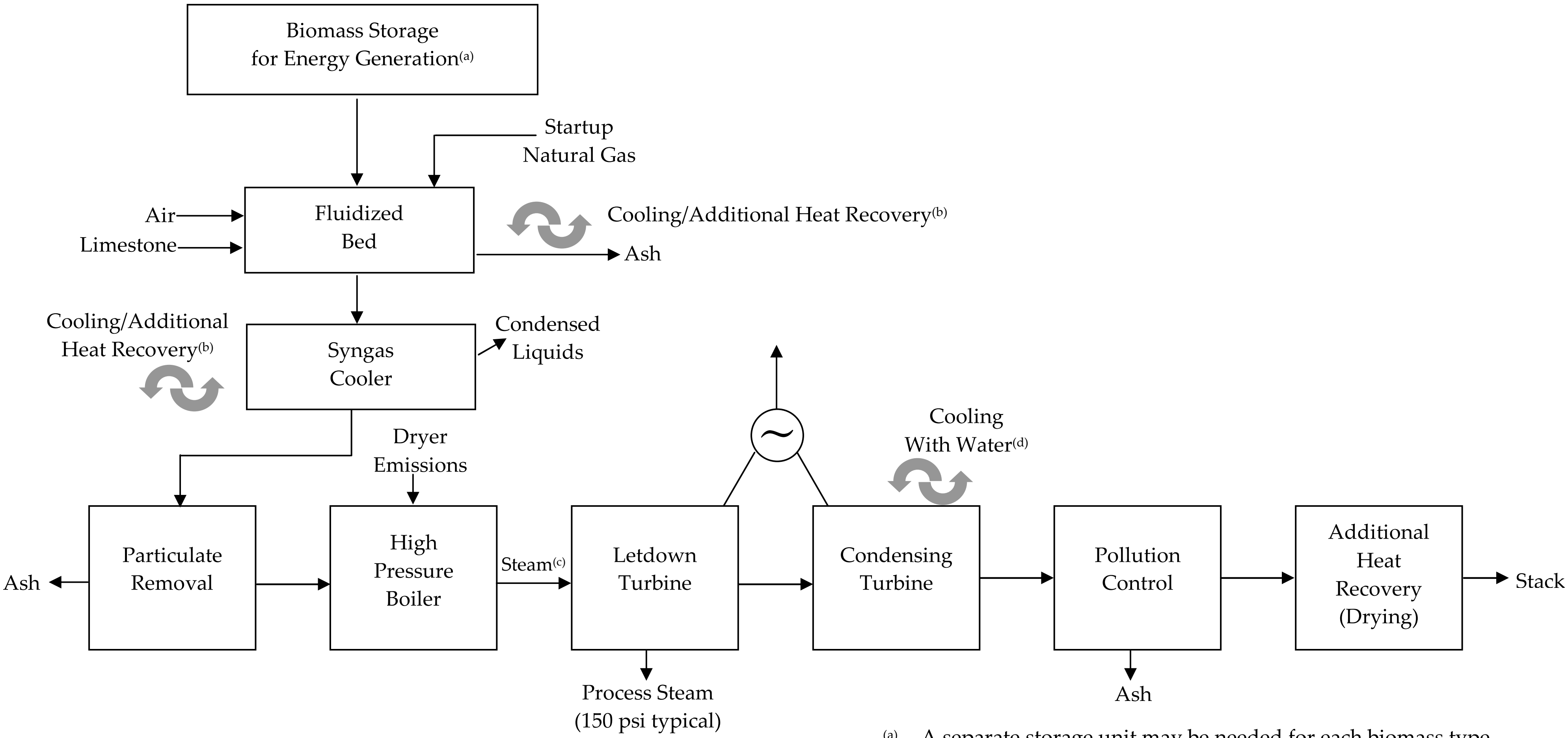
(a) A separate storage unit may be needed for each biomass type.

(b) For combustion unit air, steam generator feed water, or drying.

(c) Typically 600 psi (800°F), 900 psi (900°F), or 1,500 psi (950°F), depending on system design.

(d) Once-through or cooling tower, depending on site conditions and system design.

Figure EPO-2
Fluidized Bed Gasification with Electricity Generation and Process Heat
(Steam Turbine)

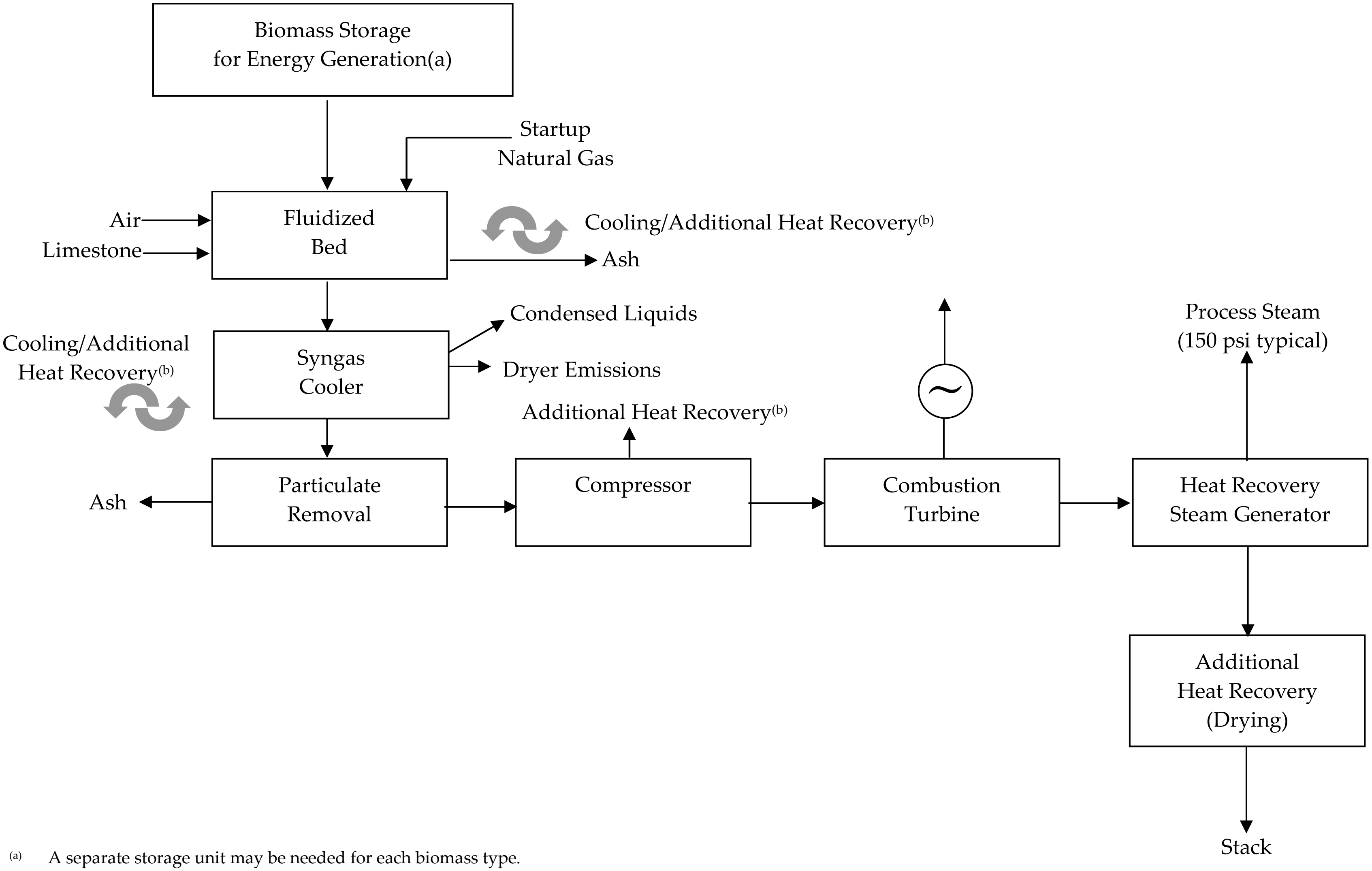


(a) A separate storage unit may be needed for each biomass type.

(b) For combustion unit air, steam generator feed water, or drying.

(c) Typically 600 psi (800°F), 900 psi (900°F), or 1,500 psi (950°F), depending on system design.

Figure EPO-3
Fluidized Bed Gasification with Electricity Generation and Process Heat (Combustion Turbine)



[a] A separate storage unit may be needed for each biomass type.

[b] For combustion unit air, steam generator feed water, or drying.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 12 – Compatibility with Existing Plant Combustion Systems

This chapter outlines potential advantages as well as disadvantages of incorporating biomass energy generation in existing plants. It was primarily prepared by project participants at RMT Inc.

Project Leaders

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

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RD56: Generating Electricity With Biomass Fuels at Ethanol Plants Report for Task 12, "Compatibility with Existing Plant Combustion Systems"

Background of the Task

An important element of this project is the evaluation of the potential for use of the co-product and corn stover fuels with existing ethanol plant infrastructure. Utilizing existing plant infrastructure could substantially lessen the capital requirements for using the co-product and corn stover fuels, could speed the processing of necessary construction and environmental permits, and could minimize the amount of new operations and maintenance (O&M) experience needed by plant staff. On the other hand, existing plant energy systems have generally been carefully designed to be optimal for the particular plant needs, and modifying the systems can be costly and problematic, including potentially increasing O&M costs and lowering energy utilization efficiencies.

All fuel ethanol plants use steam in the ethanol production and refining process, and some plants use steam in DDGS driers. Smaller amounts of steam may be used for space heating, line tracing, and other ancillary purposes. Few plants currently generate their own base load electricity for process use, although some plants have motor-generator sets (gensets) for emergency use or for electricity peak shaving. Because all ethanol plants require steam, of growing interest are systems that generate both process steam (heat) and electricity (power), referred to as combined heat and power (CHP) systems. Increasing applications of CHP systems are anticipated in the future, especially systems incorporating co-products and biomass fuels. This chapter examines some key considerations regarding the use of co-product streams and corn stover for CHP with existing plant energy infrastructure.

Electricity Generation

As described in other chapters of this report, current practical electricity production at fuel ethanol plants will use rotating generators, driven by either a combustion turbine or a steam turbine. The electric generator is not directly impacted by the fuel used to generate the steam for the steam turbine or to fire the combustion turbine. However, the reliability and stability of the electricity supply is critical for plant operations and economics. The fuel source will impact the plant electricity system to the extent that the combustion systems, and their thermal or mechanical feeds to the electricity generators, are effected by the fuel sources.

The steam generation systems for existing ethanol plants are designed with sufficient capacity to operate the plant, with perhaps some extra capacity to accommodate system maintenance and perhaps modest production increases. The steam systems generally do not have sufficient capacity to generate base load electricity for the plant and also to supply the plant steam operating needs. Of course, a combustion turbine would not be in use at the plant unless the combustion turbine was already being used for generating electricity for the plant, and any combustion turbine would be in conjunction with a heat recovery steam generator. For plants without a combustion turbine, generating electricity would therefore necessitate adding new or additional equipment. Many ethanol plants are designed and built with expansion in mind. Space and infrastructure are often provided in anticipation of additional steam production, and perhaps for also generating base load electricity. Providing such space and infrastructure during initial plant design and construction can significantly reduce both the time and cost of future expansion.

Considering in general the use of co-product fuels or corn stover in existing plant systems, an ethanol plant needs both steam and electricity to operate. Variability in the fuel supply, such as varying moisture levels and varying proportions of component fuels, may result in variability in the steam production or pressure, or, in the case of gasification, in the syngas supply and composition. This in turn may effect the amount or quality of electricity produced. From a practical standpoint, the ethanol plant may be able to supplement the electricity supply via a genset, or via drawing from the grid, although such electricity supplementation may be costly and technically challenging. Such alternatives likely will not exist for the plant steam supply. On the other hand, the plant can likely tolerate more short term variability in the steam supply than in the electricity supply. Indeed, owing to increased use of electronics and to integrated operating control systems, the more modern plants may be more sensitive to power interruptions and to power quality than some of the older plants.

Biomass-fueled systems will likely require additional maintenance and/or extended periods of outage compared to systems fueled with natural gas. Plants using natural gas may be designed to have multiple boilers, or multiple combustion turbines, to ensure continuity of steam supply during maintenance of one boiler or turbine. The capital cost and space requirements for most biomass fueled systems make redundancy in the form of additional duplicate systems a challenge. As described above, replacement electricity may be available from gensets or from the grid, but replacement steam is likely unavailable from outside the plant. Rental boilers and rental electric generation systems may be arranged for extended, planned outages. A possible installed alternative is a modest-sized natural gas fired boiler as a supplement to the biomass fueled system, to be used to maintain minimum plant operations, and to prevent freezing, during maintenance or extended outage of the biomass fueled system. Such a backup system would probably not have sufficient capacity to generate base load electricity.

Compatibility with existing CHP systems therefore depends both on the fuel-utilizing component and on the electricity supply system. Modifications may be needed in the plant electricity supply systems unless acceptable stability is designed into the fuel-utilizing components. The stability of the fuel-utilizing components in turn depends on well designed hardware, careful O&M, and close attention to the uniformity and predictability of the fuel supply.

Considering all of the above, ethanol plant co-products are nearly ideal biofuel sources for eventual in-plant electricity production because of their availability, uniformity, ease of use, and modest O&M challenges, and because the plant can exercise direct control over their production and quality.

An important consideration related to electricity generation in existing plants (as well as for new plants) is the water balance associated with the generation. As described elsewhere in this report, generating base load electricity for an ethanol plant would involve one of three turbine types. A combustion turbine could be used to directly drive the electricity generator, with steam generated in a heat recovery steam generator (HRSG). Cooling water is needed for both the combustion turbine and the electricity generator, but the cooling water would be incorporated into the overall heat recovery design of the energy system and of the plant. Most of the heat would be recovered via the HRSG in the form of preheated feed water, although some low level heat could be used for other plant uses. There would be little net additional to plant water demand.

The other two turbine types are steam turbines, that in turn drive electricity generators. In a letdown turbine, steam enters the turbine at high pressure and leaves at a pressure suitable for process use, usually 60-150 pounds per square inch (psi). The energy to drive the electricity generator is derived from the pressure differential across the turbine. A letdown turbine adds virtually no water demand to the plant. In a condensing turbine, the pressure differential across the turbine is maximized by condensing the discharging steam. A partial vacuum is created on the discharge side of the condensing turbine, making a condensing turbine inherently more efficient than a letdown turbine. However, to achieve this efficiency requires a continuous flow of cooling water to condense the steam. The heat added to the cooling water is low level, meaning that it cannot be practically recovered for other uses. The colder the cooling water, the less cooling water is needed. Many ethanol plants use groundwater, which generally has a temperature of around 55^{o}F-60^{o}F, ideal for condensing. However, much groundwater also contains high levels of hardness, that can foul heat exchangers. To help address this problem, the quantity of cooling water can be increased to minimize the temperature rise across the condenser, and so minimize deposition of hardness. This raises both pumping costs and water use. Condensing turbines can use a considerable quantity of water. As a general rule, a condensing turbine serving an electricity generator producing 1 MW of electricity requires around XXXXXXX gallons per minute of cooling water. This can amount to around XXXX% of the total water use of the ethanol plant absent the condensing turbine.

Thus, where water quantity or quality is a concern (and it is a concern nearly everywhere), careful consideration needs to be given to the overall system design for generating base load electricity at an ethanol plant. A letdown turbine or a combustion turbine will use less water, whereas a condensing turbine is efficient, and, as described elsewhere in this report, has operational advantages. A system incorporating both a letdown turbine and a small condensing turbine, or a combustion turbine and a small condensing turbine, may be optimal for some plants.

Existing Combustion and Gasification Systems

Dry grind fuel ethanol plants utilize a variety of combustion equipment. Some plants are also considering gasification systems, and several such systems are under design or construction. The applicability of the co-products and corn stover to such existing and planned equipment is discussed below.

Almost all dry grind fuel ethanol facilities have some type of on-site combustion system for steam generation. (A few plants receive steam from a different source, such as a nearby electric utility steam plant or large industrial steam generator primarily serving another facility.) Most early ethanol plants, and many new plants, rely on conventional natural gas fired boilers. As emission control requirements for VOCs, odor, and particulate matter became more stringent, especially related to co-products drying, a potential solution to the excessive emissions was to modify the boilers to allow introduction of pollutant-containing emission streams into the boilers, where the pollutants would be destroyed during the fuel combustion process. However, it is difficult to optimize both emission control and energy efficiency into a single such system, especially considering the quantity and schedule variability in both steam demand and raw emissions from co-products drying. Also, the high moisture content and potential particulate matter content of the exhaust from typical distillers wet grains dryers can result in increased maintenance and downtime for the steam generator. To address these problems, many ethanol plants have separate systems for steam generation and dryer emission control.

Natural gas fired steam generation units, either stand-alone or as part of a system incorporating a heat recovery steam generator, are still the dominant method of steam generation for most dry grind fuel ethanol plants. Some of these plants have propane in bulk storage tanks as backup for the natural gas supply. As described for coal fired combustion units below, natural gas fired units are optimized for the particular fuel and steam demand of the ethanol plant they serve. Introducing new fuel, especially if its physical and chemical characteristics differ substantially from natural gas (as all biomass fuels will), will require careful engineering and system modifications. O&M cost will increase, and efficiency will likely decrease. Considering typical natural gas fired boilers, introduction of the co-products or corn stover can be regarded as infeasible.

A few newer ethanol plants plan to burn coal to generate steam, and possibly electricity. These plants are generally in reasonable proximity to other large users of coal, such as electric utility generating stations or large industrial coal users. This allows the ethanol plant to realize savings in transportation and storage of coal, and helps ensure a reliable coal supply. The higher capital, operating, waste management, and emission control costs of using coal as compared to natural gas are felt to be more than offset by the savings in fuel cost. On a Btu basis, the cost of coal is only about ¼-½ the cost of natural gas for long term contracts, and the savings are even more pronounced when compared to recent experience with the spot price of natural gas. However, the cost of utilizing coal may escalate substantially if a CO_2 tax is imposed, or if CO_2 sequestration is required. Also, the ethanol plant's potential for realizing revenue from sale of renewable energy credits could be substantially lowered if coal is used as fuel.

It is often assumed that a steam generator system designed to burn coal can also burn biomass, including ethanol plant co-products and corn stover. This is generally not the case. A system burning solid fuel is designed to optimize burning of a particular type of fuel with particular physical and chemical characteristics. Burning other solid fuels may be possible, but usually requires hardware and operating system modifications and results in lower system efficiency, higher O&M expense, greater downtime, and higher cost per delivered Btu. As a minimum, significant pretreatment of the biomass may be needed prior to introduction into the steam generator, further raising costs. Successful introduction of substantial quantities of co-products or corn stover into a steam generator system designed for other solid fuels will require considerable capital investment, careful reengineering, and substantial operating system modifications. Even then, optimum performance may not be achieved.

Several plants are considering biomass gasification, and several are considering fluidized bed combustion systems. (Fluidized beds can also be designed for gasification systems.) As with natural gas and coal, the anticipated physical and chemical characteristics of the planned fuel will need to be considered in the system design. Introducing fuel with substantially different characteristics could be problematic. As described elsewhere in this report, the moisture content of the biomass fuel is a critical component in system design and operation. Other important fuel components include nitrogen, sulfur, and alkali metals content; density; handling characteristics (flowability, stickiness, freezing point, etc.); and the effects of aging. Some of the biomass fueled systems are anticipated to use wood chips as the primary fuel, and have been designed accordingly. If the biomass fueled systems have not been designed to accommodate the ethanol plant co-products and/or corn stover, their effective and efficient incorporation into the fuel stream may be challenging. This will be especially true for syrup, and for the co-products containing high nitrogen and sulfur.

