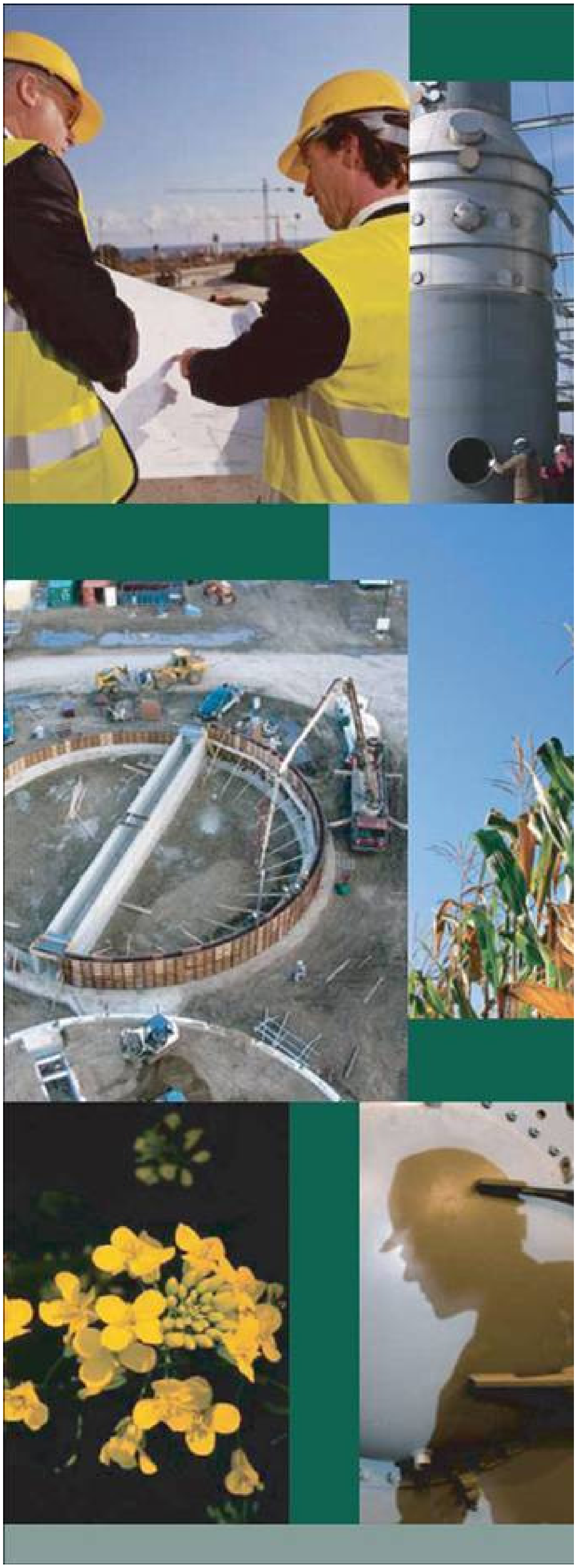


Feasibility Study for a Low Carbon Ethanol Plant in Ft. Morgan, Colorado

Report Prepared For:

Colorado Farm Bureau
9177 E. Mineral Circle
Centennial, CO 80112

November 2008

NOTICE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. EXECUTIVE SUMMARY

The Colorado Farm Bureau has retained BBI International (BBI) to conduct a feasibility study for a low carbon dry mill ethanol production facility. BBI compared a 59-mmgy plant with anaerobic digestion to a 130-mmgy plant with fractionation, biomass boiler and anaerobic digestion, near Ft. Morgan, CO. The facility would produce ethanol, distillers grains, and carbon dioxide from corn. The larger plant would also produce corn germ meal, corn oil and bran. Based on the results of the report, the Farm Bureau will be able to decide whether or not to pursue a partnership in this project.

Background

High Plains Energy is the process of developing an ethanol project in Ft. Morgan, Colorado. The Colorado Farm Bureau is considering taking an equity position in the facility.

Site Evaluation

BBI evaluated one site in Ft. Morgan, Colorado and found it an excellent site for ethanol production. BBI acknowledges that the project has already made great progress in making arrangements for the site such as securing water rights, obtaining permission to build a feeder road just off the interstate, a comprehensive water and wastewater plan, site layout, approval of railroad design and similar.

BBI makes the following recommendations regarding siting of the project:

- Ascertain the level of acceptance of the project by the city and community.
- Have the site evaluated by a local civil engineering company from a site development perspective, to identify any challenges or risks associated with developing the ethanol plant at the candidate site.
- Have the site evaluated by an ethanol process design company from an engineering and construction perspective.

Feedstock

The Ft. Morgan, CO region has sufficient supplies of corn to support a 59-mmgy plant but at 130-mmgy the amount of local supplies are relatively small to handle such a large plant. There are 32.5 million bushels available within 100 miles of the plant.

Assuming all corn is delivered by truck, the basis impact of building a 59-mmgy ethanol facility is estimated to be 26 cents, indicating a ten-year average corn price of $2.63 per bushel. The basis impact for building a 130-mmgy facility is projected to be 35 cents, indicating a ten-year average corn price of $2.72 per bushel.

Ethanol Market

The recently updated Renewable Fuels Standard ensures a long term U.S. market for biofuels. Voluntary blending is expected to occur at an increasing rate as long as the price of ethanol remains less than or equal to gasoline plus the blender's tax credit—marking blending economically attractive. The RFS requires that new corn based ethanol plants meet a 20% reduction in GHG emissions compared to a baseline plant. This project will meet that reduction through use of anaerobic digestion to produce biogas which will be used to offset natural gas use at the plant.

The project plans to market low carbon ethanol and the only existing market for this specific fuel type is California. The Colorado market is saturated with existing plants able to produce enough ethanol to account for 10% of gasoline consumption although it is expected that some of the output will go to the Colorado market. Should Colorado adopt a low carbon fuel standard, the Ft. Morgan plant will be well positioned to sell locally. As transportation costs to move ethanol to market will be lower, the netback returns will be improved.

The ability to divide product effectively between local, regional, and national markets is extremely important. So much so, that it is imperative that either an experienced marketer is hired, or the ethanol marketing be contracted to a broker or a cooperative marketing group.

BBI assumes that all ethanol is shipped to California—at least initially until other low carbon fuel markets develop. The ethanol shipping costs is estimated at 15¢ per gallon. The estimated ethanol sale price is based on the 10 year historical Los Angeles ethanol spot price of $1.76 per gallon. There is a possibility that low carbon fuels may receive a premium, however, the California LCFS does not have any language related to pricing mechanisms. Additionally, the VEETC is set to decrease from 51¢ to 45¢ per gallon in 2009 which may negate any additional price premiums for low carbon fuels.

Co-Products

The 59-mmgy plant will produce distillers grains and carbon dioxide. Ft. Morgan is an area of concentrated cattle operations and a plant in this location can easily sell all distillers grains in the wet form allowing for thermal energy savings. The area DWG demand (within 150 miles of the site) is over 4.3 million tons per year—10 times more than the plant is expected to produce (455,000 tons). The price was set to 80% the price of corn a dry weight basis accounting for both market rates and an anticipated contract that allows a 3% discount. This resulted in DWG price of $30.94/ton (based on corn at $2.63 per bushel).

For the 130-mmgy model, fractionation produces three primary by-products: high protein distillers grains (HPD), germ and bran (fiber). The plant will extract corn oil from the germ and the remaining germ is assumed to be sold as cattle feed. The bran will be used to generate steam in a biomass boiler.

The HPD yield is 6.6 pounds per bushel resulting in annual production of 158,000 tons. Dairy farms are the most likely purchasers of HPD due to the desired high protein content and lower saturated fats when compared with traditional distillers grains. Obtaining a premium from sales to other livestock types are less likely as: 1) beef cattle obtain cheap protein from urea so there would not be a premium paid, 2) there are amino acid issues for swine, and 3) poultry producers take issue with the lack of oil (fat) in the product since the germ is removed prior to ethanol production. There are approximately 116,000 head of dairy cattle in the local area capable of consuming 151,000 tons of HPD. The plant is expected to produce 158,000 tons per year. In order to obtain the premium associated with HPD, the plant may need to ship this product to distant dairy markets. The price is set to 100% the price of corn on a dry weight basis based on recent pricing for HPD ($102.86/ton based on $2.72/bu corn). The HPD market is not well developed and this indicates some level of risk. Dakota Gold (Poet), Renew Energy and Zeeland are all experienced marketers of HPD.

The germ yield is expected to be 4.4 pounds per bushel with total annual production of 105,166 tons per year. It is anticipated that the performance guarantee will be 20% oil content on a mass basis. The plant plans to use solvent extraction which is extremely efficient. The expected corn oil yield is 0.88 pounds per bushel based on 20% oil content. Corn oil is the most valuable co-product due to high prices obtained for pure vegetable oils. The plant will produce roughly 21,033 tons of corn oil per year and the price is set to the five year average USDA price of $0.355/lb ($710/ton). Operational costs for the solvent extraction system, plus transportation costs, are anticipated to be $0.045 per pound. The germ left over after the oil is extracted (3.3 pounds per bushel resulting in 78,875 tons/yr) will be sold as a low quality cattle feed priced at 50% the price of corn on a dry weight basis ($48.57/ton based on $2.72/bu corn).

The bran output will be 3.2 pounds per bushel (80,000 tons/year). It will be used to produce steam in a biomass boiler. Alternatively, the bran can be sold to food processors or as a low grade cattle feed.

Carbon dioxide from the proposed plant could be used for local food processing and beverage markets if these markets present themselves in the future, however no sales are included in this analysis. The project should aggressively seek carbon sales for the purposes of marketing low carbon fuels.

Financial Forecast

The feasibility study is based on 10 year average prices for the major inputs and outputs including the rates for corn, ethanol, and denaturant. Commodity prices can be highly variable over short time periods and evaluating the profit of any particular project using only the current prices could lead to rash decisions. Financiers including equity investors, banks, and other debt providers traditionally have preferred to evaluate ethanol projects based on historical pricing to gain an understanding of how the project could have performed and also to establish a benchmark against other projects currently in operation.

Corn and energy pricing has been much more volatile in the past 24 months and has not aligned with the average prices for the 10 year span leading up to this period. Nonetheless, the actual gross margin at many ethanol plants has proven to be relatively comparable with historical averages. Capital providers in today's markets typically prefer to evaluate a project's profitability against historical pricing, as well as consider other scenario analysis using forecasts that incorporate in potential price variability within the markets. Sensitivity tables and charts like the ones included in this report also supply additional analysis for evaluation of projected cash flows projects based on particular price points.

Two scenarios were evaluated at the Ft. Morgan site for this study; a 59-mmgy dry-mill ethanol plant with an anaerobic digester supplementing 26% of natural gas use, and a 130-mmgy dry-mill ethanol plant with fractionation and solvent oil extraction, as well as a biomass boiler and anaerobic digester supplementing 68% of natural gas use.

Financial forecasts were based on historical prices for corn and Los Angeles ethanol spot prices (inclusive of the federal excise tax exemption), which correspond to \$2.63/bu (59-mmgy) and \$2.72/bu (130-mmgy) and \$1.76/gallon, respectively. The results are summarized in the following table.

Table 1 – Financial Modeling Results, Pre-tax

Ft. Morgan Ethanol Project	59-mmgy	130-mmgy
11-year Average Annual ROI	37.4%	31.4%
Internal Rate of Return	33.0%	32.9%
Average Annual Income	\$23,411,000	\$40,231,000
EBITDA	\$31,357,238	\$61,791,400
Installed Capital Cost (\$/gal)	\$1.93	\$2.19
Plant Capital Cost	\$91,645,000	\$241,445,000
Owner's Costs	\$22,313,163	\$43,611,360
Total Project Investment	\$113,958,163	\$285,056,360
45% Equity	\$62,676,989	\$128,275,362

BBI believes that projects with an ROI greater than 25% are worth pursuing. Both scenarios achieved this hurdle, however, the 59-mmgy shows a higher average ROI over the life of the project. The better performance of the smaller plant is a factor of corn price basis and offset heating costs from the anaerobic digestion system. The smaller plant has a lower thermal energy requirement, since all distillers grains will be sold in the wet form. This also reduces capital costs as the plant will not need to purchase natural gas fired dryers. The 130-mmgy scenario with fractionation and a biomass boiler is also a promising project, however, there are more risks associated with this project due to the additional technology, and it would likely require more maintenance. On the other hand, the 130-mmgy scenario produces more products tied to the price of corn, which will help buoy its performance if ethanol prices drop. The complete year two income statement is available below. The complete summary of the scenarios is in Appendix B and C.

Sensitivity analyses demonstrated that a 59-mmgy plant would be cash-flow positive over a range of ethanol and corn prices, tolerating ethanol prices of $1.35/gallon with corn at $2.63/bu, and corn prices as high as $3.81/bu with ethanol at $1.76/gallon. The 130-mmgy scenario could endure ethanol prices down to $1.44/gallon with corn at $2.63/bu and tolerate corn prices as high as $3.61/bu with ethanol at $1.76/gallon.

Recommendations

BBI recommends that both project sizes be developed in parallel until one of the projects provides a better opportunity. The 59-mmgy plant provided the most favorable economic returns based on the assumptions and 130-mmgy plant is almost as competitive but requires a greater investment and equity funding will be more challenging.

If the decision is made to proceed with further development of the project, the project should focus efforts on:

- Developing a corn supply and procurement plan for the project
- Developing the required marketing relationships for ethanol and co-products
- Obtaining performance guarantees for the fractionation, anaerobic digestion and biomass boiler systems
- Comparison of solvent and mechanical extraction systems for removing corn oil from germ
- Developing a strategy for carbon dioxide sales as this enhances the low carbon fuel credentials of the proposed plant
- Developing a risk management strategy for the operation of the plant

Special emphasis should be placed on the issues that have the greatest impact on the project profitability: maximizing revenue from ethanol and co-products, reducing grain shipping and handling costs, and obtaining natural gas, water, and electricity at favorable long-term rates.

BBI would like to thank the Colorado Farm Bureau for the opportunity to work on this assessment of corn fractionation and biomass combustion.

II. PROJECT OVERVIEW

Purpose of Study

The Colorado Farm Bureau is exploring the opportunity for a partnership with a proposed low carbon ethanol dry mill production facility (the project) in Ft. Morgan, CO. If viable, the project would produce ethanol, distillers grains, and carbon dioxide from corn. The project would enhance economic development by becoming a processor of agricultural products and cattle processing wastes and providing jobs in the region.

The Colorado Farm Bureau has retained BBI International (BBI) to conduct a feasibility study for a proposed dry mill ethanol plant at one site in Ft. Morgan, CO. BBI evaluated two scenarios at this site. The first is a 59-mmgy plant with anaerobic digestion of area cattle processing wastes to supplement natural gas use. The second scenario is a 130-mmgy plant with front-end fractionation, anaerobic digestion and a biomass boiler (supplied by co-products of syrup and bran). The second scenario will produce ethanol, high protein distillers grains, corn oil, corn germ meal and carbon dioxide. Based on the results of the report, the Colorado Farm Bureau will be able to decide whether or not to proceed with a partnership in the project.

BBI is an independent consulting firm with no stake in the proposed project. The information detailed in this report reflects to the best of our ability, a true and accurate evaluation of the current ethanol industry, applicable markets, and the feasibility of the project.

Scope of Work

The facility envisioned is an ethanol plant with 59 or 130 million gallons per year production capacity that produces fuel ethanol, distillers grains, and carbon dioxide from corn. The 130-mmgy scenario will add fractionation and the additional co-products of corn oil and corn germ meal. The proposed facility plans on using cattle processing wastes and anaerobic digestion for a portion of process steam and the larger proposed plant would use a biomass boiler to burn the bran and syrup to further supplement steam requirements. This full feasibility study makes an evaluation of the following areas:

- Review and assess the potential site including
    - Transportation
    - Utilities
    - Water
    - Land Cost
    - Roads
    - Wastewater disposal
    - Site location relative to communities
    - Numerical ranking of site attributes
    - Required State and Federal permits
    - Site recommendation
- Appraisal of feedstock availability and price

- Review of fuel ethanol markets including
    - Local
    - Regional
    - National
- Review of the co-products, their markets, and feasibility of servicing those markets including
    - Distillers grains
    - High protein distillers grains
    - Corn oil
    - Corn germ meal
    - Carbon Dioxide
- Description of proposed project statistics including
    - Plant inputs
    - Plant outputs
    - Transportation
    - Energy demands
    - Personnel requirements
- Develop a Financial Model, including a construction budget, interim funding schedule and a ten-year operating forecast
- Conduct sensitivity studies for
    - Delivered feedstock price
    - Ethanol price
    - Co-product price(s)
    - Thermal energy price
    - Electricity price
    - Capital cost of the plant
- Summary and recommendations
- Presentation of result

III. SITE ASSESSMENT

Study Area

The project is considering a site just west of downtown Ft. Morgan, Colorado. Figure 1 and Figure 2 illustrate the site area and layout. Figure 3 and Figure 4 are pictures of the site topography and railroad.

Figure 1 – Study Area

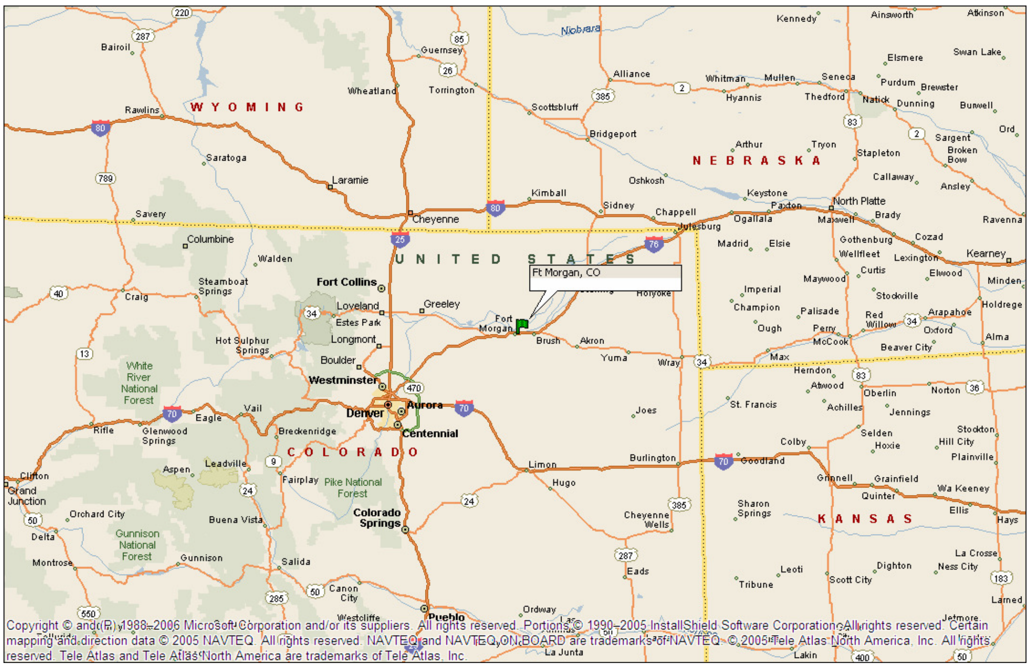


Figure 2 – Site Area

Figure 3 – Site Looking North

Figure 4 – BNSF Mainline

Site Description

The location under consideration is a green field site just west of the town of Ft. Morgan in Morgan County, Colorado. The available acreage includes 130 acres for a rail loop and 55 acres for the plant. Additional acreage is available with 80 acres northwest of the site and 35 acres directly south of the site.

The site is bordered by the railroad on the north side, County Road 13 on the west side, County Road 14 on the east side and County Road Q on the south side. The site is less than 2 miles from I76 which connects with I25 75 miles southwest and I80 105 miles northeast.

Site Evaluation

The criteria for a good ethanol plant site encompass many factors including feedstock proximity, road and rail access, and access to required utilities. Other considerations include a qualified and/or trainable labor force, access to an airport, and the presence of essential community services like medical facilities.

BBI used its in-house Site Evaluation Matrix to evaluate the project site. The Site Evaluation Matrix assigns weighted scores for desirable site attributes including:

- Feedstock availability
- Road and rail transportation infrastructure at the site
- Utilities including electricity, natural gas, water supply, and wastewater disposal
- Ethanol and co-product market proximity
- Labor availability
- Community services such as welding, electrical shop, plumbing, schools, fire protection, hospital, and airport
- Zoning and proximity to communities

Site Evaluation Criteria

Below is a discussion of each of the key items that determine the suitability of an ethanol plant site. A more detailed review of the availability of feedstock and the ethanol and co-product markets occurs in following sections of this report. Each of the key site attributes received a score and the site evaluation scores follow the discussion below. The plant inputs and outputs discussed are for a 59 mmgy and 130 mmgy dry-mill fuel ethanol plants. The site's score is presented at the end of this section rather than during the discussion of each criterion.

Feedstock Proximity

The proximity of feedstock is an important component of the site evaluation as well as the overall feasibility of an ethanol plant. An in-depth discussion and analysis of the availability of feedstock is in the Feedstock section of this report. Feedstock proximity takes into account the plant's feedstock requirement and the feedstock production within various distances. The feedstock requirement for a 59-mmgy plant is approximately 21 million bushels of corn (47 million bushels for 130 mmgy) per year. 10 points are possible in this section.

Roads

Access to Class A roads is an important requirement for an ethanol plant. The plant is located off county roads with permission from the county for use. The plant may build a feeder road for the ethanol plant off County Road 12 (Long Bridge Road) for more immediate access to I76.

Rail

Rail access can be a distinct advantage over other plant sites, and while a site on a mainline is generally better than a location on a short line rail line, there can be advantages to a short line. A Burlington Northern Santa Fe (BNSF) mainline runs along the north side of the site. The plant plans to build a double loop to accommodate unit trains with expectations of laying 22,000' of track. The rail plan has already received approval from BNSF.

An analysis of the ethanol rail shipments for the proposed plant is in Table 2. BBI assumes that all of the ethanol ships by rail and that five days of loaded ethanol rail car storage is needed at the plant.

At 59-mmgy, the ethanol plant will produce about 169,000 gallons of denatured ethanol daily (130-mmgy produces 372,000 gallons daily). An ethanol rail car holds about 30,000 gallons, filling an average of 2.4 rail cars each day. Therefore, five days of storage requires ~28 or 62 rail cars. Empty ethanol rail car storage should be twice loaded storage (56 or 124 cars).

Table 2 – Ethanol Rail Shipment Analysis

ETHANOL RAIL SHIPMENTS		
Annual ethanol production, gal	59,000,000	110,000,000
Production days per year	353	
Daily ethanol production, gal	70,822	311,614
Rail car capacity, gal	30,000	
Rail cars per day	5.6	12.4
Days rail car storage needed	5	
# loaded rail car storage needed	28	62
Empty ethanol rail car storage recommended	56	124

It is assumed that the 59-mmgy scenario will be able to sell all distillers grains locally. The 130-mmgy scenario may ship a limited about of HPD by rail to more distant dairy markets.

Electrical Service

Based on a typical electrical energy input requirement of 0.75 kWh per gallon of anhydrous ethanol produced, a 59-mmgy plant will require approximately 5.0 MW of power, or 42,000,000 kWh per year (assuming 90% capacity factor). A dry-mill ethanol plant with fractionation is expected to use 1.2 kWh per gallon of anhydrous ethanol produced or less. A 130-mmgy plant with fractionation will require approximately 17.7 MW of power, or 149 million kWh per year (assuming 90% capacity factor). The City of Ft. Morgan will provide power to the plant through an agreement with Morgan County Rural Electric Cooperative (which receives power from Xcel Energy).

Thermal Energy and Natural Gas

Most ethanol plants use natural gas to generate process steam and to fire the direct-fired distillers grain dryers. Natural gas use is typically about 32,000 BTUs for each gallon of 200-proof ethanol produced with drying the distillers grains. A 59-mmgy ethanol plant requires about 236,000 cubic feet of natural gas per hour. The plant operates 24 hours a day, about 350 days per year. The natural gas requirement is reduced is 28,000 BTU per gallon for an ethanol plant with fractionation—the removal of germ and bran prior to the ethanol process reduces the energy load.

Natural gas typically comes from a large gas transmission line with the ethanol plant installing a new line to the gas source, or from an existing gas distribution line with distribution costs paid to the local gas company. Either way, the natural gas is purchased on the open market with transmission fees paid to the transmission pipeline company and then distribution costs paid to the local gas company if local distribution lines are utilized. The transmission and distribution costs are usually negotiable. There is a large gas transmission line 3.5 miles from the site 17 points are possible in this section, accounting for service availability and proximity.

The project plans to produce low carbon fuels by supplementing natural gas use with anaerobic digestion for either size plant. The project has selected ADI Systems, Inc. to design the facility that will use a recipe of area livestock production wastes including paunch water (intestinal contents of slaughtered cows), manure and similar wastes. The resulting biogas will have an energy content of approximately 650 BTU/cubic foot (natural gas has 1000 BTU/cubic foot). The anaerobic digestion system will be designed to supply approximately 332,700 MMBTU per year. This will reduce natural gas use by 26% for the 59-mmgy (assuming all distillers grains are sold wet). A similar reduction from use of the resulting biogas of 9% is expected for the 130-mmgy plant (all distillers grains will be dried due to the fractionation technology).

The 130-mmgy plant is also evaluating using a biomass boiler using the bran (fractionation co-product) and syrup (intermediary product) to provide process steam. This will further reduce natural gas use by 59%. The combination of using anaerobic digestion and a biomass boiler at the 130-mmgy plant will result in a reduction of natural gas consumption of 68%.

Water

There are three basic sources of water used for ethanol plants: well water, municipal or district water, and surface or river water. Most plants use well water due to their rural location. Over the long term, well water is often less expensive. Cost of drilling, quality of well water, and long-term supply are important considerations when considering a water supply. The second option as a water source is city water or a rural water district, which may provide a more reliable source of water, but usually at a higher cost. The third option is surface or river water if a reliable source is available nearby. Water quality and long-term supply are important considerations just as they are with well water. The factors driving the choice of water supply are reliability, water quality, and price. The project has already obtained water rights for all water required by the plant and has also received bids on a water treatment system. The City of Ft. Morgan potable water line runs adjacent to the site. 7 points are possible in this section.

Wastewater

Today's ethanol plants typically do not discharge process water; they recover it and recycle in the dry-mill process. Most plants do have utility blow-downs where water periodically discharges from the cooling tower and steam boiler to prevent scale buildup in the equipment. There may also be wastewater discharged from makeup water treatment equipment, such as a reverse osmosis system. The blowdown water is typically very similar to the makeup water, but with an increase in the hardness. Cooling tower and boiler blowdown typically meet the discharge requirements for release to a local sewer, to surface water with appropriate permits, or to an evaporation pond. The wastewater can also be used for irrigation of crops or landscaping. The project intends to use an existing augmentation system and will not discharge to surface water.

Ethanol Market Proximity

A large local ethanol market provides a distinct advantage for an ethanol plant through lower shipping costs. Local, regional, and national markets for ethanol are differentiated by distance and transportation cost. Local markets are within 150 miles and are usually serviced by truck. Regional markets are generally considered to be within 450 miles and are serviced by truck and rail. National markets are more than 450 miles away and utilize rail. The project is planning on producing low carbon fuels and the only available market at this time is California. 10 points are possible in this section.

Co-product Market Proximity

A large local market for the plant's co-products can provide a distinct advantage for an ethanol plant through lower transportation costs. Approximately 18 pounds of DDGS are produced from each bushel of grain processed for a standard dry mill ethanol plant. If the plant is located near a significant number of feedlots, livestock operations, or dairies, the plant may be able to reduce or eliminate the drying step and sell its distillers grains as distillers wet grains (DWG). While this reduces the plant's natural gas consumption by up to one-third, it results in a perishable product that needs to sell immediately (within one week). 10 points are possible in this section.

Labor

The exact number of employees varies depending on the plant design and operating plan. It is usually preferable for the plant to obtain the majority of its workforce locally. However, the specialty positions such as the plant manager and microbiologist may require recruiting from greater distances. 7 points are possible in this section.

Community Services

Community services within 20 miles of the processing plant site are important to provide quick response to the needs of the plant and to attract and retain top employees. Desirable community services include electrical maintenance, machine shop, welding, plumbing, hospital, airport, good schools, and fire protection. 35 points are possible in this section.

Proximity to Communities

Ethanol plants bring numerous benefits to communities including job creation, adding value to local crops with diversified products, increased local tax revenues, and significant economic development across the community. There are, however, potential negative impacts associated with such facilities as well, such as increased traffic volume, visual impacts, and noise. While noise and odors from modern processing facilities are dealt with using engineering controls and operating procedures, issues such as traffic and visual impacts on the community must be considered during site selection.

In the context of site evaluation, a site in close proximity to a community or residential area will receive a lower score than a site located in a more isolated or industrial area or with a “buffer” of undeveloped land between it and its neighbors. 6 points are possible in this section.

Site Evaluation Results

BBI examined the site and rated it using the BBI Site Evaluation Matrix shown below. A score of 105 to 150 is excellent, 90 to 104 points indicates a good site, and less than 90 indicates a marginal site.

The site evaluation score is an indication of the suitability of a site and its’ potential to serve as a location for a viable and efficient ethanol production process; it is not a measure of the overall economic feasibility of the proposed project.

Table 3 – Site Analysis Scores

Site Characteristic	Ft. Morgan, CO
Feedstock Proximity	2
Proximity to Communities	6
Existing Rail Siding	0
Rail Access	10
Roads/Highways	6
Electricity	8
Natural Gas	11
Water	7
Wastewater Discharge	7
Co-product Market Proximity	10
Labor Availability	7
Ethanol Market Proximity	2
Community Services Within 20 Miles	35
TOTAL:	111

RATING

105 to 150+ – Excellent
90 to 104 – Good
Less than 90 – Marginal to Poor

Refer to Appendix A for the detailed matrix scoring for the site.

Site Issues and Recommendations

Based on these results, the Ft. Morgan site receives a score of 111, and falls into the "excellent" category. BBI acknowledges that the project has already made great progress in making arrangements for the site such as securing water rights, obtaining permission to build a feeder road just off the interstate, a comprehensive water and wastewater plan, site layout, approval of railroad design, etc.

BBI also makes the following recommendations regarding siting of the project:

- Ascertain the level of acceptance of the project by the city and community.
- Have the site evaluated by a local civil engineering company from a site development perspective, to identify any challenges or risks associated with developing the ethanol plant at the candidate site.
- Have the site evaluated by an ethanol process design company from an engineering and construction perspective.

Refer to Appendix A for the detailed matrix scoring for the site.

Required State and Federal Permits

The following is a list of permits normally required for an ethanol project. However, the size and design of the ethanol plant, the method of steam and power generation, and local permitting requirements ultimately affect the actual permits required. The air permit has already been obtained.

<u>Federal Permits</u>

Clean Air Act
- Prevention of Significant Deterioration (PSD) and Construction Permits
- Applicable Federal New Source Performance Standards (NSPS)
- Applicable National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Title V Operating Permit of the Clean Air Act Amendments of 1990
- Risk Management Plan

Clean Water Act
- National Pollutant Discharge Elimination System (NPDES)
- Oil Spill Prevention and Control Countermeasures

Comprehensive Environmental Response Compensation and Liability Act & Community Right to Know Act (CERCLA/EPCRA)
- Tier II Forms – listing of potentially hazardous chemicals stored on-site
- EPCRA Section 313 and 304 and CERCLA Section 103 track use and release of regulated substances above threshold and/or designated quantities annually.

Bureau of Alcohol, Tobacco, and Firearms (BATF)
- Alcohol Fuel Permit (AFP)

<u>State Permits</u>

- Air Quality Permits (issued)
- Storage Tank Permits
- Water Quality Permits
- State Liquor License
- State Department of Motor Fuels
- State Department of Transportation
  - Highway Access Permit
  - Possible Easement rights
- State Department of Health
- State Department of Public Service
  - Boiler License
- State Department of Natural Resources
  - Water appropriation permits
  - Other waters and wetland considerations

IV. FEEDSTOCK AVAILABILITY AND PRICE

Depending on the current market price for corn, the cost of the feedstock is typically 65-75% of the cost of production for a dry mill ethanol plant. Because of this significant impact, a detailed analysis of the availability and cost of corn completed by Cash Grain Bids, Inc. is included for the project.

Corn Supply and Demand Overview

Locally

The Northeast region of Colorado is a large producer of grains, split between feed grains and wheat. In a 5-county region around Ft. Morgan, CO the average corn production has been 32 million bushels (Figure 5). However, this is off from production levels in the late 90's of around 43 million bushels. Over this time, corn acreage has fallen by 100,000 acres leading to the lower regional production.

