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Project Title: Biomass Electricity Generation at Ethanol Plants - Achieving Maximum Impact

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Milestone Description: Second 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 to make recent results more readily available to the public.
- Continued to refine the model of biomass integrated gasification combined cycle (BIGCC) power production at corn ethanol plants. Four configurations have been modeled in detail so that equipment specifications and cost estimates can be developed. Equipment costs are an important component of the economic analysis because they allow us to develop more accurate estimates for rate of return on investment. This information is essential for potential investors to evaluate the economic viability of alternatives to generate renewable, dependable, biomass-based electricity using BIGCC.
- Developed a model of the superheated steam drying process, which provided first estimates of energy and water savings. Process energy savings allow more fuel energy to be converted to electricity to be sent to the grid, which is a major goal of the project. The superheated steam drying process allows condensation, recovery, and reuse of water removed from the distillers wet grains, which reduces the total water requirement for producing ethanol and electricity, another goal of the project.
- Continued to identify opportunities through financial markets, government policies, and incentives that will make it more attractive for potential investors to consider projects to generate renewable electricity at ethanol plants. Investors need financial and policy information, as well as technical/economic analysis, when considering these large, long-term investments.
- Updated our model for a logistics system that would deliver corn stover to an electricity generation facility at an ethanol plant on a year around basis. The cost estimates for delivering corn stover fuel are an important part of the economic analysis. We also updated our estimates of life-cycle greenhouse gas emissions for corn stover as a fuel compared to natural gas and coal. Documenting life-cycle greenhouse gas emission

reductions for producing ethanol and generating renewable electricity will be an important consideration in policy and economic decisions related to investments in alternative energy. This information will be critical to final decisions related to adopting these new renewable technologies.

- Communicated about project activities; carried out project management, accounting, and reporting functions.

Project funding provided by customers of Xcel Energy through a grant from the Renewable Development Fund.

Technical Progress

Prepared by
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Summary of Tasks Listed under Milestone 3

1A. Integrated gasification combined cycle analysis

- Complete modeling combined cycle system performance
- Complete determination of drying requirements for syrup-stover configuration
- Continue evaluation of combined cycle alternatives
- Continue specification of equipment and determination of capital and operating costs

We have continued to model BIGCC systems for a range of fuels, energy input rates, and compression levels for the gas turbine. All systems are designed to meet the process energy and electricity needs of a 50 million gallons per year ethanol plant, plus send as much electricity to the grid as possible.

Fuel inputs rates are specified in terms of MW_{th} and include: 105 MW, 110 MW, 115 MW, and 120 MW. They allow us to study the sensitivity to fuel input rates for different levels of gas compression.

Two levels of synthesis gas compression for the gas turbine are evaluated. They include: 10 atm which requires two compressors and is referred to as 10 atm (2 stage), and 20 atm which requires three compressors and is referred to as 20 atm (3 stage).

The results for the three fuel types are summarized below.

Table 1. Results for syrup and corn stover.

	105 MW (2 stage)	**110 MW (2 stage)**	**115 MW (2 stage)**	**110 MW (3 stage)**	**115 MW (3 stage)**	**120 MW (3 stage)**
Generation Efficiency	27.1%	27.1%	27.0%	28.4%	28.8%	28.6%
Thermal Efficiency	72.4%	70.1%	68.2%	70.7%	69.2%	67.2%
Power to Grid, MW	20.2	21.3	22.5	22.0	23.6	24.6
Total Power, MW	28.5	29.8	31.1	31.2	33.1	34.3

For all cases, the flow rate of syrup is 508.7 tonne/day. For 105 MW, 110 MW, 115 MW, and 120 MW, the flow rate of stover is 367.9 tonne/day, 395.6 tonne/day, 423.3 tonne/day, and 451.0 tonne/day, respectively.

Table 2. Results for corn stover.

	105 MW (2 stage)	110 MW (2 stage)	115 MW (2 stage)	110 MW (3 stage)	115 MW (3 stage)	120 MW (3 stage)
Generation Efficiency	26.7%	26.7%	26.7%	28.5%	28.4%	28.4%
Thermal Efficiency	71.6%	69.4%	67.3%	70.3%	68.3%	66.4%
Power to Grid, MW	20.0	21.1	22.1	22.2	23.3	24.4
Total Power, MW	28.1	29.4	30.7	31.3	32.7	34.1

For 105 MW, 110 MW, 115 MW, and 120 MW, the flow rate of stover is 581.6 tonne/day, 609.3 tonne/day, 637.0 tonne/day, and 664.7 tonne/day, respectively.

Table 3. Results for syrup and corncobs.

	105 MW (2 stage)	110 MW (2 stage)	115 MW (2 stage)	110 MW (3 stage)	115 MW (3 stage)	120 MW (3 stage)
Generation Efficiency	27.1%	27.1%	27.1%	28.6%	28.9%	28.9%
Thermal Efficiency	72.4%	70.2%	68.1%	70.9%	69.1%	67.3%
Power to Grid, MW	20.2	21.4	22.5	22.1	23.6	24.8
Total Power, MW	28.5	29.8	31.2	31.4	33.2	34.6

For all cases, the flow rate of syrup is 508.7 tonne/day. For 105 MW, 110 MW, 115 MW, and 120 MW, the flow rate of cobs is 360.4 tonne/day, 387.6 tonne/day, 414.7 tonne/day, and 441.8 tonne/day, respectively.

We will focus our economic analysis on syrup and corn stover, and corn stover fuels. We will also consider 110 MW_{th} fuel inputs for 10 atm (2 stage) and 20 atm (3 stage) compression, a total of four combinations. The four combinations are highlighted in Tables 1 and 2. Increasing gas compression for the gas turbine increases power to the grid by about 5% with the same fuel input in most cases with corresponding increases in generation and thermal efficiencies. It will be important to determine if the increased power output justifies the increased cost for equipment.

The following narrative describes the characteristics of the eight systems in general. The narrative focuses on the 110 MW 2-stage syrup and corn stover case and the system is shown in the diagram below (Figure 1). The detailed system characteristics have been sent to our subcontractor AMEC E&C Services so that they can provide equipment specifications and capital cost estimates.