Many plants control dryer emissions with some type of efficient dedicated emission combustion system, typically a regenerative thermal oxidizer (RTO). RTOs use alternating beds of ceramic media to thermally oxidize VOCs, and to recapture the heat of combustion to sustain the process. The RTO needs to initially be raised to oxidizing temperature by heating, usually with natural gas, and an ongoing natural gas feed to a burner in the RTO is needed to compensate for system thermal losses. Modern RTOs are designed to have thermal efficiency of 95% or greater.

Most ethanol plants have a natural gas fired flare to control emissions from tank truck and/or tank car loading. The flares may have a continuously operating natural gas fired pilot light, although designs without a continuous pilot light are available. Since the flame may be self-sustaining once initiated, and since product loading is not continuous, natural gas use for the flare is relatively low compared to other natural gas uses in the plant. Nevertheless, the cost of natural gas for the flare may reach thousands of dollars per month. Also, the ethanol and denaturant combusted is lost, not recovered. Whether syngas from the gasification of biomass could replace the natural gas in the flares is beyond the scope of this project. However, since the plant would likely want to be able to load product even when ethanol production was temporarily down (such as for steam or electricity system maintenance), having the flare solely dependent on the plant's biomass gasification system is probably inadvisable.

Some plants have emergency standby engine-generator sets (gensets). The generators are usually diesel powered, although some may use natural gas for fuel. Typical operation would be only a few hundred hours per year, or less. Whether syngas from the gasification of biomass could replace the natural gas for the genset is beyond the scope of this project. However, the genset would most likely be needed when plant electricity supply has been interrupted, and at such times the biomass gasifier would likely be down. It is therefore likely inadvisable to have the emergency genset dependent on the plant's biomass gasification system.

The remainder of this chapter focuses on the applicability of the generation of electricity using existing facility combustion systems, modified for biomass combustion. Using at least portions of existing facility combustion systems has the potential to reduce capital costs and operational disruption as compared with the installation of new systems in the same locations as the existing systems. This potential benefit is largely eliminated if the plant space and configuration allow construction of new systems separate from existing systems. However, as described above, efficiency and operating cost should also be carefully evaluated, since specially designed systems are often more efficient and cost effective over the long run than retrofit systems.

Plant Combustion Systems to be Evaluated

In a previous chapter, "Combustion Options," the following four combustion/gasification systems targeted in this project are described:

- Combustion in fluidized bed units
- Gasification in fluidized bed units
- Combustion of syrup using an injection nozzle in a standard boiler design
- Combustion of a combination of syrup and DWG, DDG, or DDGS using an injection nozzle in a standard boiler design

The compatibility of each of these four options for using biomass fuel in existing systems is discussed below. Also included is some discussion regarding combustion in coal-fired steam generators.

Combustion in Fluidized Beds

At the time this report is being prepared, only one dry grind fuel ethanol plant in the United States, Corn Plus in Winnebago, Minnesota, has a fluidized bed combustion system capable of using co-products. The system was not designed to combust corn stover. Although Corn Plus is a partner plant in this project, a patent is pending on the fluidized bed combustion application, and details of the fluidized bed combustion system design and operation are not publicly available at this time. The discussion here is therefore based on information that is publicly available, and on the evaluation performed as part of this project.

The Corn Plus fluidized bed combustion system was designed to combust syrup as produced at the plant at that time, with about 30% solids, and possibly to combust DWG. The system produces only steam. The system design incorporates supplemental feed of natural gas. Computational fluid dynamic (CFD) modeling performed by RMT as part of this project shows that syrup with a solids content of less than about 50% will not support stable and self-sustaining combustion. CFD modeling shows a similar result for DWG.

Whether the Corn Plus fluidized bed combustion system would support syrup or DWG with solids content of 50% or greater, or would support combustion of DDG or DDGS, could not be determined as part of this project.

The configuration and components of a fluidized bed combustion system are substantially different from a natural gas fired boiler. Although some components of the fluidized bed system could potentially be housed in the structures housing a natural gas fired boiler, a more likely scenario is construction of a completely new system at a location as near as possible to the existing connections of the feed water, steam, gas, and electricity lines, and convenient for the storage and supply of the co-products and/or corn stover. This would also allow for continued plant operation during construction of the new system.

Gasification in Fluidized Beds

At the time this report is being prepared, there is no fluidized bed gasification system at a dry grind fuel ethanol plant in the United States. Other types of gasification systems are under design or construction at a number of plants. The systems are planned to use biomass as a fuel source, and the biomass may include DDG or DDGS. Computational fluid dynamic (CFD) modeling performed by RMT as part of this project (albeit on fluidized bed gasification units) indicates that feed materials with a high moisture content are not good candidates for gasification systems at ethanol plants. A preliminary drying step will be required for many feed materials.

As with fluidized bed combustion systems, the configuration and components of a fluidized bed gasification system are substantially different from conventional steam generation or CHP units. In addition, depending on the configuration and system details, the fluidized bed gasification system doesn't generate steam (like a fluidized bed or conventional combustion boiler) or drive a generator shaft (like a combustion turbine) itself. The syngas produced must be used in some other device to produce steam or generate electricity, and the syngas may need to be cleaned up before such use. Thus, to serve an existing plant, a new gasification and syngas cleaning system would be needed, and existing gas combustion units would require appropriate modifications. As described above, some existing plant components, such as loadout flares and gensets, may not be good candidates for syngas. Additional safety procedures and equipment would also be needed owing to the different chemical makeup of the syngas (that has a large proportion of carbon monoxide (CO) and hydrogen) as compared with natural gas (primarily methane).

The gasification systems planned or under construction at several ethanol plants reportedly do not use a fluidized bed. Such systems have lower capital and operating costs than fluidized bed systems, but tend to be larger in size for a given output, and to have lower throughput per area. Determining what is the optimum system for a large fuel ethanol plant is beyond the scope of this project.

As discussed earlier in this report, gasification systems may have advantages over combustion systems for use of biomass in existing plants. Gasification produces a gaseous energy source that may be able to be used, with appropriate equipment modification, in some of the existing plant systems currently using natural gas. Temperatures needed for gasification are lower (typically 200-400°F [93-204°C] lower) than for fluidized bed combustion systems, potentially reducing the generation of NOx. With proper pretreatment, the syngas can be used in a combustion turbine for generating electricity, followed by a heat recovery steam generator (HRSG) to generate steam.

Injection Via Nozzle Into a Conventional (Non-Fluidized) Boiler

As discussed in previous chapters, generation of electricity and steam by injection of either syrup or syrup and solids-containing portions (DWG, DDG, and DDGS) into current plant natural gas fired boilers is projected to not be feasible from a practical standpoint. Injecting the co-products into a coal fired boiler may be feasible, although may result in lowered efficiency, increased O&M cost, and worsened emissions. Based on the analyses performed as part of this project, and on the literature, the ethanol plant biomass solids are of a size necessary for injection into a combustion unit through a nozzle, and can be mixed with syrup or with other liquid or gaseous fuel for injection into an appropriate steam generator. However, the moisture content of the syrup and DWG, as received, are too high for stable, self-sustaining combustion. A substantial reduction of the moisture content, with associated costs and energy use, would be needed prior to combustion unless the syrup and/or DWG comprises only a small proportion of the overall feed material. A new potential technology application to accomplish this moisture reduction for syrup is described below.

A new modular evaporation technology application has recently been developed and is reportedly in operation at some ethanol plants to increase the solids content of the syrup to over 50 percent, and possibly to 70% or more. CFD modeling described in a previous chapter of this report and information from the operating partner ethanol plant combusting syrup indicate that syrup with a reduced moisture content (near 50 percent moisture) may achieve stable, self-sustaining combustion, at least in a fluidized bed.

As discussed in previous chapters, liquid or slurry injection into appropriate boiler systems of all sizes is a long established technology. Details of the injection vary, depending on the feed material and the type of boiler. Heavier feeds may require augmentation to achieve adequate dispersion. The augmentation may be accomplished by a combination of heating the feed material, by mechanical dispersion, and by using special nozzles supplemented with compressed air, steam, or gaseous fuel.

There are several disadvantages to using liquid injection via nozzles into a conventional combustion unit. As discussed above, the moisture content of the syrup and DWG would need to be substantially reduced to allow for stable, self-sustaining combustion. Feeding of co-products through pressure nozzles intended for other materials might result in additional O&M expense. Ethanol co-products 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 co-products may cause problems with slagging and ash fusion. A steam generator designed for natural gas will likely not be able to handle such particulates and ash. The sulfur content of the co-products might pose an emission problem, and, unlike a fluidized bed, adding chemicals to sequester the sulfur may be much more difficult, or may even be infeasible. System modifications to allow for the combustion of co-products might limit the capabilities for the combustion of conventional solids, so that the potential for burning of other biomass might be compromised.

For a plant with a coal fired steam generator, unless the system was designed to handle the co-products, their introduction via injection would likely result in lowered efficiency, operational problems, and higher cost. If the plant had already born the additional capital cost to burn coal, had secured the necessary permits, and had arranged for a coal supply, there would appear to be little if any direct advantage to introducing the co-products as fuel. The plant could choose to utilize the co-products or corn stover for reasons of indirect advantages, such as marketing considerations, inability to handle all of the co-products produced, or carbon offsets. Thus, although the use of the co-products in a coal-fired system may be technically feasible, it is likely not practical except for plant-specific, non-technical reasons.

Conclusions

Existing plant energy systems are generally optimized for particular fuel composition and characteristics, and the particular energy needs of the ethanol plant. Unless the existing system is designed to handle co-products or corn stover, introduction of the materials, even if technically feasible, is probably directly disadvantageous. Indirect advantages may exist, and would have to be evaluated on a plant-specific basis. Using existing infrastructure to speed the construction of and to lower the cost of new energy systems using co-products and corn stover is potentially a better alternative.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 13 – Electric Generation Considerations

This chapter outlines the opportunities and challenges of generating electricity and selling it to the grid. It was primarily prepared by project participants at LLS Resources LLC and RMT Inc.

Project Leaders

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

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RD56: Generating Electricity with Biomass Fuels at Ethanol Plants "Electric Generation Considerations," Part of Report for Task 13, "Electricity Production Estimates and Development of a Conceptual Model Plant"

Introduction

The generation, transmission, distribution, and sale of electricity are heavily regulated at both the federal and state levels, and may also be subject to requirements of the utility generating the electricity and to local and regional electricity transmission and distribution organizations. The generation of electricity by nonutility sources (such as ethanol plants), and the connection of these sources to the electricity grid for purposes of buying electricity from the grid and selling electricity to the grid, add another tier of regulatory complexity. Still more regulatory complexity is added if the fuel for the electricity generation is a renewable fuel, such as ethanol plant co-products. This regulatory complexity has significant potential impact on the economic, technical, and operational success of the ethanol plant. However, new regulations have also removed some of the barriers and improved price incentives.

In this section, these complex regulatory considerations will be examined, and their economic, technical, and operational impacts on ethanol plants will be discussed. Other sections of this report also bear on the impact on ethanol plants of the complex electricity regulatory framework.

Section 1. Regulatory Aspects of On-Site Electricity Generation

1.1 Federal and State Regulations

Both federal and state regulations and programs have been put in place to encourage the generation of electricity from biomass and other renewable energy sources. The mechanisms used to encourage this generation include the creation of renewable energy markets, favorable tax treatments, and favorable regulatory status. The major applicable regulations and programs are discussed below.

1.1.1 Public Utility Regulatory Policies Act (PURPA)

Under PURPA, facilities generating their own electricity and meeting certain fuel and efficiency standards (a "Qualified Facility" or QF) are accorded special regulatory qualifications. As initially approved, PURPA required that the local utility purchase all energy sold by the owner of a QF at its avoided cost and provide standby, backup, and maintenance power to the QF. However, EPACT '05 amended PURPA, such that where the Federal Energy Regulatory Commission (FERC) determines that competitive conditions exist, such as areas that participate in regional transmission markets, a utility is no longer required to buy power from renewable energy and combined heat and power (CHP, or cogeneration) plants, even when such plants can generate power less expensively than the utility, and even when such plants would otherwise meet PURPA standards.

The revised PURPA standards do provide an exception for generating units rated 20 MW or less. Before being relieved of their purchase obligation from units rated 20 MW or less, the local utility must provide a showing that the units have access to competitive power markets. Smaller generating units, such as those at ethanol plant sites and generating only the plant load, are typically connected at distribution voltage and therefore do not have transmission access to the Regional Transmission Organization (RTO) markets, in this case the Midwest Independent System Operator's (MISO's) markets. To receive the full benefit of those parts of PURPA that still apply, a DG facility that cogenerates should be formally registered by the owner as a QF under the PURPA self-certification process. Despite any changes in federal regulations, the states of Minnesota and Wisconsin actively encourage the development of distributed generation, as discussed below.

1.1.2 Renewable Energy Credits

Customers who generate their own electricity utilizing qualified renewable fuels, such as ethanol co-products, can sell Renewable Energy Credits (RECs) into national and state markets, where such markets exist, even when the electricity is all utilized on-site. However, once sold, the RECs remain with the property of the buyer, who can further trade the RECs. The current market for RECs are small and regional, though evolving, with transactions via over-the-counter trades or bilateral deals.

1.1.3 Production Tax Credits

Under the Energy Policy Act of 2005 (EPACT '05), wholesale generators of electricity from biomass that is sold for use by others are eligible for a production tax credit (PTC), for the first 10 years of such electricity production. The PTC for 2006 for "open-loop" biomass is about one half of the $0.019/ kWh credit for other renewable energy technologies, with an annual adjustment for inflation. To be eligible for a PTC under the current law, the electricity-generating equipment must be on-line before January 1, 2008. Among other eligibility requirements for the PTCs, the regulations restrict the use of coal in the fuel-to-flame initialization and stabilization, and facilities that use the renewable energy to serve any on-site needs are ineligible. The energy associated with natural gas used in the production of electricity is not eligible for production tax credits, and any electricity produced by "co-mingling" natural gas and renewable fuels would need to be sorted by fuel type.

Similar to PTCs, renewable generation assets owned by tax exempt state and municipal utilities are eligible for renewable energy production incentive (REPI) payments from the federal government.

1.2 Distributed Generation and Utility Regulations

Action has been initiated at both state and federal levels to encourage development of smaller, dispersed generating facilities, called Distributed Generation Facilities (DGs), that supply electricity to the customer owning the generation, and/or supply electricity directly to the utility without the customer taking any of the energy (a wholesale generator). The actions at both levels of government have been aimed at removing barriers typically erected by utility organizations against DGs. DGs can provide benefits of increased grid reliability, reduced investment in transmission facilities, reduced grid system losses, and increased efficiency of energy conversion.

The definition of a DG varies by state and federal jurisdiction. Also, regulations for the interconnection of these facilities with the electricity grid may vary by electric utility. The amount paid by the utility to the DG is stipulated under various rate schedules (tariffs) approved for investor-owned utilities by the state Public Service Commission. (Electric Cooperatives and municipal electric utilities set their policies via their Board of Directors who must comply with state and federal mandates.) The electricity buyback rates may vary based on several factors, including the reliability of the DG supply and the amount of electricity delivered by the DG. DGs with capacities above certain thresholds often have the opportunity to negotiate special buyback rates outside of the tariff.

Units exceeding the state DG size threshold or PURPA applicability threshold would be subject to more lengthy and costly connection and application procedures, as outlined in the RTO or local utility connection rules. These procedures are less precise and may require extensive negotiations after utility completion of special interconnection and transmission access studies. However, if generating units at ethanol plant sites are sized to meet only the plant electric load plus steam requirements, then these units are likely to fall within the DG or PURPA applicability standard.

1.2.1 Minnesota Distributed Generation Rules

In Minnesota, distributed generation is defined as electricity-producing facilities burning clean fuels and rated 10 MW or less and operating at 35 kV or less. The electricity buyback rates offered by Northern States Power (NSP) change annually, and are based on NSP's expected marginal monthly on-peak and off-peak energy costs. The price paid by NSP for its purchase of firm capacity from DGs (the capacity buyback rate) also changes annually, based on NSP's cost of capital and the remaining life of the DG equipment and NSP's need to otherwise install its own generating facilities.

The State of Minnesota has developed a document entitled " Distributed Generation Connection Requirements," which, in addition to specifying the setting of relays and other physical aspects of interconnection, describes the technical requirements for metering, monitoring, and controlling generation. The document has been appended to NSP's Distributed Generation tariffs (Section 10, Sheets 135 through 159.6, found at www.xcelenergy.com/docs/corpcomm/Me_Section_10.pdf). The State of Minnesota has also adopted a net metering standard for very small DGs.

1.2.2 Wisconsin Distributed Generation Rules

In Wisconsin, uniform DG rules apply under PSC 119, Wisconsin Administrative Code, to all investor-owned utilities, and to all customer-owned DGs. DGs are defined as electricity-producing facilities up to 15 MW in size, operating in parallel with the utility. As a practical matter, some utility tariffs only consider DGs of 12 MWs and under, and somewhat different rules apply for DGs less than 1 MW. For generation under 20 kW, net electricity billing applies, where the customer meter is bi-directional, and runs in the reverse direction when power flows out instead of in, resulting in a net invoice to the customer showing a credit amount for the electricity sold to the utility.

A document produced by the Wisconsin Distributed Resources Collaborative, entitled "Wisconsin Distributed Generation Interconnection Guidelines," provides the technical and procedural requirements involved in interconnecting DG facilities to the grid (found at www.wisconsindr.org/library/PSC/WI_InterconnectionGuidelines.pdf). A standard interconnection agreement, which must be signed by both the applicant and the utility before parallel operation can commence, is available through the Public Service Commission of Wisconsin (found at psc.wi.gov/utilityinfo/electric/distributedGeneration/ electricgenerationForms.htm).

1.2.3 Federal Distributed Generation Rules

Federal regulations promulgating DG standards have been initiated by the Federal Energy Regulatory Commission (FERC) and are stated in FERC Order No. 2006-B which became effective on August 26, 2006. The regulations will apply to generating units rated 20 MW or less. However, the definition of lower nameplate capacity for DGs by the various states (generally 10 to 15 MW) is currently the operative definition in those states. FERC regulations regarding transmission access and facility interconnection are effective nationwide.

1.2.4 Non-DG Units

In certain cases, the availability of byproduct fuel will allow the installation of generating units with capacity ratings far in excess of the amount required to operate the plant. Although such units would be too large to qualify for DG or PURPA benefits and would require transmission access, they would meet classification as Independent Power Producers (IPPs) and could register as Exempt Wholesale Generators (EWGs). Registration as an EWG means that they are exempt from conventional utility regulation as long as they do not have majority ownership by an electric utility. An EWG also has the right of access to the transmission grid for purposes of wholesale transactions.

EWGs in Minnesota and Wisconsin must make application via the Midwest Independent System Operator (MISO) to interconnect with the transmission system and to reserve transmission capability required to transmit the output. This is done by following a complicated application procedure accompanied by substantial study funding (to be paid by the EWG) under the MISO Open Access Transmission and Energy Markets Tariff. The MISO study results provide the EWG with an interconnection configuration, along with the amount of investment the EWG must make in the transmission grid.

Prices paid for energy to the EWG are based either on MISO market prices (if the EWG becomes a market participant) or on individually negotiated bilateral contracts. EWGs are eligible for the federal PTC.

1.3 Utility Interconnection Requirements and Approvals

Customer on-site generation may be sized to meet some of the plant needs while continuing to purchase remaining plant requirements (such as during peak electricity demand) from the local utility under standard tariffs, meeting all of the plant needs and selling excess power (produced by the DG when its electricity usage is less than its peak usage) off-site, or meeting all of the plant needs and continuously generating excess electricity to the grid, even during peak plant demand. Unless electricity is to be sold off-site to a wholesale entity other than the local utility, connections to the local electrical distribution system are under the rules set by the local utility. If generating facilities at ethanol plants are sized to be under the state standard, approval will be under local utility requirements conforming to state DG standards.

Regulations regarding connecting DG facilities to a utility system vary by generator size and interconnection voltage. Details within the regulations include relaying standards, circuit breaker ratings, switch ratings, approved devices, etc. Utilities cannot make interconnection requirements more stringent than the new uniform state and federal regulations without an approved reason.