Figure 5 – Local Corn Production for 5-County Region

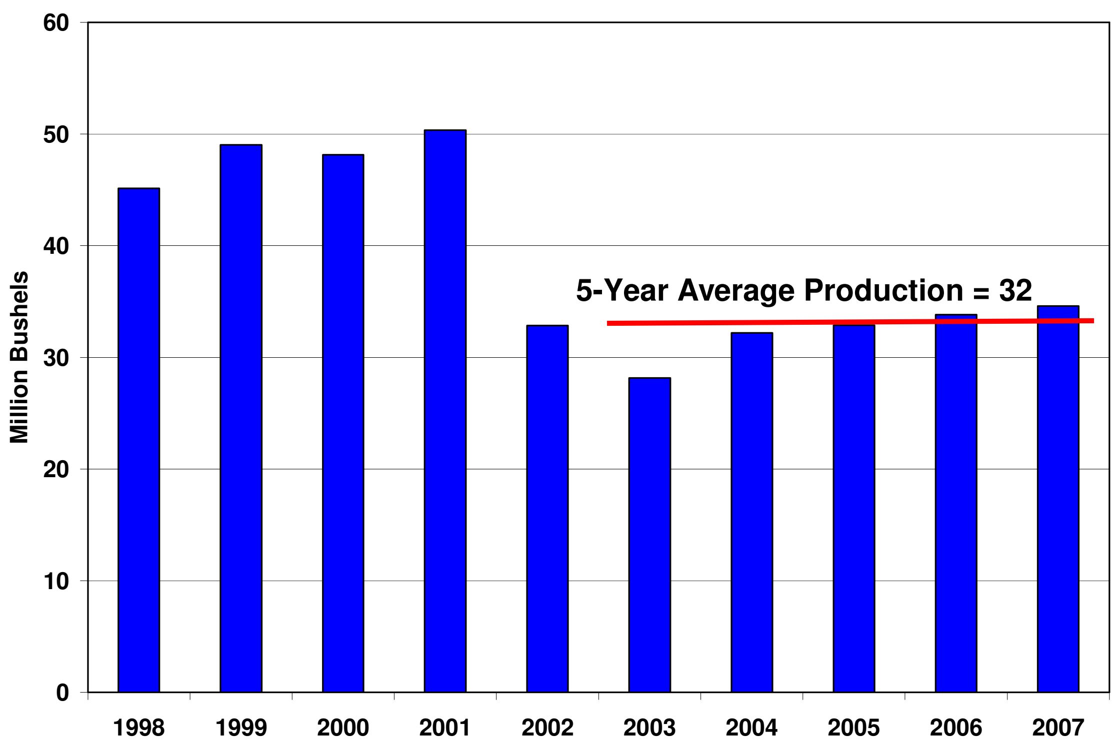


Figure 6 shows the total corn supplies in the area, while Figure 7 illustrates the net supply conditions. Net supply, in this case, is total corn less the quantity that is being used for feed.

Feed usage was calculated based on the number and types of animals being fed in the local region. The average dairy cow requires 162 bushels of corn per year according to the Kansas Dairy Farmers. The average beef cow in a feed lot requires 88 bushels per year. Grazing beef cattle require 12 bushels of supplemental corn per year (Iowa Beef Center). The above numbers assume that both dairy and beef cows are being fed 3.5 pounds of distillers grain per day. If the cows were not fed this ration of distillers grain, corn consumption would have to increase by 38%, or 62 bushels for dairy cows and 34 bushels for cows on feed. Corn is also allocated to hogs and poultry. Hogs are assumed to consume 10 bushels of corn per year, while layers and broilers are assumed to consume 1 bushel per year.

Figure 6 – Total Corn Supplies for Ft. Morgan, CO Region

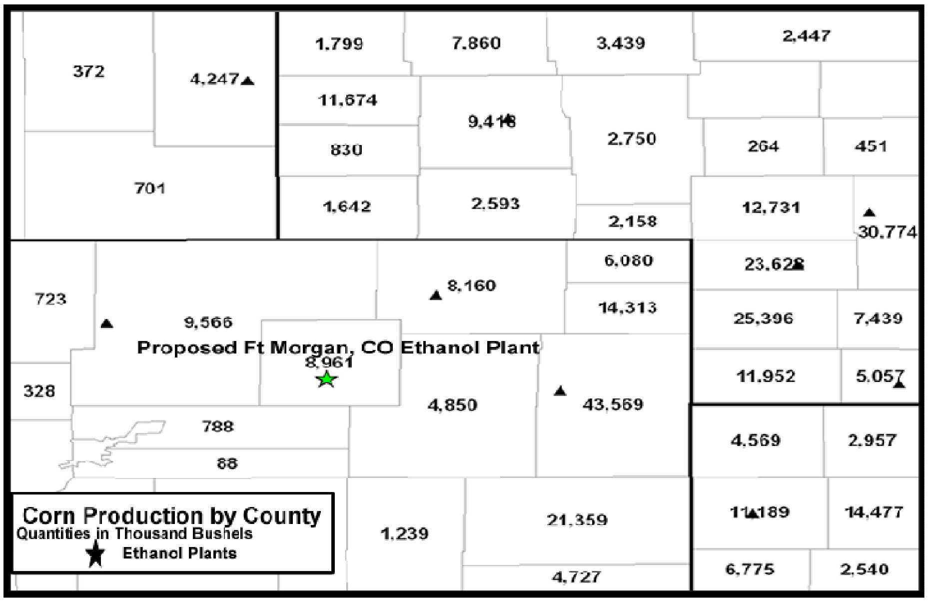
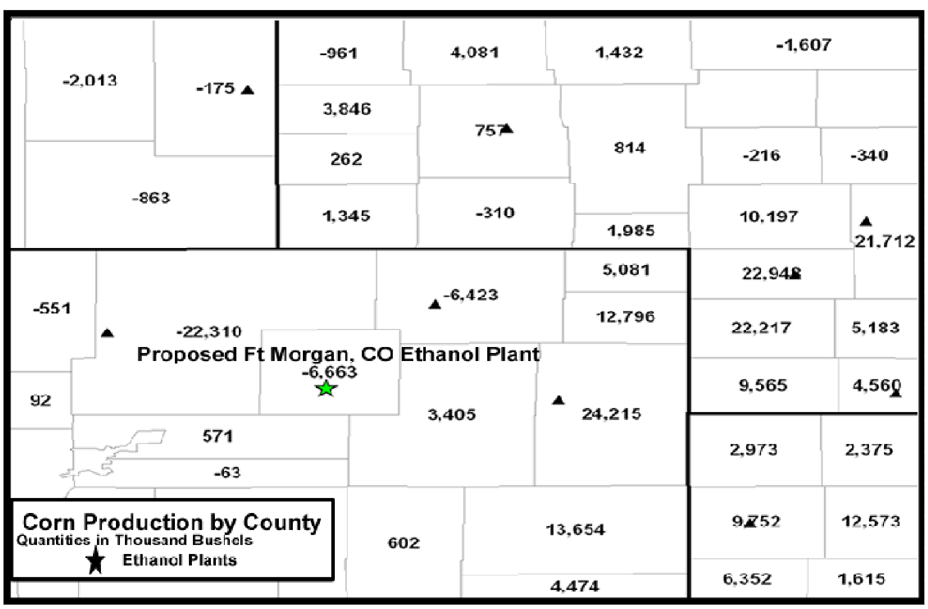


Figure 7 – Corn Net Supplies for Ft. Morgan, CO Region

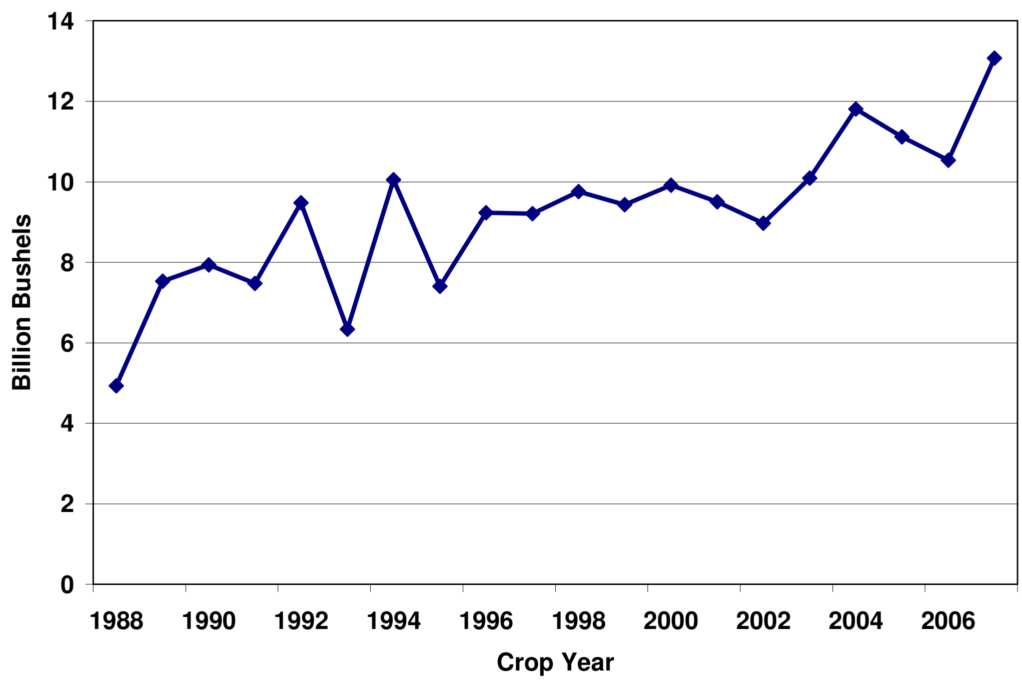


While there are relatively sizable supplies of corn in the area, feed usage along with competition from existing and new-construction ethanol plants will push local prices higher as new plants come online.

National Outlook

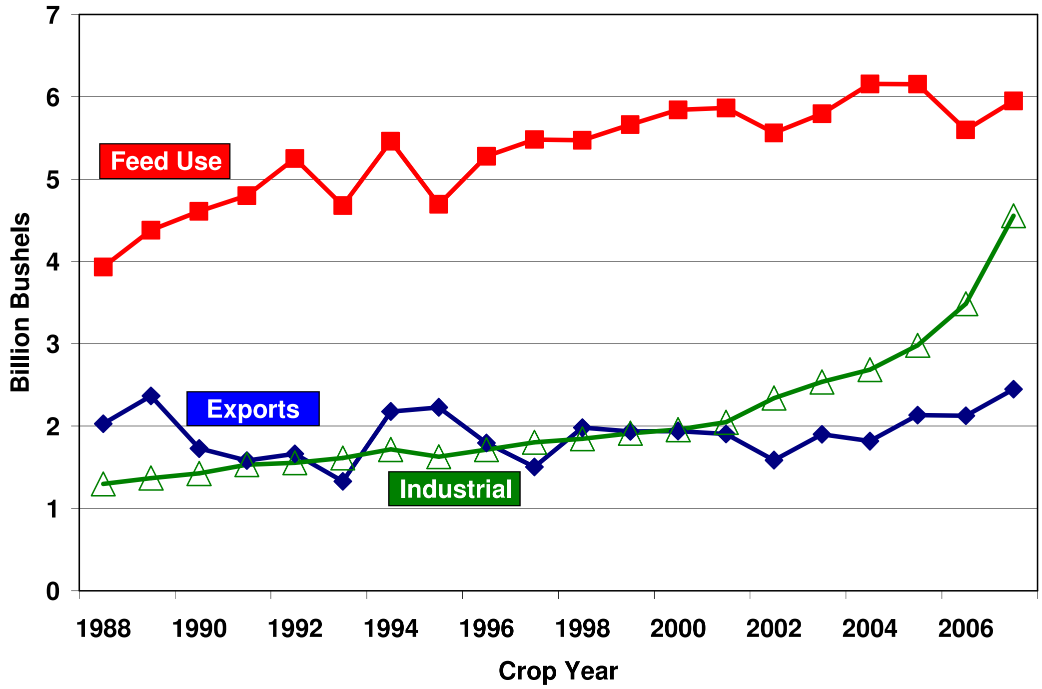
U.S. corn production has grown steadily, thanks to innovations in corn production practices and improved genetics. Although U.S. farmers have kept their corn acreage fairly stable over the past 20 years, U.S. corn yield per acre has increased at an average annual rate of 1.5 percent. While the trend over time is for higher yields, significant yield variations occur due to weather and growing conditions. As a result, U.S. corn production can change quite readily from one year to the next. Figure 8 shows historical corn production.

Figure 8 – U.S. Corn Production



Long-term growth in corn production has been mostly matched by demand-side growth. Corn used for feed is by far the largest component of corn demand, and it has grown from 4 billion bushels in the mid-1980s to more than 6 billion bushels by 2004 (Figure 9). However, changes in livestock feeding profitability, as well as relative prices of alternative feed stocks, can have an important impact on how much corn is fed each year. Exports also exhibit significant year-to-year variation, although this variability has diminished in recent years.

Figure 9 – U.S. Corn Utilization



Industrial use of corn, which includes corn utilized in the production of ethanol and high fructose corn syrup, has been a growing segment of the U.S. corn market. In 1984, industrial use of corn accounted for only 15 percent of the total corn market, but by 2007 its share reached 35 percent. With continued expansion in ethanol manufacturing for the coming years, industrial use of corn will continue to expand.

For 2008, higher input costs for corn production combined with relatively high wheat and soybean prices have limited corn plantings. Corn prices should continue to be higher for the next few years, but expansion in global production of wheat and oilseed crops will likely limit U.S. plantings of these crops and return U.S. acreage to corn production.

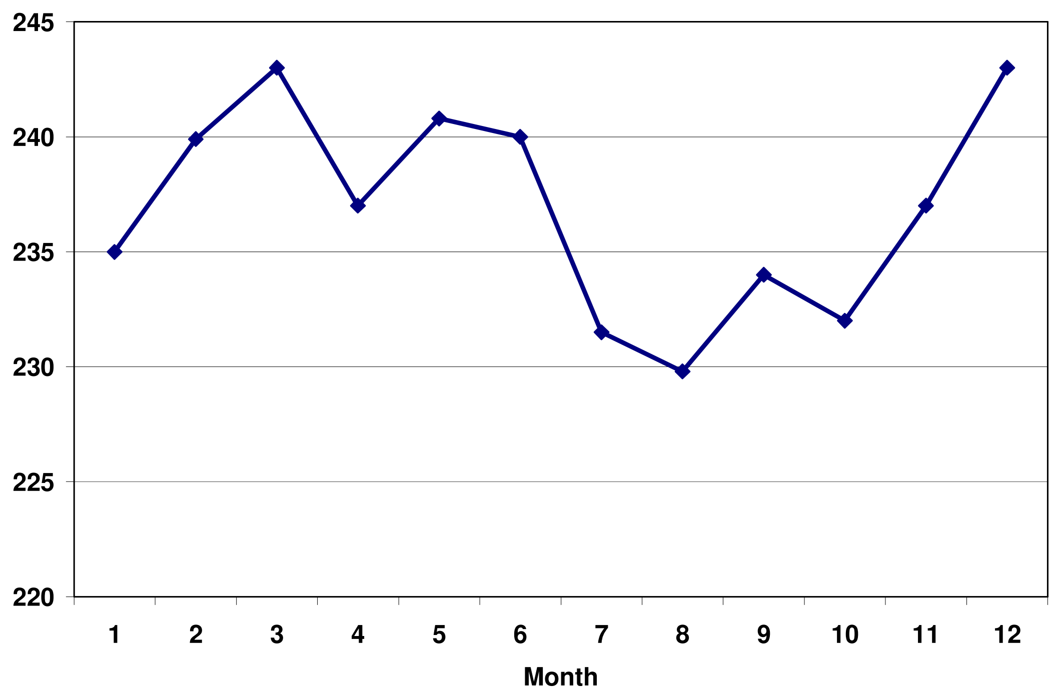
Historical and Seasonal Pricing Patterns

Current corn prices around the country are trading at record highs. In the past 10 years, corn prices in the Ft. Morgan, CO region have shown extreme variability, trading as low as $1.91 per bushel on average for the year of 2005 to $3.71 on average in 2007 (Table 4). Current corn prices in the region of Ft. Morgan are trading around $5 a bushel, but reached as high as $7 a bushel in June 2008. This variability means that grain prices may be dramatically different from one year to the next. Over the past decade the average price in the Ft. Morgan region was $2.37. Prices tend to be lowest in late summer and early fall coinciding with local harvest.

Table 4 – Annual Corn Price Variation: Ft. Morgan, CO
(Cents per bushel)

Year	Average	Max	Min
1998	231	262	204
1999	204	214	187
2000	204	230	178
2001	205	213	193
2002	229	291	188
2003	234	250	213
2004	252	299	185
2005	191	215	176
2006	245	358	196
2007	371	404	335

Figure 10 – 10-Year Average Seasonal Corn Price in Ft. Morgan, CO
(Cents per bushel)



Moving away from Ft. Morgan to the East and North, corn prices tend to decrease as available corn supplies increase. Prices are generally lower east of the proposed plant in Ft. Morgan. Prices also vary seasonally, with the lowest corn prices occurring at harvest and the highest prices occurring in the spring.

Figure 11 through Figure 17 illustrate average price and basis patterns found in the Ft.Morgan region through out the season.

Figure 11 – 10-Year Average Corn Price

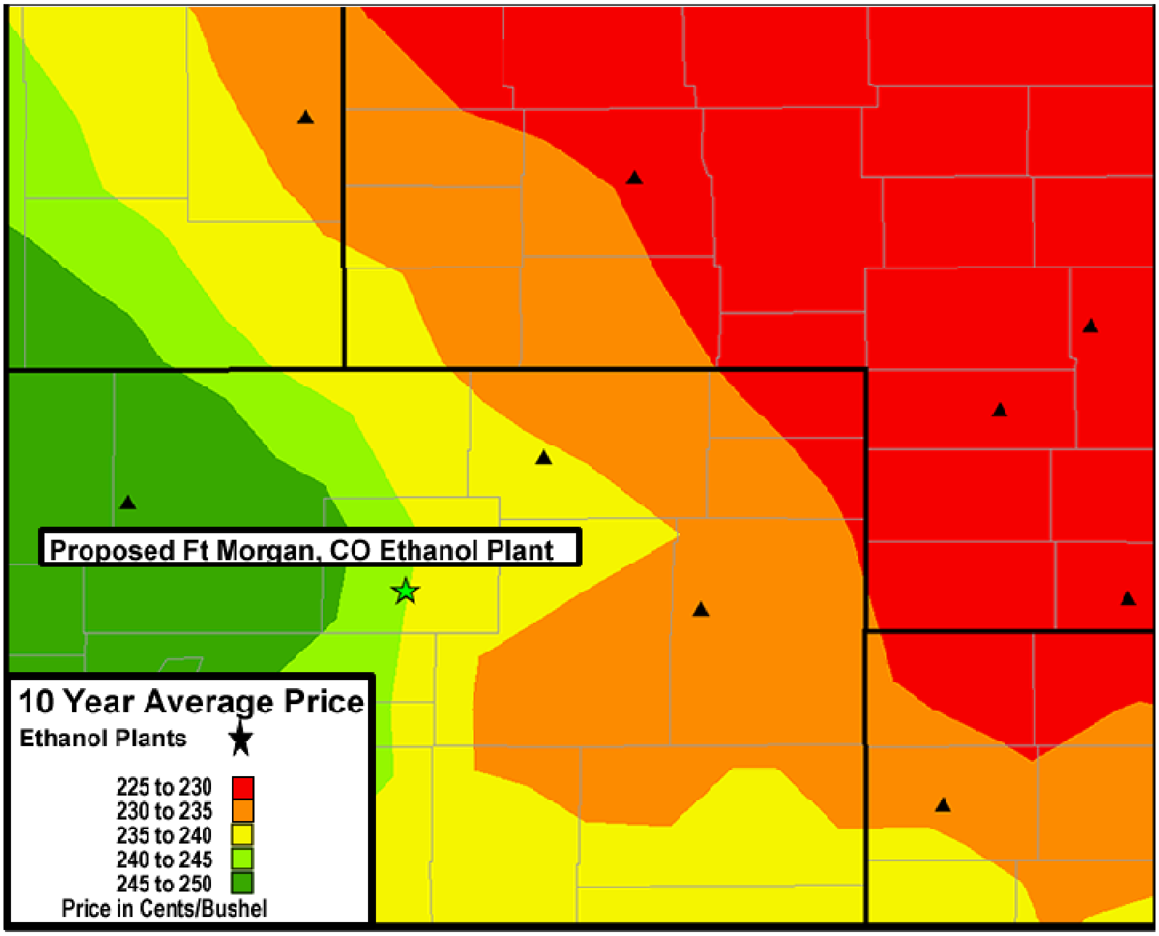


Figure 12 – 10-Year Average October Corn Price

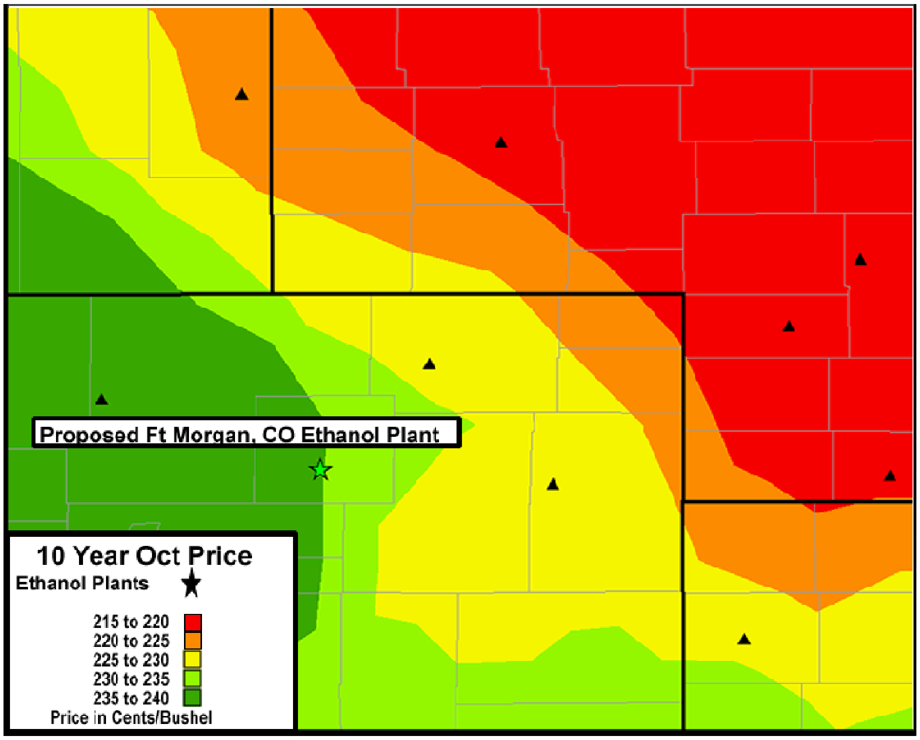


Figure 13 – 10-Year Average October Corn Basis

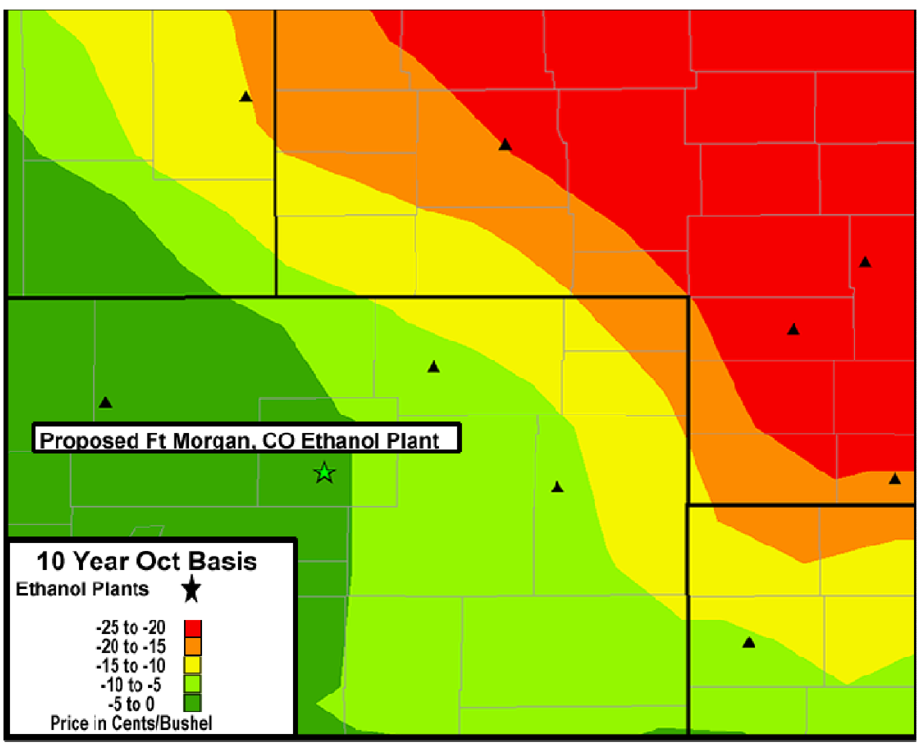


Figure 14 – 10-Year Average February Corn Price

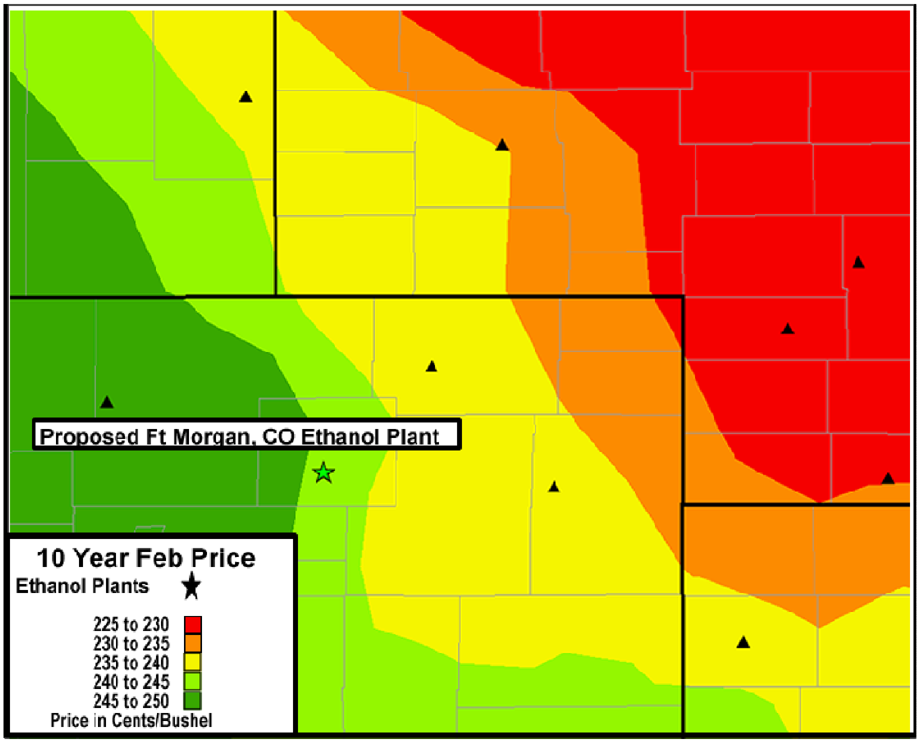


Figure 15 – 10-Year Average February Corn Basis

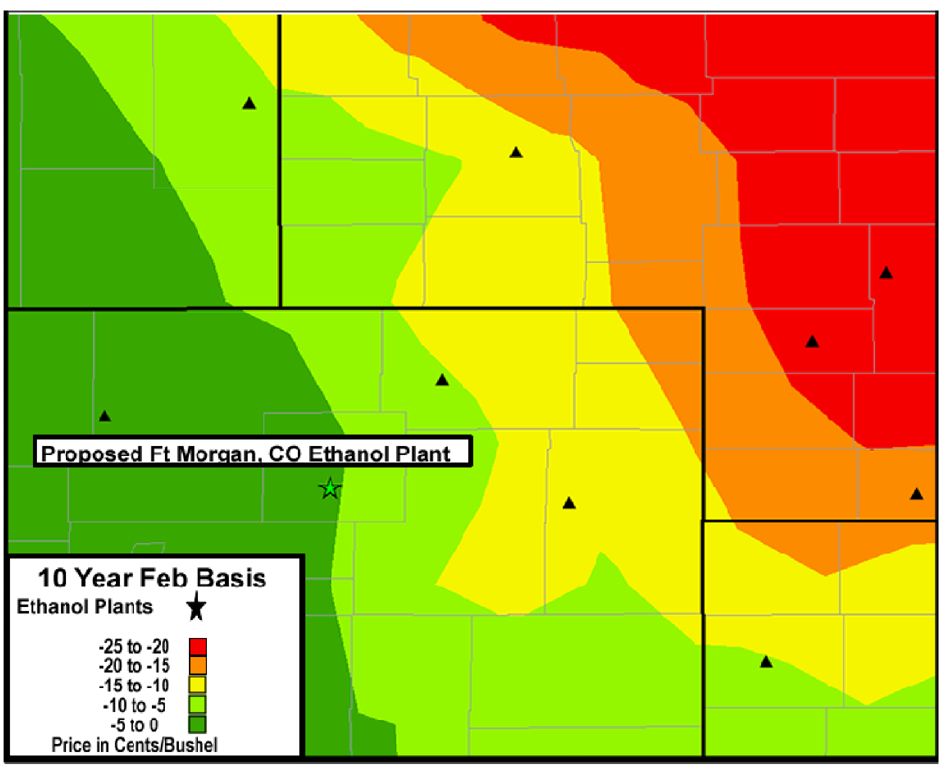


Figure 16 – 10-Year Average June Corn Price

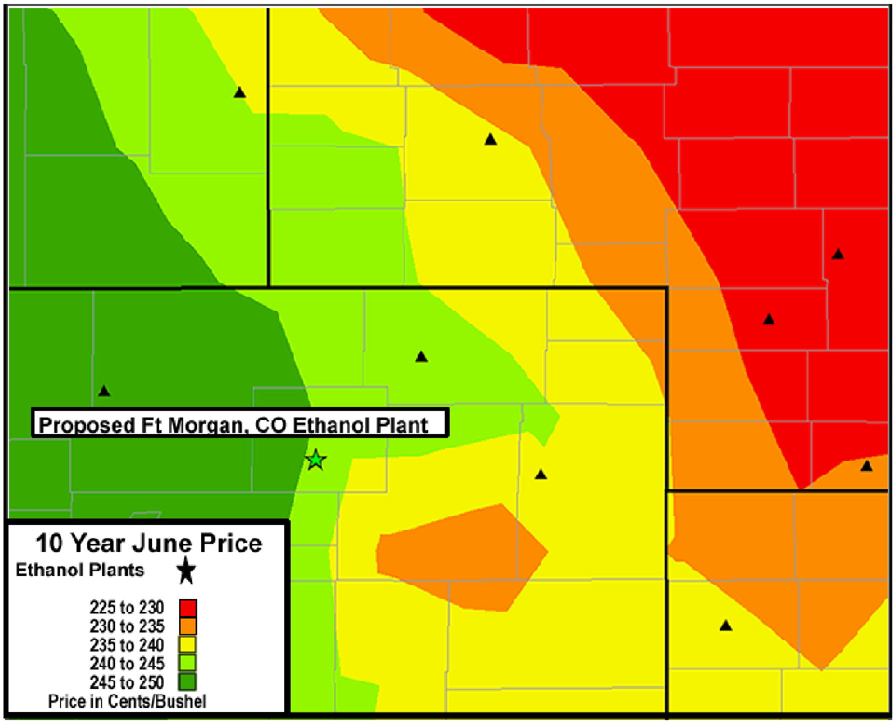
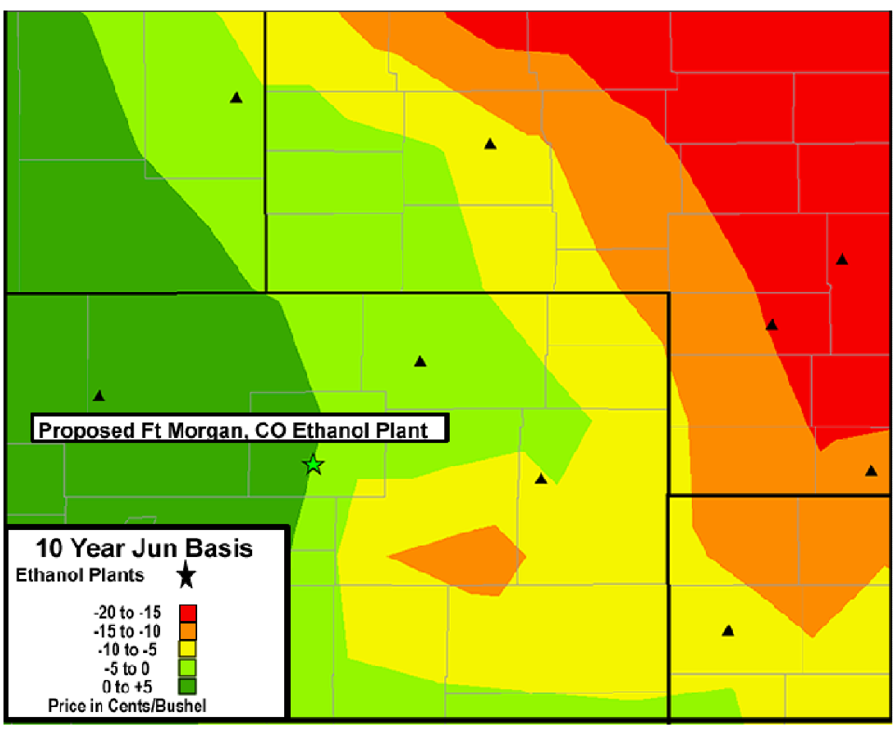


Figure 17 – 10-Year Average June Corn Basis



Spatial Equilibrium Model and Analysis Approach

Cash Grain Bids Inc. collects daily grain bid prices from elevators, feedlots, terminals, ethanol plants, and other key buyers. The data encompasses more than 2,700 markets and 17 commodities, dating back to 1996. These markets include country elevators, feed mills, ethanol plants, and terminal markets along major export routes. Along with data dissemination, a spatial arbitrage model is also deployed that helps cash grain traders pinpoint regional buying and selling opportunities. These models take into account price differences across markets, and also rail, barge, and truck shipping network systems and rates.

