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Project Title: Generating Electricity with Biomass Fuels at Ethanol Plants

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Milestone Description: Third three-month reporting period

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

Executive Summary

- Updated project web site www.biomassCHPethanol.umn.edu with most recent results
- Presentation entitled “Economic and Technical Analysis: Using DDGS or Cornstover for Process Heat and Electricity in Dry-Grind Ethanol Plants” at 2006 Fuel Ethanol Worshop and Expo in Milwaukee, Wisconsin June 20 to 23, 2006.
- Presented paper entitled “Characterization of Feed Streams and Emissions from Biomass Gasification/Combustion at Fuel Ethanol Plants” at the Annual International Meeting of the American Society of Agricultural and Biological Engineers in Portland, Oregon July 9 to 12, 2006.
- Updated combustion and emission test results
- Developed preliminary evaluation of emissions relative to standards results
- Developed preliminary evaluation of control technologies
- Developed preliminary ash characterization and evaluation results
- Defined preliminary electricity producing options
- Defined preliminary technology bundles
- Defined preliminary menu page
- Communicated about project activities; conducted a meeting of project participants in Minneapolis, MN in June; carried out project management, accounting, and reporting functions

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Technical Progress

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Summary of Tasks Listed under Milestone 3

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

- **Feed stream results** – this task was mostly complete at Milestone 2 and results were included in that report. However, at least one sample from the initial sampling of five partner ethanol plants appeared to give inconsistent results. We attempted to get another sample from that plant, but so far have not received the sample. However all of the other results, as reported in the Milestone 2 report, appear to be consistent from plant to plant and also, where available, with results from other studies so we are confident that we have representative date. Those data were summarized in the Milestone 2 report. They were also included in a paper entitled "Characterization of Feed Streams and Emissions from Biomass Gasification/Combustion at Fuel Ethanol Plants" presented at the Annual International Meeting of the American Society of Agricultural and Biological Engineers in Portland, Oregon July 9 to 12, 2006. The paper is available on the web site www.biomassCHPethanol.umn.edu .

- **Combustion options results** – this task was mostly complete at Milestone 2 and results were included in that report. We are continuing to pursue fluidized bed combustion and gasification as primary technologies for biomass conversion. However, systems involving updraft, fixed-bed gasification and stoker-grate combustion systems for DDGS are also under development by equipment suppliers so we are including them in our evaluations of technology alternatives.

- **Fuel processing results** – this task was mostly complete at Milestone 2 and results were included in that report. Combustion and emission results suggest advantages for drier fuels, either DDGS or corn stover so we are focusing our activities on fuel processing and handling systems for these materials.

- **Updated combustion tests results** – preliminary results for this task were described in the Milestone 2 report. Work has continued on modeling fluidized bed combustion and gasification. Results of computational fluid dynamics modeling of fuel combustion in a direct firing burner are described below. These results address both combustion and emissions so they contribute to the emissions tests results as well as the combustion results

Model Introduction

This study evaluates the direct firing combustion option and feasibility for dry grind ethanol plant coproducts using computational fluid dynamics (CFD) modeling. The coproducts 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 coproducts 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 (NO_x), and sulfur dioxide (SO_2). Emission of particulate matter (PM) was not included in the model, because it mainly depends on the details of the particular combustion system and because a high 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 coproducts, 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 in Figure 1, was selected for the modeling of the direct firing of the ethanol plant coproducts. 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 validated the combustion model by Peters and Weber [1]. The dimensions of the furnace are shown in Fig. 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. The total combustion air flow rates for all the fuels are set to be 770 kg/s based on the air flow rate in the experiments for coal. The modeling results for coal show that the averaged 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 ratio of the actual air flow rate to the theoretical combustion air flow 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 of the Modeling

Figure 2 shows the temperature distribution inside the IFRF furnace for different fuels. The temperature contours shown in Figure 2 are plotted on the cross-sectional surface. Figure 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 1) are also listed in Table 1.

For syrup and DWG, the flue gas temperature after combustion is around 1880 ~ 2060 °F. For DDGS and corn stover, this temperature can reach 3300 ~ 3500 °F. The difference in the flame temperature can be explained by the different heat values of the fuels, which are also listed in Figure 2. In the industry furnace, the flame stability is closely related to the adiabatic flame temperature. Fuel with higher flame temperature has 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 industry combustion facilities (e. g. T-fired unit) of PRB coal. For syrup and DWG, the flame temperatures are ~1000 °F 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.

In Figure 2, it is noted that the flue gas temperature for DDGS undergoes a slight increase near the outlet of the furnace. This is because of the gradual reaction of char and COwith O_2 in the flue gas across the furnace.

The water mass fraction inside the burner for syrup and PRB coal is shown in Figure 3. Since the syrup has much higher water content than the PRB coal, the water mass fraction in the flue gas can reach 30% for syrup combustion compared to the 11% of water mass fraction for PRB coal. It is noted that, although DDGS has less water content than PRB coal, the mass fraction of water in the flue gas from firing DDGS is slightly higher than that for PRB coal (also shown in Table 1). This is because DDGS, like other bio-fuels, 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 1. Table 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. Comparing to PRB coal, the results show that firing DDGS and corn stover generate more CO emission. The calculated SO_2 emissions for all biomass fuels are higher than that for PRB coal except for corn stover, which has relatively less sulfur content.