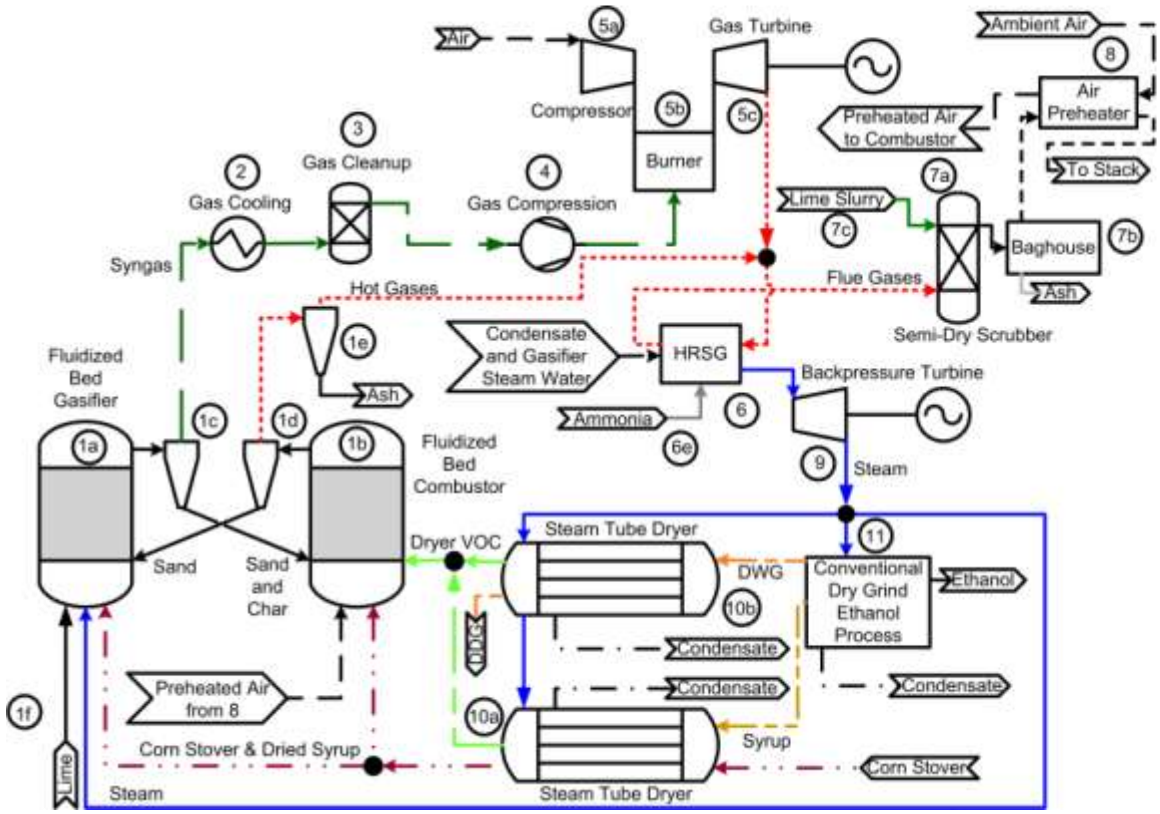

Figure 1. Schematic of BIGCC system for 110 MW syrup & corn stover fuel.

1 Twin Fluidized Bed Gasification/Combustion System Modeled after Silva Gas Process, Commercialized By FERCO.

1a Fluidized Bed Gasifier

The gasifier operates at atmospheric pressure (100 kPa or 0 psig). It is steam driven, and about 2900 kg of steam per hour is sent to the gasifier. About 65% (by weight) of fuel is fed to the gasifier. It produces about 16,254 kg/h of synthesis gas at 1143 K (1598 °F).

Since our study follows the Silva Gas process, sand is assumed to serve as the media for transferring heat from combustor to gasifier, but sand is not really modeled. A simple heat stream is used to represent the heat transferred by sand. This method eliminates the need for multiple feedback loops and decreases unnecessary modeling complexity.

1b Fluidized Bed Combustor

The combustor serves to provide heat to the gasifier to complete the gasification and to destroy VOCs from the dryer exhaust. Air needed for combustion includes dryer(s) exhaust and ambient air. The ambient air has been preheated by stack exhaust by a counter-flow heat exchanger which makes the temperature of air heated 4 °C lower than that of the stack exhaust gas leaving baghouse. The mass flow rate of exhaust from dryer for ethanol co-product (i.e., DDG) is 40,850 kg/h, and that from dryer for fuel (i.e., syrup and stover) is 32,830 kg/h. The temperature of the exhaust is about 360 K (188 °F). About 35% (by weight) of fuel is sent to the combustor to provide heat to the gasifier. About 14,660 kg/h of preheated ambient air (in addition to exhaust from dryers) is added to the combustor to provide oxygen.

1c Cyclone after Gasifier

This cyclone serves to remove char and sand from the synthesis gas, and then send them to the combustor to recover some heat. Sand here is the media transferring heat from combustor to gasifier, but sand is not really modeled.

1d The First Cyclone after Combustor

It is supposed to remove sand from exhaust gas from combustor in real production process, but is not modeled.

1e The Second Cyclone after Combustor

The second cyclone is used to remove ash from exhaust gas exiting the combustor. The flow rate of exhaust gas and ash are 97,505 kg/h and 1456 kg/h, respectively.

1f Limestone Added to the Gasifier

About 251 kg limestone per hour is sent to gasifier to reduce acid gas.

2 Gas Cooling (counter-flow heat exchanger)

The synthesis gas leaving the gasifier is first cooled by a heat exchanger using 10,000 kg/h boiler water at 7500 kPa (1073 psig) and 420.8 K (298 °F) with a vapor fraction of 0. This flow rate is adjusted to make sure that the temperature of the synthesis gas leaving the heat exchanger is 423 K (301 °F). This amount of boiler water has become vapor when it leaves the heat exchanger, and is then mixed with other steam in the power cycle before entering the super heat boiler. The temperature of the synthesis gas is 1143 K (1598 °F), and its mass flow rate is 16,250 kg/h.