A spatial arbitrage model with grain trade was used to conduct analyses. This model provides a framework for assessing the impacts of localized structural changes on cash grain markets. From regionalized production shortfalls to disruptions in grain transportation flows and the introduction of new sources of demand, their models allow them to ascertain the extent of price impacts and also to see how these impacts diffuse spatially across the market landscape.

The initial phase of this study is identifying key markets within a 200-mile radius of Ft. Morgan, CO. Daily price data on these markets was collected from January 1, 1998 through December 30, 2007. From these daily values, an average price for each location is computed. This dataset serves as the basis for the analysis.

The following analysis examines the price impacts of a 59-mmgy or 130-mmgy plant in Ft. Morgan, CO. To assess the impact of a new ethanol plant, the spatial equilibrium model adjusts the plant's corn price higher until it draws the necessary grain supplies needed to run the plant at full capacity. Supplies come from nearby elevators that have set prices and certain supplies based on corn density in their area. The relative price of corn at each elevator, adjusted for trucking costs, will dictate which markets ultimately deliver corn to the new ethanol plant. Nearby ethanol plants are included in the model. If the plant at Ft. Morgan raises price enough to bid supplies away from the competing plants' source areas, the model accounts for this by increasing their bid prices as well. This iterates until all plants are able to reach their full input levels. The plant must ultimately raise prices enough to reach its capacity level.

The output of this procedure is a final assessment of the plant price for corn and a full accounting of the market share of the feedstock the plant receives from various sources.

This study is a conservative estimate of the basis impact. It does not include any supply responses. Higher grain prices could result in more corn acreage, reducing the basis impact. Additionally, higher grain prices at the plant may pull grain from competing industries. These types of supply responses have not been included in order to maintain the conservative nature of the basis impact estimate.

Plant Analysis – Sourcing by Truck

Looking at road distance and available corn supplies, a plant with a 59-mmgy located at Ft. Morgan will have to compete aggressively for the limited local supplies.

Table 5 shows the approximate net corn supplies - after feed use - based on the 10-year average production for corn in the region. Within a 25-mile driving distance of the proposed plant site, there are hardly any net supplies of corn – less than 5 million bushels after feed use. Most of the supply is between 75 and 100 driving miles from Ft. Morgan. However, for a large plant size of 130-mmgy, corn needs would eclipse 47 million bushels, which exceeds the available supplies in the 100-mile area.

Table 5 – Net Corn Supplies within Driving Miles of Ft. Morgan, CO
(in Million Bushels)

Miles	Net Supplies
25	4.5
50	6.4
75	21.3
100	32.5

While available supplies are an important indicator of sourcing grain in a local area, it is not necessarily true that all grain within a narrow region will find its way to the plant. This is because competing uses and alternative market outlets (with potentially more advantageous prices) will keep some of the available corn from moving to the plant.

There are several ethanol plants that could compete with the proposed plant for the corn supply in the region. This analysis accounts for competing plants in Sterling, CO (47 miles), Yuma, CO (61 miles), Windsor, CO (66 miles), Bridgeport, NE (130 miles), Madrid, NE (161 miles), Sutherland, NE (164 miles), Trenton, NE (164 miles), Goodland, KS (173 miles), and Torrington, WY (201 miles).

Utilizing a truck sourcing model, which takes into account competition from both ethanol plants and corn markets in the region, Cash Grain Bids, Inc estimates the basis impact to be 26 cents a bushel for a 59-mmgy plant and 35 cents a bushel for a 130-mmgy plant resulting in a ten year average delivered price of $2.63 and $2.72 per bushel respectively. In part, this basis impact is fueled by the proposed or under construction plants that will be in operation in the next few years.

Sourcing all of the corn by truck is a viable option, but the lack of sufficient local supplies makes it costly. The plant's feedstock price has to be set high enough to be competitive against local markets and draw from sufficiently far distances. Figure 17 below illustrates the areas where the proposed plant will likely source feedstock. The local county (Morgan) and two nearby counties (Washington and Yuma) will supply about half of the proposed 59-mmgy plants' requirements.

Figure 18 – Percentage of Corn Supplies by County – 59-mmgy Plant

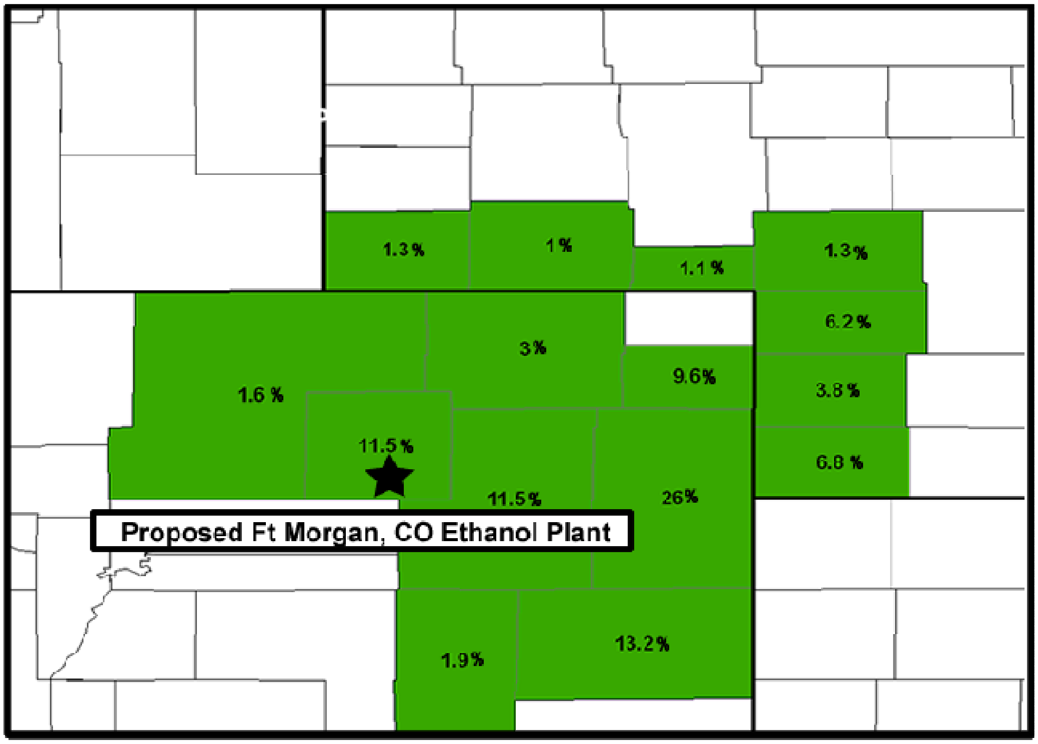
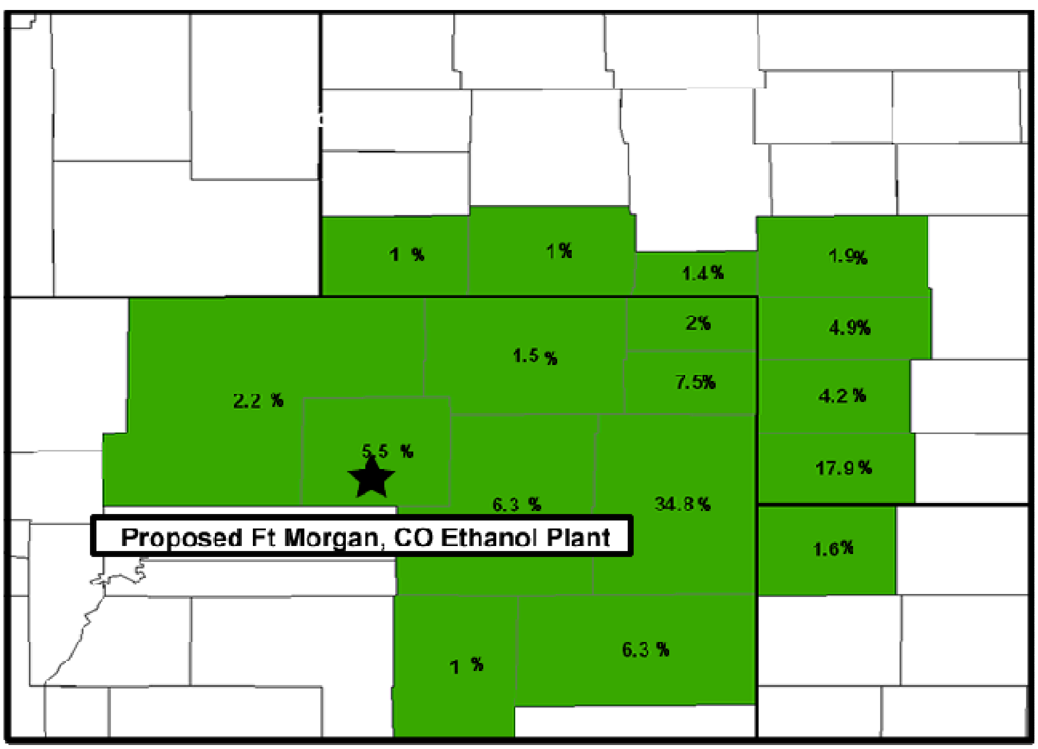


Figure 19 – Percentage of Corn Supplies by County – 130-mmgy Plant



Corn Stover

This area of the report provides basic information about corn stover and its availability in the area surrounding Ft. Morgan. There are no immediate plans to use stover as a feedstock for cellulosic ethanol or a biomass boiler at this time.

Corn stover is defined as the cobs, stalks, shuck and leaves from a corn plant left over from the harvest of kernels. Corn stover is the most plentiful crop residue in the U.S., making it an attractive feedstock due to its sheer availability. Corn stover is being tested as both an input for heat and power applications as well as a feedstock for cellulosic ethanol. Corn stover could also potentially serve as a feedstock for a range of biobased products. The National Renewable Energy Laboratory (NREL) conducted a life-cycle analysis of corn stover to ethanol and found an 80% greenhouse gas emissions reduction on a mile-by-mile basis of utilizing E85 (85% ethanol, 15% gasoline) when compared with conventional gasoline. This life-cycle analysis took into account the impact of feedstock collection and soil quality. Corn stover properties are available in Table 6.

Table 6 – Corn Stover Properties

Corn Stover Properties	
Cellulose	30-36%
Hemicellulose	25-30%
Lignin	16-20%
Moisture	9-10%
Ash	5.6-13%
Sulphur	.035-.04%
Higher Heating Value	7709 BTU/pound
Lower Heating Value	7192 BTU/pound
Theoretical Ethanol Yield	113 gallons/ton

(Source: American Society of Agriculture and Biological Engineers)

Collection and Storage

There are two methods of stover collection: large rectangular bales and large round bales. Both harvesting methods can be done in the field by using a corn combine with the chopper off, which creates windrows of corn stover that can be processed by hay baling equipment. It is also possible to collect stover as silage and bring it to a facility for processing into bales, but this method is not likely to be the most economical. Below is a summary of the two most likely forms of corn stover collection, per the Oak Ridge National Laboratory (ORNL):

Large Rectangular or Square Bales: Bale dimensions are estimated at 4'x9' (ORNL) or 3'x4'x8' (University of Minnesota) with a weight of approximately 1300 pounds. ORNL suggests the following equipment for corn stover rectangular bale collection: 160hp tractor, Case 8590 rectangular baler and bale wagon. It is assumed the baler can cover an area of 7.3 acres or 6.4 tons of stover baled per hour. The typical capacity of a bale wagon is 10 bales.

Large Round Bales: Bale dimensions are 6'x5' with a weight of 1270 dry pounds. ORNL suggests the following equipment for corn stover round bale collection: 120hp tractor, megatooth pickup head, crop processor (to increase density) and bale wagon. This method assumes a collection rate of 5.2 bale tons per hour.

The bales will either be moved to the field edge or moved directly to a storage facility. Bales can be moved by tractor and bale wagons to the field edge for later collection by truck for delivery to a storage or processing facility. Alternatively, a high-speed tractor such as the JCB 3185 and a bale wagon can move the bales to storage location within a few miles of the field. Flatbed trucks have a capacity of 26 or 28 bales for square and round bales respectively.

The expected harvest time frame is late October to mid December with October being more advantageous due to weather conditions. This short harvesting season will require storage solutions for year-round use of corn stover. If the processing facility lacks the space to store a year's worth of feedstock, it is anticipated that distributed storage facilities will supply the main facility. As with most biomass materials that are bulky and wet, it is more advantageous to deliver corn stover to a facility within 50 miles of the supply.

Stover Costs

A recent University of Minnesota study yet to be published estimated marginal costs for corn stover are $54 to $65 per dry ton. This study also predicts that rectangular bales will be the lowest cost form of corn stover. Any processor using corn stover as a feedstock is likely to obtain a supply contract from a cooperative or group of farmers that covers the costs for baling, delivery and farm profit.

Shipping costs from a storage facility to a processing facility approximately 50 miles away are estimated at $10 (ORNL cost estimate in 2002). If the storage facility is not owned by the processor, a storage fee will likely be charged. There must also be a payment to farmers that covers the costs of the nutrients removed from the land, plus some built-in profit. Different studies have calculated this cost with a range of ~$6 to $11 per ton. In areas with ample nutrient availability $10 per ton is an acceptable rate. Where there are issues with phosphorus or potassium the payment may be as high as $20 per ton.

Yield Assumptions

Several studies have been conducted to identify the expected yield of corn stover and it is entirely dependent on the corn grain yield. There are five studies that found a 1:1 ratio of corn stover to grain on a dry basis. Stover yield is provided in tons while corn yield is measured in bushels.

BBI calculated estimated corn stover production based on data obtained from the USDA National Agricultural Statistics Service database (NASS). The five year average data of harvested acres and yield was used for each county growing corn throughout the U.S. The formula used to determine corn stover production is available below.

Equation 1.

Corn Stover Production (tons) = Corn Yield (bu/acre) x 56 (pounds/bu)/2000 (pounds/ton) x harvested acres

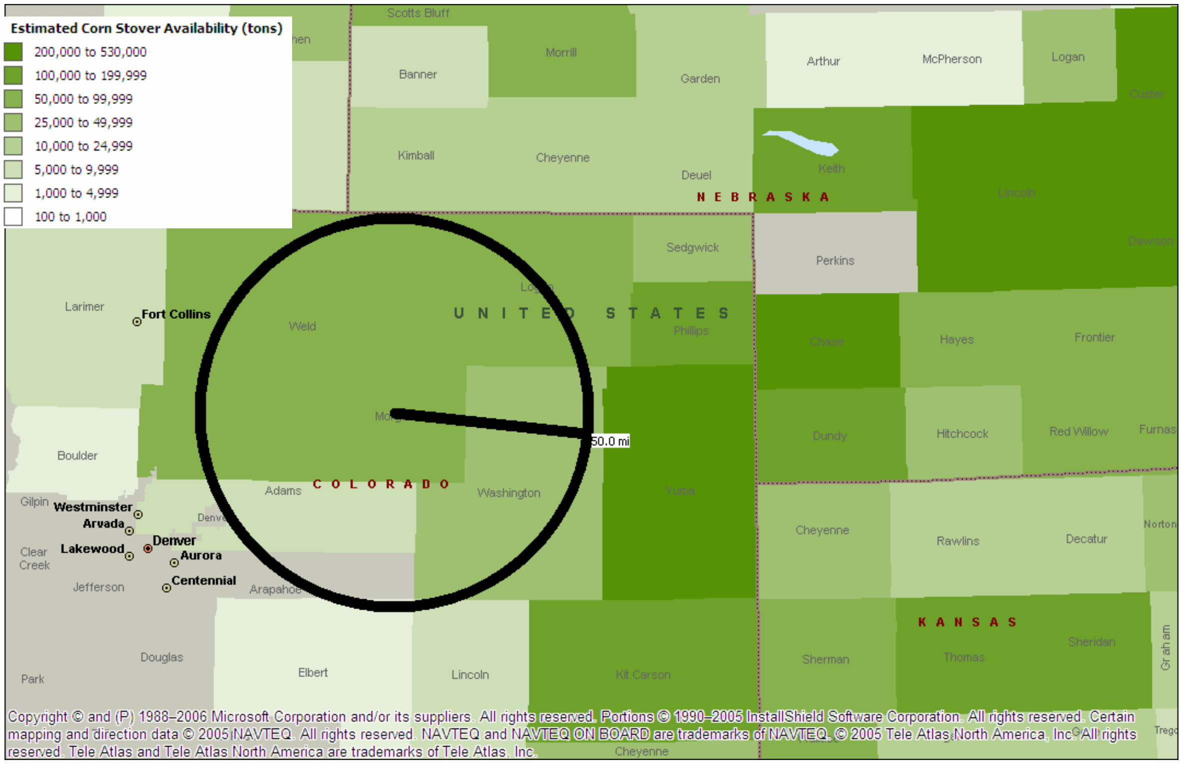
Removal Rate

The rate of corn stover that can be removed is a function of the soil type, tilling practice, topography and other related factors. Each large-scale corn stover supplier will need to evaluate their individual lands to determine the best rate of removal that allows for ample erosion protection and soil fertility. The removal rate will also be a function of the collection machinery used as there will generally be some losses. Several studies have been conducted with a focus on a 30% removal rate of corn stover as a generalized number. When looking to quantify for specific locations, county extension offices will have a good understanding of what amount can be removed for that particular area. Areas with drier soils or below average precipitation will likely need to leave a greater proportion of residues on the field. This percentage will be used as an overall removal rate for each county in the U.S. to give an overall idea of where the greatest concentrations of this feedstock will be available.

Ft. Morgan Area Corn Stover Production and Availability

The five year average corn stover production for the five counties surrounding Ft. Morgan was estimated at 891,633 tons and the average available residue is estimated at 268,851 tons (Figure 20). It is important to note that this is a total and some of the areas of the county extend beyond the 50-mile radius thought to be economical for shipping bulky and wet biomass materials. The estimated availability will also be lessened by tilling method, loss during collection and areas that cannot remove residues due to high wind erosion or similar factors.

Figure 20 – Corn Stover Estimated Availability-Ft. Morgan



Feedstock Analysis Summary

The Ft. Morgan, CO region has sufficient supplies of corn to support a 59-mmgy plant but at 130-mmgy the amount of local supplies is relatively small to handle such a large plant. There are 32.5 million bushels available within 100 miles of the plant.

Assuming all corn is delivered by truck, the basis impact of building a 59-mmgy ethanol facility is estimated to be 26 cents, indicating a ten-year average corn price of $2.63 per bushel. The basis impact for building a 130-mmgy facility is projected to be 35 cents, indicating a ten-year average corn price of $2.72 per bushel.

In future years the basis impact may be muted by a supply side response. A 26 cent basis impact in the short run will encourage producers to plant more corn acres. This increase in corn acreage is likely to dampen the basis impact slightly in the long run.

Prices vary significantly over the season, with the lowest prices occurring at harvest and the highest prices occurring in the spring. Storage strategies that allow for more grain to be purchased at harvest and less during the spring can help to reduce total grain costs.

In addition, there are nearly 270,000 tons of corn stover crop residue available in the local area. Plans are not currently set to utilize available corn stover for cellulosic ethanol production or heat and power production in a biomass boiler, but the opportunity remains available.

V. REVIEW OF ETHANOL MARKETS

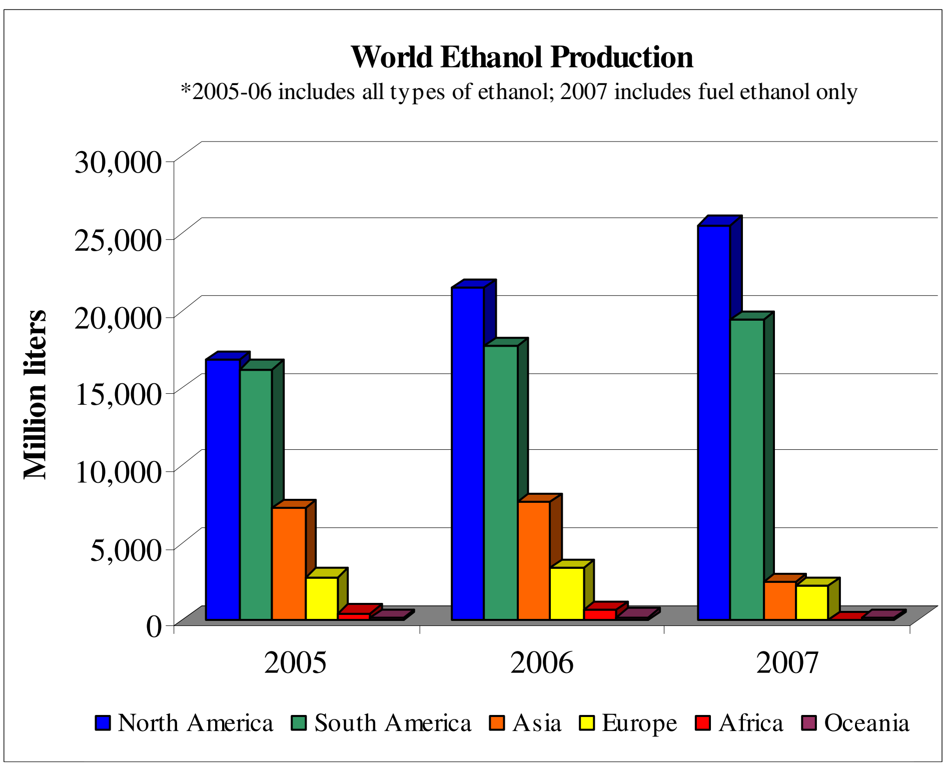
World ethanol markets are comprised of three distinct segments: fuel, industrial, and beverage (in order of production and use). At present, world economics as well as environmental and oil dependency concerns are providing enormous opportunities for world fuel ethanol growth while population growth will offer modest growth opportunities for the much smaller industrial and beverage segments. Worldwide fuel ethanol production reached approximately 13.1 billion gallons in 2007.

Of the world's total ethanol production, approximately 75% is now fuel ethanol. Even though the bulk of the world's fuel ethanol production still comes from Brazil and the U.S., there are significant developments in other countries as well. Some of these could result in the establishment of new production centers in addition to the traditional ones in the western hemisphere.

International Markets

Brazil had long been the world's number one fuel alcohol producer, making three to five billion gallons of anhydrous alcohol each year. The United States began challenging this prominence with bipartisan support for the alcohol fuel industry and the phase out of MTBE as a fuel oxygenate. U.S. ethanol production first exceeded Brazilian production in 2005. Figure 21 shows fuel ethanol production by continent.

Figure 21 – Worldwide Ethanol Production by Continent



(Source: Renewable Fuels Association)

North and South America are the world's leading ethanol production regions, with no indication of change in the near future. Total production in the Americas in 2007 reached nearly 12 billion gallons, or about 90% of the world ethanol output. Total U.S. ethanol production in 2007 was 5.3 billion gallons.

Europe produced over two billion gallons of fuel ethanol in 2007, a sharp increase over previous years, due in part to the passage of an EU Renewable Fuels Standard (note that the graph above shows all ethanol production in 2005 and 2006 and only fuel ethanol production in 2007). Currently the standard for 5.75% blending of biofuels in the EU is a directive rather than a requirement; however, the EU is considering legislation for a 10% mandated requirement by 2020.

Sizeable new production centers are emerging in Thailand, where production was 93 million gallons of fuel ethanol in 2007, as well as China where recently completed projects have raised fuel ethanol production capacity to over one billion gallons. China, however, has put a moratorium on new corn ethanol plants and any new plants will be cassava or cellulosic.

India currently requires 5% ethanol blends in most regions of the country, and the government is considering extending the ethanol blend mandate countrywide. In Latin America, new ethanol production initiatives are in place in many countries, particularly Argentina. Even Brazil – where the original fuel ethanol distilleries use molasses and sugar cane – is seeing production growth.

Renewable Fuel Standard

The 2007 Energy Bill was signed into law on December 19, 2007. The legislation included a revised Renewable Fuels Standard. The bill established a 36 billion gallon renewable fuels standard (RFS), headlining several important provisions for biofuels. H.R. 6 will take effect on January 1, 2009 – with the exception of the 9.0 billion gallon requirement for the current RFS program that will take effect in 2008.

The 36 billion gallon RFS has several different provisions for assorted types of biofuels. They are conventional biofuels, advanced biofuels, cellulosic biofuels, and biomass-based diesel. H.R. 6 defines these categories as follows:

> Conventional biofuels is ethanol derived from corn starch. Conventional ethanol facilities that commence construction after the date of enactment must achieve a 20 percent greenhouse gas (GHG) emissions reduction compared to baseline lifecycle GHG emissions. The 20 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 10 percent) by the U.S. Environmental Protection Agency (EPA) Administrator if it is determined the requirement is not feasible for conventional biofuels.
>
> Advanced biofuels is renewable fuel other than ethanol derived from corn starch, that is derived from renewable biomass, and achieves a 50 percent GHG emissions reduction requirement. The definition – and the schedule – of advanced biofuels include cellulosic biofuels and biomass-based diesel. The 50 percent GHG emissions reduction requirement

may be adjusted to a lower percentage (but not less than 40 percent) by the Administrator if it is determined the requirement is not feasible for advanced biofuels. (Cellulosic biofuels that do not meet the 60 percent threshold, but do meet the 50 percent threshold, may qualify as an advanced biofuel.)

Cellulosic biofuels is renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass, and achieves a 60 percent GHG emission reduction requirement. The 60 percent GHG emissions reduction requirement may be adjusted to a lower percentage (but not less than 50 percent) by the Administrator if it is determined the requirement is not feasible for cellulosic biofuels.

Biomass-based diesel is renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 (42 U.S.C. 13220(f)) and achieves a 50 percent GHG emission reduction requirement. Notwithstanding the preceding sentence, renewable fuel derived from co-processing biomass with a petroleum feedstock is considered an advanced biofuel if it meets advanced biofuel requirements, but is not biomass-based diesel.

H.R. 6 sets the following targets for each of these biofuel types. The following table shows RFS volumes from 2008 to 2022.

Table 7 – Renewable Fuels Standard Volumes in Billion Gallons

Year	Conventional Biofuel	Advanced Biofuels			Total RFS
		Cellulosic	Biomass-based Diesel	Undifferentiated	
2008	9.0	---	---	---	9.00
2009	10.5	---	0.50	0.10	11.10
2010	12.0	0.10	0.65	0.20	12.95
2011	12.6	0.25	0.80	0.30	13.95
2012	13.2	0.50	1.00	0.50	15.20
2013	13.8	1.00	1.00	0.75	16.55
2014	14.4	1.75	1.00	1.00	18.15
2015	15.0	3.00	1.00	1.50	20.50
2016	15.0	4.25	1.00	2.00	22.25
2017	15.0	5.50	1.00	2.50	24.00
2018	15.0	7.00	1.00	3.00	26.00
2019	15.0	8.50	1.00	3.50	28.00
2020	15.0	10.50	1.00	3.50	30.00
2021	15.0	13.50	1.00	3.50	33.00
2022	15.0	16.00	1.00	4.00	36.00

In addition to the 36 billion gallon RFS, the bill authorizes $500 million annually for FY2008 to FY2015 for the production of advanced biofuels that have at least an 80 percent reduction in lifecycle greenhouse gas (GHG) emissions relative to current fuels. It also authorizes $25 million annually for FY2008 to FY2010 for R&D and commercial application of biofuels production in states with low rates of ethanol and cellulosic ethanol production; and a $200 million grant program for FY2008 to FY2014 for the installation of refueling infrastructure for E-85.

The bill also includes appropriations for waivers to be granted based on various environmental, economical, and/or production scenarios. It authorizes the EPA Administrator, one or more States, or a refiner/blender to petition for a waiver of the renewable fuels mandate. The Administrator is authorized to waive the renewable fuels mandate if they determine that implementing the requirement would severely harm the economy or the environment, or that there is inadequate domestic supply to meet the requirement. There is a separate waiver provision for cellulosic biofuels if the minimum volume requirement is not met. The Administrator is authorized to reduce the applicable volume of required cellulosic biofuels, and make available for sale a cellulosic biofuels credit at the higher of $0.25 per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline (in the U.S.). Finally, beginning in 2017, if the EPA Administrator waives at least 20 percent of the mandate for two consecutive years, or waives 50 percent of the mandate for a single year, the Administrator is authorized to modify the volume requirement for the remaining years of the renewable fuels mandate.

The current small producer tax credit (ethanol), biodiesel tax credit, and the 51 ¢/gal VEETC blender's tax credit did not change with the passage of this bill. No new biofuels tax provisions are in H.R. 6. However, the 2008 Farm Bill reduces the VEETC to 45 ¢/gal when production hits 7.5 billion gallons per year which will occur in 2008.

Current Industry

In the U.S., ethanol's primary purpose is to serve as an octane enhancer for gasoline, a clean air additive in the form of an oxygenate, and as an aid in reducing dependence on imported oil – thereby reducing the balance of trade. In order to accomplish these tasks in the face of resistance from the oil industry, Congress established an incentive in the form of a tax credit during the mid-1970s to encourage the oil industry to blend ethanol. The tax incentive is still in place, but set to expire in 2010.

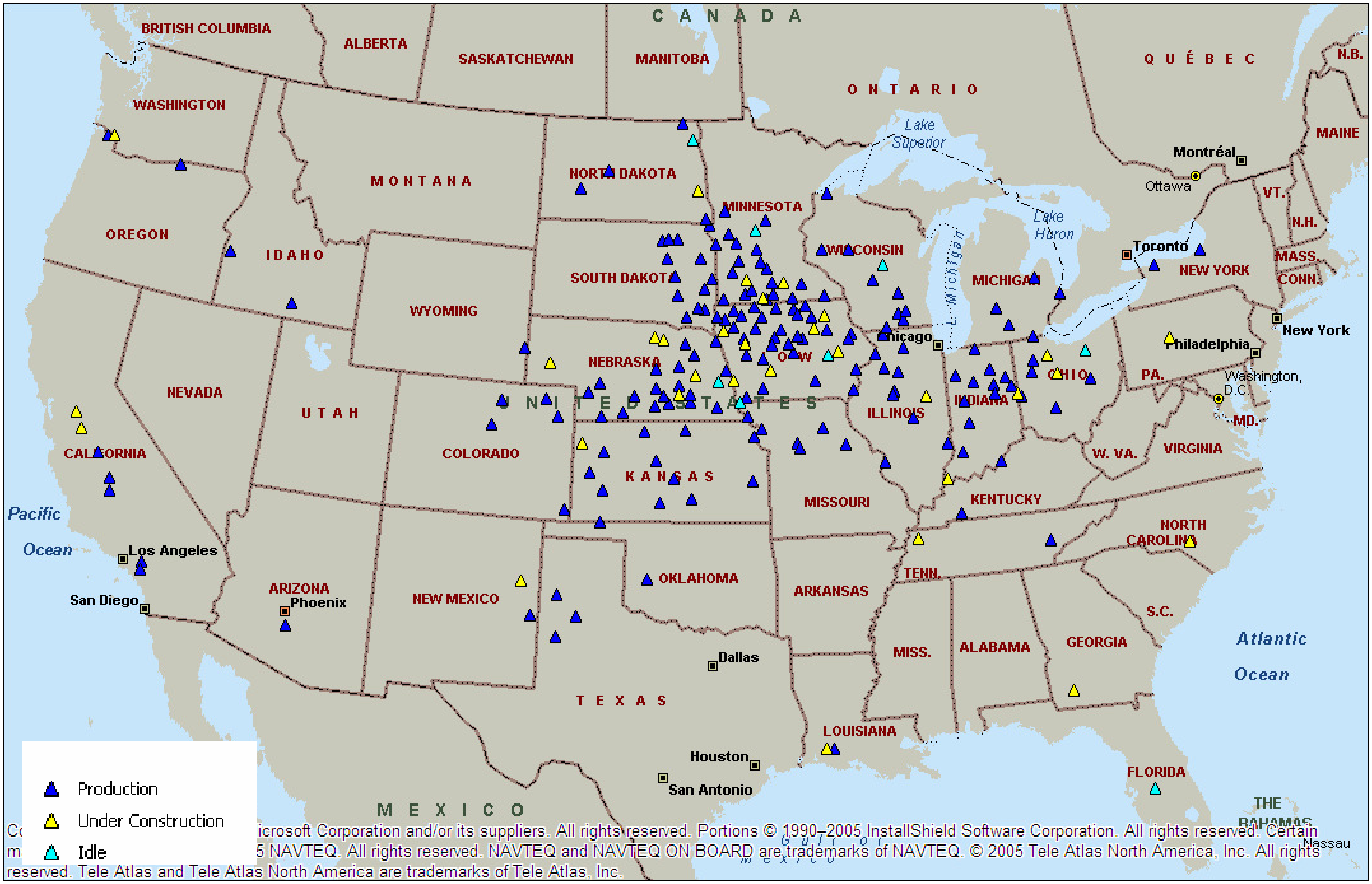
New restrictions on automobile emissions, reductions in carbon monoxide, smog mitigation programs in major cities, and a general trend toward the reduction of greenhouse gas emissions, continue to drive the demand for ethanol.