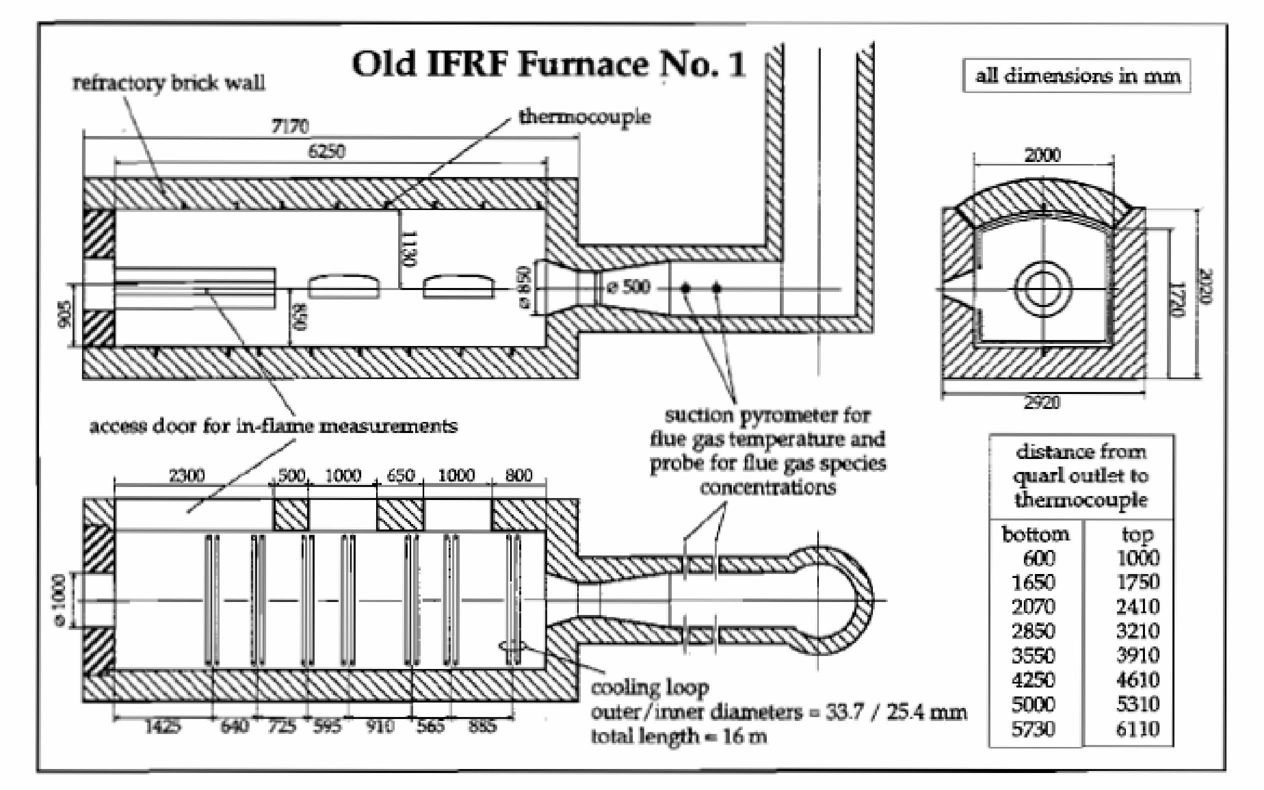
Since this study focuses on the fuel feasibility and the adiabatic combustion conditions, the NO_x emissions calculated in the model are derived from the fuel (fuel NO_x). The thermal NO_x and prompt NO_x are mostly related to the combustion process (e.g. flame temperature, excess O_2), which depends on the detailed engineering design of the combustion facility. The modeled NO_x emission for PRB coal (0.66 lb/mmBtu) in this IFRF furnace is relatively high compared to the NO_x emission from pulverized-coal boiler. This is because the IFRF burner is un-staged, in which no NO_x reduction techniques (i.e. over-fire air) was applied. The modeling results show that firing corn stover gives similar NO_x emission compared to the PRB coal. However, DWG, syrup and DDGS all give higher NO_x emission than PRB coal. With some combustion optimizations, the NO_x emission can be reduced from the predicted value. Post combustion treatment (i.e. selective non-catalytic reduction) may also be necessary for firing some fuels with high predicted NO_x emission.

Conclusion

CFD modeling was conducted for direct firing different ethanol coproducts in an IFRF furnace. Results show that DDGS and core stover have similar flame temperature as that of the PRB coal. For syrup and DWG, the flame temperatures are ~1000 °F lower than that of PRB coal, which imply the potential instability of the flame. The results show that firing DDGS and corn stover generate more CO emission than PRB coal. Except for corn stover, modeling shows that all ethanol coproducts yield higher NO_x and SO_2 emissions in direct firing than the PRB coal.

Reference

[1] Peter, A. F. and Weber, R (1997), Mathematical modeling of a 2.4 MW swirling pulverized coal flame, Combustion Science and Technology, 122, p131.



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 1. IFRF furnace [1]

