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ANALYZING INDUSTRIAL EXPANSION: A REVIEW OF THE POTENTIAL FOR SUSTAINED ETHANOL PRODUCTION IN PENNSYLVANIA

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Abstract

Analyzing Industrial Expansion: A Review of the Potential for Sustained Ethanol Production in Pennsylvania

Rapid expansion of ethanol production in the United States is reshaping the industry. From 1999–2006, production increased an average of 29% annually. According to the Renewable Fuels Association, ethanol production will double again in the next five years. Corn is the primary feedstock for ethanol production in the United States. In the past, the Midwestern location of corn production dictated the co-location of ethanol plants. The effort by different states to meet the federal renewable fuels standard (RFS) is changing the regional distribution of ethanol plants. Expansion of ethanol production is now occurring in corn-deficient regions, like Pennsylvania. The beginnings of an ethanol industry in Pennsylvania emerged in 2008 as BioEnergy LLC began to construct the first plant, which was located in Clearfield, PA. Understanding this expansion and evaluating the location decision requires answers to two basic questions (1) "why here"; and (2) "can this location be competitive?" In this thesis, I conducted a critical case study and applied industrial location theory to answer these questions. This involved a direct price comparison of the most important input factors to show which locations have a cost advantage. Analysis of the feedstock, energy and utility costs demonstrated that on a like-fuel basis, a plant in Pennsylvania is not competitive with an identical plant in Iowa, for example. However, if a plant in Pennsylvania uses coal or waste coal as a fuel, then it can compete with a natural gas-fueled plant in Iowa. Ethanol production in Pennsylvania, to be competitive with production in Iowa, must rely on the use of coal. The outlook for this production is questionable based on pending and future federal legislation that will affect both national and state energy and environmental policy.

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Chapter 1 : Introduction

Alternative energy development is an increasingly important topic in the United States, which consumes significant quantities of petroleum products. A number of reasons for consumption reduction have been cited, including national security and the trade balance. Ethanol is one of the primary alternative fuels in the United States that is currently viewed as a viable option to gasoline in the near term. This perception has led to the development and rapid expansion of the ethanol industry, which has been driven by several factors. For example, the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 have mandated the inclusion of ethanol in the national gasoline supply. These Acts, combined with state-level bans on Methyl Tert-Butyl Ether and regional efforts to attract economic development, have helped to fuel the expansion.

Initially, the expansion of the ethanol industry was limited to the corn-producing regions of the Midwest. However, growth in demand has affected the pattern of ethanol production, including the construction of facilities outside of areas that have surplus corn. This indicates that the forces shaping the industry are changing. To examine these changes and the reasons for them, for this thesis research a case study was conducted on the construction of an ethanol production facility in Clearfield, Pennsylvania. Findings from this case study offer an opportunity to examine the forces that act to change the spatial distribution of plants.

Such forces are revealed in evaluations of industrial location decisions. After all, a good location affects the potential for future profit. In profitability's strictest terms, a company must be able to cover short-term variable cost expenditures. These variable costs are influenced by economic and political forces. The analysis of this location decision is taken in three basic steps. First, examination of the industry determines which factors of production are the most important variable costs. Second, an analysis of current prices for these input factors should be conducted. The third step is an analysis of market size and location as well as legislation and regulations that impact the location decision. Framing this analysis is the comparison of a plant in Pennsylvania and a hypothetical plant in Iowa, which serves to lay the framework for the reasons for selecting a production location in Pennsylvania.

An examination of the ethanol industry is the first step in this analysis, which also includes an examination of the application of industrial location theory in this analysis. The initial portion of the analysis may be found in chapter 2 and focuses on establishing which production input factors are the most important in terms of cost. The cost for corn feedstock and the cost of the energy expended on processing constitute more than 95% of variable input costs. The price variation of these two factors determines the economic profitability of the ethanol industry. The second portion of chapter 2 deals with determining the amount of corn and energy required per gallon of ethanol. These numbers reflect rates based on recently constructed plants. The usage rate is critical to determining the cost of inputs per gallon of ethanol produced.

Having determined which input factors are the most important to ethanol production and the commonly acceptable usage rates, the next step is to determine which methods can be used to analyze this information. Chapter 3 examines the use of industrial location theory, and shows that a limited analysis based on the spatial variation of input prices can be used effectively. Price variations between the location being evaluated and a previously successful location can be used to determine the ability of the new location to compete in the established market. Analysis of location theory raises two other points that must be addressed. First, the location and size of the market are key factors in determining the location's suitability. Second, other factors influence the decision, with one of the most important being laws and regulations. These two additional points are addressed in chapters 5 and 6.

The examination of the ethanol industry described in chapter 2 led to the identification of key input factors. In chapter 3, the examination of methods for applying location theory revealed two additional topics: market size/location and legislation/regulation These points, taken together, form the heart of the study and are discussed in chapter 4 (input costs), chapter 5 (market size and location), and chapter 6 (legislation and regulation).

The spatial variation of input costs observed in the market is described in chapter 4. Using two state-level locations (Pennsylvania and Iowa), the analysis shows the relative input costs faced by a producer in each state. The time period examined is 2008, or Market Year 2007 in the case of grain prices. From this analysis it appears that the competitiveness of ethanol production in Pennsylvania is not based on input prices. When examined on a like basis, both corn and energy prices are higher in the state. These findings add importance to the examination of both market size/location as well as legislation/regulation. Another line of inquiry raised is how a plant in Pennsylvania that is being fueled by coal compares to a plant operating in Iowa that is being fueled by natural gas. In this case a plant in Pennsylvania could take advantage of lower and more stable coal prices to compete with natural gas-fired plants. With the relative costs of inputs established, the next task, discussed in chapter 4, is to identify the relative size and location of markets served by ethanol production.

The size and location of markets for ethanol products is an important consideration. Iowa facilities already in production have a sufficient market for both ethanol, which is the prime product, as well as distiller's grains, an important byproduct. This chapter determines that a plant located in Pennsylvania has a larger market for ethanol than a plant producing in Iowa and that a sufficient market exists for the distiller's grains as well. One key portion of the analysis of the ethanol market is the definition of how ethanol can be incorporated into the liquid fuels market. The different methods of incorporating ethanol have distinct impacts on the size of the market. The analysis of market size and location segues into the discussion of legislation/regulation since the ethanol market is highly influenced by both federal and state policies.

Both state and federal laws and regulations play an important part in shaping the ethanol market and thereby influencing the location of ethanol production. One difficulty in determining the impact of legislation and regulation is that it cannot be analyzed in the simple terms of a $/gallon impact. The state of Iowa has more legislation and regulations on the book than any other state. Pennsylvania in comparison has less than half as many policy incentives on the books regarding ethanol production. One key piece of legislation in Pennsylvania that supports the use of waste coal power is the Alternative Energy Portfolio Standard. This policy classifies waste coal as a Tier II alternative energy which opens up opportunities for a plant in Pennsylvania that do not exist in other states. This chapter identifies several key pieces of federal legislation that could drastically reshape the ethanol market. The first is the import tariff which levies an additional tariff on all imported ethanol. The second is the blender's tax credit which gives an incentive to gasoline blenders to include ethanol in the fuel supply. The last is the Energy Independence and Security Act of 2007. This Act could serve to remove corn-based ethanol from the list of renewable fuels, thereby removing the incentive to consume ethanol to meet the Renewable Fuels Standard. The policy environment for ethanol production currently supports ethanol substantially; however, pending and future changes such as potential regulation of greenhouse gas emission call into question how future changes will impact the industry.

Commingling the forces of input price, market size/location and legislation/regulation results in a picture that aids us in evaluating the suitability of the location decision that is bringing ethanol production to Pennsylvania. Chapter 7 summarizes the dollar cost projections for input costs developed in chapter 4 and expands upon that analysis by including a long term price projection to 2030 to address how the relative costs will change in the future. If the market conditions and legislation/regulation discussed in chapters 5 and 6 continue unchanged, then ethanol production in Pennsylvania will be able to compete with production located in Iowa both in the short and long term. The discussion and analysis continued through chapters 4, 5, and 6 also raise several issues that would benefit from further research. Pennsylvania will likely rely on waste coal to fuel development of the ethanol industry. To better project the Commonwealth's ability to expand ethanol production and estimate waste coal prices, Pennsylvania needs to create an accurate database of waste coal resources. A second concern is the ability to and cost of the transition from corn-based ethanol production to cellulosic-based ethanol production once the technology becomes economically viable. The last concern is public opinion. Several projects in ethanol have run into stiff public opposition that has slowed the development of ethanol production in the state. The findings that point to the potential for profitable ethanol production in Pennsylvania combined with several issues that require further research results in several conclusions.

The most important conclusion is that ethanol production located in Pennsylvania and fueled by coal can compete in the ethanol market. More importantly, this study shows that the use of waste coal in a co-generation facility can increase process efficiency and thereby increase competitiveness. Additionally, the use of waste coal and co-generation could be an advantage in meeting the requirements of laws and regulations.

The first step in the process is to analyze the ethanol industry to gain an appreciation for its recent developments. The rate at which it has recently expanded and the forces that have shaped the industry as it currently exists are important information in an examination of this industry.

Chapter 2 : Ethanol Industry Overview

The first step in examining the expansion of the ethanol production industry into Pennsylvania is to gain an appreciation for the industry as a whole. Examining the origins of the industry and how quickly it has recently expanded help shed light on the forces that have shaped the industry in the past. In this chapter, the current spatial distribution of the industry is examined and the production of ethanol is broken down to determine its most important input costs. By determining which inputs have the most impact on the cost of production, the spatial distribution of plants can be examined further.

Although ethanol has recently received significant attention it has a long history as a transportation fuel. In 1899 four vehicles raced from Paris to Chantilly on ethanol; in 1925 Henry Ford proclaimed ethanol "The fuel of the future" (Kovarik, 1998). The history of ethanol as a liquid fuel is filled with mixed successes—one of the reasons it eventually lost market share to the petroleum industry. The first oil well was erected in Pennsylvania by Edwin Drake in 1859. In a short time the petroleum industry changed the liquid fuels market permanently. The rise of petroleum-based fuels like kerosene occurred in part due to government regulation. An alcohol tax levied at a rate of $2.08 per gallon to pay for Civil War costs also applied to fuel alcohol; after this kerosene quickly became the primary fuel (Kovarik, 1998).

Changes in market and regulatory conditions led to rapid expansion of ethanol production. Between 1999 and 2007, production increased by more than 342% (Renewable Fuels Association, September 28, 2008). During this same time corn use in ethanol production increased by more than 434% (National Corn Growers Association, 2009). In 1980, the Department of Energy (DOE) estimated that there were fewer than 10 ethanol plants producing fewer than 50 million gallons per year (DOE EIA, September 28, 2008). In 2008, production was expected to exceed 9 billion gallons (Renewable Fuels Association, January 12, 2009). The initial expansion of the industry remained in areas with surplus stocks of corn. However, recent expansion has moved beyond corn-rich areas. The expansion of ethanol production indicates that the forces behind the regional location of plants are changing.

The expansion of the ethanol industry is easily documented through production statistics. The spatial pattern is often captured in a static manner with a production plant map, as seen in Figure 2.1 (DTN Ethanol Center, February 14, 2009).

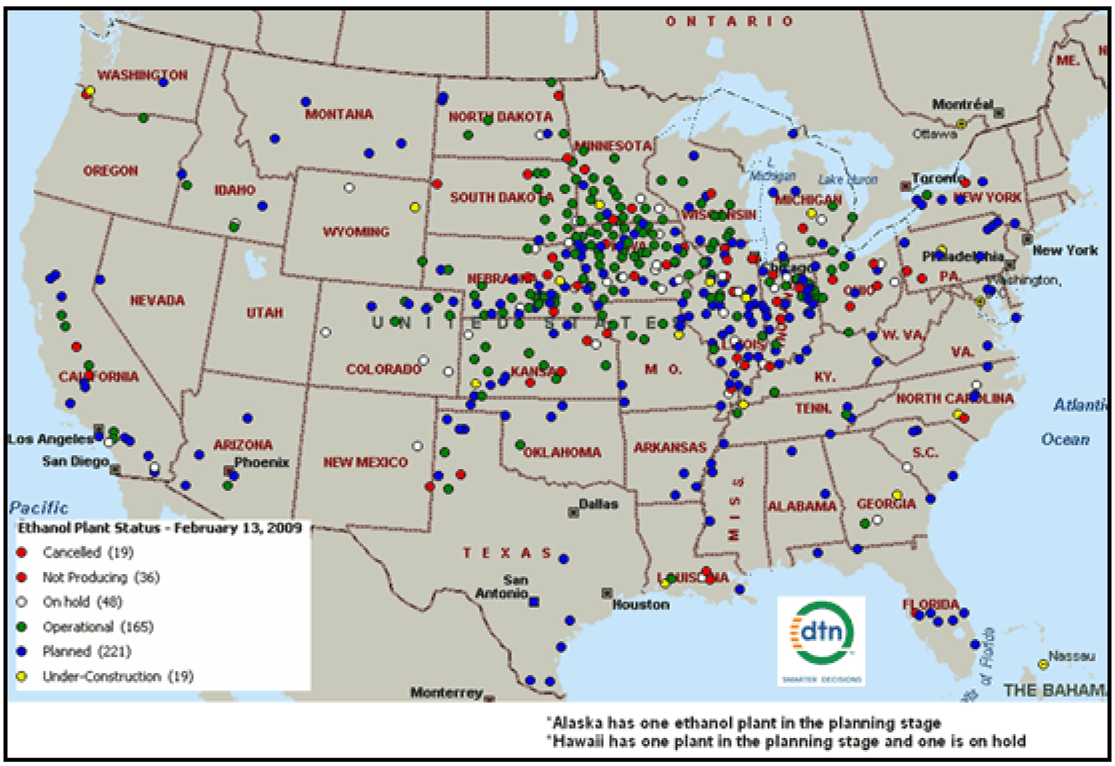


Figure 2.1 – Ethanol Plant Locations as of February 2009 – DTN Ethanol Center

This map offers a static view of the concentration of ethanol production in the Midwestern area commonly referred to as the “Corn Belt.” The blue dots and yellow dots mark the more recent expansion of the ethanol market and show a trend toward expansion outside of the previous confines of the corn-rich Midwest. An alternative method of capturing industry distribution is through production capacity statistics. Table 2.1 shows the number and total capacity of plants in each state as of November 2008 (Ethanol Producer Magazine, November 5, 2008). This table also shows the date on which operations commenced for the first and last plant constructed in each state.

