ALTERNATIVE TRANSPORTATION FUELS: NATURAL GAS IMPLICATIONS

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NOTICE

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I. EXECUTIVE SUMMARY AND CONCLUSIONS

The INGAA Foundation, Inc. (Foundation) has retained BBI International (BBI) to analyze the natural gas implications for future alternative fuels plants. This analysis will look at current and future biofuels plants, quantities and estimated thermal energy loads. Increased crop production to supply biofuels plants and the resulting increases in fertilizer requirements will be reviewed. This study will also evaluate alternative thermal energy sources for biofuels plants and energy efficiency gains that may reduce natural gas demand at biofuels plants. U.S. Energy Services will determine the natural gas infrastructure necessary to meet future biofuels production requirements.

Background

The INGAA Foundation, Inc. is a member organization tasked with preparing members to adjust to dynamic worldwide natural gas markets. The Foundation was formed for the purposes of advancing natural gas use for consumers and environmental reasons. The Foundation works to ensure a safe and efficient natural gas distribution pipeline system in the U.S. and worldwide. The member base is natural gas pipeline companies and also those companies that provide goods and/or services to pipelines.

Biofuels Industry Natural Gas Demand

In December 2007, the U.S. Congress passed an updated Renewable Fuels Standard (RFS) requiring 36 billion gallons per year of various types of biofuels (program administered by the EPA). The overall goal is to increase U.S. energy security by decreasing the amount of transport fuels that are currently imported. All fuels must meet American Society for Testing and Materials (ASTM) fuel specifications. The RFS specifically requires 15 billion gallons of starch based ethanol (corn) which is 90% complete with current and under construction capacity, 16 billion gallons of advanced cellulosic biofuels, 1 billion gallons of biodiesel and 4 billion gallons of other or undifferentiated biofuels (renewable diesel, sugar based ethanol and any other yet to be considered renewable fuels). Petroleum blenders are required to meet these quotas and are financially penalized if the obligations are not met. Chapter IV of this report details the dates and quantities that phases in this new law. There are other factors that influence the biofuels industry such as the price relative to crude oil which are addressed in Chapter IV.

Summary of Findings

As discussed in the following executive summary and conclusions, and detailed in the report, the impact of the RFS on natural gas demand is shown in Table 1. Please see Chapter IV and VII for an explanation on the reasons cellulosic ethanol and biodiesel will not result in significant natural gas demand.

Table 1 – Annual Natural Gas Demand for U.S. Plants

	Existing Demand	Contracted Demand	Future Demand
	MMcfd		
Ethanol	699	270	81
Biodiesel	23	6	0
Totals	722	276	81

The total potential future demand increase in natural gas (81MMcfd) is expected to be relatively easy for the existing pipeline companies to supply. See infrastructure section in Chapter VII.

Corn-to-Ethanol Industry

Despite volatility in the both the corn and ethanol markets production remains strong. U.S. production increased from 631 million gallons for the month of February 2008 to 730 million gallons for the month of March 2008. Corn prices are higher than expected but so too are oil prices. Ethanol plants employ a variety of risk management techniques such as locking into corn prices 12 months early to mitigate rising prices. Well managed plants continue to be profitable. Some plants may be in an "upside down" position—locked into old ethanol contracts at low prices with expiring corn contracts which could lead to such plants going idle until corn prices decline.

There are 168 existing corn ethanol facilities in the U.S. with nameplate annual capacity of 9.8 billion gallons. An additional 38 plants are under construction and will add another 3.5 billion gallons of capacity. The total installed and under construction capacity is 13.3 billion gallons per year, however, most ethanol plants are capable of producing more than nameplate capacity and an assumption of existing and under construction plants producing at 5% above capacity leaves only 1 billion gallons of capacity to meet the RFS. BBI evaluated corn basis, corn production and net exportable corn maps as well as planned corn based ethanol plant lists to narrow the region where new plants may be built. Ethanol companies first identify areas with negative basis and available corn before proceeding with site and infrastructure requirements. The areas most likely to receive new plants include western Illinois, southeastern Nebraska and northern Iowa. BBI predicts that less than 20 new corn based ethanol plants will be built in the future.

Existing ethanol plants are energy intensive and use 34,000 BTU of natural gas per gallon of ethanol produced if all distillers grains are dried. Most plants built so far are utilizing released pipeline capacity. The proportion of distillers grains dried at any particular plant is constantly changing based on demand, time of year and pricing. Generally, about 70% of distillers grains produced at U.S. ethanol plants are dried. The assumption is that future plants will use 32,000 BTU per gallon as this is the performance guarantee of the leading ethanol design firm. Annual U.S. ethanol industry natural gas demand is estimated at ~388 million MMBTU per year or 1050 MMcfd (Table 2). It is important to note that this estimated average includes all current plants, those under construction and the remaining one billion gallons of capacity that will be built prior to 2015.

The Canadian government is in the process of passing a 5% volumetric ethanol blend mandate. There are 11 existing plants with 249-mmgy of capacity (431 million litres) and 4 plants under construction with capacity of 124-mmgy (373 million litres). The mandate will require approximately 508 million gallons (1.9 billion litres) annually which leaves a shortfall of 135 million gallons (511 million litres) which can be produced in Canada (attractive federal incentives) or imported from the U.S. per NAFTA. Annual Canadian ethanol industry natural gas demand is estimated at ~15 million MMBTU per year or 42 MMcfd (inclusive of existing and under construction plants).

Table 2 – U.S. Ethanol Industry Annual Estimated Natural Gas Demand

Estimated Natural Gas Use in U.S. Fuel Ethanol Industry	Min[1]	Max[2]	Avg[3]	Min[1]	Max[2]	Avg[3]
	MMBTU/yr			MMcfd		
Existing Ethanol Capacity	191,238,667	333,404,000	258,172,200	518	903	699
Under Construction Ethanol Capacity	73,749,333	110,624,000	99,561,600	200	300	270
Future Build Out[4]	20,000,000	30,000,000	30,000,000	54	81	81
Total	**284,988,000**	**474,028,000**	**387,733,800**	**772**	**1,284**	**1,050**

1-Assumes all DDGS are sold Wet and does not include plants using coal or other alternatives
2-Assumes all DDGS are sold Dry and all plants use natural gas;
3-Assumes DDGS 70% dry and 30% wet and does not include plants using coal or other alternatives
4-Assumes all future ethanol requirements per RFS are produced in the U.S. using natural gas as the thermal energy source

Current and Future Biodiesel Industry

In the U.S., there are 110 commercial biodiesel plants with capacity of 1.5 billion gallons annually. However, skyrocketing feedstock costs representing over 90% of operational costs have caused plants to go idle or operate well below nameplate capacities. The price pressures are due to the use of vegetable oil feedstocks that have increasing demand in the food sector as a replacement for unhealthy transfats. The current U.S. biodiesel capacity utilization rate is estimated at 25%. In 2007, nearly 60% of U.S. biodiesel was exported to Europe. The updated RFS requires one billion gallons of biodiesel but that is less than what is already installed and does nothing to address the shortage of demand. There are an additional 17 plants under construction adding 364 million gallons of capacity. In the past year, 17 plants with capacity of 177 million gallons have closed permanently. The natural gas requirement is typically ~5,150 BTUs per gallon of biodiesel produced but this figure can vary for different process designs. Approximately 25% of biodiesel plants buy oilseeds as feedstock and require more thermal energy to extract the oil; about 9350 BTU/gallon. Current U.S. biodiesel industry natural gas use is estimated at 2,325,000 MMBTU per year (6 MMcfd) however this number has the potential to exceed 8,598,750 MMBTU per year (23 MMcfd) if all capacity is utilized.

Industry estimated natural gas use per year based on current utilization and maximum utilization are shown in Table 3.

Table 3 – Biodiesel Industry Estimated Natural Gas Demand

Estimated Natural Gas Use in Biodiesel Industry	25% Utilization	100% Utilization	25% Utilization	100% Utilization
	MMBTU/yr		MMcfd	
Existing Biodiesel Capacity[1]	2,325,000	8,598,750	6	23
Under Construction Biodiesel Capacity[1]	507,780	2,031,120	1	6
Canadian Biodiesel Capacity[2]	120,510	120,510	0.3	0.3
Total	**2,953,290**	**10,750,380**	**7.3**	**29.3**
1-Assumes 75% of capacity uses straight vegetable oil and 25% crush feedstock to extract oil				
2-assumes all Canadian biodiesel plants purchase oil feedstocks and none crush; assumes all capacity is in use				

Advanced Biofuels Industry

Plants will use lignin or syngas to provide steam for their process. It is possible that some plants may connect to natural gas lines for back-up and purchase on the open market if there is availability.

It will be several years before cellulosic ethanol and other advanced biofuels technologies are commercialized. The RFS requires fuel blenders to begin mixing in cellulosic fuels starting with 100 million gallons in 2010 increasing to 16 billion gallons by 2022. These plants must achieve a 60% reduction in Green House Gas Emissions against a baseline ethanol plant to qualify under this category—the baseline has yet to be established by the EPA. These plants will generate their own energy not only to reduce operating costs but to also achieve the GHG reductions. The undifferentiated category requires 100 million gallons by 2009 and four billion gallons by 2022—this category includes fuels such as renewable diesel or ethanol from molasses, sugarcane, sugar beets or other non-traditional feedstocks and any other advanced biofuels that do not fall into the other categories of the RFS.

These plants will be sited close to their feedstock since it is costly to move wet and non-dense materials such as wheat straw or wood chips long distances economically. Plants using agricultural residues such as corn stover will be sited in the Midwest and possibly as add-ons to existing ethanol plants. The greatest source of wood is in the Southeast where there are large private forests and forest industries. Sugar beets are concentrated between North Dakota and Minnesota while sugarcane is grown in southern Louisiana and southern Florida.

There are two basic pathways for conversion: biochemical and thermochemical. Biochemical typically involves a pretreatment phase to separate the feedstock into its components and send the cellulose and possibly the hemicellulose through fermentation. The thermal energy demand is estimated at 40,000 to 80,000 BTU per gallon based on pretreatment method. The energy source will be lignin. The thermochemical pathway involves heating the feedstock to produce syngas which is then quenched into a mixed alcohol. The energy source will be a portion of the syngas. These plants will require back-up energy sources for downtime and maintenance—perhaps 10%. It is possible that the plants will buy natural gas on the open market if available or propane tanks will be installed. The potential natural gas demand for the back-up to these plants is shown in Table 4. This not considered firm future demand as it is only back-up fuel.

Table 4 – Potential Natural Gas Demand at Cellulosic Biofuels Plants

Natural Gas Potential Demand at Cellulosic Plants	Min[1]	Max[2]	Min[1]	Max[2]
	MMBTU/yr		MMcfd	
Potential natural gas back-up use at cellulosic biofuels plants	14,256,000	115,200,000	39	312
1-Assumes all cellulosic RFS requirement uses thermochemical technology 2-Assumes all cellulosic RFS requirement uses biochemical technology with steam explosion pretreatment				

Renewable diesel is a nonester renewable fuel typically made from poultry fats, poultry wastes, municipal solid wastes, or wastewater sludge and oil. The process is termed thermal depolymerization. These plants will be sited at existing petroleum refineries and have a high thermal energy demand of 122,000 BTU per gallon. Assuming that half of the other/undifferentiated advanced biofuels category is met by renewable diesel (2 billion gallons) then the resulting annual natural gas demand would be 219,600,000 MMBTU (596 MMcfd). Renewable diesel is in its infancy and it is not clear how much will be produced and the numbers stated here are simply an example of the quantity of natural gas needed to produce two billion gallons.

Technical Advances to Increase Energy Efficiency

Existing corn ethanol plants are considered efficient with the exception of the distillation and evaporation systems. There are heat recovery steam generators (HRSG) collecting waste heat from boilers and dryers. New technologies include cold cook enzymes that eliminate the heat needed for liquefaction resulting in thermal energy savings of 10-15%. There will soon be a membrane distillation system available that eliminates molecular sieves and decreases distillation columns by two-thirds resulting in energy savings of approximately 40%. There is also a trend towards fractionation which is a front-end process that separates corn into its components sending only the starch through the ethanol production process. Fractionation increases electrical use but decreases natural gas use since the bran is already removed—the estimate of a fractionation plant drying all distillers grains is 26,500 BTU per gallon.

Biofuels Feedstock and Associated Fertilizer Demand

Corn plantings are expected on roughly 90 million acres annually over the next ten years but yield is expected to increase leading to estimated production of 12.8 billion bushels in 2008 corresponding to estimated fertilizer demand of: 6.3 million tons of nitrogen; 2.3 million tons of phosphorus; and 2.7 million tons of potash. The natural gas demand in the fertilizer sector is based on domestic production of fertilizer resulting in an estimated natural gas demand of ~170 trillion Btu. It should be noted that U.S. ammonia plants (which require far more natural gas than other fertilizers) tend to operate below capacity so it is unlikely that there is any incremental natural gas demand for domestic based nitrogen fertilizer production. Therefore, the required fertilizer for corn to supply an additional one billion gallons of ethanol capacity is insignificant. The corn will be grown regardless if it is used for feed or energy purposes.

Forestry use of fertilizers at tree plantations is miniscule and would not impact demand for natural gas in this sector. Dedicated energy crops are selected for their limited water and fertilizer needs as well as their ability to grow on marginal lands. Likely fertilizers for energy crops include municipal sewage sludge and manure.

Biofuels Industry Alternatives Affecting Natural Gas Use

There are a myriad of alternative sources of thermal energy for biofuels plants, however, they are geographically dependent on both the resource and the biofuels plant location. Alternatives include steam from existing power plants, landfill gas, coal fired boilers, manure, agricultural residues, wood chips or other wood wastes, co-products of the biofuels production process (syrup, distillers grains, glycerin). There are 15 existing ethanol plants using alternatives to natural gas.

Distillers grains—an ethanol plant feed co-product—have an energy value of 9422 BTU/pound. This co-product tracks corn prices and is valuable and unlikely to be used as fuel as it would inflame the food vs. fuel argument. Syrup is an intermediary by-product of ethanol production that is typically mixed into the distillers grains. Syrup has an energy value of 2765 BTU/pound and the ability to offset thermal energy needs by up to 60%. There is one plant currently using syrup as an energy source. Syrup is the most likely supplemental thermal energy alternative for ethanol plants since it is a by-product of the production process and need not be sourced from other locations as would be the case with wood or agricultural residues. Natural gas demand would be reduced from 699 MMcfd to 497 MMcfd if half of all existing ethanol capacity switched to syrup. Glycerin is a co-product from biodiesel production and while it can be used to provide heat it has a higher value for use in pharmaceuticals and future industrial applications.

Agricultural residues are another potential resource with corn stover the most likely candidate due to corn being the primary feedstock for ethanol plants. Corn stover has an energy content of 7192 BTU/pound and typically sells for $50-60 ton (~$3.48 - $4.17 per MMBTU). While this appears to be an attractive option, there are no existing corn stover heat or power applications in the U.S. This is likely due to collection, transportation and storage issues as it is a bulky and wet material. It is not probable that a commercial plant will take on the risk of demonstrating this feedstock.

Wood chips and wood wastes are a viable alternative to natural gas depending on the location of the biofuels plant. The cost of wood is largely dependent on the locale but prices often range from $50 to $100 per dry ton and the estimated net heating value is 5280 BTU/pound. All plants in Wisconsin are located in areas where it is possible to obtain wood. The current Wisconsin ethanol industry natural gas demand is estimated at 38.6 MMcfd; if these plants installed biomass boiler the natural gas demand could possibly be reduced to 13.5 MMCfd. Minnesota also has a large forest products industry that is concentrated in the north while corn and ethanol production are concentrated in the south.

Manure is an unlikely source for thermal energy generation of an ethanol plant since a typical 50-mmgy plant will require manure from ~250,000 dairy cows and there is only one county in California that meats this threshold as is not economical to move manure long distances. There are 11 ethanol plants located in the same county as landfills, however, the energy offset value is so low that it would do little to lessen natural gas demand at these plants. There are seven plants using coal but it is unlikely that any existing or new ethanol plants will use coal due to high capital costs, lengthy permitting process, and new green house gas reduction requirements per the RFS.

Biofuels Industry Natural Gas Infrastructure Requirements

Most existing ethanol and biodiesel plants currently use natural gas as the primary thermal and drying energy source. Natural gas usage for existing biofuels production is 699 MMcfd, roughly 1% of total National natural gas demand. Biofuels demand is expected to increase by 351 MMcf/day after ethanol plants under construction come online (all of these plants have obtained natural gas contracts) and one billion new gallons of capacity is built (plants not yet under construction). The Energy Independence and Security Act of 2007 (RFS-2) requires additional blending and production of biofuels. Increased biofuels production will have a corresponding increase in demand for natural gas and pipeline transportation services. Upon full implementation of RFS-2 conventional biofuels requirement (ethanol from starch with 15 billion gallons required by 2015) natural gas demand is expected to grow to 1,050 MMcfd, a 50% increase over current demand levels.

It is expected that increased biofuels production will occur in the areas that have the lowest relative corn costs. Using that metric, States and counties within those States have been identified that will most likely experience biofuels expansion (Figure 18). The identified counties generally are served by one of five pipelines. These pipelines access supply from the Western Sedimentary Basin, the Rockies production area and the Mid-Continent and Permian production areas.

The pipelines that deliver natural gas to the ethanol focus counties will generally be able to accommodate the increased demand from the biofuels industry, however, there may be significant infrastructure costs and/or relatively high commodity supply costs for certain locations. Table 30 provides estimated Interconnection, Expansion and Commodity supply cost estimates.

Increased biofuels production will be phased-in over several years likely in locations dispersed from each other. As such, relatively small demand increases will occur across several pipelines during the implementation period rather than large increases occurring during a short time period on one pipeline. If biofuels plants are phased-in and dispersed across the five pipelines, the annual incremental demand by pipeline will be 12 MMcfd, a relatively manageable amount ((1,050 MMcfd – 699 MMcfd) / 5 Pipelines / 6 years). If biofuel plants are located to a greater extent on certain pipelines the impact on those pipelines may be more significant. In light of project timing and dispersion we expect that the pipelines should be able to accommodate increased demands provided the market is willing to pay for interconnection, expansion and commodity costs.

Note: Section Vll reflects the view of U.S. Energy Services, Inc. Information contained in the report was collected based on experience and inquires with the various pipelines. The result is very much a "snap shot" and could change with time. The ability of pipelines to expand or offer backhaul services in the future is very dependent on a number of factors beyond the scope of the report.

Impact of Carbon Legislation

It appears that within the next few years a federal economy-wide GHG control program will be established. Currently, the prevailing form of such a program is a cap and trade design, where a financial incentive to reduce emissions is created by capping emissions but allowing regulated entities to buy and sell allowances to meet their compliance obligations. This creates a financial incentive to reduce emissions. The alternative approach is a tax where the regulated entity must pay a fee for each ton of carbon emitted. In either case, the result is a surcharge based on the carbon content of the fuel.

Given the current state of policy development, it is impossible to accurately determine how carbon control polices will impact the biofuels industry and in turn, the use of natural gas. However, climate change policies are certainly a major driver for both the demand for cleaner fuels and continual efficiency gains in energy production and use.

Summary

The passage of the RFS requiring petroleum blenders to use 36 billion gallons of biofuels by 2022 creates increased demand for biofuels but the incremental impact for increased natural gas demand in the sector is low. This is largely due to natural gas demand that is high for existing and under construction ethanol plants that have already secured long term natural gas supply contracts. There are only one billion gallons of traditional corn based ethanol plant capacity to be built which will have an approximate demand of 81 MMcfd. The area of the build out is expected in western Illinois, southeastern Nebraska and northern Iowa. The counties targeted for biofuels expansion will likely draw their supply of natural gas from the Western Sedimentary Basin, the Rockies and Williston production area and the Mid-Continent and Permian production area. The pipelines that deliver the natural gas from these three production areas to the ethanol focus counties will generally be able to accommodate the increased demand from the biofuels industry. There is some risk that ethanol industry natural gas demand could decrease overall if a significant amount of plants install biomass boilers to provide process steam from wood, agricultural residues or co-products of the ethanol production process. It is not possible to predict how many plants will incorporate such technology but it is expected to be small in the near term due to low profit margins and a generally conservative approach to new capital expenditures throughout the industry.

The installed biodiesel capacity already exceeds the updated RFS so future growth in capacity is not expected and the industry does not use a considerable amount of energy in the production process. Growth in renewable diesel is expected at existing oil refineries along the gulf coast and while this technology is a high thermal energy user, it is anticipated that large oil refineries will not have issues with natural gas supply and infrastructure. Second generation cellulosic biofuels plants will use by-products (lignin or syngas) production process to provide all process steam and will only use natural gas as a back-up where available, however this is not firm future demand.

II. PROJECT OVERVIEW

Purpose of Study

The INGAA Foundation, Inc., (Foundation) seeks to quantify natural gas demand and use as a result of the growing biofuels industry and report on infrastructure implications. The basis of this study is an updated Federal Renewable Fuels Standard (RFS) which requires set amounts of various types of biofuels between 2009 and 2022. This analysis will look at current and future biofuels plants, quantities and estimated thermal energy loads. Impacts of increased crop production and corresponding incremental increases in fertilizer requirements that also increase natural gas demand will be reviewed. This study will also evaluate alternative thermal energy sources for biofuels plants and energy efficiency gains that may reduce natural gas demand at biofuels plants. U.S. Energy Services will determine the necessary infrastructure necessary to meet future biofuels production requirements.

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.

U.S. Energy Services provides energy management and logistical services to over 1000 industrial, commercial and municipal sites through the United States. They manage the natural gas needs of 65% of existing ethanol production facilities. U.S. Energy Services is responsible for transportation contracts and infrastructure construction agreements with interstate pipeline companies for biofuels plants.

Scope of Work

This study will review the following topics as they relate to the biofuels industry and incremental natural gas demand increases.

- Magnitude of Increased Natural Gas Demand for Biofuels Plants
    - Review updated RFS
    - Evaluate Current Corn-to-Ethanol Industry
    - Evaluate Under Construction Ethanol Plants
    - Evaluate Current and Future Build out of Biodiesel Industry
    - Evaluate Future Build-out of the Advanced Biofuels Industry
    - Evaluate the Impact of Selling Wet or Dried Distillers Grains
    - Identify Technological Advances that Increase Biofuels Plant Efficiency
- Magnitude of Increase Natural Gas Demand Resulting from Increased Fertilizer Use
    - Calculate the Incremental Fertilizer Required by Corn
    - Calculate the Incremental Fertilizer Required for Other Biofuels Feedstocks
    - Calculate the Demand for Natural Gas as a Result of Increased Fertilizer Use
    - Calculate the Thermal Energy Required by Drying Crops After Harvest
- Factors Impacting Natural Gas Use in the Biofuels Industry
    - Quantify Alternatives to Natural Gas
    - Identify Co-Located Biofuels Plants

  - Quantify Potential Future Alternatives to Natural Gas
  - Quantify the Technological Advances which Might Increase Efficiency
  - Quantify the Effect of the Development of New Technologies for Producing Ethanol
- Natural Gas Infrastructure Requirements
  - Quantify Current Status of Natural Gas Supply Availability
  - Quantify Current Availability of Pipeline Capacity
  - Identify Proposed Pipeline Projects
  - Identify Failed Major Gas Infrastructure Projects
  - Quantify the Incremental Natural Gas Supplies and Natural Gas Infrastructure to Meet Biofuels Production Requirements per the RFS

III. GLOSSARY

Anhydrous
Describes a compound that does not contain any water. Ethanol produced for fuel use is often referred to as anhydrous ethanol, as it has had almost all water removed.

B100
100% (neat) biodiesel.

B20
A blend of biodiesel fuel with petroleum-based diesel where 20% of the volume is biodiesel.

Biochemical Conversion
The use of enzymes and catalysts to change biological substances chemically to produce energy products. For example, the digestion of organic wastes or sewage by microorganisms to produce methane is a biochemical process.

Biodiesel
A biodegradable transportation fuel for use in diesel engines that is produced through transesterification of organically derived oils or fats. Biodiesel is used as a component of diesel fuel. In the future it may be used as a replacement for diesel.

Biomass
Renewable organic matter such as agricultural crops; crop waste residues; wood, animal, and municipal waste, aquatic plants; fungal growth; etc., used for the production of energy.

Denatured Alcohol
Ethanol that contains a small amount of a toxic substance, such as methanol or gasoline, which cannot be removed easily by chemical or physical means. Alcohols intended for industrial use must be denatured to avoid federal alcoholic beverage tax.

E10 (Gasohol)
Ethanol mixture that contains 10% denatured ethanol, 90% unleaded gasoline, by volume.

E85
Ethanol/gasoline mixture that contains 85% denatured ethanol and 15% unleaded gasoline, by volume.

Energy Policy Act of 1992 (EPAct)
Passed by Congress to enhance U.S. energy security by reducing our dependence on imported oil. It mandates the use of alternative fuel vehicles, beginning with federal, then state, then fuel provider fleets.

Ethanol (also known as Ethyl Alcohol, Grain Alcohol, CH_3CH_2OH)
Can be produced chemically from ethylene or biologically from the fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. Used in the United States as a gasoline octane enhancer and oxygenate, it increases octane 2.5 to 3.0 numbers at 10% concentration. Ethanol also can be used in higher concentration in alternative fuel vehicles optimized for its use.

Feedstock
Any material converted to another form of fuel or energy product. For example, cornstarch can be used as a feedstock for ethanol production.

Fermentation
The enzymatic transformation by microorganisms of organic compounds such as sugar. It is usually accompanied by the evolution of gas as the fermentation of glucose into ethanol and CO_2.

Methane (CH_4)
The simplest of the hydrocarbons and the principal constituent of natural gas. Pure methane has a heating value of 1,012 Btu per standard cubic foot.

Methyl Ester
A fatty ester formed when organically derived oils are combined with methanol in the presence of a catalyst. Methyl Ester has characteristics similar to petroleum-based diesel motor fuels.

mmgy
Million gallons per year of capacity. Common abbreviation for noting the capacity of ethanol and biodiesel plants

RFA
Renewable Fuels Association is the lobbyist group responsible for overseeing ethanol interests in policy and government legislation.

RFS
Renewable Fuels Standard enacted by the federal government requiring specific use of biofuels volumes between 2009 and 2022.

Thermochemical Conversion
The use of heat and a catalyst to convert biomass into a syngas—a gas that can be used for heat and power or quenched to produce liquid fuels.

Transesterification
A process in which organically derived oils or fats are combined with alcohol (ethanol or methanol) in the presence of a catalyst to form esters (ethyl or methyl ester).

