Feasibility of Producing Electricity and Heat Utilizing Steam Turbines and Spark Ignited Engine Generators at Generation II's Corn Ethanol Plant
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Chapter 1
Executive Summary

Gasification of biomass offers a practical way to use a widespread fuel source to help provide the energy needed to operate many current industrial processing plants. By including a wide variety of biomass fuels, such as process by-products and agricultural crop residues, gasification shows promise in a wide scope of applications.

This document describes the final results of a research project to determine the technical and economic feasibility of a gasification system that would use the by-products of an ethanol facility to provide the energy to operate it. The original concept was to gasify distiller’s dried grains with syrup (DDGS), a by-product of the ethanol process along with corn stover, an agricultural crop residue to produce enough electrical power and thermal energy for the ethanol plant to be self-sufficient.

The project consisted of testing the drying and gasification process, an economic and technical assessment and a conceptual design of the proposed best option. As a result of the research, we developed the best case scenario for the proposed Generation II Ethanol facility. Generation II Ethanol, L. I. C. (Gen II), as a partner in the project, plans to custom design and build, own and operate an ethanol facility. Generation II is trying to incorporate an added-value plant to produce a high-value, high-quality human food ingredients into the ethanol operations. The waste product from the added-value plant would be used to produce ethanol.

The conclusion of the study was that it is technically feasible to generate the entire energy demand of the facility, but the economics of the situation will dictate the final configuration. For the Generation II case, a best plan approach was developed for the proposed facility. Based on the energy demand profile of the facility and the wastewater generated with the “syngas” gasification process, the steam turbine generator option was selected. The economics analysis drove the best plan of gasifying corn stover for thermal energy needs only. In addition to developing the best plan for the Generation II Ethanol Facility, the key findings of this study has many applications that can be used for many other opportunities.
This final report will summarize the key findings that drove the best plan and can be used for other opportunities, a summary of the best plan for the Generation II facility and a history of the project.
Chapter 2
Key Findings

The following summarizes the key finding of the study.

**Steam turbines vs. Spark Ignited Engine Generators**

- Steam turbines were selected as the appropriate technology because their energy output correlates to the energy demand of the ethanol plant, and the “syngas” cooling step generates wastewater, requiring extra costs.

- The energy requirements of an ethanol facility are mostly thermal. The ratio of thermal to electrical energy used is about 7:1. A gasification system designed for “syngas” operation in spark ignited engines provides mostly electrical energy. The only thermal energy available from a “syngas” system is the sensible heat of the “syngas” leaving the gasifier and the relatively low-grad thermal energy of the Internal Combustion (IC) engine exhaust. Conversely, a gasification system designed for steam cycle operation generates a high temperature flue gas from which energy can be recovered (using thermal fluid), and a turbine/generator provides electricity for the ethanol plant.

- The cooling step of the “syngas” gasification process generates a large amount of wastewater. Water (both moisture in the feed and combustion moisture) and tars are condensed and removed from the “syngas” and discharged from the gas cleanup system. One of the objectives of Generation II is to minimize the wastewater discharge of the ethanol facility. No wastewater treatment facility is planned for the facility, and the options to add a treatment facility would be very costly.

**Biofuel Properties**

- The supply of the biofuel must have a constant supply at a low price. Many agricultural-based waste materials are used for animal feed, and the amount available varies over time. The gasification process and emissions permit standards impose limits on the materials that can be gasified. Once a material, such as Dried Distiller Grains (DDGS) or stover, is included in the emissions permit application, it is difficult to switch materials.

- The biomass source must have a low moisture level. Drying bio-fuel before or during gasification reduces the net energy available for thermal uses.
The biomass source must not require extensive preparation. Extensive, energy consuming preparation steps before gasification lowers the net energy available.

The biomass source must be available in large quantities throughout the year. Most biofuels, such as stover, are produced once a year. Generally, this predicts the availability and costs for the twelve months.

The biomass source must be available locally. Generally, biofuels cannot be transported long distances due to transportation costs and material degradation issues.

The biomass source must have consistent composition and physical properties. Wide ranges in composition often include changes in the chemical composition, which affect the oxidation process and emission characteristics. Variations in emissions might not be allowed within the terms of the emissions permit.

Unique Bio-Fuel Gasification Characteristics of DDGS and Stover

- DDGS was found to produce more net energy (7,998 vs. 6,215 BTUs/Lb) than stover. To produce the same amount of energy with stover will require 28 - 30% more pounds of stover.