State	# Plants	Capacity (millions of gallons)	First	Last
Iowa	34	2,823	Feb 02	Oct 08
Nebraska	23	1,427	1985	Oct 07
Minnesota	18	837	Nov 94	Jan 08
South Dakota	15	977	1988	Feb 08
Kansas	12	442	Jan 91	Dec 07
Indiana	11	794	Jan 07	Sep 08
Illinois	10	1,016	Feb 80	Aug 08
Wisconsin	9	521	Jun 02	Jul 07
Ohio	6	452	Oct 07	Mar 08
California	6	171	Jan 85	Sep 08
Missouri	6	236	Feb 01	May 08
Colorado	5	138	Nov 05	Oct 07
Michigan	5	262	Jun 05	Feb 07
North Dakota	4	238	Dec 06	Jun 05
Texas	3	240	Mar 08	Apr 08
Idaho	2	55	Mar 07	
Kentucky	2	37	Mar 04	
New York	2	150	Jan 08	Aug 08
Oregon	2	143	Jun 07	Dec 07
Arizona	1	50	N/A	
Georgia	1	100	Oct 08	
Louisana	1	1.40	N/A	
New Mexico	1	30	Jul 05	
Oklahoma	1	2	Aug 06	
Tenesse	1	60	N/A	
Wyoming	1	12	N/A	
Pennsylvania	0	0	*Jun 09	
Totals	182	11,215.40	Feb 80	Oct 08

Table 2.1 – Ethanol Production Capacity by State – Ethanol Producer Magazine

Limiting ethanol production to corn-rich areas was based upon the dominance of corn in the input costs. Appendix A contains a map of corn production by county in the Corn Belt. When compared to information in Figure 2.1 and Table 2.1, this map shows the concentration of ethanol production in corn-producing areas. One bushel of corn is needed to produce approximately 2.7 gallons of ethanol, and corn accounts for the single largest variable cost for ethanol producers (Gallagher and Shapouri, 2005). A plant in Pennsylvania producing 108 million gallons of ethanol per year would require 40 million bushels of corn or approximately 11,500 train car-loads of corn. This would account for more than one-third of corn production in the state in 2008 (USDA NASS, January 15, 2009). These factors combine to limit the extent of production, but corn is not the only important input factor in ethanol production.

2.1: Dominant Variable Cost Input Factors

The most important variable input costs for ethanol production are corn and energy. The amount consumed of each is discussed further in chapter 4. The USDA cost of production survey provides one estimate of the relative input costs based on surveys of operating plants. This study found that net feedstock costs account for almost 57% of the cost per gallon while energy (fuels and electricity) account for a little more than 18% of the per-gallon cost (Shapouri and Gallagher, 2005). Another study found the costs to be 58% for corn and 17% for utilities (Kwiatkowski et al., 2006). The numbers from Kwiatkowski et al. are depicted in graphic format in Figure 2.2. The role of corn in location decisions has been the subject of several studies, but the role of energy inputs is not as well documented.

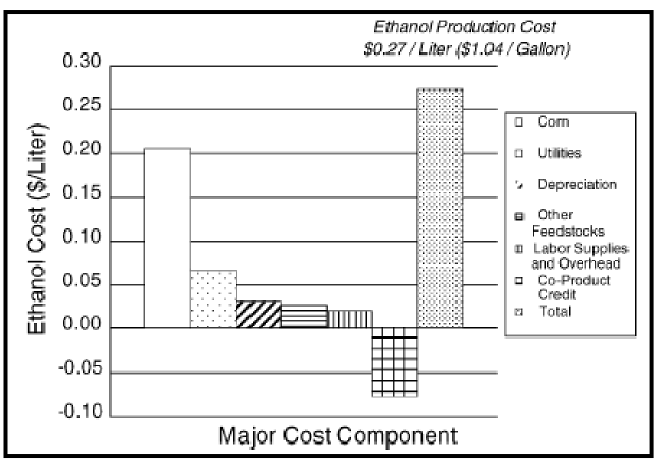


Figure 2.2 – Ethanol Production Costs

2.2: Input Cost Studies

Corn has been the most prominent factor in determining the location of ethanol plants. Many recent studies of plant location have based their analyses solely on availability of corn. In the humorously titled “Dude Where’s My Corn”, Eathington and Swenson (2007) addressed the availability of corn as a prime factor in location. In their study, Eathington and Swenson sought to develop a model to determine “the optimal placement of new ethanol plants based on the availability of feedstocks within a defined geographic territory” (p.1). The dominance of feedstock limits the discussion of market location or other possible comparative advantages which exist in areas outside ‘traditional’ ethanol-producing regions.

Even when factors beyond corn availability and price are considered, studies still limit the examination of plant location to areas with surplus corn. The University of Illinois produced a study that examined corn based ethanol production in 2007 (Eidman, 2007). In chapter 3 of the report, Eidman examined the potential cost savings from the use of coal and identified coal’s potential as an alternative fuel. However, his analysis used a generic national price for coal and did not explore the potential for locating a plant near coal production. The importance of corn and the dominance of the upper Midwest as the best location for production are also seen in Dhuyvetter’s analysis of future production locations (2005). Dhuyvetter found that the most important input factors are the cost of the feedstock and access to natural gas and electricity. On the output side, Dhuyvetter viewed ethanol and distillers grains as key features, and carbon dioxide in a minor role. Distiller’s grains are predominantly sold as animal feed while carbon dioxide is sometimes captured and sold to the beverage industry. The dominance of corn and distiller’s grains has led many studies to overlook the role of energy inputs and the location of ethanol markets. Dhuyvetter noted the importance of energy prices but viewed these forces as moving ethanol production closer to livestock locations. Co-location with livestock production takes advantage of energy savings by allowing plants to distribute Wet Distiller’s Grains (WDGs). Wet grains reduce energy requirements by removing the need to dry the grains. Wet grains are heavier and require shorter transport distances. By identifying the importance of energy inputs Dhuyvetter moves in the right direction, but does not examine the potential for altering energy inputs further to include other sources. In 2006 the USDA released a publication titled "A Guide for Evaluating Requirements of Ethanol Plants." The guide breaks down plant site selection criteria as follows: 1) Feedstock, 2) Energy Requirements, 3) Transportation, 4) Water Requirements, and 5) Site Size and Location. This study shows progress in addressing location concerns beyond feedstock. However, natural gas was still seen as the primary energy input. The USDA guide examines transportation, but chooses to focus on shipment of finished products and does not evaluate the potential for reduced product shipment distances versus short feedstock shipment distances.

The dominance of corn as the most important input factor for ethanol production has limited the scope of location studies. The construction of new plants outside of major corn producing regions shows that a potential for profit exists. Having determined which input factors have the greatest impact on the cost of production, the next step is to examine how industrial location theory can be used to evaluate the decision to place a plant in Pennsylvania.

Chapter 3 : Choosing the "Best" Location

Selecting the best location for industrial expansion of ethanol production is complex. Many different forces are at work in shaping the decision process. A simple location decision is based on the existence of only a few factors that all indicate one location as the best choice. A more difficult decision is based on an increased number of important factors, with at least two indicating a different optimal location. Defining what makes a location the best choice is also important. A company that is acting in a rational economic manner selects a location that will yield maximum profits as the best location. One important aspect of maximizing profit is minimizing costs. In this analysis the objective of the firm is to minimize the variable cost of the most important inputs. Other agents with a role in the location decision have different objectives. Local government wants to attract new companies to bring jobs and economic development to the region. State government works to create incentives and policies that will help the state economy and attract jobs to the state. The construction of an ethanol plant in Pennsylvania appears to be in conflict with the forces that have previously shaped the industry. An understanding of the way in which location theory has been applied in a location decision is important. Nearly as important is determining which forces outside of the cost minimization objective have exerted some influence on the choice.

Different actors occupy different spaces in the location decision framework. Private companies are generally left to decide which location will serve them best. Governmental actors and the private company often have different motivations. The intersection of their interests is often located in the findings from a technique known as the economic impact study. This technique attempts to determine the benefit to a region from a development project. Economic impact assessments are the sources for newspaper articles touting projects that create 70 full-time and 1,000 additional jobs during construction (Reynolds, 2007). While incredibly useful, the focus on economic impact does not interrogate the suitability of the location. Instead, this technique begins with the assumption that the location has been properly chosen and that the company will be profitable. The impacts of changing market conditions are ignored. The potential profitability of the plant is not questioned. Changing market conditions are important to the location decision and the long-term success of a company. According to *Ethanol Producer Magazine,* as of November 2008 there were seven corn-based ethanol plants that were idle due to market conditions (*Ethanol Producer Magazine* Plant List, November 6, 2009). In February 2009, this number had increased to 28 plants (*Ethanol Producer Magazine* Plant List, February 26, 2009). The costs of critical input factors, price of substitutes, and increased competition can change the potential profitability of a plant. Thus, the use of economic impact studies to shape governmental and public support of an economic development project sometimes fails to fully address the location decision.

3.1: Economic Impact Studies

In 2006 LECG L.L.C. released a study of the economic impact of the ethanol industry in the United States. This study proposed that ethanol production would add $8.9 billion to the U.S. GDP of over $13.06 trillion in 2006 (Urbanchuk, 2006). Additionally, the projection cited 143,350 new jobs, $3.9 billion in gains for consumers, $1.25 billion in federal and more than $800 million in tax revenues (Urbanchuk, 2006). These figures make a strong case for ethanol as a driver of economic development. A more focused analysis for Pennsylvania was part of a study by the Resource Systems Group in 2000. This study projected an increase of $1,032,000 in income for the state, the creation of 42 permanent jobs, and $64,000 in annual tax revenue (Resource Systems Group, 2000). Study findings were less optimistic and explicitly addressed concerns about future financial feasibility. More recent and detailed studies exist for the Midwest. Otto and Gallagher (2003) examined 12 farmer-owned facilities in Iowa and found that the 12 plants provided 403 jobs, $4.8 million in income, and $3.05 million in state revenue. Additionally, direct and indirect linkages were examined. These linkages explore the economic activity created in supporting and related areas from economic activity related to ethanol production. These additional linkages were estimated to produce an additional 1,500 jobs and $43.9 million in income. Swenson (2005) analyzed the impact of a plant located in Herbert, Iowa. According to his estimates, the plant will indirectly generate $66.2 million in regional industrial output, $11.84 million in value added, $4.2 million in income, and 135 jobs. In 2005 Stuefen released a study of the economic impact of ethanol production in South Dakota. He estimated a total impact that accounted for direct, indirect, and induced factors as well as for the cost of the ethanol subsidy provided by the state—for a total of $250.45 million in economic benefits. The numbers resulting from economic impact studies of ethanol production indicate that the construction of an ethanol plant is seen as an excellent economic development method. The concern about changing market conditions is enough to question expansion-based-only potential economic impact. Swenson himself found "a tendency for proponents of this industry to overstate, over-describe, and outright double-count economic activity linked to ethanol and other biofuels production" (Swenson, 2006, p.1). While economic impact studies offer appealing numbers to regional economic development planners, whether a project will remain profitable long enough to yield all of the benefits promised in an economic impact study is uncertain.

Based on the numbers offered in economic impact studies, ethanol appears to offer excellent opportunities to bring jobs to rural areas and income to the state. However, leaving the in depth analysis of the location decision to private firms renders a state vulnerable to changing market conditions and overstated economic impact numbers. An industry's long-term potential should be examined outside of the private sector. This is highlighted by the recent bankruptcy filing by Verasun Energy, one of the largest ethanol producers. The plant in Bloomingburg, Ohio, which began to operate in March 2008, is now idle and may yield little lasting economic benefit to the area (Sims, February 2009). Moving beyond economic impact studies is an important part of regional economic development planning. The challenge lies in the complexity of industrial location analysis. Most regions do not have the resources, and more importantly, the privileged information possessed by private firms to use in fully analyzing location decisions. Breaking down the location decision into a less complex process could yield the opportunity to examine location decisions more fully.

3.2: Industrial Location Theory's Impact on the Location Decision

A comprehensive industrial location theory study is exhaustive in nature. Even if it captures the analytical and quantitative data properly and uses it without error the output may not lead to a successful location decision. In his book, *Location, Location, Location A Plant Location and Selection Guide,* De Meirleir used numerous case studies to make this point. From standing deep-seated community feuds, to cultural misunderstandings, to outdated communications infrastructure, De Merileir showed that the location decision is a complex mix of number-crunching and personal interactions. The complexity of the decision prevents a definitive answer, but location theory offers some basic techniques that are useful in evaluating a decision. Analysis based on input costs, market locations and legislation can be used to compare two locations.

The cost to assemble goods at the point of production is an important piece of the location decision. Analyzing these costs is the basis of the foundational work by Weber as derived from his book, *Uber den Standort der Industrien* (1909; trans. Friedrich [1929], *Alfred Weber's Theory of the Location of Industries*). Weber's work is highlighted further in *Industrial Location an Economic Geography Analysis* (Smith, 1981). In Weber's construct, transport costs are the most important factor in determining plant location (Smith, 1981). Weber created the often repeated location triangle to serve as an illustration of this least-transport-cost method. Basing the triangle on one point of consumption and two material inputs is fairly simplistic compared to real markets. This method does highlight several interesting points, however. The first point from Weber is that these forces would exert pulls and create a least cost point somewhere in the triangle. The selection of an interior location is often not the case as production is located at the point of the most important material input or at the market. A second important point addressed by Weber is the introduction of weight-losing and weight-gaining industry. An industry in which the value-added processing steps create heavier production will be located closer to the market. An industry in which processing creates a product that weighs less than raw materials will be located closer to the heaviest raw materials. The location of ethanol in Pennsylvania does not appear to conform to Weber's traditional analysis. Located at a point distant from the key input of corn and yet not at the largest markets in the Eastern Seaboard, it initially appears to be somewhere in the interior of the location triangle. Applying the basic analysis from Weber may prove very beneficial in understanding the changing location of ethanol production.