Ethanol plays a key role in helping refiners extend their product by as much as 10%. The slightest upset in refining capacity (fire, shutdown, closure) sends gasoline prices soaring. U.S. refining capacity operates extremely close to capacity.

Corn is not the sole provider, but it accounts for 95% of U.S. fuel ethanol and it follows that the majority of production capacity and use of fuel ethanol is in the Midwest Corn Belt. Every state uses ethanol-blended fuel; 50% of U.S. gasoline use in 2007 was ethanol-blended fuel. Some states have rapidly increased sales of E10 while other states—most notably the southeast—do not blend as much ethanol because the infrastructure necessary is not yet in place. While corn has been the primary feedstock for fuel ethanol in the U.S., other feedstocks including wheat, milo and various waste starch and sugar streams are also used. Grain-based ethanol will likely continue to be the major contributor to ethanol production in the years ahead.

There are currently 178 commercial fermentation ethanol production facilities in operation in the U.S. with a combined production capacity of nearly 11 billion gallons per year (Figure 22). There are 31 new plants under construction, adding about 2.88 billion gallons of annual production capacity. Total production capacity in the U.S. should exceed 12 billion gallons per year by the end of 2008.

Figure 22 – Fuel Ethanol Plants in the U.S. (9/16/08)



Several factors have and will continue driving the U.S. fuel ethanol industry's growth. They are:

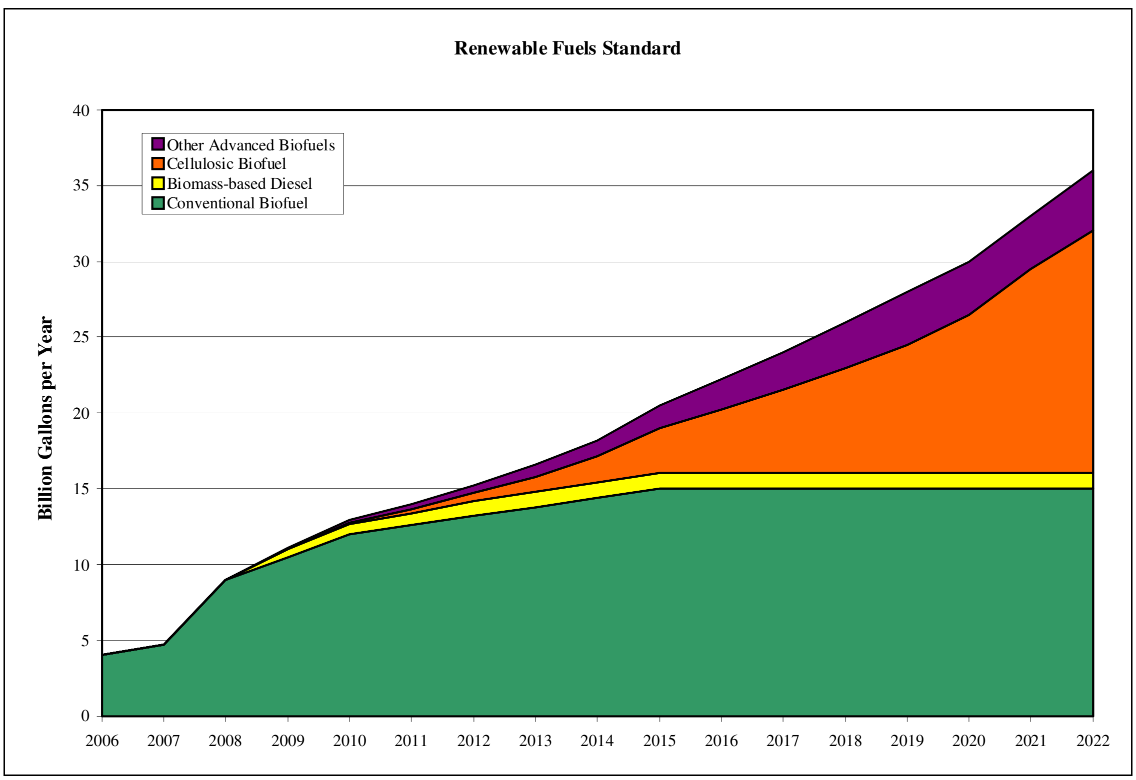
- Federal Renewable Fuels Standard
- Ethanol price relative to crude oil (or gasoline)
- Clean octane
- Oxygenate for RFG program
- Gasoline extender (refinery capacity)
- Local economic development

Following is a brief discussion of each of these drivers and their potential impacts.

Federal Renewable Fuels Standard

The RFS established a market floor of 36 billion gallons for 2022, which should provide some comfort to ethanol producers, investors, and lenders. Ethanol production above the minimum RFS is not viable unless sold at prices that are attractive to gasoline blenders i.e., rack unleaded price plus a portion of the 51¢ per gallon Volumetric Ethanol Excise Tax Credit. Otherwise, voluntary blending above the level required by the RFS will decline until ethanol prices fall to the point where voluntary blending becomes profitable. Under this scenario, wholesale gasoline prices determine ethanol demand above the RFS level. H.R. 6 enacts the following RFS volumes:

Figure 23 – H.R. 6 RFS Volumes by Year



Ethanol Price Relative to Crude Oil or Gasoline

Regardless of any potential RFS, any ethanol production in excess has to be competitive with gasoline. Voluntary blending of ethanol is profitable when the price of ethanol is less than or equal to the price of gasoline plus the VEETC, which is a blender's tax credit.
This means that with the current 51¢ per gallon VEETC, if a blender can sell a gallon of gasoline for $2.00, they will pay up to $2.51 per gallon for ethanol.

Clean Octane

Octane is a measurement of gasoline's auto-ignition resistance. The octane number gives the percentage by volume of iso-octane in a mixture of iso-octane and n-heptane that has the same anti-knocking characteristics as the fuel under consideration. For example, gasoline with a 90 octane rating has the same ignition characteristics as a mixture of 90% iso-octane and 10% heptane.

Table 8 shows the octane rating of several compounds in pure form. Frequently referred to as "Dirty Octane," Benzene, Toluene, and Xylene, have toxic human and environmental effects; in many cases, they have been strictly limited in the amount allowed in fuels.

Table 8 – Octane Ratings of Various Compounds

Compound	Octane Rating
n-heptane	0
iso-octane	100
Benzene	101
Methanol	113
Toluene	114
Ethanol	116
Xylene	117

This leaves ethanol as the highest-octane compound that does not have negative human or environmental effects. It is a great source for "Clean Octane" and this provides another incentive for its use in transportation fuels.

Oxygenate For RFG Program & MTBE Phase-out

In 2006, the EPA eliminated the 2.0% oxygen by weight requirement from the Reformulated Gasoline (RFG) program. The interesting part here is that MTBE was a very popular oxygenate, but also an extremely serious environmental and human health problem. Regardless, it was widely used because of the oxygenate requirement. The most current EIA data (from 2003) indicates that 17 states should have MTBE bans by now; even so, the EPA regulation change effectively eliminated its use.

It is true that not all areas use RFG fuel, but it is required in non-attainment areas like Denver, most of California, and New England. Even with the oxygenate requirement gone, RFG fuels still must meet certain VOC control requirements, and the easiest way to do this is with an oxygenate.

This provides as excellent market area for ethanol, although the MTBE oxygenate replacement is nearly complete, and any future growth in this sector is most likely dependent on population growth.

Gasoline Extender (Refinery Capacity)

There is some potential for ethanol, or any fuel-blending agent, to extend the supply of transportation fuels. Simply put, if someone uses 10 gallons of gasoline with no blended agents, they use 10 gallons of gasoline; however, if they use 10 gallons of gasoline blended at 10% ethanol to do the same work, they only consume 9 gallons of gasoline. Multiply this by billions of gallons, and the savings are appreciable.

Local Economic Development

An ethanol plant can re-invigorate a rural community. A typical 50-mmgy dry mill facility creates about 36 new direct jobs, the majority of them being skilled positions requiring special training or education. Repeatedly, near-ghost town communities have re-grown thanks to the new plant in town. In addition to the jobs working at the plant, a new ethanol plant creates hundreds of indirect jobs.

In 2007, the ethanol industry contributed the following to the U.S. economy:[1]

- Combination of spending for operations, ethanol transportation and capital for new plants added $47.6 GDP
- Supported the creation of 238,541 jobs in all sectors of the economy, including nearly 46,000 jobs in the manufacturing sector;
- Put an additional $12.3 billion into the pockets of American consumers; and
- Added $4.6 billion (federal subsidies were $3.4 billion) in new tax revenue for the federal government and $3.6 billion for state and local treasuries.

U.S. ethanol market growth will continue beyond the Renewable Fuels Standard due to the economics of blending ethanol, the need for clean octane in gasoline, expanding Reformulated Gasoline (RFG) markets, the need to extend fuel supplies without building new refineries, and local economic benefits.

BBI Projected Ethanol Demand

BBI has projected the demand for ethanol in the US using the following assumptions:

- Ethanol production in the US will not exceed demand less the full import allowance under the Caribbean Basin Initiative (CBI);
- Complete oxygenate demand is met using ethanol;

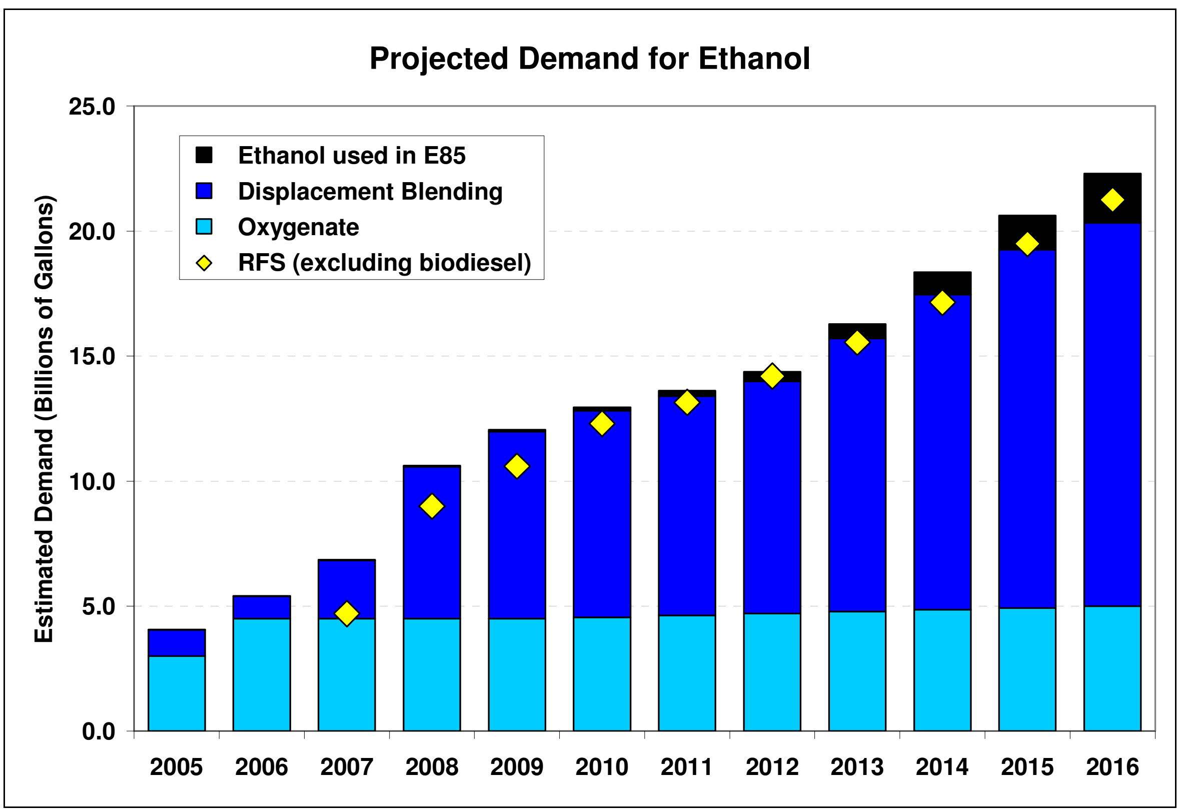
[1] From: "Contribution of the Ethanol Industry to the Economy of the United States," LECG, LLC, February 2008

- Displacement/discretionary blending will create demand up to 9.5% of the total gasoline demand;
- E85 use accounts for all of the ethanol demand beyond the oxygenate and 9.5% blend demands; and
- Adequate infrastructure – beyond plant production capacity (i.e. with blenders and distributors, E85 pumps) – exists or will exist to meet the demand.
- There is also an assumption that the EPA allows blending rates above E10

Figure 24 shows BBI's projections for ethanol demand by use category. By the end of 2006 the 4.5 billion gallon oxygenate market in the US was essentially served, with the only increases in this market due to changes in gasoline demand.

One assumption here is that the EPA designates no new Ozone/Air Quality Non-Attainment areas during the projected period. This may be a moot point though as the displacement blending projections increase to nearly 9.5% of gasoline demand by 2012. Displacement blending is an estimate of how much discretional blending will occur. Finally, E85 demand comes from Renewable Fuels Association (RFA) projections for number of E85 vehicles and their potential demand, factored by BBI estimates on the market penetration and accessibility that these vehicles will have. The most important note is that BBI assumes no infrastructure limits on demand, such as refiners/blenders capacity to store/use ethanol or distribution of the blended product.

Figure 24 – BBI Projected Ethanol Demand by Use



Low Carbon Ethanol

California is the first state to establish a Low Carbon Fuels Standard (LCFS). The LCFS essentially regulates carbon emissions associated with production of transportation fuels. California State Executive Order S-01-07 was signed January 23, 2007. The goal of the LCFS is to reduce the carbon intensity of California passenger transportation fuels by 10% by 2020. The LCFS also seeks to diversify the types of transportation fuels available in California, promote new energy industries and provide consumers with more choices. Fuel marketers in California are required to ensure their fuel mixtures meet a declining standard for GHG emissions (measured in carbon dioxide equivalents). The standard for GHG emissions will be based on life cycle analysis of fuel consumption and production. The LCFS allows the market to decide the most cost effective means of reducing GHG emissions. The LCFS is expected to lead to a 20% replacement of gasoline currently consumed in the state (2.4 billion gallons). The LCFS does not mention higher pricing for low carbon fuels.

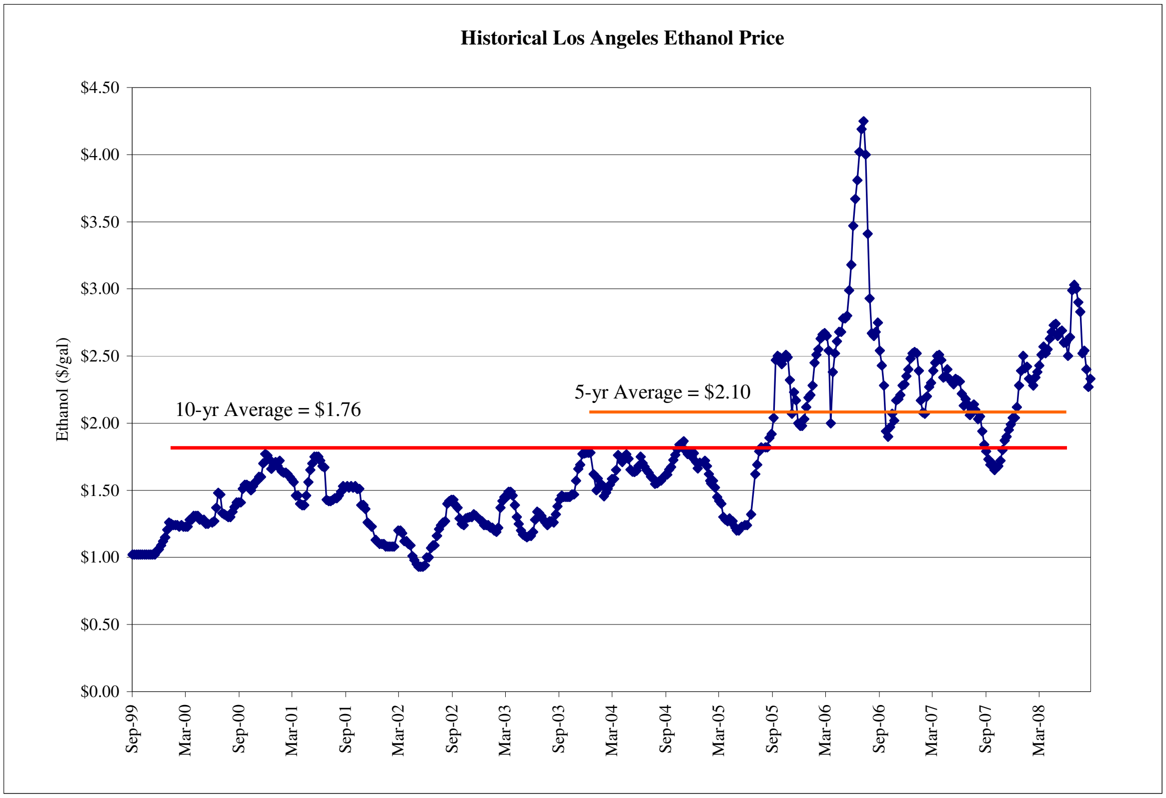
Other states, including Colorado, are considering low carbon fuels legislation. The RFS has several provisions for reducing GHG emissions at renewable fuels plant. Any ethanol plant starting construction in 2009 and beyond must demonstrate a 20% reduction in GHG emissions against a standard baseline ethanol plant yet to be defined by the EPA.

The proposed plant in Ft. Morgan plans on producing low carbon ethanol. The plant will achieve this by using waste streams from area livestock processing (manure, paunch water and similar) to provide process steam for ethanol production. This will reduce the natural gas typically used at corn based ethanol plants. The project is also considering a biomass boiler that will further reduce natural gas use in the process. The project must quantify the carbon dioxide equivalent savings of these projects to demonstrate GHG emission reductions in hopes of achieving a higher ethanol price.

Ethanol Pricing

A conservative baseline to estimate the ethanol price is the 10-year historical average price on the Chicago spot price. However, this project plans on selling low carbon ethanol to California therefore the 10-year historical average price in Los Angeles was used. This does not consider any local price advantages. Figure 25 shows Los Angeles ethanol prices over the past ten years.

Figure 25 – Historical Los Angeles Ethanol Pricing

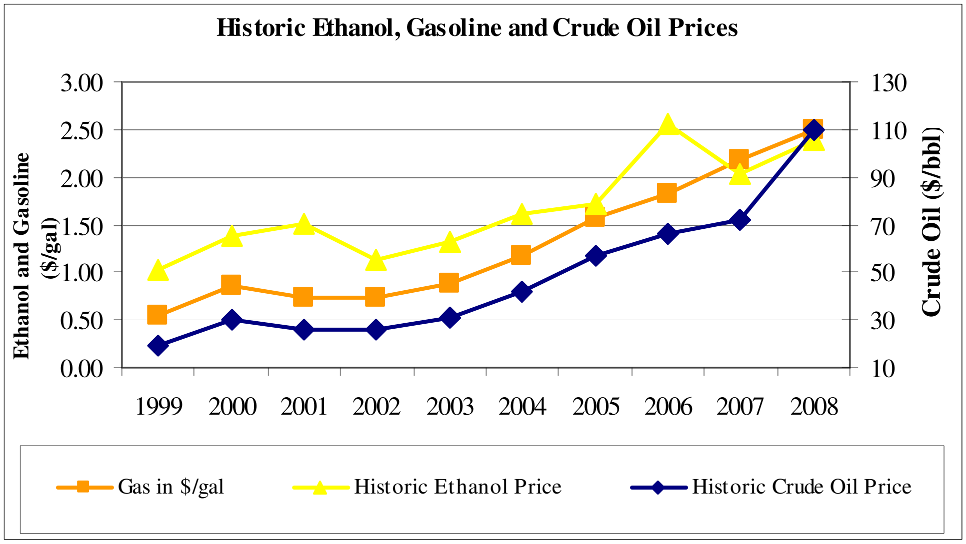


(Source – OPIS)

Ethanol Price as it relates to Crude Oil and Gasoline

Over the past 10 years, the spot prices of fuel ethanol, crude oil and gasoline have similar, upward trends (Figure 26). The price of crude oil has a significant effect on the price of gasoline; there is a correlation coefficient of 0.996 for the average annual spot market prices of crude oil and gasoline. Similarly, although not as direct, there is also a correlation between ethanol and crude oil pricing. Consequently, estimating future ethanol prices based on projections for the price of crude oil is possible. This analysis uses spot ethanol prices for Chicago as reported by OPIS. As evidenced in Figure 26, ethanol has previously traded at a higher value than gasoline presumably due to the 51¢/gallon VEETC. In the past year, the prices of ethanol and gasoline are closer indicating an over supply of ethanol as plants come online faster than the infrastructure to blend and sell ethanol to retail customers.

Figure 26 – Historic Relationship between Prices of Oil, Gas, and Ethanol (USD)



(Source – OPIS, US DOE Energy Information Administration)

Ethanol Markets Local and Regional

The Ft. Morgan proposed plant plans on marketing low carbon ethanol. The only current market for low carbon ethanol is in California. The BNSF directly connects Ft. Morgan with California and delivery costs are estimated at 15¢/gallon.

The EIA reports annual gasoline consumption of over 12 billion gallons in California and 1.4 billion gallons in Colorado. This results in respective E10 markets of 1.2 billion and 140 million gallons for California and Colorado. Current Colorado nameplate ethanol production capacity is 138 million gallons indicating saturation in the Colorado market unless low carbon fuel legislation is passed, in which case a plant in Ft. Morgan will be well positioned to serve such a market. Additionally, this scenario would provide a better netback to the plant as transportation costs would be significantly reduced. Either way, it is assumed that some ethanol will be sold locally.

California will have installed capacity of 224 million gallons per year when all construction capacity comes online. California will continue to be an excellent market opportunity for western based ethanol plants as the California permitting process has not led to much production capacity in the state. The updated RFS indicates that the E10 blending limit per the EPA will be updated to allow higher blends.

Ethanol Market Summary

The recently updated Renewable Fuels Standard ensures a long term U.S. market for biofuels. Voluntary blending is expected to occur at an increasing rate as long as the price of ethanol remains less than or equal to gasoline plus the blender's tax credit—marking blending economically attractive. The RFS requires that new corn based ethanol plants meet a 20%

reduction in GHG emissions compared to a baseline plant. This project will meet that reduction through use of anaerobic digestion to produce biogas which will be used to offset natural gas use at the plant.

The project plans to market low carbon ethanol and the only existing market for this specific fuel type is California. The Colorado market is saturated with existing plants able to produce enough ethanol to account for 10% of gasoline consumption although it is expected that some of the output will go to the Colorado market. Should Colorado adopt a low carbon fuel standard, the Ft. Morgan plant will be well positioned to sell locally improving netbacks as transportation costs to move ethanol to market will be lower.

The ability to divide product effectively between local, regional, and national markets is extremely important. So much so, that it is imperative that either an experienced marketer is hired, or the ethanol marketing be contracted to a broker or a cooperative marketing group.

BBI assumes that all ethanol is shipped to California—at least initially until other low carbon fuel markets develop. The ethanol shipping costs is estimated at 15¢ per gallon. The estimated ethanol sale price is based on the 10 year historical Los Angeles ethanol spot price of $1.76 per gallon. There is a possibility that low carbon fuels may receive a premium, however, the California LCFS does not have any language related to pricing mechanisms. Additionally, the VEETC is set to decrease from 51 to 45 cents per gallon in 2009 which may negate any additional price premiums for low carbon fuels.

VI. REVIEW OF CO-PRODUCTS

This section of the feasibility study reviews the anticipated co-products from the two evaluated scenarios for an ethanol plant in Ft. Morgan. The primary co-products of alcohol production from a dry mill ethanol plant are distillers grains (wet or dry) and carbon dioxide. The co-products from a dry mill ethanol plant with fractionation are high protein distillers grains (HPD), germ (oil and corn germ meal), bran and carbon dioxide.

Distillers Grains

Distillers grains are the residues that remain after high quality cereal grains have been fermented by yeast. In the fermentation process, nearly all of the starch in the grain is converted to ethanol and carbon dioxide, while the remaining nutrients (proteins, fats, minerals, and vitamins) undergo a three-fold concentration in the beer, which after distillation and centrifugation of the still bottoms, yields DWG and "thin stillage." The thin stillage is subsequently concentrated via evaporation and the "heavy syrup" is added back to the DWG. This material is then dried to 10% moisture, producing dried distillers grains (DDGS).

The addition of the soluble fraction increases the protein and vitamin potency of the final product and removes the logistical problems associated with marketing wet feed. It also provides a solid baseline byproduct that can be marketed while allowing development of both the wet feed and special blend feed markets. DDGS is the most common and highest volume form of feed product derived from a dry mill facility. Typical composition of DDGS from corn is in Table 9.

Table 9 – Typical Corn DDGS Composition

Component	Weight %
Moisture	9 to 10%
Protein	27 to 30%
Carbohydrates	52 to 56%
Fat	7.5 to 9%
Fiber	8 to 9%
Ash	4.5 to 5%

DDGS derived from corn contains nutrients that have been demonstrated by numerous experiments to have important growth promoting properties for dairy and beef cattle, poultry and swine. For dairy cattle the high digestibility and net energy content of DDGS and DWG, compared to other feed ingredients (soybean meal, canola meal, brewers spent grains as examples), as well as the high fat content, results in feeds that yield greater milk production. For beef cattle the improved rumen health, energy effect of the fiber, and palatability has been shown in feedlot studies to result in faster and more efficient gains.

For poultry, feeding tests have demonstrated that DDGS favorably effects fertility and hatchability. DDGS is an excellent ingredient for supplying protein to broilers where the diet has been adjusted to limit certain amino acids. For hogs, research has shown that DDGS can effectively furnish portions of the energy, protein and other key nutrients during all phases of production.

More than 15 million tons of DDGS are produced in North America and incorporated into animal feeds or exported. Several ethanol producers market a portion of their byproducts in a wet form (65% moisture) where nearby markets make it economical to deliver a perishable product and avoid drying costs. Some maintain that DWG has a higher nutritive value than DDGS due to damage to proteins and the loss of volatile compounds during drying of the distillers grain. Poultry and swine require the distillers grain to be dried, for formulation purposes, and fed as DDGS.

There is an emerging market for DDGS exports for a premium price. Most of the DDGS are exported to Japan and Korea, traditional importers of U.S. corn. At this time, China does not accept DDGS imports because the exporter would have to identify the source of corn for making all the distillers grains in the shipment.

Approximately 18 pounds of DDGS (at 10% moisture) or 46.3 pounds of DWG (at 65% moisture) are produced from each bushel of grain processed. A 59-mmgy ethanol plant will produce about 190,000 tons of DDGS or 455,000 tons of DWG each year. Table 11 summarizes the market potential in the area for a 59-mmgy plant. It is anticipated that a plant in Ft. Morgan could sell all distillers grains in the wet form.

Distillers Wet Grain

Distillers Wet Grain (DWG) is the wet cake that comes directly from the centrifuge. It has approximately 65% moisture. The syrup that is centrifuged out is evaporated and returned back into the wet cake. This product remains at about 65% moisture after the evaporated syrup is returned to the cake.

The primary market for DWG is local dairy and beef cattle. Cattle perceive DWG as sweet and readily eat it without any added sweeteners. Dairy cattle perform well on DWG. Beef cattle gain weight on DWG similar to grain, but without the problems caused by the high starch content of grain.

Although wet distillers grain is nutritionally superior compared to dry distillers grain (drying reduces digestibility), least cost ration formulation may dictate the use of the dry form as the distance between the ethanol plant and the livestock operation increases. This is because transportation costs on a dry matter basis are generally less for dry product. Thus, inclusion of wet or dry distillers grain in cattle diets must be evaluated on an individual operation basis.

Selling DWG usually reduces ethanol plant operating costs by reducing natural gas use. However, in the wet form, the distiller grain has a shelf life of about a week, so it needs to be distributed quickly.

High Protein Distillers Grains

High protein distillers grains (HPD) is the most common and highest volume form of feed product derived from a dry mill with fractionation facility. Typical compositions of HPD with and without syrup (solubles) added are available in Table 10. The protein content variation is largely a function of mixing syrup into distillers grains or separating it out (which leads to higher protein concentration). The concentration of protein is higher than traditional distillers grains due to the removal of germ and bran in the fractionation process.

Table 10 – Typical Corn HPD Composition

	HPD	HPD with Solubles
Product Yield	8 pounds/bu	14 pounds/bu
Carbohydrate (% db)	5.5-6.5%	5.8-7%
Crude Protein (% db)	44-48%	38-42%
Crude Fat (% db)	2-3%	6-7%
Ash (% db)	2-3%	4%

Use of traditional distiller grains in dairy markets is limited by unsaturated fat content. HPD contains a lower concentration of unsaturated fats and can therefore be blended into dairy feed at a higher rate than traditional DDGS. Dairy is the preferred market for HPD Sales.

It will be challenging to sell a higher valued, high protein feed to beef cattle feeders. This is due to the availability of corn and urea, an inexpensive and readily available synthetic protein. Traditional dried distiller grains have been valued at about 80% the dry weight value of corn over the past year and are sold at continuously increasing volumes into the beef cattle industry. Thus, beef cattle feeders would buy HPD but may not pay a premium for the product over DDGS as the ruminants protein needs are supplied by inexpensive urea.

There is future market potential in the swine industry after a few issues are addressed. Swine nutritionists are concerned over the lysine content of HPD as it is lower than other comparable feeds. There is the potential to add synthetic lysine, however there is an issue of different absorption rates for natural and synthetic lysine. Meal blenders and other large end users routinely mix synthetic lysine with other ration supplements. Another essential amino acid, tryptophan is also fairly low in HPD leading to a lower dollar value versus soybean meal. Such a mixture of amino acids would only be usable for grower/finisher hogs which are constantly eating.

The poultry industry is generally excited about an alternate high protein feed but not thrilled with removal of the oil as poultry need the fat. The primary concern is cost compared to traditional corn-soybean meal diets. Additional field trials will be necessary to convince the poultry industry of the benefits of HPD. Such tests will need to address the digestibility of amino acids and phosphorus as well as energy content. The poultry industry is not significant in the Ft. Morgan area so this may be a moot point.

Yields vary based on technology provider guarantees, ranging between 13 and 15 pounds per bushel (when solubles are included). A yield of 6.6 pounds per bushel was used for this study with the assumption that the syrup will be burned in a biomass boiler. A 130-mmgy ethanol plant will produce 158,000 tons of HPD each year. Table 12 summarizes the area market for HPD.

Local Dairy Market for Distillers Grain

The Dairy market is growing in Colorado with seven new dairy farms considering locating near Ft. Morgan. There is a new 26,000 head operation nearby the plant and another new 12,000 head operation in Hillrose, Colorado.