- DDGS and stover have significantly different ash fusion temperatures (the temperature at which ash becomes molten) requiring separate gasification chambers. DDGS and stover cannot be gasified at the same time.

- DDGS does not require preparation before gasification.

- Stover bales must be reduced to ½ -inch pieces by shredding the bales, and then grinding the shred. Shredding and grinding are energy intensive operations (24 hours per day, 365 days per year) and require approximately 500 horsepower for the rates required.

Gasification's Positive Impacts on Farm Income and Farming Practices

- Removing of corn stover from the fields after corn harvest allows no-tillage field practices. Note that soil conditions, land contours, and erosion control might not allow stover removal from some fields.

- If farmers remove stover in the fall, they can reduce the amount of time needed to plant in the spring, which allows for a longer growing season. It also eliminates some fall field work (chopping the corn stubble and plowing under the chopped stubble).
• Removing and selling corn stover provides another income source to farmers for minimal additional expenses. Most fields will produce two – three tons of stover per acre, adding up to $75 per acre of additional revenue.

• No-till farming, which results in “carbon sequestration”. Plowing releases carbon, which requires that the carbon be replaced with fertilizers. No-till farming eliminates the need for carbon replacement.

• In the future, carbon sequestration might become a commodity that farmers could sell (carbon credits) under terms of the Kyoto Accords. Of course, the United States would need to adopt the Kyoto Accords.

Gasification as an Answer to Dryer Exhaust Emission Issues

• The gasification process uses the dryer’s exhaust air as combustion air. The gasifier’s operating temperatures act as a thermal oxidizer for the Volatile Organic Compounds (VOC) and Particulate Matter (PM). As a result, the gasifier will release low emission exhaust complying environmental regulations for ethanol plants.

• Using the gasifier to oxidize dryer exhaust eliminates the need for a separate thermal oxidizer and the associated natural gas consumption.

• Recovering the thermal energy from gasification, in the form of process heat, eliminates the need for a natural gas fueled steam boiler, saving manufacturing costs.

Economics of Electrical Generation

• Using bio-fuel to generate the entire facilities, electrical and thermal energy requires large amounts of biomass and physically large gasification equipment. In addition, producing high pressure, super-heated steam (600 PSI at 700°F) requires expensive equipment. Operators for such equipment must have specialized training and licensing.

• The equipment required to generate steam powered electricity requires up to 40% of the capital costs for the gasification project.

• As backup to self generation, the plant would need a connection to the electrical utility, which charges an annual fee for the service—an additional expense with no return value.
- The electrical utility requires specific equipment to monitor and regulate the electric power generated on-site so that the plant can connect to the utility. This equipment is not required if all electricity is purchased.

- Since excess power generated that could be sold to the grid would be relatively small and not consistent, it is assumed that it would not justify a premium.

- See Appendix 5.2 for complete comparison of costs.
Chapter 3
Conclusion
3.1 Best Plan – Option Two

We started our research with a base plan. The base plan included gasifying all the DDGS and enough corn stover to generate all the electrical and thermal energy required for the facility. Discoveries during our research led to the formation of several options. Three of the options were investigated entirely throughout the research process.

The following provides a brief description of the base plan, and the differences between the base plan, option one, and option two (best plan).

3-1

The relationship between the base plan, option one, and option two.
3.1.1 Features that constitute the best plan (option two).

Goals
- Operate an added-value plant that uses corn or corn-derivatives as the primary feedstock.
- Produce 20 million gallons of ethanol per year.
- Use stover as fuel for the gasifier.

Gasifying Process

Produce all thermal energy required to operate the added-value and ethanol plants by gasifying stover using the following process:

1. Operate two gasifiers with stover as the fuel. The output of the gasifiers is synthesis gas.

2. Continue oxidizing the synthesis gas from the gasifiers in one overfire or residence chamber.

3. Route partially oxidized synthesis gas from the overfire chamber to the thermal oxidizer chamber.

4. In the thermal oxidizer, complete the oxidation of the synthesis gas and dryer exhaust air to produce relatively clean, hot (2,200 - 2,300°F) exhaust gas.