1.3.1 Applicable Utility Tariffs

When a DGs electricity is utilized on-site, and the DG remains connected to the utility, provisions related to standby, backup, and maintenance power apply. The price for each of these services is stated in the utility tariffs. The applicable Northern States Power (Xcel Energy, Minnesota) and Wisconsin Power & Light (Alliant Energy, Wisconsin) rates for these services, as well as pricing for the energy and capacity purchased from the customer-owned generation are discussed below.

Standby power costs are almost always a major cost component for an industrial user, and are currently priced at $2 (WP&L) to $3 (NSP) per kW-month. Backup generators at a customer's site may reduce or eliminate standby power costs, in addition to avoiding brownouts or blackouts, and allowing the industrial user to consider the use of interruptible rates from the utility. However, backup generators entail costs and environmental complications, which must be balanced against their advantages.

Buyback rates for energy sold to the grid vary by utility. The current NSP pricing for DG is $0.03/kWh to $0.125/kWh, depending on time of day and season, plus capacity credits that change annually depending on NSP's cost of capital and the value of the capacity on the NSP system. The current WP&L pricing for DG is $.06/kWh on-peak and $0.025/kWh off-peak. Additional credits may be available from the utility for the supply of energy from renewable fuels.

1.3.2 Metering, Insurance, Applications, etc.

DG regulations also state metering requirements, minimum insurance requirements, application procedures and costs, approval procedures and costs, timelines, contract formats and many other details associated with DG installations. These requirements should be reviewed and taken into account in evaluating the advisability of installing a DG facility.

In Wisconsin, DGs larger than 20 kW must have a minimum commercial liability insurance coverage starting at $1 million per occurrence. Similar insurance requirements are in effect in Minnesota for units larger than 100 kW.

1.3.3 Interconnection Studies

An engineering study by the host utility may be required for DGs that plan to produce electricity for sale onto the local electric distribution and transmission network ("grid"). The studies can vary in cost, depending on the amount of DG capacity sold to the utility. The study will determine what additional electric infrastructure is required by the utility to accommodate the output of the DG facility, including any upgrades to existing equipment. If the amount of capacity sold does not exceed the expected load of the local substation that is feeding the plant, then the DG may be considered as not affecting the transmission system, and the interconnection procedures of the local utility apply. For DG capacity sold that is greater than the load of the local substation, the procedures of the Midwest Independent System Operator (MISO) and Regional Transmission Operator (RTO) apply.

1.3.4 Generating Unit Accreditation

Capacity accreditation by the Mid-Continent Area Power Pool (MAPP), the organization responsible for ensuring adequate regional electric system reliability, or its successor organization, the Midwest Reliability Organization, may be a means of reducing utility standby charges and/or receiving capacity credits for customer-owned generation. Capacity credits are utilized by the local utility to help meet its total capacity requirements, typically equal to peak load plus 15 percent reserve. The MAPP Generation Reserve Sharing Handbook describes the accreditation process (found at www.mapp.org/assets/pdf/GRSP_Handbook_20050311.pdf). Variable capacity unit accreditation is applicable to combined heat and power units for which the amount of power available to the grid may vary and is not dispatchable by the local utility.

1.4 Regulations Summary

Table EPE 1 below provides a summary of the regulations pertaining to the generation of electricity from biomass fuels.

Table EPE 1
Summary of Regulations Pertaining to Renewable Energy Electric Generation

REGULATION	DESCRIPTION
Federal Production Tax Credit	Payment in the form of a tax credit per kWh produced and sold to the grid.
Renewable Energy Credits	Where market exists, payment by marketers for green energy sales to end-users
PURPA	Gives standards for regulation of cogeneration facilities, which states may adopt.
State Distributed Generation Rules	Define interconnection requirements by the size of the generating unit. Address insurance, application, and approval issues.
Federal Distributed Generation Rules	Provide for uniform regulations from which states cannot be more stringent.
Utility Tariffs	Rate schedules

Table EPE 1 (continued)
Summary of Regulations Pertaining to Renewable Energy Electric Generation

REGULATION	DESCRIPTION
Standby capacity service	Fee for contracted amount of reserve backup capacity.
Supplemental energy	Standby, maintenance, or supplemental energy are usually supplied under the normal tariff for which the customer qualifies.
Buyback rates	Payment by a utility to a DG for energy sold to that utility. May be at utility avoided cost (NSP) with premium for renewable energy or at a flat rate (WP&L).
Interconnection requirement	Addresses voltage, relaying, frequency, devices, metering, monitoring, control of generation, and other technical issues.
Interconnection study	Electrical engineering study of the effect of supplying additional capacity onto the local electric distribution and transmission network.
Generating unit accreditation	Recognition of capacity benefit of generation units to the regional electric system network. May help to reduce standby capacity charges.

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

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

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

Project Leaders

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

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RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 14, “Technology Options and Integration with Dry-Grind Ethanol Plants”

Introduction

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

Objectives

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

Methods

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

Biomass Property Data

A typical dry-grind corn ethanol plant produces distiller’s dried grains with solubles (DDGS) as a co-product. DDGS is a mixture of two process streams called distiller’s wet grains (DWG) and concentrated distiller’s solubles (also known as “syrup”). The DWG and syrup are mixed and dried together to become DDGS. Property data for these process streams and corn stover was needed in order to build an accurate model. Morey et al. (2006a) provides an analysis of the fuel properties of these streams based on data taken from five dry-grind ethanol plants, as well as a fuel characterization of corn stover. Table 1 provides a summary of some of the important biomass property data.

Table 1. Selected biomass property data.[1]

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

1. Morey et al. (2006a)

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

Emissions Estimates

We worked with RMT, Inc., an engineering consulting firm, to generate predictive emissions estimates from the various thermal conversion technologies and fuel combinations. Computational fluid dynamics modeling was performed for several scenarios with the results focusing mainly on emissions of oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and chlorine (HCl). An equilibrium model (minimization of the Gibbs function) is used to simulate the combustion reaction in Aspen Plus. The computational fluid dynamics emissions estimates were used to adjust the emissions output of the Aspen Plus models.

Definition of Technology Combinations

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

Thermal conversion

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

Drying and Thermal Oxidation

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

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

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

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

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

Emissions Control

The emissions estimates and technology specifications were made using data from the literature on emissions control technology and suggestions from the partner engineering firms. Combustion modeling results from RMT and our own calculations indicated that for the chosen system sizes most cases would need to be classified as a major source due to the emissions of NO_x and/or SO_x (EPA, 2006). The approach used was to benchmark existing solid fuel consuming facilities in terms of the “Best Available Control Technology” (BACT) determinations in their air quality permits. This information along with emissions modeling was use to develop emissions control equipment specifications for each case. Details of the emissions modeling are found in De Kam (2008).

Emissions of NO_x were controlled using selective non-catalytic reduction (SNCR). Selective catalytic reduction (SCR) can achieve higher destruction efficiencies, but it has a higher capital cost and requires the flue gas to exit the boiler at fairly high temperatures (the modeling assumed a minimum SCR temperature of 302 ^{o}C (575 ^{o}F) so it was not considered. For combustion systems with SNCR, ammonia is injected into the flue gases to achieve NO_x reduction. In the case of gasification, ammonia produced during gasification can assist with NO_x reduction if the producer gas is burned in a carefully designed staged combustion reactor. Additional ammonia is injected in the combustion flue gas (SNCR) to further reduce NO_x.

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

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

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

Steam Cycle and Electricity Production

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

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

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

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

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

Results

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

Corn Stover Combustion

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

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

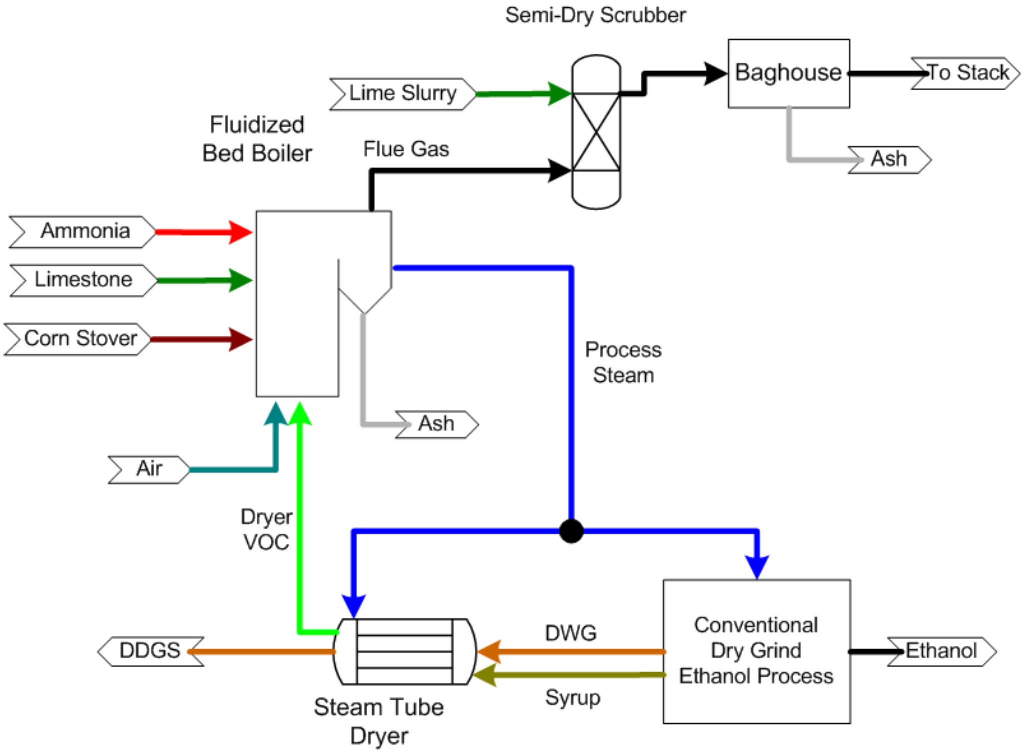

Figure 1. Corn stover combustion, level 1: process heat only.

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

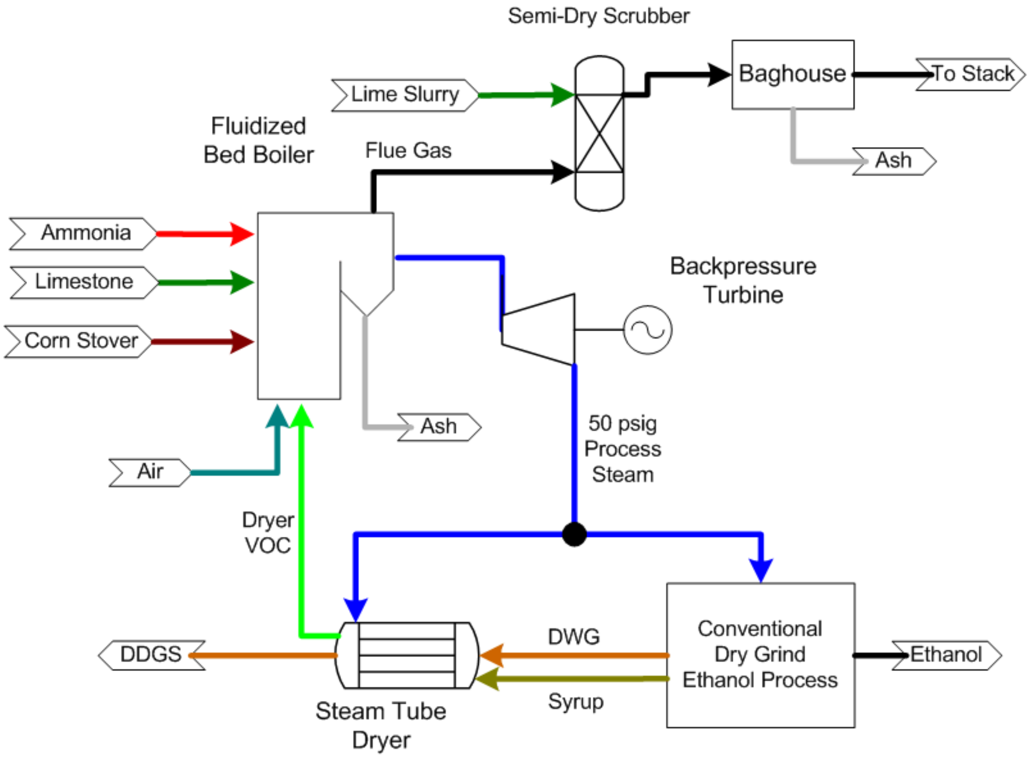

Figure 2. Corn stover combustion, level 2: CHP.

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

Syrup and Corn Stover Combustion

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

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

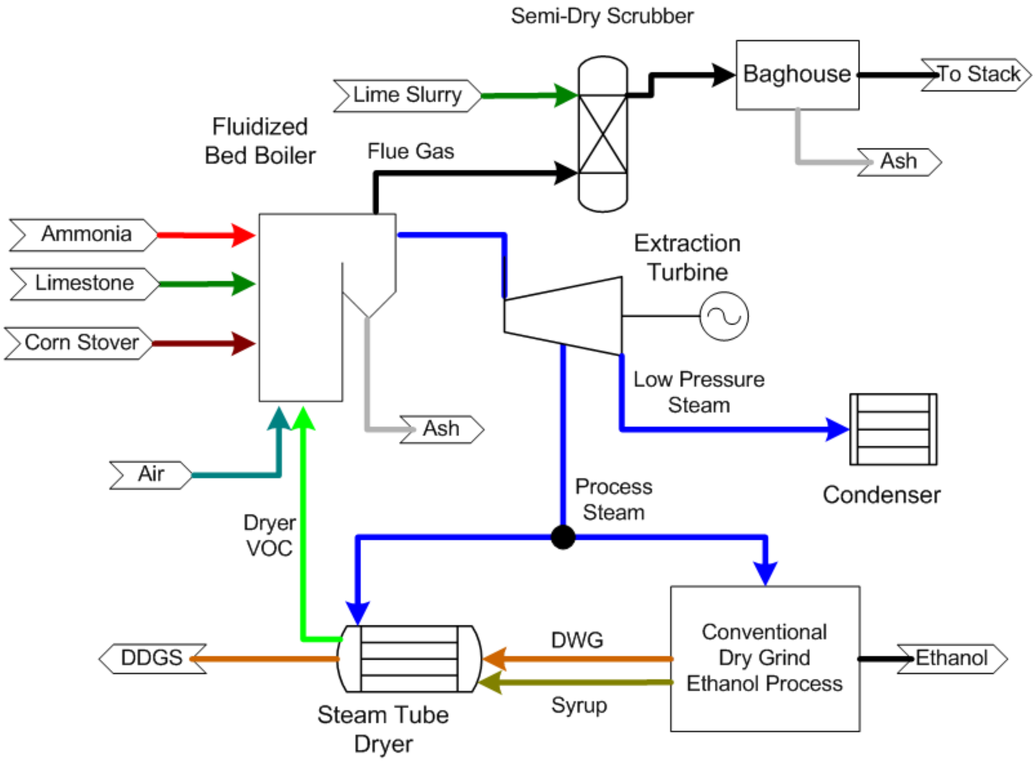

Figure 3. Corn stover combustion, level 3: CHP and electricity to the grid.

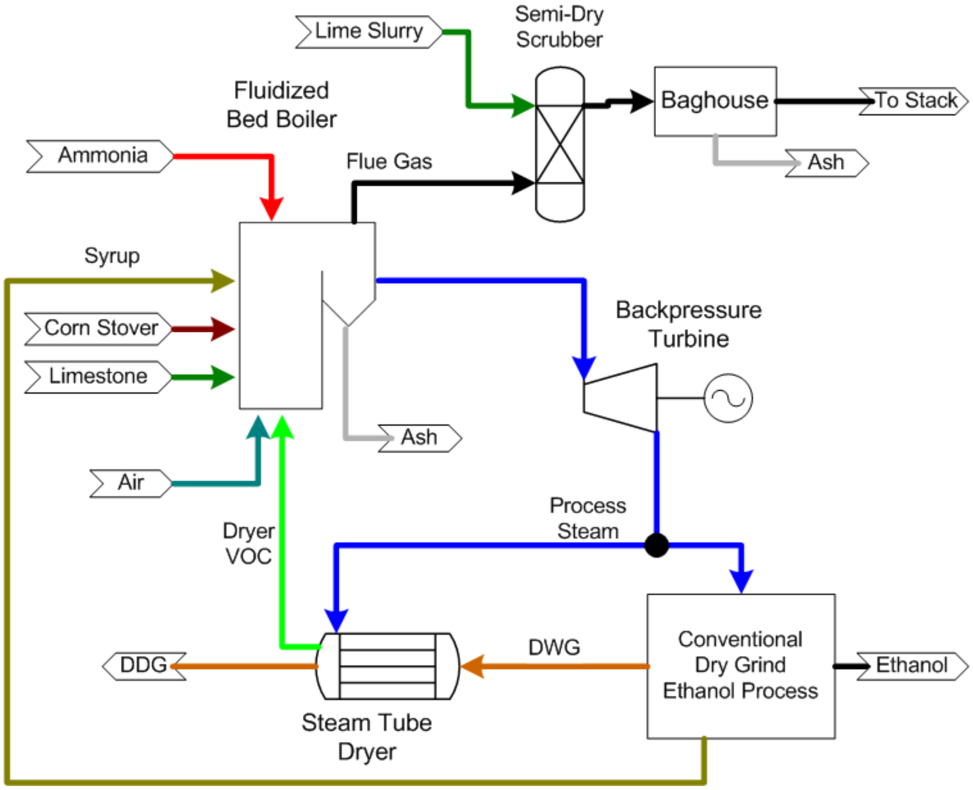

Figure 4. Syrup and corn stover combustion, level 2: CHP.

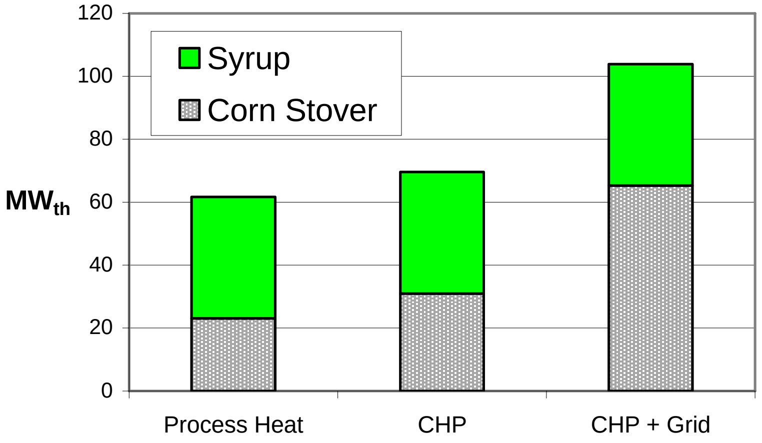

Figure 5. Syrup and corn stover combustion: fuel energy input rate contribution (HHV).

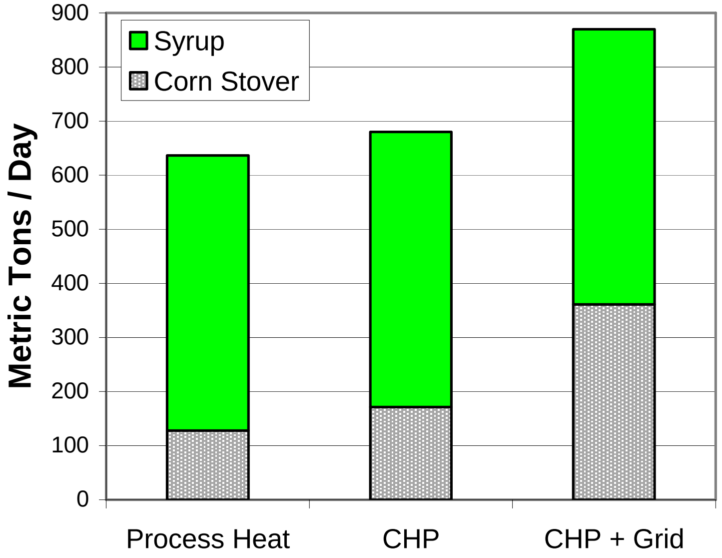

Figure 6. Syrup and corn stover combustion: fuel use.