One difficulty found in Weber's analysis is the conception of the market as a single point in space. The same assumption is made for sources of material input, but in this manner proves less troubling. Palander developed the concept of market areas by theorizing linear markets (Smith, 1981). Although Palander's work, *Beitrage zur Standorthstheorie*, was never translated into English, a summary of it may be found in *Industrial Location an Economic Geography Analysis* (Smith, 1981). The use of the linear market helps to account for differential costs in shipping materials and the final product. A plant can locate at a location that is not the least-cost production location if transportation costs for the product are significant enough to differentiate the market. Under this conception the location of ethanol production in Pennsylvania could be profitable if the production is better able to serve market areas less accessible to the Midwest production.

3.3: Important Location Theory Studies

Weber's and Palander's work served as the foundational structure for this study. Several important case studies and a piece of later work provided a more direct line of inquiry that shaped this study. The case studies focused on the U.S. steel industry, which has been the subject of location theory analysis. The case studies show that as technology changed, the Pittsburgh area lost its advantage in producing steel, which stemmed from close locations to coking coal deposits. This point is raised because a similar process could be eroding the Midwest's advantage and bringing ethanol production to the area once dominated by coal and steel.

The shift away from steel production in Pittsburgh was hampered by the base point pricing system (Isard and Capron 1949). There is no indication that a similar system exists in ethanol pricing. The lack of a base point pricing system could help explain why minor changes in input costs are leading to expanded production beyond the Midwest. Isard and Capron (1949) explored the changes taking place in the steel industry. Their approach consisted of first examining the cost of assembling the major components for steel production at one location. They then examined the cost of serving selected markets. A similar method was employed in this study. Examining the costs of assembling raw materials at a location of production provides a sense of the relative cost of production at that point. A sole focus on this least-cost production location also discounts the costs of serving the market, however. Analyzing the cost of serving the market and transport costs can lead to the situation noted by Palander, where a higher production cost location can compete due to the relative location of the market.

A more recent approach to the transportation cost problem comes from *The Economics of Industrial Location: A Logistics Cost Approach* (McCann, 1998). McCann added into logistics analysis the concept of inventory costs and concluded that transportation costs are a small portion of the overall distance costs. This is contrary to much of the analysis based on Weber and Palander's work. Additionally, McCann viewed the value of the goods being shipped and the value added by the firm as key factors in determining transportation costs. McCann's work could further support the relative advantage of the Pennsylvania location if value-added activities outweigh transportation costs and inventory holding costs are diminished. Several key critiques of Weber and Palander should be addressed also. McCann and Shepard (2003), in their article titled "The Rise and Fall of Location Theory

Again", addressed several important points. Forces of agglomeration is the one most applicable to this study. What forces act between firms operating in overlapping markets for raw materials and products? The savings or benefits that accrue to a company from being located near other similar producers are not considered. Agglomeration forces could yield an additional advantage to production in the Corn Belt via a larger workforce already trained in ethanol production and could benefit from having support services readily at hand due to the larger market size afforded by the density of production.

Also discounted by Weber and Palander are impacts on the environment and goods that are not explicitly valued in the production equation. Accounting for environmental impacts would seem to be a prime concern for the location of an ethanol production facility. However, both Levinson (1996) and Bartik (1988) found that environmental regulations did not play a dominant role in the location decision. Bartik indicated that the effect of environmental regulations only played a part in decision-making by high-polluting industries. Ethanol production facilities are not major polluters but changing governmental regulations may change this situation. The addition of a new life-cycle analysis Green House Gas emissions standard for ethanol production or new regulation of carbon emissions could rapidly reshape the ethanol market. The possible impacts of these changes is addressed in Chapter 6.

3.4: Other Factors Influencing the Location Decision

Legislation and regulation are a critical piece of any location decision. A location can appear to be superior based upon the geographical advantages of the site and labor market, yet be a poor overall choice based on legislation and regulation. Numerous pieces of legislation and regulation impact the market. Legislation at the national and state levels is discussed further in chapter 6.

One example in the U.S. market is the 54-cent-per-gallon tariff excised on all imported ethanol (Elobeid and Tokgoz, 2006). This tariff has been the focus of several studies. Understanding the impacts of the tariff is made easier by the 2006 study published by Elobeid and Tokgoz through the Iowa State

Center for Agricultural and Rural Development (CARD). This document showed the impacts of the tariff on the overall market and is supplemented by several other studies. Duffield and Collins (2006) detailed the evolution of federal legislation on the entire renewable fuels market. They captured a piece-meal approach that resembles a patchwork quilt of legislation rather than a focused legislative effort. Legislative forces primarily involve agricultural legislation, environmental legislation, energy legislation and trade regulation. Combined, they set the conditions that favor the domestic ethanol production industry. These varied pieces of legislation are discussed more fully in chapter 6. A more focused study is included in a paper by Zhange et al. titled, “Can the U.S. Ethanol Industry Compete in the Alternative Fuels Market” (2007). This study claimed that the industry’s survival depends upon federal legislation. Zhange indicated that without the support of the tariff and an additional $0.51/gallon blender’s credit, ethanol production would not be profitable in the United States.

The role of government support works at both the national scale and the state level. Bradbury et al. (1997) examined how incentivizing construction of an ethanol plant can create regional competition as different companies vie for government support. This competition among specific locations could explain the number different projects now in the planning stages in Pennsylvania (U.S. Chamber of Commerce, April 26th, 2009),(Ethanol Producer Magazine, September 2003),(Heinrichs, 2008). As production in Pennsylvania becomes a reality, different locations compete among themselves to be the first in the state. These studies all indicate that the industry, as currently conceived, is dictated largely by federal legislation and regulation. These forces will continue to shape the industry and contribute greatly to determining both its size and location.

3.5: Simplified Location Theory: A Critical Case Study

Conducting a thorough location theory study is an exhaustive process. It can be difficult for regional economic planning commissions to evaluate the location decision made by a private company.

The decision often involves proprietary information that is critical to the company's success. Regional planners rarely have the ability to fully evaluate the decision made by a company. Location theory offers the ability to conduct a limited analysis that can prove very beneficial. This limited analysis will not capture the dynamics of the market or the true complexity of the decision. However, it can offer insight into the quality of the location and some current and potential future challenges. By conducting a limited analysis based on input costs, market size/location, and relevant legislation/regulation, regional planners can increase the likelihood of creating sustained economic development. This is a critical case study approach.

An analysis of the decision-making that attends the locations of ethanol production in Pennsylvania provides insights that are important in understanding the ethanol industry as a whole and particularly the future success of production within the state. The limited analysis reveals important questions that should be asked by regional planners during the initial phase of the location decision and highlights public policy issues that will influence the industry in the future. The first step in this process is to examine the inputs that have the most influence on the cost of production.

Chapter 4 : Input Costs

Assembling the factors of production in one location is a process that is relatively simple. Finding a location where this can be done at a competitive price can be more difficult. The cost of inputs is a critical factor in determining where to locate industrial production. As seen in Chapter 2 the most important inputs for ethanol production are feedstock and energy. Corn serves as the primary feedstock in the United States and is currently the largest input cost. Energy or utilities are the second largest input cost for ethanol production. Examining the cost of these two factors and its variance by region is the most important step in evaluating the location decision. Mapping the cost of corn and energy across the entire country to identify where both are the lowest is beyond the scope of this study. The best method to conduct a critical review of the Pennsylvania production location is to compare it to a location that has been selected most often in the past. Table 2.1 shows Iowa as the most commonly selected location for ethanol production with 34 plants. It also has one of the most recently completed ethanol plants with an online operational date of October 2008. Comparing input costs between Pennsylvania and Iowa serves to evaluate the relative cost of inputs between the two. If a plant in Pennsylvania can obtain a cost advantage compared to a plant operating in Iowa it can likely compete in the wider ethanol market.

4.1 Utility Overview

The term utilities generally encompass several different inputs. An energy source is needed to provide heat for the process. This is normally natural gas, but coal is also a possible alternative. A survey conducted in by the Renewable Fuels Association in 2007 found that natural gas meets 79.2% of the energy needs for dry-mill plants while coal meets 12.7% of the energy needs (Wu, 2008). The appeal of coal comes from its more stable price history combined with an abundant domestic supply. Natural gas is more easily transported and plants using natural gas require fewer BTUs of energy. Electricity is also a component of utilities and is required for general plant operations and accounts for 7.9% of energy needs in dry-mill plants (Wu, 2008). These utility inputs have a distinct influence on the cost of operation and the potential for profit. Shaping this discussion requires answering several questions. First how much energy is needed to produce ethanol? Second, how much do these energy inputs (electricity, coal and natural gas) cost? Lastly, how are these prices expected to change in the future? The remainder of the utility discussion focuses on answering these questions.

The USDA cost of production survey published in 2005 offers a comprehensive view of the relative costs of these three inputs to the overall cost of operation. The most significant input in terms of the cash operating expenses is fuels. From 1998 to 2002 the cost for fuels increased more than 50% increasing the overall share of cash operating expenses from 22% in 1998 to 33% in 2002 (Shapouri and Gallagher, 2005). This increase is more than any other category other than denaturant. The rise in fuels cost between 1998 and 2002 is attributed to a 61% rise in natural gas prices (Shapouri and Gallagher, 2005). During this same time net feedstock costs only increased from 56% to 57% of total expenses (Shapouri and Gallagher, 2005). Feedstock remains the dominate cost factor but energy inputs are becoming increasingly important. Determining the amount of energy needed to produce ethanol is the first step in the analysis.

4.2 Energy Inputs

Ethanol production is an energy intensive industry. Identifying energy supplies is a critical portion of making the location decision. Energy supplies should be stable with regards to both availability and price. In the past this has lead to two main choices being natural gas and coal. The discussion surrounding natural gas versus coal for fueling ethanol production is not new. The use of coal as a replacement for natural gas gained wider attention starting in 2004 (Bryan, 2004). The benefit from coal comes principally from its lower cost. This benefit is offset by increased costs associated with using coal. These costs include increased handling costs as well as increased capital costs to construct more expensive equipment to burn coal (McElroy, 2006). Two other disadvantages exist for coal. The first is that “there is no such thing as a generic coal conversion system” (McElroy, 2006). Essentially every coal burning facility is tailored to the chemistry of the coal that is being used as a fuel source. Circulating Fluidized Bed reactors can help overcome some variance in the fuel source, but the uniformity of the input is still a concern. The other factor is the increased carbon emissions from coal. Using coal to produce ethanol will result in roughly a doubling of carbon emissions (Energy and Environmental Analysis Inc., 2007). Coming to a conclusion on which fuel better serves a plant must balance these considerations. For some plants though the choice of coal is a good one. The possibility of future CO_2 regulation could change the cost benefit analysis for the use of coal. Regulation of CO_2 emissions creates an entirely new market that will offer both opportunities for sequestration as well as challenges for emissions. In 2007 Red Trail Energy LLC in Richardton, N.D. began producing ethanol using coal as an energy source (Nilles, 2007). The use of coal offers other opportunities as there is a subset choice within the coal category.

Coal differs not only in geographic source but also in the type of source. The more widely publicized source is a mining company that ships coal extracted from the earth. This coal is delivered in a fairly uniform in quality. Additionally, long term contracts are often available that offer price stability. Another source of coal is waste coal. This waste coal can take several different forms and therefore names also. Coal fines are leftover from processing coal for use in industrial applications. Culm and gob are left over waste piles from mining operations. These piles pose an environmental hazard and represent an untapped energy source. Waste coal is generally available more cheaply than coal (prices are discussed more fully later in this chapter). Its disposal also offers an environmental benefit as the piles are the source of acid runoff. Waste coal requires processing prior to use and the cost of that processing is captured in the pricing based on delivered costs per million BTUs. Photo 4.1 shows a waste coal pile similar to those found throughout Western Pennsylvania (Abandoned Mine Reclamation Clearinghouse, March 28th, 2009). The impact these piles have on the landscape is unmistakable.

Photo 4.1 –View of a Waste Coal Pile – Abandoned Mine Reclamation Clearing House

Photo 4.2 – Runoff from a Waste Coal Pile - Abandoned Mine Reclamation Clearing House

The use of waste coal can provide a low cost energy source for ethanol production while also offering an opportunity to clean up the landscape. It has been used as a fuel source for electricity generation in Pennsylvania for over 20 years (McGinty, 2004). This environmental benefit may offset some of the negative perception of carbon emissions from coal. Another opportunity exists to improve energy efficiency in ethanol production through the use of co-generation. The two options of waste coal and co-generation offer a unique opportunity for ethanol production in Pennsylvania.

Something that could change the face of energy consumption in ethanol production is the use of co-generation. This is achieved by either using the waste heat from an existing industry or power plant as an energy source for ethanol production or by an ethanol facility providing waste energy to another customer. In the case of Pennsylvania ethanol production one of the earliest conceived projects was located in Curwensville and relied on coal power (Ethanol Producer Magazine, 2003). This project would provide waste steam heat from burning waste coal to the community. Co-generation is also an option for natural gas facilities, but in this case it is unlikely that the ethanol plant would be a provider of waste heat. Co-generation promises to reduce the energy needs of ethanol production in the future by nearly 55% (Wu, 2008). In 2007 there were five gas turbine cogeneration plants operating in the U.S. (Wu, 2008) The first coal fired cogeneration project was started in 2003 and slated to come online in 2007, but bankruptcy delayed the start to fall 2008 (Voegele, 2009). The long term effectiveness of cogeneration in ethanol production is not yet known, but it promises to make ethanol production much more efficient in the future. Minimizing fuel costs through the use of coal power combined with cogeneration could speed the reshaping of the ethanol market that appears to be taking place already. Without reliable data on the costs of production for cogeneration the cost of production for standard dry-mill production is used. Understanding how the future pattern of production might emerge relies on understanding what forces are influencing current location decisions. The first step is to determine how much energy is required.