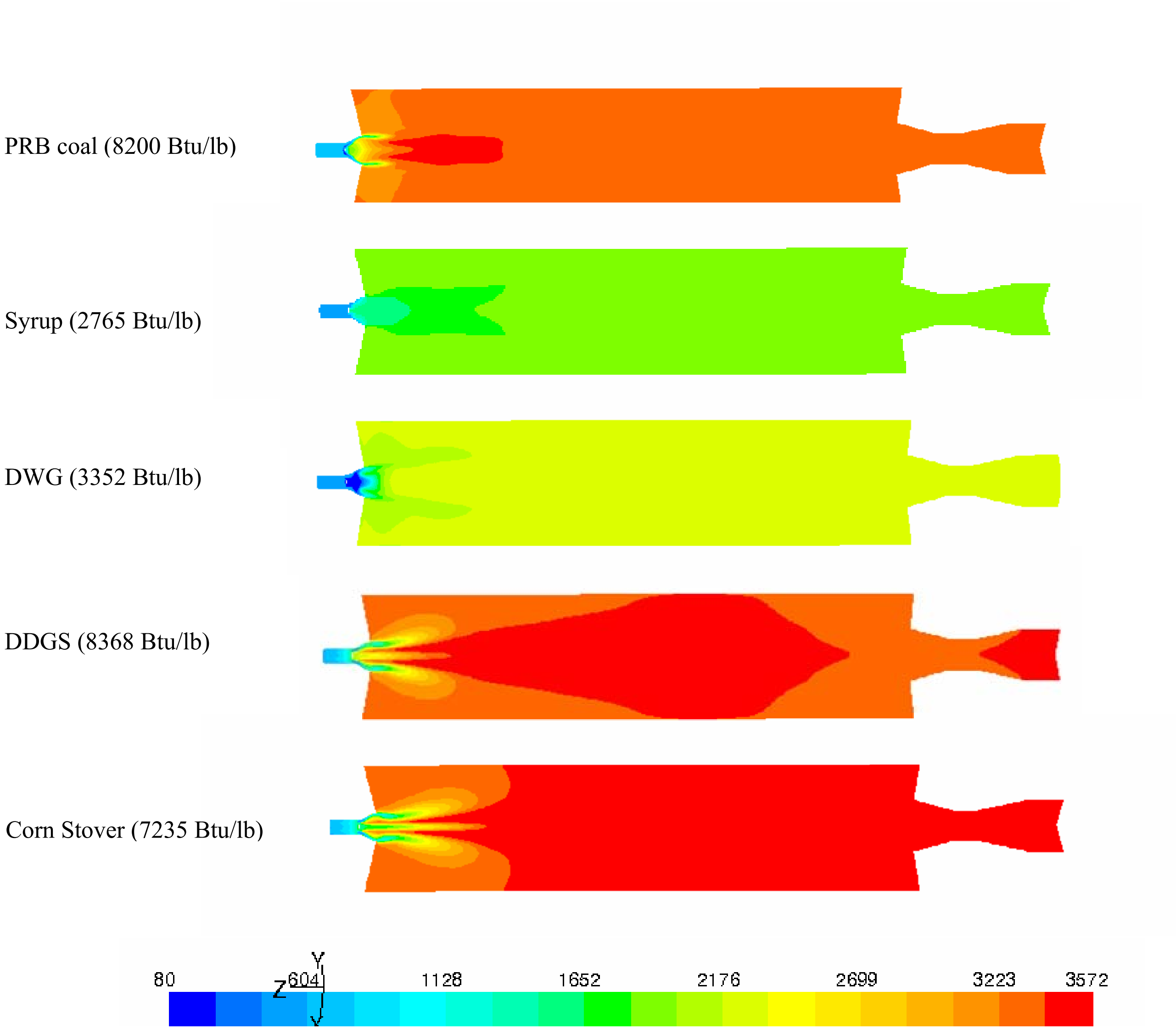


Figure 2 Simulated temperature distribution (in °F) in furnace

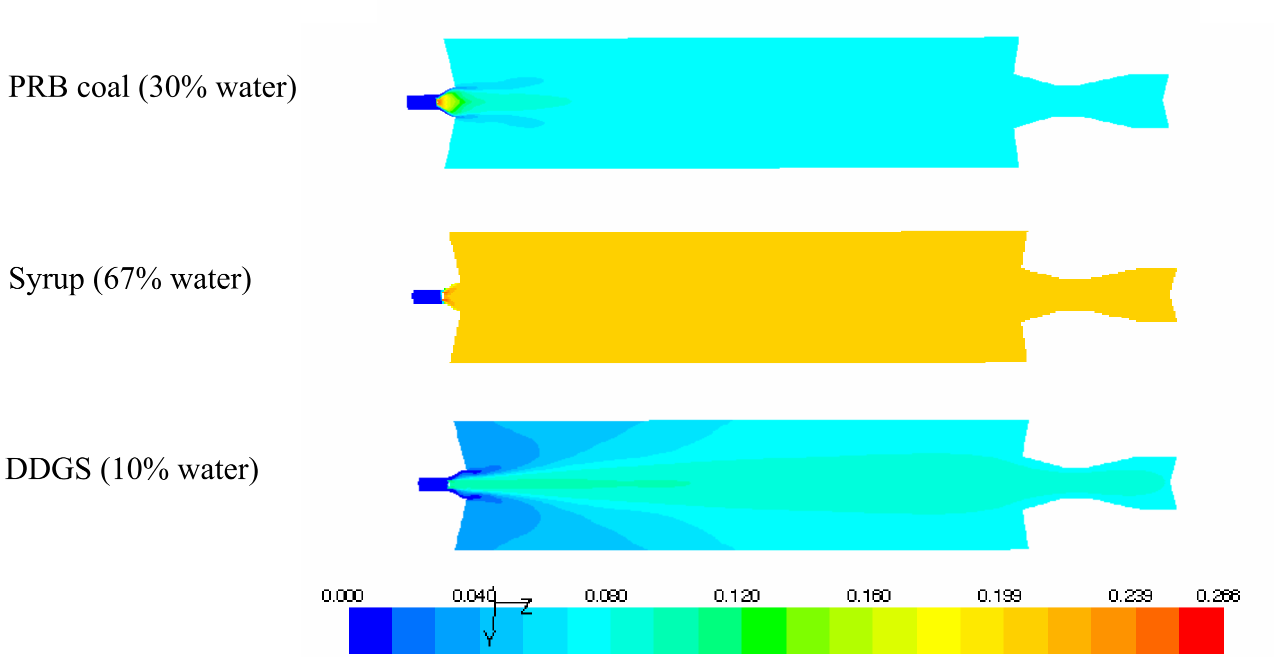


Figure 3 Simulated water mass fraction in the furnace for direct firing

	Temperature (°F)	**O_2 (% vol)**	**H_2O (% vol)**	**CO_2 (% vol)**	**CO (ppm)**	**NO_x (lb/mmBtu)**	**SO_x (lb/mmBtu)**
PRB Coal	3280	4.3	11.4	14.9	0.005	0.63	1.07
Syrup	1948	3.7	30.3	10.6	0.008	0.94	2.31
DWG	2168	3.8	30.1	13.8	0.0004	3.02	1.43
DDGS	3398	3.7	12.9	14.9	1.14	1.09	1.48
Corn Stover	3482	3.5	12.2	16.9	0.41	0.56	0.10

Table 1 Direct firing modeling results summary of flue gas temperature and composition at furnace outlet

- **Updated emissions tests results** – preliminary results for this task were described in the Milestone 2 report. The modeling results in the previous section include emission predictions. These results suggest that the lower moisture content of the DDGS compared to DWG reduces NO_x emissions. Thus, using a drier fuel may help in reducing emissions as well as improving combustion stability.

- **Preliminary evaluation of emissions relative to standards results** – This task focuses on developing baseline air quality compliance profiles for a typical small (50 MMGY) and large (100 MMGY) dry grind, corn-based ethanol fuel production facilities. The report also presents an analysis of air quality regulatory issues that may arise from the use of alternative biomass fuels at these facilities.

Typical fuel ethanol manufacturing facilities today receive whole corn and then mill, cook and ferment it to produce "beer." The beer is further distilled to produce fuel ethanol. The stillage is separated from the ethanol and either sold as a wet feed additive or dried and sold as a dry feed additive, "distiller's dried grains and solubles," or DDGS.

This manufacturing process contains numerous air contaminant emission sources, creating significant emissions of particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM10), carbon monoxide (CO), volatile organic compounds (VOC), 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 feed dryers, fermentation units, gas boilers, cooling cyclones, ethanol truck load-out systems, and the fugitive dust emissions[1] generated from facility operations, such as haul trucks.

These manufacturing processes and emission sources generally do not change in nature as the capacity of the ethanol manufacturing plant increases; nevertheless, the quantity of emissions will increase. We review a fuel ethanol manufacturing facility, as described above, with a capacity of 50 MMGY – a typical Greenfield project today – and one with a nameplate manufacturing capacity of 100 MMGY – a typical goal for an expansion project today.

Overview of Air Quality Regulation

The federal Clean Air Act, and numerous state air quality control statutes, regulates air quality using a variety of strategies. Broadly, there are two primary strategies applicable to Greenfield manufacturing facilities: (1) air quality control regulations 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. 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 airshed and regional air quality goals, dispersion characteristics, and local nuisance requirements, are included.

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

Federal Emission Standards

Section 111 of the Clean Air Act authorizes the USEPA to develop "New Source Performance Standards" 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 cut pollution from the heaviest polluting emission sources. One category of sources subject to NSPS are industrial, commercial and institutional steam generating units (*e.g.*, boilers) with a heat input capacity greater than 100 million Btu/hr. A recent USEPA memorandum states that thermal oxidizers and heat recovery steam generators used at fuel ethanol manufacturing facilities are subject to 40 CFR Part 60, Subpart Db. Subpart Db applies to sources constructed, modified, or reconstructed after June 19, 1984.

Subpart Db provides emission standards for SO_2, PM, and NO_x. The NO_x standards apply to natural gas-fired units and require either the use of continuous emission monitoring systems, or CEMS, or a parametric emission monitoring system, or PEMS. Standards for emissions of all three air contaminants apply to coal- and oil-fired units.

Potential Air Quality Control Issues for Alternative Biomass-fired Plants - Federal Standards

Small and large fuel ethanol manufacturing facilities generally use a steam generating unit with a heat input capacity exceeding 100 million Btu/hr. Consequently, NSPS Subpart Db is likely to be a requirement for alterative biomass-fueled facilities as well. However, because the biomass fuels examined in this study are not listed fuels, specific requirements will need further evaluation.

NSPS Subpart Kb will apply to small and large fuel ethanol manufacturing facilities using alternative biomass fuels. Nevertheless, the use of alternative fuels does not affect the nature or quantity of VOC emissions controlled through Subpart Kb. Consequently, Subpart Kb standards will not change for the study model plants.

Likewise, NSPS Subpart VV emission units are not affected by the change in the combustion processes in the study model plants. Consequently, Subpart VV standards will not change for the study model plants.

Depending on source status, the NESHAPs for industrial process cooling towers is likely to apply to the study model plants, as it does to the baseline plants. Nonetheless, the standard simply ensures that chromium-based water treatment chemicals are not introduced to the cooling tower process. Because the state-of-the-art for cooling water treatment has moved beyond the need for chromium, the compliance profile for the study model plants is not likely to change.