IV. BIOFUELS INDUSTRY NATURAL GAS DEMAND

This section of the report will address natural gas demand in the biofuels industry. The following will be evaluated: renewable fuels standard, current corn ethanol industry inclusive of plants under construction and remaining capacity needed to fulfill the renewable fuels standard. The biodiesel industry is also reviewed for status of operating plants and associated natural gas use. This chapter also reviews advanced biofuels and how second generation plants energy demands will be met.

Renewable Fuels Standard

The federal government has established a Renewable Fuels Standard (RFS) on two occasions for a variety of purposes with energy security being the most important. This program is administered by the RFS. The U.S. is increasingly dependent on foreign oil to meet transportation fuel demand since U.S. production of oil continues to decline and new domestic resources that are non-conventional (shale for example) and more expensive to reach. The previous RFS was passed into law in July 2005 and required 7.5 billion gallons of biofuels consumption by 2012—however the industry outpaced this mandate and the congress subsequently updated it.

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. This is the amount of biofuels that must be blended and sold in the U.S. All biofuels meet various American Society for Standard Testing (ASTM) specifications. This law 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 (including renewable 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.

The law sets the following targets for each of these biofuel types. Table 5 shows RFS volumetric blend requirements from 2008 to 2022.

Table 5 – 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. This money will largely be used for loan guarantees and for assisting in establishing demonstration scale plants. 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 allows 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 he determines 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) of $0.10 for first 15 million gallons of production for plants with 60-mmgy capacity or less did not change in this bill. The blenders credits of $1.00 per gallon of biodiesel and the Volumetric Ethanol Excise Tax Credit (VEETC) for each gallon of ethanol blended remain unchanged. The 2008 Farm Bill which is still being debated would reduce the VEETC to $0.45 per gallon for 2009 and 2010 (terminated thereafter) but would create a separate VEETC for cellulosic ethanol of $1.00 per gallon.

Current Corn-to-Ethanol 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 enhancing energy security. 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.

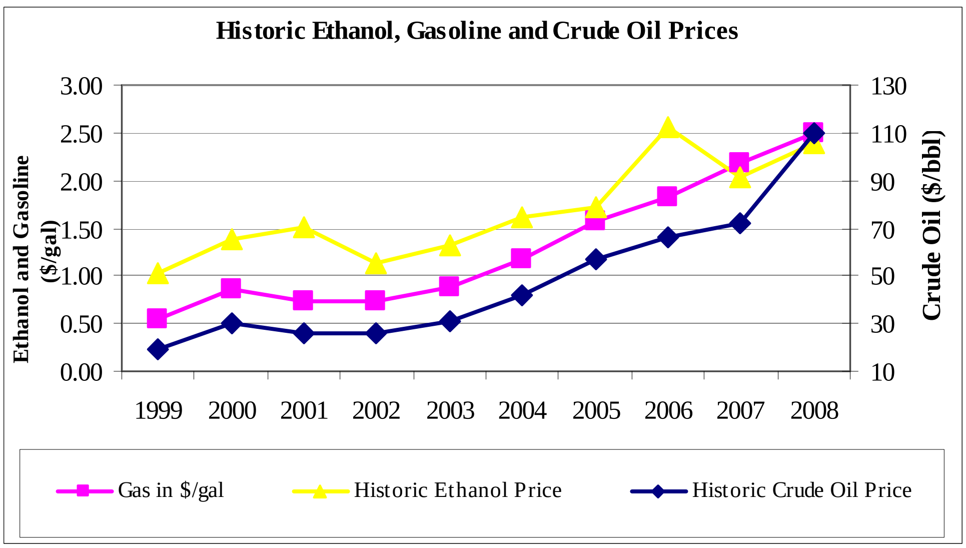
Several factors have and will continue driving or influencing the U.S. fuel ethanol industry’s growth. They are:

- Federal Renewable Fuels Standard (discussed prior to this section)
- Ethanol price relative to crude oil (or gasoline)
- Clean octane
- Gasoline extender (refinery capacity)
- Local economic development
- Green House Gas Emissions
- Food Prices and Competition for Agricultural Land

Ethanol Price Relative to Crude Oil or Gasoline

Regardless of the RFS, any excess ethanol production 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. As evidenced in Figure 1, ethanol prices are correlated to gasoline and oil. However, the chart shows that for the past two years ethanol prices are depressed as ordinarily they should be at least 50¢ per gallon to reflect the VEETC the blender receives. This is partially explained by ethanol production outpacing infrastructure for blending it.

Figure 1 – Ethanol, Crude Oil and Gasoline Price Comparison



(Source: EIA, OPIS)

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 6 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 6 – 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.

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. U.S. gasoline refineries are operating at or near capacity.

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 billion to the nations 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.

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

Green House Gas Emissions Reductions

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. Table 7 show emissions impacts of using E10 (10% ethanol, 90% gasoline) and E85 (85% ethanol and 15% gasoline).

Table 7 – E10 and E85 Emissions Profiles

Emission	E10	E85
Carbon Monoxide (CO)	25-35% reduction	40% reduction
Carbon Dioxide (CO2)	10% reduction	14-102% reduction
Nitrogen Oxides	5% reduction	10% reduction
Volatile Organic Compounds (VOCs)	7% reduction	30% or more reduction
Sulfur Dioxide (SO2)	Some reduction	Up to 80% reduction
Particulates	Some reduction	Insufficient data
Aldehydes	30-50% increase but negligible due to catalytic converter	Insufficient data
Aromatics (Benzene and Butadiene)	Some reduction	More then 50% reduction

(Source: EPA Fact Sheet 420-F-00-035)

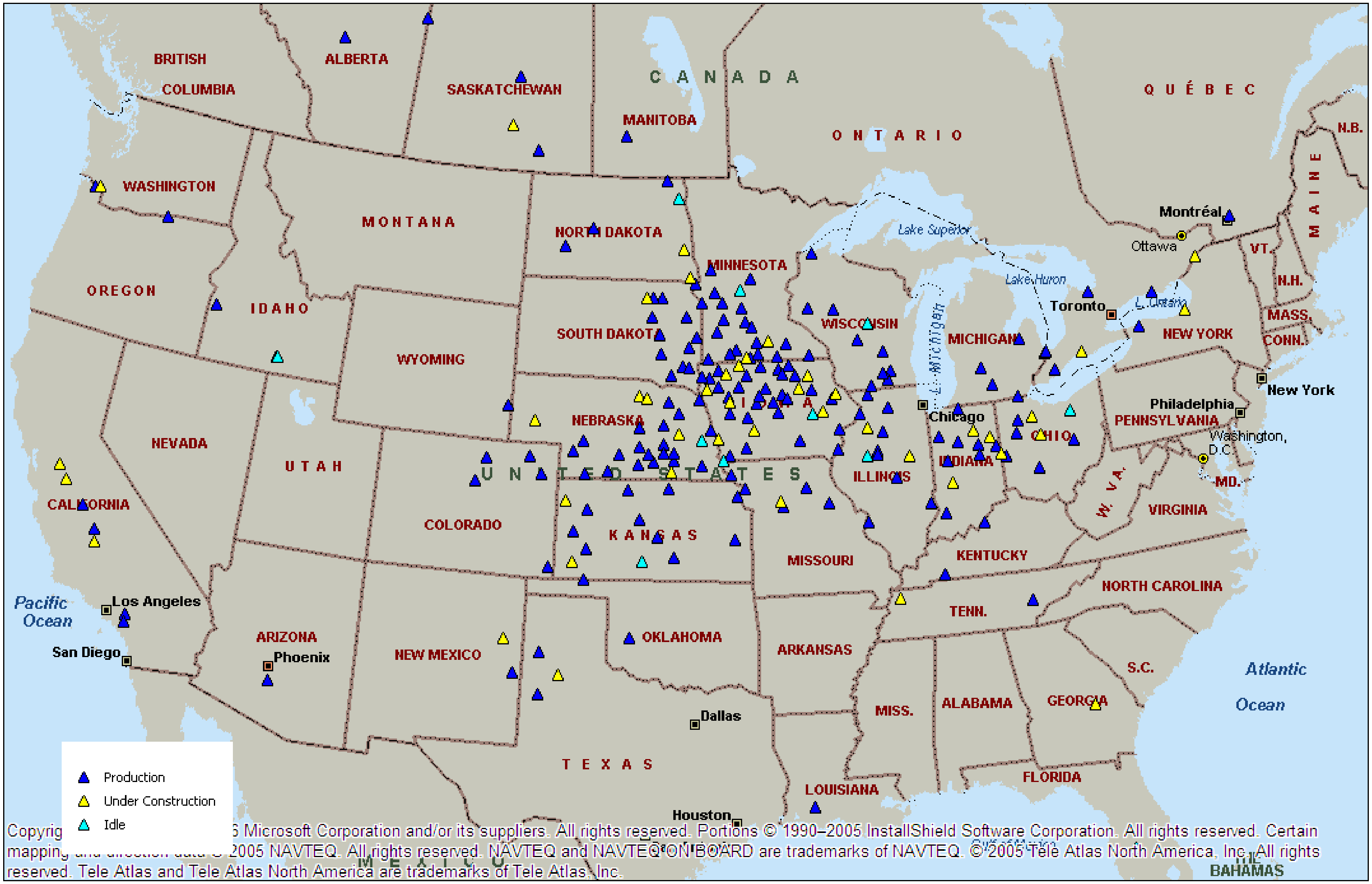
Current Industry

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. Figure 2 shows the percent of state gasoline sold as E10 (10% ethanol, 90% gasoline). 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.

There are currently 168 commercial fermentation ethanol production facilities in operation in the U.S. with a combined production capacity of about 9.8 billion gallons per year (Figure 3). A summary of capacity by state is shown in Table 8 and a full list of existing plants is available in Appendix A. Of existing U.S. plants, 86% are in the Midwest accounting for 91% of capacity. There are 38 new U.S. plants under construction, adding about 3.5 billion gallons of annual production capacity (a list is included in the appendix). There are 11 idle plants with 181 million gallons of capacity. The upcoming plants are still concentrated in the Midwest. Total production capacity in the U.S. should exceed 10 billion gallons per year by the middle of 2008.

Figure 2 – U.S. Ethanol Market E10 Penetration

Figure 3 – Fuel Ethanol Plants in the North America (5/15/08)



(Source: Ethanol Producer Magazine)

Table 8 – Existing U.S. Ethanol Capacity by State

State	Existing Capacity (mmgy)	# of Plants	State	Existing Capacity (mmgy)	# of Plants
Arizona	55	1	Nebraska	1,343	22
California	69	4	New Mexico	30	1
Colorado	138	5	North Dakota	128	3
Iowa	2,337	30	New York	50	1
Idaho	55	2	Ohio	384	5
Illinois	916	9	Oklahoma	2	1
Indiana	625	9	Oregon	143	2
Kansas	443	12	South Dakota	887	15
Kentucky	37	2	Tennessee	60	1
Michigan	262	5	Texas	240	3
Minnesota	809	18	Wisconsin	518	9
Missouri	236	6	Wyoming	12	1

Corn Ethanol Future Build-Out

The RFS requires 15 billion gallons annual of corn based ethanol production by 2015. U.S. existing and under construction capacity is nearly 13.3 billion gallons per year. Nearly all these plants are capable of operating above name plate capacity. Using a conservative estimate of 5% over nameplate capacity indicates that existing (including plants under construction) plants can produce 13.93 billion gallons annually by third quarter 2009. This leaves a gap of ~1 billion gallons needed to meet the RFS. The RFS does not require that biofuels consumed in the U.S. be produced in the U.S. but most of the production will be U.S. based. Only a handful of nations are able to export biofuels to the U.S. without an import duty through various trade agreements and include Canada, Mexico (no ethanol production), Central America and several Caribbean countries.

In order to determine the most likely locations of future ethanol plants, BBI evaluated corn basis, net available corn, corn production, and planned plant lists. The most important factors in selecting an area for an ethanol plant are corn availability and price—after that has been determined the project will then locate specific sites in that area that have the required infrastructure. It is possible that existing plants that are financially secure—for example Poet—may expand capacity. BBI predicts that less than 20 new corn based ethanol plants will be built.

It is useful to evaluate corn basis when approximating the geographical location where new ethanol plants may be built. Corn basis is the difference between the current spot price in a location and the price of the futures contract on the Chicago Board of Trade (CBOT). Maps follow that show the basis in Chicago is not $0.00 as may be expected. This is due to convergence defined as the cash price coming inline with the futures price at expiration. Prior to 2006, convergence at Chicago was within $0.01 per bushel. However, in the past three years, the convergence has averaged $0.13 below the futures. Basis at non-delivery locations is influenced by transportation costs, storage and ownership costs, supply of and demand for storage in the local market, and merchandising risk (margin risk). All of these factors have likely contributed to weaker basis at many non-delivery markets. Solutions to this issue include changing the rule on the CBOT corn contracts to bring better convergence between cash and futures prices, as well as managing the role of speculators within the market.

Plants will look for areas with excess corn supply and low basis impact for building a plant in that location. It is likely that most new ethanol plants will be built by existing companies that have the equity to build new plants rather than the previous model of small co-op or start-up companies.

Prior to the recent boom from biofuels, the corn prices in markets throughout were dependent primarily on the distance from 1.) major rivers (Mississippi, Ohio Rivers) as well as 2.) livestock and poultry markets (Kansas, Texas, Southeastern states). The rivers provide low transportation costs from production areas to export markets such as China. Corn prices were the lowest in areas such as North Dakota, Minnesota, and South Dakota where the costs to deliver product to export markets or livestock feeders was high. The prices in these areas would typically reflect a discount to the major futures market for corn (Chicago Board of Trade) which is defined as negative basis. Areas that were closer to these major corn demand centers benefited from higher prices and typically had a positive basis, or a price that exceeded the CBOT price (Figure 4).

However, the growth in the biofuels sector has created demand for corn within several local markets that were traditionally exporters of corn. Ethanol plants serve as a local captive demand for corn and have bid the prices up to attract an adequate level of feedstock away from other needs. This has consequently shifted the basis in many regions from its historical average (Figure 5). While the northern U.S. still has a negative basis, several regions that have ethanol plants operating nearby have seen corn prices increase in relation to the futures price. Areas such as Minnesota, Iowa, North Dakota and South Dakota have seen the difference between the local price and the futures price shrink (strengthening basis). As long as the corn ethanol industry remains profitable and operating at or near full capacity, it is expected that the traditional basis patterns will be replaced due to the new demands for corn within these regions.

BBI believes that most of the remaining corn based ethanol capacity to be built in the U.S. will continue to be concentrated in the Midwest. BBI predicts that between 10 and 20 new corn based ethanol plants will be built. Plants will be located in the Midwest where basis is more negative and corn is available (red and deep orange areas of the maps on following pages). The red area between Arkansas and Missouri is an area of low basis but does not produce enough corn to support an ethanol plant so plants will not be sited in this area of low basis.

Destination plants are those outside of the Corn Belt but are near large population centers and cattle—both are essential for plant profitability by reducing ethanol transportation costs and natural gas costs (by selling distillers grains wet) to compensate for higher corn costs. It is unlikely that many more destination plants will be built due to unfavorable economic conditions since the corn price is higher due to freight costs typically leading to poor economic performance. It is possible that a destination plant will be located in Arkansas or Mississippi outside of the traditional Corn Belt as both states have turned over cotton acres to corn resulting in a tripling of production in both states and neither has sufficient corn storage leading to lower corn prices.

Figure 4 – U.S. Three Year Average Corn Basis Map (2005-2007)

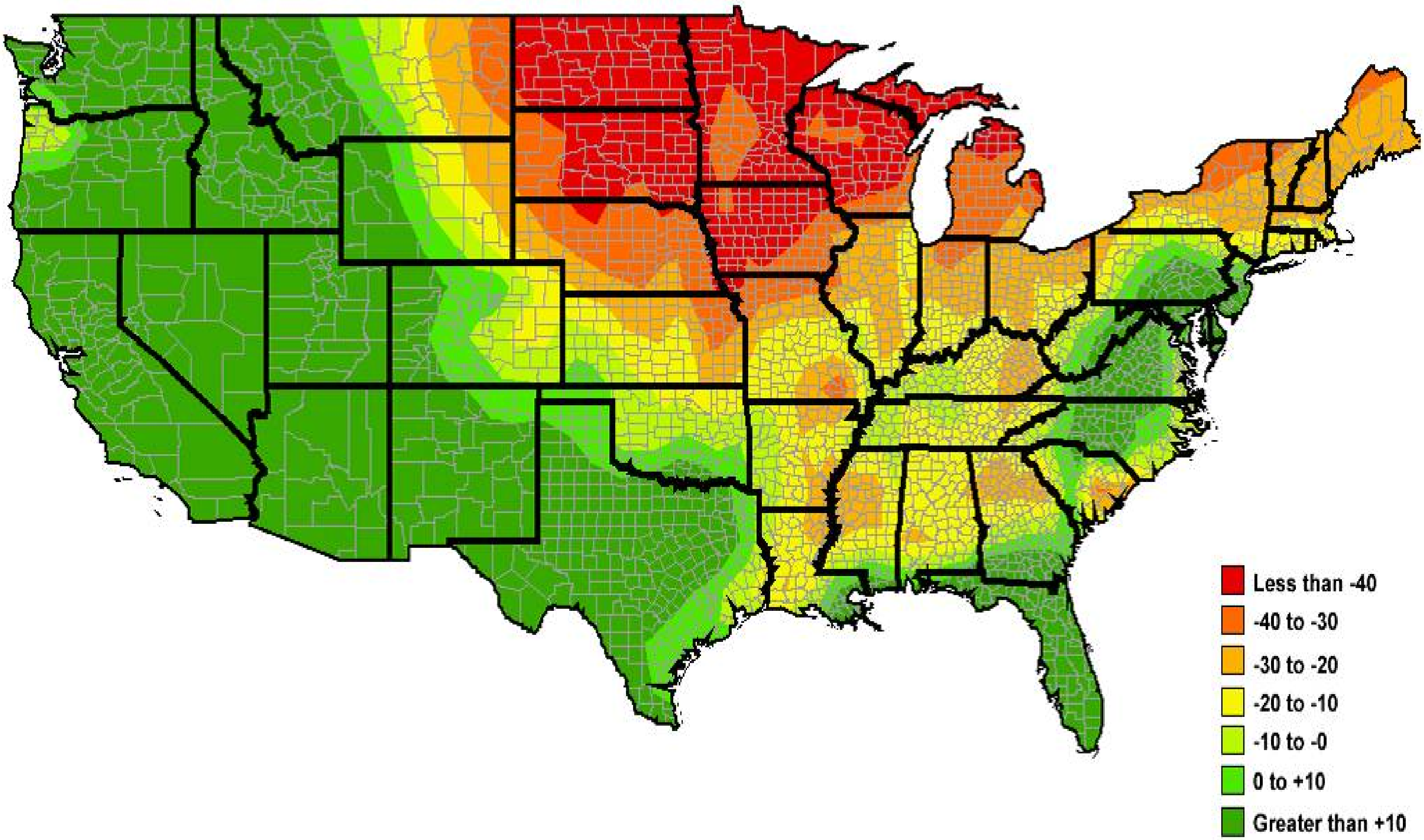
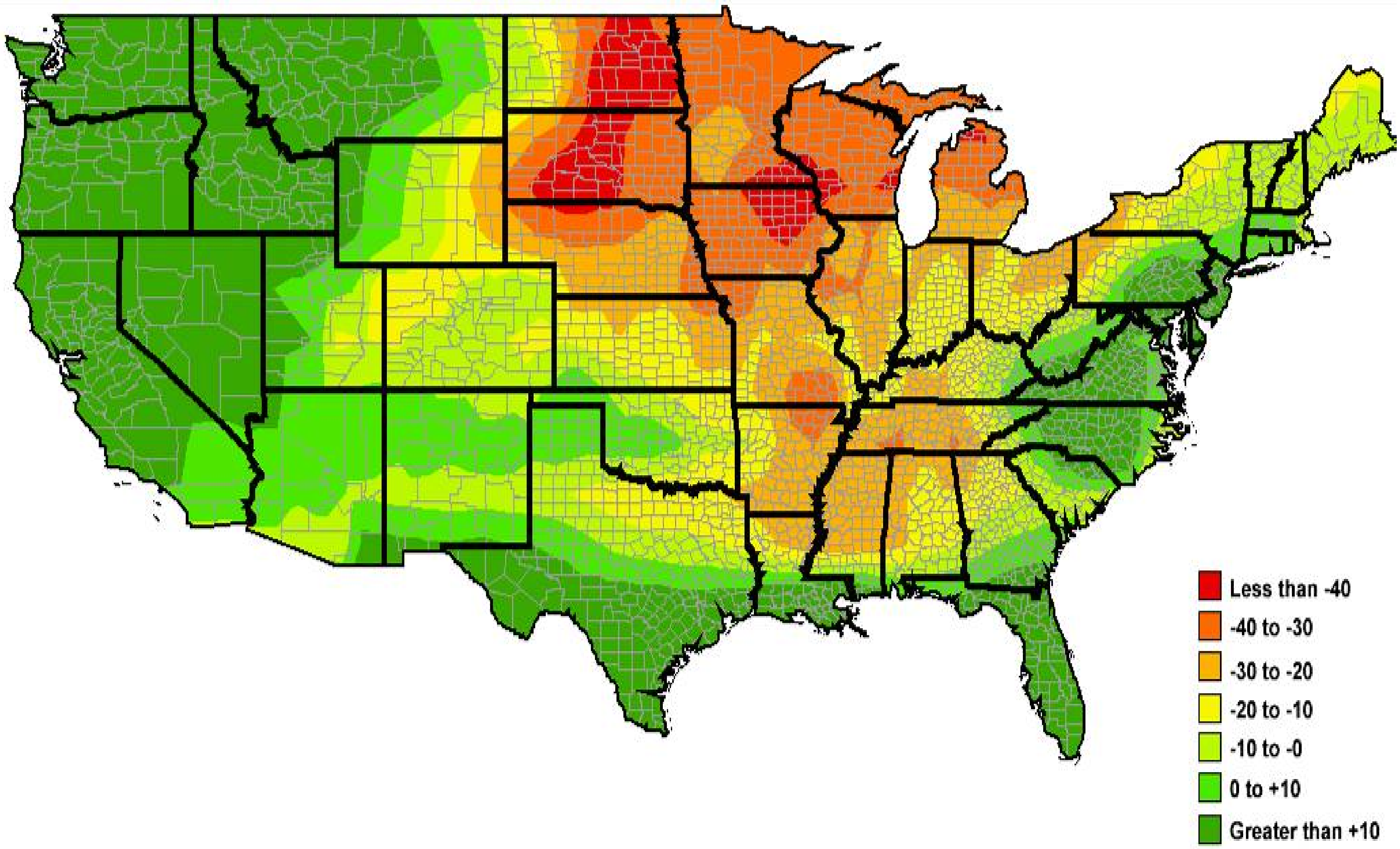


Figure 5 – U.S. One Year Average Corn Basis Map (April 2007-March 2008)

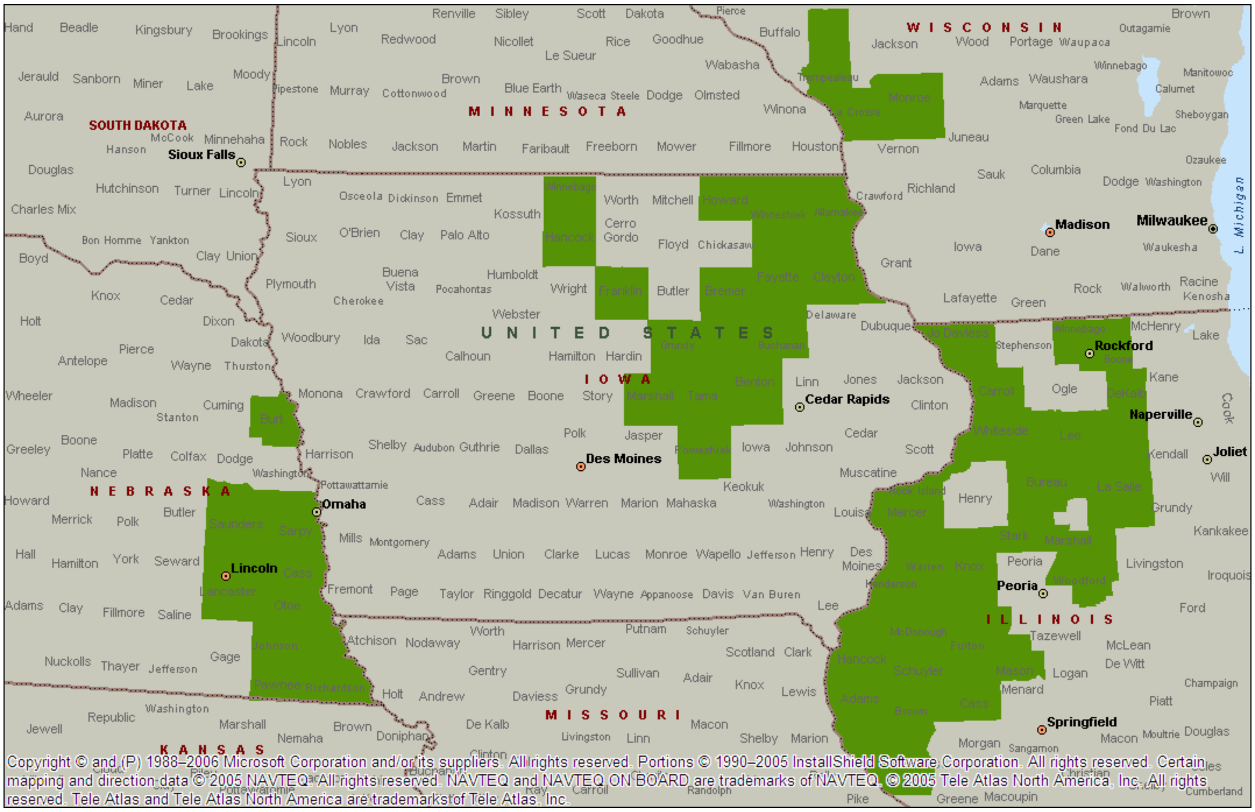


BBI also evaluated available public data on corn production from the USDA and expected net exportable corn for the 2008-09 marketing year (Figure 6). A 50-mmgy and 100-mmgy ethanol plant requires approximately 18 and 36 million bushels respectively. States with the highest likelihood of future corn ethanol plants are Illinois, Iowa and Nebraska due to available excess corn production and pockets of negative basis. Additionally, Illinois had the most planned plants followed by Nebraska. Wisconsin does not have much available corn but there is one planned plant that is viable along the Minnesota border. Figure 7 highlights the counties with strong corn production and negative basis where ethanol plants are likely to be built (counties with existing ethanol plants in these regions were removed).