Creating an estimate of how much energy is used per gallon of ethanol allows a comparison on a $/gallon basis. The USDA cost of production survey also offers a starting point to determine average energy input requirements. These numbers are generated by a survey of 21 dry mill plants all which operated using natural gas. The survey found, that on average, plants used 1.19 kWh per gallon of ethanol produced. The range was from 0.6 kWh to 2.0 kWh per gallon. For thermal inputs the average amount was 34,800 BTU per gallon with a range from 26,000 to 54,000 BTU per gallon. In the survey Shapouri and Gallagher state newer ethanol plants are using less than 30,000 BTU and less than 1 kWh per gallon of ethanol produced. Rhys Dale and Wallace Tyner offer similar numbers in an April 2006 staff paper from the University of Purdue. According to their estimates ethanol production requires 31,879 BTU and 1.17 kWh per gallon of ethanol (Dale and Tyner, 2006). This would indicate that the 30,000 BTU and 1 kWh estimate for newer plants made by Shapouri and Gallagher from 2002 data is a very reliable estimate for new plants and plants still under construction. Another key consideration is the difference between coal and natural gas as a fuel source. Natural gas burns much more cleanly than coal and the two do not substitute on a 1:1 basis in ethanol production due to differing energy content. Douglas Tiffany at the University of Minnesota states the usage rates for electricity and fuel are slightly different at plants fueled with coal. The thermal input required in coal and biomass plants is 37,000 BTU/gallon compared to a stated 34,000 BTU/gallon for natural gas (Tiffany and Eidman, 2006.) The electricity required is also slightly greater averaging 0.20 kWh higher in coal plants than natural gas plants (Tiffany and Eidman, 2006). These translate into 8.8% increase in BTUs required and a 16% increase in electricity required for ethanol production. Based on the 30,000 BTU and 1 kWh estimate for natural gas a modern coal fueled ethanol plant would require 32,640 BTUs and 1.16 kWh of electricity.

These final figures for natural gas and coal are used in this analysis.   With the amount of energy required determined the analysis turns to determining appropriate prices.

4.3 Utilities Prices

The Federal Energy Regulatory Commission (FERC) provides excellent estimates for fuel prices. Figure 4.1 compares oil, coal, and natural gas spot prices at the national level.

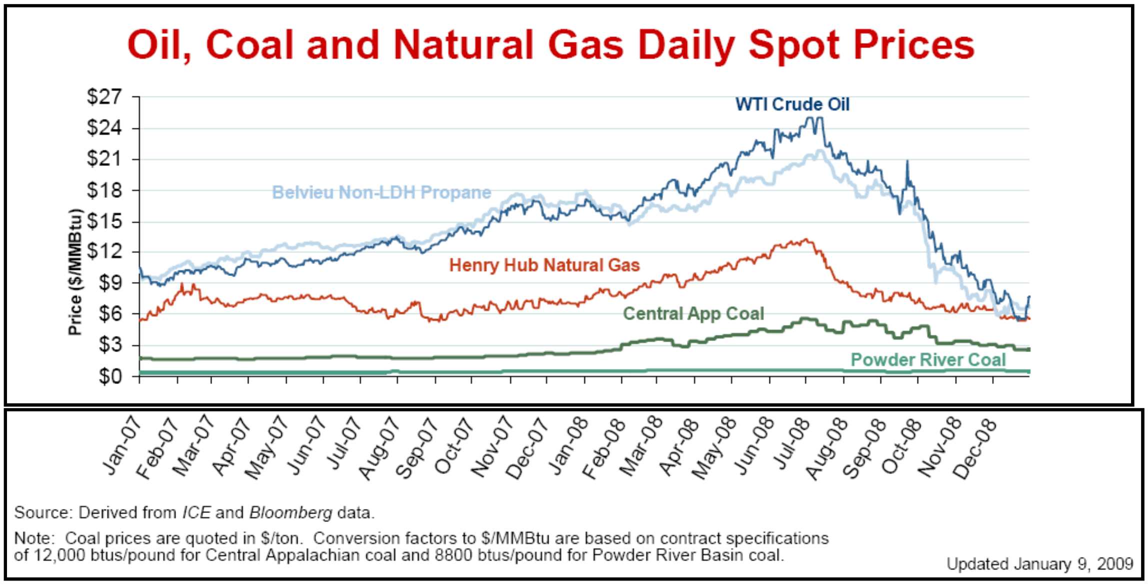


Figure 4.1 – U.S. Fossil Fuel Spot Prices Jan 2007 to Dec 2008 - FERC

From this figure it is apparent that natural gas prices fluctuate more than coal prices. This is true for both Central Appalachian Coal and even more so for Powder River Basin (PRB) coal. Additionally, from the figure it is apparent that there is, as of December 2008, nearly a $3.00 per million BTU difference between natural gas and Appalachian coal. There is an even more significant spread between PRB coal and natural gas. These differences are important in determining what figure should be used in comparing the operating expense for coal fueled versus natural gas fueled ethanol plants. These price figures highlight the national picture, but may not accurately capture prices at regional levels. To determine which prices should be used regionally, the EIA data for commercial customers provides a better figure.   These numbers are compiled at a state level and capture regional differences that occur due to uneven influence of futures trading and demand/distribution issues. The price for natural gas varied widely in Pennsylvania during the previous eight years. Table 4.1 shows data for 2000-2007 for commercial and also residential customers (DOE EIA, September 11th, 2008). Commercial prices for natural gas have increased 96% over the last seven years or around 13.7% annually. The range for price variation is $6.40 and the mean value is $10.47. National natural gas prices for 2008 not including November and December have averaged $12.51 per million BTU (DOE EIA, December 11th, 2008). For Pennsylvania the average price for the same time period is $15.05 per million BTU (DOE EIA, December 11th, 2008). Prices for natural gas in Iowa are significantly different from Pennsylvania. In Iowa the price for natural gas for calendar year 2008 through October is $11.09 per million BTU (DOE EIA, December 11th, 2008). The price difference between the two is nearly $4.00 per million BTU or nearly 36% more expensive for a commercial customer in Pennsylvania. This factor alone would discourage ethanol production in Pennsylvania. While natural gas is by far the most common fuel used in the production of ethanol, the use of coal is an option.

PA Natural Gas Prices ($/million BTU)	Residential	Commercial
2000	8.26	7.51
2001	11.20	10.38
2002	9.20	7.49
2003	10.57	9.01
2004	11.94	10.31
2005	13.82	12.68
2006	16.00	13.91
2007	14.28	12.47

Table 4.1 - PA Natural Gas Prices 2000-2007

Coal has received more attention over the last four years as a possible fuel for ethanol production. If coal prices are sufficiently lower than natural gas they could potentially make ethanol production in Pennsylvania competitive with an existing natural gas plant. As shown in Figure 4.1 coal is substantially less expensive than natural gas also much less price volatile. The EIA maintains the prices for 2008 by state for industrial customers that purchase coal. The price and energy content of coal varies by region. In Pennsylvania the average price for 2008 is $62.60 per short ton. To convert this price to an equivalent $ per BTU content the average value for BTU per lb for Appalachian coal of 12,000 BTU/lb. is used. This conversion yields a price of $2.60 per million BTU. From 2007 to 2008 Pennsylvania faced a 14.9% increase in coal prices. Coal prices in Iowa are slightly lower per short ton, but when converted to a BTU basis they end up being slightly more expensive. Iowa averaged $48.60 per short ton during 2008. Coal consumed in Iowa is imported principally from the Powder River Basin (PRB) region (DOE EIA, December 12th, 2008). This coal has a lower thermal content than the Appalachian coal due to higher oxygen value and moisture content. It is converted to BTUs using an average net calorific value of 8,000 BTU/lb. The conversion yields a price of $3.04 per million BTU. From 2007 to 2008 Iowa experienced a 10.4% increase in coal prices. The cost per million BTU of coal in Iowa differs from that seen for PRB coal shown in Figure 4.1 due to the inclusion of delivery cost. Pennsylvania does import some coal from the PRB region but it was only approximately 6.0% of total coal used in the state (DOE EIA , March 28th, 2009). Based on these numbers, in a $/BTU basis, Pennsylvania enjoys an almost 17% cost advantage in fuel. Coal fueling, however, requires 8.8% more thermal input on a BTU basis as previously discussed. Equating natural gas to coal requires incorporating this additional conversion factor. Per million BTU of natural gas Iowa paid $11.09 while a coal fired plant in PA would face an adjusted cost of $2.83 per million natural gas equivalent BTUs.

Another coal fueling option exists for PA. The employment of waste coal offers a unique opportunity in the state. The EIA maintains data for delivered cost of cleaned waste coal to non-utility customers on a cents per million BTU basis (McNerney, 2008). This fuel has a significantly lower fuel cost coming in at $1.79 per million BTU. Comparing the figures for natural gas, coal, and waste coal for PA yields a fuel cost comparison. The results are summarized in Table 4.2 below. Iowa enjoys a more than 35% cost advantage when employing natural gas as primary energy source. When coal is used Pennsylvania enjoys a 16.6% cost advantage. However, when waste coal is used as the primary fuel in

Pennsylvania compared to natural gas in Iowa the cost advantage for Pennsylvania increases to more than 69%.

There are additional considerations when using waste coal that result from it being considered a Tier II renewable energy in Pennsylvania under the State's Alternative Energy Portfolio Standard (AEPS). These considerations are discussed further in Chapter 6.

2008 Fuel Costs	Natural Gas $/Million BTU	Coal $/NG BTU	Waste Coal $/NG BTU
Pennsylvania	15.05	$2.83	$1.95
Iowa	11.09	$3.30	N/A – coal figure used
Cost Difference PA-IA	-35.7%	+16.6%	+69.2%

Table 4.2 - Energy Costs (coal based on equivalent natural gas BTU rating)

While coal and natural gas serve are the dominate energy sources for ethanol production electricity is also an important input cost. The cost of electricity varies across the country and also varies by season and even daily based on overall loads. Regional prices can vary widely based making the examination of electricity costs an important consideration.

The FERC maintains spot and peak prices for electricity by region. Iowa and Pennsylvania are in two different electric power markets. The rates in Pennsylvania are slightly higher than in Iowa. The average on-peak spot prices for electricity for the PA market is taken from PJM West figures and was $71.15 per mega-watt hour (mWh) which is a $9.25 increase from the previous year (FERC, November 14th, 2008). This converts into $0.07115 per kilo-watt hour (kWh). The same price for Iowa taken from the NI hub in the Midwest is $58.93 per mWh which is an increase of $6.41 from the previous year (FERC, November 14th, 2008). This number converts to $0.05893 per kWh. These prices reflect spot prices for on-peak demand. In other words, these reflect the maximum rates paid in each region.

Another price per kWh paid by industrial customers is taken from the EIA utility database. This number serves as an average cost paid by industrial customers for calendar year 2008. Industrial customers in PA paid $0.0699/kWh while industrial customers in IA paid $0.046/kWh (DOE EIA, Dec 12th, 2008). Iowa enjoy nearly a 52% cost advantage for electricity costs.

With usage rates determined and price estimates defined a cost comparison is needed. The numbers above show that Iowa's fuel costs are lower for both electricity and natural gas, but slightly higher for coal. To further that analysis energy prices are compared across fuel types (natural gas vs. coal). Additionally, projections for future price trends are also developed to indicate whether the current cost advantages are expected to continue or change drastically in the future.

4.4 Utility Price Comparison

When compared on an identical natural gas fired plant basis Iowa possesses an advantage in both electricity and fuel. If coal is used as the fuel, Pennsylvania possesses a slight advantage in fuel and a disadvantage in electricity. However, if an Iowa plant uses natural gas while a Pennsylvania plant uses waste coal, PA possesses a significant cost advantage due to energy prices. The results are summarized below (Table 4.3) on a per gallon energy input basis.

	Electricity		**Natural Gas**		**Coal**		**Waste Coal**	
	$/kWh	$/gallon	$/mBTU	$/gallon	$/mBTU	$/gallon	$/mBTU	$/gallon
PA	0.070	0.081	15.05	0.452	2.83	0.092	1.95	0.064
IA	0.046	0.046	11.09	0.333	3.30	0.108	N/A	N/A
PA - IA		-43%		-26%		17%		69%

Equivalency Factors			
1	kWh	1 gallon ethanol	NG
1.16	kWh	1 gallon ethanol	coal
0.3571	bushel	1 gallon ethanol	
30,000	BTU	1 gallon ethanol	NG
32,640	BTU	1 gallon ethanol	coal

Table 4.3 - Ethanol Production Energy Cost Summary

The relative cost savings show that Iowa has a significant advantage if both plants use natural gas and is at a slight disadvantage if both plants were to use coal. These numbers show relative advantage but it is also useful to examine how these figures translate into annual costs based on a plant producing 108 million gallons per year (mgpy).

	Electricity		Natural Gas		Coal		Waste Coal	
	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost
PA	0.081	8,769,600	0.452	48,762,000	0.092	9,976,090	0.064	6,873,984
IA	0.046	4,968,000	0.333	35,931,600	0.108	11,632,896	N/A	
PA-IA	-43%	-$3,801,600	-26%	-$12,830,400	17%	$1,656,806	69%	$4,758,912

Table 4.4 - Energy Costs for Ethanol Production of 108 million gallons annually

Iowa	Pennsylvania	Advantage	
Gas	Gas	IA	$16,632,000
Coal	Coal	IA	$2,144,794
Coal	Waste Coal	PA	$957,312
Gas	Coal	PA	$20,497,104
Gas	Waste Coal	PA	$25,256,016

Table 4.5 – Ethanol Production Energy Cost Comparison

The estimated annual costs are shown in Table 4.4 for a comparison between like fuels. This comparison shows relative advantages in each category but does not compare costs for plants using different fuel types. Allowing plants to use different fuels demonstrates how a PA plant would compete with existing natural gas plants based on energy costs. Table 4.5 is based on annual costs and accounts for Iowa always having a nearly $2.6 million per year advantage based on electricity costs. From Table 4.5 it appears that the options that give Pennsylvania a significant cost advantage is the use of coal when an Iowa plant uses natural gas. This cost advantage is increased if waste coal is used. If plants in Iowa can switch to coal or if new plants are built using coal then it is unlikely that Pennsylvania will be able to create enough of a cost savings to cover the cost the additional cost of importing corn into the state. Fuel switching between coal and natural gas is not a simple process. A significant portion of capital infrastructure would have to be replaced. It is unlikely an existing plant would switch fuel sources and there are no documented cases of a plant switching between fuels. The figures above reflect the estimated energy costs based on average energy prices in 2008. Determining a potential range for future prices will indicate whether these advantages might change significantly. The overall price trends and the price volatility determine the outlook for future costs. Discussion in sections 4.5 and 4.6 focuses on future price projections and volatility. These are then brought together after a discussion of corn prices in Section 4.11 to generate a comprehensive review of input prices for both 2008 and 2030. These two time periods demonstrate the current and likely future price scenarios that a plant in Iowa or Pennsylvania will face.