The total number of dairy cattle in a 150-mile radius of Ft. Morgan averaged 88,045 head over the past 5 years (USDA NASS 2003-2007). The regional average (450 mile radius) over the same period of time was over 2.5 million head. A dairy cow can consume approximately 2600 pounds of HPD annually or 3910 pounds of DWG per year. The area dairy market can consume half of the DWG from the 59-mmgy. The area market for HPD is slightly smaller than HPD production from the 130-mmgy fractionation scenario. Additionally, it is not certain that all area cattle farms will buy HPD from the plant. The BNSF connects Ft. Morgan and Clovis, New Mexico—an area with high concentrations of dairy cattle. The project must work with an experienced marketer to obtain the highest price for this valuable co-product. Table 11 and Table 12 summarize the dairy cattle market potential for DWG and HPD respectively.

Local Cattle Market for Distillers Grain

The total number of cattle within a 150-mile radius has averaged 3.2 million head over the past five years. A beef cow can consume 1,671 pounds of DWG per year while cattle on feed can consume 5,214 pounds of DWG per year. Ft. Morgan is located in an area of concentrated beef production and will have no issues selling DWG locally. The plant would likely not receive a premium for the HPD due to availability of low cost synthetic urea (see HPD section above). Table 11 summarizes the cattle DWG market for the 59-mmgy plant.

Local Swine Market for Distillers Grain

The total number of hogs and pigs within a 150-mile radius was over 440 thousand head in the 2002 Agricultural Census. If one swine consumes 230 pounds of DDGS annually, local hogs and pigs could consume about 66 thousand tons of DDGS, far less than the production from the proposed plant. Swine require distillers grains in the dry form and due to the voluminous markets for DWG in the beef and diary markets, the project should forgo this market with the 59-mmgy scenario. It is unlikely that premium would be paid for HPD over DDGS due to the amino acid issues (refer to the HPD section above).

Local Poultry Market for Distillers Grain

The total poultry inventory within a 150-mile radius was 12.8 million head in the 2002 Agricultural Census. DDGS consumption by poultry is about 8 pounds per animal per year.

Based on the populations of layers, broilers, and turkeys, the population could consume 12 thousand tons annually. This market is too small to pursue.

Table 11 – DWG Market Potential for 59-mmgy Plant (150-mile radius)

Location	Dairy Cattle (head)	Beef Cattle (head)	Cattle on Feed (head)
Colorado	86,375	308,260	927,934
Colorado (new dairy lots)	28,000	--	--
Nebraska		263,000	360,154
Kansas			32,158
Wyoming	1,670	33,247	66,752
Total	**116,045**	**604,507**	**1,386,998**
DWG Consumption (lb/yr/head)	3,910	1,671	5,214
DWG Feed Market (tons/yr):	**226,868**	**505,066**	**3,615,904**
59 mmgy DWG production (tons/yr)	454,899	438,000	696,377
Potential DWG Market (% of production)			
59 mmgy	50%	111%	795%

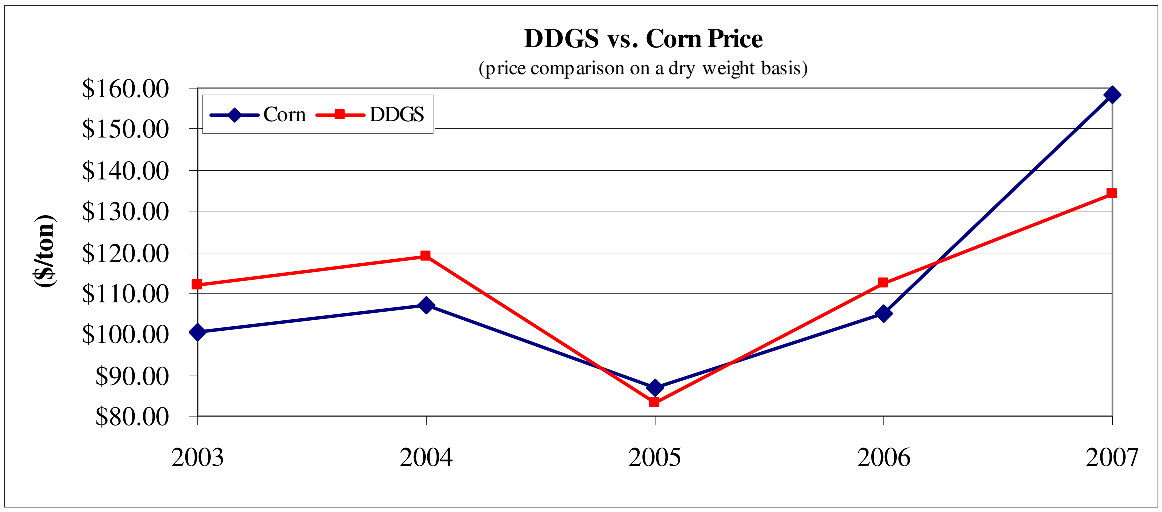
Table 12 – HPD Market Potential for 130-mmgy Plant (150-mile radius)

Location	Dairy Cattle (head)
Colorado	86,375
Colorado (new dairy lots)	28,000
Wyoming	1,670
Total	**116,045**
DDGS Consumption (lb/yr/head)	2,600
HI PRO DDG Feed Market (tons/yr):	**150,859**
130 mmgy Hi Pro DDG production (tons/yr)	157,750
Potential DDGS Market (% of production)	
130 mmgy	96%

Distillers Grain Pricing

In the U.S., the base market value for distillers grains historically has been set by producers of distilled spirits and more recently by the large corn dry-millers that operate fuel ethanol plants. As shown in Figure 27, corn and DDGS prices do not track exactly, but they do generally follow each other on a dry basis. The price of corn was higher than DDGS prices in 2007. This was due in part to a record number of ethanol plants coming online and a need to find additional markets for distillers grains. Also, in summer, wet distillers grains degrade more rapidly leading to sales at lower prices which impacts dried distiller grains prices.

Figure 27 – Historical Pricing of DDGS and Corn



(Source: Corn-CBOT; DDGS-Feedstuffs)

Distillers grains market price is determined through a number of factors that include the market value of local feed grain, the market value of soybean meal and other competitive protein ingredients, the performance or value of distillers grain in a particular feed formulation, the supply and demand within the market, and, most importantly, acceptance by animal producers. Over the past year, DDGS have been selling for roughly 80% of the corn price on a dry weight basis. Previous years saw DDGS sell at a premium or at about 100% the price of corn (dry weight basis).

For the proposed project, BBI used a conservative approach to establish pricing for the 59-mmgy plant's distillers grains (either wet or dry). The price of the plant's DDGS was set equal to 85% of the price of corn on a dry weight basis ($84.58/ton) although it is assumed that all distillers grains can be sold in the wet form. For wet distillers grain, the price was set equal to 80% of the price of corn based on market rates and a 3% contractual discount on a dry weight basis ($30.94/ton). This approach assumes that the plant receives no credit for the higher protein and nutritional value of the distillers grain compared to corn.

HPD Pricing

HPD is a fairly new feed product on the market. According to Dakota Gold Marketing, marketer of Poet's (formerly Broin) fractionated distiller grain product, HPD is almost exclusively utilized in dairy diet rations.

Historical data for HPD is not currently available due to small quantities. The University of Missouri collects weekly data for a variety of dairy feed products and there is a listing of HPD for $265 per ton which is consistent with corn pricing over the same time frame resulting in a selling price 100% of corn on a dry weight basis. For the purposes of this study, HPD was set at $102.86 per ton with corn at $2.72 per bushel. The model is designed to increase the price of corn and HPD annually.

BBI recommends the project take advantage of the expertise of a HPD marketing company in the sales of the 130-mmgy plants' distillers grains. The HPD market is not well developed and this indicates some level of risk. Dakota Gold (Poet), Renew Energy and Zeeland are all experienced marketers of HPD.

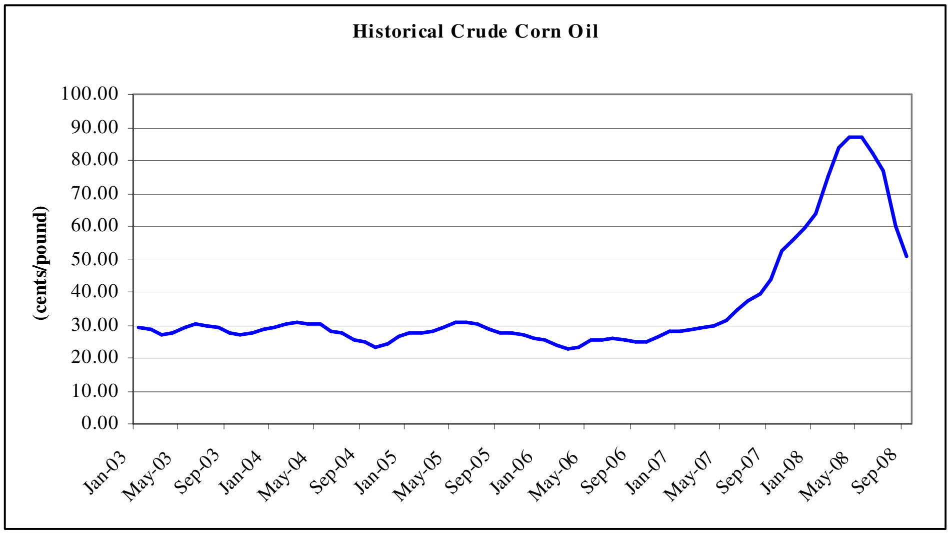
Corn Germ, Corn Oil and Corn Germ Meal

Germ (oil) is another by-product of the fractionation process yielding approximately 4.4 pounds per bushel of processed corn. The 130-mmgy plant with fractionation would produce approximately 105,166 tons of germ annually.

At this time, corn germ is the highest value co-product of fractionation due to the high prices of vegetable oils. The USDA reports crude corn oil prices and the historical five year average is $0.355 per pound (Figure 28). Currently, refined corn oil is selling for $0.85 to $1.00 per pound. Prices for vegetable oils have risen considerably as many food processors have switched from partially hydrogenated oils (trans fats) to healthier whole oils. Oil extraction requires additional capital expenditures and the project plans on installing solvent extraction equipment. Most fractionation technology providers guarantee oil content of 20% although ICM (the design company the project is considering) projects oil content of 25% of germ by mass. BBI used a conservative yield of 0.88 pounds of oil per bushel of corn processed with the assumption that ICM will provide a process guarantee of 20% oil content similar to other technology providers. Total annual production of corn oil is about 21,033 tons. It is expected that the plant will sell all corn oil to a Midwest processor that can upgrade the crude corn oil to food grade or similar products. It is assumed that operation costs for the solvent extraction system and shipping costs total $0.045/pound.

The plant can sell the remaining germ product after the oil has been extracted as a corn germ meal. This co-product is similar to hominy feed and is considered a low quality protein feed. The expected yield is 3.3 pounds per bushel of corn processed with annual production of 78,875 tons. The value of corn germ meal was set to 50% of the corn price on a dry weight basis. In the financial models, the corn price is set at $2.72 per bushel yielding a corn germ meal price of $48.57 per ton. The price is set to increase at a rate of 2% annually.

Figure 28 – Historical Crude Corn Oil Prices



(Source: USDA AMS)

If the decision was made to sell the corn germ to a processor, the most significant corn oil processors and germ buyers are Cargill and ADM. Cargill processes corn germ in three locations: Eddyville, IA; Blair, NE; Memphis, TN. Cargill has several existing germ suppliers and does not have plans to source germ from new sources. Although not stated, it is believed that Cargill corn oil facilities are operating at capacity. ADM processes corn germ in Decatur, IL and Clinton, IA and will consider new germ suppliers.[2]

Bran

Bran, also referred to as fiber, is another by-product of fractionation process. The expected yield is 3.2 pounds of bran per a bushel of corn processed. Annual production total would be 76,000 tons. The project plans to burn the fiber for thermal energy generation in a biomass boiler—bran has a heat value of 7699 BTU/pound.

Carbon Dioxide Markets

Dry ice and liquid carbon dioxide (CO_2) are principally used as expendable refrigerants in the food industry. Carbon dioxide, whether solid, liquid, or gaseous, is recognized as safe for use in foods.

Currently in the U.S. about one-forth of the CO_2 produced by ethanol plants is captured and the rest vented to the atmosphere. In most cases, the carbon dioxide captured is from very large ethanol plants. Capture of CO_2 from medium sized and smaller plants is usually not justified unless special market conditions are present. If justified, the ethanol plant can easily capture raw carbon dioxide. However, further processing is necessary if it is to be used for commercial

[2] For germ sales, contact Greg Morris at ADM greg_morris@admworld.com

purposes. At most, the revenue potential from the sale of CO_2 is approximately 3% of total plant revenues. This study assumes no carbon dioxide sales.

Co-Products Summary

The 59-mmgy plant will produce distillers grains and carbon dioxide. Ft. Morgan is an area of concentrated cattle operations and a plant in this location can easily sell all distillers grains in the wet form allowing for thermal energy savings. The area DWG demand (within 150 miles of the site) is over 4.3 million tons per year—10 times more than the plant is expected to produce (455,000 tons). The price was set to 80% the price of corn a dry weight basis accounting for both market rates and an anticipated contract that allows a 3% discount. This resulted in DWG price of $30.94/ton (based on corn at $2.63 per bushel).

For the 130-mmgy model, fractionation produces three primary by-products: high protein distillers grains (HPD), germ and bran (fiber). The plant will extract corn oil from the germ and the remaining germ is assumed to be sold as cattle feed. The bran will be used to generate steam in a biomass boiler.

The HPD yield is 6.6 pounds per bushel resulting in annual production of 158,000 tons. Dairy farms are the most likely purchasers of HPD due to the desired high protein content and lower saturated fats when compared with traditional distillers grains. Obtaining a premium from sales to other livestock types are less likely as beef cattle obtain cheap protein from urea so there would not be a premium paid. Additionally, there are amino acid issues for swine and poultry producers takes issue with the lack of oil (fat) in the product since the germ is removed prior to ethanol production. There are approximately 116,000 head of dairy cattle in the local area capable of consuming 151,000 tons of HPD. The plant is expected to produce 158,000 tons per year. In order to obtain the premium associated with HPD, the plant may need to ship this product to distant dairy markets. The price is set to 100% the price of corn on a dry weight basis based on recent pricing for HPD ($102.86/ton based on $2.72/bu corn). The HPD market is not well developed and this indicates some level of risk. Dakota Gold (Poet), Renew Energy and Zeeland are all experienced marketers of HPD.

The germ yield is expected to be 4.4 pounds per bushel with total annual production of 105,166 tons per year. It is anticipated that the performance guarantee will be 20% oil content on a mass basis. The plant plans to use solvent extraction which is extremely efficient. The expected corn oil yield is 0.88 pounds per bushel based on 20% oil content. Corn oil is the most valuable co-product due to high prices obtained for pure vegetable oils. The plant will produce roughly 21,033 tons of corn oil per year and the price is set to the five year average USDA price of 0.355 cents/pound ($710/ton). Operational costs for the solvent extraction system and transportation costs are anticipated to cost $0.045 per pound. The germ left over after the oil is extracted (3.3 pounds per bushel resulting in 78,875 tons/yr) will be sold as a low quality cattle feed priced at 50% the price of corn on a dry weight basis ($48.57/ton based on $2.72/bu corn).

The bran output will be 3.2 pounds per bushel (80,000 tons/year). It will be used to produce steam in a biomass boiler. Alternatively, the bran can be sold to food processors or as a low grade cattle feed.

Carbon dioxide from the proposed plant could be used for local food processing and beverage markets if these markets present themselves in the future, however no sales are included in this analysis. The project should aggressively seek carbon sales for the purposes of marketing low carbon fuels.

VII. OVERVIEW OF TECHNOLOGIES

The production of ethanol or ethyl alcohol from starch or sugar-based feedstocks has been practiced for thousands of years. While the basic process steps remain the same, the process has been considerably refined in recent years, leading to a highly efficient process that now yields more energy in the ethanol and co-products than is required to make the products.

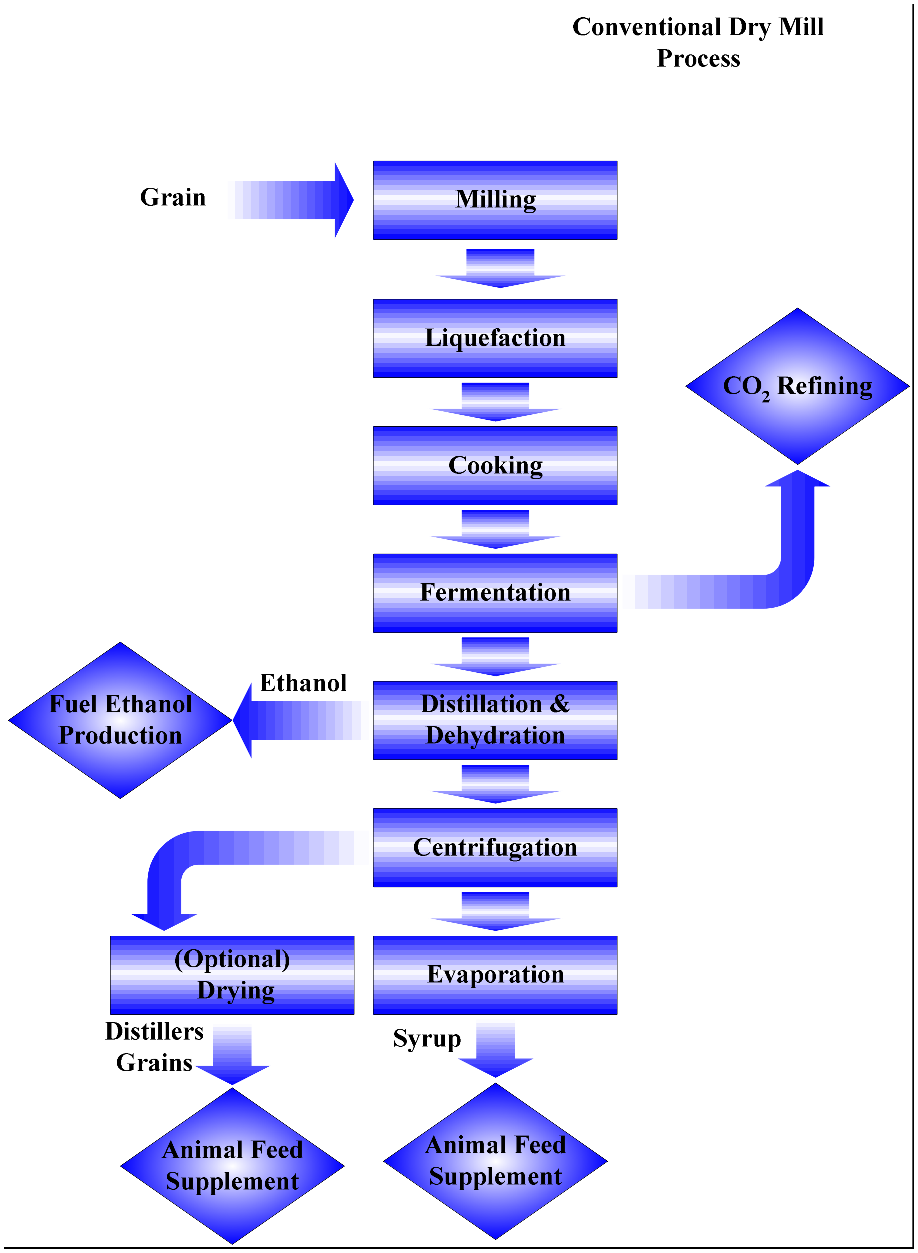
In the dry milling process, corn, wheat or other high-starch grains are first ground into meal and then slurried with water to form a mash. Enzymes are added to the mash to convert the starch to the simple sugar, dextrose. Ammonia is also added for pH control and as a nutrient to the yeast. The mash is processed through a high temperature cook step, which reduces bacteria levels prior to fermentation. The mash is cooled and transferred to the fermenters where yeast is added and the conversion of sugar to ethanol and carbon dioxide (CO_2) begins.

After fermentation, the resulting "beer" is transferred to distillation where the ethanol is separated from the residual "stillage." The ethanol is concentrated to 190 proof using conventional distillation and then is dehydrated to approximately 200 proof in a molecular sieve system. The resulting anhydrous ethanol is blended with about 5% denaturant (usually gasoline) and is then ready for shipment to markets throughout the country.

The stillage is separated into a coarse grain fraction and a "soluble" fraction by centrifugation. The soluble fraction is concentrated to about 30% solids by evaporation. This intermediate is called Condensed Distillers Solubles (CDS) or "syrup." The coarse grain and syrup fractions are then mixed and dried to produce distillers dried grain and solubles (DDGS), a high protein animal feed product.

A simplified block diagram of a typical dry milling ethanol plant follows in Figure 29.

Figure 29 – Flow Diagram for Dry Mill Ethanol Plant



Corn Dry-Mill Technology Overview

The project sponsor should ensure that reputable design and construction firms are engaged throughout the development, design, and construction of the project. The construction firm should guarantee the completion of the project within a fixed budget and time schedule and must warrant all workmanship for a period of not less than a year following startup. The firm should be capable of posting performance, materials, and labor bonds and should be willing and financially able to accept liquidated damages provisions in their contract, if it is required by the sources of debt financing for the project.

The supplier of the ethanol process technology and the designer of the process should be experienced and well regarded, to guarantee the performance of the plant so long as the construction firm builds it to the designer's specifications. This guarantee should include a minimum yield requirement, and specific quality requirements of products. The guarantee should also include quality and quantity requirements of feedstock (usually a bushel of #2 yellow corn). Requirements for energy and utility consumption for the use of chemicals and enzymes, and for the process water, with respect to consumption, should be stated in the process guarantee. The volume and characteristics of wastewater should also be addressed in this guarantee, and all requirements should be presented on a per bushel basis. The guarantee is normally considered satisfied if a successful performances test of several days duration is completed after plant startup.

In some cases, the same firm may be both the designer and the constructor. In such cases, the General Constructor (GC) will provide the performance guarantees and the process designer will act as a subcontractor to the GC. In cases where separate contracts are held for both the designer and the construction contractor, the process and construction guarantees would be in separate documents. BBI recommends that there be a single "turnkey" contract providing the strongest possible financial resources to back the design and construction scope of work.

What follows is a list and short description of firms that BBI knows to be successful and reliable in the ethanol industry.

Fagen, Inc. (Granite Falls, MN)

Fagen Inc. has been the design-build contractor, E.P.C. contractor, general contractor, or subcontractor for at least 48 ethanol plant projects, both new construction and expansion jobs, and claims more ethanol industry experience than any other U.S. firm during the past decade. With the addition of Fagen Engineering LLC and Fagen Management LLC, Fagen now performs the civil, structural, mechanical, and electrical engineering aspects for ethanol projects and provides management services after construction and startup. They typically utilize the ethanol process design of ICM, Inc.

Fagen, Inc. is located at 501 West Highway 212, Granite Falls, MN 56241
Telephone (320) 564-3324. Web address: http://www.fageninc.com/

Delta-T Corporation (Williamsburg, VA)

Headquartered in Williamsburg, VA, Delta-T is a design-build firm that provides alcohol plants, systems and services to the fuel, beverage, industrial and pharmaceutical markets. Delta-T is known for pioneering many of the innovations currently in use by the newest generation of ethanol plants, including the commercialization of molecular sieve dehydration, zero discharge of process wastewater, and more efficient refining and purification systems to produce high quality alcohols. Delta-T has provided alcohol production, dehydration and purification solutions to more than 60 clients worldwide, including projects in Russia, India, Western and Eastern Europe, Africa, the Caribbean and South America.

Delta-T Corporation is located at 323 Alexander Lee Parkway, Williamsburg, VA 23185
Telephone (757) 220-2955. Web address: http://www.deltatcorp.com/

ICM, Inc. (Colwich, KS)

ICM, Inc. of Colwich, KS, serves the agricultural industry by developing and implementing innovative and practical processing solutions. ICM, Inc. employs about 100 people in all aspects of ethanol project development and operation including cash and commodity trading of corn, marketing of ethanol and distillers grain, process consulting, engineering, equipment fabrication, field installation, and plant start-up. The former technology leader of High Plains Corporation formed ICM. High Plains operates plants in Nebraska, Kansas, and New Mexico. ICM does own and operate a facility in Russell, Kansas, which acts as both a training and research facility for their technology. Six of the latest ethanol plants in the United States have utilized ICM technology.

ICM Inc. is located at 310 N. First Street, Colwich, KS 67030
Telephone (316) 796-0900. Web address: http://www.icminc.com/

Katzen International, Inc. (Cincinnati, OH)

Katzen is one of the most experienced ethanol plant process designers and technology suppliers in the world, having operated worldwide for over forty years. Katzen International, Inc. was formed in 1955 by Dr. Raphael Katzen. Katzen International provides innovative and advanced design concepts in a wide variety of industries, such as agriculture, chemicals, sugar, cryogenic and pulp and paper. Although based in the United States, Katzen has completed projects in over 25 countries.

Katzen International Inc. is located at 2300 Wall Street, Suite K, Cincinnati, Ohio 45212
Telephone (513) 351-7500. Web address: http://www.katzen.com/

Lurgi/PSI, Inc. (Memphis, TN)

This firm was created approximately three years ago with the purchase of Process Systems, Inc. ("PSI") of Memphis by Lurgi AG of Germany. The company is part of the GEA Group, the largest food technology company in the world. PSI is best known as a process engineer and as a turnkey contractor in the corn wet milling and the sugar beet processing industries. The company's ethanol work in the United States has been in association with its wet milling activities and in the expansion of large dry milling facilities with respect to corn as a feedstock.

Lurgi PSI Inc. is located at 1790 Kirby Parkway, Suite 300, Memphis, TN 38138
Telephone (901) 756-8250. Web address: http://www.lurgipsi.com/

Vogelbusch USA, Inc. (Houston, TX)

Vogelbusch USA, Inc. is a subsidiary of Vogelbusch GMBH, a large process engineering company, headquartered in Vienna, Austria. The worldwide company claims to have more ethanol capacity in place, utilizing its technology, than any other designer. Vogelbusch provides technologies for fermentation, separation, distillation, and evaporation with a focus on contracting of tailor-made plants based on Vogelbusch proprietary technology or client technology for the sugar, starch, pharmaceutical, chemical and food industries. The U.S. operation offers its license and design services in tandem with other firms and does not undertake any construction activity.

Vogelbusch USA, Inc. is located at 10810 Old Katy Road, #107, Houston, Texas 77043
Telephone (713) 461-7374. Web Address: http://www.vogelbusch.com/

Poet, LLC (formerly Broin & Associates, Inc. (Sioux Falls, SD))

Poet has executed over 20 ethanol projects as a technology supplier and oftentimes as a turnkey contractor providing all required services for dry mill ethanol plants ranging in size from five to 60 million gallons of annual ethanol production. The family of Poet companies can provide plant management, grain procurement, ethanol marketing, DDGS marketing and other services. Our understanding is that all business conducted by Poet today is as a turnkey contractor.

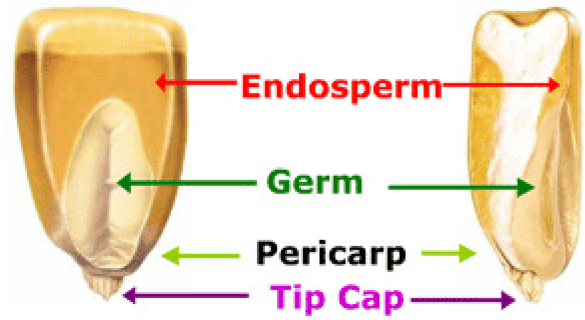
Poet, LLC; 4615 North Lewis Avenue, Sioux Falls, SD 57104
Telephone (605) 965-2200. Web address: http://www.poetenergy.com/

Fractionation Technology Overview

Fractionation technology has long been used in the corn wet milling industry. Wet mills tend to be large in scale and produce ethanol as well as valuable co-products for the human food industry. Dry mill fractionation also has a long history for production of human corn flour and meal. This section will evaluate technologies provided by both Delta-T and Buhler.

The goal of fractionation is to separate the fermentable and non-fermentable components of corn. The corn kernel consists of the pericarp, the endosperm, the germ and the tip cap (Figure 30). The tip cap attaches the kernel to the cob. The germ is the embryo of the seed which contains oil, protein and enzymes responsible for the germination process. The bran is the fibrous hard outer layer. The endosperm contains 95% of usable starch which is the key component fermented into alcohol in the ethanol production process.

Figure 30 – Components of Corn



(source: Ethanol Producer Magazine, October 2006)

The expected benefits of utilizing fractionation technology are listed below as sited from Ethanol Producer Magazine[3].

- By removing non-fermentable products (fiber and germ) at the front end of the process the percentage of starch in the slurry is higher, and a 9 percent to 10 percent increase in ethanol yield per batch can be achieved (this requires more corn).
- It is conceived that with less non-fermentable product in the process, the enzymes can more easily access the starch and reduce the enzyme requirement by up to 30 percent.
- The non-fermentable product, if left in the process, becomes wet and requires drying at the back end of the process. Removing the germ and fiber reduces the drying load.
- By removing the germ, a large percentage of the oil is taken out of the process; oil tends to clog up and coat the heat exchangers, distillation, beer columns and evaporators. This requires periodic shutdowns for cleaning.
- Removing the bran reduces the amount of fiber in the DDGS, which by concentration increases the protein content of the DDGS, as well as reducing the non-detergent fiber (NDF). This protein-enhanced DDGS will now be welcome into the hog feed markets at a much higher value. Protein increases from 27-30% to 38-48%.
- The germ byproduct contains a high enough oil content that can now be extracted by either pressing or solvent extraction, or can be toll extracted at existing corn oil facilities.
- The fiber fraction also has many new opportunities, which include cattle feed, human fiber additive, corn fiber oil extraction, or even on-site burning to reduce natural gas costs.

[3] Foster, Glen, Process Engineer, FWS Technologies, "Corn Fractionation for the Ethanol Industry", *Ethanol Producer Magazine*, November 2005.

Ethanol dry mill fractionation is currently commercial although it is only used in a few plants (Table 13). Poet (formerly Broin) uses BFrac—a front-end fractionation technology that is employed at several plants. The resulting HPD is called Dakota Gold and marketed primarily to dairies. ICM, the leading U.S. ethanol plant technology provider, invested in and built an ethanol plant to utilize the starch from an existing fractionation plant in St. Joseph, Missouri. Renew Energy started operations in early 2008 and is the most recent ethanol dry mill with fractionation.