While Ohio and Indiana have corn available—the price is generally higher and cannot be overcome by lower rail costs for shipping ethanol. Many planned plants in Ohio and Indiana have been canceled. Minnesota has available corn but is difficult for permitting and not viewed as a favorable state for development. North Dakota has two large scale plants under construction that will utilize much of the available corn and there is only one planned plant for the entire state that is unlikely to go forward. South Dakota, Michigan, and Kansas have small, dispersed amounts of corn available with few planned plants and are not viewed as likely areas for future corn ethanol plants.

Figure 6 – Projected Net Exportable Corn 2008-09 Marketing Year

Figure 7 – Projected Regions of Future Corn Ethanol Plants



Canadian Ethanol Plants

The Canadian government is in the process of passing legislation for a federal renewable content of 5% volumetric blend in gasoline by 2010. The bill is currently in the Senate. If the legislation passes, Canadian ethanol demand would be about 508 million gallons annually. Several provinces had previously set mandates for ethanol use but only Saskatchewan (7.5%) and Manitoba (10% in most gasoline) have higher mandates than the new 5% federal mandate. Several provinces provide tax exemptions for production within the province.

There exists a shortfall of 135 million gallons to meet the expected federal mandate. NAFTA allows this mandate to be met with U.S. produced ethanol but it is anticipated that two or three new Canadian plants will be built due to favorable federal assistance. The Canadian government provides funds for ethanol plants should return on investment fall below a certain threshold.

Table 9 – Existing and Under Construction Canadian Ethanol Plants

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Producing					
Collingwood Ethanol LP	Collingwood	ON	Corn	14	N/A
GreenField Ethanol	Tiverton	ON	Corn	7	N/A
GreenField Ethanol	Chatham	ON	Corn	49	N/A
GreenField Ethanol	Varennes	PQ	Corn	32	Jan-07
Husky Energy	Minnedosa	MB	Wheat	34	mid-2007
Husky Energy	Lloydminster	SK	Wheat	34	mid-2006
Husky Energy	Minnedosa	MB	Wheat	3	N/A
NorAmera BioEnergy Corp.	Weyburn	SK	Wheat	7	Nov-05
Permolex	Red Deer	AB	Wheat	11	N/A
Pound-Maker Agventures Ltd.	Lanigan	SK	Wheat	3	N/A
St. Clair Ethanol Plant	Sarnia	ON	Corn	56	mid-2006
Total-Producing				**249**	
Company	**City**	**State**	**Feedstock**	**Capacity (mmgy)**	**Start Date**
GreenField Ethanol	Cardinal	ON	Corn	53	2008 Q2
Integrated Grain Processors Co-op	Aylmer	ON	Corn	11	2008 Q3
Kawartha Ethanol Inc.	Havelock	ON	Corn	21	2009 Q3
Terra Grain Fuels Inc.	Belle Plaine	SK	Wheat	40	2008 Q2
Total-Under Construction				**124**	
TOTAL				**373**	

(Source: Ethanol Producer Magazine)

Corn Dry Mill Ethanol Energy Demand

Electrical Service

The typical electrical energy input requirement is 0.75 kWh per gallon of anhydrous ethanol produced. Most ethanol plants operate above nameplate capacity and by the third year of operation a typical 50 or 100 million gallon per year plant would require 4.7 or 9.4 MW respectively. This equates to annual electricity use of approximately 39.4 million kWh (50-mmgy) or 78.8 million kWh (100-mmgy). The predominant uses of electricity in ethanol plants are for motors in mechanical operations such as corn milling, conveyor belts, pumps and other control devices and systems. Ethanol plants generally select a site with an existing electrical supply (substation with adequate capacity), or one adjacent to a transmission or distribution line. Electricity requirements are summarized in Table 10.

Natural Gas

Most ethanol plants use natural gas to generate process steam and to fire the direct-fired distillers grains dryers. Natural gas use is typically about 34,000 BTUs for each gallon of 200-proof ethanol produced with drying the distillers grains. A 50-mmgy ethanol plant requires about 200,000 cubic feet of natural gas per hour. The plant operates 24 hours a day, about 350 days per year with total demand of 1.6 million MMBTU. The areas of the plant using the majority of natural gas include the distillation/evaporation systems and dryers. Thermal energy requirements are summarized in Table 10.

Natural gas typically delivered directly from a transmission line via a lateral pipeline 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 distribution fees paid to the local gas company if local distribution lines are utilized.

Table 10 – Standard Ethanol Dry-Mill Energy Requirements

Energy Requirements	Nameplate Capacity	
	50-mmgy	100-mmgy
Electricity Use (kWh/gal *anhydrous* ethanol)	0.75	0.75
Electricity Demand (MW)	4.69	9.38
Annual Electricity Use (million kWh/year)	39.375	78.75
Thermal Energy (NG or Steam)*		
Natural Gas		
Natural Gas Use with Drying (BTU/*denatured* gal)	34,000	34,000
Annual Natural Gas Use (MMBTU/year)	1,624,350	3,498,600
Annual Natural Gas Use (MMcf/year)	1,606	3,459
Daily Natural Gas Use	4.4	9.5
Natural Gas Rate (cubic feet per hour)	~200,000	~400,000
Steam		
Steam Use with DDGS drying (BTU/denatured gal)	37,000	37,000
Annual Steam Use (MMBTU/year)	1,767,675	3,807,300
* Inputs are based on ramped up production in 3rd year of operations since most ethanol plants operate above capacity		

Natural gas use is set at 34,000 BTUs per gallon of ethanol with drying of distillers grains for existing capacity and reduced to 32,000 BTUs per gallon for plants under construction. These figures are based on the performance guarantee by the leading designer of ethanol plants in the U.S. For future projects, performance guarantees are expected to drop to 30,000 BTUs per gallon of ethanol with drying—this figure was used for future build out of corn based ethanol plants. BBI used a proprietary model to estimate natural gas use for existing, under construction and future build out. Categories shown in Table 11 include minimum natural gas demand if all distillers grains were sold wet—an impossible scenario per concentrations and quantities of ruminants; maximum natural gas demand if all distillers grains are sold in the dry form and all plants use natural gas—unlikely as many plants economics depend on the ability to sell all or some distillers grains wet and some plant use coal; and finally average which assumes that 30% of distillers grains are sold wet and 70% are sold dry (excludes plants using coal and other alternatives). Table 12 shows estimated natural gas use at ethanol plants in Canada using the same methodology. All plants are assumed to use natural gas.

Actual natural gas use in the ethanol industry is a moving target and depends on the proportion of distillers grains that are sold in the wet form. Ethanol plants are constantly changing the quantity of distillers grains sold in the wet and dry form based largely on demand and time of year—wet distillers grains (DWG) are perishable and generally cannot be stored for more than a week and less if the weather is hot and humid. Drying distillers grains (DDGS) accounts for 1/3 of natural demand use in an ethanol plant.

Table 11 – U.S. Ethanol Industry Estimated Natural Gas Demand

Estimated Natural Gas Use in U.S. Fuel Ethanol Industry	Min[1]	Max[2]	Avg[3]	Min[1]	Max[2]	Avg[3]
	MMBTU/yr			MMcfd		
Existing Ethanol Capacity	191,238,667	333,404,000	258,172,200	518	903	699
Under Construction Ethanol Capacity	73,749,333	110,624,000	99,561,600	200	300	270
Future Build Out[4]	20,000,000	30,000,000	30,000,000	54	81	81
Total	**284,988,000**	**474,028,000**	**387,733,800**	**772**	**1,284**	**1,050**

1-Assumes all DDGS are sold Wet and does not include plants using coal or other alternatives
2-Assumes all DDGS are sold Dry and all plants use natural gas;
3-Assumes DDGS 70% dry and 30% wet and does not include plants using coal or other alternatives
4-Assumes all future ethanol requirements per RFS are produced in the U.S. using natural gas as the thermal energy source

Table 12 – Canadian Ethanol Industry Estimated Natural Gas Demand

Estimated Natural Gas Use in Canadian Fuel Ethanol Industry	Minimum[1]	Maximum[2]	Average[3]	Min[1]	Max[2]	Avg[3]
	MMBTU/yr			MMcfd		
Existing Ethanol Capacity	5,577,600	8,366,400	7,529,760	15	23	20
Under Construction Ethanol Capacity	2,810,667	4,216,000	3,794,400	8	11	10
Future Build Out[4]	3,060,000	4,590,000	4,131,000	8	12	11
Total	**11,448,267**	**17,172,400**	**15,455,160**	**31**	**47**	**42**

1-Assumes all DDGS are sold Wet; 2-Assumes all DDGS are sold Dry; 3-Assumes DDGS 70% dry and 30% wet;
4-assumes mandate of 5% is passed and resulting required renewable fuels are produced in Canada

The future U.S. build-out would require an incremental increase of 714 million kWh. The EIA reported that approximately 20% of electricity was generated by natural gas in 2006—this would equate to natural gas necessary to produce 143 million kWh. Since most natural gas turbines for electrical generation are smaller and for peak demand, BBI assumes a 10MW gas turbine is 35% efficient requiring 9748 BTUs of natural gas per kWh. This would require 1,399,000 MMBTU. INGAA has requested that this information be broken out by region but this request is difficult as DOE does not have a list of gas fired power plants or booster stations.

Current and Future Biodiesel Industry

The emergence of the biodiesel market in the United States is being driven three principal drivers:

- Economic & National Security
- Environmental & Regulatory
- Legislative

Economically, the drivers pushing the growing interest in biodiesel are the rising cost of petroleum diesel, the desire to stimulate rural economic development through value-added agricultural applications, and the desire to reduce our dependence on foreign oil and extend domestic refining capacity for trade balance and national security reasons. **Sharp increases in feedstock prices for biodiesel have made competition with petroleum diesel exceptionally difficult. The feedstocks are typically vegetable oils which have been commanding higher prices as a replacement for transfats in the food industry. The price pressures on vegetable oils are expected to continue in the long term.**

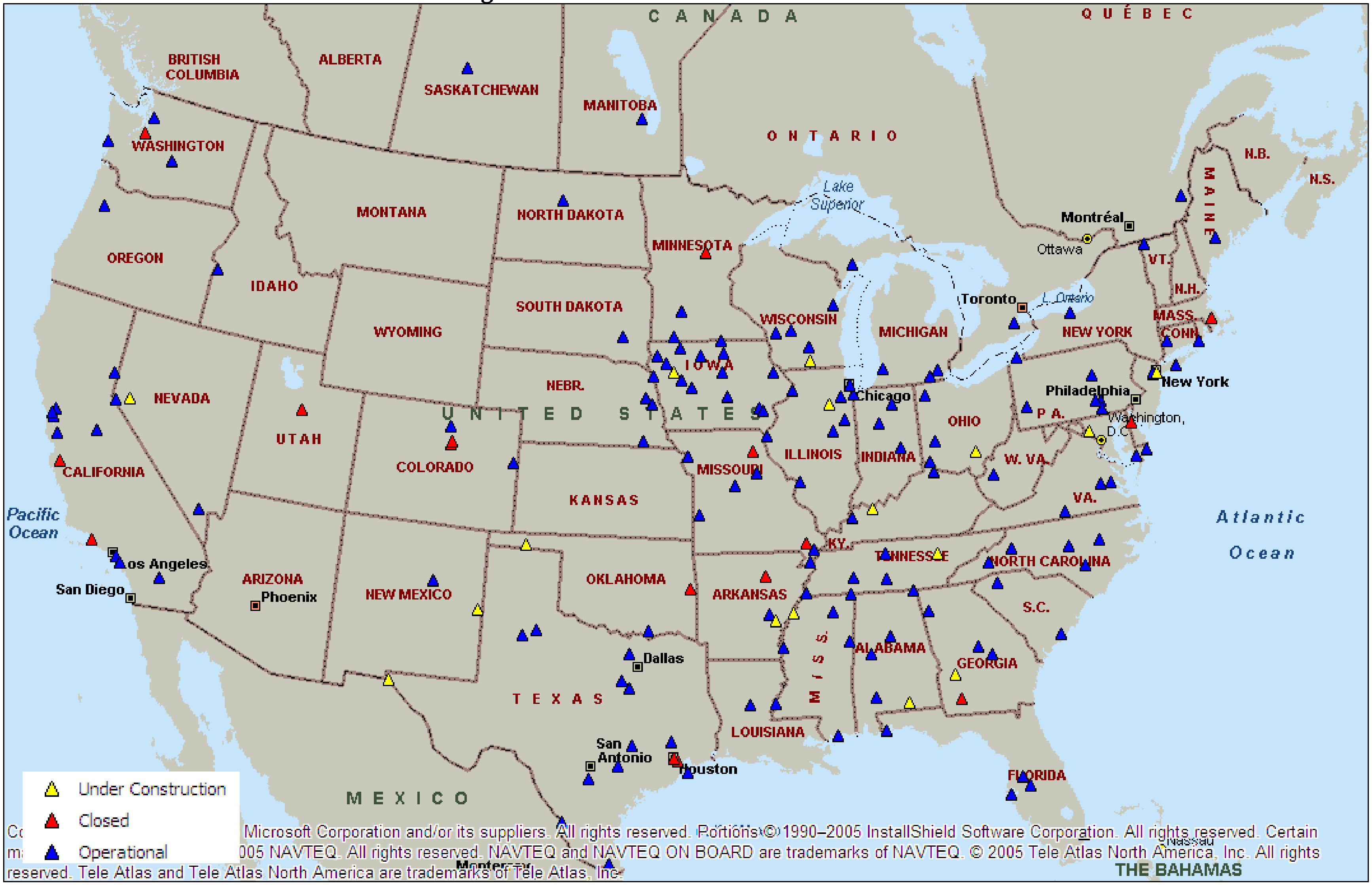
Environmentally, the benefits of biodiesel as an oxygenate and for pollution reduction are significant and well-documented. Biodiesel contains 11% oxygen by weight and reduces the emission of carbon monoxide, unburned hydrocarbons and soot through improved ignition characteristics. In addition, biodiesel meets the low-sulfur diesel requirements established by the Environmental Protection Agency.

The legislative measures driving the biodiesel industry consist of usage mandates and incentive programs. The federal and certain state governments have passed legislative mandates requiring compliance with renewable energy standards and alternative fuel use; these mandates, such as the landmark federal EPAct bill passed in 1992 and the recently updated federal RFS, have encouraged public and private sector fleet operators to utilize biodiesel blends. The EPA is responsible for administering and regulating the RFS program. Fuel blenders are responsible for blending biofuels and also receive the tax credits from the IRS.

To succeed in this industry, tomorrow's biodiesel plant must be the lowest cost producer. The mandated market will only support 1 billion gallons of biodiesel. After that threshold is reached, BBI expects oil refineries to co-process biodiesel feedstocks with petroleum; this will allow them fill the mandate for Other Advanced Biofuels requirements. Oil refineries will likely compete directly with biodiesel producers for feedstocks to fulfill this mandate which would constrain the profitability of biodiesel production via transesterification.

As of April 2008, there are an estimated 110 operating biodiesel facilities in the U.S. with a combined stated nameplate capacity of ~1.5 billion gallons per year (a full list of plants is available in Appendix B). There are an additional 25 plants that are idle presumably due to high feedstocks costs. Over the past year, 17 plants have closed taking 177 million gallons of capacity offline. Biodiesel facilities are widely distributed across the U.S. with a higher concentration in the Midwest (Figure 8). There are 17 plants under construction with a combined capacity of 364 million gallons. Those plants are expected to come online within the next 12 months, bringing the total industry production capacity to 2.1 billion gallons by the end of 2008.

Figure 8 – North America Biodiesel Plants

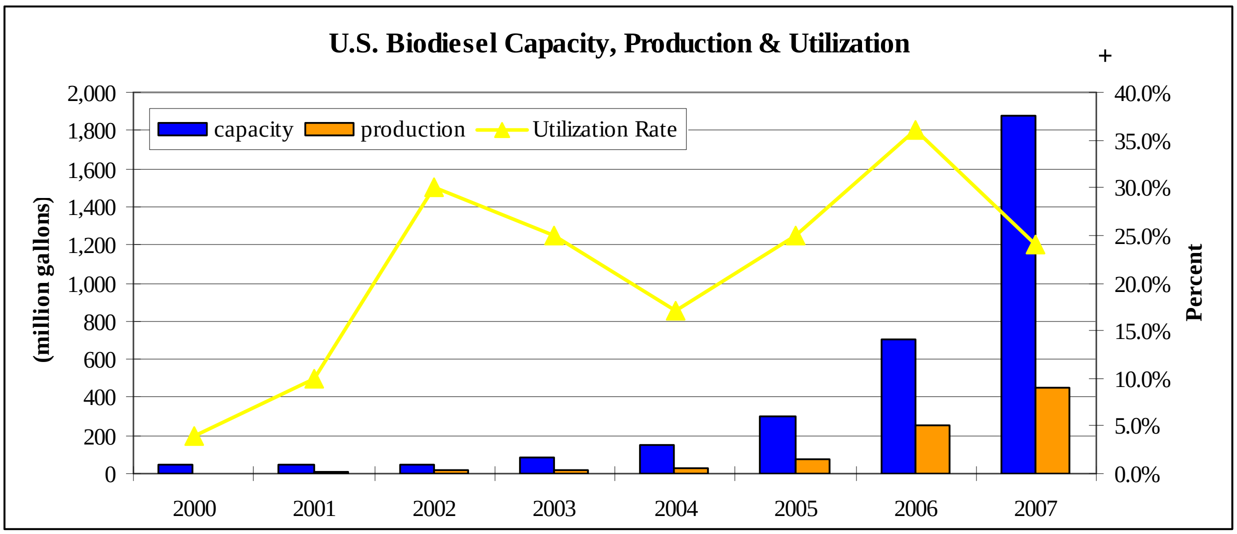


(Source: Biodiesel Magazine)

While the US biodiesel industry has added over one billion gallons of production capacity in the past year, demand has not kept pace. Biodiesel production for 2007 is estimated at 450 million gallons—far lower than installed capacity (Figure 9). At least half of U.S. biodiesel production in 2007 was exported to EU nations. The utilization rate dropped considerably in 2007 presumably due to high feedstock costs. Biodiesel production plants are built with a theoretical nameplate production capacity which often does not equal the plant's real-world production rate. Nonetheless, the industry has struggled with a low utilization level, even after accounting for the construction in progress each year. An April 2008 survey conducted by Biodiesel Magazine found that only seven plants are operating at 100% of capacity.

Producers have managed through these periods of economic turmoil in various ways. Many smaller, less efficient producers have shut down completely while some larger facilities have operated their plants at a portion of full capacity if they have hedged feedstock costs.

Figure 9 – U.S. Biodiesel Capacity, Production and Utilization Rate, 2000-2007



(Source: National Biodiesel Board, Iowa State University)

The RFS requires one billion gallons of biodiesel and existing capacity exceeds this mandate. The conditions for biodiesel are challenging as illustrated by the utilization rate. While it is likely that a few new traditional transesterification plants will be built, it is just as likely that a similar number of plants will cease operations permanently due to feedstock costs and supplies. Plants likely to stay in business are those that buy whole soybeans for the oil as these plants can chose to make biodiesel or simply sell virgin soybean oil depending on market conditions. It is expected that renewable diesel (discussed later in this chapter) and other alternatives will supplant the existing biodiesel industry.

Canadian Biodiesel Plants

The Government of Canada is considering legislation requiring 2% renewable content in diesel by 2012 but it has not yet passed into law. A 2% blend would require approximately 86 million gallons. Only British Columbia has passed a law requiring a 5% biodiesel volumetric blend which requires a bit over 22 million gallons annually. British Columbia, Alberta, Manitoba and Ontario each offer some type of production incentive or tax exemption for biodiesel production or use (Table 13).

There are four existing biodiesel plants in Canada using a variety of feedstocks with total installed capacity of 26 million gallons (Table 14). There are no plants under construction, however, passage of a nationwide mandate of 2% may encourage projects currently on-hold to move forward. There are several planned plants in various stages of development but most are stalled due to high feedstock costs and tight financial markets and stringent lending rules.

Table 13 – Canadian Biodiesel Mandates and Incentives

Province	Renewable Fuel Mandate	Biodiesel Requirement gallons per year	Tax Exemptions/Credits/Incentives
British Columbia	5% biodiesel blend by 2010	22,205,579	Road Tax Exemption: $0.09/L for biodiesel (exemption for ethanol and biodiesel portion of a blend).
Alberta	No Mandates		Direct Producer Incentive for Renewable Fuels: $0.14/L, 4-years
Manitoba	No Mandates		Provincial Fuel Tax Credit: up to $0.115/L for Biodiesel produced in MB.
Ontario	No Mandates		$0.143/L exemption for Biodiesel.
Federal	No Mandates		Fuel Excise Tax exemption for portion of biodiesel blended

(Source: Canadian Statistics)

Table 14 – Canadian Biodiesel Plants

Plant Name	City	State	Feedstock	Capacity (mmgy)	Start Date
Bifrost Bio-Blends Ltd.	Arborg	MB	canola oil	1	N/A
Biox Corp.	Hamilton	ON	tallow	16	N/A
Milligan Bio-Tech Inc.	Saskatoon	SK	multi-feedstock	0.26	N/A
Rothsay Biodiesel	Ville Sainte Catherine	Quebec	animal fats/yellow grease	9	Nov-05
Total				**26**	

(Source: Biodiesel Magazine)

Biodiesel Energy Demand

Natural Gas

Biodiesel processing uses natural gas to generate process steam and to power the evaporation and distillation operations necessary to produce biodiesel. The natural gas requirement is typically ~5,150 BTUs per gallon of methyl ester produced but this figure can vary for different process designs. Biodiesel plants typically locate by sites adjacent to transmission lines. Plants that buy oilseeds and extract oil use nearly twice as much thermal energy (about 9,350 BTUs per gallon).

Electrical Service

The electricity requirement for a biodiesel plant that buys vegetable oil for production is very low at 0.08 kWh/gallon. The process is fairly simple and electricity is primarily used in pumps, controls and lighting systems. The electricity load is considerable higher when a plant purchases oilseeds and must crush or otherwise extract the oil, requiring 1.5 kWh per gallon produced. Table 15 details both electric and natural gas demands for two types of biodiesel plants.

Table 15 – Biodiesel Plant Energy Requirements

Energy Requirements	Vegetable Oil	Vegetable Oil with Crusher
Electricity		
Electricity Use (kWh/gal)	0.08	1.5
Natural Gas		
Natural Gas Use (BTU/gal)	5,150	9,350

Unfortunately, the biodiesel industry is not as transparent as the ethanol industry. There are many different plant designs and it is expected that both electric and thermal energy use varies widely on a per gallon basis. The break out of biodiesel plants that have crushers or simply buy straight vegetable oils is unknown and unavailable. BBI has assumed that 25% of existing and under construction capacity crush their feedstocks and 75% buy some type of oil feedstock. Table 17 shows two scenarios of natural gas use in the biodiesel industry—using 25% of capacity and 100% of capacity. Based on a recent survey soon to be published by Biodiesel Magazine—plants are operating at 25% capacity on average and some plants are currently idle. Capacity utilization for Canada is not known and unlikely to be reported due to the small number of plants.

Table 16 – Biodiesel Industry Estimated Natural Gas Demand

Estimated Natural Gas Use in Biodiesel Industry	25% Utilization	100% Utilization	25% Utilization	100% Utilization
	MMBTU/yr		**MMcfd**	
Existing Biodiesel Capacity[1]	2,325,000	8,598,750	6	23
Under Construction Biodiesel Capacity[1]	507,780	2,031,120	1	6
Canadian Biodiesel Capacity[2]	120,510	120,510	0.3	0.3
Total	**2,953,290**	**10,750,380**	**7.3**	**29.3**
1-Assumes 75% of capacity uses straight vegetable oil and 25% crush feedstock to extract oil				
2-assumes all Canadian biodiesel plants purchase oil feedstocks and none crush; assumes all capacity is in use				

Future Build-Out of the Advanced Biofuels Industry

This section reviews the advanced biofuels requirement of the RFS with a review of technologies and energy requirements associated with second generation biofuels. It is extremely important to note that in the case of cellulosic ethanol nearly all plants will seek to generate energy from the process for both electric and thermal energy. These plants will use natural gas and grid electricity for start-up, maintenance and back-up purposes only.

The RFS requires cellulosic fuels starting with 100 million gallons in 2010 increasing to 16 billion gallons by 2022. These plants must achieve a 60% reduction in Green House Gas Emissions (GHG) against a baseline ethanol plant to qualify under this category—the baseline has yet to be established by the EPA. These plants will generate their own energy not only to reduce operating costs but to also meet the GHG reductions. The undifferentiated category requires 100 million gallons by 2009 and four billion gallons by 2022—this category includes fuels such as renewable diesel or ethanol from molasses, sugarcane, sugar beets or other non-traditional feedstocks and any other advanced biofuels that do not fall into the other categories of the RFS.

Geographic Locations of Future Plants

Advanced biofuels will largely be built near to their selected feedstock as wood chips, corn stover and similar are bulky and therefore cannot be transported long distances economically. The most likely candidates for crop residues are corn stover (leaves and stalks) and wheat straw. It is possible that advanced biofuels plants using agricultural residues will be smaller additions to existing ethanol plants. For example, Poet—a leading ethanol producer plans to build smaller cellulosic ethanol plants at its larger corn based ethanol plants.

The National Renewable Energy Laboratory (NREL) conducted a biomass resource assessment for the U.S. The quantified feedstocks included: agricultural residues (crops and animal manure), wood residues (forests, mills and urban), municipal wastes (methane from landfills and wastewater treatment facilities) and dedicated energy crops (to be grown on Conservation Reserve Program lands and Abandoned Mine lands). Most, but not all, of these feedstocks are suitable for biofuels production as NREL was establishing biomass resources for all energy projects—not just biofuels. The map shown in Figure 10 identifies areas of biomass feedstock concentrations.

Figure 11 shows several maps to identify areas where advanced biofuels plants may be built. Wheat straw is a bulk non-dense residue left over from harvesting straw. The deepest shades of orange identify states that are likely candidates for wheat straw based cellulosic ethanol plants. Similarly, the areas of dark green in the Corn Belt identify regions likely to build corn stover based cellulosic ethanol plants. Federal regulation makes sugarcane or sugar beet based ethanol unlikely but there is a possibility that the molasses by-product could be used as an ethanol feedstock. The highest concentration of sugar beet molasses is located in the Red River Valley between North Dakota and Minnesota. Sugarcane production is concentrated in southern Florida with over 80% of the production in the area surrounding Lake Okeechobee. Louisiana also produces sugarcane. Any biofuels plant using sugarcane or sugarcane molasses would use bagasse for thermal energy generation.