3 Gas Cleanup
3a Wet Scrubber
The gas leaving the heat exchanger first passes a wet scrubber where a certain amount of water at 25 °C and 1 atm is added to remove tar and particles as well as to cool the synthesis gas to 358 K (184 °F). Tar begins to condense when temperature is below 355 K (179 °F). Tar removal has not been modeled until now, and the amount of water used is about 654 kg/h.

3b Acid Gas Removal
Tar and other acid gases such as HCl, H_2S and ammonia are removed here, and the removal efficiency is assumed to be 100%.

The flow rates of tar and acid gases are: 91 kg/h of tar, 50 kg/h of H_2S, 26 kg/h of HCl, and 222 kg/h of ammonia. Currently, the gas cleanup is simply modeled, and in the future, the combination of wet scrubber + venturi scrubber + demister will be employed to remove tar and acid gases as well as to cool the synthesis gas.

4 Gas Compressors
For the 10 atm (2 stage) compression system, no heat energy is captured from either compressor. Synthesis gas enters the first compressor at 358 K (184 °F) and 100 kPa (0 psig), and leaves at 500 K (440 °F) and 316 kPa (31 psig). After the intercooler between the first and second compressors, synthesis gas enters the second compressor at 423 K (302 °F) and 316 kPa (31 psig), and leaves at 584 K (591 °F) and 1000 kPa (130 psig).

For 20 atm (3 stage) compression system, energy is captured between the second and third compressors by a heat exchanger using about 2000 kg/h of boiler water. A cross-flow heat exchanger is used to convert this amount of boiler water into steam. Steam side pressure drop is 0.5 MPa (58 psig). This steam is then mixed with other steam before entering the super heat boiler. Synthesis gas enters the first compressor at 358 K (184 °F) and 100 kPa (0 psig), and leaves at 480 K (404 °F) and 271 kPa (25 psig). After the intercooler between the first and second compressors, synthesis gas enters the second compressor at 423 K (302 °F) and 271 kPa (25 psig), and leaves at 560 K (548 °F) and 737 kPa (92 psig). Synthesis gas enters the third compressor at 423 K (302 °F) and 737 kPa (92 psig), and leaves at 581 K (586 °F) and 2000 kPa (275 psig).

5 Gas Turbine
5a Air Compressor

The amount of air input is adjusted to keep the temperature of the stream entering the gas turbine at 1351 K (1972 °F). The flow rate of air is 197,906 kg/h. The air is compressed from 100 kPa (0 psig) to 1000 kPa (130 psig) [for the 2-stage syngas compression system].

5b Burner
Air and synthesis gas are mixed and combusted here. The flow rate of synthesis gas is 16,518 kg/h, and that of stream leaving the burner is 214,425 kg/h. The operating pressure is 1000 kPa (130 psig) [for the 2-stage syngas compression system].

5c Gas Turbine
Power generated is about 18.4 MW. Gas enters the turbine at 1351 K (1972 °F) and 1000 kPa (130 psig). The gas leaves at 845 K (1061 °F) and 100 kPa (0 psig).

6 HRSG (Heat Recovery Steam Generator)
It comprises an economizer, an evaporator, and a super heat boiler. For the 2-stage compression system, boiler water (i.e., condensate and gasifier steam make up water) is divided into 2 parts: one part goes to the gas cooling heat exchanger, and the rest goes to the economizer. The flow rate of boiler water is about 88,000 kg/h. For 3-stage compression system, boiler water is divided into 3 parts: one part goes to the gas cooling heat exchanger, another part goes to the intercooler heat exchanger between the second and third compressors, and the rest goes to the economizer. All these 3 parts of water will converge before entering into the super heat boiler.

6a Super Heat Boiler
Steam is super-heated here by hot gases from gas turbine and combustor. The flow rate of synthesis gas is 311,930 kg/h. Steam side pressure drop is 0.7 MPa (87 psig).

6b Evaporator
Boiler water leaving economizer is heated to vapor here by hot gas exiting super heat boiler. Steam side pressure drop for evaporator is 0.5 MPa (58 psig).

6c Economizer
Boiler water is heated to 500 K (440 °F) here by gas exiting evaporator.

6d Blowdown Water
About 3% of boiler water is taken out of the cycle as blowdown water, and this amount of water is added to the steam exiting the steam turbine. The flow rate of blowdown water is 2318 kg/h.

6e Ammonia Injected in HRSG
About 4 kg/h of ammonia is injected to the gas leaving the super heat boiler to reduce NO.

7 Stack Gas Cleanup
7a Semi-dry Scrubber
In the scrubber, lime slurry is used to reduce SO_2 and HCl. Particles are then captured by the baghouse. The flow rate for 110 MW 2-stage syrup and stover are: 35 kg/h of quick lime, 14 kg/h of SO_2 entering the scrubber, 2.9 kg/h of SO_2 leaving the scrubber, 14 kg/h of HCl entering the scrubber, and 2.1 kg/h of HCl leaving the scrubber.

7b Baghouse
Particles are captured in the baghouse.

7c Limestone for Semi-dry Scrubber
About 63 kg/h of $CaCO_3$ is added to form CaO.

8 Heat Exchanger for Recovering Heat from Stack Gas
A counter flow heat exchanger which sets the hot inlet and cold outlet temperature difference of 4 °C is used to recover heat from the stack gas by preheating the ambient air input to combustor. For 110 MW 2-stage syrup and stover case, the flow rate of air is 14,661 kg/h, and the temperature of air leaving the heat exchanger is 445 K (341 °F).

9 Backpressure Steam Turbine
Power generated is about 11.3 MW. Steam enters at 6300 kPa (89 psig) and 750.4 K (891 °F), and leaves at 446 kPa (50 psig) and 481.3 K (407 °F). After leaving the steam turbine, a small amount of steam is taken out and sent to the gasifier, and then an amount of room temperature water equal to the flow rate of blowdown water is added to the steam. This steam whose temperature becomes 446 K (343 °F) and pressure is 446 kPa (50 psig) goes to ethanol production process and steam tube dryers.