4.5 Utility Price Future Projections

The previous analysis has focused on energy prices in 2007/2008. While relevant for the current location decision these prices are not necessarily indicative of future price behavior and the risk associated with price changes. Examining the likely changes in prices in the future is an important piece of evaluating the location decision. Large scale capital intensive projects such as an ethanol plant see operating life-spans of 30-60 years that guarantee they will experience significant changes in input costs over the life of the facility (Nilles, 2006).

Price volatility and historic price trends are a good entry point for establishing possible future price scenarios. Price variance is very different in the three energy markets examined here. It will be shown that natural gas experiences the most volatility, but this does not necessarily mean that it will experience the greatest average price increase over a more extended period. These projections serve as an estimate for examining future changes in profitability and the relative advantage of different locations and fuels.

Data from the EIA serves as the basis for this analysis. The general trend for nominal dollars is increasing prices from all three energy sources. There are some price fluctuations, but in terms of nominal dollars these are small. When examining real dollars the situation is different. Comparing the

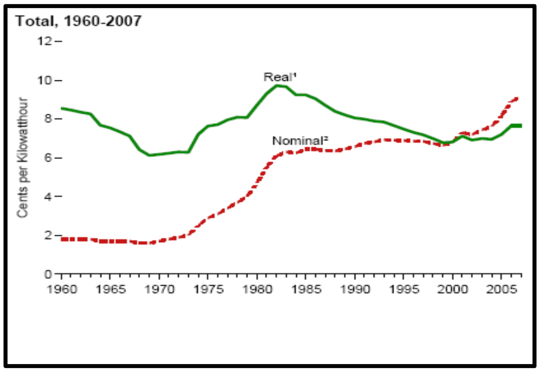


Figure 4.2 – Electricity Prices 1960-2007 - EIA

price between 1970 and 2007 coal increased 7% in terms of real dollars; electricity increased 48% while natural gas increased 764% (EIA Annual Energy Report, 2007). This is only a comparison between a beginning year and ending year price and may not capture price trends throughout the period accurately. Figure 4.3 and

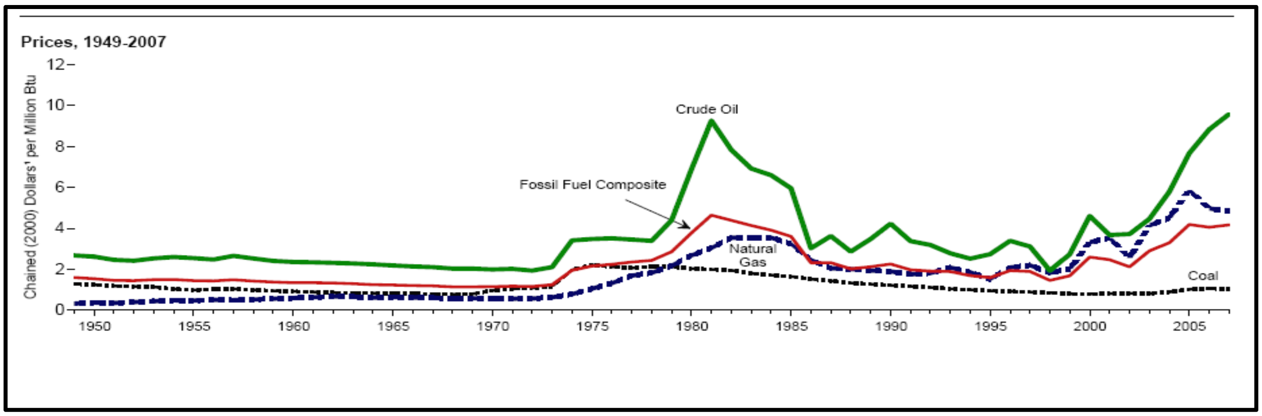


Figure 4.4 - Fossil Fuel Prices – 2007 Annual Energy Review (released June 2008)

4.4 below from the 2007 Annual Energy Review graph the price trends for electricity and fossil fuels respectively.

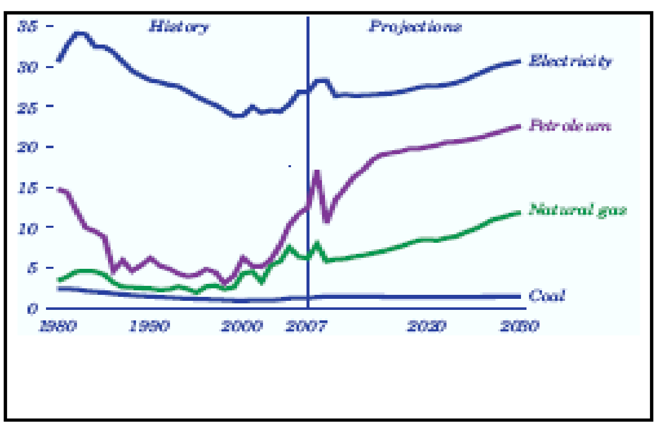


Figure 4.3 – Annual Energy Outlook 2009 Energy Price Future Estimates

Taking the data that make up these graphs and running a simple statistical analysis helps to reveal what trends are present and helps to further the discussion. The complete fuels price table for Electricity, Coal and Natural Gas is contained in Appendix B. Minitab version 14 was used to identify trends present in the data. The data for electricity, coal and natural gas were all normal with a 95% confidence interval. The most interesting aspect comes from the trend analysis of the data. Using a linear trend model results in a negative slope for coal (-0.029) and electricity (-0.014); both of these inputs have actually become less expensive over the last 37 years in terms of real dollars. Natural gas shows a different trend with a positive slope of 0.081. The situation changes when data is limited to the last ten years. Using this time period all three energy sources show an increasing trend. The linear regression model yields a positive slope for coal (0.029), electricity (0.080) and natural gas (0.394). Overall the trend appears to be a slight increase for coal and electricity with a more substantial increase for natural gas. The DOE publishes the Annual Energy Outlook (AEO) that contains projections for these three commodities. Comparing this projection with the trends indicated by the historical price data helps shape the future estimate and Figure 4.4 shows the projected trends graphically. The 2009 AEO projections appear to correlate well with the historic price data trends from the last ten years. Electricity is projected to decrease by around 6.5% through 2012 and then increase 16.7% by 2030. Overall electricity is projected to increase by 9.4% by 2030. Coal prices are expected to increase by around 15% through 2009 and then decrease by 5% through 2020 and then increase by 4% by 2030. Overall coal prices are anticipated to increase by 14% between 2007 and 2030. Natural gas is expected to stabilize through 2011 and then increase by 42% by 2030) (DOE Annual Energy Outlook Early Release, 2009). Using the projected rates of increase from the Annual Energy Outlook prices for 2030 are generated from the price data for 2008 contained in Table 4.3. The prices are summarized in Table 4.6.

	Electricity $/kWh		Natural Gas $/mBTU		Coal $/mBTU		Waste Coal $/mBTU	
	2008	2030	2008	2030	2008	2030	2008	2030
PA	0.070	0.08	15.05	21.37	2.83	3.23	1.95	2.22
IA	0.046	0.05	11.09	15.75	3.30	3.76	N/A	N/A

Table 4.6 - Projected Utility Costs in 2030

Taking the costs from Table 4.6 the costs for 2030 are converted into a $/gallon basis in the same manner as Table 4.3. These numbers are then used to calculate the change in annual costs resulting from the increased prices projected for 2030. These values remain in 2007 dollars and do not reflect future inflation. On a nominal basis the prices in 2007 dollars for 2030 would be significantly higher if adjusted for annual inflation and presented in nominal terms. Table 4.7 reflects the estimated annual cost associated with each fuel type by state.

	Electricity		Natural Gas		Coal		Waste Coal	
	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost
PA	0.089	9,593,942	0.641	69,242,040	0.105	11,372,742	0.073	7,836,342
IA	0.050	5,434,992	0.472	51,022,872	0.123	13,261,501	N/A	
PA vs. IA	-43%	-$4,158,950	-26%	-$18,219,168	17%	$1,888,759	69%	$5,425,160

1 year of production		108 million gallons of ethanol	
1	kWh	1 gallon ethanol	NG
1.16	kWh	1 gallon ethanol	coal
0.3571	bushels	1 gallon ethanol	
30,000	BTU	1 gallon ethanol	NG
32,640	BTU	1 gallon ethanol	coal

Table 4.7 - Utility Costs at Projected 2030 Prices (2008 dollars)

These price changes don't impact the relative advantage when like fuels are compared. The relative changes are reflected in Table 4.8 showing the estimated annual operating costs based on 2030 numbers.

Iowa	Pennsylvania	Advantage	2008	2030
Gas	Gas	IA	$16,632,000	$22,378,118
Coal	Coal	IA	$2,144,794	$2,270,191
Coal	Waste Coal	PA	$957,312	$1,266,209
Gas	Coal	PA	$20,497,104	$33,602,420
Gas	Waste Coal	PA	$25,256,016	$39,027,580

Table 4.8 - Annual Energy Cost Comparison 2008 and Projected 2030

The cost comparison for 2030 shows that the cost advantage for Pennsylvania using coal compared to a gas fueled plant in Iowa increased by more than 50% (Table 4.5 and Table 4.8). This analysis assumes that prices increase uniformly at a national scale. For the purpose of this estimate the uniform increase assumption for 2030 is sufficient. Additionally, these price trends assume no major legislative or technology changes occur impacting either energy production or usage. If legislation is enacted that significantly impacts the use of an energy source then this analysis would need to be revisited. One possible change would be the implementation of a carbon tax or a CO_2 emissions permitting system similar to the SO_2 and NO_X systems currently in place in the United States. This scenario is addressed further in Chapter 6. Another consideration beyond the increase of prices is the amount those prices are likely to fluctuate. Volatile prices can lead to significant changes in profitability over short periods.

4.6 Utility Price Volatility

Price volatility can be overlooked when analyzing long term price trends. A price could be very volatile and still demonstrate a slow increase in the average or mean value. The amount of volatility and its impact on prices are both important considerations. Once volatility levels are determined they can be combined with price projections from section 4.5 to create an estimate of price ranges a company could expect to encounter during a normal business year.

The increase in the range of values that comes with volatility is reflected in the standard deviation. The analysis of the utility prices over the last 37 and 10 years (Table 4.9) shows the difference between the chosen energy sources and the differences between these two periods. Coal is by far the least volatile of all of the fuels. The standard deviation for coal prices is less than half of electricity. Coal offers both a price advantage in a lower mean value (lowest $/gallon cost) but also a much lower standard deviation. The likelihood of a price spike that drastically alters the cost of

Fuel	1970-2007		1998-2007	
	Mean	Std Dev	Mean	Std Dev
Electricity	5.548	1.085	4.868	0.273
Coal	1.342	0.483	0.897	0.105
Natural Gas	2.424	1.299	3.762	1.344

Table 4.9 – Historic Energy Price Variation – EIA data

production is greatly reduced. The volatility of natural gas also appears to be following a trend opposite to that of coal and electricity. Both of those fuels saw substantial drops in the standard deviation between the two periods of analysis while natural gas saw an increase. How this volatility impacts production cost is an important consideration.

Vernon R. Eidman uses the 34,000 BTU per gallon number in analyzing the sensitivity of ethanol production to price changes in fuels. Eidman finds that a $1.00 rise in natural gas prices translates into

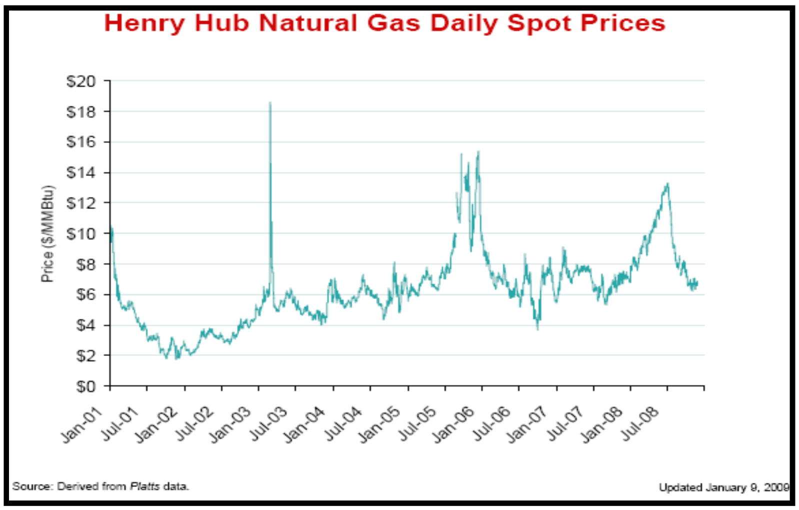


Figure 4.5 - Natural Gas Price Volatility 2001-2008 - FERC

Month	Average Monthly Volatility	Coefficient of Variation
January	25.38%	52.98%
February*	27.45%	99.06%
March	16.49%	70.37%
April	12.63%	42.30%
May	11.38%	31.47%
June	12.87%	30.06%
July	12.67%	30.72%
August	16.32%	35.42%
September	17.05%	43.89%
October	22.79%	43.76%
November	24.75%	58.43%
December	26.74%	47.29%

Note: The darkest shading represents the months with the highest volatility levels. The lighter shading indicates the two shoulder months. *The calculated February values exclude the first two weeks in February 1996. If these weeks were included average February volatility would be 38 percent with a coefficient of variation of 69 percent.