DDGS Gasification

The last option analyzed was the gasification of DDGS (see Figure 7). The system chosen uses an air-blown fluidized bed gasifier to convert the DDGS into producer gas. Particulates are removed from the gas stream in high-temperature cyclones. The producer gas is not allowed to cool significantly in order to avoid condensation of tars. A staged combustion reactor is used to combust the producer gas. Ambient air and exhaust from the DDGS dryer are added at separate stages. This combustion reactor acts as a thermal oxidizer for the dryer exhaust stream and eliminates that capital expense. Immediately following the combustor is a heat recovery steam generator (HRSG) where steam is produced for the ethanol process, co-product drying, and electricity production depending on the specific case. The flue gas exiting the HRSG enters an SNCR unit where NO_x emissions are reduced. Limestone is added in the fluidized bed gasifier and the flue gas passes through a semi-dry scrubber to control SO_x and HCl.

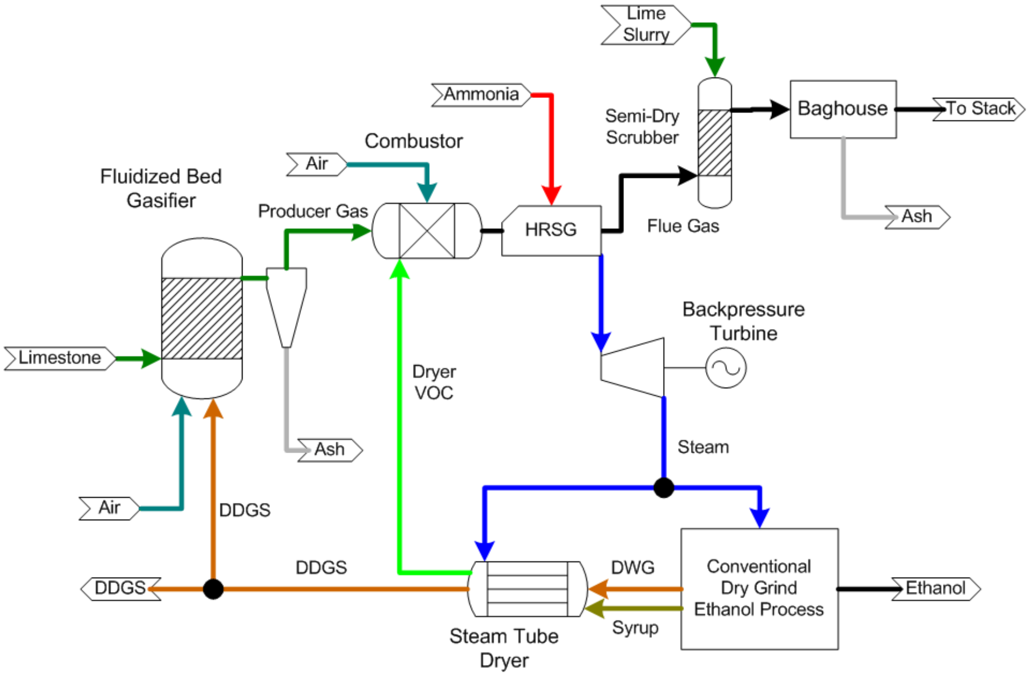

Figure 7. DDGS gasification, level 2: CHP.

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

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

System Performance Comparison

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

Table 2. System performance results for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.[1]

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

[1] All energy and power values in this table are based on the fuel Higher Heating Value (HHV).

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

[3] Negative values refer to power purchased from the grid by the ethanol facility.

[4] Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity).

Stack emissions results with control technologies in place for NO_x, SO_x, and HCl are presented in Tables 3, 4, and 5 respectively. None of the cases emit a pollutant at a rate above the current regulatory threshold of 227 metric tons (250 tons) per year which would put them in the major source category. However, if plant capacities were expanded to 380 million liters (100 million gallons) per year, a number of the cases would exceed the major source regulatory threshold for NO_x and/or SO_x.

The relatively high nitrogen content of DDGS contributes to potentially high NO_x emissions in the gasification cases; however, the control technologies that are modeled suggest that it is possible to significantly reduce these emissions. The sulfur content of syrup and DDGS contribute to potentially high SO_X emissions that require significant control technologies to achieve suitable reductions.

Table 3. Emissions of NO_x after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.[1]

	NO_x Emissions Reduction Efficiency[2]	**NO_x Emissions Rate[3]**		**NO_x Annual Emissions**	
		g/MJ	**(lb/MMBtu)**	**t/yr**	**(tn/yr)**
Corn Stover Combustion					
Level 1: Process Heat Only	40%	0.05	(0.11)	86	(106)
Level 2: CHP	47%	0.05	(0.12)	128	(142)
Level 3: CHP & Elec. to Grid	53%	0.05	(0.12)	263	(179)
Syrup & Corn Stover Combustion					
Level 1: Process Heat Only	60%	0.06	(0.13)	113	(124)
Level 2: CHP	61%	0.05	(0.13)	127	(140)
Level 3: CHP & Elec. to Grid	62%	0.05	(0.12)	163	(179)
DDGS Gasification					
Level 1: Process Heat Only	48%	0.06	(0.14)	131	(144)
Level 2: CHP	61%	0.07	(0.16)	181	(199)
Level 3: CHP & Elec. to Grid	70%	0.07	(0.15)	214	(236)

[1] All NO_x emissions are calculated as NO_2.

[2] Emissions controls include selective non-catalytic reduction (SNCR) in all cases plus staged combustion for DDGS gasification.

[3] Values are based on the fuel Higher Heating Value (HHV).

Table 4. Emissions of SO_x after control technology for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.[1]

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

[1] All SO_x emissions are calculated as SO_2.

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

[3] Values are based on the fuel Higher Heating Value (HHV).

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

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

[1] All chlorine emissions are calculated as HCl.

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

[3] Values are based on the fuel Higher Heating Value (HHV).

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

(Energy in Ethanol + Co-product Energy + Electricity to Grid Energy) / (Fossil Energy Input)

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

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

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

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

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

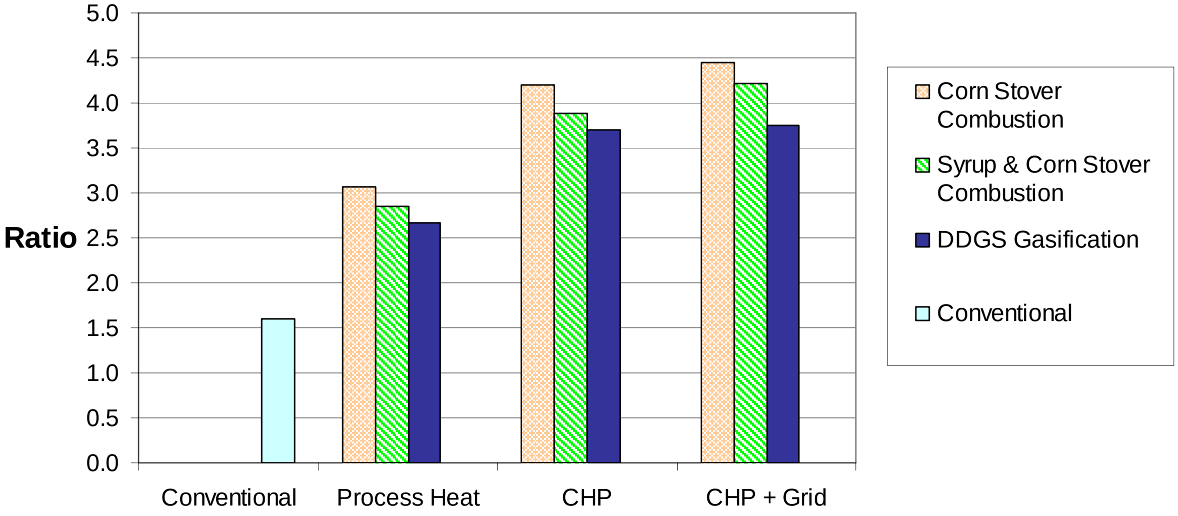

Figure 8. Renewable energy ratio (LHV).

Conclusion

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

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

Acknowledgements

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Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 15 – Spreadsheet Architecture

This chapter describes development of the architecture of the spreadsheet used to conduct the economic analysis of Chapter/Task 16. It was primarily prepared by project participants at the University of Minnesota.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 15, “Spreadsheet Architecture”

Overall Analysis Needs of the Project

This project required a means of evaluating the economic feasibility of using biomass fuels with appropriate technologies to produce process heat and power at fuel ethanol plants. In addition to a conventional plant using natural gas and purchased electricity, we evaluated nine configurations of fuel and equipment for all levels of analysis. In addition we investigated two other biomass options that utilized syrup supplemented by natural gas. To make economic comparisons of the numerous technology-fuel choices and keep track of our operating assumptions, electronic workbooks consisting of numerous spreadsheets were developed. Aspen Plus modeling was conducted to determine the likely methods of combustion as well as the necessary capacities of equipment and operating expenses to utilize biomass at different levels of intensity. A key consideration was that of determining if a biomass system could comply with prevailing standards of emissions and sustain associated expenses.

In order to compare the economics of plants using by-products such as DDGS, syrup, and corn stover as fuels versus conventional, natural gas powered plants, spreadsheets of unique annual operating statements or proformas were designed and organized into workbooks. Starting from spreadsheets designed to analyze the profitability of dry-grind plants using natural gas, a template was prepared to capture the unique elements of systems using biomass fuels. This approach allowed fair comparisons in terms of returns on investment of combinations of technologies and biomass fuels to power the plants and reflect various options including the use of biomass at the following levels of intensity:

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

Another requirement for the spreadsheets’ design was to have the ability to change various cost categories to represent the various biomass fuels and technologies to utilize them. Using a workbook, a menu page was created to establish key assumptions at baseline conditions and then allow one or more of these to be changed in an effort to understand the sensitivity of the system. The assumptions of the menu page are thus available to be applied by the individual spreadsheets represent specific technology bundles.

Details on Individual Spreadsheets for Specific Technology Bundles

Capital Costs

Depending upon the fuel and combustion system chosen, ASPEN Plus Software was used to determine equipment specifications in order to determine appropriate capital costs. With biomass fuels there are likely to be additional capital costs for the following:

1) feed mechanisms for the biomass
2) the combustion unit, itself
3) emissions control equipment

4) ash handling costs

Fuel and Electricity Costs

In ethanol plant economics one key factor of success is the cost of biomass fuel, itself. We analyzed the total cost of using various biomass fuels. In some cases that included the need to purchase the biomass from others, while in the cases of syrup and DDGS, the biomass fuel was produced concurrently with ethanol production at the plant. In cases using DDGS or syrup as fuel, the plant has less DDGS to sell. An ethanol plant combusting syrup also reduces 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 useful groundcover. As discussed in the economics paper, the corn stover price presumes that densified material is delivered to the plant.

When electricity is produced at the ethanol plant such as the case of combined heat and power (CHP) and CHP plus sales to the grid, no purchases of electricity are made. When electric power is produced beyond the requirements of the plant, they become a revenue source for the plant.

Operating Costs Associated with Combustion Technology Used

Details of operating expense are contained on the individual spreadsheets representing specific technology bundles. Among these expenses are the following:

1) maintenance and repairs (based on published sources and capital costs)
2) labor (based on published sources)
3) management (assumed at 1/3 of labor expenses)
4) ground limestone and quicklime (based on Aspen Plus modeling for sulfur capture
5) anhydrous ammonia (based on Aspen Plus)
6) ash derived from biomass was determined to have a value as a fertilizer consisting of (0-18-28) analysis of N-P-K. This revenue source was assumed to have a value of $200 per ton, based on the experience of Corn Plus, Winnebago, MN.

Spreadsheet for Dry-Grind Plant Using Natural Gas

On the following page one can see the spreadsheet 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 different ethanol prices, DDGS prices, CO2 prices on annual revenues for the plant. The spreadsheet allows one to calculate **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 kilowatt-ours 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.

At the right of row 10 is the calculated rate of return on invested capital of 13.05%, which is the annual income divided by the capital cost.($14,686,250/$112,500,000).

Although representing the comparison case of the typical conventional ethanol plant buying natural gas and electricity, categories of additional revenue sources and credits as well as expense items have been established that apply only to the biomass cases.

1	**Base Case; Natural Gas & Electricity**				**Copyright: Douglas Tiffany**			
2	**Purchased NG & Elect.**	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**		**50MM Gal**	**1/10/2008**		**Plant Totals**
3	**Nameplate Ethanol Prod. (Denat. Gal.)**	**50,000,000**						
4	**Investment per Nameplate Gallon**	**$2.25**				**Plant Cost**	**$**	**112,500,000**
5	**Factor of Nameplate Capacity**	**1.20**	(80%- 150%)					
6	**Debt-Equity Assumptions**							
7	Factor of Equity	**0.40**						
8	Factor of Debt	**0.60**				**Initial Debt**	**$**	**67,500,000**
9	Interest Rate Charged on Debt	**0.08**				Payback of Addl Invest.		(Not Applicable)
10	Rate of Return Reqd. by Investors on Equity	**0.12**				**Rate of Return**		**13.05%**
12	**Conversion Efficiency Assumptions**				**Annual Production**			
13	Anhydrous Ethanol Extracted (Gal. per Bu.)	**2.750**	2.5-2.9 gal/bu		**Bushels Ground**	**Denat. Gallons**		**Tons of DDGS Sold**
14	DDGS per Bushel (lb. per Bu.)	**18.152**	15-19 lb./bu		**21,398,601**	**60,000,000**		**194,214**
15	CO2 extracted per Bushel (lb. per Bu.)	**18**	15-19lb./bu					
17	**Establishment of Gross Margin**	**Price per Unit**			**Revenue/Bu. Ground**	**Revenue/Gal. Denatured Sold**		**Plant Totals**
18	Ethanol Price (denatured price) $/gal.	**$2.30**	$.80 to $2.50		$6.4490	$2.3000	$	138,000,000
19	DDGS Price $/T	**$145.00**	$55-$130		$1.3160	$0.4693	$	28,160,987
20	CO2 Price ($ per Ton liq. CO2)	**$8.00**	$2- $12 / liq.Ton		$0.0720	$0.0257	$	1,540,699
21	Electricity Price Sold @		KWH per gallon	0				
22	Ash Sold @ $ per Ton		Tons	0				
23	Federal Small Producer Credit	**$0.10**			$0.0701	$0.0250	$	1,500,000
24	RFS Ethanol Tradable Credit	**$0.07**			$0.1925	$0.0687	$	4,119,231
25	Federal Renewable Electric Credit							
26	Prem for Low-Carbon Imprint for Ethanol				$0.0000	$0.0000	$	-
27	**Revenue per Unit**				**$8.0996**	**$2.8887**	**$**	**173,320,917.48**
29	Corn Price Paid by Processor ($ per bu.)	**$5.00**	$1.60---$3.25		$5.0000	$1.7832	$	106,993,006.99
30	**Gross Margin**				**$3.0996**	**$1.1055**	**$**	**66,327,910.49**
32	**Operating Expenses Per Bushel**	**Price per Unit**			**Cost /Bushel Ground**	**Cost /Gal. Denatured Sold**		**Plant Totals**
33	Natural Gas Price ($ 1,000,000 Btu)	**$10.00**	($3-$15/Dtherm)		$0.9343	$0.3332	$	19,992,000
34	LP (Propane) Price ($ per gallon)	**$1.50**	$.80- $2.00/gal.		$0.0312	$0.0017	$	668,122
35	Factor of Time Operating on Propane	**0.02**	0-.12					
36	Stover Price @	**0.00**	Stover Tons					
37	Syrup Price @	**0.00**	Syrup Tons					
38	DDGS Used @ $ per Ton	**0.00**	DDGS Tons	0				
39	BTU's of Heat fr Fuel Req./ Denat. Gal.	**34,000**	28,500-55,000					
40	Combined Heating Cost				$0.9655	$0.3443	$	20,660,122
41	Electricity Price ($ per kWh)	**$0.06**	$.025-$.090/kWh					
42	Kilowatt Hours Required per Denat.Gal.	**0.75**	.70 -1.25 kWh/denat. gal.					
43	Electrical Cost				$0.1262	$0.0450	$	2,700,000
44	Total BTU's of Fuel and Electricity	**41,500**						
45	**Total Energy Cost**				**$1.0917**	**$0.3893**	**$**	**23,360,122**
47		**Cost/Denat. Gal. Ethanol**						
48	Enzymes	**$0.0400**			$0.1122	$0.0400	$	2,400,000
49	Yeasts	**$0.0040**			$0.0112	$0.0040	$	240,000
50	Other Proc.Chemicals & Antibiotics	**$0.0200**			$0.0561	$0.0200	$	1,200,000
51	Boiler & Cooling Tower Chemicals	**$0.0050**			$0.0140	$0.0050	$	300,000
52	Water	**$0.0030**	$.005-.010		$0.0084	$0.0030	$	180,000
53	Denaturant Price per Gal.	**$3.0000**	Denat/100 gal An	**2**	$0.1618	$0.0577	$	3,461,538
54	Ammonia Price per Ton for NOx Control @		Tons Required					
55	Limestone Price per Ton for Sulfur Capture @		Tons Required					
56	Quicklime Price per Ton for Scrubber							
57	**Total Chemical Cost**				**$0.3636**	**$0.1297**	**$**	**7,781,538**
59	Depreciation based on C49 asset life	**15**	Years		$0.3505	$0.1250	$	7,500,000
60	Maintenance & Repairs	**$0.0400**			$0.1122	$0.0400	$	2,400,000
61	Interest Expense				$0.2524	$0.0900	$	5,400,000
62	Labor	**$0.0500**	$.04--$.06		$0.1402	$0.0500	$	3,000,000
63	Management & Quality Control	**$0.0167**	$.010-$.022		$0.0467	$0.0167	$	1,000,000
64	Real Estate Taxes	**$0.0020**			$0.0056	$0.0020	$	120,000
65	Licenses, Fees& Insurance, Waste Mgmt.	**$0.0140**	.0030-.0050		$0.0393	$0.0140	$	840,000
66	Other Expenses	**$0.0040**	$.01-$.03		$0.0112	$0.0040	$	240,000
67	**Total of Other Processing Costs**				**$0.9580** #	**$0.3417**	**$**	**20,500,000**
68	**Total Processing Costs**				**$2.4133**	**$0.8607**	**$**	**51,641,661**
69	**Net Margin Achieved Per Unit**				**$0.6863**	**$0.2448**	**$**	**14,686,250**
70	**Investor Reqd. Return on Equity**	**12.00%**			**$0.2524**	**$0.0900**	$	5,400,000
71	**Increment of Success/Failure to Meet Required Return**				**$0.4340**	**$0.1548**	**$**	**9,286,250**
73	**Ethanol Plant Profits for Shareholders and Principal Reduction**			**50MM Gal**	**$14,686,250**	**$14,686,250**	**$**	**14,686,250**

Spreadsheets for Technology Bundles Using Biomass

Individual spreadsheets for ethanol plants using biomass to provide process heat and electricity are shown on pages **6,7, and 8.** They represent biomass usage for process heat with corn stover, CHP with syrup and corn stover, and CHP + grid sales for DDGS, respectively. The individual spreadsheets of the biomass cases are similar to the spreadsheet for the conventional plant shown on the previous page, but more details are represented. For example, many have revenues for sale of electricity, federal credits for renewable electricity, sales of ash, and premiums for the sale of ethanol having a lower carbon footprint. The specific lines for these revenue sources are the following:

1) electricity sold---**line 21** has price and kWh of electricity sold per gallon of ethanol
2) ash sold—**line 22** has the price per ton of ash assumed as well as the amount of ash per per year.
3) CHP and CHP + grid cases (2 and 3)---**line 25** has the federal renewable electric credit
4) DDGS price for in the case of syrup + stover cases---**line 19** assumes that a 10% higher price is received per ton of DDG than traditional DDGS.