10 Steam Tube Dryers (modeled as counter-flow heat exchangers)
10a Steam Tube Dryer for Fuel
Steam enters at 446 kPa (50 psig) and 446 K (343 °F), and leaves as water at 446 kPa (50 psig) and 420.8 K (298 °F). The fuel leaves the steam tube dryer with 10% moisture. The dryer exhaust has a humidity ratio of 0.75 kg water/kg dry air. The flow rate is 16,482 kg/h for stover, 21,197 kg/h for syrup, and 17,350 kg/h for steam. The initial moisture content is 13% for stover, 66.79% for syrup.

10b Steam Tube Dryer for Co-product
The co-product leaves the steam tube dryer with 10% moisture, and the dryer exhaust has a humidity ratio of 0.75 kg water/kg dry air. For 110 MW 2-stage syrup and stover case, the flow rate of DWG is 28,556 kg/h. The moisture content of DWG is 64.46%.

11 Steam for Ethanol Production Process
About 46,000 kg/h steam is used to provide 27.89 MW heat for the ethanol production process.

12 Water Cleanup / Deaerator
It is used to remove impurities in the water. The condensate from steam tube dryer(s) and ethanol production process, and make up water are mixed here. The flow rate of water leaving water cleanup is 85,344 kg/h. The temperature and pressure of water are 419.5 K (295.4 °F) and 446 kPa (50 psig).

13 Pump for Water
After the water cleanup/deaerator, the pressure of the water is increased to 7500 kPa (1073 psig). The flow rate of water is 85,344 kg/h.

14 Fans
14a Fan at Combustor to Supply Preheated Air
The flow rate of preheated air is 14,611 kg/h.

14b Fan at Combustor to Supply Fuel Dryer Exhaust
The flow rate of exhaust is 32,835 kg/h.

1B. Gasification – gas cleanup modeling and technology evaluation

- Complete modeling gasifier performance
- Complete fuel and emissions analysis
- Continue specifying gas cleanup technologies
- Continue determination of capital and operating costs
- Begin determination of requirements for gas clean up

Details of gasifier performance, fuel requirements, and predicted emissions are described in the narrative for the complete system under task 1A. Equipment and systems to meet these requirements will be specified along with capital costs by AMEC E&C Services.

Preliminary requirements for gas cooling and clean up are also included in the system description for task 1A. The synthesis gas cooling, scrubbing, and cleanup system is shown schmatically in Figure 2. It involves initial cooling of the gas in a heat exchanger with the heat captured to partially reheat the condensed process steam. Gas is further cooled in a wet scrubber where water is sprayed to cool the gas by evaporation. Once the mixture is saturated with water vapor, additional water scrubs particles and tars from the synthesis gas. The synthesis gas then passes through an acid gas clean up system to remove harmful components such as H_2S, HCl, and NH_3.

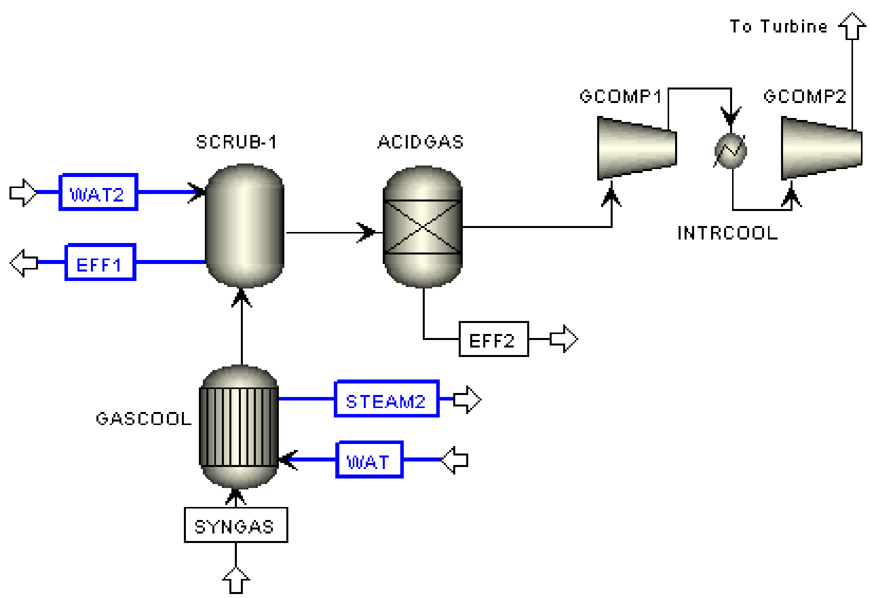

Figure 2. Synthesis gas cooling, scrubbing and cleanup followed by compression.

1C. Integration of super heated steam dryer technology

- Complete modeling characteristics that impact the ethanol process
- Begin determination of process energy reduction
- Begin determination of process water reduction
- Begin determination of impact on electricity generation
- Begin study of changes in capital and operating costs

Super heated steam dryers will replace the steam tube dryers shown schematically in Figure 1. If the fuel is a mixture of syrup and corn stover there will be two dryers (Figure 1), one which dries the distillers wet grains (wet cake) to produce distillers dried grains (DDG) and another which dries a mixture of syrup and corn stover to produce dry fuel for gasification and combustion. If the fuel is corn stover there will be one dryer, which dries a mixture of distillers wet grains (wet cake) and syrup to produce distillers dried grains with solubles (DDGS).

The Aspen Plus model of the superheated steam dryer is the same for each configuration. Input streams will vary based on flow amount and moisture content. A schematic of the superheated steam drying process is shown in Figure 3.