The study model plants have the potential for emitting greater than 10 tpy of a single hazardous air pollutant and/or 25 tpy of a combination of hazardous air pollutants. Consequently, case-by-case MACT is a possibility. The study model plants do not include emission sources, in addition to the baseline plants, that are defined as affected facilities. Thus, no source category MACT standards apply, only case-by-case MACT is a potential standard.

BACT/LAER

The federal new source review program requires the application of control technology to newly constructed sources on a case-by-case basis. New source review is a pre-construction permit program that serves as the procedure for determining appropriate control technology for a new emission source, among other things. For sources proposed for attainment areas, the NSR control technology standard is “best available control technology,” or BACT. For sources proposed for nonattainment areas, the NSR control technology standard is “lowest achievable emission rate,” or LAER, the most stringent control standard in use. These standards were intended to be “technology-forcing” standards. That is, the Clean Air Act anticipates that control technologies will change and improve over time. Therefore, the NSR control standards would increasingly reduce emissions with each new source review of available control technology.

- **Preliminary evaluation of control technologies** – Combustion of biomass coproducts feed streams in any of the combustion technologies considered in this project will produce emissions of criteria pollutants such as particulate matter (PM), sulfur dioxide (SO2), oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs), as well as hazardous air pollutants (HAPs) which are a subcomponent of the total VOC emissions. These emissions must comply with local, state, and federal requirements at the exhaust point from the combustion system and in the ambient air surrounding the fuel ethanol facility. Because of the costs and energy requirements of emission controls, the technical analysis must include both emissions intrinsic to the particular combustion system and emissions following emission control.

Based on the results of emission predictions performed in this project, and the identification of the expected emission rate(s) and regulatory limitations 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 emissions control options were identified, including both demonstrated and proposed techniques, and certain add-on or process modifications. Technically feasible control options and combinations were evaluated and ranked based on potential emissions 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 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 and add-on or process modifications, applicable to the proposed source and pollutant.
2. Elimination of 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. Ranking of the remaining control technology options by pollutant control effectiveness.
4. Evaluation to determine the most effective emission control options 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. Selection of the ‘best’ emission control options for the proposed source.

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

Control Technologies Evaluated

The project proposal included an evaluation of potential alternative control technologies for these pollutants. However, no demonstrated alternative control technologies for these pollutants have come to light in the course of this project. Regarding pollutant control effectiveness, all of 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 on site-specific factors.

Table CTXX. Summary of Feasible Control Technology Options by Pollutant

PM	**SO_2**	**NO_x**	**CO**	**VOCs/HAPs**
Demonstrated Control Technologies				
- Fabric Filtration - Wet Scrubbing - Electrostatic Precipitation	- Fuel Alternatives - Wet Scrubbing - Dry Scrubbing - Fuel Additives	- Fuel Alternatives - Low NO_x Burners - Combustion Controls - Selective Non-Catalytic Reduction (SNCR) - Selective Catalytic Reduction (SCR)	- Catalytic oxidation	- Carbon Adsorption - Condensation - Fume Oxidiation

- **Preliminary ash characterization and evaluation results** – Combustion of any of the biomass coproduct 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 coproduct streams was determined through laboratory testing of the samples obtained at the partner ethanol plants. Samples were ashed in laboratory furnaces at a maximum temperature of 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 coproducts ranges from less than 2% to over 8%, while the ash content of corn stover is typically around 6%-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.

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 to the atmosphere will be negligible. An ethanol plant with a nominal capacity of 4 tons per year of DDGS. Assuming the DDGS is 10% moisture, this amounts to about 120,000 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.

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 mgy fuel ethanol plant will use about 15 million bushels of corn annually. At 56 pounds per bushel, this is 420,000 tons of corn per year. At 1.4% ash in the corn, the maximum ash production is calculated to be 5,900 tons per year.

Ash Mineral Analysis

Ash samples from syrup, DWG, DDG, DDGS, and corn stover were subjected to a standard analysis of mineral content. Results 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 coproduct streams, so all data are from project samples. The ash mineral composition of the coproduct 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%.

Physical Characteristics of the Ash

Ash samples from a fluidized bed burning syrup were analyzed for physical characteristics, including sieve distribution, bulk density, and specific gravity. Note that significant fluidized bed material (limestone) is mixed with the ash, affecting both physical and chemical characteristics. However, the sample is representative of materials requiring 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 coproducts (except syrup), at 32.5 lb/ft^3.

Literature data were not available for the physical characteristics of ash.

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 under both oxidizing and reducing conditions.
For the oxidizing atmosphere, the ash fusion temperatures differed widely among partner ethanol plants and among coproduct 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 at which the tested ash samples demonstrated problematic behavior.

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 600°F-800°F 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.

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. Note that significant fluidized bed material (limestone) is mixed with the ash, affecting both physical and chemical characteristics. However, the sample is representative of materials requiring 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.

Ash Management Equipment

Ash will be collected from both the bottom of the combustion chamber (bottom ash) and equipment (i.e., pollution control and heat recovery) beyond the combustion chamber (fly ash). For the purposes of this discussion, fly ash encompasses a larger variety of ash collected from pollution control and heat recovery equipment. Various types of ash management equipment have been used with coal-fired furnaces as well as biomass-fired furnaces. These include hydraulic and mechanical systems for bottom ash; and vacuum/pressure and dense-phase systems for fly ash. In any case, the ash handling systems will need to be customized to meet the specific CHP system.

Handling the ash will be difficult because of its fine particle size and its water-absorbent nature. Hydraulic handling of ash may be less problematic. However, the additional water will require additional transport and storage costs. Furthermore, the additional weight would add to disposal costs if the ash is not reused.

Ash Beneficial Use

Ash has potential for beneficial use in several ways: as nutrient recovery for application to the land, for aquaculture, etc.; as fill material or aggregate in construction and manufacturing; as cover in landfill disposal operations; and as road abrasive in cold weather conditions. Each of these is discussed in more detail below.

Nutrient Recovery - The high phosphorus and potassium content of the ash make it a good soil additive for agriculture.

Fill Material - The ash can be used for a variety of structural and low-strength fill applications, such as use in mineral filler in paints, shingles, and carpet backing; use in mortars and stuccos; and use in the production of concrete. It can be used for fill in road beds, for waste stabilization, and as an alloying material for lightweight castings.