Table 13 – Existing Ethanol Dry Mills with Front-end Fractionation

Plant	City	State	Ethanol Capacity (mmgy)	Fractionation Technology
Poet	Scotland	SD	9	BFrac
Poet	Alberta Lea	MN	45	BFrac
Poet	Coon Rapids	IA	54	BFrac
Lifeline Foods	St. Joseph	MO	40	Applied Milling
Renew Energy	Jefferson	WI	130	CPT

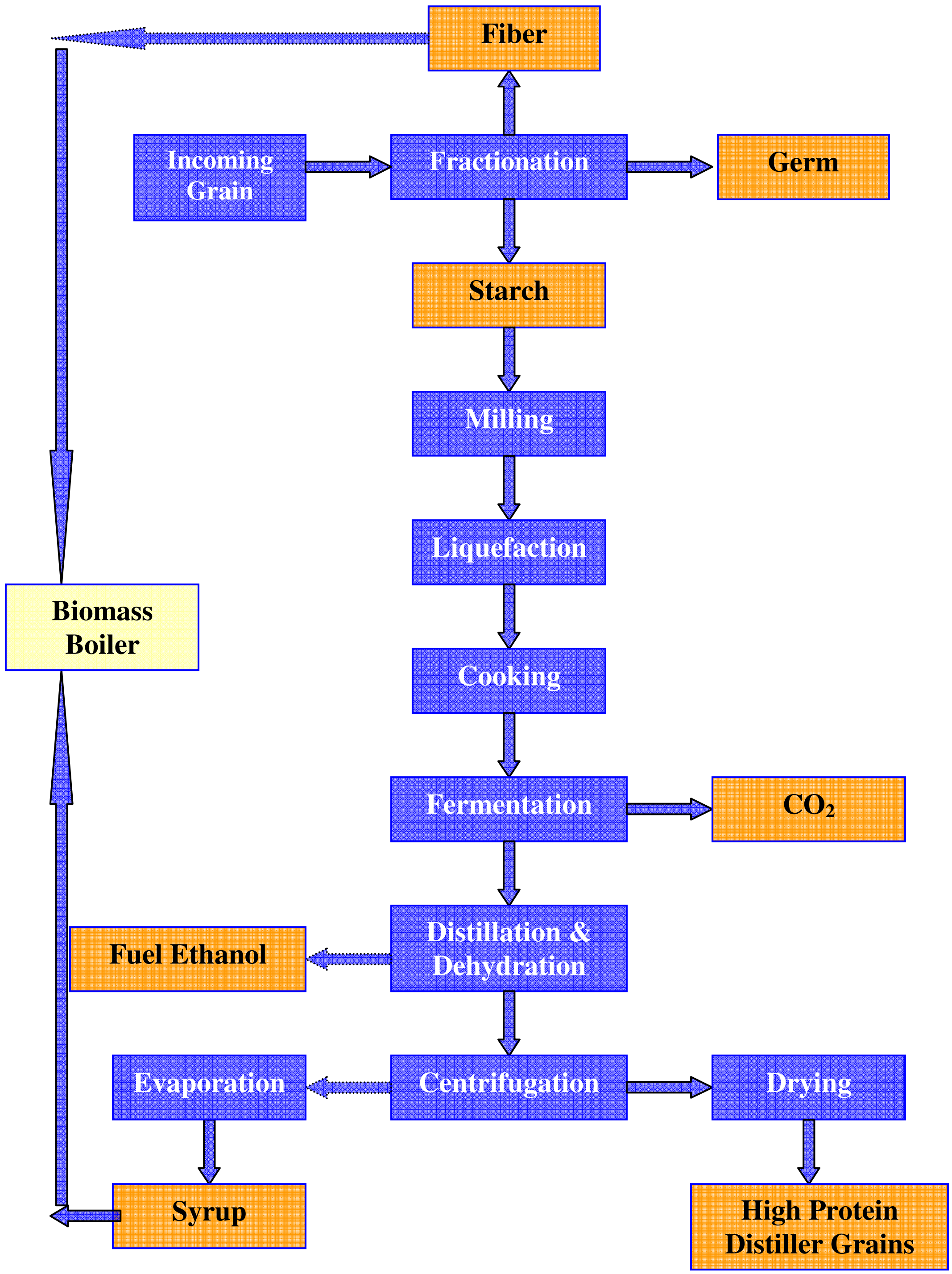
The process typically involves using friction to remove the bran and germ then a series of polishing, drying and sifting using both gravity tables and purifiers concentrate the separate components of endosperm, bran and germ. Although the process is termed dry fractionation, it typically requires some water. A basic flow diagram of the process is shown in Figure 31.

The yields vary based on technology selected and composition of incoming corn. Typical yields are shown in Table 14.

Table 14 – Comparison of Fractionation Technologies

Comparison	Yield Range
Denatured Ethanol Yield (gallon/bu)	2.60-2.75
HPD w/ solubles Yield (pounds/bu)	13.0-15.3
Germ (pounds/bu)	4.0-5.6
Germ Moisture	14-17%
Fiber (pounds/bu)	1.4-3.2
Fiber Moisture	10-17%
Starch loss	4%
Germ Oil Content	20%
Natural Gas Use (BTU/gallon)	27,000
Electricity Use (kWh/gallon)	1.4
Water Use (gallon per gallon of ethanol)	3.1

Figure 31 – Diagram of Corn to Ethanol with Fractionation Process



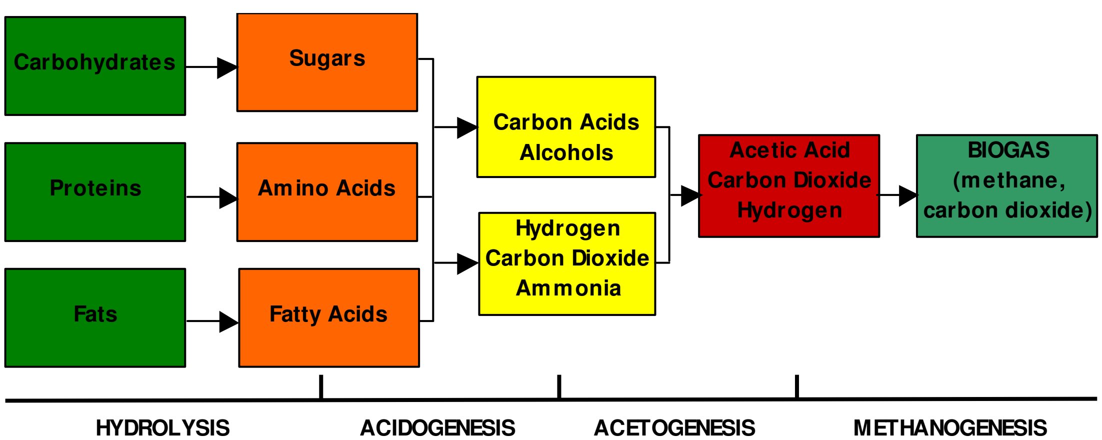
Anaerobic Digestion Technology Overview

Anaerobic Digestion is the natural, biological degradation of organic matter in absence of oxygen yielding biogas. Volatile solids in organic matter are converted to biogas composed of methane, carbon dioxide and trace amounts of other gases. Biogas is capable of operating in nearly all devices intended for natural gas with minimal adjustments to account for lower Btu content. Biogas composition and methane quantity is a function of feedstock type, method of manure removal and digester technology. Biogas is generally comprised of 55-70% methane and 30-45% carbon dioxide with trace amounts of other gases.

This project plans to use paunch water (a waste product of meat packing), manure and similar cattle wastes as feedstock for the digester. The wastes will be diluted to 8% solids content. The plant expects to receive 260,000 pounds of waste feedstocks daily and methane content of the biogas is expected to be 63%. The system is expected to produce 332,700 MMBTU/year augmenting natural gas use by 26.1% for the 59-mmgy scenario and by 9.1% for the 130-mmgy scenario.

The degradation and conversion process occurs in four steps with different classes of bacteria responsible for each phase. In manure digestion, hydrolysis is often the rate-limiting step due to lignin's' resistance to degradation. Figure 32 illustrates the microbial process where the first two steps are facultative and the latter two are strictly anaerobic.

Figure 32 – Anaerobic Digestion Process



The rate and efficiency of the anaerobic digestion process is influenced by feedstock type, pH, alkalinity, temperature, hydraulic retention time, solids retention time, ratio of organic matter to microorganisms, loading rate, and presence of toxic/foreign materials. It is essential to standardize the organic loading rate (volatile solids) to a digester to optimize methane production and minimize risk of a system shutdown. Overloading a digester with organic materials will send a digester into shock leading to reduced or discontinued methane production. The USDA NRCS in conjunction with the EPA developed Conservation Practice Standards for Methane Recovery from anaerobic digesters.

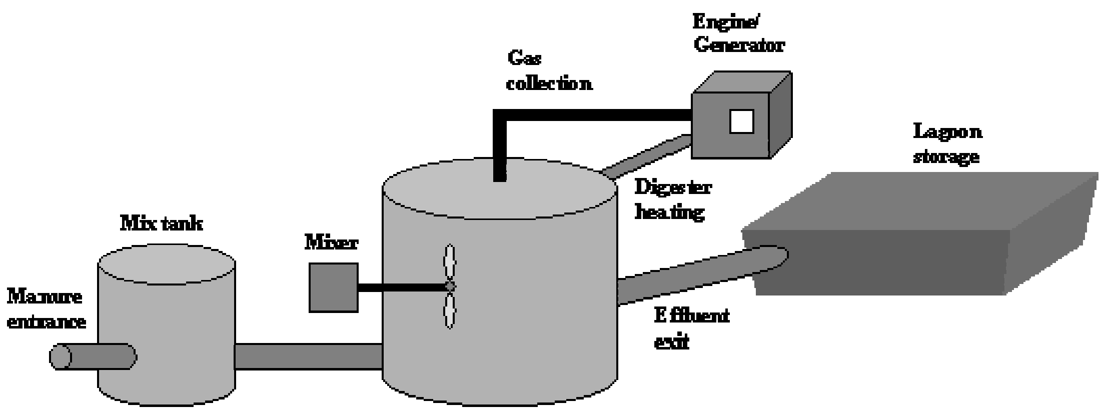
Biogas can be used to generate heat and/or electricity. A portion of generated biogas is required to maintain temperature and provide energy for other functions of the digestion process. The plan is to generate steam from the digester for use in the ethanol plant with expected production of 332,700 MMBTU per year.

There are several types of digester technology and the project has decided on a mesophilic (temperature range of 68°F to 105°F) complete mix digester consisting of a large above or below ground steel or concrete reactor. Waste is mechanically mixed keeping microbes and volatile solids in suspension providing good contact and efficient biogas production. The mixing also provides a homogenous effluent useful as a fertilizer or soil conditioner.

Considerations for complete mix digesters:

- Volumes range from 81- 1982 m^3 with capacity of 94,635-1.8 million liters of manure
- Operate in mesophilic (32-43°C) or thermophilic (48-60°C) temperature range
- Insulation and heat exchangers maintain temperature from biogas or waste heat recovered from engine exhaust and cooling systems
- Typically takes 5-6 months to achieve steady state for economic methane recovery
- Sewage sludge from a waste water plant is often used to inoculate digester to establish microbial populations prior to loading manure

Figure 33 – Complete Mix Digester Schematic



(Source: AgStar Technical Series: Complete Mix Digesters – A Methane Recovery Option for All Climates.)

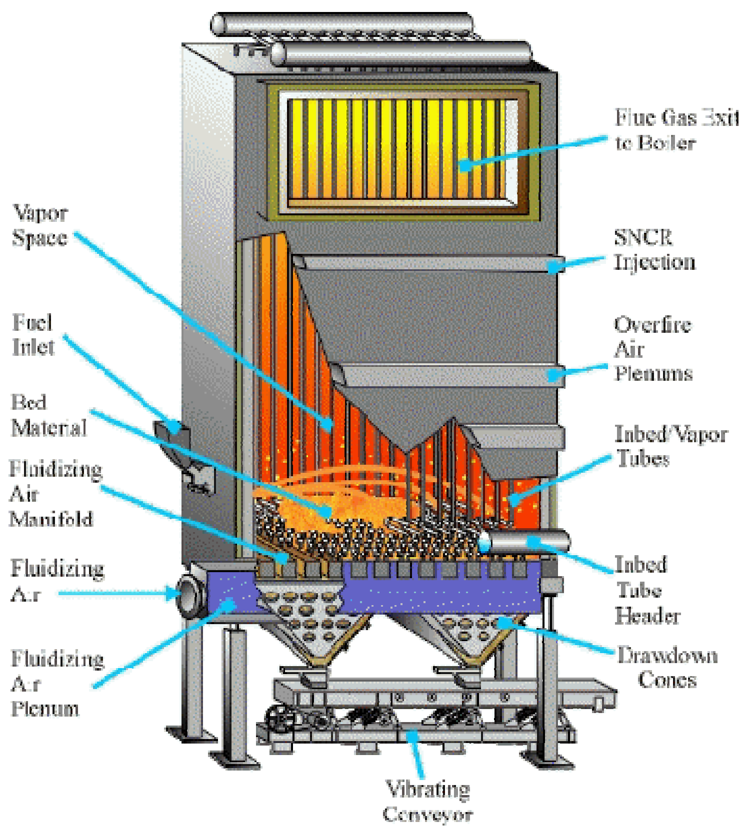
The effluent of anaerobic digestion consists of biosolids and wastewater. The proposed plant in Ft. Morgan intends on extensively treating the wastewater prior to returning in to a nearby river. Anaerobic digestion processes increase concentrations of nitrogen, phosphorous, potassium and other trace elements. Additionally, effluent nitrogen is in mineralized form, the same as commercial fertilizer, thus increasing availability to crops when compared with composted or raw organic nitrogen. Biosolids can be composted for use as a soil amendment.

Biomass Boiler Technology Overview

The project plans to include a biomass boiler for the 130-mmgy scenario. The feedstocks will be co-products of the production process (bran and syrup). Bran is a co-product from the fractionation process and has a heating value of 7699 BTU/pound. Syrup is a by-product of the ethanol production process resulting from the extraction of ethanol from the corn mash during distillation. The syrup contains 2765 BTU per pound with moisture content of 67%. Corn Plus, an existing ethanol plant, has a biomass gasifier (Frontline) using syrup as the feedstock.

The project is considering a biomass boiler for direct combustion of the aforementioned process co-products. There are several types of boilers, however, the type under considerations is a fluidized bed. Fluidized beds were designed for burning pulverized coal but are capable of utilizing other feedstocks. The biomass materials are burned in a bed of inert material (typically sand) with forced air. The gas passes upward through the packed bed causing a pressure drop which increases the velocity until the bed particles expand and become supported in the gas stream with high rates of heat transfer. Figure 34 shows a drawing of a fluidized bed to give a better understanding of the process. The boiler is expected to produce 2,150,000 MMBTU/year, offsetting natural gas use by 59% annually. The 130-mmgy plant can reduce natural gas use by 68% by using biogas from the anaerobic digester and steam from the biomass boiler.

Figure 34 – Fluidized Bed Illustration



(Courtesy of EPI)

VIII. PROJECT STATISTICS

The project statistics shown in the following tables are general guidelines only and may change with the specific plant design and other project variables. Refer to the Appendices for each plant scenario's specific statistics.

Ethanol Plant Statistics

The project statistics for both ethanol plants are shown in the following table.

Table 15 – Ethanol Plant Statistics

	59-mmgy	130-mmgy
Plant Inputs		
Corn (Bu/yr)	21,045,122	47,802,905
Water (Gal/yr)	252,541,466	573,635,000
Electricity (kWh/yr)	42,142,857	148,571,429
Thermal Energy (MMBTU/yr)	1,258,667	3,640,000
Plant Outputs		
Denatured Ethanol (GPY)	59,000,000	130,000,000
DWG (Tons/yr)	487,044	--
HPD (Tons/yr)	--	157,750
Corn Oil (Tons/yr)	--	21,033
Corn Germ Meal (Tons/yr)	--	78,875
CO_2 (Tons/yr)	185,429	314,300
Wastewater (Gal/yr)	50,508,000	84,600,000
Transportation Statistics		
Incoming		
Grain		
(Truckloads, 900 bu/truck) or	23,383	53,114
(Railcars, 3500 bu/car)	6,013	13,658
Outgoing		
Ethanol		
(Truckloads) or	7,375	16,250
(Railcars)	1,947	4,290
DWG or HPD		
(Truckloads)	19,482	6,310
Corn Germ Meal		
(Truckloads)		3,230

Personnel Requirements

The personnel requirements used in the feasibility study are listed in Table 16. The positions and salaries shown are typical of the industry. The personnel requirements for a standard dry-mill plant were increased to account for the anaerobic digestion system and in the case of the 130-mmgy plant for fractionation and a biomass boiler.

Table 16 – Personnel Requirements for Dry Mill Plant

Position	59-mmgy	130-mmgy	Annual Salary
Administration/Management			
General Manager	1	1	128,700
Plant Manager	1	1	94,100
Quality Control Manager	1	1	59,400
Controller	1	1	79,200
Commodity Manager	1	2	54,500
Administrative Assistant	2	3	29,700
Production Labor			
Microbiologist	1	1	44,600
Lab Technician	3	4	29,700
Shift Team Leader	5	6	43,600
Shift Operator	12	14	36,600
Yard/Commodities Labor	6	12	26,700
Maintenance			
Boiler Operator	0	1	49,500
Maintenance Manager	1	1	54,500
Maintenance Worker	2	4	36,600
Welder	1	2	41,600
Electrician	1	2	39,600
Instrument Technician	1	2	39,600
Total Number of Employees	40	58	

IX. FINANCIAL FEASIBILITY

BBI prepared two financial scenarios to evaluate an ethanol plant in Ft. Morgan, Colorado. The first model is a 59-mmgy plant producing ethanol, wet distillers grains, and carbon dioxide from corn. Additionally, the 59-mmgy plant intends to offset a portion of natural gas use with an anaerobic digester. The second scenario is 130-mmgy dry mill ethanol plant with front end fractionation and both a biomass boiler and anaerobic digester to augment natural gas use. The 130-mmgy plant will produce ethanol, high protein distillers grains, corn oil, corn germ meal, and carbon dioxide from corn.

The key model inputs include product and co-product yields, product and raw material pricing, shipping costs, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the ethanol plant and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs.

The BBI models produce ten-year operating forecasts for the projects including a balance sheet, income statement, and cash flow statement. Complete 11-year proformas for both scenarios are included in the appendix. The impacts of critical project variables have been determined and the viability of the projects with regard to each has been evaluated.

Assumptions Used in the Financial Forecast

The major variables for the financial analysis are ethanol price, feedstock price, distillers grains price, and energy costs. In addition to these issues, various financial model input sensitivities were analyzed and are described below. The assumptions used in the financial forecasts that have the greatest impact on the project risk and return are:

- *Ethanol Price*. The ethanol price used in the financial forecast is $1.76 per gallon of denatured ethanol. The net price includes denatured ethanol product sold at $1.76 per gallon less shipping (15¢/gallon) and 1% per gallon sales commission.

- *Ethanol Yield.* The ethanol yield is an important variable for profitable ethanol production. Reputable ethanol process design companies will guarantee a yield of 2.67 gallons of anhydrous ethanol for each 56-pound bushel of #2 yellow corn (at 15% moisture or less) processed. The anhydrous yield for the 130-mmgy plant with fractionation is 2.59 anhydrous gallons of ethanol for each bushel of corn processed.

- *Feedstock Price*. The delivered feedstock prices for grain in the analysis are $2.63 and $2.72 per bushel for the 59- and 130-mmgy scenarios.

- *Distillers Grain*. For the 59-mmgy plant, it is assumed that all distillers grains are sold wet. The yield is 46.3 pounds per bushel of corn processed. The selling price for DWG is assumed to be 80% of the price of corn on a dry weight basis. ($30.94/ton with corn at $2.63/bu).

- *High Protein Distillers Grains*. For the 130-mmgy scenario the yield for HPD is 6.6 pounds per bushel of corn processed. The selling price for HPD is assumed to be 100% of the price of corn on a dry weight basis based on the increased protein content over traditional distillers grains. ($102.86/ton).

- *Germ*. The germ yield is set at 4.4 pounds per a bushel of corn processed.

- *Corn Oil.* Corn oil will be extracted from the germ with an expected yield of 0.88 pounds per bushel of corn processed. The corn oil price is $0.355/pound.

- *Corn Germ Meal*. The corn germ meal will be the remaining product left from the germ after the oil is extracted. The yield is expected at 3.3 pounds per bushel and the price is set to 50% of corn a dry weight basis ($48.57/ton).

- *Bran.* The bran yield is set to 3.2 pounds per bushel of corn processed. All bran will be burned in a biomass boiler to provide steam for the ethanol production process.

- *Electricity Price.* The electric rate is 5.4¢ per kWh based on data provided by City of Ft. Morgan.

- *Water Usage.* Depending on the process design, water use in ethanol production can range from as high as 14 gallons per bushel to as low as 4 gallons per bushel. 9 gallons per bushel was used as input to the financial model for standard dry mill operations.

- *Natural Gas Price*. BBI uses a 5-year average City Gate price to estimate natural gas costs. City Gate gas pricing for Colorado from August 2003 through July 2008 is shown in Figure 35. The average natural gas price in Colorado for the 5-year period was $5.90 per MMBtu.
    - 59-mmgy scenario: plant will offset natural gas use by 26% with an anaerobic digestion system; the natural gas price was reduced by 21% to reflect the savings but also down-time of the anaerobic digestion system resulting in a weighted natural gas price of $4.66 per MMBTU.
    - 130-mmgy scenario: plant will offset natural gas use by a total of 68% (9% with an anaerobic digestion system and 59% with a biomass boiler); the natural gas price was reduced by 60% to reflect the savings but also down-time of the anaerobic digestion and biomass boiler systems resulting in a weighted natural gas price of $2.36 per MMBTU.

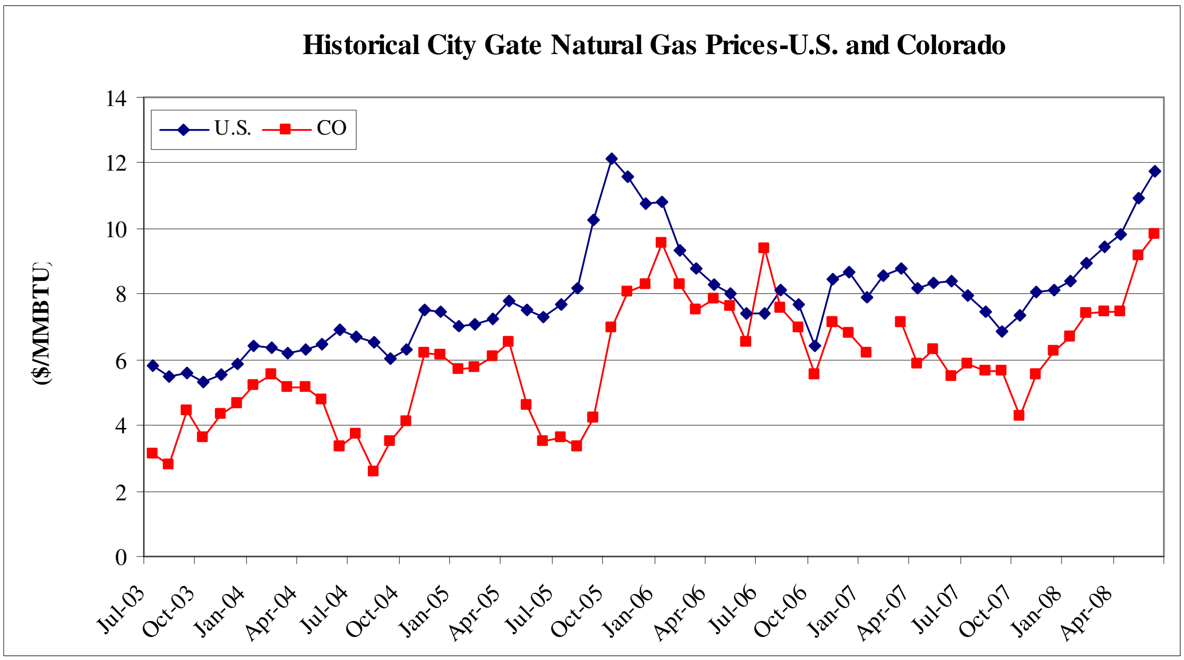
- *Carbon Dioxide Sales*. It is assumed that no carbon dioxide is sold.

- *Incentive Payments.* The financial forecast does not include any state tax credits or ethanol incentive payments. The Federal Small Producer Tax Credit (60-mmgy and below) is included in the analysis for the 59-mmgy scenario.

- *Financing*. For the base scenario the plant is paid off. For the fractionation and biomass scenarios financing is assumed at 45% equity and 55% debt at 9% interested amortized over 10 years.

Table 17 shows the key project assumptions discussed above plus additional assumptions used in the financial projections. Table 18 shows a breakdown of the ethanol plant capital costs and owner's costs.

Figure 35 – Historical Natural Gas Prices



(source: EIA)

Table 17 – Assumptions Used In the Financial Forecast

Ft. Morgan Ethanol Project	59-mmgy	130-mmgy
Nameplate Ethanol Production (gal/year)	**59,000,000**	**130,000,000**
Anhydrous Ethanol Production (gal/year)	**56,190,476**	**123,809,524**
Product Values		
Conversion Rate (anhydrous gal/bushel)	2.67	2.59
Grain ($/Bu)	2.63	2.72
Grain Elevator Fee ($/bu)	0.03	0.03
Ethanol ($/gal)	1.76	1.76
Ethanol Sales Commission (%)	1.0%	1.0%
Ethanol Shipping Cost ($/gal)	0.15	0.15
HPD (% of corn price, dry weight basis)	--	100%
HPD Commission	--	2%
HPD Price ($/ton)	--	102.86
Corn Oil Price ($/pound)	--	0.355
Corn Germ Meal Price ($/ton)	--	48.57
DWG (% of corn price, dry weight basis)	80%	--
DWG Price ($/ton)	30.94	--
Denaturant ($/gal)	1.75	1.75
Weighted Natural Gas ($/MMBTU)	4.66	2.36
Electricity ($/kWh)	0.0540	0.054
Makeup Water ($/1000 gal)	1.00	1.00
Wastewater ($/1000 gal)	1.00	1.00

Table 18 – Ft. Morgan Project Average Capital Cost Estimate

Ft. Morgan Ethanol Project	59-mmgy	130-mmgy
Nameplate Ethanol Production (gal/year)	**59,000,000**	**130,000,000**
Anhydrous Ethanol Production (gal/year)	56,190,476	123,809,524
Project Engineering & Construction Costs		
EPC Contract	$58,000,000	$115,000,000
Anaerobic Digestion System	$17,000,000	$17,000,000
Fractionation/Biomass Boiler/Solvent Extraction	--	$86,000,000
Site Development	$6,304,000	$6,604,000
Rail	$4,941,000	$4,941,000
Contingency	$5,400,000	$11,900,000
Total Engineering and Construction Cost	**$91,645,000**	**$241,445,000**
Owners Costs		
Inventory - Feedstock	$1,599,000	$3,714,969
Inventory - Chemicals, Yeast, Denaturant	$236,000	$520,000
Inventory - Spare Parts	$600,000	$800,000
Start-up Costs	$1,900,000	$2,250,000
Land	$841,750	$841,750
Fire Protection & Potable Water	$2,760,000	$3,010,000
Administration Building & Office Equipment	$642,000	$670,000
Insurance & Performance Bond	$225,000	$375,000
Rolling Stock & Shop Equipment	$480,000	$480,000
Organizational Costs & Permits	$1,189,500	$1,519,500
Capitalized Interest & Financing Costs	$1,599,913	$7,098,416
Working Capital/Risk Management	$9,135,000	$22,331,725
Total Owners Costs	**$22,313,163**	**$43,611,360**
Total Project Capital Cost	**$113,958,163**	**$285,056,360**

Economic Modeling Results

Pre-tax average annual Return on Investment (ROI) was used to measure the projected profitability of the project. The results are summarized in Table 19. The ROI is the average of the return for the 11 years of the financial forecast including the construction year. Results that are more detailed are shown on the following pages and the complete 11-year economic forecast for the project is included in the appendices.

Table 19 – Financial Modeling Results

Ft. Morgan Ethanol Project	59-mmgy	130-mmgy
11-year Average Annual ROI	37.4%	31.4%
Internal Rate of Return	33.0%	32.9%
Average Annual Income	$23,411,000	$40,231,000
EBITDA	$31,357,238	$61,791,400
Installed Capital Cost ($/gal)	$1.93	$2.19
Plant Capital Cost	$91,645,000	$241,445,000
Owner's Costs	$22,313,163	$43,611,360
Total Project Investment	$113,958,163	$285,056,360
45% Equity	$62,676,989	$128,275,362

In general, BBI uses a hurdle rate of 25% average annual pre-tax ROI for ethanol project "go/no go" recommendations. BBI uses the following guidelines for determining the feasibility of a project and as a guideline for determining if a project will be able to compete in today's competitive ethanol industry.

Average Annual ROI (40% equity)	Competitive Status of the Project
Less than 20%	project is typically not worth pursuing
20% to 24%	less than average project – needs improvement
25% to 29%	a good project – should be able to compete
30% and higher	an excellent project

The above scale is based on BBI's methods and history of evaluating the feasibility of over 170 ethanol projects. This scale should not be used for financial projections done by others. In addition, as projects progress, the assumptions used in the financial analysis may change and the resulting projected returns may change significantly.

Based on the results and competitive guidelines, both scenarios evaluated as excellent projects. The better performance of the smaller plant is a factor of corn price basis and offset heating costs from the anaerobic digestion system. The smaller plant has a lower thermal energy requirement since all distillers grains will be sold in the wet form and this also reduces capital costs as the plant will not need to purchase natural gas fired dryers. The 130-mmgy scenario with fractionation and a biomass boiler is also a promising project, however, there are more risks associated with this project due to the additional technology. This project would likely perform better during a period of depressed ethanol prices since more of the co-products, and therefore a higher percentage of the total plan income, are tied to the price of corn. The complete year two income statement is available below. The complete summary of the scenarios is in Appendix B and C.

Table 20 – Year 2 Income Statement

Proforma Income Statement for Year 2	59-mmgy		130-mmgy	
Ethanol Production (gal/year)				
Net Revenue	$/Year	$/gal	$/Year	$/gal
Ethanol	$95,830,632	1.62	$211,152,240	$1.620
Germ Meal	$0	$0.000	$3,792,751	$0.030
Bran	$0	$0.000	$0	$0.000
Corn Oil	$0	$0.000	$13,021,703	$0.100
HPD	$0	$0.000	$16,063,415	$0.120
DWG	$15,220,419	0.26	$0	$0.000
Federal Small Producer Tax Credit	$1,500,000	$0.030	$0	$0.000
Total Revenue	**$112,551,051**	**$1.910**	**$244,030,108**	**$1.880**
Production & Operating Expenses				
Feedstocks	$56,533,511.68	$0.960	$132,758,227.62	$1.020
Chemicals, Enzymes & Yeast	$3,972,667	$0.070	$8,753,333	$0.070
Steam or Coal	$0	$0.000	$0	$0.000
Natural Gas	$5,982,694	$0.100	$8,762,208	$0.070
Electricity	$2,321,229	$0.040	$8,183,314	$0.060
Denaturants	$5,015,000	$0.090	$11,050,000	$0.090
Makeup Water	$191,300	$0.000	$434,528	$0.000
Effluent Treatment & Disposal	$38,260	$0.000	$86,906	$0.000
Production Labor & Benefits	$1,218,597	$0.020	$1,289,245	$0.010
Total Production Costs	**$75,273,258**	**$1.280**	**$171,317,762**	**$1.320**
Gross Profit	**$37,277,793**	**$0.630**	**$72,712,346**	**$0.560**
Administrative & Operating Expenses				
Maintenance Materials & Services	$1,903,125	$0.030	$5,531,750	$0.040
Repairs & Maintenance, Wages & Benefits	$318,391	$0.010	$504,300	$0.000
Property Taxes & Insurance	$1,965,197	$0.030	$4,744,525	$0.040
Admin. Salaries, Wages & Benefits	$608,978	$0.010	$573,488	$0.000
Office/Lab Supplies & Miscellaneous	$424,320	$0.010	$424,320	$0.000
Total Administrative & Operating Expenses	**$5,220,011**	**$0.090**	**$11,778,382**	**$0.090**
EBITDA	32057782.52	0.54	$60,933,964	$0.47
Less:				
Interest - Operating Line of Credit	$0	$0.000	$0	$0.000
Interest - Senior Debt	$4,353,781	$0.070	$12,826,950	$0.100
Interest - Working Capital	$0	$0.000	$0	$0.000
Depreciation & Amortization	$6,667,977	$0.110	$15,901,134	$0.120
Current Income Taxes	$0	$0.000	$0	$0.000
Year 2 Net Earnings Before Income Taxes	**$21,036,025**	**$0.360**	**$32,205,880**	**$0.250**
11-Year Average Annual Pre-Tax Income	**$23,411,000**	**$0.400**	**$40,231,000**	**$0.310**
11-Year Average Annual Pre-Tax ROI	**37.4%**		**31.4%**	
Internal Rate of Return (IRR)	**33.0%**		**32.9%**	
Note - $/gal figures are based on annual denatured ethanol production				

Sensitivity and Breakeven Analysis

The variables that have the greatest impact on the project's profitability are the delivered price for corn and the ethanol selling price. This is the case for all fuel ethanol plants, not just the proposed ethanol project. A series of sensitivity analyses were run to examine the effect of critical parameters on the projected 11-year Average Annual After-Tax ROI. The parameters analyzed include:

- Feedstock Price
- Ethanol Price
- Thermal Energy Price
- Electricity Price
- DWG Price
- HPD Price
- Corn Oil Price
- Corn Germ Meal Price
- Capital Cost

The results of these parameter studies are shown in the graphs that follow. Each of the sensitivity figures that follows assumes that only one variable is changing and that all others are constant as listed in the financial assumptions towards the beginning of this chapter. As expected, the projected profitability as measured by the ROI is very sensitive to corn and ethanol prices; moderately sensitive to the HPD, Corn Oil, Corn Germ Meal price, and natural gas price; and relatively insensitive to the electricity price.

The sensitivity to feedstock price shows that, for an ethanol price of $1.76/gal, the ROI breaks even at corn prices $3.81 in the 59-mmgy scenario, and $3.61 for the 130-mmgy plant (Figure 36). This indicates that the plant could sustain a substantial increase in grain prices if ethanol prices remain at or above ten year historical averages. Corn prices have a more profound impact on the 130-mmgy scenario since more of the co-products track the price of corn.

Similarly, the ROI breaks even with ethanol prices of $1.35 per gallon at 59-mmgy and $1.44 per gallon for the 130-mmgy (Figure 37).