Figure 4.6 – Monthly Volatility in Natural Gas Prices - EIA

an increase of $0.034 per gallon of ethanol (2007). Using a similar calculation an increase in coal prices of $1.00 would result in a $0.037 per gallon increase in ethanol prices. Although coal prices are less volatile an equal price change in coal and natural gas would impact the cost of production more for a plant using coal. Price changes in both the short and long run have a distinct impact on profitability. Natural gas reached a high in Jul/Aug 08 at just over $13.00 per million BTU. This is not a longer term historical high and this high was short lived as the global economy slowed. Figure 4.5 highlights these price changes and the volatility of natural gas prices from 2001-2008 (FERC January 15th, 2009). This graph also shows what appears to be a cyclical movement in price. Some of the more abrupt and significant shifts are due to hurricane interruptions and the smaller cycles are due in large to the seasonal demand for Natural Gas. These seasonal variations are seen in Figure 4.5 (DOE EIA, December

12th 2008). This figure shows both the degree of volatility as well as the time of year variations occur. Figure 4.6 captures the monthly volatility but does not show the maximum price variation within a single calendar year. The percent variance between the highest and lowest price during a year has ranged from a low of 34% in 2007 to a high of 92% in 2006 for the period 2005-2008. Table 4.10 further shows the volatility that could be expected within a single year based from EIA data. The impact of this volatility is discussed further during the sensitivity analysis as price ranges are developed. These price range limits serve to define the high and low values for natural gas prices for the 2018 and 2030 projections. The high price is 40% above the anticipated and the low is 40% below.

	Variation	Mean	Above Mean	Below Mean
2005	75.25%	8.67	39.68%	25.47%
2006	92.88%	7.81	38.74%	39.03%
2007	34.48%	7.58	8.58%	23.86%
2008	61.76%	10.02	30.48%	23.97%

Table 4.10 - Annual Price Fluctuations for Natural Gas 2005-2008 – EIA data

Price estimates for coal and electricity based on volatility and historic prices are more stable than natural gas. The range for coal prices in 2030 is taken from the 2008 Annual energy outlook. The high price is 52% above the reference case while the low is 29% below. For the 2008 and 2030 prices the relation of standard deviation to mean for 1998-2007 is used to calculate the high and low prices. The standard deviation is 11.6% of the mean. The high is 11.6% above the anticipated value and the low is 11.6% below the anticipated value. For electricity the relationship between the mean and standard deviation is greater (19%) for 1970-2007 as opposed to only 5.6% for 1998-2007. The larger variance is used for 2030. For 2008 the percent change from the average price to the highest and lowest price observed are used and in both cases the number is 10.6%. The 2008 Annual Energy Outlook does not offer a range of prices for electricity as it does for natural gas or coal. The method used above though creates an acceptable range in lieu of a formal projection from the DOE.

In conclusion, utility prices strongly favor a plant location in Iowa when like fuels are used. However, a plant located in Pennsylvania using coal or waste coal as a fuel would have an advantage over a plant of the same capacity using natural gas as a fuel. How these facts impact potential profitability is discussed in Chapter 7. The analysis of utility prices indicate that using coal to fuel an ethanol plant might be economically competitive with natural gas based ethanol production in Iowa. These utility costs are secondary though to the feedstock costs. Determining how the price of corn varies between corn-rich Iowa and the corn-deficient Commonwealth of Pennsylvania may eliminate the potential advantage from coal use. An examination similar to that just conducted for energy prices is now undertaken for corn. The analysis of energy and corn prices is then combined in section 4.11 to determine the relative cost advantage of ethanol production in Pennsylvania based on energy source selected.

4.7 Feedstock Prices

The cost of feedstock for the production of ethanol is the largest input cost. In the United States corn is the dominate feedstock used in ethanol production. Determining reasonable price estimates for each region is a critical step in determining the potential profitability of a plant. Corn costs are most directly related to the amount of corn produced in the surrounding area and the regional as well as wider area demand. The United States is responsible around 60% of the world's corn exports (USDA, March 14th, 2008). This global market also impacts prices at both a national and regional level. Prices are likely to vary greatly between Iowa and Pennsylvania as Iowa produces far more corn than it uses and Pennsylvania is corn-deficient and imported around 36,000 bushels in 2005 (Dunn, 2008). Another key factor that must be examined is the usage rate. Determining the amount of corn needed to produce a gallon of ethanol is the first step in examining the impact of a factor of production on the overall cost of production.

4.8 Corn Requirements for Production

The rate at which corn is converted into ethanol has changed as technology has changed. Accepted rates have increased from 2.6 gallons per bushel several years ago to around 2.8 gallons per bushel for newer plants. The conversion rate depends on several factors: the amount of starch present, plant age, plant efficiency, type of equipment present, and management practices (Shapouri and Gallagher, 2005).

The USDA cost of production survey provides a starting estimate of a gallons per bushel conversion rate. The survey found a conversion rate range of 2.5 to 2.8 gallons per bushel with a weighted average of 2.68 gallons per bushel (Shapouri and Gallagher, 2005). Other projections fall within this range: 2.75 (Tiffany & Eidman, 2004), 2.75 (Eidman, 2007), 3.0 (Elobeid et al., 2006), and 2.8 (Rendleman and Shapouri, 2007). For the purpose of this analysis both plants are assumed to operate at 2.8 gallons per bushel of corn.

4.9 Corn Prices

Corn prices vary regionally based on availability, demand, and transportation costs. The corn market in the United States and worldwide is more developed than the ethanol market and significant transportation capacity exists. The impact of the maturity of this world market is complex but two trends emerge from the data. Corn is generally decreasing in price based on real terms, and it is extremely vulnerable to price volatility. Because of these two trends it is difficult to create accurate price estimates. A significant weather event (floods or droughts) in a major production area can, with little warning, reshape the market. Corn, like fossil fuels, experienced a large price increase in 2008 adding uncertainty to both near term prices as well as future price projections. As previously discussed, natural gas is impacted by price volatility but the exposure in the corn market is even more extreme. In contrast to the energy discussion, the examination of corn prices starts with volatility and then moves to projecting near and long term prices for the IA and PA markets. Six major spikes have occurred in the corn market between 1974 and 2008 (Ray, December 12th 2008). These price spikes in 1974, 1980, 1983, 1988, 1996 and 2008 vary in length but are starkly apparent in Figure 4.8 (Annual Volatility) and Figure 4.9 (Corn Prices 1970-2008). These price spikes are difficult for both farmers and consumers of corn. The rise in corn prices in 2008 lead to one of the larger ethanol producers declaring bankruptcy. VeraSun announced that it was filing for bankruptcy on October 31st, 2008 (McCracken et al., November 14th, 2008). As corn prices climbed in 2008 producers like VeraSun moved to lock in corn supplies before prices increased more, instead corn prices receded and these locked in contracts became a financial burden. The dramatic rise of corn prices in 2008 is seen in Figure 4.7(CME Group, February 1st, 2009).

Figure 4.7 - Annual Price Fluctuations for Natural Gas 2005-2008 – CME Group

Even more dramatic than the rise starting in late 2007 was the fall in prices in the second half of 2008. A regression analysis of corn prices from 1970-2007 confirms the concept showing a slow increasing price trend (slope = 0.0133) but a fairly large degree of variance (std deviation = 0.67) around a mean value of $2.44/bushel. The challenge in corn procurement is timing purchases around the cyclical variations. Understanding the cyclical variations in the market is critical for the success of ethanol producers. Figure 4.8 shows some fluctuations, but does not properly capture the volatility of the market. The

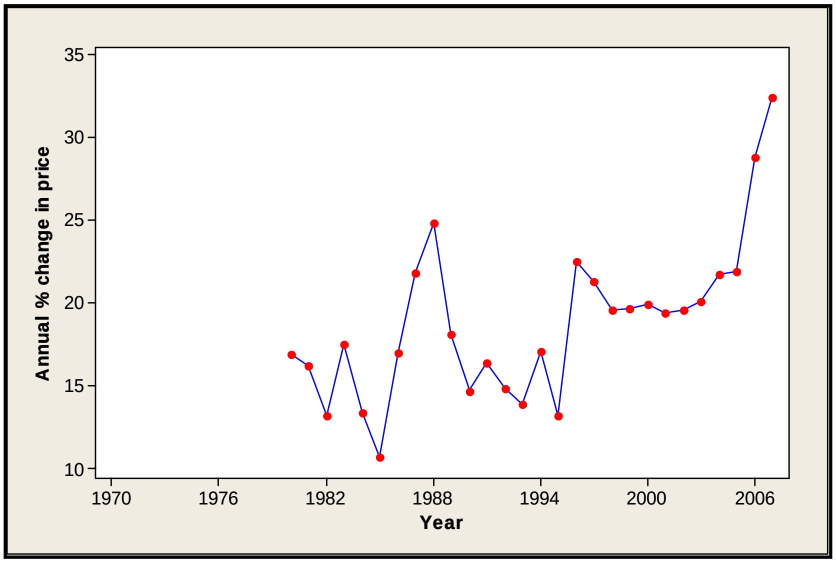


Figure 4.8 – Annual Volatility in Natural Gas Prices

Chicago Board of Trade (CBOT) maintains volatility estimates for the corn market for the last 27 years (CBOT, February 1st, 2009). A time series plot from Minitab for annual % change in volatility (Figure 4.8) shows the annual volatility (% variation in price) through 2007. Based on the price fluctuations seen in Figure 4.8 the trend of increasing volatility that started in 2005 is expected to continue through 2008. Over the last five years (2003-2007) volatility has ranged from just over 20% to near 30%. The greatest monthly price fluctuation was 43.5% in October, 2006 and the smallest was 9.51% in November, 2005. Based on these numbers it is not unreasonable to expect annual volatility to remain around 25%. The estimate of 25% is slightly lower than the average 27% variation seen based on the standard deviation and mean from the regression analysis for 1970-2007. Figure 4.9 is a time series graph of prices between 1970 and 2007 shown in both nominal and real terms. The real dollars are calculated using the Bureau of Labor Statistics (BLS) Consumer Price Index (CPI) inflation calculator

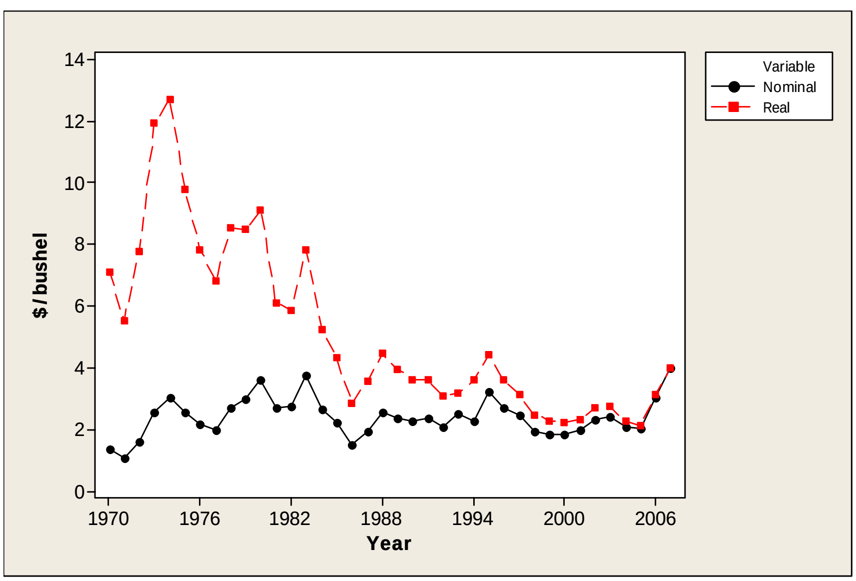


Figure 4.9 – Nominal and Real U.S. Corn Prices 1970-2007

(BLS, December 17th, 2008). This graph shows the decrease in corn prices in terms of real dollars and the fairly stable price in terms of nominal dollars. When analyzing real dollars over the entire period the standard deviation is increased greatly (55% of the mean). This is not unexpected based on the graph in Figure 4.10. Conversely taking just the last 15 years (1993-2007) the price variation decreases with the standard deviation decreasing to only 23% of the mean. Based on historic prices and volatility an annual variance of 25% is a reasonable estimate. Combining this analysis with the USDA projections for corn prices will yield an estimate for future corn prices.

4.10 : Future Corn Price Projections

Future corn price trends will determine the profitability of the ethanol industry as a whole. Some areas will likely remain profitable longer than others, but if corn rises significantly and remains above historical norms it will be difficult for any producer to remain in operation without significant government support and/or increasing oil prices. Two main sources serve as the basis for predicting future prices. The first source is the USDA Long-Term Projections Report OCE-2009-01 which contains projections through 2018. The second source is the 2007 USDA publication by Paul Westcott which examined how the agricultural sector will likely respond to increased ethanol production. This second source is based off of the Long-Term Projections report from 2007. The most recent values for national and state prices come from the Crop Values 2008 Summary released by the USDA in February, 2009. This last report does not contain projections but does offer the most current pricing information (through December, 2008). Understanding the trends in pricing requires analyzing the previous publications and the most recent to gain a full picture of where prices have been and where they are going.

The recent price data and the OCE-2009-01 report indicate that corn prices decrease following the 2008 Market Year (MY) which goes through July, 2009. Westcott's publication sees prices decreasing following 2009/10 through the end of their projection period in 2017/18. Westcott estimates that prices will increase to $3.75/bushel by 2009/10 and then fall to around $3.30/bushel by 2016/17 (2007). These prices must be examined in the context of projections made in late 2006 and early 2007. The data used in this report correlates exactly to the estimates contained in the Long Term Projection Report OCE-2007-01 from February 2007. In comparing the prices projected from 2007 to 2008 (OCE 2008-01) the USDA revised its peak price to $3.80/bushel occurring in 2009/10 and revised the projected drop from the 2007 report upward from $3.30/bushel in 2016/17 to $3.50 in 2011/12 and 2012/13. The price of corn would then increase to $3.60 by 2016/17. The price for corn as recently as mid 2006 stood at under $2.50 per bushel so the increases stated seemed to be substantial for 2007, but still seem out of sync with the reality of corn prices already emerging in 2007. OCE 2009-01 revised these estimates again placing the peak at $4.40 for MY 2008. This estimate may be too high. The 2008 price summary shows the 2008 MY price falling to $3.90/bushel (Sep-Dec 2008). Unless there is a price rebound for Jan-Jul 2009 the price peak will occur for 2007 MY at $4.20 (Aug 2007 – Jul 2008). Current futures prices show a price of $3.83 for delivery in July, 2009 and $4.31/bushel for July, 2010 (CBOT, February 13th, 2009). This would indicate that the $4.40 price predicted for MY 2008 (2008/09) by OCE 2009-01 is too high and the peak average price may stay at $4.20.