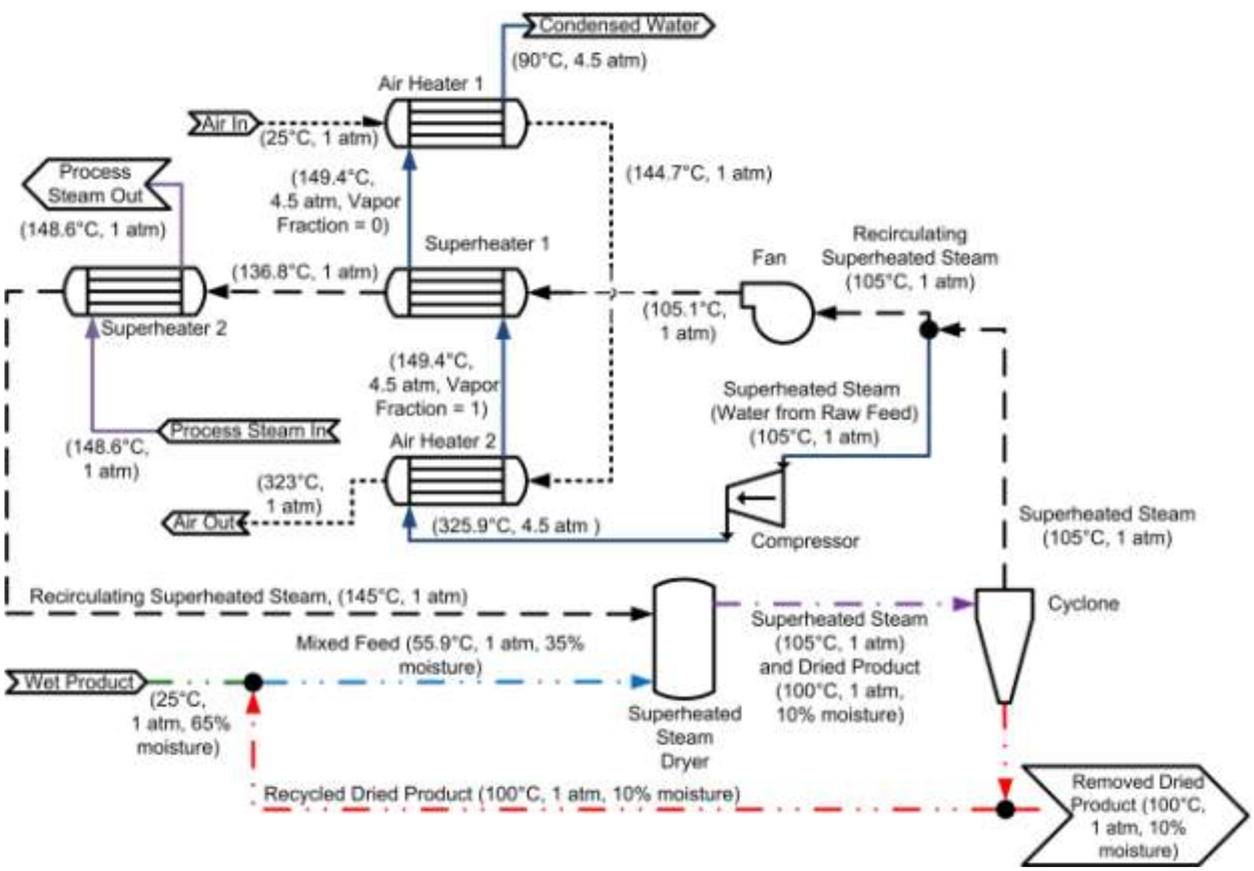

Figure 3. Schematic of superheated steam dryer to produce DDG with 10% moisture.

Water vapor is removed from the distillers wet grains (DWG) and mixes with the superheated steam in the dryer. The mixture of superheated steam and dried product is separated in the cyclone. Some of the dried product (DDG) is removed and some recycled to reduce the moisture content of the product entering the dryer.

After the superheated steam leaves the cyclone, an amount of vapor equal to the water removed from the product in the dryer is separated for compression and condensing. The remainder is recirculated for drying. The recirculated superheated steam is partially reheated in a heat exchanger using energy from the condensing portion of the water removed. The recirculated super heated steam is brought to its final temperature with process steam.

The water vapor removed is compressed to increase its condensing temperature and then run through a series of heat exchangers to preheat the combustion air (air heaters 1 and 2) and to preheat the recirculated super heated steam. Our modeling shows that we can condense all of the water and use it to preheat combustion air and the recirculated super heated steam. The net energy required to remove water in the superheated steam dryer including the compressor and fan energy is about 400 kJ/kg (170 Btu/lb) compared to about 2680 kJ/kg (1150 Btu/lb) in the steam tube dryer.

In addition, because the water is condensed and can be reused in the ethanol process when a superheated steam drying process is employed, the water requirement for producing ethanol is reduced by about 1.2 gallons of water/gallon of ethanol. This is not possible with the steam tube dryer because the water leaves as vapor in the drying air and is not easily recaptured. Current ethanol production technology requires on the order of 2.7 to 3.7 gallons of water/gallon of ethanol at the plant. Thus, implementing a super heated steam dryer could reduce the requirement to the range of 1.5 to 2.5 gallons of water/gallon of ethanol.

The condensed mixture will be separated with a membrane process (not shown in Figure 3) into a relatively clean stream of water that flows back into the process and a dirtier stream which will contain volatile organic compounds (VOCs) and other materials released in the drying process. This portion will be a feed stream to the combustor where the VOCs and other materials will be destroyed in the high temperature process. There will no longer be an exhaust air stream from the dryer which will flow into the combustor.

We have started to integrate the superheated steam dryer model into overall BIGCC model.

2. Develop and test business model

- Continue specification of key elements
- Continue grid evaluation and feasibility study
- Continue evaluation of technical issues and develop standard systems of implementation
- Begin development of plans for expedited permitting and regulatory approval
- Begin modeling procurement system

Activities—Understanding Current Financial Markets

Larry Schedin invited and coordinated two important meetings with investors and financial consultants serving investors in the power utility sector. The first meeting was with Mr. Bil Hawks, Mr. Gary Munson and Mr. Brett Bain, and the second was with Mr. Dan O'Neill. All of these individuals have close contacts in the power utilities investment business. Our U of M research team made presentations and described how ethanol plants could benefit from using CHP from a policy standpoint and economically.

Mr. Hawks has invested in renewable electricity projects in the past and was pleased to see the technical analysis and economic sensitivity we had done on our earlier Xcel Energy Renewable Development Fund project. Other requirements that he or other investors would like to see include involvement of farmer members who would be responsible for the biomass supply for an ethanol plant that has been well run and remains financially sound.