Wood is expected to be a significant feedstock for cellulosic ethanol. Figure 11 shows pulp mills and this would be a likely source of wood wastes but also indicates where wood is available. Several cellulosic firms are targeting the southeast due to the proximity to large scale private forests that can guarantee long term supply of wood chips or other similar wood feedstock. Many western forests are on federal land and there is only one example of a long term supply agreement. Until the U.S. Forest Service provides long term supply contracts, wood based biofuels plants will not locate in these areas. MSW based biofuels plants will locate near urban areas.

Dedicated energy crops are grown exclusively for energy related uses. Dedicated crops for biofuels production include switchgrass, cottonwoods, and hybrid willows. It is expected that energy crops will be grown on marginal lands not suitable for row crop production. The area available for growing these crops is extremely limited in the U.S.

Figure 10 – NREL Biomass Resources by County

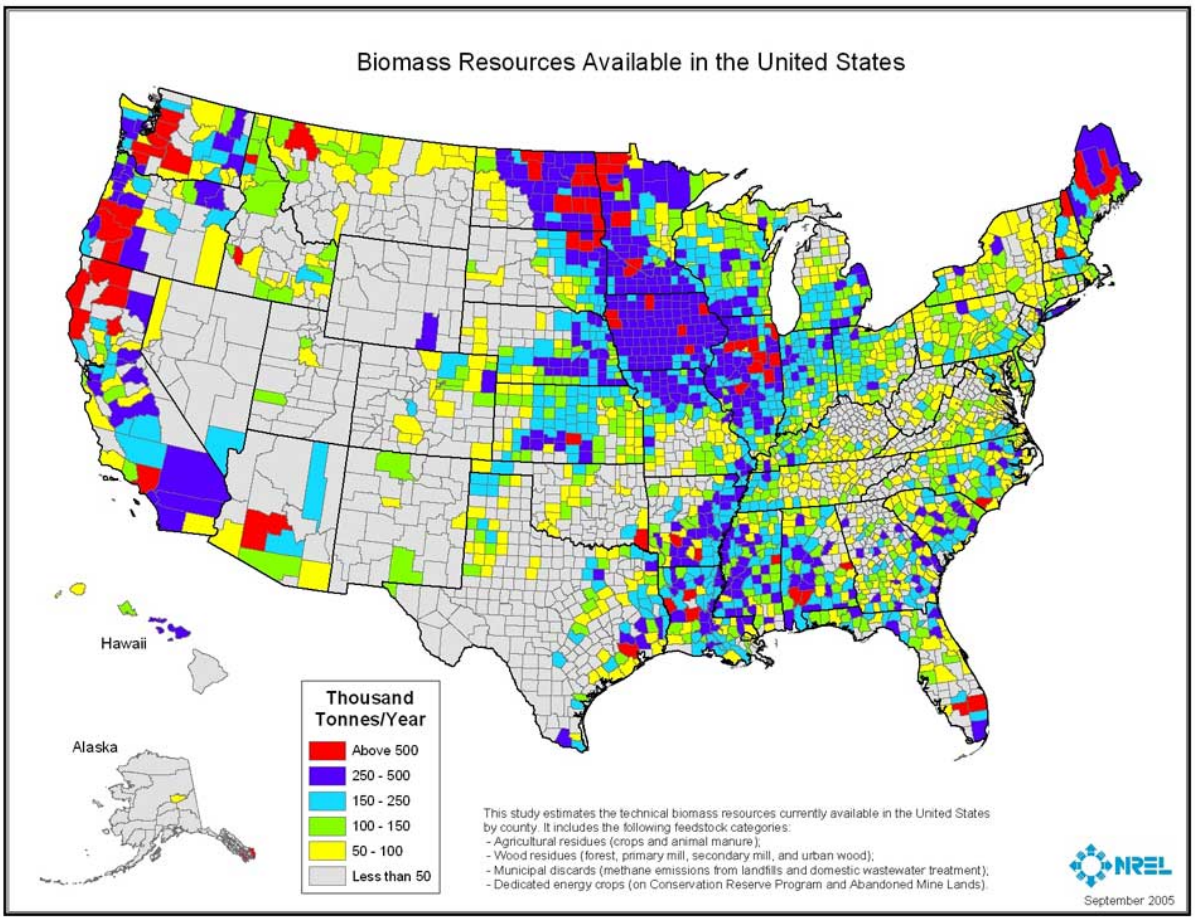
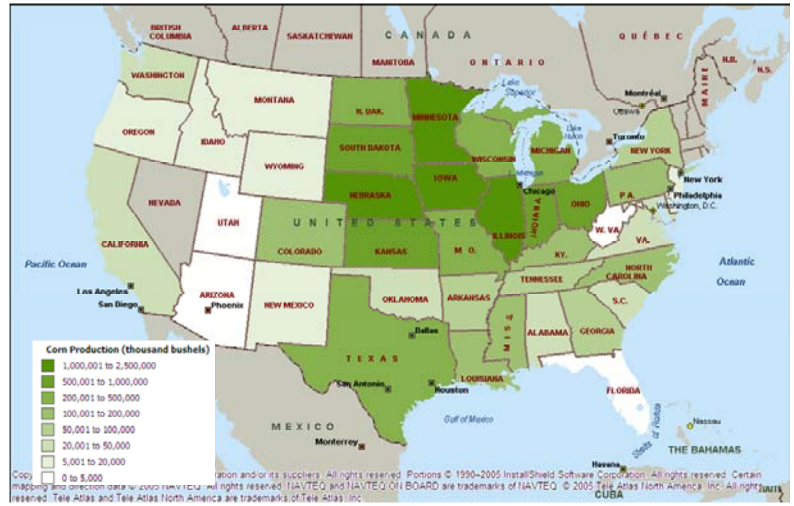


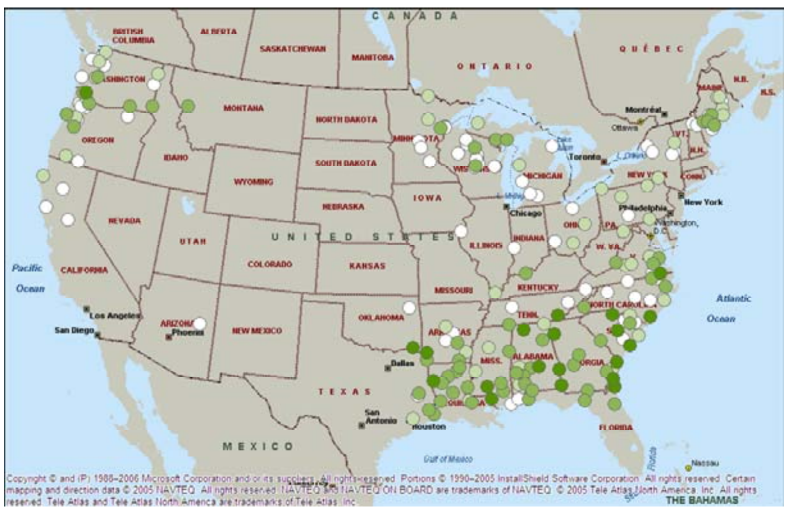
Figure 11 – U.S. Cellulosic Feedstock Supply Maps

Wheat Straw Map

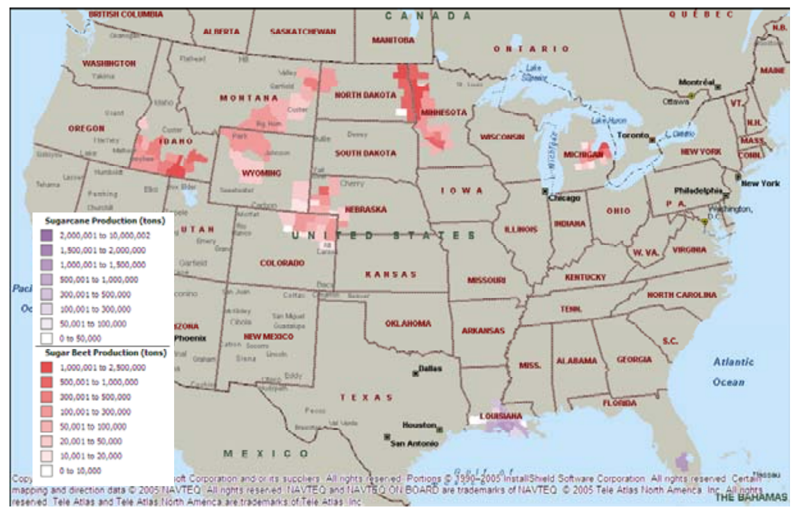
Corn Stover Map



U.S. Pulp Mill Map



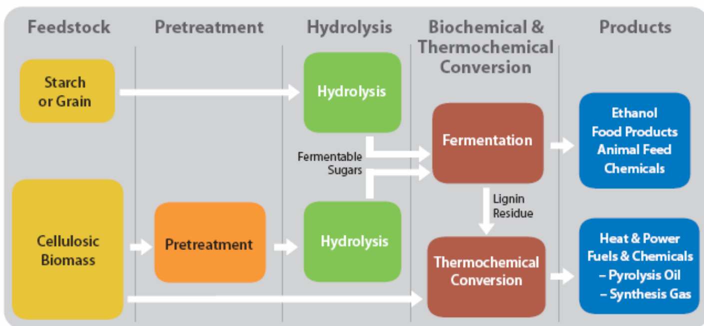
Sugar Beet and Sugarcane Map



Overview of Cellulosic Ethanol Technologies

The federal government is promoting and requiring that biofuels utilize non-food feedstocks at an increasing rate. The U.S. Department of Energy suggests that there are enough cellulosic feedstocks to produce 60 billion gallons of ethanol annually. There are two predominant pathways for cellulosic ethanol—biochemical (fermentation) and thermochemical (Figure 12). There is also a third method—a hybrid of sorts using gasification to produce syngas and using bacteria to ferment syngas into ethanol. Traditionally, much of the research focused on biochemical conversion. Detailed descriptions of these technical pathways are available in Appendix G.

Figure 12 – Illustration of Integrated Ethanol Biorefinery



(Courtesy of NREL)

Cellulosic Ethanol Plants Status

There are several bench scale and demonstration scale cellulosic ethanol plants currently operating. Table 17 shows existing and planned cellulosic ethanol plants. In some cases the feedstock and/or capacity is not disclosed. As plants enter construction phases more information is expected to be available. **These plants intend to produce their own process steam and will need either natural gas or propane only for start-up and during times of biomass boiler maintenance.** As evidenced in these tables, the feedstocks and geographic locations are wide ranging unlike corn based ethanol plants that are largely located in the Midwest.

Table 17 – Existing and Planned Cellulosic Ethanol Plants

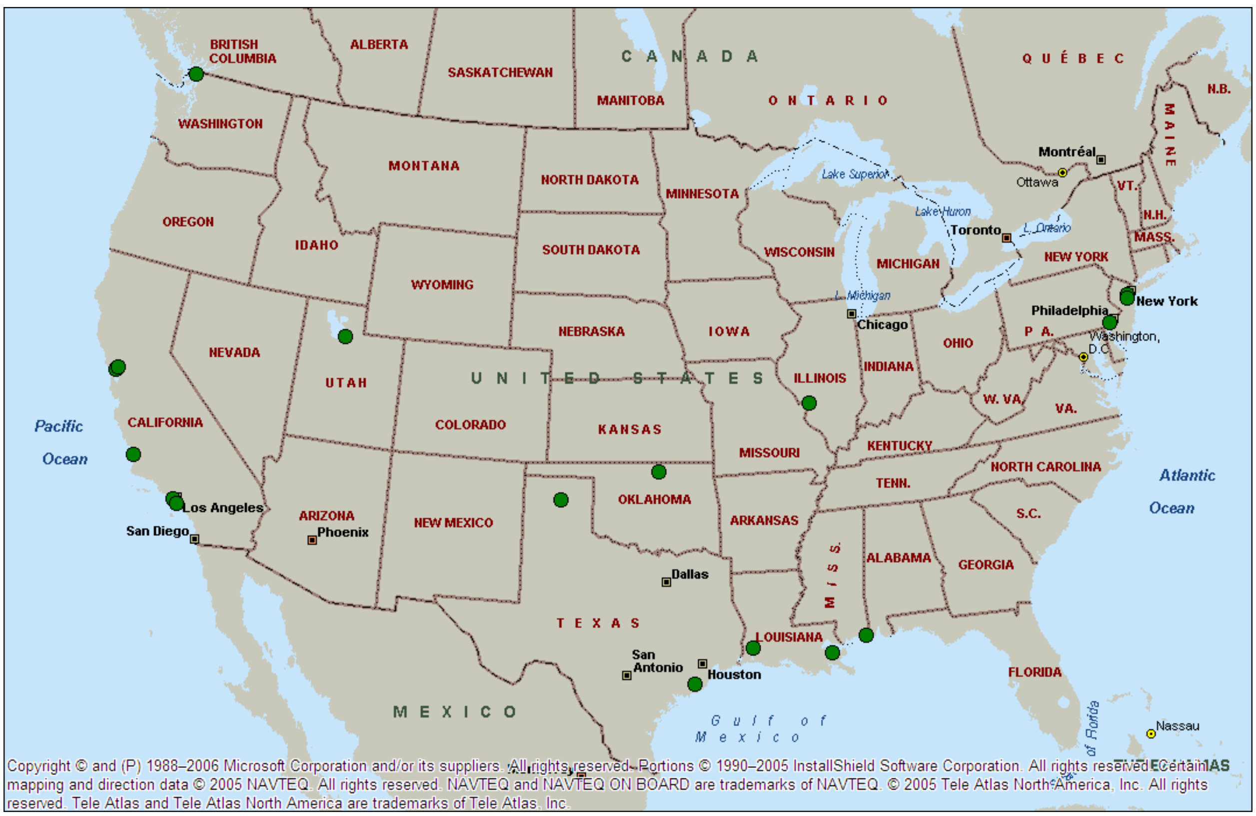
Company Name	Location	Technology	Functioning Plant	Size (mmgy)	Feed Stock
Abengoa	Chesterfield, Missouri	BcyL	NO	11.4	corn stover, wheat straw, milo stubble, switchgrass
ADM	Illinois		NO		
Alico	Florida	BRI process	NO	14	MSW
American Process, Inc.	Wisconsin	AVAP (American Value Added Pulping)	NO	20	waste pulp liquor
Bioengineering Resources Inc	Arkansas	BRI Process patented Micro-organism	YES	Bench Scale	Any carbon rich mass
Bluefire	Irving, CA	Arkenol	NO	19	sorted green waste and wood waste
Celunol	Louisiana	GMO E. Coli	YES	0.05	wood chips
Colusa	California	Silicate separation	NO		rice hulls
Diversa	California	Enzyme production DirectEvolution®	NO		
DuPont	unknown	Zymomonas mobilis	NO		wheat straw
Dyadic	Florida	Enzyme prodution	YES	1.3	wheat straw
Genahol	Ohio	Turn-key units	YES	0.8	MSW
Globex	unknown	supercritical fluid (SCF) technology	NO		woodchips
Green Star Products Inc	California	waterless continuous flow process reator	NO		
Iogen Corp	Ottawa Canada	cellulose conversion plants	YES	0.77	wheat straw, barley straw,
Iogen Corp	Shelley, Idaho	cellulose conversion plants	NO	18	wheat straw, barley straw, corn stover, switchgrass, and rice straw
KL Design	Upton, Wyoming	enzymatic fermentation	YES	1.5	wood wastes
Lignol Energy Corporation	Canada	enzymatic saccharification and fermentation	NO		woodchips
Mascoma	Rome, NY	thermophilic Simultaneous Saccarification and Fermentation (tSSF)	NO		paper sludge, wood chips, switch grass and corn stalks
Nova Fuels	California	Novahol	NO		
Poet	South Dakota	LIBERTY	NO	50	corn fiber and stalks
Poet	Sioux Falls, SD	LIBERTY	NO		corn fiber and stalks
Pure Energy	New Jersey	Acid Hydrolysis	YES		unknown
Range Fuels Inc.	Colorado	2 step Thermo-chemical process	YES	10	woodchips
SunOpta	Ontario	high pressure anhydrous ammonia.	YES	Bench Scale	woodchips
Verenium	Jennings, LA	biochemical	YES	1.4	bagasse
Xethanol	New York	biochemical	NO	35	orange peels

Renewable Diesel

Renewable diesel is a nonester renewable fuel typically made from poultry fats, poultry wastes, municipal solid wastes, or wastewater sludge and oil. The process is termed thermal depolymerization. The feedstock is first reduced in size in some type of pretreatment process. The feedstock is then mixed with water in a reactor with temperatures around 250 C and pressure of 600 psi. The pressure is released to drive off the water resulting in a slurry of crude long chain hydrocarbons and solid minerals which are separated. A second reactor uses heat to reduce the chain size of the hydrocarbons which are then distilled.

NREL and Chevron started five year collaboration for research and development on renewable diesel in 2006. ConocoPhillips and Tyson entered into a long term feedstock supply contract. The locations of Chevron and ConocoPhillips refineries are shown in Figure 13. Based on the animal fat feedstock, the most likely locations for renewable diesel facilities located with existing refineries are in Texas, Louisiana and Mississippi.

Figure 13 – Chevron and ConocoPhillips Refinery Locations



(Source: Google Earth)

Cellulosic and Renewable Diesel Energy Demand

There are no commercial scale cellulosic ethanol plants in the United States. Several companies are working on setting up large demonstration scale projects including Range Fuels in Georgia. Until facilities are operational it is impossible to know the exact energy requirements for a particular technology. The figures provided in the following tables are based on research performed at the Department of Energy's National Renewable Energy Laboratory (NREL) and are the best available estimates for energy use for cellulosic plants using either the biochemical or thermochemical pathways. Although most cellulosic ethanol plants will attempt to meet all energy needs internally, there will likely be circumstances where the additional power or heat is needed from the grid in addition to back up power to account for power system maintenance (possibility of 10% of thermal energy demand from back up sources such as natural gas or propane).

Power and heat used in the biochemical pathway will depend upon the pre-treatment process used. For example, steam explosion will require more energy than acid hydrolysis. Energy loads will also depend on how the cellulose and hemicellulose streams flow through the process. Plants using the biochemical pathway will use energy rich lignin (separated out from the cellulose and hemicellulose in the feedstock) for power and heat generation. The range of expected energy demand for ethanol produced biochemically from biomass is detailed in Table 18.

NREL used an indirect steam gasification system as the chosen thermochemical pathway due to previous R&D in this area for production of methanol and hydrogen from biomass. There are also partial oxidation gasifiers which are directly heated but energy requirements are not available at this time. This process assumes an ethanol yield of 80 gallons per a dry ton of biomass with the assumption that 28% of the resulting syngas is diverted to a steam and power generation unit. BBI believes the thermal energy estimate of 9900 Btu/gallon may be underestimated.

The thermal energy load for renewable diesel is considerable at 122,000 BTU per gallon. A large part of this load is due to superheating of water for mixture with the feedstock (likely poultry wastes). Energy use for renewable diesel was provided by UOP, a process technology design firm with experience designing renewable diesel plants. Renewable diesel is a nonester renewable fuel typically made from poultry fats, poultry wastes, municipal solid wastes, or wastewater sludge and oil. Both Chevron and ConocoPhillips are developing renewable diesel projects at their existing oil refineries. The process involves using superheated water and pressure to produce biodiesel. The thermal energy requirements are significant at 122,000 BTU per gallon. The electric energy requirement is estimated at 0.29 kWh per gallon of biodiesel produced.

Table 18 shows the electricity and thermal energy demands for various advanced biofuels. The annual energy use estimates assume that all cellulosic requirements per the RFS (16 billion gallons) are met entirely by either the biochemical or the thermochemical pathway. This is for illustration purposes only as the RFS requirement will be met by a variety of technologies that have differing energy inputs. There is also the 4 billion gallon requirement of other or undifferentiated biofuels that may include renewable diesel or can be made up from existing biodiesel capacity. There may be a few plants using alternative feedstocks such as sweet sorghum or molasses—these plants will likely be small in scale and the energy requirements and how this RFS category will be met are not clear. For the purposes of this study, BBI assumes that half of the undifferentiated advanced biofuels requirement is met by renewable diesel.

Table 18 – Estimated Cellulosic Ethanol and Renewable Diesel Energy Requirements

Energy Requirements	Biochemical[1]	Thermochemical[2]	Renewable Diesel[3]
Electricity*			
Electricity Use (kWh/gal)	1.4-1.8	1.5	0.29
Maximum Annual Electricity Use (billion kWh/year)	27.43	22.86	0.55
Thermal Energy			
Thermal Energy Use (BTU/gal)	40,000-80,000	9900	122,000
Maximum Annual Thermal Energy Use (MMBTU/year)	1,152,000,000	142,560,000	219,600,000
1-For Annual Energy Use assumes all RFS Cellulosic requirement (16 BG) is met by biochemical conversion-also assumes the 1.8 kWh and 80,000 kWh per gallon; 2-For Annual Energy Use assumes all RFS Cellulosic requirement (16 BG) is met by biochemical conversion 3-For Annual Energy Use assumes half of RFS Undifferentiated Advanced Biofuels Requirement (4 BG total) is met by Renewable Diesel Production			

(Source: cellulosic estimates-NREL/ Renewable Diesel requirements-UOP)

All cellulosic plants will require some form of back-up thermal energy for downtime, maintenance and firing up biomass boilers. The most likely candidates are natural gas and propane—likely for plants located far from natural gas lines. It is expected that up to 10% of the thermal energy requirement for cellulosic plants will come from fossil fuel based energy—either natural gas purchased on the open market where available or propane.

Table 19 – Potential Natural Gas Demand at Cellulosic Biofuels Plants

Natural Gas Potential Demand at Cellulosic Plants	Min[1]	Max[2]	Min[1]	Max[2]
	MMBTU/yr		MMcfd	
Potential natural gas back-up use at cellulosic biofuels plants	14,256,000	115,200,000	39	312
1-Assumes all cellulosic RFS requirement uses thermochemical technology 2-Assumes all cellulosic RFS requirement uses biochemical technology with steam explosion pretreatment				

Impact of Selling Wet or Dried Distillers Grains with Solubles

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 distillers wet grains (DWG) and "thin stillage." The thin stillage is subsequently concentrated via evaporation and the "heavy syrup" is added back to the DWG. This material can then dried to 10% moisture, producing distillers dried 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 the following table.

Table 20 – 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 distiller's grains. Poultry and swine require the distillers grains 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.

Distillers Wet Grains

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 distillers grains 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 grains (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 grains 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. The plant must insure that it maximizes the price of its byproducts and should not sell DWG for less than the equivalent price at which it can sell DDGS plus drying costs.

Impact on Natural Gas Use

Historically, distillers grains have been sold to the cattle industry but that situation is changing and other livestock—notably swine and poultry are increasingly using distillers grains as corn and soybean prices rise. Distillers Grains sold to swine or poultry industries must be in the dried form thus requiring between 32,000 and 34,000 Btu per gallon of ethanol produced. If a plant is selling all of its distillers grains in the wet form (all plants in Texas) then the natural gas requirement is reduced to ~22,000 Btu per gallon of ethanol. It is estimated that approximately 70% of distillers grains are sold in the dry form and that is reflected in the estimated average industry natural gas usage in Table 11 in Corn Dry Mill Ethanol Energy Demand section.

Opportunities for selling distillers grains in the wet form are decreasing as the market is largely tapped in the Midwest, however, new ethanol plants will usually be able to sell some portion to area cattle.

Export markets for DDGS are growing considerably and plants positioned near to Chicago or rivers may chose to sell more of their distillers grains in the dry form if they are able to obtain a higher price for their product.

It is important to note that ethanol plants are constantly changing the proportion of distillers grains that are sold in the wet or dry form dependent on market demand and time of year. Plants located in Texas, California and Colorado sell all DWG as their economics depend on it to compensate for the high cost of delivering corn to corn-deficit areas.

Biofuels Plants Energy Efficiency

Existing ethanol plants are considered efficient with the exception of the distillation and evaporation systems. There are heat recovery steam generators (HRSG) collecting waste heat from boilers and dryers. Excess heat from the dryer is supplied to the thermal oxidizer. ICM—the leading U.S. ethanol plant designer stated that additional improvements will include removing the hydro heaters in the cook tubes but the focus of this is more to reduce the recharge time of enzymes than for energy savings.

Raw starch hydrolysis, or “cold cook enzymes”, eliminates the alpha-amylase and glucoamylase enzymes and uses a new enzyme in the starch conversion process eliminating the need for heat for liquefaction. Since this steam is typically injected into the mash, this practice also reduces water use. Thermal energy savings are estimated at 10% to 15%. This process increases the alcohol content coming out of the fermentation process from the typical value of 10% to values as high as 20%. Additional benefits include less time to complete the fermentation process, less cooling water use during fermentation, and less energy in the distillation process. This process has been incorporated in approximately 17 plants across the U.S. and since the enzymes are produced by two separate companies the costs are more competitive.

The distillation and evaporation area of an ethanol plant uses the largest amount of thermal energy and is considered the area where the most energy efficiency gains can be achieved. Vaperma has developed membrane distillation system that decreases the number of distillation columns from three to one and does away with molecular sieve dehydration. Thermal energy savings are estimated at 40% but electrical use will increase with the use of vacuums for the membranes. This technology is currently being demonstrated on a commercial scale at the Greenfield Ethanol plant in Chatham in Ontario, Canada.

There is a trend towards fractionation, a process that separates corn into its components of germ, bran, endosperm and carp. This process increases electric energy use but decreases thermal energy load particularly for drying since the bran has previously been removed. The expected performance guarantee is 27,000 BTU/gallon with drying distillers grains. There are four existing dry mill ethanol plants with fractionation but several existing and planned plants are considering adding fractionation on the front-end of the plant.

Many ethanol plants are considering supplementing natural gas with syrup (a by-product typically mixed with the distillers grains) by adding a biomass boiler. Use of syrup can offset natural gas use by 60%. This will be discussed in Chapter V.

Biofuels Industry Natural Gas Demand Summary

In December 2007, the U.S. Congress passed an updated RFS requiring 36 billion gallons of biofuels. The RFS specifically requires 15 billion gallons of starch based ethanol (corn), 16 billion gallons of advanced cellulosic biofuels, one billion gallons of biodiesel and 4 billion gallons of other or undifferentiated biofuels (renewable diesel, molasses ethanol, etc.).