Summarizing OCE 2007-01, 2008-01 and 2009-01 projections (Table 4.11) in terms of decline from the price high will help guide the future price estimates. This table shows the variance in the USDA projections that was likely a result of the unprecedented rise in corn prices experienced principally during marketing year 2007 (calendar year 2008). Using the decreasing price trend as a common theme three alternatives for future prices are constructed for 2018. The first is

Report	High	Year	Low	Year	%
2007	3.75	2009/10	3.30	2016/17	-12.0%
2008	3.80	2009/10	3.60	2016/17	-5.3%
2009	4.40	2008/09	3.75	2016/17	-14.8%

Table 4.11 - USDA Price Projection Summary OCE 2007/08/09

based on the 2008 projection and assumes a slight 5% decrease in prices through 2018. The second based off of the 2007 and 2009 reports and anticipates a price reduction of 13%. The recent decreases would indicate a bias toward choosing a larger decrease. Meanwhile the slightly lower high price \$4.20/bushel coupled with the expectation of prices stabilizing above 2006 levels leads to bias towards choosing a smaller decrease. The third case is based on the regression of historic prices and calls for a 19% decrease by 2018. This large scale decrease is not anticipated, but is not outside the realm of possibility. Projections to 2030 are much more uncertain and this is reflected in the variance between the high and low prices. The high is taken from the data from 1970-2008 prices and is \$12.70/bushel in terms of 2007 dollars. This price would be a more than 200% increase over the recent high average observed price of \$4.20/bushel. The minimum value during this same timeframe is \$2.02/bushel occurring in 2005. This price is less than half of the recent highest observed average price. The total range is \$10.68 and is more than 250% of the 2007 average price. The expected price is \$5.08 and is taken from the mean of corn prices in real dollars between 1970 and 2008. The prices for Iowa and Pennsylvania are based off of the relationship between state and national prices in 2007 where Iowa was 2.14% higher and Pennsylvania was 8.57% higher.

The current corn prices and future estimates are combined with energy prices to form the summary of input costs. These costs taken in total show how costs are expected to influence ethanol production during 2008 and 2030 for both Iowa and Pennsylvania (USDA NASS, August 2008).

4.11 Input Cost Summary

Choosing where to locate industrial production is a difficult and complex decision. One of the most important concerns is the cost required to assemble the required inputs at the point of production. The prevailing thought in the ethanol industry was that production should be located close to corn supplies. Examining the input costs shows that a cost advantage exists in the energy market if coal is used as an energy source. Iowa still possesses an advantage in corn prices, but these are current advantages based on current prices. The relative cost for electricity, coal, natural gas and corn are summarized in Table 4.12. This table shows costs on a per gallon basis while Table 4.13 shows relative costs for plants using both like and different fuels. The estimated input costs critical for ethanol production are summarized in Table 4.14. This table shows both the actual values for 2008 and projected prices for 2018 and 2030. These prices are used to test the sensitivity of production price fluctuations within a feasible range in Chapter 7.

	Electricity		Natural Gas		Coal		Waste Coal		Corn	
	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost	$/gallon	Annual Cost
PA	0.089	9,593,942	0.641	69,242,040	0.105	11,372,742	0.073	7,836,342	1.97	212,503,068
IA	0.050	5,434,992	0.472	51,022,872	0.123	13,261,501	N/A		1.85	199,776,024
PA vs. IA	-43%	-$4,158,950	-26%	-$18,219,168	17%	$1,888,759	69%	$5,425,160	-6%	-$12,727,044

1 year of production	108 million gallons of ethanol	
1 kWh	1 gallon ethanol	NG
1.16 kWh	1 gallon ethanol	coal
0.3571 bushels	1 gallon ethanol	
30,000 BTU	1 gallon ethanol	NG
32,640 BTU	1 gallon ethanol	coal

Table 4.12 –Annual Ethanol Production Input Costs

Iowa	Pennsylvania	Advantage	2007	2030
Gas	Gas	IA	$27,432,000	$35,105,162
Coal	Coal	IA	$12,944,794	$14,997,235
Coal	Waste Coal	IA	$9,842,688	$11,460,835
Gas	Coal	PA	$9,697,104	$20,875,376
Gas	Waste Coal	PA	$16,571,088	$26,300,536

Table 4.13 - Annual Cost Comparison 2007 and Projected 2030

	Electricity $/kWh			Natural Gas $/mBTU			Coal $/mBTU			Waste Coal $/mBTU			Corn $/bushel		
	2008	2018	2030	2008	2018	2030	2008	2018	2030	2008	2018	2030	MY 2007	2018	2030
PA	0.07	0.07	0.08	15.05	17.36	21.37	2.83	3.12	3.23	1.95	2.15	2.22	4.56	3.96	5.51
High	0.08	0.08	0.09	19.02	24.30	29.92	3.16	3.48	4.90	2.18	2.40	3.38	7.25	4.33	13.78
Low	0.06	0.05	0.06	13.19	10.42	12.82	2.50	2.76	2.29	1.72	1.90	1.58	3.25	3.69	2.19
IA	0.05	0.04	0.05	11.09	13.30	15.75	3.30	3.64	3.76	N/A	N/A	N/A	4.29	3.73	5.18
High	0.05	0.05	0.06	13.91	18.62	22.05	3.68	4.06	5.72				7.25	4.07	12.97
Low	0.04	0.03	0.04	8.25	7.98	9.45	2.92	3.22	2.67				3.25	3.47	2.06

Table 4.14 - Input Factors Price Projection

Table 4.12 and Table 4.13 show the relative cost of production for the two most important input costs, utilities and corn feedstock. The advantage created by using coal versus a natural gas plant seen in Table 4.8 is greatly reduced when the cost of corn is included. A coal plant in Pennsylvania does possess a cost advantage when compared with a natural gas fired plant in Iowa based on input cost for utilities and corn feedstock. This advantage is projected at more than $9 million dollars based on input costs in

2007/08. If waste coal is used the advantage increases to more than $16 million. If these numbers are accurate than a coal fired plant in Pennsylvania could only compete against gas fired plants. Additionally, these numbers indicate that a coal fueled plant in Iowa would have a more than $37 million advantage over a gas fired plant in Iowa. These numbers are revisited again in Chapter 7 to examine potential profitability of ethanol production under price scenarios taken from Table 4.14. Examining the forces acting to shape the industrial location decision requires analyzing more than input costs. The location and size of the market served by the plant is important. Key legislation and regulatory impacts also play a major role in shaping the landscape that determines the "best" location. The next two chapters examine the role of market and the role of regulations and legislation in shaping the location decision. While a coal fired plant location in Pennsylvania possesses a cost advantage over natural gas fired plants in Iowa this advantage alone does not make it a "better" location to build a plant.

Chapter 5 : Market Size

Input costs are only one side of the equation when attempting to determine potential for profit. The other side of the equation is the products. A location that offers the lowest cost point for inputs is not a good location if there is no access to the market. Determining both the size and location of the markets for ethanol products and byproducts is the next step in evaluating the location decision. There are three principal markets that exist for the products from an ethanol plant. The first is ethanol which is sold in the liquid fuels market. In this market ethanol serves as a substitute for gasoline or gasoline extender and also as an oxygenate. As an extender ethanol is sold at a 10-20% rate mixed with standard gasoline. As a substitute ethanol is sold at up to 85% ethanol in gasoline and commonly referred to as E85. As an oxygenate ethanol is mixed at a 5-7% rate (sometimes as high as 10%). The second most important market is the market for distiller's grains. This is a high protein product that is sold to animal feeding operations. The last market is for carbon dioxide. Ethanol production produces food grade carbon dioxide that is suitable for the beverage industry. This last market is the least important and many plants do not bother to capture CO_2 and instead vent it to the atmosphere. Another option could exist for CO_2. The possibility for future CO_2 emission regulation could make reducing emissions an activity that yields permits which could then be sold. Reductions could be achieved through scrubbing or sequestration.

Determining the relative location and size of the market for both ethanol and distillers grains is essential to selecting a location for ethanol production. Current production centers in the Midwest are near both large scale corn production and also large scale cattle feeding operations.

5.1: Distillers Grains Overview

The market for distiller's grains is an important part of profitable ethanol production. The sale of Distiller's Grains (DG) could recoup almost 33% of the cost of corn purchases (Kwiatkowski et al., 2006). The USDA cost of production survey calculates approximately a $0.25 per gallon credit for the sale of DGs (Shapouri and Gallagher, 2005). This reduces feedstock costs by more than 30% (Shapouri and Gallagher, 2005). Expanding ethanol production offers an opportunity for both ethanol producers and livestock operations to benefit. The key factors are the location and type of animals. Geoff Cooper examined the expanding ethanol industry and calculated a national market of 40.2 million metric tons of DGS (2006). This potential national market is very large compared to the expected 17 million metric tons of DGS expected to come to market by 2012 if Renewable Fuels Standard (RFS) requirements are met. How these grains will impact the livestock and feed markets is yet to be seen. At the regional level ethanol production in Pennsylvania could be a benefit for both corn producers and livestock producers. Is a production facility located in Clearfield, PA positioned to take advantage of this new feed market?

Distiller's grains are distributed in two basic forms. First, are the more common Dried Distiller's Grains with Solubles (DDGS). Second, and becoming more common are Wet Distiller's Grains with Solubles (WDGS). Both are used principally as feed for livestock. The capacity of livestock to consume Distilier's Grains (DGs) varies widely by type of animal. The key factors in determining potential market are the type of livestock, the number of each type, the distance from the ethanol refinery, and the cost for DGs (if a market exists) or the competing protein feedstock (Kwiatkowski et al., 2006).

There are several cost benefit tradeoffs between the two forms. DDGS are easier to store and transport but require additional energy to dry. WDGS, are nearly opposite in terms of costs and benefits. As energy prices have risen WDGS became more widely seen as ethanol producers could save money by not drying the grains. This does decrease the storage time and increase transportation costs making WDGS production favor plant locations close to livestock feeding operations. The plant being built in Clearfield, PA is a dry-mill plant and is expected to produce the industry average 18 lbs. of DDGS per bushel of corn (Eidman, 2006). Operating at nameplate capacity of 108 million gallons per year this will result in the production of 682,105,263 million lbs. of DDGS assuming a 2.85 gallon per bushel conversion ratio. This is an incredibly large amount of new feed material being introduced into West-Central PA. This is an area that is not nationally known for livestock production. Are there sufficient numbers of animals to support a local/regional market?

5.2: Distillers Grains Market Size

Determining the market size is based on several factors. The type and number of livestock are both important. Livestock are not fed a 100% DGS diet and different types of livestock can be fed a larger proportion than others. Clemens and Babcock summarize feed recommendations in their 2008 publication from Midwest Agribusiness Trade Research and Information Center (MATRIC) (2008). They cite a recent USDA report indicating 30-40% inclusion levels for cattle. They do acknowledge the work of Westcott (2007) and Loy (2007) that indicate higher levels around 40-50% yield satisfactory results. Dairy cows, however, require a different feed ration of 20-25%. (Clemons and Babcock, 2008) The inclusion level for growing and finishing hogs is 20% and 15% for poultry (Clemons and Babcock, 2008). Justin Sexten of The University of Illinois Extension maintains a 20% dry matter limit for the inclusion of DGS (Sexten, 2009). This translates into the following for DDGS:

Growing Calves (500-700lbs.)	3 lbs. daily
Finishing Cattle (900-1200lbs.)	4-6 lbs. daily
Cows (1200-1500lbs.)	5-7 lbs. daily

These numbers are gross simplifications of the complexities of determining feed requirements. Issues of phosphorous and sulfur content arise when feeding DDGS and calcium to phosphorous should be maintained around a 1.5-1 ratio (Sexten, 2009). Creating the correct balance of nutrient intake is done on a case by case basis. The above estimates are, however, accurate enough to generate an estimate for market size.

Livestock numbers come from the United States Department of Agriculture (USDA) National Agricultural Statistics Service (NASS). These numbers are broken down by county and two figures are used. The first is the number of livestock in the eight adjacent counties. The second is based on a 60 mile straight line radius with all livestock within a county counted if any portion of that county falls within the radius. The eight adjacent counties: Blair, Cambria, Cameron, Centre, Clinton, Elk, Jefferson, and Indiana. The 60 mile radius expands the selection to include the above counties plus: Armstrong, Bedford, Clarion, Forest, Huntingdon, Juniata, McKean, Mifflin, Lycoming, Snyder, Somerset, Tioga, Union, Warren and Westmoreland. The numbers of livestock for these two areas are totaled below in Table 5.1

	Cattle & Calves	Dairy Cows	Hogs & Pigs	Poultry	Total # Animals
State Totals	1,600,000	550,000	1,160,000	177,209,000	180,519,000
Eight Adjacent	125,900	46,100	9,300	0	181,300
% of Total	7.87%	8.38%	0.8%	0.0%	0.1%
60 Mile Radius	476,600	166,300	192,300	38,032,000	38,867,200
% of Total	29.8%	30.2%	16.6%	21.5%	21.5%

Table 5.1 - Pennsylvania Potential Distillers Grains Consuming Animal Populations

Using the above numbers and the daily feed in pounds from Sexton a simple multiplication will yield a market size estimate for cattle and calves. An average daily feed weight of 4lbs. of DDGS is used as a conservative estimate out of the 3-6 lbs. range taken from Sexten for calves (3lbs.) and cattle (4-6lbs.). Dairy cow feed rates are taken from the NASS-USDA 2007 survey which cites 455kg/year/animal feeding at approximately 8% inclusion. The hog feed rate from the same source is 27 kg/year/animal at a 10% inclusion rate. The data for poultry is based on the Grain Consuming Animal Units (GCAU) number of 0.0020 (Westcott, 2007). This number represents an equivalent grain demand for chickens (broilers) as a percentage of that consumed by dairy cows (Table 5.2).