Mr. O'Neill of Northland Securities suggested that the current situation presents a wounded financial industry with significant opportunities that may arise as people investigate various aspects of the Stimulus Package and revisions to the tax code. 1) For example, it may be possible to "raise" funds to build renewable energy projects in the form of IRS grant funds that would work like a 30% Investment Tax Credit (ITC) in lieu of the old Production Tax Credit. 2) "New Market Tax Credits" of up to $25 million of future tax credits can be sold to U.S. Banks for $6.4 million of cash. 3) Mr. O'Neill also suggested that we make contact with John Deere Financial, which has 20% of its investment in wind assets or $1.5 Billion to learn of their interest in owning electrical power generation assets in ethanol plants. 4) Mr. O'Neill suggested that returns on investment of 18-22% pre-tax, might be needed to attract private investors to such a project. 5) Much as Larry Schedin has asked in the past, Mr. O'Neill suggested that we must study the market transactions, when available, to try to determine what a Renewable Energy Credit (REC) is worth.

Avenues of Inquiry Related to Implementation of BIGCC

1. Review <u>Distributed Generation</u> (DG): There are policy measures that encourage customer on-site installations rated 10 MW or smaller but using a "clean burning" fuel. This would presumably include natural gas as well as renewable fuels as defined by statute. However, treating such fuels as municipal solid waste (MSW) as "clean burning" has not been tested. MPUC rules define extensive policies and prices relating to DG. Also, Xcel Energy has recently clarified that DG can be owned by a third party. In any event, such designation is highly useful for ethanol plant BIGCC, but the10 MW upper limit must be increased in order to recognize likely grid output from typical ethanol plants.

Policy suggestion: It would be helpful for BIGCC projects if the scale parameters were expanded through legislation at the state level. In light of our preliminary estimates of the amount of electricity available to be sold from a 100 million gallon per year ethanol plant, it would be useful if the DG definition were expanded to 60 to 70 MW of capacity.

A technical question to address is: Will MSW work with corn stover and/or corn stover and syrup as a compatible fuel in terms of heat recovered and emissions released?

2. Review Dispersed Renewable Generation (DRG): Also defined by statute but defined as generation (not necessarily on site) rated 10-40 MW but using a renewable fuel. It is the focus of the forthcoming (Sept 15) DRG Phase II Transmission Study.

The MISO queue process was recently changed from first come, first served to first ready, first served. Nevertheless, the queue remains flooded. The concept of DRG was initiated by state legislators in hopes that renewable projects rated 10-40 MW could be sited with minimum grid disruption thereby avoiding extensive MISO transmission studies. The DRG Phase I Study issued in June, 2008 was aimed at siting 600 MW of DRG capacity by the year 2010. The Phase II Study is aimed at whatever spots will work for minimum grid disruption in the year 2013. Such spots are few and far between but will be examined with respect to potential BIGCC projects. In any event, we recommend that the MISO queue process be further modified to recognize that BIGCC projects should be expedited. Very few biomass projects have been submitted to meet the MN Renewable Energy Standard (RES).

3. Review conclusions from the forthcoming DRG Phase II Report which is scheduled for release on September 15, 2009. These conclusions should be compared to the conclusions from the Phase I report issued in June, 2008. At this time, results are being closely held under a confidentiality agreement signed by all Technical Review Committee (TRC) members. (Larry Schedin is a TRC member.)

A regulatory opening may become evident that favors DRG. The public and public interest groups have become more active in opposing coal-fired plants such as Big Stone II with great amounts of testimony directed toward policies favoring the use of more renewables. In addition a U.S. Department of Energy report issued in December of 2008 made a strong case favoring CHP plants, such as ethanol plants or other businesses able to utilize process heat. The report suggests that the U.S. could double its amount of CHP by the year 2030 and still be below the levels attained in Germany, Japan, and several other countries.

4. Our team needs to estimate base load generation values using base load installations for yardsticks to measure the potential value of ethanol plant electrical generation capacity to the grid. Observations are limited, but here are a few that we will study:

a. Xcel repowering and life extension investments at Prairie Island, Monticello and Sherburne County. We will attempt to determine incremental $ per KW of increased capacity.
b. Big Stone 2 estimated capital cost.
c. Great River Energy-Cargill 100 MW CHP plant at Spiritwood, ND.
d. Minnesota Power possible re-powering work at Clay Boswell plant in Cohasset.

e. Mid-American Energy's new unit at Council Bluffs, Iowa.
f. Intermediate combined cycle plants at Riverside and High Bridge (not really base load).

Knowledge of these investment decisions can help us to evaluate the willingness of investor owned utilities (IOUs) to own power generation assets as well as the rates of return they seek.

5. Review the Midwest Renewable Energy Tracking System (MRETS) and value of Renewable Energy Credits (RECs) from BIGCC. MRETS now tracks renewable energy registrations and tracks application and sale of RECs. These are applicable to the value of generation from BIGCC. The current system does not include tracking and credits for thermal energy recovered via CHP. However, Arizona has initiated such recognition, and this treatment will be reviewed along with District Energy St Paul’s efforts to have MN also apply RECs value to energy recovered from CHP.

The action by Arizona acknowledges the value of CHP as a strategy toward reducing Greenhouse Gases by capturing and utilizing more of the energy released by burning a fuel. By issuing RECs, the incentives for CHP will be sweetened. The Minnesota Legislature could follow the example of Arizona and provide this valuable incentive for CHP projects.

6. Review efforts to quantify and audit the carbon footprint of ethanol plants will become important as witnessed by the Low Carbon Fuel Standard of California and the GHG reductions identified for ethanol or other biofuels according to EPA.

Two local firms investigating and likely to be involved in the documentation of renewable energy systems are Wenck Environmental Engineering and U.S. Energy. The product of their documentation will be used so that ethanol from particular plants can qualify in particular markets with Low Carbon Fuel Standards (LCFS), but also to determine the value of RECs. U.S. Energy serves as an agent to purchase electricity and natural gas for many firms and organizations around the U.S., including a majority of the ethanol plants. In the future, U.S. Energy may serve the same ethanol plants by acting as an agent to sell the power that is generated on their sites from biomass.