Corn-to-Ethanol Industry

There are 168 existing corn ethanol facilities with nameplate annual capacity of 9.8 billion gallons. An additional 38 plants are under construction and will add another 3.5 billion gallons of capacity. Most ethanol plants are capable of producing more than nameplate capacity and an assumption of existing and under construction plants producing at 5% above capacity leaves only 1 billion gallons of capacity to meet the RFS. BBI evaluated corn basis, corn production and net exportable corn maps as well as planned corn based ethanol plant lists to narrow the region where new plants may be built. Ethanol companies first identify areas with negative basis and available corn before proceeding with site and infrastructure requirements. The areas most likely to receive new plants include western Illinois, southeastern Nebraska and northern Iowa. BBI predicts that less than 20 new corn based ethanol plants will be built.

Existing ethanol plants use 34,000 BTU of natural gas per gallon of ethanol produced if all distillers grains are dried. The proportion of distillers grains dried at any particular plant is constantly changing based on demand, time of year and pricing. Generally, about 70% of distillers grains produced at U.S. ethanol plants are dried. The assumption is that future plants will use 32,000 BTU per gallon as this is the performance guarantee of the leading ethanol design firm. Annual U.S. ethanol industry natural gas demand is estimated at ~388 million MMBTU per year or 1050 MMcfd

The Canadian government is in the process of passing a 5% volumetric ethanol blend mandate. There are 11 existing plants with 249-mmgy of capacity (431 million litres) and 4 plants under construction with capacity of 124-mmgy (373 million litres). The mandate will require approximately 508 million gallons (1.9 billion litres) annually which leaves a shortfall of 135 million gallons (511 million litres) based which can be produced in Canada (attractive federal incentives) or imported from the U.S. per NAFTA. Annual Canadian ethanol industry natural gas demand is estimated at ~15 million MMBTU per year or 42 MMcfd.

Current and Future Biodiesel Industry

In the U.S., there are 110 commercial biodiesel plants with capacity of 1.5 billion gallons annually. However, skyrocketing feedstock costs representing over 90% of operational costs have caused plants to go idle or operate well below nameplate capacities. The price pressures are due to using vegetable oil feedstocks that have increasing demand in the food sector as a replacement for the unhealthy transfats. The current U.S. capacity utilization rate is estimated at 25%. In 2007, nearly 60% of U.S. biodiesel was exported to Europe. The updated RFS requires one billion gallons of biodiesel but that exceeds what is already installed and does nothing to address the shortage of demand. There are an additional 17 plants under construction adding 364 million gallons of capacity. In the past year, 17 plants with capacity of 177 million gallons have closed permanently. The natural gas requirement is typically ~5,150 BTUs per gallon of biodiesel produced but this figure can vary for different process designs. Approximately 25% of biodiesel capacity buy oilseeds as feedstock and require more thermal energy to extract the oil; about 9350 BTU/gallon. Current U.S. biodiesel industry natural gas use is estimated at 2,325,000 MMBTU (6 MMcfd) however this number has the potential to exceed 8,601,000 MMBTU (23 MMcfd) if all capacity was utilized.

Advanced Biofuels Industry

The RFS requires cellulosic fuels starting with 100 million gallons in 2010 increasing to 16 billion gallons by 2022. These plants must achieve a 60% reduction in Green House Gas Emissions against a baseline ethanol plant to qualify under this category—the baseline has yet to be established by the EPA. These plants will generate their own energy not only to reduce operating costs but to also achieve the GHG reductions. The undifferentiated category requires 100 million gallons by 2009 and four billion gallons by 2022—this category includes fuels such as renewable diesel or ethanol from molasses, sugarcane, sugar beets or other non-traditional feedstocks and any other advanced biofuels that do not fall into the other categories of the RFS.

These plants will be sited close to their feedstock since it is costly to move wet and non-dense materials such as wheat straw or wood chips long distances economically. Plants using agricultural residues such as corn stover will be sited in the Midwest and possibly as add-ons to existing ethanol plants. The greatest source of wood is in the Southeast where there are large private forests and forest industries. Sugar beets are concentrated between North Dakota and Minnesota while sugarcane is grown in southern Louisiana and southern Florida.

There are two basic pathways for conversion: biochemical and thermochemical. Biochemical typically involves a pretreatment phase to separate the feedstock into its components and send the cellulose and possibly the hemicellulose through fermentation. The thermal energy demand is estimated at 40,000 to 80,000 BTU per gallon based on pretreatment method. The energy source will be lignin. The thermochemical pathway involves heating the feedstock to produce syngas which is then quenched into a mixed alcohol. The energy source will be a portion of the syngas. These plants will require back-up energy sources for downtime and maintenance—perhaps 10%. It is possible that the plants will buy natural gas on the open market if available or propane tanks will be installed.

Renewable diesel is a nonester renewable fuel typically made from poultry fats, poultry wastes, municipal solid wastes, or wastewater sludge and oil. The process is termed thermal depolymerization. These plants will be sited at existing petroleum refineries and have a high thermal energy demand of 122,000 BTU per gallon. Assuming that half of the other/undifferentiated advanced biofuels category is met by renewable diesel (2 billion gallons) then the resulting annual natural gas demand would be 219,600,000 MMBTU. It is presumed that natural gas infrastructure is sufficient at large scale oil refineries in the southeast.

Technical Advances to Increase Energy Efficiency

Existing ethanol plants are considered efficient with the exception of the distillation and evaporation systems. There are heat recovery steam generators (HRSG) collecting waste heat from boilers and dryers. New technologies include cold cook enzymes that eliminate the heat needed for liquefaction resulting in thermal energy savings of 10-15%. There will soon be a membrane distillation system available that eliminates molecular sieves and decreases distillation columns by two-thirds resulting in energy savings of approximately 40%. There is also a trend towards fractionation which is a front-end process that separates corn into its components sending only the starch through the ethanol production process. Fractionation increases electrical use but decreases natural gas use since the bran is already removed—the estimate of a fractionation plant drying all distillers grains is 26,500 BTU per gallon.

V. BIOFUELS FEEDSTOCK AND ASSOCIATED FERTILIZER DEMAND

Incremental Fertilizer Required by Corn

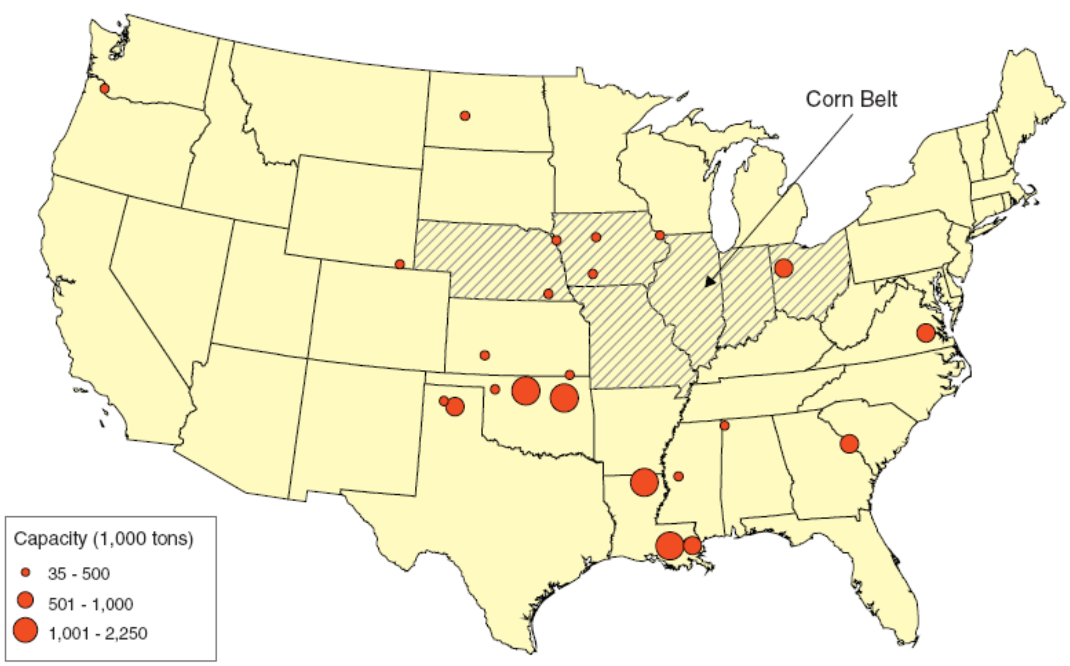
Essential nutrients for corn growth include nitrogen, phosphate and potassium. North Dakota State University recommends the following nutrients: 1.25 pounds per bushel (lb/bu) of nitrogen, 0.6 lb/bu of phosphorus, and 1.4 lb/bu of potash. Some of these nutrients exist in the soil but supplemental fertilizers must be added to achieve optimum production.

Nitrogen Fertilizer

Over the past 12 years, the U.S. has gone from being the world's largest nitrogen fertilizer exporter to the largest importer (production and imports are available in Figure 15). According to the USDA, ammonia plants tend to operate below capacity. Existing ammonia plants as of 2006 are shown in Figure 14. Reduced U.S. production and shutting down of ammonia plants was largely a result of rising costs for natural gas which accounts for 72-85% of the operating costs. Ammonia is the main ingredient for nitrogen fertilizer. Ammonia can be applied directly to soil but is more often refined into urea or ammonium nitrate—both are concentrated dried fertilizers.

Trinidad & Tobago typically accounts for over 50% of U.S. Ammonia imports followed by Russia, Canada, Ukraine and the Persian Gulf. Only two new ammonia production plants opened in 2007 throughout the world—one in Saudi Arabia and the other in Iran. The Middle East accounts for all planned plants.

Figure 14 – Existing U.S. Ammonia Plants



(Source: USDA ERS)

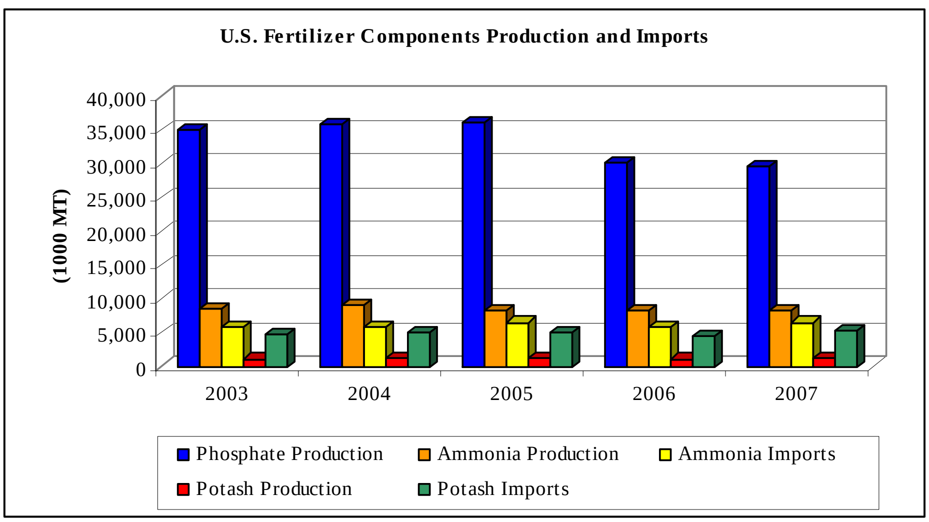
Phosphorus

Phosphate rock is the main ingredient for phosphate fertilizers. The U.S. is the leading phosphate rock and phosphate fertilizer supplier worldwide. Florida and North Carolina account for 85% of phosphate rock mining with lesser amounts in Idaho and Utah. Phosphate rock is not soluble in its natural form and must be refined into a range of solutions for use as a fertilizer including: diammonium phosphate (DAP) and monoammonium phosphate (MAP), both are produced by reacting phosphoric acid with ammonia, and triple superphosphate, produced by a reaction of phosphate rock with phosphoric acid. Domestic phosphate fertilizer use is estimated at 4.5 million tons annually. According to the USDA, phosphate fertilizer use in corn has averaged 1.7 million tons over the past five years.

Potash

Potash is a common term used for potassium. Potash is further refined into a range of fertilizer products including potassium chloride, potassium nitrate, potassium magnesium sulfate and potassium sulfate. The U.S. is not a large scale producer, averaging less than 1.2 million tons of production over the past five years (Figure 15). New Mexico is the main source of production followed by Michigan and Utah. The fertilizer industry uses about 85% of domestic potash production. Canada is the leading potash producer and the main supplier of U.S. imports.

Figure 15 – U.S. Fertilizer Precursors Production and Imports



(Source: USGS)

The Food and Agriculture Policy Research Institute (FAPRI) projects grain acres, production and yield through 2016. The USDA reports average fertilizer use for a variety of crops through 2006. Based on corn production the following figures were used to determine both corn fertilizer requirements and also associated natural gas demand from fertilizer production. USDA five year average corn fertilizer use recorded in pounds per bushel are: 0.89 nitrogen, 0.329 phosphorus and 0.378 potash. The additional one billion gallons of corn based ethanol will require approximately 429 million bushels of corn requiring about 190,714 tons of nitrogen fertilizers, 70,500 tons of phosphorus fertilizer and 81,000 tons of potash.

Table 21 – U.S. Corn Projections and Associated Fertilizer Demand

Corn Projections				Fertilizer Required		
Year	Acres	Bushels	Yield	Nitrogen	Phosphorus	Potash
	millions		bu/acre	tons		
2008	90	12,832	155.1	5,710,333	2,110,899	2,425,288
2009	90	13,064	157.3	5,813,413	2,149,003	2,469,068
2010	91	13,283	159.5	5,910,793	2,185,001	2,510,427
2011	91	13,476	161.7	5,996,891	2,216,828	2,546,994
2012	91	13,651	163.9	6,074,824	2,245,637	2,580,094
2013	90	13,790	166.1	6,136,403	2,268,401	2,606,248
2014	90	13,921	168.3	6,194,694	2,289,949	2,631,005
2015	90	14,070	170.6	6,261,355	2,314,591	2,659,317
2016	89	14,238	172.8	6,336,092	2,342,218	2,691,059
Incremental Increase to support 1billion additional gallons of corn based ethanol						
Corn & Fert for 1 billion gal		429		190,714	70,500	81,000

(Source: Corn data-FAPRI; Fertilizer-USDA ERS)

Incremental Fertilizer Required by Other Feedstocks

Other feedstocks include other crops such as wheat, sugarcane, and sugar beets. Each of the aforementioned feedstocks are considered too expensive for biofuels operational costs. The focus will be on non-food feedstocks including agricultural residues, wood, MSW and dedicated energy crops. The most common agricultural residues considered for biofuels feedstock include corn stover and wheat straw.

Corn stover fertilizer requirements are already included in those for corn shown in Table 21. Wheat straw would be available from existing wheat farms and FAPRI projections for wheat and associated fertilizer demand are shown in Table 22. Fertilizer demand for wheat was based on five year historical average fertilizer use per the USDA (1.73 lb/bu nitrogen; 0.627 lb/bu phosphorus; 0.452 lb/bu of potash).

Table 22 – U.S. Wheat Projections and Associated Fertilizer Demand

Wheat Projections				Fertilizer Required		
Year	Acres	Bushels	Yield	Nitrogen	Phosphorus	Potash
	millions		bu/acre	tons		
2008	59	2,121	42.4	1,834,665	664,934	479,346
2009	58	2,109	42.7	1,824,285	661,172	476,634
2010	58	2,124	43.0	1,837,459	665,946	480,076
2011	58	2,138	43.3	1,849,526	670,319	483,229
2012	58	2,151	43.7	1,860,286	674,219	486,040
2013	58	2,165	44.0	1,872,500	678,646	489,231
2014	58	2,174	44.3	1,880,744	681,634	491,385
2015	57	2,183	44.6	1,888,477	684,436	493,405
2016	57	2,192	44.9	1,896,080	687,192	495,392

(Source: Wheat data-FAPRI; Fertilizer-USDA ERS)

Soybeans will be grown largely for feed and foodstuffs but also for biodiesel feedstock. The RFS does not require any more installed capacity above what already exists today. FAPRI projections for soybeans and associated fertilizer demand are shown in Table 23. Fertilizer demand for soybeans was based on five year historical average fertilizer use per the USDA (0.100 lb/bu nitrogen; 0.309 lb/bu phosphorus; 0.592 lb/bu of potash).

Table 23 – U.S. Soybean Projections and Associated Fertilizer Demand

Soybeans Projections				Fertilizer Required		
Year	Acres	Bushels	Yield	Nitrogen	Phosphorus	Potash
	millions		bu/acre	tons		
2008	69	2,841	41.7	142,050	438,935	840,936
2009	70	2,916	42.1	145,800	450,522	863,136
2010	70	2,948	42.5	147,400	455,466	872,608
2011	70	2,973	43.0	148,650	459,329	880,008
2012	70	3,001	43.5	150,050	463,655	888,296
2013	70	3,035	43.9	151,750	468,908	898,360
2014	70	3,068	44.4	153,400	474,006	908,128
2015	70	3,098	44.8	154,900	478,641	917,008
2016	70	3,126	45.3	156,300	482,967	925,296

(Source: Soybean data-FAPRI; Fertilizer-USDA ERS)

Public forests are not fertilized and any wood feedstocks sourced from public lands would not require any additional fertilizer production in the U.S. Private tree plantations are common in the Southeast—particularly southern pine. The southeast has approximately 32 million acres of pine plantations and approximately 1.4 million acres are fertilized with nitrogen and phosphorus. The Forest Nutrition Cooperative lists fertilizer rates of 50 pounds per acre of phosphorus at stand establishment—DAP is the most common used. At five years, the cooperative recommends a one time application of 200 pounds per acre of nitrogen fertilizer and 25 pounds per acre of phosphorus fertilizer. The Forest Nutrition Cooperative believes that greater yield is obtained from plantations that use fertilizer, particularly when a stand is young. The fertilization rate and amount of acres that it is applied to is exceptionally small and will not have much of an impact on natural gas use for fertilizer demand in tree plantations.

Dedicated energy crops are selected based on their ability to grow with minimal water and fertilizers and on marginal lands. Both municipal sewage sludge and manure are considered appropriate fertilizers for biomass crops. Until there are large scale operations of switchgrass, poplar, willows, algae and other feedstocks, it is impossible to calculate required fertilizers as quantities and acreages are unknown at this time.

Natural Gas Required to Meet Increased Fertilizer Production

Fertilizer demand for crops was determined by using future projections for crop production by FAPRI and average fertilizer from USDA ERS. Natural gas requirements for fertilizers were determined as 33 MMBTU per ton of ammonia—the primary ingredient in nitrogen fertilizer

(USDA), 6.62 MMBTU per ton of phosphorus and 5.47 MMBTU per ton of potash.[2] The proportion of natural gas required for domestically produced fertilizers was based on U.S. production, imports and total consumption sourced from the USGS. All phosphorus fertilizers are presumed to be produced in the U.S., while the figure is reduced to 72% and 24% for nitrogen and potash based fertilizers respectively.

As evidenced in Table 24, the incremental increase in natural gas for fertilizers to support an additional one billion gallons of ethanol is insignificant. The corn will be grown regardless of its end use as feed, food or ethanol. The continued rise of natural gas prices will likely result in more imports of nitrogen based fertilizer from Trinidad and Tobago to meet any additional fertilizer requirements. Additionally, increases in crop plantings and production will be in response to total demand (feed, food, exports, and biofuels) and not biofuels alone.

Table 24 – U.S. Natural Gas Demand for Fertilizer Production

Commodity	Fertilizer Required			Natural Gas Requirement (MMBTU)			Est. U.S. Natural Gas Requirement (MMBTU)[1]		
	Nitrogen	Phosphorus	Potash	Nitrogen	Phosphorus	Potash	Nitrogen	Phosphorus	Potash
	tons			MMBTU			MMBTU		
Corn	6,336,092	2,342,218	2,691,059	209,091,051	15,505,486	14,720,095	150,545,557	15,505,486	3,532,823
Corn for 1 billion gallons	158,929	58,750	67,500	5,244,643	388,925	369,225	3,776,143	2,574,684	88,614
Wheat	1,896,080	687,192	495,392	62,570,640	4,549,211	2,709,794	45,050,861	15,322,591	650,351
Soybeans	156,300	482,967	925,296	5,157,900	3,197,242	5,061,369	3,713,688	3,197,424	1,214,729
Total[2]	**8,388,472**	**3,512,377**	**4,111,747**	**276,819,591**	**23,251,939**	**22,491,259**	**199,310,105**	**34,025,501**	**5,397,902**
1-Estimated nat gas use is based on % of fertilizer estimated to be produced in the U.S.: 72% for N; 100% for P; 24% source-USGS									
2-Total includes totals for corn, wheat and soybean rows									

(Source: Fertilizer-USDA; Natural Gas Requirement (USDA, USGS, Encyclopedia of Life Support Systems)

Biofuels Feedstock and Associated Fertilizer Demand Summary

Corn plantings are expected on roughly 90 million acres annually over the next ten years but yield is expected to increase leading to estimated production of 12.8 billion bushels in 2008 corresponding to estimated fertilizer demand of: 6.3 million tons of nitrogen; 2.3 million tons of phosphorus; and 2.7 million tons of potash. The natural gas demand in the fertilizer sector is based on domestic production of fertilizer resulting in an estimated natural gas demand of ~170 trillion Btu. It should be noted that U.S. ammonia plants tend to operate below capacity so it is unlikely that there is any incremental natural gas capacity for domestic based nitrogen fertilizer production. Therefore, the required fertilizer for corn to supply an additional one billion gallons of ethanol capacity is insignificant.

Forestry use of fertilizers at tree plantations is miniscule and would not impact demand for natural gas in this sector. Dedicated energy crops are selected for their limited water and fertilizer needs as well as their ability to grow on marginal lands. Likely fertilizers for energy crops include municipal sewage sludge and manure.

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[2] C. Gellings, K. Parmenter, *Energy Efficiency in Fertilizer Production and Use*, Encyclopedia of Life Support Systems

VI. BIOFUELS INDUSTRY IMPACTS AFFECTING NATURAL GAS USE

Alternatives to Natural Gas

There are a myriad of alternative sources of thermal energy for biofuels plants, however, they are geographically dependent on both the resource and the biofuels plant location. Alternatives include steam from existing power plants, landfill gas, coal fired boilers, manure, agricultural residues, wood chips or other wood wastes, by-products of the biofuels production process (syrup, distillers grains, glycerin). Biofuels are also seen as a more environmentally friendly substitute for fossil fuels when using biomass for energy generations since there is a short carbon cycle of growing, harvesting, burning and re-growing biomass contributes less to global warming, (biomass is seen as a CO2 neutral fuel). Since fuel property characteristics differ between wet cake and condensed solubles, agricultural residues, animal waste, coal and urban wood waste, it is essential to evaluate the fuel and to study the energy conversion technology options. Burning alternative feedstocks requires fuel flexibility and reliable technology, plus good combustion efficiency with low emissions.

Largely the focus will be on ethanol plants since some have cash on hand and the ability to possibly install a biomass boiler or other technologies. The energy load is low for biodiesel plants and the current 2008 capacity utilization rate is 24%. The main concern for biodiesel plants is feedstock supply and pricing which accounts for over 90% of operating costs.

There are some examples of plants using other forms of thermal energy (Table 25). Several of the larger ADM plant use coal as well as a few smaller plants. BBI believes that no more coal based ethanol plants will be built due to the lengthy permitting process and the updated RFS provision that requires a reduction of GHG emissions that would be difficult to achieve using coal. Additionally, some of the coal based ethanol plants are struggling to keep emissions below permitted levels. There remains a possibility that a plant could co-locate at a coal plant and buy excess steam. Corn Plus recently qualified for carbon credits and is listed on the Chicago Climate Exchange and is selling carbon credits based on fossil fuel displaced from using syrup.

Generally, plants installing biomass boilers, gasifier, anaerobic digester or similar will produce steam for use in the distillation and evaporation area of the plant and not for drying. Nearly all ethanol plants have natural gas fired dryers and plants are unlikely to change to expensive steam tube dryers. Therefore, an alternative energy system only has the ability to offset 65% of thermal energy requirement at a plant.

Table 25 – Existing Ethanol Plants Using Alternatives to Natural Gas

Plant Name	Capacity	City	State	Thermal Energy Source
ADM	237	Clinton	IA	Coal
ADM	420	Cedar Rapids	IA	Coal
ADM	290	Decatur	IL	Coal
Corn LP	50	Goldfield	IA	Coal
Heron Lake Bioenergy LLC	50	Heron Lake	MN	Coal
Lincolnway Energy LLC	50	Nevada	IA	Coal
Chippewa Valley Ethanol Co.	45	Benson	MN	Expansion will be powered by wood wastes
Central Minnesota Ethanol Cooperative	21	Little Falls	MN	Gasification of Wood
Red Trail Energy LLC	50	Richardton	ND	Lignite
Poet-Big Stone	75	Big Stone	SD	Steam and Natural Gas
Blue Flint Ethanol LLC	50	Underwood	ND	Steam from Coal Plant
Coors	3	Golden	CO	Steam from Coal Plant
Panda Ethanol Hereford LLC	100	Hereford	TX	Syngas from Manure
Corn Plus LLC	44	Winnebago	MN	Syrup
U.S. Energy Partners	50	Russell	KS	Waste Heat from City Gas Turbines

Biofuels Production Co-Products

Distillers Grains

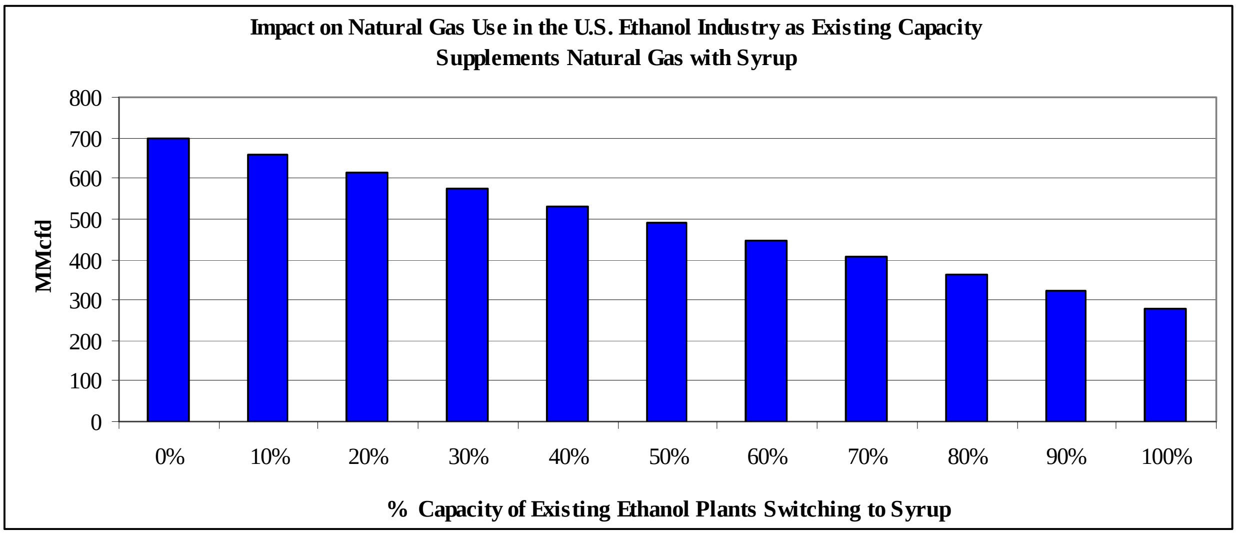
Distillers wet grains and condensed solubles have significant energy potential. Depending on the market situation of natural gas compared to DDGS, it may be more cost-effective to burn DDGS as fuel rather than convert to animal feed. The Agricultural Utilization Research Institute states that dried distillers grains with solubles have a heating value of 9422 BTU/pound. Distillers grains are a valuable co-product of the ethanol production process and prices track corn on a dry weight basis. Natural gas prices would have to rise to average above $13.00/MMBTU for it to make economic sense to install a biomass boiler and burn distillers grains. However, it does not make ethical sense to burn a valuable feed product that is used in ever increasing volumes in all livestock industries. This would lead to ever higher corn prices and would certainly qualify as a foolish idea given the food vs. fuel arguments.