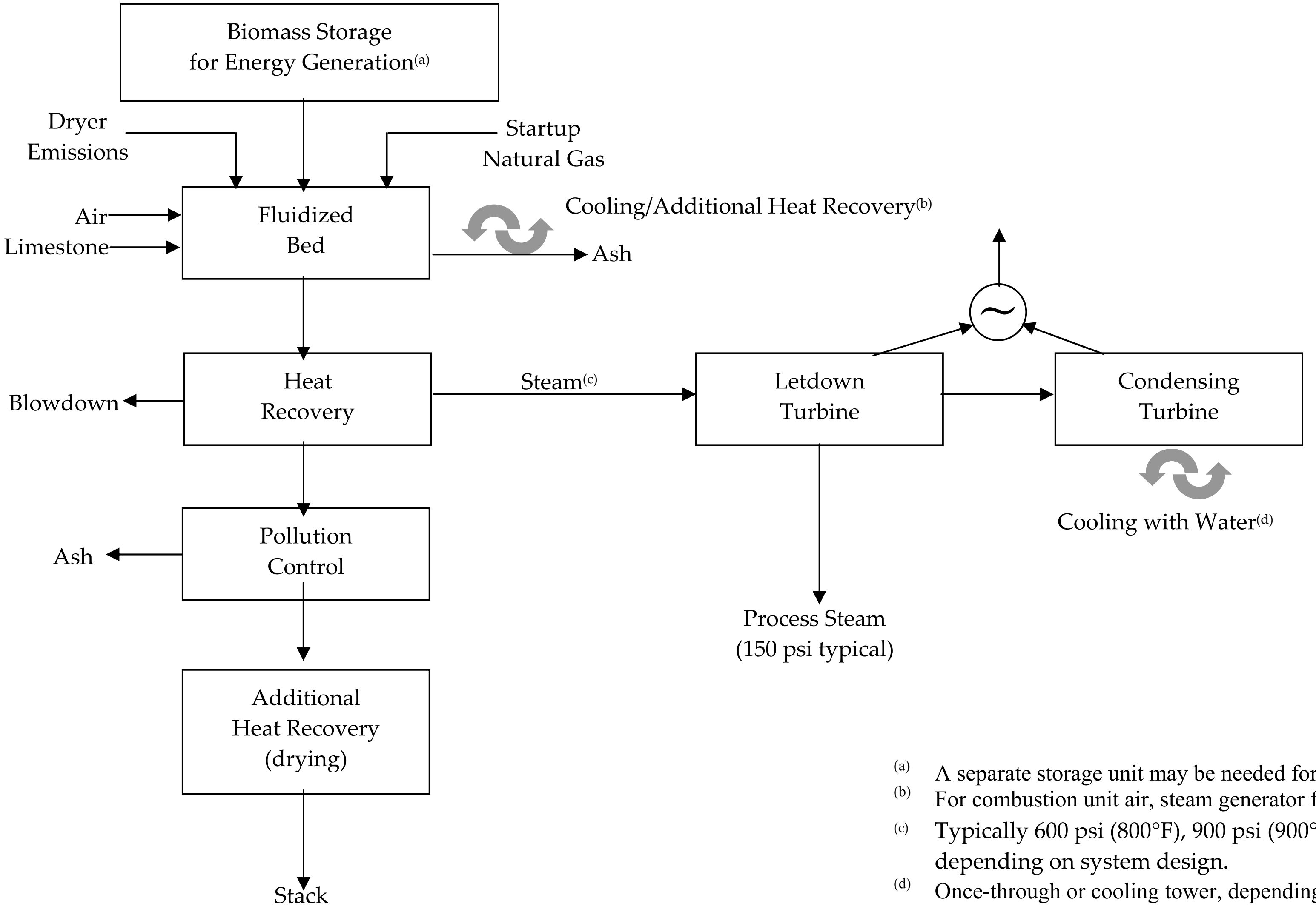
Landfill Cover - In a stable form, the ash may provide suitable cover material at landfills
.
Road Abrasive - In a stable form, the ash could be used as a road surface additive to reduce icing.

For any type of use, both environmental regulatory and ash handling potential health issues will need to be addressed. In most environmental frameworks, ash from the combustion of various fuels (coal, biomass, etc.) is often considered an industrial byproduct, which could require state agency interactions, such as characterization and reporting. Also, because of the expected variability of the ash captured/collected from the CHP system, it is difficult to predict ash characteristics. However, based on the information discussed in this chapter, beneficial use of the ash is likely.

Owing to the high pH, the fine particle size, and hygroscopic nature of the ash, it poses an exposure threat to those working with the ash.

- **Preliminary electricity producing options** – the following diagrams outline preliminary options for producing electricity and process heat or process heat alone. They include options for biomass conversion – combustion or gasification – and possible ways of generating electricity from with those conversion technologies.

Fluidized Bed Combustion with Electricity Generation and Process Heat



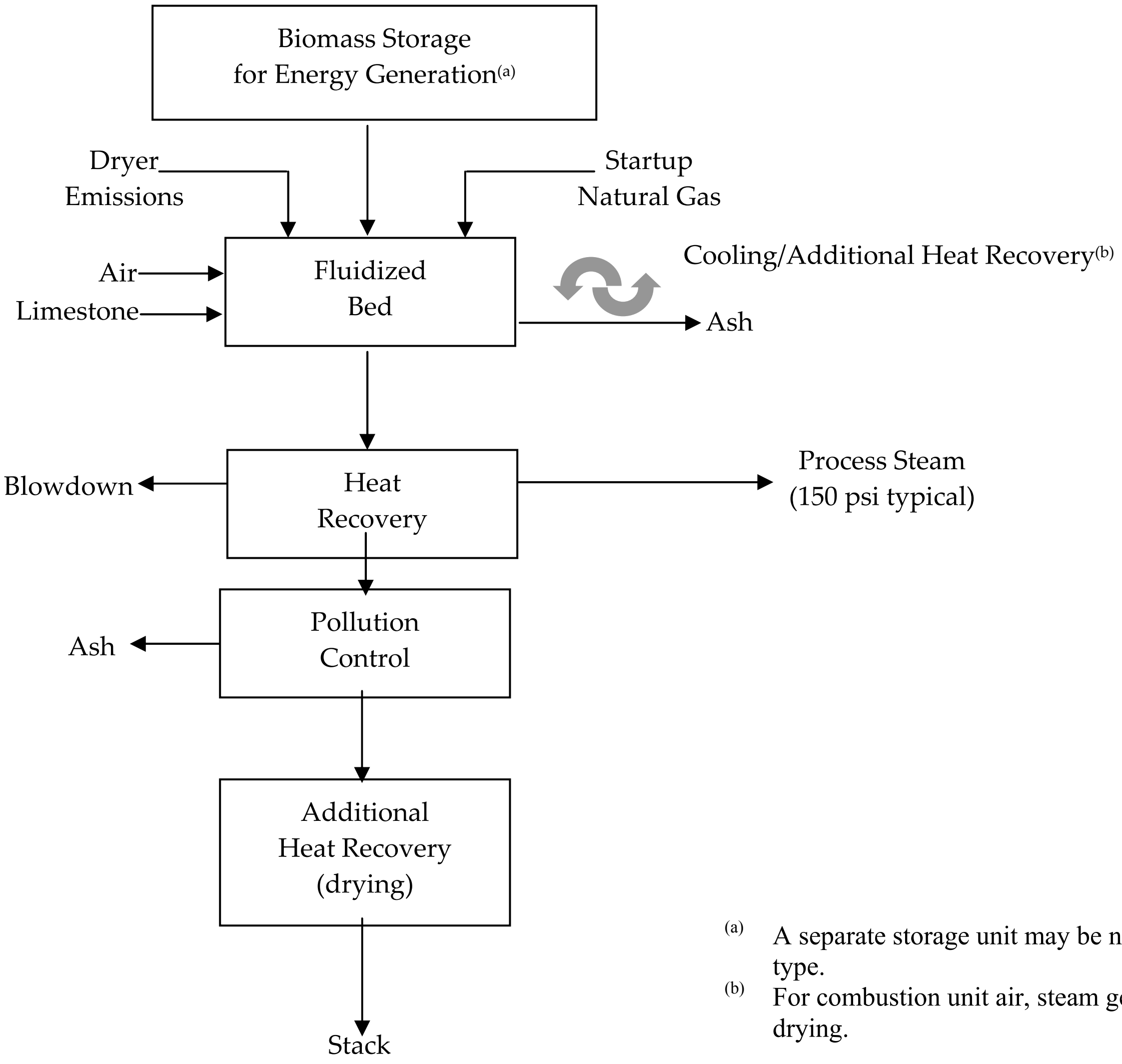
(a) A separate storage unit may be needed for each biomass type.