5. Use some of the exhaust gases to power the reboiler, which will generate process steam at 150 psi.

6. Use remaining hot exhaust gases to heat thermal fluid, which in turn heats the dryer's inlet air.
Operations

- Operate the facility 24 hours per day, 360 days per year
- Use bio-diesel as an alternative fuel in the gasifier to replace stover, if needed. Bio-diesel was chosen because the Heron Lake facility does not have access to natural gas supplies.
- Provide on-site stover storage to supply two to three days of operation
- Shred and grind stover bales before gasification.
- Evaporate the liquid waste from the drying process in the energy building and add it to the distiller’s wet grains.
- Dry the distiller’s wet grains and wet waste from the added-value plant using a flash dryer with low inlet air temperatures.
- Supplement combustion air at the thermal oxidizer with exhaust air from the wet distiller’s grain dryer, which eliminates dryer exhausts as an emissions point. Dryer exhaust air will not be released directly into the atmosphere. This process ensures that volatile organic compounds (VOCs) are oxidized in the thermal oxidizer, and the exhaust has significantly reduced levels of VOC and other pollutants.

Logistics

- The support services and facilities associated with an ethanol plant (administrative, maintenance, quality assurance, lunchroom, etc.) are assumed to be adequate to support an energy plant. These costs were not included in the economic analysis.
- The added value plant will not increase the amount of corn that the site will receive.

Economics

- Purchase baled stover for $25 per ton delivered FOB (free-on-board) to the Generation II plant in Heron Lake, MN. Farmers are responsible for baling, moving, storing, and transporting bales at all off-site locations. Generation II employees are responsible for unloading, storing, and moving bales on-site.
- Sell all DDGS generated by the ethanol plant for animal feed, and credit the revenues from the sales against the cost of stover and electricity.
3.1.2 Benefits of the Best Plan

The research team anticipates the following benefits from implementing the best plan (in comparison to the base plan):

- Sales of DDGS for the first year are expected to produce $4.31 million in revenue
- Purchases of stover are expected to provide the farmer/members of the Generation II cooperative with revenues of $2.75 million
- Reduce capital costs by 45% (compared to the base plan) by eliminating equipment specific to generating electricity, and reduce the associated depreciation costs.
- Reduce employee skill requirements for operation of a 150 psi steam system compared to the 600 psi steam system required for electricity production
- Reduce ash disposal costs from $660,000 for the base plan, to $351,000 for the best plan for savings of $309,000 in the first year.
- Enjoy insulation from escalating natural gas and fuel oil prices
- Reduce total fuel and energy expenses:

<table>
<thead>
<tr>
<th></th>
<th>Base Plan</th>
<th>Best Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net fuel and electricity expenses (Cash flow only. See the Economic and Technical Assessment Report for detail)</td>
<td>$2.31 million</td>
<td>$0.35 million</td>
</tr>
<tr>
<td>Expenses with stover handling and preparation, and lime and ash removal.</td>
<td>$3.84 million</td>
<td>$1.28 million</td>
</tr>
<tr>
<td><strong>Cost Savings</strong></td>
<td><strong>$1.56 million</strong></td>
<td><strong>$1.07 million</strong></td>
</tr>
</tbody>
</table>

- Experience long term cost containment. Over a ten year period, using present value methods, the best plan results in total energy costs (including labor, depreciation and maintenance costs) that are lower than the cost to use traditional thermal energy fuels (natural gas or fuel oil).

<table>
<thead>
<tr>
<th></th>
<th>Best Plan</th>
<th>Base Plan</th>
<th>Natural Gas-Fueled Ethanol Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>$53.91 million</td>
<td>$82.22 million</td>
<td>$61.62 million</td>
<td></td>
</tr>
</tbody>
</table>
3.1.3 Disadvantages of the Best Plan
The research team anticipates the following disadvantages from implementing the best plan (in comparison to the base plan).

- The stover requirements for the best plan are more than 271,000 bales, compared to 244,000 bales for the base plan. To produce that much corn stover, farmers would need to harvest over 65,000 acres with an average yield of 2.5 tons of stover per acre. For the base plan, farmers would need to harvest 58,000 acres.

- At present, the farm level infrastructure for baling, transporting, and storing stover does not exist. New or modified farm equipment and transportation methods and vehicles might need development.

- The plan assumes that ash will be disposed at a commercial landfill willing to accept a large quantity of ash and capable of handling it. Such a landfill has not yet been identified.

**NOTE:** Ash from the gasification process might have value as a component of fertilizer. Research into this possibility was not included in the scope of research, and should be explored. If feasible, selling ash could offset some or all of the disposal costs and increase gasification’s potential for profit.

- Since the site would purchase electricity from the local utility, they would be vulnerable to power failures.

- The plan depends on a consistent supply of stover. Delays in harvesting could force the plant to use bio-diesel for fuel, which would increase energy costs.