Syrup

Syrup is a by-product of the ethanol production process resulting from the extraction of ethanol from the corn mash during distillation. Usually the syrup is mixed in with the distillers grains. The syrup contains 2765 BTU per pound with moisture content of 67% (approximately 8 pounds of syrup are produced for every gallon of ethanol). The syrup can be combusted or gasified to provide process steam and power for the production process. It is estimated that using syrup for steam could offset natural gas use by as much as 60%. It is possible and even likely that ethanol plants with sustained high natural gas prices will evaluate and consider investment in an energy system for syrup. This will depend on both the price of natural gas (most alternatives look good when natural gas is above $10 per MMBTU) and the plant's economic situation. While the syrup is an intermediary by-product, it is not free since it has value in the DDGS. In order to maintain nutritional requirements, the syrup must remain in the distillers grains for plants selling to poultry farms.

It is not possible to predict how many ethanol plants will supplement natural gas use with syrup. Figure 16 shows the anticipated impact as plants utilize syrup—for example 10% assumes that 844 million gallons of existing capacity uses syrup to supply 60% of thermal energy needs.

Figure 16 – Impact on Natural Gas Use if Plants Supplement with Syrup



Glycerin

Glycerin is a by-product of the biodiesel transesterification production process whereby glycerol is liberated from the oil after it is reacted with methanol. Phase separation occurs and methanol is recovered leaving a glycerol-water mixture which is dried to form glycerin. Each gallon of biodiesel produced yields 0.89 pounds of glycerin. The glycerin price has fluctuated widely over the past two years with prices as low as $50.00 per ton and current prices at about $1000 per ton. When the price is quite low, some plants burn a portion of their glycerin to generate process steam. The energy content of glycerin is 7688 BTU/lb. There is significant R&D by DuPont and Dow underway to upgrade glycerin into a range of valuable products. When this technology reaches commercialization, it is expected that both the price and demand for glycerin will preclude it from being used as a fuel source.

Agricultural Residues

Agricultural or crop residues leftover from harvesting, such as corn stover, can be collected and are another potential biomass energy source for ethanol plants. The proportion of stover that can be collected is dependent on soil type, topography, climate, tilling method and other similar variables. Agricultural residues cannot be economically transported over long distances due their bulkiness and water content. Therefore, corn stover is likely to be used in the Corn Belt where ethanol plants are plentiful. It costs between $50-60 per ton for baled corn stover. There are no existing biofuels plants using corn stover as an energy source but this resource can be utilized as better equipment is available for collection. The heating value of corn stover is 7192 BTU/lb (moisture content of 6%). The estimated cost of thermal energy from corn stover is $3.48 - $4.17 per MMBTU.

Based on the thermal energy costs corn stover looks like and attractive option, however, there are no U.S. examples of agricultural residue heat or power systems. There is certain risk in being the first to demonstrate the feedstock at a commercial facility. There are significant collection issues and further risk in a rainy year as farmers will not likely do a second pass over their lands to collect residues. An additional issue is that Illinois, Iowa, Minnesota, Missouri, and Wisconsin all have renewable portfolio standard's that require a certain portion of electricity be obtained from renewable resources such as biomass which may compete with biofuels plants for access to agricultural residues.

Wood

Wood chips and wood wastes are a viable alternative to natural gas depending on the location of the biofuels plant. The greatest availability of low cost wood is in Southern states-Georgia, Alabama, and Mississippi—however this is not an area of concentrated biofuels plants. Wood is likely available to some plants in Wisconsin and Minnesota (one plant in Minnesota gasifies wood for process steam). BBI has evaluated the potential for using wood at several plants based in the Midwest but found that wood was generally not available close enough to the facility for favorable economics. In general, projects look to supply wood from a 50 mile radius or less due to the bulkiness and moisture content of wood. The cost of wood is largely dependent on the locale but prices often range from $50 to $100 per dry ton. The U.S. Forest Service estimates air dried wood (80% dry) has a net heating value of 10.56 MMBTU per ton.

Wisconsin is the leading state in paper production and mill work. All eight plants in Wisconsin have access to wood and could potentially use it to produce 65% of their thermal energy requirement. The estimated natural gas demand of ethanol plants in Wisconsin is 38.6 MMcfd. If all the Wisconsin plants switch to wood fired boilers then the natural gas demand will be reduced to 13.5 MMcfd for use in the natural gas fired dryers.

In Minnesota, the forest products industry is concentrated northern part of the state while corn and ethanol production are concentrated in the southern area of the state. Only two plants are located near significant forests—Central Minnesota Ethanol Co-op which already uses wood and Poet Biorefining-Preston with capacity of 46-mmgy requiring about 3.5 MMcfd.

Manure

Livestock wastes such as cattle manure or poultry litter can be used as a feedstock for biogas production through combustion, gasification or anaerobic digestion. The ability to use manure will depend in part on how it is collected and the amount of other materials in the manure. Dairy and beef cattle provide the greatest amount of potential energy production of all types of livestock and are most concentrated in northeast Colorado, Panhandle of Texas, southwest Texas, and the San Joaquin Valley of California. There are also concentrated dairy and beef operations in various counties throughout Nebraska and Wisconsin.

Anaerobic digestion is a biological process that typically occurs in a cement vessel with acidic bacteria in the absence of oxygen to produce simple acids which are digested by methane forming bacteria. Biogas production of various livestock and the energy expected from anaerobic digestion are available in Table 26.

Table 26 – Energy Content of Livestock Wastes and Anaerobic Digestion

Livestock Type	Animal Weight	Biogas Production*	Energy Gross	Content Net**
	lbs	ft3/head/day	---------BTU/head/day---------	
Dairy Cow	1400	46.4	27,800	18,000
Beef Feeder	800	27.6	16,600	10,700
Market Hog	135	3.9	2,300	1,500
Poultry Layer	4	0.29	180	110
* 60% methane; ** Assumes 35% of gross energy is used to operate the digester.				

(Source: J. Barker, "Methane Fuel Gas from Livestock Wastes", North Carolina Cooperative Extension Service)

A 50-mmgy plant drying all distillers grains would require manure from over 270,000 dairy cattle daily to meet all thermal energy needs. There is only one county in California that has more than this number of dairy cattle. It is not considered economical to transport manure long distances. The same size plant would need manure from 454,000 beef cattle each day. At best, anaerobic digestion of manure could supplement natural gas use at a plant but would be unlikely to replace all natural gas needs.

Thermal chemical conversion processes for manure include combustion and gasification. Direct combustion of manure is inefficient due to the ash content and is not advised. Gasification involves heating the manure in oxygen depleted air resulting in syngas that consists of hydrogen and carbon monoxide. Panda Ethanol in Hereford, Texas plans to supply some or all of the thermal energy requirements with a large scale manure gasifier.

Landfill Gas

Landfill gas is emitted from landfills as wastes decompose. The gas is generally composed of equal parts methane and carbon dioxide with trace amounts of oxygen, nitrogen and hydrogen. A landfill can produce gas upwards of twenty years after the landfill has been sealed. The Environmental Protection Agency (EPA) has identified over 500 landfills that meet the criteria for landfill gas capture and use. There are 396 existing landfill gas projects but these already have established end users. Federal law requires landfills with more than 2.5 million tons of waste to collect and either flare or use their gas. The EPA reports that one ton of landfill waste produces about 0.432 cubic feet of gas. The University of Massachusetts Floriculture Department estimates the heating value of landfill gas at 500 BTU/cubic foot—about half that of pure methane.

An ethanol plant can extract gas from an existing landfill and use pipes to deliver the gas to the ethanol plant. The Midwest Combined Heat and Power (CHP) Application Center estimates 2004 gas collection equipment costs of $600,000 per million tons of waste. Piping costs vary by region but are generally around $50 per foot installed.

BBI compared the EPA list of landfills with potential for gas extraction with the locations of ethanol plants. As evidenced in Table 27, landfill gas can only offset a small portion of thermal energy demand from a standard size ethanol plant between 50 and 100 million gallons. There are 11 plants located in the same counties as 10 landfills identified as prime for landfill gas projects by the EPA. There are no existing ethanol plants using landfill gas.

Table 27 – Ethanol Plants near Landfills and Potential Energy Availability

Ethanol Plant Name	Landfill Location		Plant Capacity	Thermal Energy Demand	Landfill Capacity	Est. Landfill Energy Production	% Offset of NG use
Plants with Landfills in Town	city	state	mmgy	MMBTU/day[1]	tons	MMBTU/day[2]	
Archer Daniels Midland	Clinton	IA	237	25,383	3,697,808	799	3%
Big River Resources LLC	West Burlington	IA	52	5,569	2,597,642	561	10%
Illinois River Energy LLC	Rochelle	IL	50	5,355	1,800,000	389	7%
Reeve Agri Energy	Garden City	KS	12	1,285	1,339,005	289	23%
Bonanza BioEnergy LLC	Garden City	KS	55	5,891	see above	see above	5%
Commonwealth Agri-Energy LLC	Hopkinsville	KY	33	3,534	2,439,142	527	15%
Poet Biorefining-Glenville East	Albert Lea	MN	45	4,820	1,060,161	229	5%
Poet Biorefining-Macon	Macon	MO	36	3,856	2,832,000	612	16%
LifeLine Foods, LLC	St. Joseph	MO	40	4,284	2,995,346	647	15%
Elkhorn Valley Ethanol LLC	Norfolk	NE	40	4,284	820,000	177	4%
VeraSun Fort Dodge LLC	Fort Dodge	IA	110	11,781	1,000,000	216	2%
1-max. demand assumes all distillers grains are dried; 2-assumes .432 cubic feet of landfill gas per ton of waste per day-heating value is 500 Btu/cubic ft							

(Sources: EPA, University of Massachusetts, Ethanol Producer Magazine)

Coal

Only seven U.S. ethanol plants have installed coal boilers and it is unlikely that any existing plants will convert. The primary reasons are due to high capital costs and lengthy permitting processes. A coal based ethanol plant would also be unlikely to meet the green house gas emission reduction requirements of the RFS for any plants beginning construction in 2009.

There is the possibility of co-locating with an existing coal plant and buying excess steam. There are two existing ethanol plants that are co-located with coal plants. The motivation for co-location would be to obtain steam at a discount to natural gas. The distances of the existing ethanol plants in close proximity to coal plants is shown in Table 28. Ethanol plant designers prefer that the plant be closer than one mile to the steam source and only an ADM plant meets that requirement.

Table 28 – Ethanol Plants Located Near Coal Power Plants

Ethanol Plant	Capacity (mmgy)	Coal Plant Name	County	State	Approx Distance (miles)
ADM	695	Sixth Street	Linn	IA	1
Grain Processing Corp.	10	Muscatine #1	Muscatine	IA	2
MGP Ingredients Inc.	78	E D Edwards	Peoria	IL	3
Marysville Ethanol LLC	50	Marysville	St. Clair	MI	2
Granite Falls Energy LLC	50	Minnesota Valley	Chippewa	MN	2
Otter Tail Ethanol LLC	57.5	Hoot Lake	Otter Tail	MN	3
Poet-Big Stone	75	Big Stone	Grant	SD	3

(Source: NETL, Ethanol Producer Magazine)

Alternatives to Natural Gas Summary

There are a myriad of alternative sources of thermal energy for biofuels plants, however, they are geographically dependent on both the resource and the biofuels plant location. Alternatives include steam from existing power plants, landfill gas, coal fired boilers, manure, agricultural residues, wood chips or other wood wastes, co-products of the biofuels production process (syrup, distillers grains, glycerin). There are 15 existing ethanol plants using alternatives to natural gas.

Distillers grains—an ethanol plant feed co-product—have an energy value of 9422 BTU/pound. This co-product tracks corn prices and is valuable and unlikely to be used as fuel as it would inflame the food vs. fuel argument. Syrup is an intermediary by-product of ethanol production that is typically mixed into the distillers grains. Syrup has an energy value of 2765 BTU/pound and the ability to offset thermal energy needs by up to 60%. There is one plant currently using syrup. Syrup is the most likely supplemental thermal energy alternative for ethanol plants since it is a by-product of the production process and need not be sourced from other locations as would be the case with wood or agricultural residues. Glycerin is a co-product from biodiesel production and while it can be used to provide heat it has a higher value for use in pharmaceuticals and future industrial applications.

Agricultural residues are another potential resource with corn stover the most likely candidate due to corn being the primary feedstock for ethanol plants. Corn stover has an energy content of 7192 BTU/pound and typically sells for $50-60 ton (~$3.48 - $4.17 per MMBTU). While this appears to be an attractive option, there are no existing agricultural residue heat or power applications in the U.S. This is likely due to collection, transportation and storage issues as it is a bulky and wet material. It is not probable that a commercial plant will take on the risk of demonstrating the feedstock.

Wood chips and wood wastes are a viable alternative to natural gas depending on the location of the biofuels plant. The cost of wood is largely dependent on the locale but prices often range from $50 to $100 per dry ton and the estimated net heating value is 5280 BTU/pound. All plants in Wisconsin are located in areas where it is possible to obtain wood. The current Wisconsin ethanol industry natural gas demand is estimated at 38.6 MMcfd; if these plants installed biomass boilers the natural gas demand could possibly be reduced to 13.5 MMCfd. Minnesota also has a large forest products industry that is concentrated in the north while corn and ethanol production are concentrated in the south.

Manure is an unlikely source for thermal energy generation of an ethanol plant since a typical 50-mmgy plant will require manure from ~250,000 dairy cows and there is only one county in California that meets this threshold as is not economical to move manure long distances. There are 11 ethanol plants located in the same county as landfills, however, the energy offset value is so low that it would do little to lessen natural gas demand at these plants. There are seven plants using coal but it is unlikely that any additional existing or new ethanol plants will use coal due to high capital costs, lengthy permitting process, and new green house gas reduction requirements per the RFS.

VII. BIOFUELS INDUSTRY NATURAL GAS INFRASTRUCTURE REQUIREMENTS

Most existing ethanol and biodiesel plants currently use natural gas as the primary thermal and drying energy source. Current natural gas demand from the Biofuels industry is 699 MMcfd or 257 Bcf/yr. This represents roughly 1% of all natural gas consumed in the United States annually. Table 29 shows projected natural gas demand based on information from previous sections.

Table 29 – Projected Natural Gas Demand in Biofuels Industry

Projected Natural Gas Demand Assuming RFS Forecasted Ethanol Production Capacity			
Year	Ethanol Production (Gallons)	Annual Natural Gas Usage (MMcf)	Daily Natural Gas Usage (MMcfd)
2007	6,500,000,000	170,370	467
2008	9,000,000,000	235,897	646
2009	10,500,000,000	274,277	751
2010	12,000,000,000	310,199	850
2015	15,000,000,000	383,250	1,050

If "conventional ethanol" production is expanded to the RFS-2 conventional ethanol mandate level, natural gas demand will likely increase from 257 Bcf/year to 383 Bcf/yr, a 49% increase. At that point, biofuels natural gas demand is expected to be approximately 1.5% of United States natural gas demand.

Another category of biofuels mandated in the RFS-2 legislation is "advanced biofuels". Advanced biofuels generally includes cellulosic ethanol production and renewable biodiesel production. By definition, an "Advanced Biofuel" requires a GHG profile significantly lower than would currently be possible with conventional fossil fuels. The expectation, therefore, is that an expansion of the advanced biofuels industry would not require a significant increase in fossil fuel inputs.

BBI expects most of the new "conventional" facilities to be located in areas with relatively low corn basis values. Figure 17 below shows this area to be generally the six state area comprising Minnesota, Iowa, Wisconsin, North Dakota, South Dakota and Nebraska. We have further refined the analysis to include Illinois, as well as specific counties within each of the States which are most likely to support incremental ethanol plants. The counties selected represent those with significant corn production and relatively low priced corn. We have limited our analysis to focusing on natural gas supply and transportation in these areas since it is likely these areas where development will occur.

Figure 17 shows the Interstate Pipelines that serve this area and the associated supply basins from which each pipeline accesses natural gas supply. Generally, the production areas that serve this region are the Western Sedimentary Basin (Canada), the Rockies and the Mid-continent. Figure 18 shows the specific counties where development is expected to occur and an overlay of existing Interstate pipelines.

Figure 17 – Interstate Pipeline Map Serving Biofuels Production Area

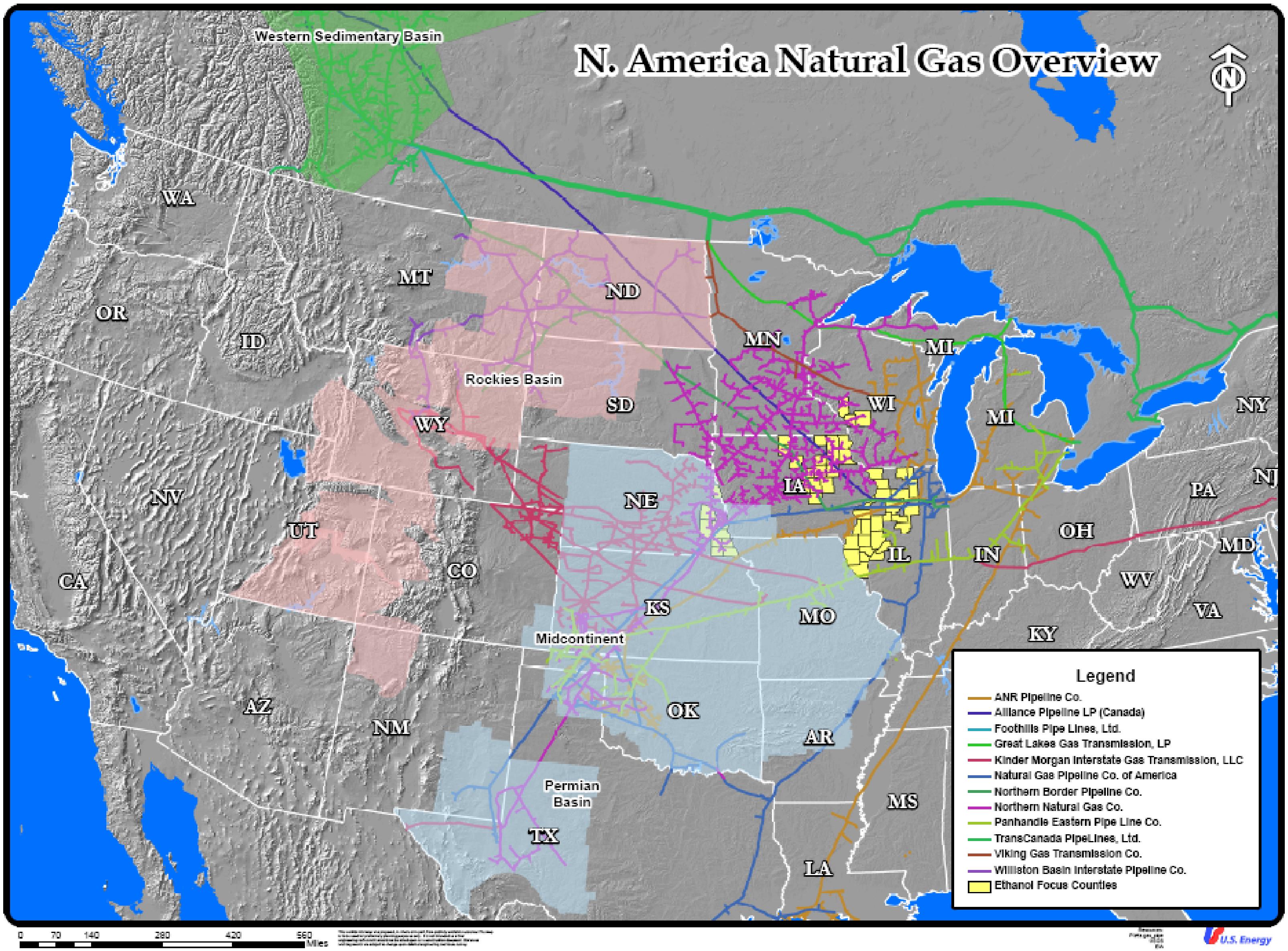
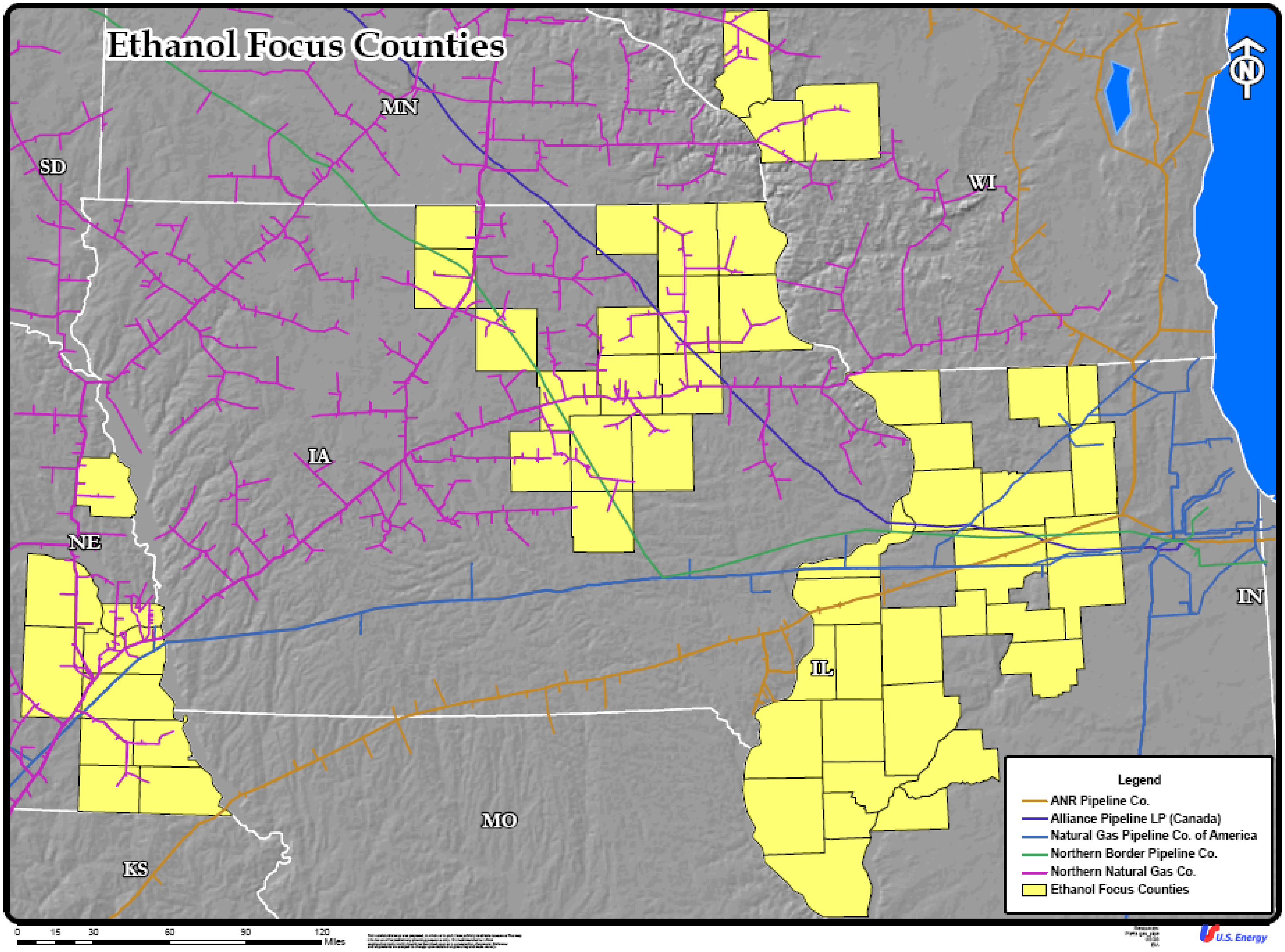


Figure 18 – Interstate Pipeline Map with Selected Counties



Commodity Supply Services

This section provides a brief overview of each production area.

Western Canadian Sedimentary Basin

The Western Sedimentary Basin accounts for the majority of Canada's natural gas production and is concentrated largely in British Columbia and Alberta. In 2005, the basin produced 16.7 Bcfd of conventional natural gas. It is currently believed that conventional production has reached its peak. Future growth potential rests with the development of unconventional sources such as tight-gas, shale-gas and coal bed methane deposits that are generally more expensive and difficult to extract. If natural gas prices remain high there will be economic incentive to further develop these unconventional sources.
(Source: http://www.eia.doe.gov)
(Source: http://www.petroleumeconomist.com)
*See related INGAA Foundation Report on Unconventional Gas Supplies expected Fall 2008

Rockies/Williston

The Rockies Production Area extends from Northern New Mexico to Montana, and then meets the Williston Basin as it crosses through the Dakotas and into Canada. Until the last decade, the region has been a relatively small contributor to national supply. The surge in natural gas prices, and the development of new drilling technologies, however, have increased production in the Rockies to 8 Bcf/d or about 15% of the U.S. production. It is expected that Rockies production will continue to grow in size and importance.
(Source: http://www.ferc.gov)

Mid-Continent/Permian

The Midcontinent/Permain Production Area includes the gas producing regions in Mainland Texas, east of the Rockies Basin, west of Missouri, and south of the Dakotas. After decades of relatively high, but flat to declining production levels, recent technologies and natural gas prices are spurring the exploration into unconventional sources which are creating increased production levels. For example, the Barnett Shale basin alone has 27-30 Tcf in unconventional reserves.
(Source: www.ferc.gov)
(Source: http://www.barnettshaleexpo.com)

Two of the three production areas – Rockies and Mid-continent -- appear to have positive trends with respect to production capabilities. The final production area – Western Sedimentary – is a bit more uncertain due to high potential demand within Canada related to Oil Sands production.