(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.

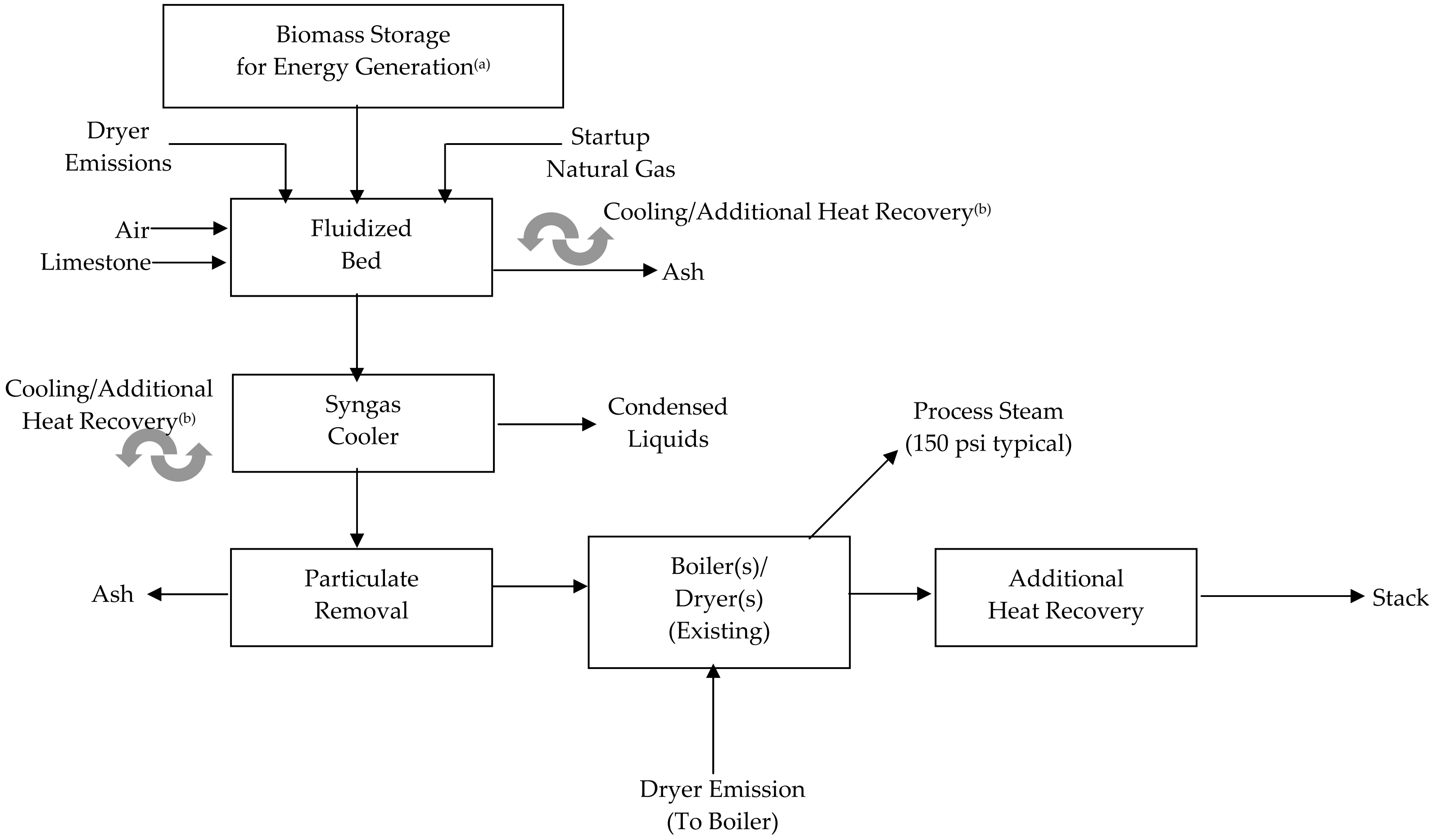
Fluidized Bed Combustion with Only Process Heat



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

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

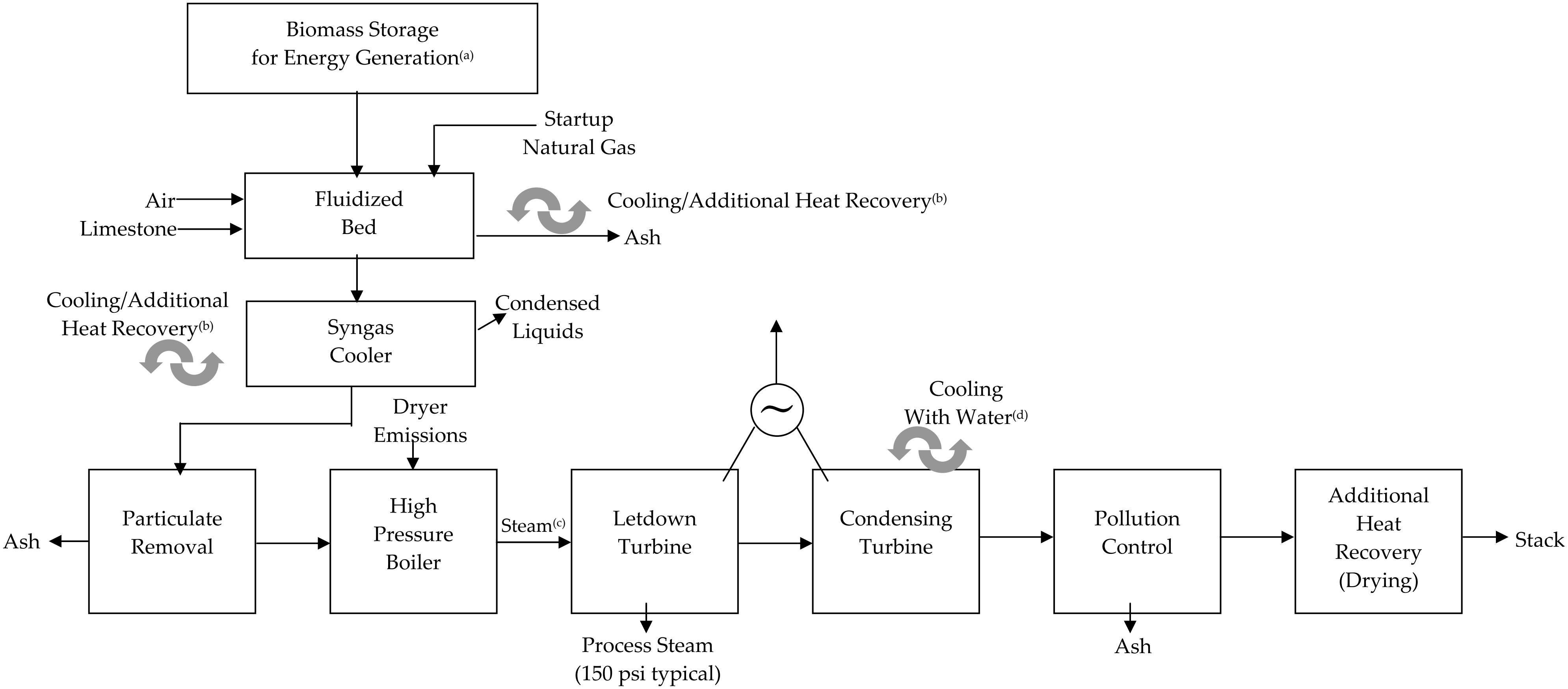
Fluidized Bed Gasification with Only Process Heat