With respect to expenses, the biomass technology bundles have the following lines populated with data applied to calculate their economics:

1) **Line 36** contains the price and amount of corn stover required.
2) **Line 42** contains the amount of electricity required per gallon of ethanol produced.
3) **Line 54** contains the price and tons of anhydrous ammonia required.
4) **Line 55** contains the price and tons of limestone required.
5) **Line 56** contains the price and tons of quicklime required

Menu Page

The menu page contains both assumptions applied to all the individual spreadsheets as well as the results of the analysis in both graphical and numerical forms.

The menu page in each workbook (with an example for a 50 million gallon per year plant shown on page 9) offers the opportunity to feed assumptions to all spreadsheets in the workbook for ethanol plants of that particular size. The menu page offers current assumptions in active cells that are shaded either pink or yellow to the individual spreadsheets. A blue line is drawn across the top of each bar of the histogram to designate the rates of return on investment at baseline conditions so that the effects of subsequent changes to one or more variables can be seen, graphically.

1	**Fluidized Bed Combustion; Indirect Steam Drier; Level**					**1**	**Copyright: Douglas Tiffany**	
2	**Corn Stover**	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**			**50MM Gal**	**1/10/2008**	**Plant Totals**
3	**Nameplate Ethanol Prod. (Denat. Gal.)**	**50,000,000**						
4	**Investment per Nameplate Gallon**	**$ 3.04**					**Plant Cost**	**$ 151,819,000**
5	**Factor of Nameplate Capacity**	**1.06**	(80%- 150%)					
6	**Debt-Equity Assumptions**							
7	Factor of Equity	**0.40**						
8	Factor of Debt	**0.60**					**Initial Debt**	**$ 91,091,400**
9	Interest Rate Charged on Debt	**0.08**					**Payback of Addl Inves**	**4.8**
10	Rate of Return Reqd. by Investors on Equity	**0.12**					**Rate of Return**	**15.04%**
12	**Conversion Efficiency Assumptions**					**Annual Production**		**Tons of**
13	Anhydrous Ethanol Extracted (Gal. per Bu.)	**2.750**	2.5-2.9 gal/bu			**Bushels Ground**	**Denat. Gallons**	**DDGS Sold**
14	DDGS per Bushel (lb. per Bu.)	**18.152**	15-19 lb./bu			**18,902,098**	**53,000,000**	**171,555.44**
15	CO2 extracted per Bushel (lb. per Bu.)	**18**	15-19lb./bu					
17	**Establishment of Gross Margin**	**Price per Unit**				**Revenue/Bu. Ground**	**Revenue/Gal. Denatured Sold**	**Plant Totals**
18	Ethanol Price (denatured price) $/gal.	**$2.30**	$.80 to $2.50			$6.4490	$2.3000	$ 121,900,000
19	DDGS Price $/T	**$145.00**	$55-$130			$1.3160	$0.4693	$ 24,875,539
20	CO2 Price ($ per Ton liq. CO2)	**$8.00**	$2- $12 / liq.Ton			$0.0720	$0.0257	$ 1,360,951
21	Electricity Price Sold @	**$0.10**	KWH per gallon	**0.000**		$ -	$ -	$ -
22	Ash sold @ per Ton	**$200.00**	Tons	8046	**8,529**	$ 0.0902	$ 0.0322	$ 1,705,752
23	Federal Small Producer Credit	**$0.10**				$0.0794	$0.0283	$ 1,500,000
24	RFS Ethanol Tradable Credit	**$0.07**				$0.1925	$0.0687	$ 3,638,654
25	Federal Renewable Electric Credit							
26	Prem for Low-Carbon Imprint for Ethanol	**$0.18**				$0.4950	$0.1765	$ 9,356,538
27	**Revenue per Unit**					**$8.6941**	**$3.1007**	**$ 164,337,434**
28								
29	Corn Price Paid by Processor ($ per bu.)	**$5.00**	$1.60---$7.00			$5.0000	$1.7832	$ 94,510,490
30	**Gross Margin**					**$3.6941**	**$1.3175**	**$ 69,826,945**
32	**Operating Expenses Per Bushel**	**Price per Unit**				**Cost /Bushel Ground**	**Cost /Gal. Denatured Sold**	**Plant Totals**
33	Natural Gas Price ($ 1,000,000 Btu)	**$10.00**	($3-$15/Dtherm)					
34	LP (Propane) Price ($ per gallon)	**$1.50**	$.80- $2.00/gal.					
35	Factor of Time Operating on Propane	**0.00**	0-.12			$0.0000	$0.0000	$ -
36	Stover Price @ $ per Ton	**$ 80.00**	Stover Tons	**128,947**	**136,684**	$ 0.5785	$ 0.2063	$ 10,934,706
37	Syrup Used @ $ per Ton	**0.00**	Syrup Tons		**-**			
38	DDGS Used @ $ per Ton	**0.00**	DDGS Tons		**-**			
39	BTU's of Heat fr Fuel Required	**37,000**	28,500-55,000					
40	Combined Heating Cost					$0.5785	$0.2063	10,934,706
41	Electricity Price ($ per kWh)	**$0.06**	$.025-$.090/kWh					
42	Kilowatt Hours Purchased per Denat.Gal.	**0.943**	.70 -1.25 kWh/denat. gal.					
43	Electrical Cost					$0.1586	$0.0566	`
44	Total BTU's of Fuel and Electricity	**46,430**						
45	**Total Energy Cost**					**$0.7371**	**$0.2629**	**$ 13,933,446**
47		**Cost/Denat. Gal. Ethanol**						
48	Enzymes	**$0.0400**				$0.1122	$0.0400	$ 2,120,000
49	Yeasts	**$0.0040**				$0.0112	$0.0040	$ 212,000
50	Other Proc.Chemicals & Antibiotics	**$0.0200**				$0.0561	$0.0200	$ 1,060,000
51	Boiler & Cooling Tower Chemicals	**$0.0050**				$0.0140	$0.0050	$ 265,000
52	Water	**$0.0030**	$.005-.010			$0.0084	$0.0030	$ 159,000
53	Denaturant Price per Gal.	**$3.0000**	Denat/100 gal Anhyd.		**2**	$0.1618	$0.0577	$ 3,057,692
54	Ammonia Price per Ton for NOx Control @	**$ 700.00**	Tons Required	**105.00**	**111**	$0.0041	$0.0015	$ 77,910
55	Limestone Price per Ton for Sulfur Capture @	**$ 25.00**	Tons Required	**420.00**	**445**	$0.0006	$0.0002	$ 11,130
56	Quicklime Price per Ton for Scrubber	**$ 77.13**	Tons Required	**78.00**	**83**	$0.0003	$0.0001	$ 6,377
57	**Total Chemical Cost**					**$0.3687**	**$0.1315**	**$ 6,969,109**
59	Depreciation based on C49 asset life	**15**	Years			$0.5355	$0.1910	$ 10,121,267
60	Maintenance & Repairs	**$0.0611**	per $ Plant Cost			$ 0.1713	$ 0.0611	$ 3,238,805
61	Interest Expense					$0.3855	$0.1375	$ 7,287,312
62	Labor	**$0.0601**	per $ Plant Cost			$ 0.1684	$ 0.0601	$ 3,184,000
63	Management & Quality Control	**$0.0200**	$.010-$.022			$ 0.0561	$ 0.0200	$ 1,061,333
64	Real Estate Taxes	**$0.0023**	per $ Plant Cost			$ 0.0063	$ 0.0023	$ 120,000
65	Licenses, Fees& Insurance, Waste Mgmt.	**$0.0158**	.0030-.0050			$ 0.0444	$ 0.0158	$ 840,000
66	Miscellaneous Expenses	**$0.0045**	$.01-$.03			$ 0.0127	$ 0.0045	$ 240,000
67	**Total of Other Processing Costs**					**$1.3804**	**$0.4923**	**$ 26,092,717**
68	**Total Processing Costs**					**$2.4862**	**$0.8867**	**$ 46,995,272**
69	**Net Margin Achieved Per Unit**					**$1.2079**	**$0.4308**	**$ 22,831,673**

1	**Fluidized Bed Combustion; Indirect Steam Drier; Level**					2	Copyright: Douglas Tiffany	
2	**Stover and Syrup**	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**			**50MM Gal**	**1/10/2008**	**Plant Totals**
3	**Nameplate Ethanol Prod. (Denat. Gal.)**	50,000,000						
4	**Investment per Nameplate Gallon**	$ 3.15					**Plant Cost**	**$ 157,535,000**
5	**Factor of Nameplate Capacity**	1.06	(80%- 150%)					
6	**Debt-Equity Assumptions**							
7	Factor of Equity	0.40						
8	Factor of Debt	0.60					**Initial Debt**	**$ 94,521,000**
9	Interest Rate Charged on Debt	0.08					Payback of Addl Inv	3.6
10	Rate of Return Reqd. by Investors on Equity	0.12					**Rate of Return**	17.17%
12	**Conversion Efficiency Assumptions**	18.152	0.589614573			**Annual Production**		
						Bushels Ground	**Denat. Gallons**	**Tons of DDG Sold**
13	Anhydrous Ethanol Extracted (Gal. per Bu.)	2.750	2.5-2.9 gal/bu			18,902,098	53,000,000	101,151.59
14	DDGS per Bushel (lb. per Bu.)	10.70268374	15-19 lb./bu					
15	CO2 extracted per Bushel (lb. per Bu.)	18	15-19lb./bu					
17	**Establishment of Gross Margin**	**Price per Unit**				**Revenue/Bu. Ground**	**Revenue/Gal. Denatured Sold**	**Plant Totals**
18	Ethanol Price (denatured price) $/gal.	$2.30	$.80 to $2.50			$6.4490	$2.3000	$ 121,900,000
19	DDGS Price $/T	$159.50	$55-$130			$0.8535	$0.3044	$ 16,133,678
20	CO2 Price ($ per Ton liq. CO2)	$8.00	$2- $12 / liq.Ton			$0.0720	$0.0257	$ 1,360,951
21	Electricity Price Sold @	$0.10	KWH per gallon	1.392		$ 0.3828	$ 0.1365	$ 7,235,723
22	Ash sold @ per Ton	$200.00	Tons	13,955	14,792	$ 0.1565	$ 0.0558	$ 2,958,460
23	Federal Small Producer Credit	$0.10				$0.0794	$0.0283	$ 1,500,000
24	RFS Ethanol Tradable Credit	$0.07				$0.1925	$0.0687	$ 3,638,654
25	Federal Renewable Electric Credit							
26	Prem for Low-Carbon Imprint for Ethanol	$0.20				$0.5500	$0.1962	$ 10,396,154
27	**Revenue per Unit**					**$8.7357**	**$3.1155**	**$ 165,123,620**
29	Corn Price Paid by Processor ($ per bu.)	$5.00	$1.60---$3.25			$5.0000	$1.7832	$ 94,510,490
30	**Gross Margin**					**$3.7357**	**$1.3323**	**$ 70,613,131**
32	**Operating Expenses Per Bushel**	**Price per Unit**				**Cost /Bushel Ground**	**Cost /Gal. Denatured Sold**	**Plant Totals**
33	Natural Gas Price ($ 1,000,000 Btu)	$10.00	($3-$15/Dtherm)					
34	LP (Propane) Price ($ per gallon)	$1.50	$.80- $2.00/gal.					
35	Factor of Time Operating on Propane	0.00	0-.12			$0.0000	$0.0000	$ -
36	Stover Price @ $ per Ton	$ 80.00	Stover Tons	72,898	77,272	$ 0.3270	$ 0.1166	$ 6,181,750
37	Syrup Used @ $ per Ton		Syrup Tons	185,056	196,159			
38	DDGS Used @ $ per Ton	0.00	DDGS Tons	0				
39	BTU's of Heat fr Fuel Required	37,000	28,500-55,000					
40	Combined Heating Cost					$0.3270	$0.1166	6,181,750
41	Electricity Price ($ per kWh)	$0.06	$.025-$.090/kWh					
42	Kilowatt Hours Purchased per Denat.Gal.	0.956	.70 -1.25 kWh/denat. gal.					
43	Electrical Cost					$0.1608	$0.0574	$ 3,040,080
44	Total BTU's of Fuel and Electricity	46,560						
45	**Total Energy Cost**					**$0.4879**	**$0.1740**	**$ 9,221,830**
47		**Cost/Denat. Gal. Ethanol**						
48	Enzymes	$0.0400				$0.1122	$0.0400	$ 2,120,000
49	Yeasts	$0.0040				$0.0112	$0.0040	$ 212,000
50	Other Proc.Chemicals & Antibiotics	$0.0200				$0.0561	$0.0200	$ 1,060,000
51	Boiler & Cooling Tower Chemicals	$0.0050				$0.0140	$0.0050	$ 265,000
52	Water	$0.0030	$.005-.010			$0.0084	$0.0030	$ 159,000
53	Denaturant Price per Gal.	$3.0000	Denat/100 gal A	2		$0.1618	$0.0577	$ 3,057,692
54	Ammonia Price per Ton for NOx Control @	$ 700.00	Tons Required	216.00	228.96	$0.0085	$0.0030	$ 160,272
55	Limestone Price per Ton for Sulfur Capture @	$ 25.00	Tons Required	5739.00	6083.34	$0.0080	$0.0029	$ 152,084
56	Quicklime Price per Ton for Scrubber	$ 77.13		539.00	571.34	$0.0023	$0.0008	$ 44,067
57	**Total Chemical Cost**					**$0.3825**	**$0.1364**	**$ 7,230,115**
59	Depreciation based on C49 asset life	15	Years			$0.5556	$0.1982	$ 10,502,333
60	Maintenance & Repairs	$0.0634	per $ Plant Cost			$ 0.1778	$ 0.0634	$ 3,360,747
61	Interest Expense					$0.4000	$0.1427	$ 7,561,680
62	Labor	$0.0635	per $ Plant Cost			$ 0.1782	$ 0.0635	$ 3,368,000
63	Management & Quality Control	$0.0212	$.010-$.022			$ 0.0594	$ 0.0212	$ 1,122,667
64	Real Estate Taxes	$0.0023	per $ Plant Cost			$0.0063	$0.0023	$ 120,000
65	Licenses, Fees& Insurance	$0.0158	.0030-.0050			$0.0444	$0.0158	$ 840,000
66	Miscellaneous Expenses	$0.0045	$.01-$.03			$0.0127	$0.0045	$ 240,000
67	**Total of Other Processing Costs**					**$1.4345**	**$0.5116**	**$ 27,115,427**
68	**Total Processing Costs**					**$2.3049**	**$0.8220**	**$ 43,567,373**
69	**Net Margin Achieved Per Unit**					**$1.4308**	**$0.5103**	**$ 27,045,758**
70	**Investor Reqd. Return on Equity**	12.00%				**$0.4000**	**$0.1427**	$ 7,561,680

1	**Fluidized Bed Combustion; Indirect Steam Drier; Level**					**3**	**Copyright: Douglas Tiffany**	
2	**DDGS**	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**			**50MM Gal**	**1/10/2008**	**Plant Totals**
3	**Nameplate Ethanol Prod. (Denat. Gal.)**	**50,000,000**						
4	**Investment per Nameplate Gallon**	**$ 3.50**	$1.00- $2.00				**Plant Cost**	**$ 175,240,000**
5	**Factor of Nameplate Capacity**	**1.06**	(80%- 150%)					
6	**Debt-Equity Assumptions**							
7	Factor of Equity	**0.40**						
8	Factor of Debt	**0.60**					**Initial Debt**	**$ 105,144,000**
9	Interest Rate Charged on Debt	**0.08**					Payback of Addl Inv	**7.5**
10	Rate of Return Reqd. by Investors on Equity	**0.12**					**Rate of Return**	**13.14%**
11								
12	**Conversion Efficiency Assumptions**						**Annual Production**	
13	Anhydrous Ethanol Extracted (Gal. per Bu.)	**2.750**	2.5-2.9 gal/bu			**Bushels Ground**	**Denat. Gallons**	**Tons of DDGS Sold**
14	DDGS per Bushel (lb. per Bu.)	**18.152**	15-19 lb./bu			**18,902,098**	**53,000,000**	**0.00**
15	CO2 extracted per Bushel (lb. per Bu.)	**18**	15-19lb./bu					
16								
17	**Establishment of Gross Margin**	**Price per Unit**				**Revenue/Bu. Ground**	**Revenue/Gal. Denatured Sold**	**Plant Totals**
18	Ethanol Price (denatured price) $/gal.	**$2.30**	$.80 to $2.50			$6.4490	$2.3000	$ 121,900,000
19	DDGS Price $/T	**$145.00**	$55-$130			$0.0000	$0.0000	$ -
20	CO2 Price ($ per Ton liq. CO2)	**$8.00**	$2- $12 / liq.Ton			$0.0720	$0.0257	$ 1,360,951
21	Electricity Price Sold @	**$0.10**	KWH per gallon	**2.439**		$ 0.6707	$ 0.2392	$ 12,678,110
22	Ash sold @ per Ton	**$200.00**	Tons	**17,210**	**18,243**	$ 0.1821	$ 0.0649	$ 3,442,000
23	Federal Small Producer Credit	**$0.10**				$0.0794	$0.0283	$ 1,500,000
24	RFS Ethanol Tradable Credit	**$0.07**				$0.1925	$0.0687	$ 3,638,654
25	Federal Renewable Electric Credit	**$0.020**				$0.1341	$0.0478	$ 2,535,622
26	Prem for Low-Carbon Imprint for Ethanol	**$0.20**				$0.5500	$0.1962	$ 10,396,154
27	**Revenue per Unit**					**$8.3298**	**$2.9708**	**$ 157,451,490**
28								
29	Corn Price Paid by Processor ($ per bu.)	**$5.00**	$1.60---$3.25			$5.0000	$1.7832	$ 94,510,490
30	**Gross Margin**					**$3.3298**	**$1.1876**	**$ 62,941,001**
31								
32	**Operating Expenses Per Bushel**	**Price per Unit**				**Cost /Bushel Ground**	**Cost /Gal. Denatured Sold**	**Plant Totals**
33	Natural Gas Price ($ 1,000,000 Btu)	**$10.00**	($3-$15/Dtherm)					
34	LP (Propane) Price ($ per gallon)	**$1.50**	$.80- $2.00/gal.					
35	Factor of Time Operating on Propane	**0.00**	0-.12			$0.0000	$0.0000	$ -
36	Stover Purchased @ $ per Ton	**$ 80.00**	Stover Tons			$ -	$ -	$ -
37	Syrup Used @ $ per Ton	**0.00**	Syrup Tons					
38	DDGS Used @ $ per Ton	**0.00**	DDGS Tons	166,968	**171,555**			
39	BTU's of Heat fr Fuel Required	**37,000**	28,500-55,000					
40	Combined Heating Cost					$0.0000	$0.0000	-
41	Electricity Price ($ per kWh)	**$0.06**	$.025-$.090/kWh					
42	Kilowatt Hours Purchased per Denat.Gal.	**0.925**	.70 -1.25 kWh/denat. gal.					
43	Electrical Cost					$0.1556	$0.0555	$ 2,941,500
44	Total BTU's of Fuel and Electricity	**46,250**						
45	**Total Energy Cost**					**$0.1556**	**$0.0555**	**$ 2,941,500**
46								
47		**Cost/Denat. Gal. Ethanol**						
48	Enzymes	**$0.0400**				$0.1122	$0.0400	$ 2,120,000
49	Yeasts	**$0.0040**				$0.0112	$0.0040	$ 212,000
50	Other Proc.Chemicals & Antibiotics	**$0.0200**				$0.0561	$0.0200	$ 1,060,000
51	Boiler & Cooling Tower Chemicals	**$0.0050**				$0.0140	$0.0050	$ 265,000
52	Water	**$0.0030**	$.005-.010			$0.0084	$0.0030	$ 159,000
53	Denaturant Price per Gal.	**$3.0000**	Denat/100 gal A	**2**		$0.1618	$0.0577	$ 3,057,692
54	Ammonia Price per Ton for NOx Control @	**$ 700.00**	Tons Required	321.0	340.3	$0.0119	$0.0042	$ 224,700
55	Limestone Price per Ton for Sulfur Capture @	**$ 25.00**	Tons Required	9,005.0	9,545.3	$0.0119	$0.0042	$ 225,125
56	Quicklime Price per Ton for Scrubber	**$ 77.13**	Tons Required	1,625.0	1,722.5	$0.0066	$0.0024	$ 125,336
57	**Total Chemical Cost**					**$0.3941**	**$0.1405**	**$ 7,448,854**
58								
59	Depreciation based on C49 asset life	**15**	Years			$0.6181	$0.2204	$ 11,682,667
60	Maintenance & Repairs	**$0.0705**	per $ Plant Cost			$ 0.1978	$ 0.0705	$ 3,738,453
61	Interest Expense					$0.4450	$0.1587	$ 8,411,520
62	Labor	**$0.0635**	per $ Plant Cost			$ 0.1782	$ 0.0635	$ 3,368,000
63	Management & Quality Control	**$0.0212**	$.010-$.022			$ 0.0594	$ 0.0212	$ 1,122,667
64	Real Estate Taxes	**$0.0023**	per $ Plant Cost			$ 0.0063	$ 0.0023	$ 120,000
65	Licenses, Fees& Insurance	**$0.0158**	.0030-.0050			$0.0444	$0.0158	$ 840,000
66	Miscellaneous Expenses	**$0.0045**	$.01-$.03			$0.0127	$0.0045	$ 240,000
67	**Total of Other Processing Costs**					**$1.5619**	**$0.5570**	**$ 29,523,306**
68	**Total Processing Costs**					**$2.1116**	**$0.7531**	**$ 39,913,660**
69	**Net Margin Achieved Per Unit**					**$1.2182**	**$0.4345**	**$ 23,027,341**