Commodity supply and demand balances are encouraged and maintained through price signals. If prices are relatively low, drilling activity slows down and supply conforms to demand. If prices are relatively high, drilling activity accelerates (and other resources are developed such as LNG) and supply expands to meet demand. Changes in natural gas prices constantly provide suppliers with real time price signals regarding how the market values their product. We expect that if demand remains strong and prices remain high, production capacity will expand to meet incremental biofuels related requirements.

Pipeline Transportation Services

There are eleven pipelines that serve the six State study region and five pipelines that serve the selected Counties within the States. Below is brief discussion of each of five pipelines serving the selected counties followed by the other six pipelines that are in the Corn Belt Area.

ANR
ANR Pipeline Company (ANR), a subsidiary of TransCanada, operates one of the nation's largest interstate natural gas pipeline systems. Through its approximately 10,600 miles of pipeline, ANR delivers more than 1 trillion cubic feet of natural gas annually. ANR has a peak-day delivery capacity of more than 6 Bcf, with total underground storage capacity exceeding 235 Bcf. (Source: ANRPL.COM)

Northern Natural Gas Company
Northern Natural Gas operates an interstate natural gas pipeline extending from the Permian Basin in Texas to the Upper Midwest. The system includes: 15,700 miles of natural gas pipeline; 5.1 Bcfd of Market Area design capacity; and 5 natural gas storage facilities with a total firm and operational capacity of 65 Bcf.

Northern Natural Gas accesses supply from every major Mid-Continent basin, as well as the Rocky Mountain and Western Canadian basins. This supply is ultimately delivered to end-use customers located in Minnesota, Iowa, Nebraska, South Dakota, Wisconsin, Illinois and the Upper Peninsula of Michigan. (Source: Northernnaturalgas.com)

Kinder Morgan Pipeline – NGPL
Natural Gas Pipeline Company of America LLC (Natural) is an interstate gas transmission subsidiary of NGPL Pipeco LLC, an affiliate of Kinder Morgan. With over 10,000 miles of wholly and jointly owned interstate pipelines, Natural's system moves gas from major U.S. and Canadian producing areas to Midwest markets and other pipelines serving North America. (Source: Kindermorgan.com)

Alliance Pipeline
From its gathering system in northeastern British Columbia and northwestern Alberta, Alliance transports 1.325 Bcfd of rich natural gas through its 3719 kilometer pipeline system, traversing British Columbia, Alberta, Saskatchewan, North Dakota, Minnesota, Iowa and Illinois, to the Chicago hub. (Source: Alliancepipeline.com)

Northern Border Pipeline Company
Northern Border Pipeline is a 1,249-mile interstate natural gas pipeline system with a design capacity of approximately 2.4 Bcfd. The pipeline system extends from the Montana-Saskatchewan border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana. Northern Border is a key link in the transportation of natural gas supply from the Western Canada Sedimentary Basin to the U.S. Midwest market. (Source: tcpipelineslp.com)

Other Pipelines in the area but outside the targeted county area include:

Viking Gas Transmission
Viking connects with major pipeline system (TransCanada, Northern Natural, Great Lakes Transmission and ANR), allowing it to serve strategic markets in North Dakota, Minnesota, and Wisconsin. (Source: vgt.oneokpartners.com). Viking's capacity exceeds 400 MMcf/day.

Great Lakes Gas Transmission
Great Lakes Gas Transmission Company (a subsidiary of TransCanada) transports over 2.2 Bcf of pipeline quality natural gas per day through 2,100 miles of dual, high-pressure pipelines. The pipeline provides a link between western Canada's natural gas basin and to major industrial and market centers in Minnesota, Wisconsin, Michigan and eastern Canada. (Source: glgt.com)

Kinder Morgan Pipeline – Trailblazer
Trailblazer Pipeline Company LLC (Trailblazer) is a 436-mile pipeline extending from northeast Colorado to Gage County in Nebraska. This pipeline provides an outlet for Rocky Mountain gas seeking Midwest and East Coast markets. (Source: Kindermorgan.com)

Kinder Morgan Pipeline – REX
The 1,678-mile Rockies Express (REX) project will provide infrastructure allowing producers in the Rocky Mountain region to deliver natural gas to markets in the Midwest and eastern parts of the country. The project is being anchored by long-term, firm transportation contracts with a number of shippers for virtually all of the 1.8 Bcfd of available capacity on REX. The route of the pipeline originates at the Meeker Hub in Rio Blanco County, Colo. and will extend to the Clarington Hub in eastern Ohio. (Source: Kindermorgan.com)

Panhandle Eastern Pipeline Company
Panhandle Eastern Pipe Line Company operates a 6,500-mile pipeline system with access to diverse supply sources and can deliver 2.8 Bcfd of natural gas to Midwest and East Coast markets. (Source: Panhandle.com)

Williston Basin Interstate Pipeline
Williston Basin Interstate Pipeline Company provides natural gas transportation and underground storage to customers throughout the Upper Midwest Region. (Source: wbip.com) Current capacity is under 300 MMcf/day.

Collectively, the above listed pipelines have the capability to transport over 25 Bcfd or roughly 40% of average daily natural gas demand.

In order to get a sense of what delivery constraints there may be in the region generally and specifically on each of the pipelines we prepared a matrix of key service factors. These factors can be used to estimate potential service reliability as biofuels related natural gas demand grows.

Below is a description of each factor.

Open Access – All of the pipelines provide "open-access" services. This means potential customers can request and receive service if they are willing to pay the incremental cost to expand pipeline facilities to meet service requirements. In some cases, expansion payments may not be necessary as new customers can request service and there may not be a need for an expansion.

Capacity Available – Indicates if the pipeline currently has transportation service available.

Routinely Expands – Some pipelines regularly expand their system to meet incremental system demand. For these pipelines, it is relatively easy to secure incremental transportation service; however, the cost can be relatively high.

Significant Delivered Sales – Producers/Marketers control significant capacity on certain pipelines. On these pipelines, service can be very reliable even if no transportation service is available directly from the pipeline since supply can be purchased on a long term agreement from Producers/Marketers.

Reliable Backhaul Service – Often times transportation service can be provided on a "sold out" pipeline through "back haul" or displacement service. Typically, backhauls only work when there is a reliable supply source downstream from the point at which service is required.

Table 30 – Pipeline Information

Pipeline Name	Open Access	Capacity Available	Routinely Expands	Significant Delivered Sales	Reliable Backhaul Capacity
ANR (SW)	x				
Northern Natural Gas Company	x		x		
Alliance Pipeline	x	x		x	
Northern Boarder Pipeline Company	x	x		x	
Viking Gas Transmission	x				
Greak Lakes Gas Transmission	x	x			
Kinder Morgan Pipeline - NGPL (Amarillo)	x			x	x
Kinder Morgan Pipeline - Trailblazer	x			x	
Kinder Morgan Pipeline - REX	x			x	
Panhandle Pipeline Company	x				
Williston Basin Interstate Pipeline	x		x		

Nine of the eleven pipelines listed have characteristics that would likely result in a potential customer being able to secure reliable service. The cost of such service, however, can and likely will vary dramatically depending upon the specific location and pipeline. It is important to note that even when pipeline service costs are relatively high, they are generally less than 10% of burnertip supply costs.

Service is challenging on two of the pipelines. The first, Viking Gas Transmission, is relatively small and extends through areas that are not likely to experience significant biofuels development activity. Forward haul capacity is not currently available and backhaul service may be problematic since supply would have to be delivered into Viking at a relatively constrained part of the ANR system. The second, Panhandle Eastern Pipeline, is in the heart of the biofuels development area although it is on the top end of the targeted countries. Backhaul service is possible on Panhandle, however, it requires buying supply in the Gulf production region, transporting on Trunkline Pipeline, then backhaul on Panhandle. The full cost can be relatively high. Panhandle had expansion "open season" recently, however, there wasn't sufficient interest at the expected project cost to move the project forward.

It appears that generally the pipeline industry will be available to accommodate increased Biofuels demand for two reasons. First, the increase in demand is not significant compared to overall demand and capability. Biofuels demand is expected to increase by 351 MMcf/day after all ethanol plants under construction and the one billion gallons of capacity still to be built come online. Ethanol plants under construction likely have already arranged for transportation service. This is relatively small compared to total pipeline capacity in the region. Second, it appears most of the pipelines have "characteristics" that will allow for reliable service.

It is important to note that this analysis is in isolation from other factors that may impact demand for pipeline transportation services. For example, if there is a significant shift in the generation of electricity from coal to natural gas there may big significant constraints for both commodity supply and transportation services. .

Finally, we have assumed that natural gas prices will remain relatively high (above $8.00) providing natural gas producers with incentive to develop increasingly expensive resources and allowing adequate cash flows to finance pipeline expansion projects to move supply from production areas to consumption areas.

The Section above provides a general overview of the six State region with respect to commodity supply and interstate pipeline services. However, to provide a more detailed and targeted analysis we have also identified Counties within the States that are more likely to have Bioenergy facility development and construction. There are five Pipelines that run through these Counties: Northern Natural Gas Company, ANR, NGPL, Northern Border and Alliance Pipeline. We have directly contacted each of the pipelines to assess whether capacity would be available to serve incremental Bioenergy facility related demand. None of the pipelines currently have capacity available from production areas to the select counties. Below is discussion of each pipeline with respect to constraints and opportunities.

Northern Natural Gas Company –Expansions will be necessary on this line but costs are variable based on length, size and other factors.

NGPL - Forward haul capacity is not available, however, backhaul capacity from Chicago is available. It is important to note, however, that with a backhaul from Chicago the commodity supply cost will be materially higher than purchasing supply in the field and transporting to the bioenergy facility.

ANR – Forward capacity is not currently available on the SW leg and back haul service, while not physically constrained, may be challenging depending on location. ANR has indicated that some backhaul capacity is available; however, service may not be reliable during certain parts of the year in some areas. ANR currently has no plans to expand their system for forward haul in this area.

Northern Border Pipeline Company – Forward haul capacity beyond Ventura is not available. However, since most of the transportation capacity is held by marketers/producers reliable service can be provided as long as the market is willing to pay a price competitive with Chicago prices.

Alliance Pipeline Company – Forward haul capacity is not available. Similar to Northern Border, however, most of the transportation capacity is held by marketers/producers so reliable service can be provided as long as the market is willing to pay a price competitive with Chicago prices. An added complication with Alliance Pipeline is that the interconnect cost tends to be high ($2-$3 Million) and a separate contract must be executed with the Aux Sable gas processing plant to compensate Aux Sable for lost liquids revenue. The Aux Sable reimbursement can increase gas costs by 10%.

Table 31 summarizes the expected capital and infrastructure costs for a typical 100 million gallon ethanol plant for each of the five pipelines listed above.

Table 31 – Capital and Infrastructure for an Ethanol Plant on Pipelines

	Interconnection Costs	**Natural Gas Costs (1)**
Northern Natural Gas Company	$1,000,000	$12.29
ANR (SW)	$1,000,000	not available
Kinder Morgan Pipeline - NGPL (Amarillo)	$1,000,000	$12.51
Northern Boarder Pipeline Company	$1,500,000	$12.51
Alliance Pipeline	$3,000,000	$13.26
(1) Based on NYMEX futures and basis prices on 6/19/2008		

Minimal pipeline capacity and infrastructure will be required to accommodate expanded bioenergy facility requirements on three of the pipelines. Costs for expansions to bring natural gas to ethanol plants are highly variable depending on line, distance size and similar considerations. However, the delivered cost of gas is higher to take service from these pipelines. Northern Natural Gas Company has the lowest delivered cost of gas. Service from ANR will be challenging unless they choose to expand their system.

Natural Gas Infrastructure Summary

Most existing ethanol and biodiesel plants currently use natural gas as the primary thermal and drying energy source. Natural gas usage for existing biofuels production is 699 MMcfd, roughly 1% of total National natural gas demand. Biofuels demand is expected to increase by 351 MMcf/day after ethanol plants under construction come online (all of these plants have obtained natural gas contracts) and one billion new gallons of capacity is built (plants not yet under construction). The Energy Independence and Security Act of 2007 (RFS-2) requires additional blending and production of biofuels. Increased biofuels production will have a corresponding increase in demand for natural gas and pipeline transportation services. Upon full implementation of RFS-2 conventional biofuels requirement (ethanol from starch-2015) natural gas demand is expected to grow to 1,050 MMcfd, nearly a 50% increase over current demand levels.

It is expected that increased biofuels production will occur in the areas that have the lowest relative corn costs. Using that metric, States and counties within those States have been identified that will most likely experience biofuels expansion (Figure 18). The identified counties generally are served by one of five pipelines. These pipelines access supply from the Western Sedimentary Basin, the Rockies production area and the Mid-Continent and Permian production areas.

The pipelines that deliver natural gas to the ethanol focus counties will generally be able to accommodate the increased demand from the biofuels industry, however, there may be significant infrastructure costs and/or relatively high commodity supply costs for certain locations. Table 30 provides estimated Interconnection, Expansion and Commodity supply cost estimates.

Increased biofuels production will be phased-in over several years likely in locations dispersed from each other. As such, relatively small demand increases will occur across several pipelines during the implementation period rather than large increases occurring during a short time period on one pipeline. If biofuels plants are phased-in and dispersed across the five pipelines, the annual incremental demand by pipeline will be 12 MMcfd, a relatively manageable amount ((1,050 MMcfd – 699 MMcfd) / 5 Pipelines / 6 years). If biofuel plants are located to a greater extent on certain pipelines the impact on those pipelines may be more significant. In light of project timing and dispersion we expect that the pipelines should be able to accommodate increased demands provided the market is willing to pay for interconnection, expansion and commodity costs.

Note: Section Vll reflects the view of U.S. Energy Services, Inc. Information contained in the report was collected based on experience and inquires with the various pipelines. The result is very much a “snap shot” and could change with time. The ability of pipelines to expand or offer backhaul services in the future is very dependent on a number of factors beyond the scope of the report.

VIII. IMPACT OF CARBON CONTROL LEGISLATION

According to the U.S. Environmental protection Agency (EPA), transportation sources accounted for 29 percent of total U.S. greenhouse gas (GHG) emissions in 2006[i]. According to the U.S. Department of Energy (DOE), transportation energy use is expected to increase 48 percent between 2003 and 2025, despite modest improvements in the efficiency of vehicle engines. This projected rise in energy consumption closely mirrors the expected growth in transportation GHG emissions.[ii] Transportation is the fastest-growing source of GHGs in the U.S., accounting for 47 percent of the net increase in total U.S. emissions since 1990. Transportation is also the largest end-use source of CO2, which is the most prevalent greenhouse gas.

The Foundation asked that BBI and U.S. Energy Services discuss the potential impact on the Biofuels industry if a carbon control program is implemented.

It appears that within the next few years a federal economy-wide GHG control program will be established. Currently, the prevailing form of such a program is a cap and trade design, where a financial incentive to reduce emissions is created by capping emissions but allowing regulated entities to buy and sell allowances to meet their compliance obligations. This creates a financial incentive to reduce emissions. The alternative approach is a tax where the regulated entity must pay a fee for each ton of carbon emitted. In either case, the result is a surcharge based on the carbon content of the fuel.

Biofuels, especially ethanol, is gaining increasing attention as a potential alternative to gasoline, but it is still unclear what impact the introduction of carbon control policies will have on the biofuel industry. Theoretically, climate control legislation will increase the demand for cleaner burning fuels and thus increase the potential market for ethanol. Based on direct emissions, Ethanol provides significant greenhouse gas emissions savings when compared to fossil fuels such as petroleum and diesel. Therefore, using biofuels to replace a proportion of the fossil fuels that are burned for transportation can reduce overall greenhouse gas emissions.

However, climate change policies are trending towards a life-cycle approach that considers not just direct emissions, but also emissions created in the production of ethanol. This uses a "cradle to grave" or "well to wheels" approach to calculate the total amount of GHG emitted during production, including land use activities and delivery. The issue is further complicated by the fact that corn farming incorporates land-use practices that emit GHG emissions such as soil tillage and considerable use of nitrogen fertilizer, which can lead to the production of nitrogen dioxide, a covered GHG. If such an approach is adopted, the GHG footprint of ethanol production would have to consider, at a minimum, the carbon fuel surcharge cost from feedstocks like natural gas. The impact of this could be considerable as shown in Table 32.

Table 32 – CO_2 Surcharge Impact on Fuel Price

$/Tonne$CO_2$	Natural Gas ($/MMBTU)
$10	$0.53
$20	$1.06
$30	$1.60
$40	$2.13
$50	$2.66

Given the current state of policy development, it is impossible to accurately determine how carbon control polices will impact the biofuels industry and in turn, the use of natural gas. However, climate change policies are certainly a major driver for both the demand for cleaner fuels and continual efficiency gains in energy production and use.

APPENDIX A: EXISTING ETHANOL PLANT LIST

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Pinal Energy LLC	Maricopa	AZ	Corn	55	N/A
Golden Cheese Co. of California	Corona	CA	Cheese Whey	5	Jan-85
Phoenix Bio Industries	Goshen	CA	Corn	25	Sep-05
Pacific Ethanol Inc.	Madera	CA	Corn	35	Oct-06
Parallel Products	Rancho Cucamonga	CA	Beverage Waste	4	N/A
Merrick/Coors	Golden	CO	Beverage Waste	3	N/A
Sterling Ethanol LLC	Sterling	CO	Corn	42	Nov-05
Sun Energy LLC	Walsh	CO	Corn	3	N/A
Front Range Energy LLC	Windsor	CO	Corn	40	May-06
Yuma Ethanol LLC	Yuma	CO	Corn	50	Oct-07
U.S. Bio Albert City	Albert City	IA	Corn	100	Nov-06
Poet Biorefining-Ashton	Ashton	IA	Corn	55	Mar-04
Archer Daniels Midland	Cedar Rapids	IA	Corn	420	N/A
Penford Corporation	Cedar Rapids	IA	Corn	40	Dec-07
VeraSun Charles City LLC	Charles City	IA	Corn	110	Apr-07
Archer Daniels Midland	Clinton	IA	Corn	237	N/A
Poet Biorefining-Coon Rapids	Coon Rapids	IA	Corn	54	2002
Poet Biorefining-Corning	Corning	IA	Corn	60	May-06
Amaizing Energy LLC	Denison	IA	Corn	55	Sep-05
Cargill Inc.	Eddyville	IA	Corn	35	N/A
Poet Biorefining-Emmetsburg	Emmetsburg	IA	Corn	50	Apr-05
Hawkeye Renewables	Fairbank	IA	Corn	115	Jun-06
VeraSun Fort Dodge LLC	Fort Dodge	IA	Corn	110	Oct-05
Quad County Corn Processors	Galva	IA	Corn	30	Feb-02
Corn LP	Goldfield	IA	Corn	50	Dec-05
Poet Biorefining-Gowrie	Gowrie	IA	Corn	60	summer 2006
Poet Biorefining-Hanlontown	Hanlontown	IA	Corn	55	Feb-04
Permeate Refining Inc.	Hopkinton	IA	Sugars & Starches	1.5	N/A
Hawkeye Renewables	Iowa Falls	IA	Corn	100	Nov-04
Poet Biorefining-Jewell	Jewell	IA	Corn	60	Mar-06
Midwest Grain Processors LLC	Lakota	IA	Corn	100	Nov-02
Little Sioux Corn Processors LP	Marcus	IA	Corn	52	Apr-03
Golden Grain Energy LLC	Mason City	IA	Corn	80	Dec-04
Grain Processing Corp.	Muscatine	IA	Corn	10	N/A
Lincolnway Energy LLC	Nevada	IA	Corn	50	May-06
Green Plains Renewable Energy Inc.	Shenandoah	IA	Corn	50	Jun-07
Siouxland Energy & Livestock Co-op	Sioux Center	IA	Corn	25	N/A
Absolute Energy LLC	St. Ansgar	IA	Corn	100	Feb-08
Pine Lake Corn Processors LP	Steamboat Rock	IA	Corn	20	Mar-05
Big River Resources LLC	West Burlington	IA	Corn	52	Apr-04
Pacific Ethanol-Magic Valley LLC	Burley	ID	corn	50	May-08
Idaho Ethanol Processing LLC	Caldwell	ID	Potato Waste/Corn	5	Mar-07
Archer Daniels Midland	Decatur	IL	Corn	290	N/A
Marquis Energy LLC	Hennepin	IL	Corn	100	N/A
Adkins Energy LLC	Lena	IL	Corn	43	Aug-02

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Aventine Renewable Energy Inc.	Pekin	IL	Corn	160	1981
MGP Ingredients Inc.	Pekin	IL	Corn	78	Feb-80
Archer Daniels Midland	Peoria	IL	Corn	100	N/A
Lincolnland Agri-Energy LLC	Robinson	IL	Corn	45	Jul-04
Illinois River Energy LLC	Rochelle	IL	Corn	50	Nov-06
Center Ethanol Company LLC	Sauget	IL	Corn	50	Feb-08
Poet Biorefining-Alexandria	Alexandria	IN	Corn	65	N/A
AltraBiofuels Indiana LLC	Cloverdale	IN	corn	88	May-08
Andersons Clymers Ethanol LLC, The	Clymers	IN	Corn	110	May-07
VeraSun Linden LLC	Linden	IN	Corn	100	Aug-07
Central Indiana Ethanol LLC	Marion	IN	Corn	40	Mar-07
Poet Biorefining-Portland	Portland	IN	Corn	60	N/A
Iroquois Bio-Energy Company LLC	Rensselaer	IN	Corn	40	Jan-07
New Energy Corp.	South Bend	IN	Corn	102	N/A
Grain Processing Corp.	Washington	IN	Corn	20	N/A
MGP Ingredients Inc.	Atchison	KS	Corn / Wheat Starch	4	N/A
Abengoa Bioenergy Corporation	Colwich	KS	Milo / Corn	25	Dec-02
Bonanza BioEnergy LLC	Garden City	KS	Corn / Milo	55	Oct-07
Reeve Agri Energy	Garden City	KS	Corn / Milo	12	N/A
East Kansas Agri-Energy LLC	Garnett	KS	Corn	35	Jun-05
ESE Alcohol	Leoti	KS	Seed Corn	1.5	Jan-91
Arkalon Energy LLC	Liberal	KS	Corn / Milo	110	Dec-07
Kansas Ethanol LLC	Lyons	KS	Milo / Corn	55	N/A
Western Plains Energy LLC	Oakley	KS	Corn / Milo	45	Jan-04
Prairie Horizon Agri-Energy LLC	Phillipsburg	KS	Milo / Corn	40	Jul-06
U.S. Energy Partners LLC	Russell	KS	Milo / Wheat Starch	50	N/A
Nesika Energy	Scandia	KS	Corn	10	N/A
Commonwealth Agri-Energy LLC	Hopkinsville	KY	Corn	33	Mar-04
Parallel Products	Louisville	KY	Beverage Waste	4	N/A
Andersons Albion Ethanol LLC, The	Albion	MI	Corn	55	2006
Poet Biorefining-Caro	Caro	MI	Corn	50	2002
U.S. Bio Woodbury	Lake Odessa	MI	Corn	50	Sep-06
Marysville Ethanol LLC	Marysville	MI	Corn	50	N/A
Midwest Grain Processors LLC	Riga	MI	Corn	57	Feb-07
Poet Biorefining-Glenville East	Albert Lea	MN	Corn	45	1999
Bushmills Ethanol LLC	Atwater	MN	Corn	49	Dec-05
Chippewa Valley Ethanol Company LLL	Benson	MN	Corn	45	1996
Poet Biorefining-Bingham Lake	Bingham Lake	MN	Corn	30	1997
Minnesota Energy	Buffalo Lake	MN	Corn	18	N/A
Al-Corn Clean Fuel	Claremont	MN	Corn	36	May-96
Biofuel Energy Corp	Fairmont	MN	Corn	110	Jan-08
Otter Tail Ag Enterprises LLC	Fergus Falls	MN	Corn	57.5	N/A
Granite Falls Energy LLC	Granite Falls	MN	Corn	50	Nov-05
Heron Lake BioEnergy LLC	Heron Lake	MN	Corn	50	N/A
Poet Biorefining-Lake Crystal	Lake Crystal	MN	Corn	56	May-05

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Central Minnesota Ethanol Co-op	Little Falls	MN	Corn	20.5	Jan-99
Agri-Energy LLC	Luverne	MN	Corn	21	Feb-99
Archer Daniels Midland	Marshall	MN	Corn	40	N/A
DENCO LLC	Morris	MN	Corn	24	Sep-99
Poet Biorefining-Preston	Preston	MN	Corn	46	1998
Corn Plus LLLP	Winnebago	MN	Corn	44	Nov-94
Heartland Corn Products	Winthrop	MN	Corn	95	N/A
Show Me Ethanol LLC	Carroll County	MO	corn/milo	55	May-08
Golden Triangle Energy Co-op Inc.	Craig	MO	Corn	20	Feb-01
Poet Biorefining-Laddonia	Laddonia	MO	Corn	45	N/A
Poet Biorefining-Macon	Macon	MO	Corn	36	2000
Mid-Missouri Energy	Malta Bend	MO	Corn	40	Jan-05
LifeLine Foods, LLC	St. Joseph	MO	Corn	40	N/A
Red Trail Energy LLC	Richardton	ND	Corn	50	Dec-06
Blue Flint Ethanol LLC	Underwood	ND	Corn	50	Feb-07
Archer Daniels Midland	Walhalla	ND	Corn	28	N/A
E Energy Adams LLC	Adams	NE	Corn	50	Nov-07
VeraSun Albion	Albion	NE	Corn	100	Oct-07
Nebraska Energy LLC	Aurora	NE	Corn	50	1995
Cargill Inc.	Blair	NE	Corn	85	N/A
Standard Ethanol Cambridge LLC	Cambridge	NE	Corn	44	N/A
U.S. Bio Platte Valley LLC	Central City	NE	Corn	96	Apr-04
Archer Daniels Midland	Columbus	NE	Corn	100	N/A
Advanced BioEnergy	Fairmont	NE	Corn	100	Oct-07
Ag Processing Inc.	Hastings	NE	Corn	52	1992
Chief Ethanol Fuels Inc.	Hastings	NE	Corn	62	1985
Siouxland Ethanol LLC	Jackson	NE	Corn	50	May-07
Cornhusker Energy Lexington LLC	Lexington	NE	Corn	40	Dec-05
Standard Ethanol Madrid LLC	Madrid	NE	Corn	44	N/A
KAAPA Ethanol LLC	Minden	NE	Corn	40	Nov-03
Elkhorn Valley Ethanol LLC	Norfolk	NE	Corn	40	Sep-07
U.S. Bio Ord	Ord	NE	Corn	45	May-07
Husker Ag LLC #	Plainview	NE	Corn	27	Mar-03
Abengoa Bioenergy of Ravenna	Ravenna	NE	Corn	88	Jul-07
Midwest Renewable Energy LLC	Sutherland	NE	Corn	25	N/A
Trenton Agri Products LLC	Trenton	NE	Corn / Milo	40	Mar-04
Biofuel Energy Corp	Wood River	NE	Corn	110	Mar-07
Abengoa Bioenergy Corporation	York	NE	Corn	55	Dec-93
Abengoa Bioenergy Corporation	Portales	NM	Milo	30	Jul-05
Western New York Energy LLC	Shelby	NY	Corn	50	Jan-08
VeraSun Bloomingburg	Bloomingburg	OH	Corn	100	Mar-08
AltraBiofuels Coshocton Ethanol LLC	Coshocton	OH	Corn	60	Oct-07
Andersons Marathon Ethanol LLC, The	Greenville	OH	Corn	110	Mar-08
Poet Biorefining-Leipsic	Leipsic	OH	Corn	60	fall 2007
Greater Ohio Ethanol LLC	Lima	OH	Corn	54	Nov-07
Dean CEG LLC	Burns Flat	OK	Corn	2	Aug-06
Pacific Ethanol-Columbia LLC	Boardman	OR	Corn	35	Jun-07