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

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

Fluidized Bed Gasification with Electricity Generation and Process Heat (Steam Turbine)

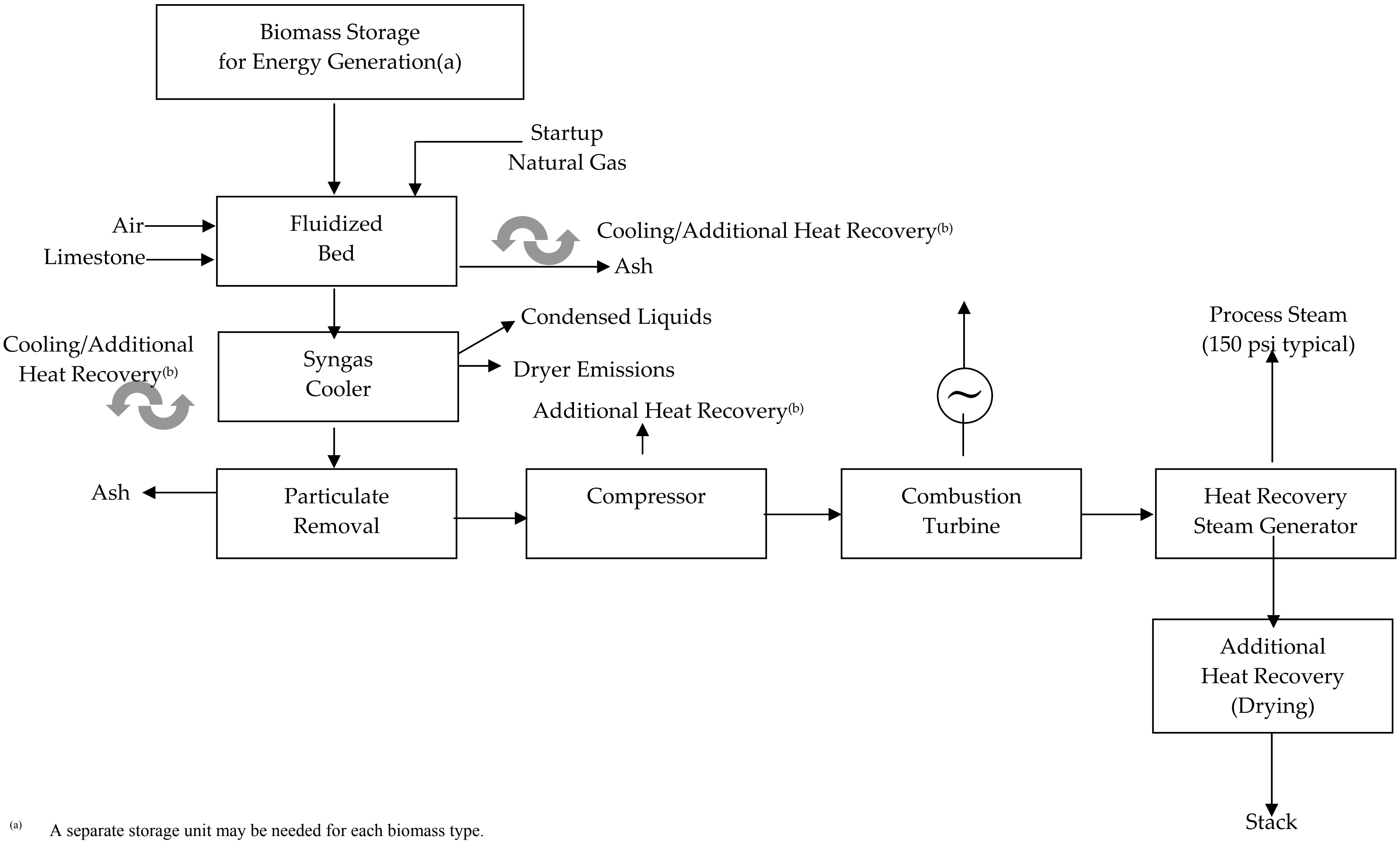


(a) A separate storage unit may be needed for each biomass type.

(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.

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.

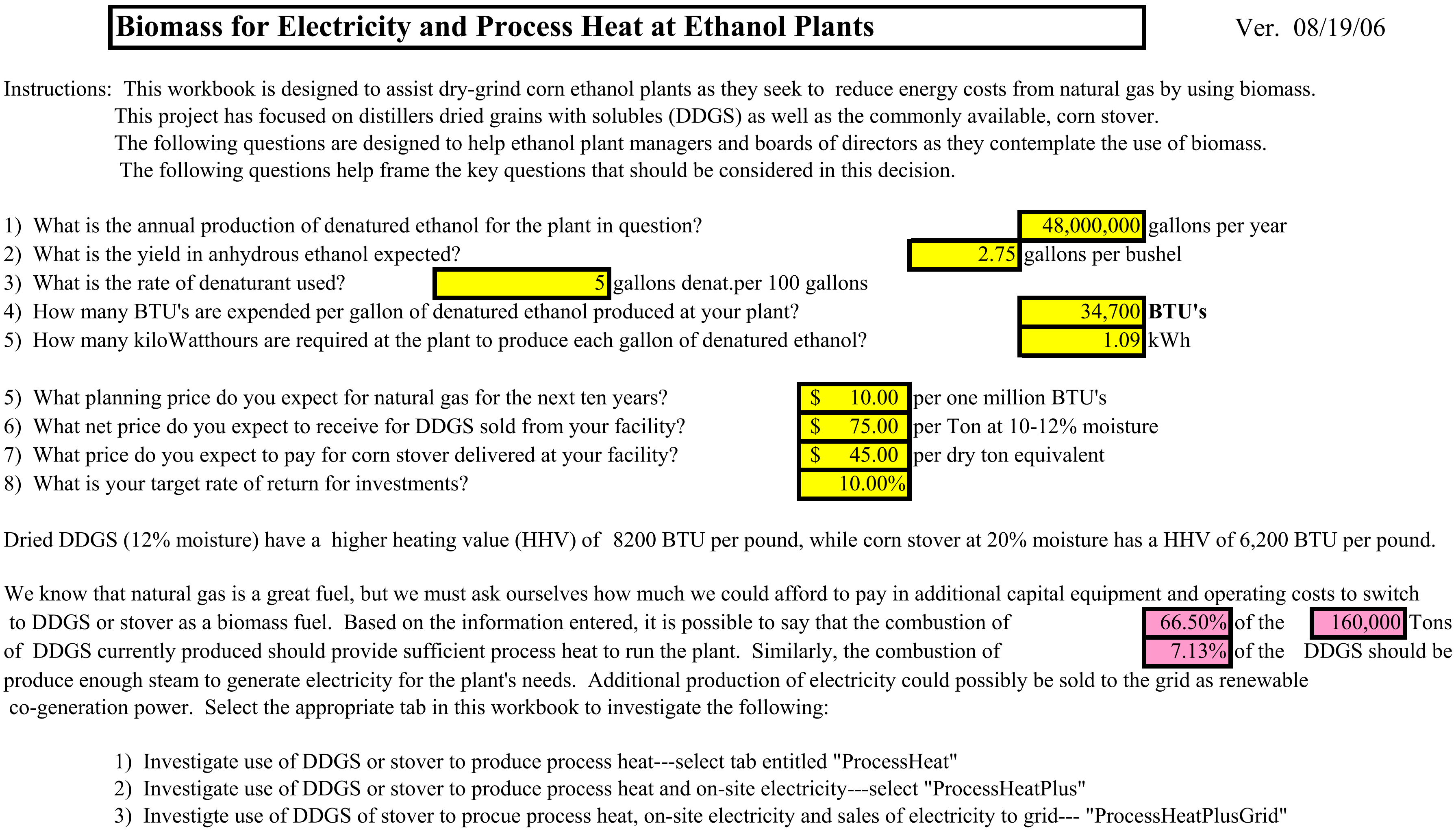
- **Preliminary specification of technology bundles** – We are specifying technology bundles for biomass fuels in terms of thermal conversion process (combustion or gasification), thermal conversion technology (fluidized bed, updraft, downdraft, stoker-grate), and process heat only or power generation (steam turbine, gas turbine, combined cycle) plus process heat. These alternatives are shown in the spreadsheet below.