Assumptions Common Across All Processes

6/2/2008

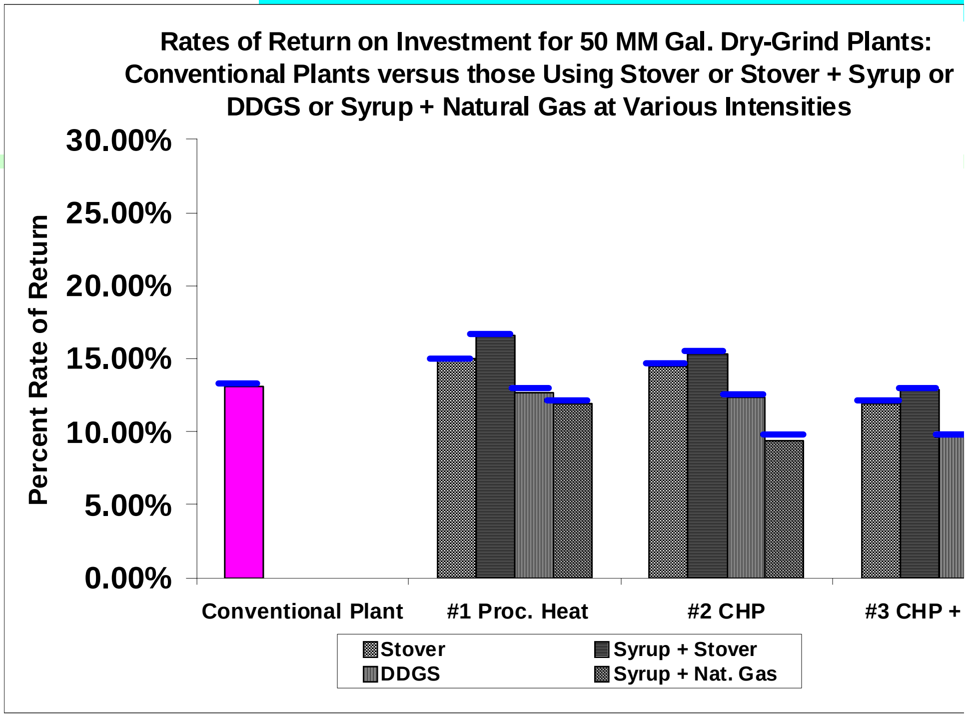
INSTALLED COSTS

	Active Val.	Base Val.
Debt-Equity Assumptions		
Factor of Equity	**40%**	40%
Factor of Debt	60%	60%
Interest Rate Charged on Debt	**8%**	8%
Investor Required Return on Equity	**12%**	12%
Depreciation based on asset life (years)	**15**	15
Output Market Prices		
Ethanol Price (denatured price) $/gal.	**$2.30**	$2.30
DDGS Price $/T	**$145.00**	$145.00
Electricity Price (Plant is Seller) ($ per kWh)	**$0.06**	$0.06
Value of Ash ($ per Ton)	**$200.00**	$200.00
CO2 Price ($ per Ton liq. CO2)	**$8.00**	$8.00
Max. Premium for Low-Carbon ($.00 per gallon)	**$0.20**	$0.20
Government Subsidies		
Federal Small Producer Credit ($/gal.)	**$0.10**	$0.10
RFS Ethanol Tradable Credit ($/gal.)	**$0.07**	$0.07
Fed. Renew Elect Cred Closed-Loop ($/kWh)	**$ 0.020**	$0.020
Feedstock Delivered Prices Paid by Processor		
Corn Price ($ per bu.)	**$5.00**	$5.00
Energy Prices		
Natural Gas Price ($ per 1,000,000 Btu)	**$10.00**	$10.00
Stover Purchased @ ($ per dry Ton)	**$80.00**	$80.00
Electricity Price (Plant is Buyer) ($ per kWh)	**$0.06**	$0.06
LP (Propane) Price ($ per gallon)	**$1.10**	$1.10
Operating Costs/Input Prices		
Denaturant Price / gal	**$3.00**	$3.00
Denat/100 gal Anhyd.	**2**	2
Feedstock-to-Ethanol Conversion Yields		0.06
Ethanol Yield (anhydrous gal per bushel)	**2.75**	2.75

50MM Gal

Author: Douglas G. Tiffany, University of Minnesota 6/2/2008

Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid	
13.05%	15.04%	14.49%	11.92%	**Stover**
	16.55%	15.37%	12.84%	**Syrup + Stover**
	12.71%	12.38%	9.73%	**DDGS**
	11.93%	9.41%		**Syrup + Nat. Gas**



Rates of Return on Investment for 50 MM Gal. Dry-Grind Plants: Conventional Plants versus those Using Stover or Stover + Syrup or DDGS or Syrup + Natural Gas at Various Intensities

Years to Payback Additional Investment

Conventional Plant	#1 Proc. Heat	#2 CHP	#3 CHP + Grid	**50MM Gal**
Not Applicable	4.8	5.8	9.7	**Stover**
	3.2	4.7	8.0	**Syrup + Stover**
	8.7	9.3	26.5	**DDGS**
	14.6	-279.5		**Syrup + Nat. Gas**

Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 16 – Economic Analysis

This chapter presents results of an economic analysis comparing the nine biomass fuel-technology combinations to each other and to a conventional plant using natural gas and purchased electricity. It was primarily prepared by project participants at the University of Minnesota.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 16, “Economic Analysis”

Introduction

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

We have identified the leading methods of thermal conversion of ethanol co-products or field residues that would be technically feasible and financially prudent under a range of economic conditions. We have collected and analyzed technical data related to characteristics of DDGS, syrup, and corn stover in order to model the conversion of energy derived from these biomass fuels (Morey et al., 2006a). We have modeled combustion and gasification performance to help predict emissions of NOx and SOx from the biomass fuels. In addition, issues of ash fusion caused by the alkali metals in the biomass have been studied to help identify combustion/gasification strategies that will have operational reliability. Further details of the systems we modeled are presented in Chapter/Task 14 “Technology Options and Integration with the Dry-Grind Ethanol Plant” and De Kam et al. (2007).

Key Economic Drivers for Adopting Biomass

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

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

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

Figure 1. Industrial natural gas prices in Iowa from 2001-2008 (source: Energy Information Agency, 2008).

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

Use of by-products of the ethanol plant (DDGS, DDG, or syrup) or use of corn stover as a fuel to operate the plant can improve the net energy balance of the whole process of making fuel ethanol from corn. This occurs because fossil sources of energy are replaced by renewable sources.

Morey et al. (2006b) estimated net renewable energy values for corn ethanol with biomass to operate the plant comparable to estimates for cellulosic ethanol based on biochemical processes.

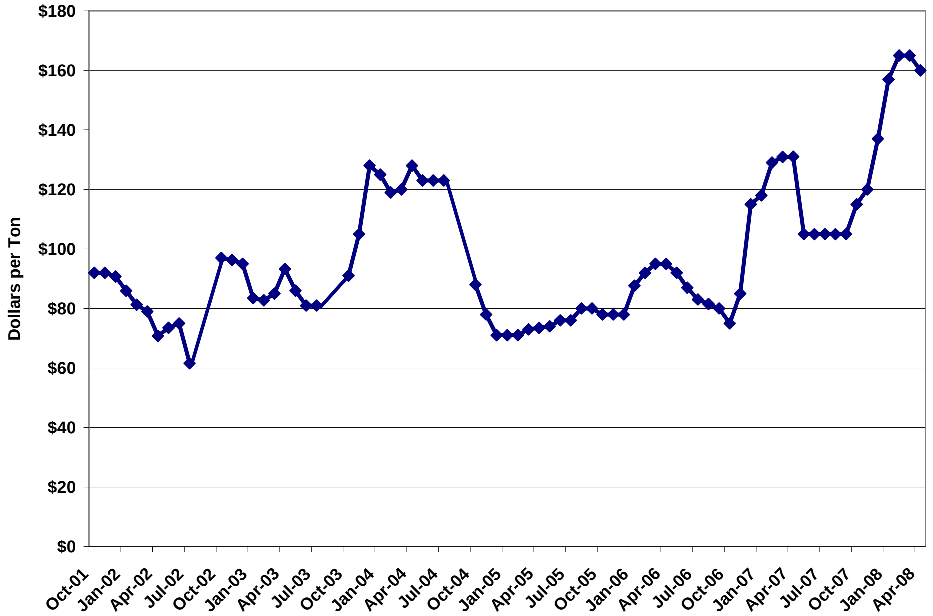


Figure 2. Historical prices of distillers dried grains at Lawrenceburg, Indiana (source: USDA-ERS, 2008).

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

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

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

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

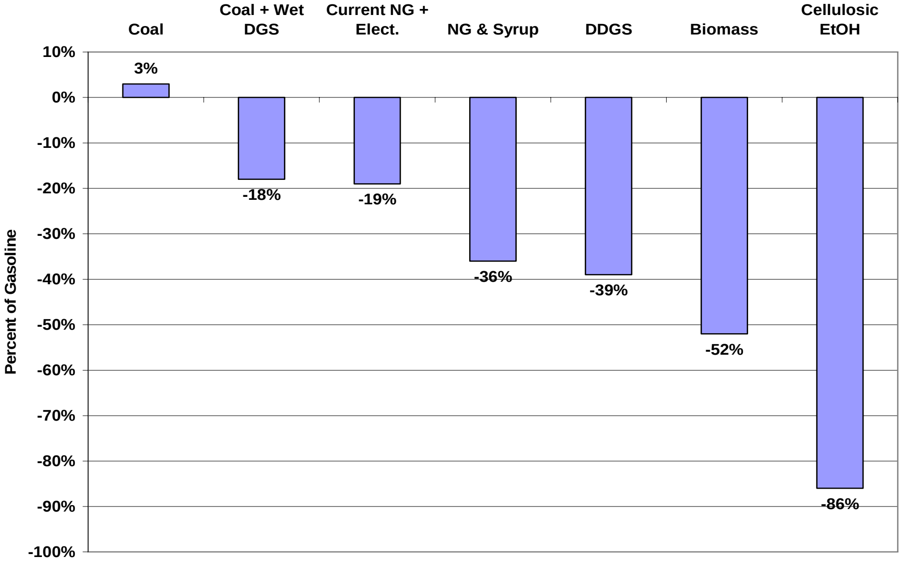


Figure 3. Well to wheels greenhouse gas emissions changes from fuel ethanol produced using various fuels and conversion assumptions at the plant relative to gasoline (source: Wang et al., 2007).

Objectives

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

Methods

The technical analysis for integrating biomass energy into the dry-grind ethanol process is described in detail in De Kam et al. (2007). Some of the important features are summarized here. The analysis was performed primarily using Aspen Plus process simulation software. An Aspen Plus model of the dry-grind ethanol process was obtained from the USDA Agricultural Research Service (McAloon et al., 2000; McAloon et al., 2004; Kwiatowski et al., 2006), and was used as the basis for the energy conversion system models that followed. Biomass systems that produce 190 million liter (50 million gallon) per year of denatured ethanol were modeled. The primary components of the process such as fermentation, distillation, and evaporation were not changed. Only those components impacted by using biomass fuel were modified. They included steam generation (biomass combustion or gasification), thermal oxidation, co-product drying, and emissions control. Process data from several ethanol plants participating in the project were also taken into account in the modeling process. Several sensitivity analyses were performed on each simulation to ensure good performance.

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

Fluidized bed combustion was used for corn stover and the mixture of corn stover and syrup. Fluidized bed gasification was used for DDGS to overcome problems with low ash fusion temperatures. Appropriate drying modifications were made to accommodate each configuration. The necessary emissions control technologies, primarily for oxides of nitrogen (NO_x), oxides of sulfur (SO_x), and chlorine (HCl), 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 (AMEC) 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, because the dryer exhaust was routed to the combustion unit in the biomass systems, 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 3.33 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

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**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$1,275,000	6%		$1,400,000	5%		$1,750,000	5%	
Fluidized Bed Boiler & Steam System.	new	$10,394,000	50%		$13,203,000	49%		$15,314,000	47%	
Ash Handling	new	$650,000	3%		$650,000	2%		$650,000	2%	
Emissions Control	new	$2,520,000	12%		$2,575,000	10%		$2,950,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,900,000	11%		$5,566,000	17%	
Steam Tube Dryer	new	$6,129,000	29%		$6,312,000	23%		$6,312,000	19%	
Total Cost: new items		$20,968,000	100%	$69,749,000	$27,040,000	100%	$89,697,000	$32,542,000	100%	$107,773,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-43%	($30,430,000)	($9,000,000)	-33%	($30,430,000)	($9,000,000)	-28%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$11,968,000	57%	$39,319,000	$18,040,000	67%	$59,267,000	$23,542,000	72%	$77,343,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$151,819,000**			**$171,767,000**			**$189,843,000**

Syrup and Corn Stover Combustion		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	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	$9,264,000	53%		$11,731,000	52%		$13,867,000	49%	
Ash Handling	new	$650,000	4%		$650,000	3%		$650,000	2%	
Emissions Control	new	$2,481,000	14%		$2,517,000	11%		$2,565,000	9%	
Steam Turbine Generator & Acc	new	$0	0%		$2,600,000	11%		$5,497,000	20%	
Steam Tube Dryer	new	$3,700,000	21%		$3,810,000	17%		$3,810,000	14%	
Total Cost: new items		$17,370,000	100%	$57,928,000	$22,708,000	100%	$75,465,000	$28,139,000	100%	$93,308,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-52%	($30,430,000)	($9,000,000)	-40%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$8,370,000	48%	$27,498,000	$13,708,000	60%	$45,035,000	$19,139,000	68%	$62,878,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$139,998,000**			**$157,535,000**			**$175,378,000**

DDGS Gasification		**Process Heat Only**			**CHP**			**CHP plus electricity to the grid**		
		FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost	FOB Equip. Cost	% new	Total Project Cost
Biomass Fuel Handling	new	$790,000	4%		$890,000	4%		$990,000	4%	
Fluidized Bed Gasifier & Steam System.	new	$9,054,000	49%		$10,586,000	45%		$12,216,000	43%	
Ash Handling	new	$350,000	2%		$350,000	1%		$350,000	1%	
Emissions Control	new	$2,300,000	12%		$2,414,000	11%		$2,673,000	10%	
Steam Turbine Generator & Acc	new	$0	0%		$2,870,000	12%		$5,556,000	20%	
Steam Tube Dryer	new	$6,129,000	33%		$6,312,000	27%		$6,312,000	22%	
Total Cost: new items		$18,623,000	100%	$62,045,000	$23,422,000	100%	$77,811,000	$28,097,000	100%	$93,170,000
Natural Gas Dryer & Thermal Oxidizer	avoided	($9,000,000)	-48%	($30,430,000)	($9,000,000)	-38%	($30,430,000)	($9,000,000)	-32%	($30,430,000)
Total Additional Cost: Net (new-avoided)		$9,623,000	52%	$31,615,000	$14,422,000	62%	$47,381,000	$19,097,000	68%	$62,740,000
Typical Conventional Ethanol Plant Cost	baseline			$112,500,000			$112,500,000			$112,500,000
Biomass Powered Ethanol Plant Grand Total:				**$144,115,000**			**$159,881,000**			**$175,240,000**

(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 1.6245. Thus, the cost for 380 million liter plant is estimated to be 1.6245 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 3. Nameplate installed costs for conventional and biomass-fueled dry-grind ethanol plants.

Type	**190 MM liter (50 MM gallon) Plants**		**380 MM liter (100 MM gallon) Plants**	
	Capital Cost	**Name Plate Cost $/L ($/gal)**	**Capital Cost**	**Name Plate Cost $/L ($/gal)**
Conventional	$112,500,000	$0.59 ($2.25)	$182,757,000	$0.48 ($1.83)
Corn Stover				
Process Heat	$151,819,000	$0.80 ($3,04)	$246,631,000	$0.65 ($2.47)
CHP	$171,767,000	$0.90 ($3.44)	$279,036,000	$0.73 ($2.79)
CHP + Grid	$189,843,000	$1.00 ($3.80)	$308,401,000	$0.81 ($3.08)
Corn Stover + Syrup				
Process Heat	$139,998,000	$0.74 ($2.80)	$227,427,000	$0.60 ($2.27)
CHP	$157,535,000	$0.83 ($3.15)	$255,916,000	$0.67 ($2.56)
CHP + Grid	$175,378,000	$0.92 ($3.51)	$284,902,000	$0.75 ($2.85)
DDGS				
Process Heat	$144,115,000	$0.76 ($2.88)	$234,116,000	$0.62 ($2.34)
CHP	$159,881,000	$0.84 ($3.20)	$259,727,000	$0.68 ($2.60)
CHP + Grid	$175,240,000	$0.92 ($3.50)	$284,678,000	$0.75 ($2.85)

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 $0.61/liter ($2.30/gallon) received at the ethanol plant. Corn price is assumed to be $197/tonne ($5.00/bushel) (for the next ten years) based on the 2007

Baseline Report of the U.S. Department of Agriculture. Natural gas is established at $10 per decatherm (1.06 million kJ or 1 million BTUs). Electricity is assumed to be priced at 6¢/kWh under baseline conditions, whether the plant is buying or selling.

Table 4. Common assumptions for all systems.