Energy costs typically represent 15 to 20 percent of a plant's operating expenses. The 59-mmgy scenario sees less impact from natural gas prices because a smaller portion of distiller grains are sold, even so, it requires natural gas to be $16.05 per MMBTU to break even (Figure 38). It also shows that the 130-mmgy plant can sustain natural gas prices up to $13.63 per MMBTU. This plant will be less sensitive to natural gas prices then similarly-sized plants, since a portion of the thermal need will be offset by an anaerobic digestion system and a biomass boiler.

The cost of electricity has a small affect on the average annual after-tax ROI; doubling the cost of electricity is projected to reduce ROI by about four to five percent (Figure 39).

The price of HPD has a moderate effect on the profitability of the facility (Figure 40). Although corn oil prices are higher than the other co-products, the volume is small and the overall impact is moderate on the ROI (Figure 41). Similarly, the impact of corn meal price on plant performance is small (Figure 42). The DWG price has a moderate impact on the performance of the 59-mmgy (Figure 43). As mentioned previously, the price obtained for these co-products are generally correlated to the cost of corn.

Figure 36 – Effect of Corn Price on 11-year Average ROI

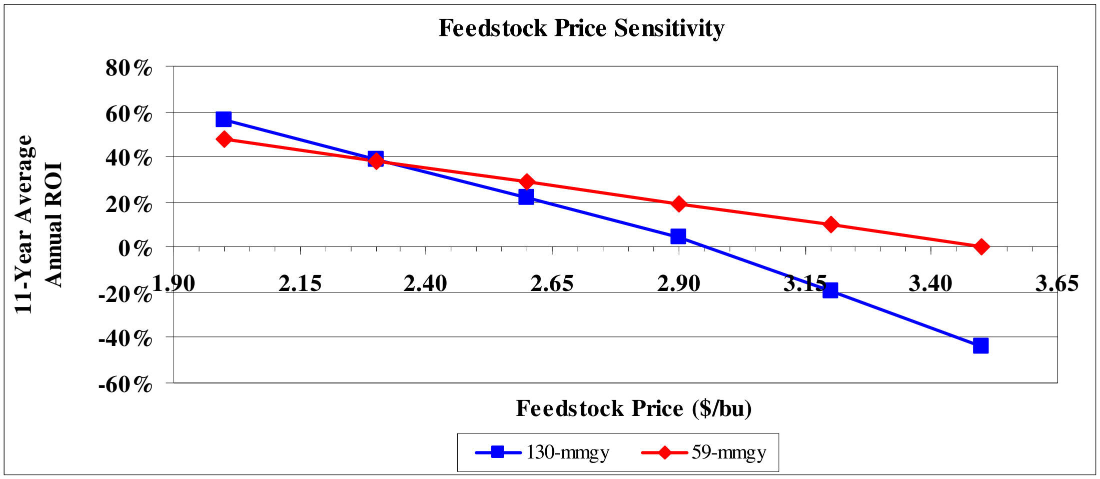


Figure 37 – Effect of Ethanol Price on 11-year Average ROI

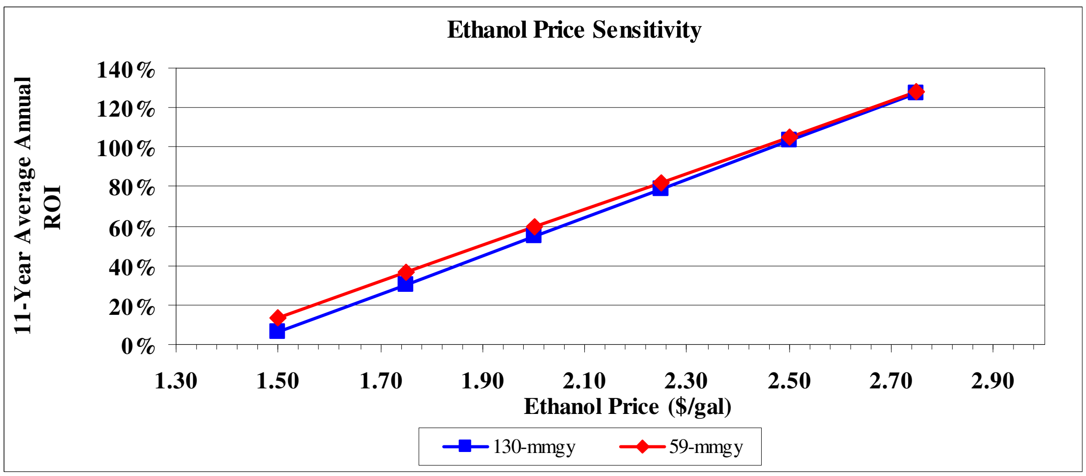


Figure 38 – Effect of Thermal Energy Price on 11-year Average ROI

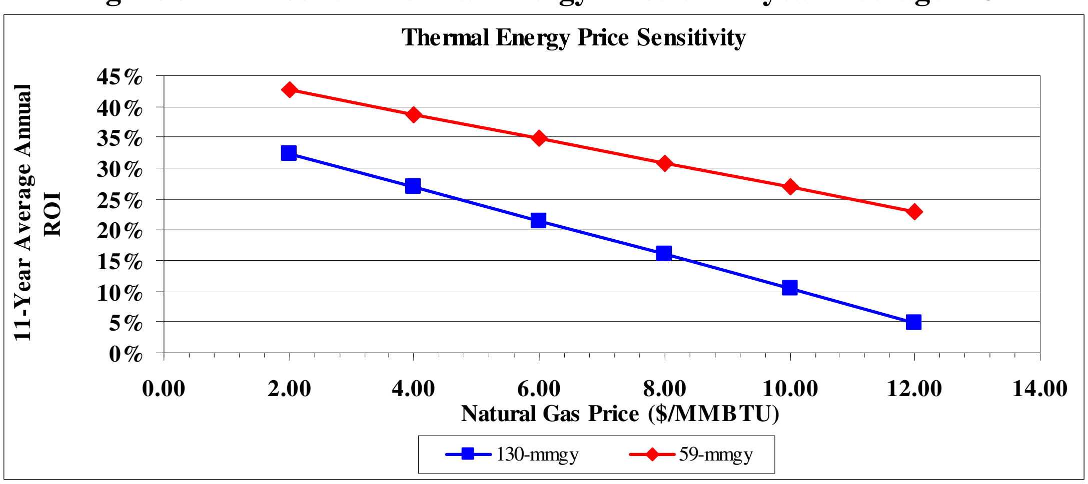


Figure 39 – Effect of Electricity Price on 11-year Average ROI

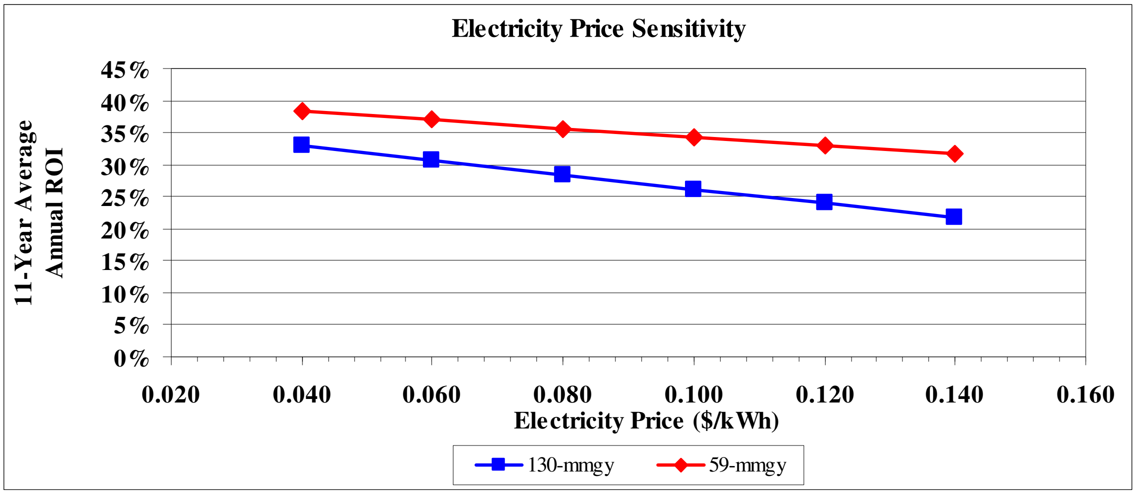


Figure 40 – Effect of HPD Price on 11-year Average ROI

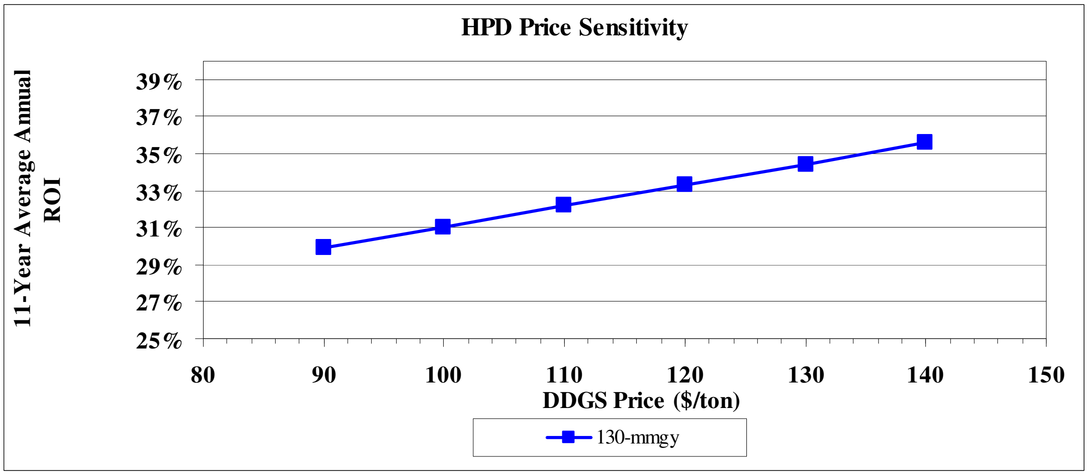


Figure 41 – Effect of Corn Oil Price on 11-year Average ROI

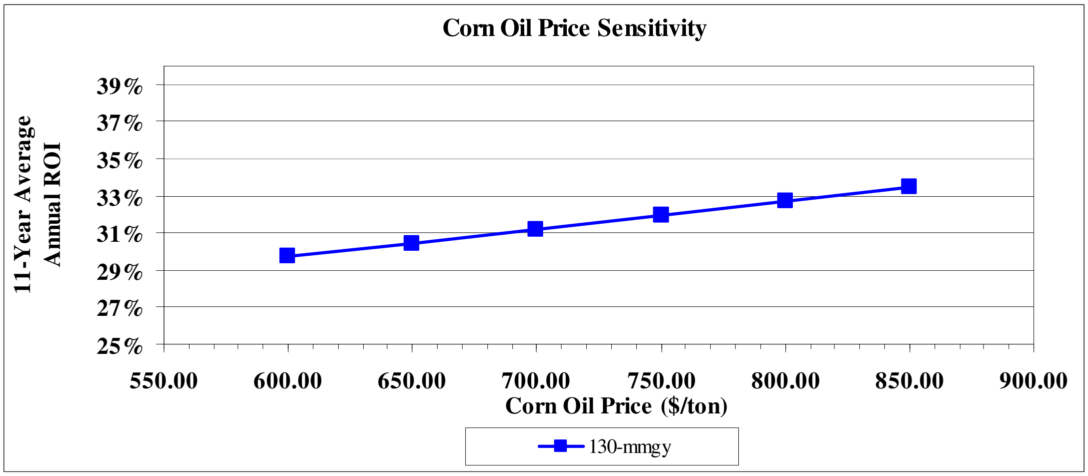


Figure 42 – Effect of Corn Germ Meal Price on 11-year Average ROI

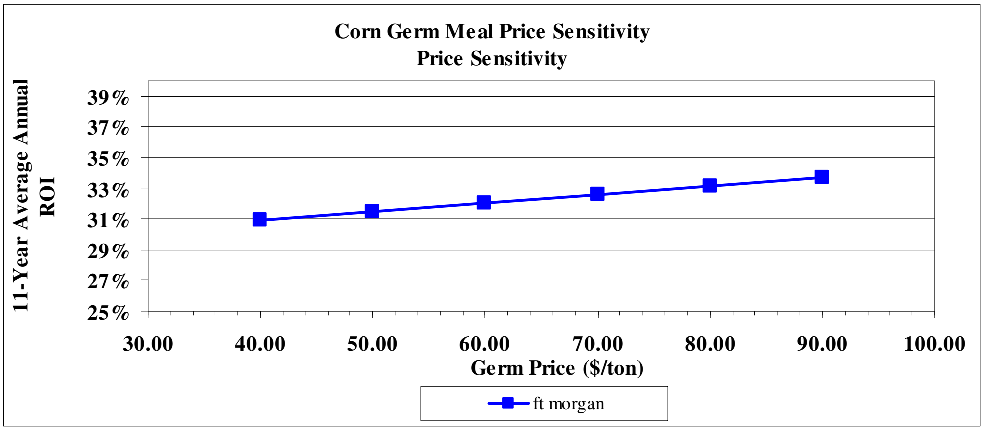


Figure 43 – Effect of DWG Price on 11-year Average ROI

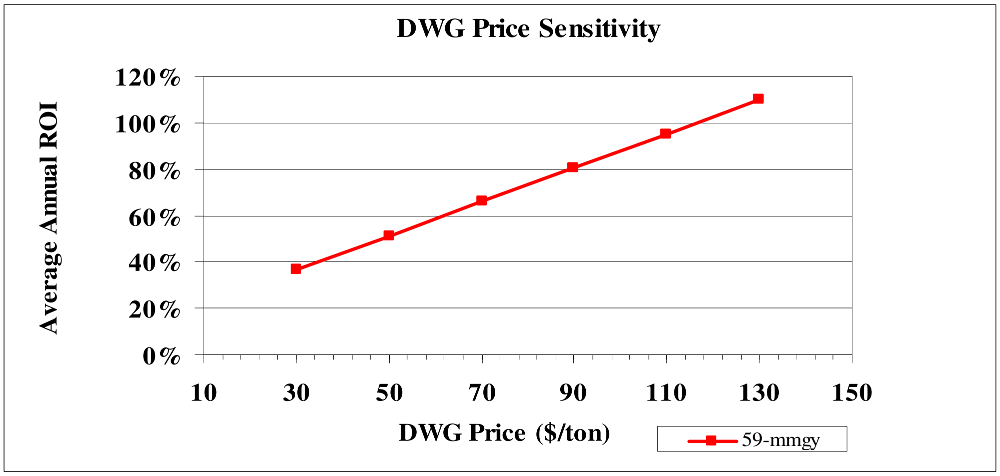
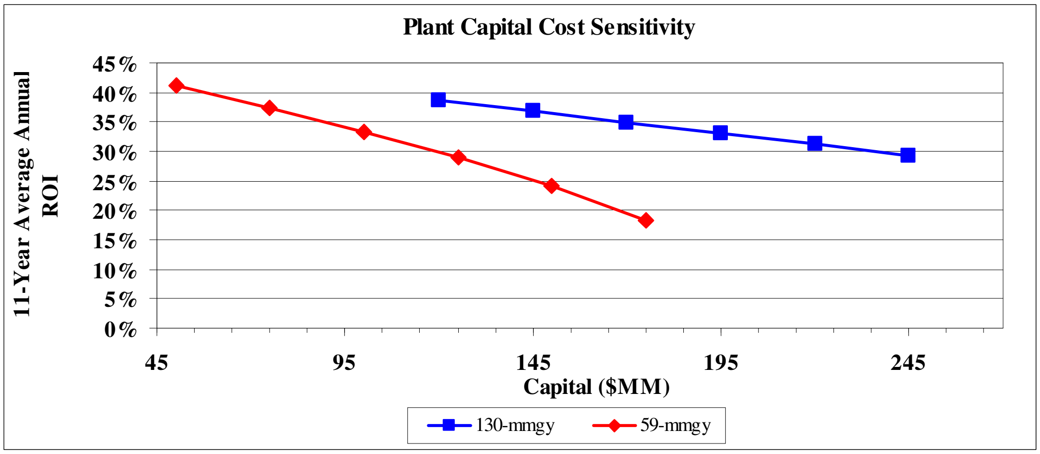


Figure 44 – Effect of Capital Price on 11-year Average ROI



The following table shows the change in the projected average annual ROI for the project for changes in both ethanol and corn price.

Table 21 – Sensitivity and Breakeven Analysis for 59-mmgy

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
59 MMGPY Plant

Feedstock ($/bushel)	Ethanol ($/gallon)										
	0.76	**0.96**	**1.16**	**1.36**	**1.56**	**1.76**	**1.96**	**2.16**	**2.36**	**2.56**	**2.76**
1.73	-35.1%	-9.2%	10.8%	29.1%	47.4%	65.7%	84.1%	102.4%	120.7%	139.0%	157.3%
2.03	-48.7%	-22.6%	1.4%	19.7%	38.0%	56.3%	74.6%	92.9%	111.2%	129.5%	147.8%
2.33	-62.3%	-36.3%	-10.3%	10.2%	28.5%	46.8%	65.1%	83.4%	101.7%	120.0%	138.3%
2.63	-75.9%	-49.9%	-23.8%	0.7%	19.0%	37.4%	55.7%	74.0%	92.3%	110.6%	128.9%
2.93	-89.5%	-63.5%	-37.5%	-11.5%	9.6%	27.9%	46.2%	64.5%	82.8%	101.1%	119.4%
3.23	-103.1%	-77.1%	-51.1%	-25.0%	0.1%	18.4%	36.7%	55.0%	73.3%	91.6%	109.9%
3.53	-116.7%	-90.7%	-64.7%	-38.7%	-12.7%	9.0%	27.3%	45.6%	63.9%	82.2%	100.5%
3.83	-130.3%	-104.3%	-78.3%	-52.3%	-26.2%	-0.6%	17.8%	36.1%	54.4%	72.7%	91.0%
4.13	-143.9%	-117.9%	-91.9%	-65.9%	-39.9%	-13.9%	8.3%	26.6%	44.9%	63.2%	81.5%
4.43	-157.5%	-131.5%	-105.5%	-79.5%	-53.5%	-27.4%	-1.5%	17.2%	35.5%	53.8%	72.1%
4.73	-171.1%	-145.1%	-119.1%	-93.1%	-67.1%	-41.1%	-15.1%	7.7%	26.0%	44.3%	62.6%
5.03	-184.7%	-158.7%	-132.7%	-106.7%	-80.7%	-54.7%	-28.6%	-2.7%	16.5%	34.8%	53.1%
5.33	-198.3%	-172.3%	-146.3%	-120.3%	-94.3%	-68.3%	-42.3%	-16.3%	7.1%	25.4%	43.7%
5.63	-211.9%	-185.9%	-159.9%	-133.9%	-107.9%	-81.9%	-55.9%	-29.9%	-3.9%	15.9%	34.2%
5.93	-225.5%	-199.5%	-173.5%	-147.5%	-121.5%	-95.5%	-69.5%	-43.5%	-17.5%	6.4%	24.7%
6.23	-239.1%	-213.1%	-187.1%	-161.1%	-135.1%	-109.1%	-83.1%	-57.1%	-31.1%	-5.1%	15.3%
6.53	-252.7%	-226.7%	-200.7%	-174.7%	-148.7%	-122.7%	-96.7%	-70.7%	-44.7%	-18.7%	5.8%

Table 22 – Sensitivity and Breakeven Analysis for 130-mmgy

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
Ft. Morgan Ethanol Project

130 MMGPY Plant

Feedstock ($/bushel)	Ethanol ($/gallon) 0.76	0.96	1.16	1.36	1.56	1.76	1.96	2.16	2.36	2.56	2.76
1.82	-49.1%	-21.7%	4.2%	23.6%	43.0%	62.4%	81.8%	101.2%	120.6%	140.0%	159.4%
2.12	-63.8%	-36.4%	-9.1%	13.2%	32.6%	52.0%	71.4%	90.9%	110.3%	129.7%	149.1%
2.42	-78.5%	-51.2%	-23.8%	2.9%	22.3%	41.7%	61.1%	80.5%	99.9%	119.3%	138.7%
2.72	-93.3%	-65.9%	-38.6%	-11.2%	12.0%	31.4%	50.8%	70.2%	89.6%	109.0%	128.4%
3.02	-108.0%	-80.7%	-53.3%	-26.0%	1.4%	21.0%	40.4%	59.8%	79.2%	98.6%	118.0%
3.32	-122.8%	-95.4%	-68.1%	-40.7%	-13.3%	10.7%	30.1%	49.5%	68.9%	88.3%	107.7%
3.62	-137.5%	-110.1%	-82.8%	-55.4%	-28.1%	-0.6%	19.8%	39.2%	58.6%	78.0%	97.4%
3.92	-152.2%	-124.9%	-97.5%	-70.2%	-42.8%	-15.5%	9.4%	28.8%	48.2%	67.6%	87.0%
4.22	-167.0%	-139.6%	-112.3%	-84.9%	-57.6%	-30.2%	-2.8%	18.5%	37.9%	57.3%	76.7%
4.52	-181.7%	-154.4%	-127.0%	-99.7%	-72.3%	-44.9%	-17.6%	8.1%	27.5%	46.9%	66.4%
4.82	-196.5%	-169.1%	-141.8%	-114.4%	-87.0%	-59.7%	-32.3%	-5.0%	17.2%	36.6%	56.0%
5.12	-211.2%	-183.9%	-156.5%	-129.1%	-101.8%	-74.4%	-47.1%	-19.7%	6.7%	26.3%	45.7%
5.42	-225.9%	-198.6%	-171.2%	-143.9%	-116.5%	-89.2%	-61.8%	-34.5%	-7.1%	15.9%	35.3%
5.72	-240.7%	-213.3%	-186.0%	-158.6%	-131.3%	-103.9%	-76.5%	-49.2%	-21.8%	5.1%	25.0%
6.02	-255.4%	-228.1%	-200.7%	-173.4%	-146.0%	-118.6%	-91.3%	-63.9%	-36.6%	-9.2%	14.6%
6.32	-270.2%	-242.8%	-215.5%	-188.1%	-160.7%	-133.4%	-106.0%	-78.7%	-51.3%	-24.0%	3.4%
6.62	-284.9%	-257.6%	-230.2%	-202.8%	-175.5%	-148.1%	-120.8%	-93.4%	-66.1%	-38.7%	-11.3%

APPENDIX A: SITE EVALUATION MATRIX

BBI SITE EVALUATION MATRIX

Plant Criteria	Available Yes/No	20 Miles	40 Miles	60 Miles	80 Miles	100 Miles	Potential Plant Site
Feedstock Proximity	-----	10	8	6	4	2	2
Proximity of Communities	6	-----	-----	-----	-----	-----	6
Rail	On Site	0.25 mile	0.50 mile	0.75 mile	1.0 mile	More than 1 mile	
Existing Rail Siding	7	-----	-----	-----	-----	-----	0
Mainline Rail	10	9	8	7	6	5	10
Short line Rail	6	5	4	3	2	1	0
Access to two Railroads	8	-----	-----	-----	-----	-----	0
Roads/Highways							
Class A Road Access	8	-----	-----	-----	-----	-----	0
Class B Road Access	6	-----	-----	-----	-----	-----	6
Electricity							
Non-Interruptible Service	8	-----	-----	-----	-----	-----	8
Interruptible Service	4	-----	-----	-----	-----	-----	0
Natural Gas							
On site	9	-----	-----	-----	-----	-----	0
Within 2 miles of the site	6	-----	-----	-----	-----	-----	0
2-4 miles from the site	3	-----	-----	-----	-----	-----	3
Non-Interruptible Service	8	-----	-----	-----	-----	-----	8
Interruptible Service	4	-----	-----	-----	-----	-----	0
Water							
City Water	7	-----	-----	-----	-----	-----	7
Well Water	5	-----	-----	-----	-----	-----	0
Waste Water Treatment							
To POTW (city treatment system)	7	-----	-----	-----	-----	-----	7
To Surface Waters	5	-----	-----	-----	-----	-----	0
Ability to land apply	3	-----	-----	-----	-----	-----	0
Co-product Market Proximity	-----	10	8	6	4	2	10
Labor Availability	-----	7	5	3	2	0	7
Ethanol Market Proximity	-----	10	8	6	4	2	2
Community Services	Within 10 Miles	Within 15 Miles	Within 20 Miles				
Electrical Maintenance	5	3	1	-----	-----	-----	5
Machine Shop/Welding	5	3	1	-----	-----	-----	5
Pipe Fitting/Plumbing	5	3	1	-----	-----	-----	5
Hospital	6	4	2	-----	-----	-----	6
Airport	4	2	1	-----	-----	-----	4
Schools	4	2	1	-----	-----	-----	4
Fire Protection	6	4	2	-----	-----	-----	6
	-----	-----	-----	-----	-----	**Total Points**	111

APPENDIX B: FINANCIAL FORECAST 59-MMGY

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	59,000,000
Anhydrous Ethanol Production (gal/year)	56,190,476
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Previous Year	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	2.6700	
Denatured Ethanol Sold (gal/year)	50,276,429	59,000,000	59,000,000	59,000,000	59,000,000	59,000,000	59,000,000	59,000,000	59,000,000	59,000,000	
Ethanol Price ($/gal)	$1.7600	$1.7952	$1.8311	$1.8677	$1.9051	$1.9432	$1.9820	$2.0217	$2.0621	$2.1034	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.1500	$0.1530	$0.1561	$0.1592	$0.1624	$0.1656	$0.1689	$0.1723	$0.1757	$0.1793	2.00%
Delivered Feedstock Price ($/bu)	$2.6300	$2.6563	$2.6829	$2.7097	$2.7368	$2.7642	$2.7918	$2.8197	$2.8479	$2.8764	1.00%
Feedstock Procurement Fees ($/bu)	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	0.00%
Feedstock Usage (bu/year)	18,414,482	21,045,122	21,045,122	21,045,122	21,045,122	21,045,122	21,045,122	21,045,122	21,045,122	21,045,122	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
Available DWG (ton/yr)	426,164	487,044	487,044	487,044	487,044	487,044	487,044	487,044	487,044	487,044	
% Available DWG Sold	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
DWG Yield (lb/bu)	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	46.286	
DWG Sold (ton/year)	426,164	487,044	487,044	487,044	487,044	487,044	487,044	487,044	487,044	487,044	
DWG Price, FOB ($/ton)	$30.941	$31.251	$31.563	$31.879	$32.198	$32.519	$32.845	$33.173	$33.505	$33.840	1.00%
DWG Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DWG Sales Commission ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	0.00%
DDGS Yield (lb/bu)	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	18.000	
DDGS Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
DDGS Price, FOB ($/ton)	$84.536	$85.381	$86.235	$87.097	$87.968	$88.848	$89.736	$90.634	$91.540	$92.455	1.00%
DDGS Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
DDGS Sales Commission ($/ton)	$1.691	$1.691	$1.691	$1.691	$1.691	$1.691	$1.691	$1.691	$1.691	$1.691	0.00%
CO2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO2 Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
CO2 Price ($/ton)	$6.000	$6.060	$6.121	$6.182	$6.244	$6.306	$6.369	$6.433	$6.497	$6.562	1.00%

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
Production Assumptions, continued

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Electricity Use (kWh/bu)	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	2.003	
Annual Electricity Use (million kWh/year)	36.875	42.143	42.143	42.143	42.143	42.143	42.143	42.143	42.143	42.143	
Electricity Price ($/kWh)	$0.0540	$0.0551	$0.0562	$0.0573	$0.0585	$0.0596	$0.0608	$0.0620	$0.0633	$0.0645	2.00%
Thermal Energy Use (BTU/gal)	21,333	21,333	21,333	21,333	21,333	21,333	21,333	21,333	21,333	21,333	
Annual Thermal Energy Use (MMBTU/year)	1,072,564	1,258,667	1,258,667	1,258,667	1,258,667	1,258,667	1,258,667	1,258,667	1,258,667	1,258,667	
Thermal Energy Price ($/MMBTU)	$4.6600	$4.7532	$4.8483	$4.9452	$5.0441	$5.1450	$5.2479	$5.3529	$5.4599	$5.5691	2.00%
Fresh Water Use (1000 gal/bu)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	
Annual Fresh Water Use (1000 gal/year)	165,730	189,406	189,406	189,406	189,406	189,406	189,406	189,406	189,406	189,406	189,406,100
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	33,146	37,881	37,881	37,881	37,881	37,881	37,881	37,881	37,881	37,881	37,881,220
Effluent Water Disposal Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Denaturant Use (% of ethanol sold)	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Annual Denaturant Use (gal/year)	2,458,333	2,809,524	2,809,524	2,809,524	2,809,524	2,809,524	2,809,524	2,809,524	2,809,524	2,809,524	
Denaturant Price ($/gal)	$1.7500	$1.7850	$1.8207	$1.8571	$1.8943	$1.9321	$1.9708	$2.0102	$2.0504	$2.0914	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Number of Employees	40	40	40	40	40	40	40	40	40	40	
Average Salary Including Benefits	$52,341	$53,649	$54,990	$56,365	$57,774	$59,219	$60,699	$62,217	$63,772	$65,366	2.50%
Maintenance Materials & Services (% of Capital Equipm	2.500%	2.538%	2.576%	2.614%	2.653%	2.693%	2.734%	2.775%	2.816%	2.858%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	2.000%	2.060%	2.122%	2.185%	2.251%	2.319%	2.388%	2.460%	2.534%	2.610%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$75,000,000
Site Development	$6,304,000
Rail	$4,941,000
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$5,400,000
Total Engineering and Construction Cost	$91,645,000
Development and Start-up Costs	
Inventory - Feedstock	$1,599,000
Inventory - Chemicals, Yeast, Denaturant	$236,000
Inventory - Spare Parts	$600,000
Start-up Costs	$3,005,000
Land	$841,750
Fire Protection & Potable Water	$2,760,000
Administration Building & Office Equipment	$642,000
Insurance & Performance Bond	$225,000
Rolling Stock & Shop Equipment	$480,000
Organizational Costs & Permits	$1,189,500
Capitalized Interest & Financing Costs	$1,599,913
Working Capital/Risk Management	$9,135,000
Total Development Costs	$22,313,163
TOTAL USES	**$113,958,163**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$51,281,173	45.00%
Interest Rate	9.00%	fixed
Lender and Misc. Fees	$512,812	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	9.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10	years
Equity Investment		
Total Equity Amount	$62,676,989	55.00%
Placement Fees	$0	0.000%
Common Equity	$62,676,989	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$113,958,163**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0.000
Estimated annual payment	$0
Incentive duration, years	5
Other Incentive Payments	
Small Producer Tax Credit	Yes
% of CCC Payment	0%

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	50.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol & Biodiesel	14		8
Distillers Grain	14		8
Denaturants		10	15
Chemicals & Enzymes		15	20
Feedstock		10	10
Utilities		15	

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	27,035,710	50,461,573	74,025,114	98,802,645	124,825,211	152,125,085	180,736,787	210,694,747	242,033,321	274,789,195
Accounts Receivable - Trade	0	4,239,718	4,442,042	4,524,795	4,609,142	4,695,114	4,782,744	4,872,063	4,963,106	5,055,905	5,150,496
Inventories											
Feedstock	0	1,399,501	1,615,243	1,631,215	1,647,347	1,663,640	1,680,096	1,696,717	1,713,503	1,730,458	1,747,582
Chemicals, Enzymes & Yeast	0	236,000	227,010	229,280	231,572	233,888	236,227	238,589	240,975	243,385	245,819
Denaturant	0	210,714	214,929	219,227	223,612	228,084	232,646	237,299	242,044	246,885	251,823
Finished Product Inventory	0	1,481,027	1,720,532	1,741,055	1,761,854	1,782,935	1,804,301	1,825,956	1,847,905	1,870,153	1,892,703
Spare Parts	0	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Total Inventories	0	3,927,242	4,377,713	4,420,777	4,464,386	4,508,547	4,553,269	4,598,560	4,644,428	4,690,881	4,737,928
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	35,202,671	59,281,328	82,970,685	107,876,172	134,028,872	161,461,098	190,207,410	220,302,281	251,780,107	284,677,618
Land	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	78,997,730	97,840,250	98,090,250	98,340,250	98,590,250	98,840,250	99,090,250	99,340,250	99,590,250	99,840,250	100,090,250
Less Accumulated Depreciation & Amortization	0	3,284,096	9,811,077	16,247,087	22,572,842	28,812,344	35,028,877	41,182,761	47,238,616	53,256,728	59,241,785
Net Property, Plant & Equipment	78,997,730	94,556,154	88,279,173	82,093,163	76,017,408	70,027,906	64,061,373	58,157,489	52,351,634	46,583,522	40,848,465
Capitalized Fees & Interest	140,257	1,409,951	1,268,956	1,127,960	986,965	845,970	704,975	563,980	422,985	281,990	140,995
Total Assets	79,979,737	132,010,526	149,671,207	167,033,558	185,722,296	205,744,498	227,069,196	249,770,630	273,918,649	299,487,369	326,508,828
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	2,192,509	2,294,507	2,322,263	2,350,397	2,378,914	2,407,820	2,437,121	2,466,823	2,496,932	2,527,455
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	3,477,342	3,801,024	4,154,836	4,541,582	4,964,328	5,426,424	5,931,533	6,483,660	7,087,180	3,787,267
Current Maturities of Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	5,669,850	6,095,531	6,477,099	6,891,979	7,343,241	7,834,243	8,368,654	8,950,483	9,584,113	6,314,722
Senior Debt (excluding current maturities)	19,728,314	46,177,834	42,376,810	38,221,974	33,680,392	28,716,064	23,289,641	17,358,108	10,874,448	3,787,267	0
Subordincated Debt (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	19,728,314	51,847,684	48,472,341	44,699,073	40,572,371	36,059,306	31,123,884	25,726,761	19,824,930	13,371,380	6,314,722
Capital Units & Equities											
Common Equity	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989	62,676,989
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(2,425,566)	17,485,852	38,521,877	59,657,496	82,472,936	107,008,203	133,268,323	161,366,879	191,416,730	223,438,999	257,517,117
Total Capital Shares & Equities	60,251,423	80,162,841	101,198,866	122,334,486	145,149,926	169,685,193	195,945,312	224,043,868	254,093,719	286,115,989	320,194,106
Total Liabilities & Equities	79,979,737	132,010,526	149,671,207	167,033,558	185,722,296	205,744,498	227,069,196	249,770,630	273,918,649	299,487,369	326,508,828