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Cascade Grain Products LLC	Clatskanie	OR	Corn	108	Dec-07
Heartland Grain Fuels LP #	Aberdeen	SD	Corn	8	N/A
VeraSun Energy LLC	Aurora	SD	Corn	120	Dec-03
Poet Biorefining-Big Stone	Big Stone City	SD	Corn	75	2002
Poet Biorefining-Chancellor	Chancellor	SD	Corn	100	Mar-03
Poet Biorefining-Groton	Groton	SD	Corn	50	May-03
Poet Biorefining-Hudson	Hudson	SD	Corn	55	May-04
Heartland Grain Fuels LP	Huron	SD	Corn	30	Nov-99
Poet Biorefining-Mitchell	Loomis	SD	Corn	60	Dec-06
U.S. Bio Marion	Marion	SD	Corn	110	Feb-08
Aberdeen Energy LLC	Mina	SD	corn	100	May-08
Redfield Energy LLC	Redfield	SD	Corn	50	Dec-06
North Country Ethanol LLC	Rosholt	SD	Corn	20	Mar-05
Poet Research Center	Scotland	SD	Corn	9	1988
Glacial Lakes Energy LLC	Watertown	SD	Corn	50	Dec-00
Dakota Ethanol LLC	Wentworth	SD	Corn	50	2001
Tate & Lyle	Loudon	TN	Corn	60	N/A
White Energy Hereford LLC	Hereford	TX	Corn	100	fourth quarter 2007
Panda Hereford Ethanol LP	Hereford	TX	Corn / Milo	100	Mar-08
Levelland/Hockley County Ethanol LL	Levelland	TX	Corn / Milo	40	N/A
Western Wisconsin Energy LLC	Boyceville	WI	Corn	45	late fall 2006
Didion Ethanol LLC	Courtland	WI	Corn	50	N/A
United Wisconsin Grain Producers LL	Friesland	WI	Corn	52	Apr-05
Renew Energy LLC	Jefferson	WI	Corn	130	Jul-07
United Ethanol LLC	Milton	WI	Corn	42	Jan-07
Badger State Ethanol LLC	Monroe	WI	Corn	55	2002
Castle Rock Renewable Fuels LLC	Necedah	WI	Corn	50	fourth quarter 2007
Ace Ethanol LLC	Stanley	WI	Corn	42	Jun-02
Utica Energy LLC	Utica	WI	Corn	52	Apr-03
Wyoming Ethanol LLC	Torrington	WY	Corn	12	N/A

APPENDIX B: ETHANOL PLANTS UNDER CONSTRUCTION

Plant Name	City	State	Feedstock	Capacity (mmgy)
Plants Expected to Start-up in Q2 2008				
Cilion Ethanol LLC	Keyes	CA	corn	55
Calgren Renewable Fuels LLC	Pixley	CA	corn	52
VeraSun Hartley LLC	Hartley	IA	corn	110
Superior Ethanol LLC	Superior	IA	corn	50
Patriot Renewable Fuels LLC	Annawan	IL	corn	100
Indiana Bio-Energy LLC	Bluffton	IN	corn	101
Verasun Welcome LLC	Welcome	MN	corn	110
U.S. Bio Hankinson	Hankinson	ND	corn	110
NEDAK Ethanol LLC	Atkinson	NE	corn	44
AltraBiofuels Nebraska LLC	Carleton	NE	corn	110
Holt County Ethanol LLC	O'Neill	NE	corn	100
Route 66 Ethanol, LLC	Tucumcari	NM	corn	10
Northeast Biofuels LLC	Volney	NY	corn	100
White Energy Plainview LLC	Plainview	TX	corn/milo	100
2008 Q2 Total				**1,152**
Plants Expected to Start-up in Q3 2008				
First United Ethanol LLC	Camilla	GA	corn	100
Platinum Ethanol LLC	Arthur	IA	corn	110
Plymouth Energy LLC	Merrill	IA	corn	50
Southwest Iowa Renewable Energy LLC	Council Bluffs	IA	corn	110
U.S. Bio Dyersville	Dyersville	IA	corn	110
Cardinal Ethanol LLC	Union City	IN	corn	100
U.S. Bio Janesville	Janesville	MN	corn	110
Ethanol Grain Producers	Obion	TN	corn	100
2008 Q3 Total				**790**
Plants Expected to Start-up in Q4 2008				
Pacific Ethanol-Stockton	Stockton	CA	corn	50
Hawkeye Renewables	Menlo	IA	corn	110
Hawkeye Renewables	Shell Rock	IA	corn	110
Tharaldson Ethanol LLC	Casselton	ND	corn	100
Archer Daniels Midland	Columbus	NE	corn	275
Bridgeport Ethanol LLC	Bridgeport	NE	corn	45
Poet Biorefining-Fostoria	Fostoria	OH	corn	65
Poet Biorefining-Marion	Marion	OH	corn	65
Northwest Renewable LLC	Longview	WA	corn	55
2008 Q3 Total				**875**
Plants Expected to Start-up in Q1 2009				
Poet Biorefining-North Manchester	North Manchester	IN	corn	65
Nexsun Ethanol LLC	Ulysses	KS	milo/corn	40
2009 Q1 Total				**105**
Plants Expected to Start-up in Q2 2009				
Homeland Energy Solutions	Lawler	IA	Corn	100
One Earth Energy Formerly Alliance	Gibson City	IL	corn	100
2009 Q2 Total				**200**
Plants Expected to Start-up in Q3 2009				
Archer Daniels Midland	Cedar Rapids	IA	corn	275
Clean Burn Fuels	Raeford	NC	corn	60

APPENDIX C: ETHANOL PLANTS IDLE

Company	City	State	Feedstock	Capacity (mmgy)	Start Date
Alchem LLP	Grafton	ND	Corn	10.5	1990
Central Illinois Energy Co-op	Canton	IL	corn	37	Jun-07
Central Wisconsin Alcohol	Plover	WI	Seed Corn / Whey	7	N/A
E3 BioFuels LLC	Mead	NE	corn	25	Dec-06
Gateway Ethanol LLC	Pratt	KS	corn/milo	55	Jun-07
Liquid Resources of Ohio LLC	Medina	OH	Beverage Waste	6	N/A
Manildra Ethanol Corporation	Hamburg	IA	Corn / Wheat Starch	8	N/A
Melrose Dairy Proteins LLC	Melrose	MN	Cheese Whey	3	N/A
Parallel Products	Bartow	FL	Beverage Waste	4	N/A
Renova Energy of Idaho LLC	Heyburn	ID	corn	20	N/A
Xethanol Biofuels LLC	Blairstown	IA	Corn	5.5	N/A

APPENDIX D: EXISTING BIODIESEL PLANTS

Some listed plants are idle

Plant Name	City	State	Feedstock	Capacity *	Start Date
Alabama Biodiesel Corp.	Moundville	AL	soy oil	10	N/A
Eagle Biodiesel Inc	Bridgeport	AL	soy oil	30	N/A
Patriot BioFuels	Stuttgart	AR	soy oil/animal fats	3	N/A
Bay Biodiesel LLC	San Jose	CA	virgin oils/yellow grease	5	Oct-06
Blue Sky Biofuels Inc.	Oakland	CA	multi-feedstock	20	Feb-07
Imperial Western Products	Coachella	CA	yellow grease	12	N/A
LC Biofuels	Richmond	CA	canola oil	1	N/A
SoCal Biofuels	Anaheim	CA	waste vegetable oil	1	Dec-06
Bio-Pur Inc.	Bethlehem	CT	soy oil	0.4	N/A
Agri-Source Fuels LLC	Dade City	FL	multi-feedstock	20	May-07
Purada Processing LLC	Lakeland	FL	multi-feedstock	18	N/A
Renewable Energy Systems Inc.	Pinellas Park	FL	recycled vegetable oil	0.5	N/A
Alterra Bioenergy of Middle Georgia	Gordon	GA	multi-feedstock	15	Sep-07
Middle Georgia Biofuels	East Dublin	GA	soy oil/poultry fat	2.5	Sep-06
Peach State Labs	Rome	GA	soy oil	10	N/A
U.S. Biofuels Inc.	Rome	GA	multi-feedstock	10	N/A
Pacific Biodiesel Inc.	Honolulu	HI	yellow grease	1	Oct-02
Pacific Biodiesel Inc.	Kahului	HI	yellow grease	0.5	Nov-96
Ag Processing Inc.	Sergeant Bluff	IA	soy oil	30	Sep-07
Cargill Inc.	Iowa Falls	IA	soy oil	37	N/A
Central Iowa Energy LLC	Newton	IA	multi-feedstock	30	Apr-07
Freedom Fuels LLC	Mason City	IA	soy oil/animal fats	30	Mar-07
Iowa Renewable Energy	Washington	IA	soy oil	30	Jul-07
Nova Biofuels	Clinton	IA	soy oil	10	Sep-06
Renewable Energy Group	Ralston	IA	soy oil	12	N/A
Riksch Biofuels	Crawfordsville	IA	multi-feedstock	9	N/A
Sioux Biochemical Inc.	Sioux Center	IA	corn oil/animal fats	1.5	Mar-07
Soy Solutions	Milford	IA	soy oil	2	N/A
Tri-City Energy	Keokuk	IA	multi-feedstock	5	Nov-06
Western Dubuque Biodiesel	Farley	IA	soy oil	30	Jun-07
Western Iowa Energy	Wall Lake	IA	soy oil-animal fats	30	Jun-06
American Biorefining Inc.	Saybrook	IL	soy oil	10	N/A
Columbus Foods Co.	Chicago	IL	soy oil	3	N/A
Incobrasa Industries Ltd.	Gilman	IL	soy oil	30	Jan-07
Midwest Biodiesel Products	South Roxanna	IL	soy oil	30	N/A
Stepan Co.	Joliet	IL	multi-feedstock	21	N/A
Evergreen Renewables LLC	Hammond	IN	soy oil	5	N/A
Heartland Biofuel	Flora	IN	soy oil	0.5	N/A
Integrity Biofuels	Morristown	IN	soy oil	5	N/A
Louis Dreyfus Agricultural Industri	Claypool	IN	soy oil	80	Sep-07
Griffin Industries	Butler	KY	soy oil/tallow/yellow grease	2	Dec-98
Union County Biodiesel Co. LLC	Sturgis	KY	soy oil	5	Jul-07
Allegro Biodiesel Corp.	Pollock	LA	soy oil	15	N/A
Maryland Biodiesel	Berlin	MD	soy oil	0.5	N/A
Bean's Commercial Grease	Vassalboro	ME	waste vegetable oil	0.25	N/A
Ag Solutions Inc.	Gladstone	MI	soy oil	5	May-06

Plant Name	City	State	Feedstock	Capacity *	Start Date
Michigan Biodiesel	Bangor	MI	soy oil	10	N/A
Milan Biodiesel Co. o	Milan	MI	undeclared	0	N/A
NextDiesel	Adrian	MI	soy oil	20	N/A
FUMPA Biofuels	Redwood Falls	MN	soy oil/animal fats	3	N/A
Minnesota Soybean Processors	Brewster	MN	soy oil	30	N/A
Ag Processing Inc.	St. Joseph	MO	soy oil	28	Sep-07
Mid-America Biofuels LLC	Mexico	MO	soy oil	30	N/A
Natural Biodiesel Inc.	Braggadocio	MO	multi-feedstock	5	Apr-07
Prairie Pride Inc.	Nevada	MO	soy oil	30	Aug-07
Delta Biofuels	Natchez	MS	soy oil	20	N/A
North Mississippi Biodiesel	New Albany	MS	soy oil	7	N/A
Scott Petroleum Corp.	Greenville	MS	multi-feedstock	20	Jul-07
Blue Ridge Biofuels	Asheville	NC	multi-feedstock	2	Sep-07
Evans Environmental Energies	Wilson	NC	multi-feedstock	3	May-07
Foothills Bio-Energies LLC	Lenoir	NC	soy oil	5	N/A
Piedmont Biofuels	Pittsboro	NC	yellow grease/animal fats	1	Sep-06
Archer Daniels Midland	Velva	ND	canola oil	85	Apr-07
Beatrice Biodiesel LLC	Beatrice	NE	soy oil	50	Sep-07
Horizon Biofuels Inc.	Arlington	NE	animal fats	0.4	Sep-06
Fuel:Bio One LLC	Elizabeth	NJ	multi-feedstock	50	Feb-07
Innovation Fuels	Newark	NJ	soy oil	24	N/A
Rio Valley Biofuels LLC	Anthony	NM	multi-feedstock	0.5	N/A
Bently Biofuels	Minden	NV	multi-feedstock	1	N/A
Biodiesel of Las Vegas	Las Vegas	NV	multi-feedstock	8	N/A
Biodiesel of Las Vegas Inc.	Las Vegas	NV	soy oil	3	N/A
Jatrodiesel Inc.	Dayton	OH	multi-feedstock	5	Oct-06
Peter Cremer	Cincinnati	OH	soy oil	30	N/A
Sequential-Pacific Biodiesel LLC	Salem	OR	yellow grease	1	N/A
Agra Biofuels Inc.	Middletown	PA	soy oil	3	N/A
Biodiesel of Pennsylvania Inc.	White Deer	PA	multi-feedstock	3.6	Jan-07
Keystone Biofuels	Shiremanstown	PA	soy oil	2	Jan-06
Lake Erie Biofuels	Erie	PA	multi-feedstock	45	Dec-07
United Biofuels Inc.	York	PA	soy oil	1	N/A
United Oil Co.	Pittsburg	PA	multi-feedstock	2	Dec-04
Mason Biodiesel LLC	Westerly	RI	undeclared	1.2	N/A
Carolina Biofuels LLC	Taylors	SC	soy oil	5	Jun-07
Southeast BioDiesel LLC	North Charleston	SC	multi-feedstock	6	Feb-07
Midwest Biodiesel Producers	Alexandria	SD	soy oil	7	N/A
Agri Energy Inc.	Lewisburg	TN	soy oil	5	N/A
Memphis Biofuels LLC	Memphis	TN	multi-feedstock	36	Sep-06
Milagro Biofuels	Memphis	TN	soy oil	5	Sep-06
Biodiesel Industries of Greater Dal	Denton	TX	multi-feedstock	3	N/A
BioSelect Galveston Bay	Galveston Island	TX	multi-feedstock	20	Apr-07
Brownfield Biodiesel LLC	Ralls	TX	multi-feedstock	2	Jul-06
Central Texas Biofuels	Giddings	TX	vegetable oils	1	N/A
Huish Detergents	Pasadena	TX	tallow/palm oil	4	N/A
Johann Haltermann Ltd.	Houston	TX	soy oil	20	N/A

Plant Name	City	State	Feedstock	Capacity *	Start Date
Pacific Biodiesel Texas	Carl's Corner	TX	multi-feedstock	2	Aug-06
Smithfield Bioenergy LLC	Cleburne	TX	animal fats	12	Jan-06
SMS Envirofuels Inc.	Poteet	TX	soy oil	5	Jun-06
South Texas Blending	Laredo	TX	beef tallow	5	N/A
Chesapeake Custom Chemical	Ridgeway	VA	soy oil	5	N/A
Reco Biodiesel LLC	Richmond	VA	soy oil	10	May-06
Virginia Biodiesel Refinery	New Kent	VA	soy oil	2	N/A
Biocardel Vermont LLC	Swanton	VT	soy oil	4	N/A
Central Washington Biodiesel LLC	Ellensburg	WA	canola oil	3	Feb-07
Imperium Grays Harbor	Grays Harbor	WA	multi-feedstock	100	Jul-07
Standard Biodiesel	Arlington	WA	waste vegetable oil	8	N/A
Best Biodiesel Cashton LLC	Cashton	WI	multi-feedstock	8	Jul-07
Renewable Alternatives	Howard	WI	soy oil	0.365	N/A
Sanimax Energy Biodiesel	De Forest	WI	multi-feedstock	20	Jan-07
Walsh Biofuels LLC	Mauston	WI	multi-feedstock	5	Feb-07
A C & S Inc.	Nitro	WV	soy oil	3	N/A

APPENDIX E: UNDER CONSTRUCTION BIODIESEL PLANTS

Plant Name	City	State	Feedstock	Capacity *	Start Date
Alternative Liquid Fuel Industries	McArthur	OH	multi-feedstock	6	2008 Q1
Alterra Bioenergy of Plains, Ga.	Plains	GA	multi-feedstock	30	N/A
Ares Blue Sun Clovis	Clovis	NM	soy oil	15	2008 Q2
Arkansas Soy Energy Group LLC	Dewitt	AR	soy oil	3	on hold
Biodiesel of America	Ft. Lauderdale	FL	waste oil	3	N/A
Chesapeake Green Fuels	Adamstown	MD	multi-feedstock	1	N/A
Delta American Fuel LLC	Helena	AR	soy oil/cottonseed oil	40	N/A
Global Alternative Fuels LLC	El Paso	TX	multi-feedstock	5	2008 Q2
High Plains Bioenergy	Guymon	OK	multi-feedstock	30	2008 Q2
Infinifuel Biodiesel	Wabuska	NV	multi-feedstock	5	
Maple River Energy	Galva	IA	soy oil/corn oil	5	2008 Q4
Northington Energy	Wartburg	TN	soy oil	3	2008 Q2
Nova Biosource Fuels LLC	Seneca	IL	undeclared	60	N/A
Owensboro Grain Biodiesel	Owensboro	KY	soy oil	50	N/A
Perihelion Global	Opp	AL	peanut oil/ multi-feedstock	60	2008 Q2
Tri-State Biodiesel	Brooklyn	NY	waste vegetable oil	3	N/A
North Prairie Productions LLC o	Evansville	WI	soy oil	45	N/A

APPENDIX F: CLOSED BIODIESEL PLANTS

Plant Name	City	State	Feedstock	Capacity *	Start Date
Better BioDiesel	Spanish Fork	UT	multi-feedstock	3	Sep-06
Biodiesel Industries-Port Hueneme	Ventura	CA	multi-feedstock	3	N/A
BioEnergy of Colorado I	Commerce City	CO	soy oil	10	N/A
BioEnergy of Colorado II	Denver	CO	soy oil	10	N/A
Energy Alternative Solutions Inc.	Gonzales	CA	tallow	2.5	Feb-07
FutureFuel Chemical Co.	Batesville	AR	soy oil	24	N/A
Global Fuels LLC	Dexter	MO	chicken fat	3	N/A
Green Earth Fuels LLC	Houston	TX	multi-feedstock	43	Jul-07
Green Range Renewable Energy	Ironton	MN	recycled cooking oil	0.15	N/A
Missouri Bio-Products Inc.	Bethel	MO	soy oil	2	N/A
Momentum Biofuels Inc.	Pasadena	TX	soy oil	20	Dec-06
MPB Bioenergy LLC	Bridgewater	MA	recycled cooking oil	0.5	N/A
OK Biodiesel	Gans	OK	soy oil	10	N/A
Organic Fuels LLC	Houston	TX	multi-feedstock	30	Apr-06
Seattle Biodiesel	Seattle	WA	virgin vegetable oils	5	N/A
Sunshine Biofuels LLC	Camilla	GA	soy oil	6	N/A
Mid-Atlantic Biodiesel	Clayton	DE	multi-feedstock	5	N/A

APPENDIX G: CELLULOSIC ETHANOL TECHNOLOGY DESCRIPTION

Biochemical Conversion

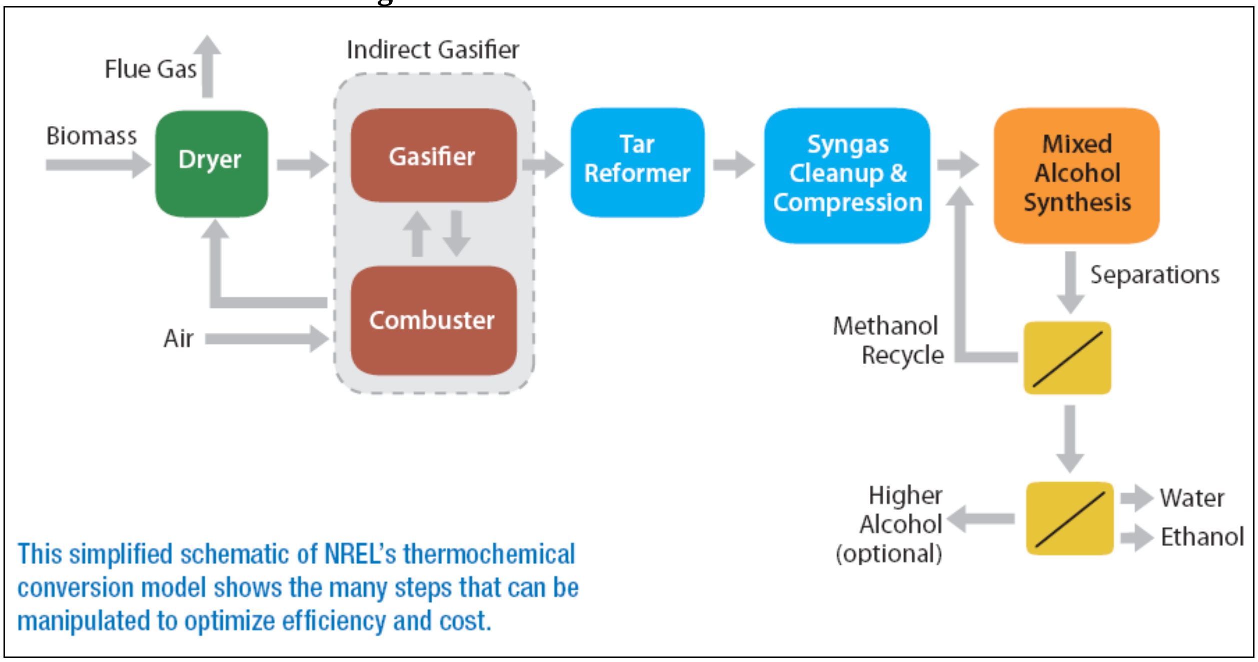
Biomass is composed of cellulose, hemicellulose, lignin and small amounts of fats and ash. Approximately two-thirds of the matter is composed of cellulose and hemicellulose on a dry weight basis; much of the remainder is lignin. The fermentable sugars in cellulose and hemicellulose are locked in complex polysaccharides. The first step is a pre-treatment process which generally involves acid hydrolysis (other options include steam explosion, ammonia fiber expansion, alkaline wet oxidation and ozone pretreatment) to dissolve the hemicellulose into xylose (five carbon sugar) and separate it from the cellulose and lignin. The cellulose then passes through an enzymatic hydrolysis process using cellulase enzymes to convert it into glucose. This is an area of intense research to find the best and lowest cost cellulase enzyme cocktails that speed up the release of sugars from cellulose. The released sugars then go through fermentation process where fungi and/or bacteria convert sugars to ethanol. This is a challenging environment as the incoming hydrolyzate (term used for slurry resulting from pretreatment processes) includes acetic acid and other compounds that are toxic to the fermentation bugs (fungi, bacteria, yeast). Research is focused on combining the correct combination of super bugs to maximize ethanol yield and tolerate the harsh operating conditions. Removed lignin will generally be combusted to provide heat for the production processes.

Leading companies that have or are building demonstration facilities include: Iogen, Abengoa, ADM, Poet, and Verenium Biofuels. Other companies exploring commercial plants using biochemical conversion technology are Colusa, Diversa, Dyadic, Xethanol, and Bluefire.

Thermochemical Conversion

In thermochemical conversion, heat and a catalyst are applied to biomass to produce syngas—a combination consisting primarily of carbon monoxide and hydrogen. This process converts all the cellulose, hemicellulose and lignin into ethanol. This is a particularly attractive process for conversion of wood products due to the high lignin contents. The overall process is similar to petroleum refining. The syngas produced from heating the biomass contains tar and sulfur that must be cleaned prior to reforming it into ethanol and other products. A simplified diagram of this process is shown below in Figure 19. Range Fuels and Nova Fuels are leading companies in using the thermochemical pathway for ethanol production.

Figure 19 – Thermochemical Conversion



(Courtesy of NREL)

Hybrid Conversion

This process involves gasifying biomass as described in the thermochemical conversion described in this chapter and then using specialized bacteria to ferment syngas into ethanol. BRI has patented several strains of bacteria capable of converting hydrogen, carbon monoxide, and other flue gasses into a range of chemicals including ethanol. The BRI process can use any feedstock that can be gasified including tires, MSW, cellulosic biomass, plastics, etc. Costaka is working with General Motors on a similar process. Energy requirements for this process are not available but assumed to fall between the requirements for biochemical and thermochemical pathways described in this chapter.

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[i] ***Greenhouse-Gas Emissions from the U.S. Transportation Sector: 1990-2003*, U.S. Environmental protection Agency, Washington, DC**

[ii] **U.S. Energy Information Administration, *Annual Energy Outlook 2005 with Projections to 2025*, Table A2. U.S. Department of Energy, Energy Information Administration, Washington, DC.**