3. Analysis of a biomass procurement system

- Continue study of biomass availability
- Continue study of biomass collection, local storage, and transport to processing facility
- Continue study of biomass processing facility

We have continued to focus on the following components of the proposed system.

- Logistics associated with collection including shredding, raking, baling (1250 lb round bales), and bale moving of corn stover to a local storage within 1 to 2 miles of the field immediately after corn grain harvest in the fall. This process occurs in a 4 to 6 week period from October to mid-November. We considered nutrient replacement for the material removed.

- Bale to bulk processing at the local storage including tub grinding, roll compaction to 240 kg/m^3 (15 lb/ft^3), and loading trucks (25 tons each). Processing will occur throughout the year with mobile units moving from site to site. Processing will occur at the rate of 25 tons/hour (one truck load) with at least 200 tons per day. Thus, each local storage should contain at least 200 tons (320 bales at 1250 lbs each).

- Truck transport in 25 ton loads of bulk corn stover to end users.

We have further refined our analysis of the cost, energy use, and greenhouse gas emissions for the corn stover logistics system. We have included updated estimates of upstream emissions for fossil fuels. We have also updated estimates for greenhouse gas emissions due to corn stover combustion.

Cost, life-cycle fossil energy consumption, and life-cycle greenhouse gas emissions for the corn stover logistics system are summarized in Table 4. The total cost, life-cycle fossil energy consumption, and life-cycle GHG emission for delivering roll-press compacted corn stover are $84.87/t ($76.99/ton), 936 MJ/t, and 114 kg CO_2e/t, respectively.

The lower heating value (LHV) of dry corn stover is 16.7 MJ/kg (Morey et al., 2009a). Thus, the total fossil energy consumption for nutrient replacement, collection, processing at the local storage, and transport to the end user is equivalent to approximately 6.6% of the energy content of the biomass. The total life-cycle GHG emission is 7.98 g CO_2e/MJ of dry corn stover including corn stover combustion. The GHG emission value does not include any contribution for reduction in soil organic carbon. While there is uncertainty related to allowable removal levels, this is a reasonable assumption if a conservative approach to stover removal is followed.

The four operations in the actual logistics process (collection/transport to local storage, local storage and loss, tub-grinding/roll-press compaction, and truck transport) comprise almost 65% of the total cost, approximately 56% of the life-cycle fossil energy input, but only about 33% of the life-cycle GHG emissions for heat and power applications. Over half (36% out of 65%) of the cost is attributed to the collection/transport to local storage step. This suggests that focusing on cost reduction, particularly for collection/transport to local storage, will be an important activity for these key operations in the logistics process.

The life-cycle GHG emissions for corn stover, natural gas, and coal as fuels for heat and power applications are compared in Figure 4. These estimates show that for heat and power applications, corn stover reduces life-cycle fossil GHG emissions by factors of approximately 8 and 14 compared to natural gas and coal, respectively.

Truck transport to the end user contributes 8.3, 6.7, and 4.2% to total cost, life-cycle fossil energy use, and life cycle GHG emissions, respectively, for transport within a 48 km (30 mile) radius. Doubling the radius from 48 km (30 mile) to 96 km (60 mile) would increase total cost, life-cycle fossil energy use, and life-cycle GHG emissions by another 8.3, 6.7, and 4.2%, respectively, while increasing the area from which to draw corn stover by a factor of 4. Increasing the radius by a factor of 4 from 48 km (30 mile) to 192 km (120 mile) would increase the area from which to draw corn stover by a factor of 16 with increased total cost, life-cycle fossil energy use, and life-cycle GHG emissions by 24.9, 20.1, and 12.7%, respectively. This suggests that the effect of increased transport distance on total cost and life-cycle GHG emissions with this type of logistics system may not be as great as for logistics system involving transport of lower density biomass.

Table 4. Cost, life-cycle fossil energy consumption, and life-cycle GHG emission for corn stover.▲

Operation	**Cost**		**Life-cycle energy**		**Life-cycle GHG emission**	
	$/t ($/ton)	%	MJ/t	%	kg CO_2e/t	%
Payment to Farmer for Participation	$7.50 ($6.80)	8.8	--	--	--	--
Nutrient Replacement (N-P-K)	$22.66 ($20.56)	26.7	412.7	44.1	31.0	27.3
Collection/Transport to Local Storage	$30.75 ($27.90)	36.2	196.9	21.0	13.1	11.6
Local Storage Cost/Local Storage Loss #	$3.41 ($3.09)	4.0	30.5	3.3	2.2	1.9
Tub-Grinding/Roll-Press Compaction	$13.49 ($12.24)	15.9	233.7	25.0	17.9	15.7
Truck Transport of Compacted Corn Stover	$7.05 ($6.40)	8.3	62.4	6.7	4.8	4.2
Combustion of Corn Stover *	--	--	--	--	44.5	39.2
Total	$84.87 ($76.99)	100.0	936.2	100.0	113.5	100.0

▲Mass or weight is defined at 15% (wet basis) moisture content unless otherwise indicated.
Dry matter loss during storage was assumed to be 5%. The cost due to the storage and storage loss is equal to the sum of 36¢/t (33¢/ton) for the land rent charge, plus 5% of the costs for payment to farmer for participation, nutrient replacement, and collection/transport to local storage. The energy or GHG emission due to storage loss is equal to the sum of 5% of the corresponding values for nutrient replacement, and collection/transport to local storage.
* Combustion of corn stover in industrial boilers emits 0.0036 g of CH_4/MJ and 0.0102 g of N_2O/MJ of dry corn stover (GREET, 2009).

More details of the analysis are presented in Morey et al. (2009b). This paper has also been submitted for publication.