- The plan provides sufficient storage two or three days of operation, which might not be sufficient for winter, holidays, and three-day weekends. Incorporating additional storage space would increase capital costs associated with building size and stover handling equipment.

3.1.4 Economic Summary—Base Plan, Option One, and Option Two
The following is a summary of the economic analysis of the base plan, option one and option two.
The following table provides estimates of the anticipated operating expenses, comparing the base plan, option one, and option two.

<table>
<thead>
<tr>
<th>Fuel and Energy</th>
<th>Base Plan</th>
<th>Option One</th>
<th>Option Two</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stover purchases</td>
<td>$2,395,325</td>
<td>$998,209</td>
<td>$2,746,604</td>
</tr>
<tr>
<td>DDGS</td>
<td></td>
<td>$(4,306,500)</td>
<td></td>
</tr>
<tr>
<td>Electricity (export)</td>
<td>$(84,671)</td>
<td>$1,908,403</td>
<td>$1,908,403</td>
</tr>
<tr>
<td>Sub-Total</td>
<td>$2,310,654</td>
<td>$2,906,612</td>
<td>$348,507</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Operations</th>
<th>Base Plan</th>
<th>Option One</th>
<th>Option Two</th>
</tr>
</thead>
<tbody>
<tr>
<td>Labor</td>
<td>$572,000</td>
<td>$286,000</td>
<td>$572,000</td>
</tr>
<tr>
<td>Lime</td>
<td>$11,902</td>
<td>$11,902</td>
<td>$11,902</td>
</tr>
<tr>
<td>Ash disposal</td>
<td>$660,105</td>
<td>$481,565</td>
<td>$351,016</td>
</tr>
<tr>
<td>Turbine generator maintenance</td>
<td>$181,440</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stand-by service</td>
<td>$108,432</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sub-Total</td>
<td>$1,533,879</td>
<td>$779,467</td>
<td>$943,918</td>
</tr>
<tr>
<td>Total</td>
<td>$3,844,533</td>
<td>$3,686,079</td>
<td>$1,283,425</td>
</tr>
</tbody>
</table>

The significant points in the summary include:

- Selling DDGS at $75 per ton and buying stover at $25 per ton has a major impact on profitability, and totally compensates for the purchase of electricity.

- Option two requires 14% more stover than the base plan, but due to the character differences between stover and DDGS, produces 88% more ash.

- Purchasing electricity eliminates almost $300,000 of annual expense by eliminating the need for turbine generator maintenance and stand-by service.

- Selling DDGS, rather than burning it for fuel, reduces ash disposal expenses by $300,000.

The team estimates that the operating cost for option two would be less than one-third of the cost for the base plan, and require less capital.
3.2 Sensitivity Comparisons

The research team made some basic assumptions about future prices for gas, fuel, oil, DDGS, and stover. Some assumptions, including escalations in natural gas and fuel oil prices, were based on public information generated by government agencies and industrial trade groups. There were no projections available for DDGS and corn stover prices, therefore the research team made a consensus estimate based on information from the ethanol industry. A sensitivity analysis was performed to determine what the effect variations in the assumptions of future pricing and costs would have on the economic model.
3.2.1 Energy Production Expenses

The selling price for DDGS was set at $75 per ton—the market price at the start of the project. The industry forecasted that the price would drop to $50 per ton, but two years later, the price rose to $85 per ton. Such wide variations can have a significant impact on profitability.

Currently, either corn stover is not available, or available in limited quantities. The research team was unable to find a source in Minnesota that could supply even a small percentage of the annual requirement to fuel the site. Conversations with Generation II farmers led the team to believe that paying $25 per ton for stover would likely induce enough farmers to meet the annual requirements. The research team estimated a potential price fluctuation of $20-30 per ton.

The potential cost fluctuations impact the economics of the project significantly. The research team developed sensitivity analysis to show the potential impact of these extremes. The research team used the following parameters:

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>Projected</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>DDGS Selling Price</td>
<td>$50</td>
<td>$75</td>
<td>$85</td>
</tr>
<tr>
<td>Effect</td>
<td>33% decrease</td>
<td></td>
<td>13% increase</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>Projected</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stover Cost</td>
<td>$20</td>
<td>$25</td>
<td>$30</td>
</tr>
<tr>
<td>Effect</td>
<td>20% decrease</td>
<td></td>
<td>20% increase</td>
</tr>
</tbody>
</table>

In this sensitivity analysis, the costs include stover purchase costs, stover preparation labor, ash handling and disposal, purchased electricity, lime, operations and maintenance expenses, and debt service (depreciation and payback of the construction loan). The debt service costs remain constant through the twenty-year analysis period. All other costs are expected to increase. The revenue from DDGS sales are credited against the costs.
In Figure 3-1, the blue line represents the projected energy production expenses for the best plan. The shaded area represents the range of increase and decrease in expenses at the limits of the sensitivity range.