Category	**Baseline Values**
Debt-Equity Assumptions	
Factor of Equity	40%
Factor of Debt	60%
Interest Rate Charged on Debt	8%
Depreciation Period	15 years
Output Market Prices	
Ethanol Price	$0.61/liter ($2.30/gallon)
DDGS Price	$160/tonne ($145/ton)
Electricity (excess) Sale Price	6¢/kWh
Sale Price of Ash	$220/tonne ($200/ton)
CO_2 Price per liquid unit	$8.80/tonne ($8/ton)
Low-Carbon Premium	5.3¢/liter (20¢/gallon)
Government Subsidies	
Federal Small Producer Credit	2.6¢/liter(10¢/gallon)
RFS Ethanol Tradable Credit	1.8¢/liter(7¢/gallon)
Federal Renewable Electricity Credit	2¢/kWh
Feedstock Delivered Prices Paid by Processor	
Corn Price	$197/tonne ($5.00/bushel)
Energy Prices	
Natural Gas	$10/decatherm
Stover Delivered to Plant	$88/tonne ($80/ton)
Electricity Price	6¢/kWh
Propane Price	$0.40/liter ($1.50/gallon)
Operating Costs—Input Prices	
Denaturant Price per gallon	$0.79/liter ($3.00/gallon)
Denaturant Rate (volume units per 100 of anhydrous)	5
Ethanol Yield (anhydrous)	0.41 liter/kg (2.75gallon/bushel)

DDGS are established at the price of $160/tonne ($145/ton). In the scenarios when the syrup is combusted, the resulting by-product is DDG, which we assume has a market value 110% 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 2¢/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 1.8¢/liter (7¢/gallon) based on recent sales of Renewable Identification Number (RIN) certificates.

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 1.6245) 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.

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 $10 to $13 per decatherm would decrease the rate of return for a conventional ethanol plant with no effects shown on the biomass plants when all plants are at baseline conditions. A decrease in natural gas price from $10 to $7 per decathterm obviously favors the conventional plant. Ethanol plants are very sensitive to natural gas prices, and despite the higher capital costs to implement the biomass options, higher rates of return will be captured by plants utilizing biomass under conditions of high natural gas prices.

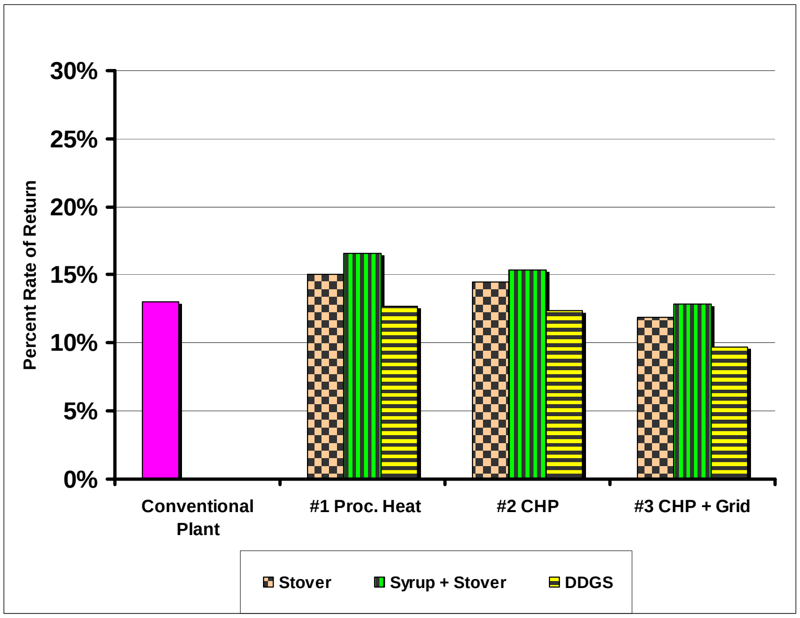


Figure 4. Baseline rates of return for 190 million liter (50 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

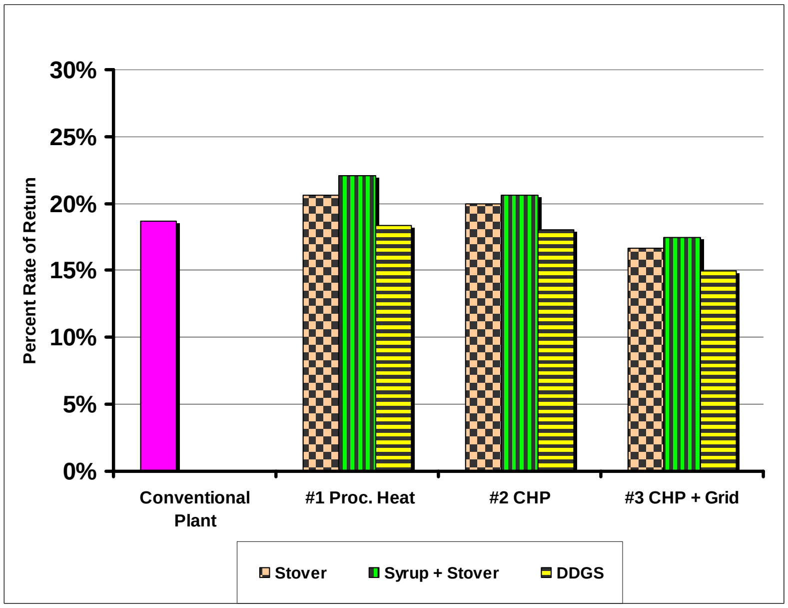


Figure 5. Baseline rates of return for 380 million liter (100 million gallon) per year capacities for the nine biomass fuel/technology combinations and the conventional plant.

Increases in DDGS prices from $160 to $191 per tonne ($145 to $174 per ton) result in higher RORs for the conventional plants and are exceeded only by the cases of plants using stover (smaller plants only) for process heat and stover and syrup for process heat as well as combined heat and power (CHP). Declines in DDGS prices from $160 to $128 per tonne ($145 to $116 per ton) have result in significantly lower RORs for conventional plants 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 are impacted least 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 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 $0.61/liter ($2.30/gallon) at baseline to $0.67/liter ($2.55/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 $0.61/liter ($2.30/gallon) to $0.54/liter ($2.05/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 7.1¢/liter (20 to 27¢/gallon), the biomass-powered plants at all fuel/technology combinations except CHP plus grid for DDGS are favored over conventional ethanol plants. If the price premium is 3.4 ¢/liter (13 ¢/gallon) instead of the 5.3 ¢/liter (20 ¢/gallon) assumed in the baseline, the RORs of the biomass-powered plants are reduced, with only the stover and syrup CHP case superior to the conventional plant.

In instances where excess electricity can be sold at a favorable price of 10¢/kWh versus 6¢/kWh, the CHP and 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 result in a higher rates of return for all biomass options but one (CHP plus grid for DDGS) compared to the conventional natural gas-fired plant.

A rise in corn price from the $197/tonne ($5.00/bushel) baseline to $224/tonne ($5.70/bushel) reduces the rates of return for 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 $197/tonne ($5.00 per

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**
Baseline case	13.1.%	15.0%	16.6%	12.7%	14.5%	15.4%	12.4%	11.9%	12.8%	9.7%
Natural gas: $10 to $13/decatherm	7.7%	15.0%	16.6%	12.7%	14.5%	15.4%	12.4%	11.9%	12.8%	9.7%
Natural gas: $10 to $7/decatherm	18.4%	15.0%	16.6%	12.7%	14.5%	15.4%	12.4%	11.9%	12.8%	9.7%
DDGS: $145 to $174/ton	18.1%	18.3%	18.9%	13.8%	17.4%	17.4%	12.9%	14.5%	14.7%	9.7%
DDGS: $145 to $116/ton	8.0%	11.8%	14.2%	11.6%	11.6%	13.3%	11.9%	9.3%	11.0%	9.7%
Ethanol: $2.30 to $2.55/gallon	26.4%	23.8%	26.0%	21.9%	22.2%	23.8%	20.7%	18.9%	20.4%	17.3%
Ethanol: $2.30 to $2.05/gallon	-0.3%	6.3%	7.1%	3.5%	6.8%	7.0%	4.1%	4.9%	5.3%	2.2%
Low carbon premium: 20¢ to 27¢/gal.	13.1%	17.2%	18.9%	15.0%	16.6%	17.7%	14.7%	13.8%	14.9%	11.8%
Low carbon premium: 20¢ to 13¢/gal.	13.1%	12.9%	14.2%	10.4%	12.4%	13.1%	10.1%	10.0%	10.8%	7.7%
Electricity sale price: 6¢ to 10¢/kWh	13.1%	15.0%	16.6%	12.7%	15.4%	15.9%	13.5%	13.8%	14.6%	11.5%
Corn price: $5.00 to $5.70/bu.	-0.3%	6.3%	7.1%	3.5%	6.8%	7.0%	4.1%	5.0%	5.3%	2.2%
Corn price: $5.00 to $4.30/bu.	26.4%	23.8%	26.0%	21.9%	22.2%	23.8%	20.7%	18.9%	20.4%	17.3%
Corn stover price: $80 to $100/ton	13.1%	13.2%	15.8%	12.7%	12.6%	14.4%	12.4%	9.6%	11.3%	9.7%
Corn stover price: $80 to $60/ton	13.1%	16.8%	17.3%	12.7%	16.4%	16.3%	12.4%	14.3%	14.4%	9.7%
Natural gas: $10 to $13/decatherm and DDGS: $145 to $116/ton	2.7%	11.8%	14.2%	11.6%	11.6%	13.3%	11.9%	9.3%	11.0%	9.7%
Natural gas: $10 to $13/decatherm and Corn stover price: $80 to $140/ton	7.7%	9.6%	14.3%	12.7%	8.7%	12.4%	12.4%	4.9%	8.1%	9.7%
Sell-all, buy-all electricity: Sell at 6¢/kWh; buy at 6¢/kwh	13.1%	15.1%	16.6%	12.7%	15.1%	16.2%	12.9%	12.5%	13.4%	10.2%
Sell-all, buy-all electricity: Sell at 10¢/kWh; buy at 6¢/kwh	13.1%	15.1%	16.6%	12.7%	17.1%	18.1%	15.2%	15.5%	16.4%	13.1%

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**
Baseline case	18.7%	20.6%	22.1%	18.4%	19.9%	20.7%	18.0%	16.7%	17.4%	15.0%
Natural gas: $10 to $13/decatherm	12.1%	20.6%	22.1%	18.4%	19.9%	20.7%	18.0%	16.7%	17.4%	15.0%
Natural gas: $10 to $7/decatherm	25.2%	20.6%	22.1%	18.4%	19.9%	20.7%	18.0%	16.7%	17.4%	15.0%
DDGS: $145 to $174/ton	24.8%	24.6%	24.9%	19.7%	23.5%	23.2%	18.6%	19.9%	19.7%	15.0%
DDGS: $145 to $116/ton	12.5%	16.6%	19.2%	17.0%	16.4%	18.1%	17.4%	13.4%	15.2%	15.0%
Ethanol: $2.30 to $2.55/gallon	35.1%	31.3%	33.7%	29.7%	29.4%	31.0%	28.2%	25.3%	26.7%	24.3%
Ethanol: $2.30 to $2.05/gallon	2.3%	9.9%	10.4%	7.0%	10.4%	10.3%	7.8%	8.1%	8.1%	5.7%
Low carbon premium: 20¢ to 27¢/gal.	18.7%	23.3%	24.9%	21.2%	22.5%	23.5%	20.8%	19.0%	20.0%	17.5%
Low carbon premium: 20¢ to 13¢/gal.	18.7%	17.9%	19.2%	15.6%	17.3%	17.8%	15.2%	14.3%	14.9%	12.4%
Electricity sale price: 6¢ to 10¢/kWh	18.7%	20.6%	22.1%	18.4%	21.0%	21.4%	19.3%	18.9%	19.6%	17.2%
Corn price: $5.00 to $5.70/bu	2.3%	9.9%	10.4%	7.1%	10.4%	10.3%	7.8%	8.1%	8.1%	5.7%
Corn price: $5.00 to $4.30/bu.	35.1%	31.3%	33.7%	29.7%	29.4%	31.0%	28.2%	25.2%	26.7%	24.3%
Corn stover price: $80 to $100/ton	18.7%	18.4%	21.1%	18.4%	17.6%	19.4%	18.0%	13.8%	15.5%	15.0%
Corn stover price: $80 to $60/ton	18.7%	22.8%	23.0%	18.4%	22.3%	21.9%	18.0%	19.5%	19.4%	15.0%
Natural gas: $10 to $13/decatherm and DDGS: $145 to $116/ton	5.9%	16.6%	19.2%	17.0%	16.4%	18.1%	17.4%	13.4%	15.2%	15.0%
Natural gas: $10 to $13/decatherm and Corn stover price: $80 to $140/ton	12.1%	13.9%	19.2%	18.4%	12.8%	17.0%	18.0%	8.0%	11.6%	15.0%
Sell-all, buy-all electricity: Sell at 6¢/kWh; buy at 6¢/kwh	18.7%	20.6%	22.1%	18.4%	20.6%	21.7%	18.7%	17.3%	18.1%	15.6%
Sell-all, buy-all electricity: Sell at 10¢/kWh; buy at 6¢/kwh	18.7%	20.6%	22.1%	18.4%	23.2%	24.0%	21.4%	21.0%	21.8%	19.2%

bushel). A decrease in corn price from $197/tonne ($5.00/bushel) to $170/tonne ($4.30/bushel) with all other levels at baseline favors the conventional plants because they have lower capital costs.

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 the 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 low as $66/tonne ($60/ton), then RORs of three (smaller plants) or four (larger plants) additional biomass options would exceed the natural gas fired plant, including the corn stover and syrup plus stover options producing CHP plus electricity for the grid.

The fourth to last case 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 $156 to $128/tonne ($145 to $116/ton) and natural gas were to rise from baseline at $10 to $13 per decatherm, the ROR of a conventional plant would be reduced to just 2.7% for the 190 million liters (50 million gallons) per year case, while all plants using biomass would be producing favorable rates of return of 9.3% or better. Although, all rates of return are higher for the larger plant, biomass alternatives produce much higher RORs than the conventional plant under these assumptions.

In the third to last case in Tables 5 and 6, the price of natural gas rises from $10 to $13 per decatherm at the same time that the price of corn stover rises from $88 to $154/tonne ($80 to $140/ton). These two changes from baseline result in higher rates of return for the biomass process heat and biomass CHP options at both plant sizes. For biomass CHP plus grid options, the results depend on the type of biomass. Use of DDGS results in higher RORs than the conventional system for both plant sizes. Use of corn stover results in lower RORs than the conventional system for both plant sizes. Use of syrup plus corn stover results in a ROR higher than a conventional system under these prices for the smaller plants, but lower ROR than a conventional system for the larger plants, probably due to the loss of the federal small producer credit. These results illustrate that as natural gas prices climb, biomass fueled systems can yield higher rates of return than conventional plants even at fairly high corn stover prices.

The last two cases in Tables 5 and 6 show the effect of an ethanol plant selling all the electricity it produces from biomass and buying back the necessary power for its operations from the grid, sometimes referred to as “sell-all, buy-all”. This situation arises when power utilities are motivated to increase the amounts of renewable electricity in their portfolios according to state renewable energy objectives. An advantage of power produced by ethanol plants is that it would generally be constant, thus fulfilling the criterion of dependable, base load (high capacity factor) power, and therefore could be the recipient of favorable rates due to capacity payments from the utilities. In the next to last case in both tables all electricity produced is sold at 6¢/kWh and the required electricity is purchased at 6¢/kWh. Comparing this result to the base case, the electricity producing options for “sell-all, buy all” have higher rates of return than the base case because all electricity produced receives the 2¢/kWh Federal renewable electricity credit, not just the net produced for sale. The last case in both tables illustrates a “sell-all, buy-all” scenario where electricity is sold at 10¢/kWh and purchased at 6¢/kWh. When compared to the case where only excess power is sold at 10¢/kWh, significantly higher rates of return are achieved because all electricity produced receives the higher sale rate as well as the 2¢/kWh Federal renewable electricity credit.

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.

Acknowledgements

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Final Report

Xcel Renewable Development Fund Project (RD-56)

Generating Electricity with Biomass Fuels at Ethanol Plants

Chapter/Task 17 – Special Scenarios

This chapter outlines several special scenarios, which all focus on using the syrup since alternatives involving the syrup had the most favorable rates of return in the economic analysis (Chapter/Task 16). The scenarios include syrup and corn cobs in place of corn stover, partial use of biomass (syrup) along with natural gas, and a preliminary evaluation of electricity generation with integrated gasification combined cycle technology using syrup and corn cobs as fuel. It was primarily prepared by project participants at the University of Minnesota.

Project Leaders

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

June 13, 2008

RD56: Generating Electricity With Biomass Fuels at Ethanol Plants
Report for Task 17, "Special Scenarios"

Background of the Task

This chapter outlines several special scenarios, all of which focus on using the syrup since alternatives involving the syrup had the most favorable rates of return in the economic analysis (Chapter/Task 16). The scenarios include syrup with corn cobs in place of corn stover, partial use of biomass (syrup) along with natural gas, and a preliminary evaluation of electricity generation with integrated gasification combined cycle technology using syrup and corn cobs as fuel.

Corn cobs are part of the corn residue, but most cobs would not be captured in conventional corn stover harvest. They make up approximately 18% of the total biomass that could be available in the corn stover. They can be collected in the process of harvesting the corn, rather than in a subsequent step such as with the corn stover. When combined with the syrup, there is enough energy in the cobs to provide process heat and electricity to process the ethanol made from the corresponding corn grain produced on an acre of land. Corn cobs have physical characteristics that might allow them to be utilized without as much processing, for example densification, as corn stover. They also have lower ash content than corn stover.

Another 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 is 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 or corn cobs. In addition, the quality and value of the DDG, resulting from removal of the syrup, may be enhanced.

Integrated gasification combined cycle (IGCC) systems produce greater levels of electricity for the same amount of biomass fuel used and process heat supplied at ethanol plants. The greater levels of electricity production with this technology will provide increased revenue for ethanol plants and may justify a larger low-carbon fuel premium for the ethanol produced.

Syrup-Corn Cobs

We modeled the technical performance of the syrup-corn cob alternative. Since the cobs are quite similar to the corn stover in terms of composition, the performance was approximately the same. Because of the lower ash content slightly less fuel was used and ash produced. Since cobs and stover are so similar, there was no change in the capital or operating cost assumptions. Thus, we did not perform a separate economic analysis. The results for the syrup-corn stover case should apply with the possibility that the delivered cost of corn cobs may be less than corn stover leading to somewhat higher rates of return. The effect of biomass fuel (stover or cobs) costs on rates of return are illustrated in the sensitivity results in Chapter/Task 16.

Syrup-Natural Gas

We modeled the technical performance of the syrup-natural gas alternative. We modeled only the process heat and combined heat and power cases, since all of the available syrup was consumed in those cases. We did not model a syrup-natural gas scenario producing CHP and sales of electricity to the grid because generating more electricity to send to the grid would require supplying more natural gas without using any additional biomass. Thus the extra electricity generated would not have any renewable component.

The fluidized bed combustion system is basically unchanged with the syrup-natural gas alternative, since the natural gas needs to be added either in the bed or prior to the bed in order to sustain combustion of the syrup, which is over 65% moisture. Most of the fuel nitrogen, sulfur, and chlorine from the syrup-corn stover or syrup-corn cob cases is in the syrup so substituting natural gas for the stover or cob portion does not significantly reduce the need for emissions control technology. There was no change in the steam tube dryer that was used.

The primary changes in capital costs involved the fuel handling equipment. There was only one type of biomass fuel (syrup) used, compared to the two types in the syrup-stover or syrup-cobs cases. The reduction in fuel handling equipment costs reduced the overall capital cost estimates for the 50 million gallon per year plants to $137,263,000 from $139,998,000 for process heat and to $154,473,000 from $157,535,000 for combined heat and power. The overall capital cost estimates for the 100 million gallon per year plants were reduced to $222,984,000 from $227,427,000 for process heat and to $250,942,000 from $255,916,000 for combined heat and power.

Integrated Gasification Combined Cycle

A special case of IGCC technology was evaluated on a basic level because it has the capability to produce increased amounts of renewable electricity with the co-product fuel that is available. A simplified diagram of the power generation system for this case is shown in Figure 1.

In this arrangement biomass fuel is gasified and combusted in a twin fluidized bed process to produce synthesis gas. The synthesis gas passes through a gas cooler which generates some process steam. The gas is then cleaned, compressed and combusted in a gas turbine. The hot combustion products from the gas turbine and the fluidized bed combustor are used to provide heat to the steam generator. The assumptions made for steam generation are the same as in all previous cases.