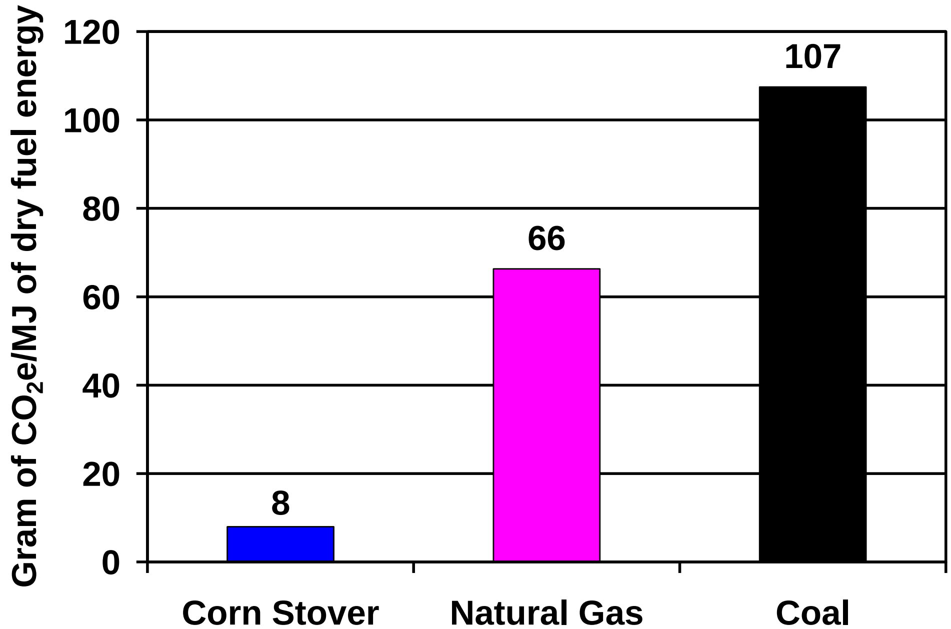

Figure 4. Life-cycle greenhouse gas emissions for heat and power applications. The GHG data for natural gas and coal include upstream (i.e., fuel production and transport) and combustion emissions as fuels in industrial boilers (GREET, 2009).

GREET. 2009. The greenhouse gases, regulated emissions, and energy use in transportation (GREET) model. Version GREET 1.8c.0. Argonne, IL: Center for Transportation Research, Energy Systems Division, Argonne National Laboratory. Available at: http://www.transportation.anl.gov/modeling_simulation/GREET/index.html. Accessed 7 July 2009.

Morey, R.V., D.L. Hatfield, R. Sears, D. Haak, D.G. Tiffany, and N. Kaliyan. 2009a. Fuel properties of biomass feed streams at ethanol plants. *Applied Engineering in Agriculture* 25(1): 57-64.

Morey, R.V., N. Kaliyan, D.G. Tiffany, and D.R. Schmidt. 2009b. A biomass supply logistics system. ASABE Paper No. 096660. St. Joseph, Mich.: ASABE.

4. Outreach and education for investors, policy makers, utilities and the public

- Update web site
- Continue development of models, spreadsheets and other decision aids
- Begin workshops or presentations at conferences
- Begin presentation of papers
- Identify and document policy issues

We updated the web site to reflect the most recent project results. New information includes two papers that were recently presented. We are also adding new sections on biomass logistics and biomass densification.

A spreadsheet model for the biomass logistics system has been developed. We are using it to generate results for our analysis, but it is being designed in a format that will allow us to make it available to a variety of users as the project progresses.

The following papers were prepared and presented related to project activities.

Morey, R.V., N. Kaliyan, D.G. Tiffany, and D.R. Schmidt. 2009. A biomass supply logistics system. ASABE Paper No. 096660. St. Joseph, Mich.: ASABE. (This paper has also been submitted for publication.)

Kaliyan, N., R.V. Morey, M.D. White, and D.G. Tiffany. 2009. A tub-grinding/roll-press compaction system to increase biomass bulk density: preliminary study. ASABE Paper No. 096658. St. Joseph, Mich.: ASABE.

Seminars and Conference Presentations by Doug Tiffany

8/26/09 "Biomass for Combined Heat and Power at Ethanol Plants," NCGA Land Use Conference. Saint Louis, Missouri.

8/25/09 "Ethanol Production: Technologies and Rates of Return," Minnesota Extension Ag Lenders Conference. Lamberton, Minnesota.

6/23/09 "Economics of Expanding Biofuel Production in the Upper Midwest," National Academies of Science Conference, Second Generation Biofuels. Madison, Wisconsin.

6/17/09 "Biomass for Combined Heat and Power at Ethanol Plants," Fuel Ethanol Workshop Denver, Colorado.

6/11/09 "Ethanol Update: Getting Paid to Reduce our Footprint," Minnesota Extension Ag Lenders Conference. Stewartville, Minnesota.

6/1/09 "Comparing Financial Performance of Current and Future Ethanol Production Technologies," International Starch Technology Conference. Champaign, Illinois.

5/26/09 "Ethanol Economics Update: More Excitement Ahead," Minnesota Extension Ag Lenders Conference, Montevideo, Minnesota.

Selected publications by Doug Tiffany

Tiffany, D. and S.J. Taff. Current and future ethanol production technologies: costs of production and Rates of Return on invested capital. Int. J. Biotechnology. 11(1/2):75-91. 2009.

Tiffany, Douglas G. and Steven J. Taff. Will New Technologies Preserve Minnesota's Ethanol Industry? Rural Minnesota Journal. Volume 4 , pp. 1-12. 2009. www. ruralmn.org.

Tiffany, D.G. 2009. Economic and Environmental Impacts of U.S. Corn Ethanol Production and Use, Federal Reserve Bank of St. Louis Regional Economic Development, 2009, 5(1), pp. 42-58.

Project Status

Overall we continue to make good progress. We made major progress this summer in modeling the details of several BIGCC systems and in developing an Aspen Plus model of super heated steam drying. We have overcome major learning curves for working with these models for new people on the project. We should be able to rapidly model and study new configurations with the experience that we have now gained.

We updated results on biomass logistics and submitted a paper for publication. We continue to participate in extension and outreach activities related to the project, primarily through the work of Doug Tiffany.

We had several meetings with our subcontractor, Larry Schedin, LLS Resources, to discuss various incentive programs and business models. He arranged several meetings with perspective investors so that they could learn about our work and we could gain a better understanding of their interests.

We have also been meeting with our subcontractor, AMEC E&C Services to discuss practical equipment configurations to include in our modeling efforts. We are now working with them to develop equipment configurations and cost estimates for several of the systems that we have modeled.