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	80,060,185	95,830,632	97,747,245	99,702,190	101,696,233	103,730,158	105,804,761	107,920,856	110,079,274	112,280,859
DDGS	0	0	0	0	0	0	0	0	0	0	0
DWG	0	13,186,007	15,220,419	15,372,624	15,526,350	15,681,613	15,838,430	15,996,814	16,156,782	16,318,350	16,481,533
Carbon Dioxide	0	0	0	0	0	0	0	0	0	0	0
State Producer Payment	0	0	0	0	0	0	0	0	0	0	0
Federal Small Producer Tax Credit	0	1,500,000	1,500,000	0	0	0	0	0	0	0	0
USDA CCC Bioenergy Program	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	94,746,192	112,551,051	113,119,868	115,228,539	117,377,847	119,568,588	121,801,575	124,077,638	126,397,623	128,762,392
Production & Operating Expenses											
Feedstocks	0	48,982,522	56,533,512	57,092,533	57,657,145	58,227,403	58,803,363	59,385,084	59,972,621	60,566,034	61,165,380
Chemicals, Enzymes & Yeast	0	3,441,667	3,972,667	4,012,393	4,052,517	4,093,042	4,133,973	4,175,313	4,217,066	4,259,236	4,301,829
Thermal Energy	0	4,887,822	5,982,694	6,102,348	6,224,395	6,348,883	6,475,861	6,605,378	6,737,486	6,872,235	7,009,680
Electricity	0	1,991,250	2,321,229	2,367,653	2,415,006	2,463,306	2,512,572	2,562,824	2,614,080	2,666,362	2,719,689
Denaturants	0	4,302,083	5,015,000	5,115,300	5,217,606	5,321,958	5,428,397	5,536,965	5,647,705	5,760,659	5,875,872
Makeup Water	0	165,730	191,300	193,213	195,145	197,097	199,068	201,058	203,069	205,100	207,151
Wastewater Disposal	0	33,146	38,260	38,643	39,029	39,419	39,814	40,212	40,614	41,020	41,430
Direct Labor & Benefits	0	990,729	1,218,597	1,249,062	1,280,288	1,312,296	1,345,103	1,378,731	1,413,199	1,448,529	1,484,742
Total Production Costs	0	64,794,950	75,273,258	76,171,146	77,081,132	78,003,405	78,938,151	79,885,564	80,845,839	81,819,174	82,805,773
Gross Profit	0	29,951,242	37,277,793	36,948,723	38,147,407	39,374,442	40,630,436	41,916,011	43,231,800	44,578,449	45,956,619
Administrative & Operating Expenses											
Maintenance Materials & Services	0	1,640,625	1,903,125	1,931,672	1,960,647	1,990,057	2,019,908	2,050,206	2,080,959	2,112,174	2,143,856
Repairs & Maintenance - Wages & Benefits	0	258,854	318,391	326,350	334,509	342,872	351,444	360,230	369,236	378,466	387,928
Consulting, Management and Bank Fees	0	150,000	153,000	156,060	159,181	162,365	165,612	168,924	172,303	175,749	179,264
Property Taxes & Insurance	319,358	1,596,790	1,965,197	1,890,968	1,812,504	1,730,113	1,643,147	1,549,954	1,451,232	1,347,676	1,237,584
Admin. Salaries, Wages & Benefits	269,208	553,896	608,978	624,203	639,808	655,803	672,198	689,003	706,228	723,884	741,981
Legal & Accounting/Community Affairs	1,099,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Office/Lab Supplies & Expenses	84,000	120,000	122,400	124,848	127,345	129,892	132,490	135,139	137,842	140,599	143,411
Travel, Training & Miscellaneous	653,500	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755
Total Administrative & Operating Expenses	2,425,566	4,466,165	5,220,011	5,205,999	5,188,931	5,169,136	5,145,994	5,117,877	5,085,508	5,049,610	5,008,508
EBITDA	(2,425,566)	25,485,078	32,057,783	31,742,724	32,958,476	34,205,306	35,484,443	36,798,134	38,146,291	39,528,839	40,948,111
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	2,289,564	4,353,781	4,030,099	3,676,287	3,289,541	2,866,795	2,404,699	1,899,590	1,347,463	743,942
Interest - Sub Debt	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	3,284,096	6,667,977	6,577,005	6,466,749	6,380,498	6,357,528	6,294,879	6,196,851	6,159,107	6,126,051
Pre-Tax Income	(2,425,566)	19,911,418	21,036,025	21,135,619	22,815,440	24,535,267	26,260,119	28,098,556	30,049,851	32,022,270	34,078,118
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(2,425,566)	19,911,418	21,036,025	21,135,619	22,815,440	24,535,267	26,260,119	28,098,556	30,049,851	32,022,270	34,078,118
Pre-Tax Return on Investment	-3.9%	31.8%	33.6%	33.7%	36.4%	39.1%	41.9%	44.8%	47.9%	51.1%	54.4%
11-Year Average Annual Pre-Tax ROI	37.4%										

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(2,425,566)	19,911,418	21,036,025	21,135,619	22,815,440	24,535,267	26,260,119	28,098,556	30,049,851	32,022,270	34,078,118
Non cash charges to operations											
Depreciation & Amortization	0	3,284,096	6,667,977	6,577,005	6,466,749	6,380,498	6,357,528	6,294,879	6,196,851	6,159,107	6,126,051
	(2,425,566)	23,195,514	27,704,001	27,712,625	29,282,189	30,915,765	32,617,647	34,393,435	36,246,702	38,181,376	40,204,169
Changes in non-cash working capital balances											
Accounts Receivable	0	4,239,718	202,324	82,753	84,347	85,972	87,630	89,319	91,043	92,799	94,591
Inventories	0	3,927,242	450,471	43,064	43,609	44,162	44,722	45,291	45,868	46,453	47,047
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(2,192,509)	(101,998)	(27,756)	(28,134)	(28,517)	(28,906)	(29,301)	(29,702)	(30,109)	(30,523)
	0	5,974,452	550,797	98,060	99,822	101,617	103,446	105,309	107,208	109,143	111,115
Investing Activities											
Land Purchase	841,750	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	78,997,730	18,842,520	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Capitalized Fees & Interest	140,257	1,269,694	0	0	0	0	0	0	0	0	0
	79,979,737	20,112,214	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Financing Activities											
Senior Debt Advances	19,728,314	31,552,859	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(1,625,998)	(3,477,342)	(3,801,024)	(4,154,836)	(4,541,582)	(4,964,328)	(5,426,424)	(5,931,533)	(6,483,660)	(7,087,180)
Subordinated Debt	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	62,676,989	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	27,035,710	23,425,863	23,563,541	24,777,532	26,022,566	27,299,874	28,611,702	29,957,960	31,338,573	32,755,874
Cash (Indebtedness), Beginning of Year	0	0	27,035,710	50,461,573	74,025,114	98,802,645	124,825,211	152,125,085	180,736,787	210,694,747	242,033,321
Cash (Bank Indebtedness), End of Year	0	27,035,710	50,461,573	74,025,114	98,802,645	124,825,211	152,125,085	180,736,787	210,694,747	242,033,321	274,789,195
IRR	33.0%										

Ft. Morgan Ethanol Project - Ft Morgan 59-mmgy

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		25,485,078	32,057,783	31,742,724	32,958,476	34,205,306	35,484,443	36,798,134	38,146,291	39,528,839	40,948,111
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(5,974,452)	(550,797)	(98,060)	(99,822)	(101,617)	(103,446)	(105,309)	(107,208)	(109,143)	(111,115)
Investing Activities (Capital Expenditures)		(20,112,214)	(250,000)	(250,000)	(250,000)	(250,000)	(250,000)	(250,000)	(250,000)	(250,000)	(250,000)
Senior Debt Advances		31,552,859	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		30,951,272	31,256,986	31,394,664	32,608,654	33,853,689	35,130,997	36,442,825	37,789,083	39,169,696	40,586,997
Senior Debt P&I Payment		3,915,561	7,831,123	7,831,123	7,831,123	7,831,123	7,831,123	7,831,123	7,831,123	7,831,123	7,831,123
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		7.90	3.99	4.01	4.16	4.32	4.49	4.65	4.83	5.00	5.18
10-year Average Debt Coverage Ratio	**4.85**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	2,064,804	4,129,609	4,129,609	4,129,609	4,129,609	4,129,609	4,129,609	4,129,609	4,129,609	4,129,609
Minor process equipment	15 year SLN	455,472	910,943	910,943	910,943	910,943	910,943	910,943	910,943	910,943	910,943
Process buildings	30 year DDB	543,370	1,050,515	980,480	915,115	854,107	797,167	744,022	694,421	648,126	604,918
Vehicles	5 year DDB	48,000	105,600	92,160	55,296	33,178	60,442	48,000	0	0	0
Office building	30 year DDB	15,000	29,000	27,067	25,262	23,578	22,006	20,539	19,170	17,892	16,699
Office equipment	5 year DDB	7,200	15,840	13,824	8,294	4,977	9,066	7,200	0	0	0
Start-up cost	20 year DDB	150,250	285,475	256,928	231,235	208,111	187,300	168,570	151,713	136,542	122,888
Annual capital expenditures	10 year SLN	0	0	25,000	50,000	75,000	100,000	125,000	150,000	175,000	200,000
Total Depreciation		3,284,096	6,526,981	6,436,010	6,325,754	6,239,503	6,216,533	6,153,884	6,055,856	6,018,112	5,985,056

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)
Note 2: Only 50% of the "1st Year Operations" depreciation shown in the above table is claimed

APPENDIX C: FINANCIAL FORECAST 130-MMGY

Ft. Morgan Ethanol Project
Production Assumptions

Nameplate Denatured Fuel Ethanol (gal/year)	130,000,000
Anhydrous Ethanol Production (gal/year)	123,809,524
Operating Days Per Year	350

Product Yields & Energy Consumption	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Ethanol Production Increase Over Previous Year	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
Anhydrous Ethanol Yield (gal/bushel)	2.5900	2.5900	2.5900	2.5900	2.5900	2.5900	2.5900	2.5900	2.5900	2.5900	
Denatured Ethanol Sold (gal/year)	89,111,905	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	130,000,000	
Ethanol Price ($/gal)	$1.7600	$1.7952	$1.8311	$1.8677	$1.9051	$1.9432	$1.9820	$2.0217	$2.0621	$2.1034	2.00%
Ethanol Sales Commission (% of Ethanol Price)	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	1.000%	0.00%
Ethanol Transportation ($/gal)	$0.1500	$0.1530	$0.1561	$0.1592	$0.1624	$0.1656	$0.1689	$0.1723	$0.1757	$0.1793	2.00%
Delivered Feedstock Price ($/bu)	$2.7200	$2.7472	$2.7747	$2.8024	$2.8304	$2.8587	$2.8873	$2.9162	$2.9454	$2.9748	1.00%
Feedstock Procurement Fees ($/bu)	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	$0.0300	0.00%
Feedstock Usage (bu/year)	33,860,391	47,802,905	47,802,905	47,802,905	47,802,905	47,802,905	47,802,905	47,802,905	47,802,905	47,802,905	
Grain Test Weight (lb/bu)	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	56.000	
Germ Meal Yield (lb/bu)	3.300	3.300	3.300	3.300	3.300	3.300	3.300	3.300	3.300	3.300	
Germ Meal Sold (ton/year)	54,593	78,875	78,875	78,875	78,875	78,875	78,875	78,875	78,875	78,875	
Germ Meal Price ($/ton)	48.571	49.057	49.548	50.043	50.544	51.049	51.560	52.075	52.596	53.122	1.00%
Germ Meal Transportation ($/ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.00%
Germ Meal Sales Commission ($/ton)	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.971	0.00%
Bran Yield (lb/bu)	3.200	3.200	3.200	3.200	3.200	3.200	3.200	3.200	3.200	3.200	
Bran Produced (ton/year)	52,938	76,485	76,485	76,485	76,485	76,485	76,485	76,485	76,485	76,485	
Bran Price ($/ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.00%
Bran Transportation ($/ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.00%
Bran Sales Commission ($/ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00%
Corn Oil Yield (lb/bu)	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880	0.880	
Corn Oil Sold (ton/year)	14,558	21,033	21,033	21,033	21,033	21,033	21,033	21,033	21,033	21,033	
Corn Oil Price ($/ton)	710.000	717.100	724.271	731.514	738.829	746.217	753.679	761.216	768.828	776.517	1.00%
Corn Oil Transportation ($/ton)	90.000	90.900	91.809	92.727	93.654	94.591	95.537	96.492	97.457	98.432	1.00%
Corn Oil Sales Commission ($/ton)	7.100	7.100	7.100	7.100	7.100	7.100	7.100	7.100	7.100	7.100	0.00%
HPD Yield (lb/bu)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
HPD Sold (ton/year)	106,950	157,750	157,750	157,750	157,750	157,750	157,750	157,750	157,750	157,750	
HPD Price, FOB ($/ton)	$102.857	$103.886	$104.925	$105.974	$107.034	$108.104	$109.185	$110.277	$111.380	$112.493	1.00%
HPD Transportation ($/ton)	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	1.00%
HPD Sales Commission ($/ton)	$2.057	$2.057	$2.057	$2.057	$2.057	$2.057	$2.057	$2.057	$2.057	$2.057	0.00%
CO_2 Yield (lb/gal)	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	6.600	
Percernt of CO_2 Produced that is Sold	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	
CO_2 Sold (ton/year)	0	0	0	0	0	0	0	0	0	0	
CO_2 Price ($/ton)	$5.500	$5.555	$5.611	$5.667	$5.723	$5.781	$5.838	$5.897	$5.956	$6.015	1.00%
Electricity Use (kWh/bu)	3.108	3.108	3.108	3.108	3.108	3.108	3.108	3.108	3.108	3.108	
Annual Electricity Use (million kWh/year)	105.238	148.571	148.571	148.571	148.571	148.571	148.571	148.571	148.571	148.571	
Electricity Price ($/kWh)	$0.0540	$0.0551	$0.0562	$0.0573	$0.0585	$0.0596	$0.0608	$0.0620	$0.0633	$0.0645	2.00%
Natural Gas Use (BTU/gal)	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	28,000	
Annual Thermal Energy Use (MMBTU/year)	2,495,133	3,640,000	3,640,000	3,640,000	3,640,000	3,640,000	3,640,000	3,640,000	3,640,000	3,640,000	
Natural Gas Price ($/MMBTU)	$2.3600	$2.4072	$2.4553	$2.5045	$2.5545	$2.6056	$2.6577	$2.7109	$2.7651	$2.8204	2.00%
Fresh Water Use (1000 gal/bu)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	
Annual Fresh Water Use (1000 gal/year)	304,744	430,226	430,226	430,226	430,226	430,226	430,226	430,226	430,226	430,226	
Fresh Water Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%

Ft. Morgan Ethanol Project
Production Assumptions, continued

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Effluent Water Disposal (1000 gal/bu)	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	
Annual Effluent Water Disposal (1000 gal/year)	60,949	86,045	86,045	86,045	86,045	86,045	86,045	86,045	86,045	86,045	
Effluent Water Disposal Price ($/1000 gal)	$1.0000	$1.0100	$1.0201	$1.0303	$1.0406	$1.0510	$1.0615	$1.0721	$1.0829	$1.0937	1.00%
Denaturant Use (% of ethanol sold)	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	5.000%	
Annual Denaturant Use (gal/year)	4,384,921	6,190,476	6,190,476	6,190,476	6,190,476	6,190,476	6,190,476	6,190,476	6,190,476	6,190,476	
Denaturant Price ($/gal)	$1.7500	$1.7850	$1.8207	$1.8571	$1.8943	$1.9321	$1.9708	$2.0102	$2.0504	$2.0914	2.00%
Chemicals & Enzymes Cost ($/gal ethanol)	$0.0700	$0.0707	$0.0714	$0.0721	$0.0728	$0.0736	$0.0743	$0.0750	$0.0758	$0.0766	1.00%
Number of Employees	58	58	58	58	58	58	58	58	58	58	
Average Salary Including Benefits	$39,816	$40,811	$41,831	$42,877	$43,949	$45,048	$46,174	$47,328	$48,511	$49,724	2.50%
Maintenance Materials & Services (% of Capital Equipment Cost)	2.500%	2.538%	2.576%	2.614%	2.653%	2.693%	2.734%	2.775%	2.816%	2.858%	1.50%
Property Tax & Insurance (% of Depreciated Property, Plant & Equipment)	2.000%	2.060%	2.122%	2.185%	2.251%	2.319%	2.388%	2.460%	2.534%	2.610%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$218,000,000
Site Development	$6,604,000
Rail	$4,941,000
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$11,900,000
Total Engineering and Construction Cost	$241,445,000
Development and Start-up Costs	
Inventory - Feedstock	$3,714,969
Inventory - Chemicals, Yeast, Denaturant	$520,000
Inventory - Spare Parts	$800,000
Start-up Costs	$2,250,000
Land	$841,750
Fire Protection & Potable Water	$3,010,000
Administration Building & Office Equipment	$670,000
Insurance & Performance Bond	$375,000
Rolling Stock & Shop Equipment	$480,000
Organizational Costs & Permits	$1,519,500
Capitalized Interest & Financing Costs	$7,098,416
Working Capital/Risk Management	$22,331,725
Total Development Costs	$43,611,360
TOTAL USES	**$285,056,360**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$156,780,998	55.00%
Interest Rate	9.00%	fixed
Lender and Misc. Fees	$1,567,810	1.000%
Placement Fees	$0	0.000%
Amortization Period	10	years
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	9.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10	years
Equity Investment		
Total Equity Amount	$128,275,362	45.00%
Placement Fees	$0	0.000%
Common Equity	$128,275,362	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$285,056,360**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0.000
Estimated annual payment	$0
Incentive duration, years	5
Other Incentive Payments	
Small Producer Tax Credit	no
% of CCC Payment	0%

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	0.0%
15	0.0%
16	50.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Fuel Ethanol	14		8
Distillers Grain	14		8
Denaturants		10	15
Chemicals & Enzymes		15	20
Feedstock		10	10
Utilities		15	

Ft. Morgan Ethanol Project - Site 1
Proforma Balance Sheet

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	27,566,742	61,466,774	100,255,014	141,716,183	185,922,361	232,947,971	282,872,072	335,771,150	391,726,647	450,822,334
Accounts Receivable - Trade	0	8,668,845	9,088,626	9,264,103	9,443,024	9,625,457	9,811,472	10,001,140	10,194,533	10,391,725	10,592,791
Inventories											
Feedstock	0	2,660,459	3,793,092	3,830,613	3,868,510	3,906,785	3,945,443	3,984,488	4,023,923	4,063,753	4,103,980
Chemicals, Enzymes & Yeast	0	520,000	500,190	505,192	510,244	515,347	520,500	525,705	530,962	536,272	541,635
Denaturant	0	464,286	473,571	483,043	492,704	502,558	512,609	522,861	533,318	543,985	554,864
Finished Product Inventory	0	2,743,544	3,915,835	3,961,506	4,007,773	4,054,645	4,102,131	4,150,238	4,198,978	4,248,359	4,298,391
Spare Parts	0	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000
Total Inventories	0	7,188,289	9,482,689	9,580,355	9,679,231	9,779,335	9,880,683	9,983,293	10,087,182	10,192,368	10,298,870
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	43,423,875	80,038,089	119,099,472	160,838,438	205,327,154	252,640,126	302,856,505	356,052,865	412,310,740	471,713,995
Land	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750	841,750
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	219,770,750	245,563,250	246,163,250	246,763,250	247,363,250	247,963,250	248,563,250	249,163,250	249,763,250	250,363,250	250,963,250
Less Accumulated Depreciation & Amortization	0	16,088,275	31,231,561	46,183,598	60,980,371	75,647,974	90,304,208	104,758,117	119,135,901	133,447,032	147,700,312
Net Property, Plant & Equipment	219,770,750	229,474,975	214,931,689	200,579,652	186,382,879	172,315,276	158,259,042	144,405,133	130,627,349	116,916,218	103,262,938
Capitalized Fees & Interest	2,875,895	7,578,481	6,820,633	6,062,785	5,304,937	4,547,089	3,789,241	3,031,393	2,273,544	1,515,696	757,848
Total Assets	223,488,395	281,319,081	302,632,161	326,583,659	353,368,004	383,031,268	415,530,159	451,134,780	489,795,509	531,584,405	576,576,531
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	5,010,334	5,232,533	5,294,868	5,358,035	5,422,046	5,486,914	5,552,652	5,619,273	5,686,790	5,755,217
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	11,115,000	12,149,621	13,280,548	14,516,746	15,868,012	17,345,060	18,959,595	20,724,417	22,653,515	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	16,125,334	17,382,154	18,575,416	19,874,781	21,290,059	22,831,974	24,512,247	26,343,690	28,340,305	5,755,217
Senior Debt (excluding current maturities)	98,363,850	135,497,515	123,347,894	110,067,345	95,550,600	79,682,588	62,337,528	43,377,932	22,653,515	0	0
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	98,363,850	151,622,848	140,730,048	128,642,762	115,425,381	100,972,646	85,169,502	67,890,180	48,997,205	28,340,305	5,755,217
Capital Units & Equities											
Common Equity	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362	128,275,362
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(3,150,817)	1,420,871	33,626,751	69,665,535	109,667,261	153,783,260	202,085,295	254,969,238	312,522,941	374,968,738	442,545,952
Total Capital Shares & Equities	125,124,546	129,696,233	161,902,113	197,940,898	237,942,623	282,058,622	330,360,657	383,244,600	440,798,303	503,244,100	570,821,314
Total Liabilities & Equities	223,488,395	281,319,081	302,632,161	326,583,659	353,368,004	383,031,268	415,530,159	451,134,780	489,795,509	531,584,405	576,576,531

Ft. Morgan Ethanol Project - Site 1
Proforma Income Statement

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Revenue											
Ethanol	0	141,901,797	211,152,240	215,375,285	219,682,790	224,076,446	228,557,975	233,129,135	237,791,717	242,547,552	247,398,503
Corn Germ Meal	0	2,598,609	3,792,751	3,831,444	3,870,525	3,909,997	3,949,863	3,990,128	4,030,795	4,071,869	4,113,354
Corn Oil	0	8,922,619	13,021,703	13,153,413	13,286,440	13,420,798	13,556,500	13,693,558	13,831,987	13,971,800	14,113,011
HPD	0	10,780,607	16,063,415	16,227,294	16,392,812	16,559,986	16,728,831	16,899,364	17,071,603	17,245,564	17,421,265
Total Revenue	0	164,203,631	244,030,108	248,587,436	253,232,568	257,967,227	262,793,168	267,712,184	272,726,102	277,836,785	283,046,133
Production & Operating Expenses											
Feedstocks	0	93,116,075	132,758,228	134,071,469	135,397,843	136,737,480	138,090,514	139,457,079	140,837,309	142,231,341	143,639,313
Chemicals, Enzymes & Yeast	0	6,138,889	8,753,333	8,840,867	8,929,275	9,018,568	9,108,754	9,199,841	9,291,840	9,384,758	9,478,606
Natural Gas	0	5,795,111	8,762,208	8,937,452	9,116,201	9,298,525	9,484,496	9,674,186	9,867,669	10,065,023	10,266,323
Electricity	0	5,682,857	8,183,314	8,346,981	8,513,920	8,684,199	8,857,883	9,035,040	9,215,741	9,400,056	9,588,057
Denaturants	0	7,673,611	11,050,000	11,271,000	11,496,420	11,726,348	11,960,875	12,200,093	12,444,095	12,692,977	12,946,836
Makeup Water	0	304,744	434,528	438,874	443,262	447,695	452,172	456,694	461,261	465,873	470,532
Wastewater Disposal	0	60,949	86,906	87,775	88,652	89,539	90,434	91,339	92,252	93,175	94,106
Direct Labor & Benefits	209,633	1,257,800	1,289,245	1,321,476	1,354,513	1,388,376	1,423,085	1,458,662	1,495,129	1,532,507	1,570,820
Total Production Costs	209,633	120,030,036	171,317,762	173,315,893	175,340,087	177,390,731	179,468,213	181,572,933	183,705,295	185,865,709	188,054,594
Gross Profit	(209,633)	44,173,596	72,712,346	75,271,544	77,892,481	80,576,496	83,324,955	86,139,251	89,020,807	91,971,076	94,991,540
Administrative & Operating Expenses											
Maintenance Materials & Services	0	3,860,417	5,531,750	5,614,726	5,698,947	5,784,431	5,871,198	5,959,266	6,048,655	6,139,385	6,231,475
Repairs & Maintenance - Wages & Benefits	73,750	492,000	504,300	516,908	529,830	543,076	556,653	570,569	584,833	599,454	614,441
Consulting, Management and Bank Fees	0	150,000	153,000	156,060	159,181	162,365	165,612	168,924	172,303	175,749	179,264
Property Taxes & Insurance	882,450	4,412,250	4,744,525	4,578,281	4,401,972	4,214,459	4,014,729	3,799,493	3,572,707	3,330,822	3,072,949
Admin. Salaries, Wages & Benefits	271,483	559,500	573,488	587,825	602,520	617,583	633,023	648,848	665,070	681,696	698,739
Legal & Accounting/Community Affairs	1,429,500	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Office/Lab Supplies & Expenses	84,000	120,000	122,400	124,848	127,345	129,892	132,490	135,139	137,842	140,599	143,411
Travel, Training & Miscellaneous	200,000	50,000	51,000	52,020	53,060	54,122	55,204	56,308	57,434	58,583	59,755
Total Administrative & Operating Expenses	2,941,183	9,740,167	11,778,382	11,730,546	11,674,732	11,609,842	11,534,900	11,446,660	11,349,118	11,238,768	11,114,762
EBITDA	(3,150,817)	34,433,429	60,933,964	63,540,998	66,217,749	68,966,654	71,790,055	74,692,591	77,671,689	80,732,308	83,876,778
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	13,773,466	12,826,950	11,792,329	10,661,402	9,425,204	8,073,937	6,596,890	4,982,354	3,217,532	1,288,435
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	16,088,275	15,901,134	15,709,885	15,554,621	15,425,452	15,414,082	15,211,758	15,135,631	15,068,979	15,011,129
Pre-Tax Income	(3,150,817)	4,571,688	32,205,880	36,038,784	40,001,726	44,115,998	48,302,036	52,883,943	57,553,703	62,445,797	67,577,214
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(3,150,817)	4,571,688	32,205,880	36,038,784	40,001,726	44,115,998	48,302,036	52,883,943	57,553,703	62,445,797	67,577,214
Pre-Tax Return on Investment	-2.5%	3.6%	25.1%	28.1%	31.2%	34.4%	37.7%	41.2%	44.9%	48.7%	52.7%
11-Year Average Annual Pre-Tax ROI	31.4%										

Ft. Morgan Ethanol Project - Site 1
Proforma Statements of Cash Flows

	Construction (Year 0)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(3,150,817)	4,571,688	32,205,880	36,038,784	40,001,726	44,115,998	48,302,036	52,883,943	57,553,703	62,445,797	67,577,214
Non cash charges to operations											
Depreciation & Amortization	0	16,088,275	15,901,134	15,709,885	15,554,621	15,425,452	15,414,082	15,211,758	15,135,631	15,068,979	15,011,129
	(3,150,817)	20,659,963	48,107,014	51,748,669	55,556,347	59,541,450	63,716,117	68,095,700	72,689,335	77,514,776	82,588,343
Changes in non-cash working capital balances											
Accounts Receivable	0	8,668,845	419,781	175,477	178,921	182,433	186,015	189,668	193,393	197,192	201,066
Inventories	0	7,188,289	2,294,400	97,666	98,876	100,104	101,348	102,610	103,889	105,186	106,502
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(5,010,334)	(222,199)	(62,335)	(63,167)	(64,011)	(64,868)	(65,738)	(66,621)	(67,517)	(68,427)
	0	10,846,800	2,491,982	210,808	214,631	218,526	222,495	226,540	230,661	234,861	239,141
Investing Activities											
Land Purchase	841,750	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	219,770,750	25,792,500	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Capitalized Fees & Interest	2,875,895	4,702,586	0	0	0	0	0	0	0	0	0
	223,488,395	30,495,086	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000	600,000
Financing Activities											
Senior Debt Advances	98,363,850	58,417,148	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(10,168,484)	(11,115,000)	(12,149,621)	(13,280,548)	(14,516,746)	(15,868,012)	(17,345,060)	(18,959,595)	(20,724,417)	(22,653,515)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	128,275,362	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	27,566,742	33,900,032	38,788,240	41,461,168	44,206,179	47,025,610	49,924,101	52,899,078	55,955,497	59,095,687
Cash (Indebtedness), Beginning of Year	0	0	27,566,742	61,466,774	100,255,014	141,716,183	185,922,361	232,947,971	282,872,072	335,771,150	391,726,647
Cash (Bank Indebtedness), End of Year	0	27,566,742	61,466,774	100,255,014	141,716,183	185,922,361	232,947,971	282,872,072	335,771,150	391,726,647	450,822,334
IRR	32.9%										

Ft. Morgan Ethanol Project - Site 1

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		34,433,429	60,933,964	63,540,998	66,217,749	68,966,654	71,790,055	74,692,591	77,671,689	80,732,308	83,876,778
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(10,846,800)	(2,491,982)	(210,808)	(214,631)	(218,526)	(222,495)	(226,540)	(230,661)	(234,861)	(239,141)
Investing Activities (Capital Expenditures)		(30,495,086)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)
Senior Debt Advances		58,417,148	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		51,508,691	57,841,982	62,730,190	65,403,118	68,148,129	70,967,560	73,866,051	76,841,028	79,897,447	83,037,637
Senior Debt P&I Payment		23,941,950	23,941,950	23,941,950	23,941,950	23,941,950	23,941,950	23,941,950	23,941,950	23,941,950	23,941,950
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		2.15	2.42	2.62	2.73	2.85	2.96	3.09	3.21	3.34	3.47
10-year Average Debt Coverage Ratio	**2.88**										

Note: the '1st Year Operations' consists of 4 months of construction and startup, plus 8 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968	10,592,968
Minor process equipment	15 year SLN	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684	2,336,684
Process buildings	30 year DDB	2,787,623	2,601,782	2,428,330	2,266,441	2,115,345	1,974,322	1,842,700	1,719,854	1,605,197	1,498,184
Vehicles	5 year DDB	96,000	115,200	69,120	41,472	24,883	96,000	0	0	0	0
Office building	30 year DDB	30,000	28,000	26,133	24,391	22,765	21,247	19,831	18,509	17,275	16,123
Office equipment	5 year DDB	20,000	24,000	14,400	8,640	5,184	20,000	0	0	0	0
Start-up cost	20 year DDB	225,000	202,500	182,250	164,025	147,623	132,860	119,574	107,617	96,855	87,170
Annual capital expenditures	10 year SLN	0	0	60,000	120,000	180,000	240,000	300,000	360,000	420,000	480,000
Total Depreciation		16,088,275	15,901,134	15,709,885	15,554,621	15,425,452	15,414,082	15,211,758	15,135,631	15,068,979	15,011,129

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)
Note 2: Only 50% of the "1st Year Operations" depreciation shown in the above table is claimed