Superheated steam at 482° C (900° F) and 6,300 kPa (900 psig) exits the steam generator and is piped to a backpressure steam turbine losing 5° C (9° F) along the way. The turbine specifications are the same as those used in the CHP cases. After desuperheating, process steam is then supplied at 446 kPa (50 psig) to the ethanol process, the ethanol co-product dryer, and the gasifier fuel dryer. The gasifer fuel is a mixture of syrup and corn cobs. Because the gasification process requires fuel moisture contents less than about 20%, the syrup and corn cobs are mixed and then dried before gasification.

The model for IGCC is preliminary. It includes heat and power estimates and fuel use, but does not yet model emissions control and gas clean up technology. Since we did not model all elements of the system, we did not develop capital cost estimates or perform an economic analysis.

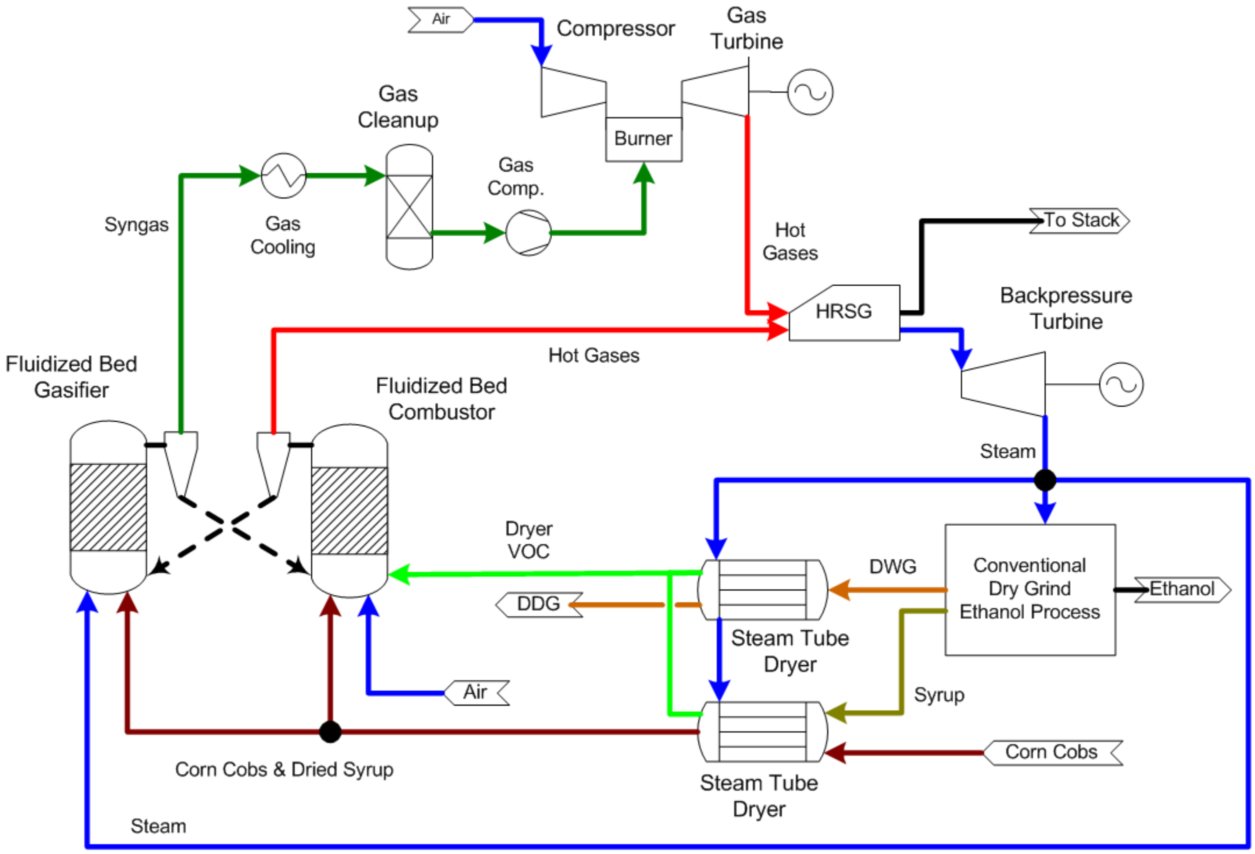

Figure 1. Integrated gasification combined cycle diagram

Results for the Special Scenarios

Table 1 presents some important performance results for the three special scenarios. Results for syrup and corn cob combustion are very similar to the results for syrup and corn stover combustion presented in Chapter/Task 16. The performance results for syrup and natural gas combustion are similar to the syrup and corn cob combustion results for the first two cases. The third case was not simulated because all of the required additional fuel to generate electricity for the grid would be natural gas. The syrup and corn stover integrated gasification combined cycle (IGCC) modeling results show the potential for increased generation and generation efficiency for this technology. This technology bundle appears to warrant further analysis.

Emissions after application of control technology for NO_x, SO_2, and HCL are shown in Figures 1 through 3, respectively. Syrup and corn cobs combustion and syrup and natural gas combustion are compared to the three primary fuels of Chapter/Task 16 (corn stover combustion, syrup and corn stover combustion, and DDGS gasification. Emissions for all three cases involving combustion of syrup with another fuel, either corn stover, corn cobs or natural gas, were similar. Most of the fuel nitrogen, sulfur, and chlorine is in the syrup component; therefore emission results are similar for all three cases.

Table 1. System performance results for a 190 million liters (50 million gallons) per year dry-grind ethanol plant.[1]

	Biomass Fuel Use [2] (Wet Basis) ton/day	Fuel Energy Input Rate MW_{th}	Power Generated (Gross) MW_e	Power To Grid (Net)[3] MW_e	Power Generation Efficiency	System Thermal Efficiency[4]
Syrup & Corn Cob Combustion						
Process Heat Only	711	64	0	-5.7	-	62.4%
CHP	777	75	8.8	2.8	11.7%	64.5%
CHP & Elec. to Grid	951	104	16.0	9.6	15.4%	53.0%
Syrup & Natural Gas Combustion						
Process Heat Only	561	63	0	-5.8	-	62.8%
CHP	561	74	8.8	2.7	11.8%	64.9%
Syrup & Corn Cob Integrated Gasification Combined Cycle (IGCC)						
CHP & Elec. to Grid	984	109	30.3	21.6	27.7%	71.0%

[1] All energy and power values in this table are based on the fuel Higher Heating Value (HHV).

[2] Moisture contents: Corn cobs – 13%; Syrup – 66.8%; Syrup and corn cob combustion – 55%, 52%, 45% for levels 1, 2, 3, respectively; Syrup and corn cob IGCC – 44%.

[3] Negative values refer to power purchased from the grid by the ethanol facility.

[4] Efficiency of converting fuel energy into other useful forms of energy (process heat and electricity).

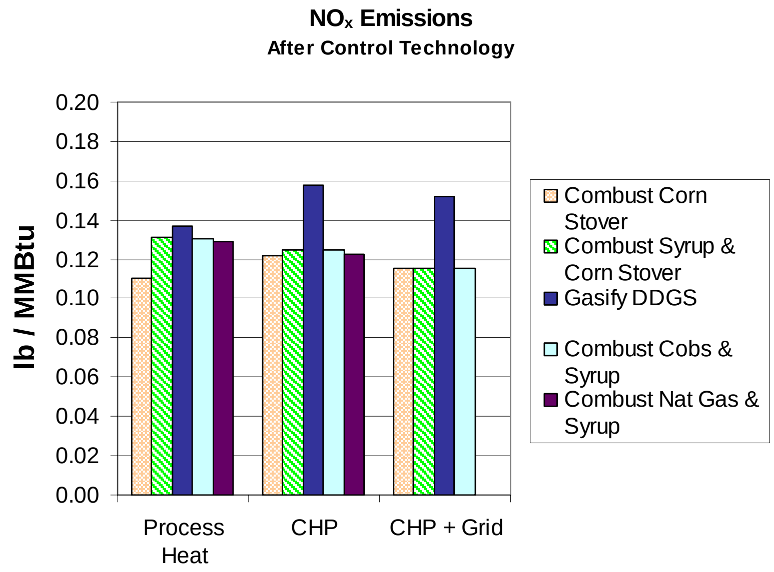

Figure 1. NO_x emissions after control technology.

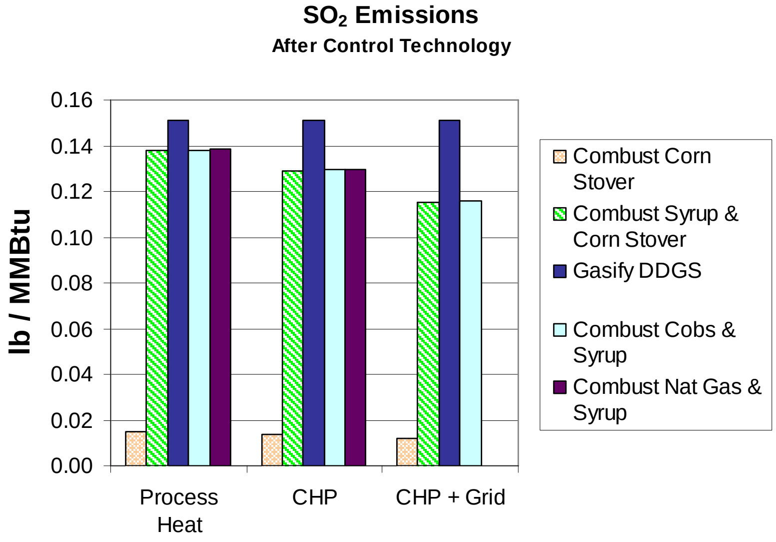

Figure 2. SO_2 emissions after control technology.

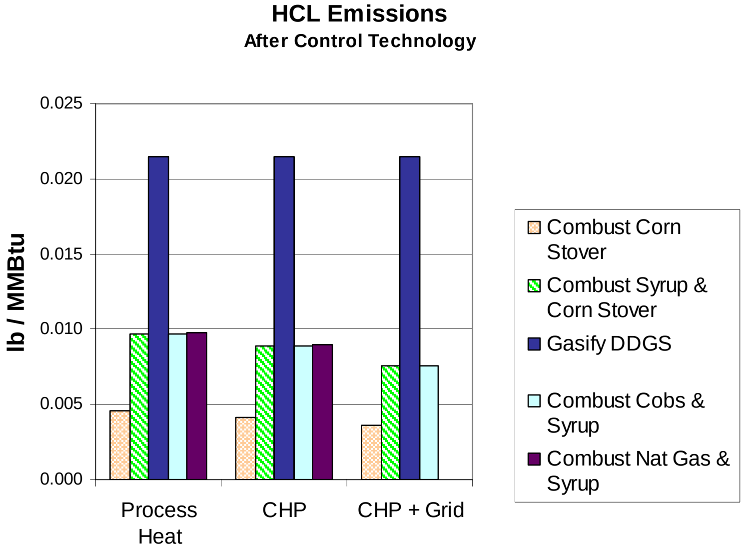

Figure 3. HCL emissions after control technology.

The renewable energy ratio for the three special scenarios and the three primary fuels are compared in Figure 4. Syrup and corn cob combustion has the same renewable energy ratio as syrup and corn cob combustion at all levels. The renewable energy ratio for syrup and natural gas is less than the case with syrup and either corn stover or corn cobs because more fossil fuel is being used. However, the renewable energy ratio is higher than the conventional case. The renewable energy ratio for syrup and corn cobs IGCC is greater than 5, reflecting the greater levels of renewable electricity being produced.

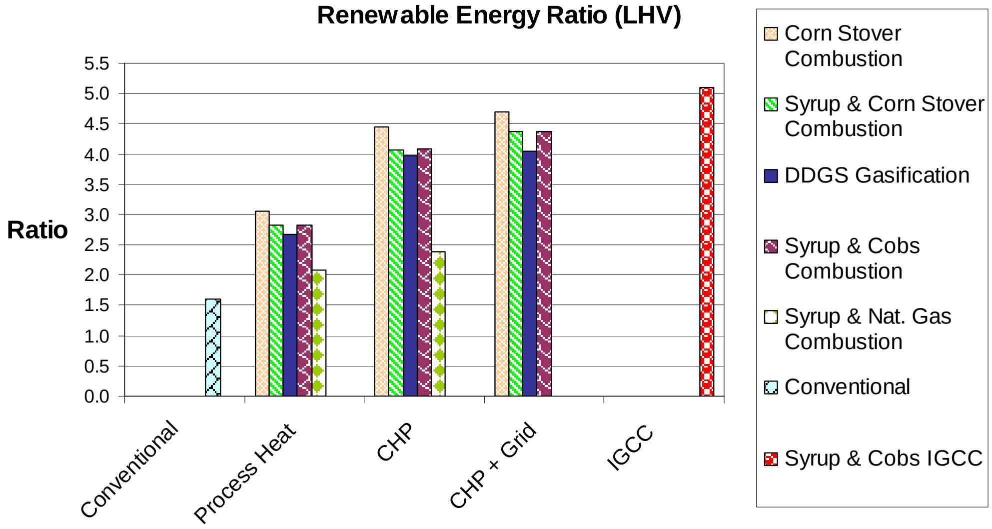

Figure 4. Renewable energy ratio (LHV).

Economic Analysis of Syrup and Natural Gas Combustion

Baseline rates of return for syrup and natural gas are compared to the other alternatives for 50-million and 100-million gallon per year capacities in Figures 5 and 6, respectively. At baseline conditions rates of return are lower for the syrup and natural gas alternatives than for the corresponding syrup and stover alternatives as well as for the conventional plants for both capacities. Because most of the increased capital costs to combust biomass are incurred for the syrup-natural gas alternatives, but the natural gas savings are not as great, this alternative has lower rates of return than both the conventional natural gas system and the syrup-stover alternatives.

Sensitivity results for rates of return for 50 million gallon per year plants are shown in Table 2. In all of the cases evaluated the rates of return for syrup and natural gas were lower than the corresponding syrup and corn stover alternative. It appears that the only scenario where syrup and natural gas might provide a higher rate of return than both the conventional natural gas system and the syrup-stover system would be for process heat under conditions of fairly high natural gas (e.g. $13/decatherm) and very high stover prices (e.g. on the order of $240/ton). This might correspond to a case where stover was not available for some reason. Thus, based on our analysis it appears that the best choice when using syrup would be to design for a system that uses biomass (corn stover or corn cobs) rather than natural gas as the other fuel in the mix.

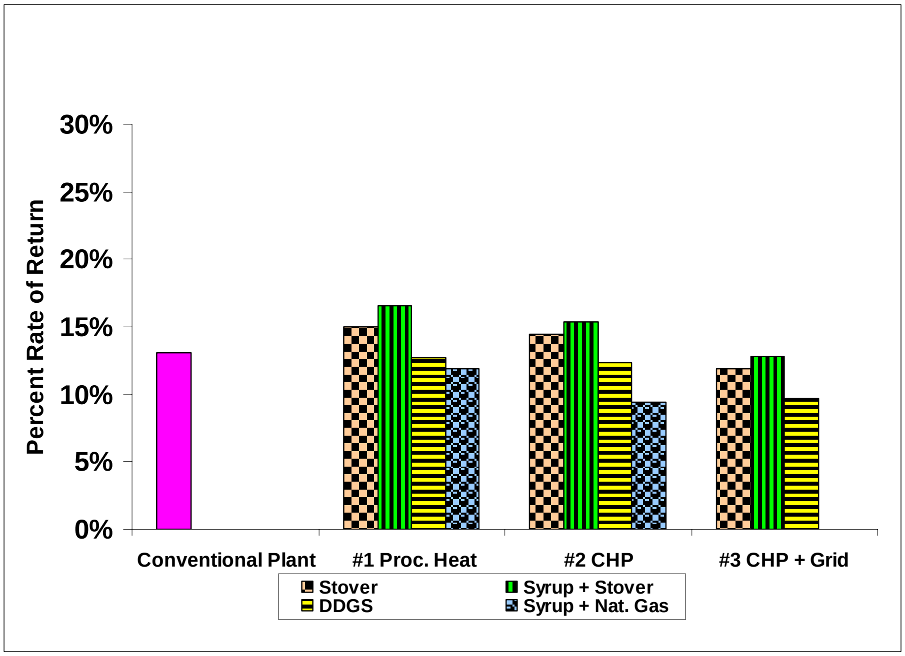

Figure 5. Baseline rates of return for 50 million gallon per year capacities.

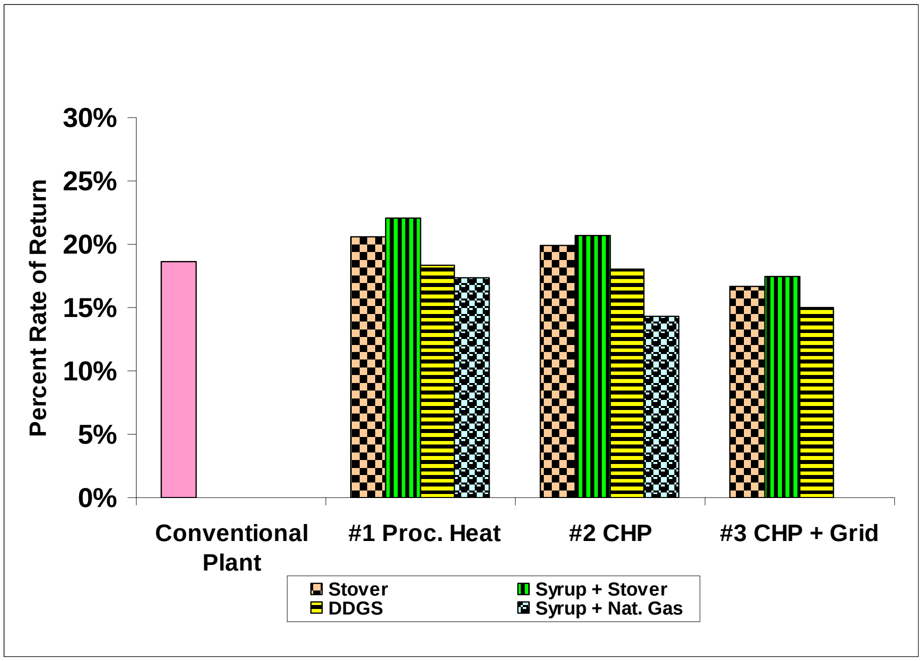

Figure 6. Baseline rates of return for 100 million gallon per year capacities.

Table 2. Sensitivity of rates of return on investment to changes in key economic parameters for 50 million gallon per year capacties.

Economic Parameters	**Convent. Plant Nat. gas Electric**	**Process Heat**		**CHP**	
		Syrup & Stover	**Syrup & Nat. Gas**	**Syrup & Stover**	**Syrup & Nat. Gas**
Baseline case	13.1%	16.6%	11.9%	15.4%	9.4%
Natural gas: 10 to $13/decatherm	7.7%	16.6%	10.4%	15.4%	7.5%
Natural gas: 10 to $7/decatherm	18.4%	16.6%	13.4%	15.4%	11.4%
DDGS: $145 to $174/ton	18.1%	18.4%	14.3%	17.4%	11.5
DDGS: $145 to $116/ton	8.0%	14.2%	9.6%	13.3%	7.3%
Corn stover price: $80 to $100/ton	13.1%	15.8%	11.9%	14.4%	9.4%
Corn stover price: $80 to $60/ton	13.1%	17.3%	11.9%	16.3%	9.4%
Electricity sale price: 6¢ to 10¢/kWh	13.1%	16.6%	11.9%	15.9%	10.0%
Low carbon premium: 20¢ to 27¢/gal.	13.1%	18.9%	13.4%	17.7%	10.6%
Natural gas: $10 to $13/dekatherm DDGS: $145 to $116/ton	2.7%	14.2%	8.1%	13.3%	5.4%