Technology Bundle	Priority	Modeling Difficulty	Thermal Conversion Technology		Power Generation or Other Equipment
1a	A	1	Combustion	Fluidized bed	Steam Turbine
1b	A	1	Combustion	Fluidized bed	Boiler (only process heat)
2a	B	1	Combustion	Stoker/Grate	Steam Turbine
2b	B	1	Combustion	Stoker/Grate	Boiler (only process heat)
3a	A	2	Gasification	Fluidized bed	Steam Turbine
3b	A	2	Gasification	Fluidized bed	Boiler (only process heat)
4a	C	3	Gasification	Fluidized bed	Gas Turbine or Combined Cycle
4b	C	2	Gasification	Fluidized bed	Boiler (only process heat)
5a	B	2	Gasification	Updraft	Steam Turbine
5b	B	2	Gasification	Updraft	Boiler (only process heat)
6a	C	3	Gasification	Updraft	Gas Turbine or Combined Cycle
6b	C	2	Gasification	Updraft	Boiler (only process heat)
7a	A	2	Gasification	Downdraft	Steam Turbine
7b	A	2	Gasification	Downdraft	Boiler (only process heat)
8a	C	3	Gasification	Downdraft	Gas Turbine or Combined Cycle
8b	C	2	Gasification	Downdraft	Boiler (only process heat)

We are evaluating potential performance of these technology alternatives using an Aspen Plus model of the complete dry-grind ethanol process. We have obtained an Aspen Plus model of the existing dry-grind process from USDA-ARS. We are adding components for biomass thermal conversion technologies, emissions prediction and control, process heat utilization, and combined heat and electric power production.

We hope that the model will allow us to effectively and accurately compare systems by keeping track of mass and energy flows throughout the system as we evaluate various alternatives. Using this information we can specify equipment components and develop estimates for capital and operating costs associated with these biomass alternatives.

- **Preliminary development of menu page** – example below



Biomass for Electricity and Process Heat at Ethanol Plants

Ver. 08/19/06

Instructions: This workbook is designed to assist dry-grind corn ethanol plants as they seek to reduce energy costs from natural gas by using biomass.
This project has focused on distillers dried grains with solubles (DDGS) as well as the commonly available, corn stover.
The following questions are designed to help ethanol plant managers and boards of directors as they contemplate the use of biomass.
The following questions help frame the key questions that should be considered in this decision.

1) What is the annual production of denatured ethanol for the plant in question? 48,000,000 gallons per year
2) What is the yield in anhydrous ethanol expected? 2.75 gallons per bushel
3) What is the rate of denaturant used? 5 gallons denat.per 100 gallons
4) How many BTU's are expended per gallon of denatured ethanol produced at your plant? 34,700 **BTU's**
5) How many kiloWatthours are required at the plant to produce each gallon of denatured ethanol? 1.09 kWh

5) What planning price do you expect for natural gas for the next ten years? $ 10.00 per one million BTU's
6) What net price do you expect to receive for DDGS sold from your facility? $ 75.00 per Ton at 10-12% moisture
7) What price do you expect to pay for corn stover delivered at your facility? $ 45.00 per dry ton equivalent
8) What is your target rate of return for investments? 10.00%

Dried DDGS (12% moisture) have a higher heating value (HHV) of 8200 BTU per pound, while corn stover at 20% moisture has a HHV of 6,200 BTU per pound.

We know that natural gas is a great fuel, but we must ask ourselves how much we could afford to pay in additional capital equipment and operating costs to switch to DDGS or stover as a biomass fuel. Based on the information entered, it is possible to say that the combustion of 66.50% of the 160,000 Tons of DDGS currently produced should provide sufficient process heat to run the plant. Similarly, the combustion of 7.13% of the DDGS should be produce enough steam to generate electricity for the plant's needs. Additional production of electricity could possibly be sold to the grid as renewable co-generation power. Select the appropriate tab in this workbook to investigate the following:

1) Investigate use of DDGS or stover to produce process heat---select tab entitled "ProcessHeat"
2) Investigate use of DDGS or stover to produce process heat and on-site electricity---select "ProcessHeatPlus"
3) Investigte use of DDGS of stover to procue process heat, on-site electricity and sales of electricity to grid--- "ProcessHeatPlusGrid"

- **Summary of project management activities, travel, etc. for period (RMT)** – Dennis Hatfield met with Doug Tiffany and Vance Morey on June 7 in the Twin Cities for project planning. The group also met with AMEC personnel and toured the University of Minnesota steam plant to view the recirculating fluidized bed boiler. Dennis Hatfield attended the Fuel Ethanol Workshop in Milwaukee, WI on June 20 to 22.

- **Summary of project management activities, travel, etc. for period (UofM) –** activities supported progress on tasks described above. Doug Tiffany and Vance Morey met with Dennis Hatfield, AMEC personnel and toured the University of Minnesota steam plant as described above. Matt DeKam jointed the project as a graduate research assistant on June 12. Doug Tiffany, Matt DeKam, and Vance Morey attended the Fuel Ethanol Workshop in Milwaukee, WI on June 20 to 22. Doug Tiffany presented a paper on economic and technical issues associated with using biomass generate electricity and process heat at ethanol plants. We distributed cards describing our project at the meeting.