The lower line of the shaded area represents the lowest production expenses based on a low stover purchase price, and a high DDGS selling price. The upper line represents the highest production expenses based on a high stover purchase price, and a low DDGS selling price.

![Figure 3-1](image)

*Projected energy production expenses with sensitivity comparisons*

### 3.2.2 Present Value Economic Evaluation of Sensitivities

The original economic evaluation included a present value analysis method for incremental capital costs and energy production operating expenses. For consistency, the research team applied the same present value analysis to the annual energy production expenses for a ten year period using previously defined inflation/deflation factors. Annual energy production expenses include operating costs for producing thermal energy and hot air for the dryer, purchased electricity, depreciation on incremental capital, and debt recovery for borrowed capital.
The research team used the same sensitivity parameters.

<table>
<thead>
<tr>
<th></th>
<th>Low</th>
<th>Projected</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>DDGS Selling Price</td>
<td>$50</td>
<td>$75</td>
<td>$85</td>
</tr>
<tr>
<td>Stover Cost</td>
<td>$20</td>
<td>$25</td>
<td>$30</td>
</tr>
</tbody>
</table>

The present value analysis supports the selection of option two as the best plan, proving the economic advantages of selling DDGS and fueling the energy plant with corn stover. Comparing the best plan to the base plan reveals savings in the range of $10-65 million.

![Range of Present Values with Sensitivity Analysis](image)

**Figure 3-2**

*Range of present values with sensitivity analysis.*
3.2.3 Sensitivity Conclusion
The present value analysis supports the selection of option two as the best plan, proving the economic advantages of selling DDGS. The results of the sensitivity analysis reinforced the economic analysis that option two was the best plan. The potential variations in pricing was greater for the best plan as opposed to the base plan, however there were no situations where the base plan was better than option two. The sensitivity analysis also showed that it was a more likely to realize more savings as opposed less
Chapter 4
Project History

The project was awarded and approved in May of 2002. The dryer test was the first major task and was conducted from June 4, 2002 through July 26, 2002 in southwestern Minnesota. Material was shipped from the dryer test site to Primenergy’s facility in Oklahoma. The gasification tests were conducted from October 29, 2002 through November, 1 2002. Preliminary tests were run prior to the actual tests to determine operating test parameters to be used in the testing.

At the completion of the testing, an economic and technical assessment was completed to determine the best plan for the Generation II facility. The assessment was conducted from November, 2002 through April, 2003. After the economic and technical assessment, a conceptual design was developed which included equipment sizing, layout and costs estimate. The conceptual engineering was completed from May, 2003 through July, 2003.
4.1 Previous Reports
Throughout the project, Sebesta Blomberg provided reports detailing the results of the research at specific milestones. The following is a list of previous reports. Please see the specific reports for details:

- Project Plan and Test Protocols (May 23, 2002)
- Dryer Test Report (October 24, 2002)
- Interim Report (January 20, 2003)
- Economic and Technical Assessment Report (April 24, 2003)
- Conceptual Engineering Cost Estimate (July 11, 2003)
Chapter 5
Appendix

The following sections contain additional information about the results of the research project.
5.1 Option Two (Best Plan) Drawings

5.1.1 Process Flow Diagram
5.1.2 Site Plan
5.1.3 General Arrangement-01
5.1.4 General Arrangement-02
5.1.5 General Arrangement-03
5.2 Cost Comparisons

5.2.1 Comparison of Cost: Process Heat

Biomass Heat Recovery reflects 75% allocation of operating expenses including fuel, incremental labor, lime, interest and depreciation.
5.2.2 Comparison of Costs: Electricity

Biomass Electric Generation reflects 25% allocation of operating expenses including fuel, incremental labor, lime, interest and Depreciation, plus a full allocation of stand-by service charges and turbine generator maintenance expenses. Interest and Depreciation are based on total capitalized project cost of $30.37 million. The term of debt is 20-years at 6% interest. Depreciation expense reflects a 20-year straight line basis.