	Cattle & Calves	Dairy Cows	Hogs & Pigs	Broilers	Total lbs
Eight Adjacent	181,814,000	46,243,062	553,581	0	228,610,643
60 Mile Radius	695,836,000	166,816,078	11,446,621	76,300,049	950,398,748
DDGS Production					682,105,263

Table 5.2 - Pennsylvania Grain Consuming Animal Units Total Potential Demand

The results here indicate that cattle and calves in the eight adjacent counties will not create sufficient demand even with 100% of animals on DDGS. Within counties which lay at least in part within the 60 mile radius sufficient numbers of cattle and calves exist to create sufficient demand. However, this requires that all cattle and calves utilize DGS. This is an unlikely event. The NASS-USDA 2007 survey on the use of co-products shows a much lower usage rate. The survey questioned 9,400 livestock operations across 12 Midwest states. This survey indicates that 22% of dairy operations, 14% of cattle on feed, and 37% of hogs use distiller's grains in feeding operations (NASS-USDA, 2007). Taking the selected livestock groups into consideration the potential market within counties within a 60 mile radius could potentially absorb 140% of the DDGS produced at a 108 million gallon per year facility

The demand within a 60 mile radius is more than sufficient and the 60 mile radius represents a fairly small market area for DDGS. WDGS are more limited in market area. They are generally limited to a radius of 150 miles from the distillery indicating that the easier to transport DDGS could serve a larger area (Kaiser, 2005). The 60 mile radius is likely a conservative estimate of market area, but shows that potential demand is sufficient to support the co-production of DDGS in West-Central PA. The next market to examine is the most important. The size and location of ethanol demand in relation to Pennsylvania could be a significant advantage.

5.3: Ethanol Market Overview

The market for ethanol in the United States is directly related to the liquid fuels market and more directly the gasoline market. Ethanol serves in three roles in the gasoline market. At an 85% mix it is primarily a substitute. At 10-20% is serves as a gasoline extender. At 5-10% it serves primarily as an oxygenate to reduce emissions. Estimating the amount of ethanol a market could potentially absorb is derived from analyzing the current gasoline usage. The decision to use ethanol and at what rate it should be used is influenced by both legislative rulings and regulations. The discussion of these influences on the market is left to chapter 6.

Three different approaches are used to calculate potential ethanol. First the ethanol market is calculated based on a 10% volumetric replacement of gasoline. This is in line with both observed usage as well as the stated goal of the PA governor. Governor Rendell's mandate is to bring ethanol use to 10% of gasoline consumption when state wide production reaches 200 mgpy (PA Department of Agriculture, October 5th, 2008). The second examines market size if current gasoline usage switched to 85% ethanol and 15% gasoline. The third approach examines potential market size given three assumptions. First gasoline usage decreases by 25% and is then composed of 85% of sales at 10% ethanol and 15% of sales at E85. In conducting the analysis three different areas are also considered. First, consumption at the national level is examined. Second, state consumption in PA and Iowa is examined. Lastly, analysis for Petroleum Administration for Defense Districts (PADD) I (East coast) and II (Midwest) are examined.

5.3.1: Potential Size of the National Ethanol Market

The potential size of the U.S. market is influenced by many factors. Determining the current amount of gasoline use is the starting point for examining the potential size of the U.S. ethanol market.

Determining how much ethanol can easily be integrated into the market will help shape projections for the industry. The legislative blend limits as well as the ability of current technology to use higher ethanol blend rates impact the analysis. Additionally, the ability of current transportation infrastructure to handle greatly increased ethanol production is questionable (Denicoff, 2007), (Ginder, 2007). A last concern is the decrease in overall consumption from 2007 to 2008. Taking these factors together three estimates for market sizes are created.

In 2007 the United States consumed 142.349 billion gallons of gasoline (DOE EIA, September 27th, 2008). Ethanol production in 2007 was 6.521 billion gallons according to the EIA database (DOE EIA, September 27th, 2008). This is slightly above the projected 6.485 billion gallons from the 2007 Annual Energy Review (AER) from the DOE and represents 4.58% of gasoline consumption. The EIA shows that for 2007 2/3 of the gasoline market is conventional gasoline while only 1/3 is reformulated gasoline (DOE EIA, September 27th, 2008). Using the gasoline consumption number and assuming a 10% mix for all gasoline sold the total national market would be 14.2 billion gallons. The second estimate, based on total integration of E85 shows the market size would be 120 billion gallons. This is a highly unlikely scenario due to the amount of corn required to produce this much ethanol in the near term. As technologies change, and cellulosic production comes online, this number could serve as a reasonable upper bound for how much ethanol the market could consume. The third scenario, with a 25% reduction in overall gasoline use and a mix of 85% E10 and 15% E85, results in a national market size of 22.7 billion gallons (9 billion for E10 and 13.6 billion for E85).

Estimates similar to the 14.2 billion gallons estimate are what gave rise to a discussion in 2007 of a perceived “blend wall.” The topic was recently revisited as the USDA and EPA discussed altering the 10% blend cap (Lundell, February 10th, 2009). The discussion surrounds whether the EPA should raise the blending rate to 15-20% from the current 10%. These higher blend rates are often referred to as intermediate blends. Any fuel blended at 10% or under is considered “substantially similar” to standard gasoline and is sold as gasoline. Increasing the blend cap would effectively shift the blend wall by increasing the market size. Using the same method as in the first estimate (above) would increase national market size to 21 billion gallons using E15 and 28 billion gallons if every gallon of gasoline was blended as E20. The ability to quickly transition to these intermediate blends is questionable. There are concerns over the technical aspects of use in motor vehicles as well as regulatory issues. Two changes would be necessary. First, manufacturers would have to ensure warranty coverage is not affected by use of E15 or E20. Secondly, the EPA would have to issue a CAA waiver to classify these blends as "substantially similar" to gasoline.

Another issue to consider at the national level is the overall consumption of motor fuels. The DOE Short Term Energy Outlook (STEO) for February 2009 shows a decrease in gasoline consumption. From 2007 to 2008 U.S. consumption decreased 3.4% (STEO, 10 February, 2009). Continued decreases in gasoline usage could significantly alter the ethanol market. Minor short term decreases in usage make the push to change the EPA regulated "blend wall" more important for the ethanol industry. The 2009 ethanol outlook from the Renewable Fuels Association (RFA) focuses heavily on the blend wall (RFA, 2009).

The ability of the transportation infrastructure to support the continued expansion of the ethanol industry is also a concern. The inability to ship ethanol in existing pipelines is problematic and requires infrastructure different from that which has served to distribute gasoline effectively in the past. Restructuring transport through the use of rail cars and redesigning blending facilities is a large scale project that requires significant capital investment. The stock of rail cars to carry ethanol is currently insufficient and significant backlogs exist for new cars (Denicoff, 2007).

Given the current concerns and constraints it is not unreasonable to see the lowest estimate of 14.2 billion gallons as a current maximum market size. With ethanol production at 6.521 billion gallons in 2007 this allows for ethanol production to grow by nearly 218%. Production numbers for 2008 through November indicate the production again increased rapidly. The Renewable Fuels Association (RFA) shows production at 8,382 billion gallons through November (Renewable Fuels Association, January 12th, 2009). If production for December is assumed to maintain the levels seen in OCT/NOV (20 million barrels/ month) then annual production would reach 9,224 billion gallons (Renewable Fuels Association, January 12th, 2009). Between 2002 and 2007 ethanol production increased by 205% (Renewable Fuels Association, January 12th, 2009). Projecting sustained growth at this rate would cause ethanol production to approach the theoretical maximum market size of 14.2 billion gallons by 2012.

The impact of MTBE bans, the uncertainty introduced by the Energy Independence Security Act (EISA) 2007 (see chapter 6), and current challenges in the ethanol market would indicate that the recent growth will not continue indefinitely. The massive production increase from 2006-2008 should be seen as a growth spurt and not a sustainable rate. Given recent trends in ethanol production, corn, gasoline and energy (coal or natural gas) markets ethanol producers should expect downward pressure on ethanol prices. The decreasing cost of corn feedstock will benefit producers. The decreasing petroleum prices put downward pressure on production costs which are of benefit, but also put downward pressure on ethanol prices. Increasing costs for natural gas likewise put pressure on producers as input costs increase. Ethanol production expansion will likely slow in 2009 as planned facilities are scrapped, construction on some facilities is delayed, and producing facilities are sometimes idled. Ethanol producer magazine tracks production capable plants that are not producing and as of February 2009 they show 35 total plants with a capacity over 2 billion gallons being idle (Ethanol Producer Magazine Plant List, February 3rd, 2009).

Given these forces the use of coal to fuel ethanol production facilities would seem to be a good alternative that could yield protection from input cost increases. However, as chapter 6 will show it is unlikely that widespread adoption of coal fuels will occur. The country can likely sustain 14 billion gallons of production and increased use of E85, a change in the EPA 10% blend cap, and legislative requirements create a positive future for growth in that demand.

5.3.2: Potential Size of State Ethanol Markets

The state markets are different from the national market and relative sizes are influenced by several factors. One of the principal issues with regional markets is available infrastructure and transportation assets. The approach for market size remains similar to the national market size. Three estimates are made based on three different ethanol use scenarios.

Pennsylvania consumed around 3.6% of the Nation's motor gasoline in 2007 while having approximately 4.12% of the population (DOE EIA, January 28th, 2009). This equates to 123,970 thousand barrels or 5.2 billion gallons of motor gasoline. Assuming a 10% blend rate for the entire state the market size would be 520.67 million gallons of ethanol. The state market size is sufficient to consume all of the ethanol from a 108 mgpy plant. Estimating based on total E85 adoption the market size grows to 4.43 billion gallons. Using the last estimate of 85% E10 as well as 15% E85 and a 25% reduction in consumption the state market would be 3.71 billion gallons.

There are two other issues that should be addressed in examining the potential market size for ethanol production in Pennsylvania. The first is the location of significant refining capacity in eastern PA along the Delaware River and the construction of a new ethanol terminal in Baltimore that can receive ethanol unit trains. The second is the mandated use of reformulated gasoline in Philadelphia and the eastern seaboard markets as well as Pittsburgh.

Iowa consumed 1.2% (89,921 thousand barrels or 3.7 billion gallons of motor gasoline) of the Nation's motor gasoline in 2007 while having less than 1% of the population (DOE EIA, January 28th, 2009). Whereas Pennsylvania has no existing ethanol production, Iowa is the Nation's leading producer with more than 26% of the total national capacity. Ethanol production in Iowa was estimated at 2.059 billion gallons which is nearly 56% of the Iowa motor gasoline market. Ethanol consumption in Iowa was only 116 million gallons or about 5.6% of production, thus majority of ethanol produced in Iowa must be shipped to outside markets. These outside markets are currently dominated by areas mandating reformulated gasoline. Using the previous market size calculation methods Iowa would be expected to have a market size of 370 million gallons of ethanol if all gasoline was blended as E10. The market size for complete E85 use would rise to 3.145 billion gallons. Assuming a 25% decrease and use rates of 85% for E10 and 15% for E85 the market would be 2.63 billion gallons.

The analysis of state markets shows a very different trend for Iowa and Pennsylvania. Iowa serves as an exporter of ethanol. Its state market is not large enough to consume all the ethanol produced and it lacks markets that mandate reformulated gasoline usage. Pennsylvania has both a large enough market and two major metropolitan areas that mandate the use of reformulated gasoline. The issue of market size and location sheds light on the trade-offs between production locations in each state. Pennsylvania based ethanol production must import corn, but will likely save on transport costs for the finished product. Iowa has an abundance of corn, but must pay to have the final production shipped to market. A short analysis of transportation costs follows to examine the relative impact of this tradeoff.

5.4 Corn and Ethanol Transportation Costs

A transportation cost analysis comparing the cost of transporting ethanol to the cost of transporting corn could reveal an advantage for one of the locations. The location of corn has held the greatest influence but there is no guarantee that this advantage remains. With the banning of MTBE major markets are guaranteed principally in coastal regions. If the transportation cost of for ethanol is high enough locating ethanol production closer to markets could explain some of the changes in the location of ethanol plants.

5.4.1 Ethanol Transportation Costs

Ethanol transportation is one of the major concerns when analyzing constraints facing the ethanol industry. Approximately 75% of ethanol shipments move by rail according to Ethanol Producer Magazine (Young, June 2008). The USDA 2007 Transportation Backgrounder estimates that 60% of ethanol is shipped by rail (Denicoff, 2007). The remainder is moved by truck (30%) or barge (10%) (Denicoff, 2007). Rail company estimates offers the best opportunity to calculate rail costs. There are several concerns that arise when considering rail transport of ethanol. The first is rail car availability. The rapid growth of the ethanol industry left a shortage of rail cars. The second concern is the limited infrastructure prepared to accept large shipments of ethanol. In an attempt to minimize both concerns railroads are expanding their capacity and refineries are building new facilities to accept shipments.

CSX and Burlington Northern Santa Fe (BNSF) both run specialized ethanol trains. The CSX train is called the Express Ethanol Delivery or ethex. The BNSF train is called the Ethanol Express. CSX primarily handles the Eastern United States while BNSF handles the Western United States. These are railroad owned unit trains. The BNSF train started operation in 2003 and by 2004 had carried 10,000 car loads to California (Burlington Northern, January 2nd, 2009). The program recently expanded to include Dallas Fort Worth (Burlington Northern, January 3rd, 2009). CSX launched its own service in 2004 which transported ethanol from the Midwest to Albany, NY where it was trans-loaded onto barges to service the eastern market (Ethanol Producer Magazine, January 3rd, 2009). Facilities like the U.S. Development Group's Baltimore Transload Terminal are coming online to improve the transportation network (U.S. Development, January 11th, 2009).

CSX rates for ethanol shipment are taken from CSXT 4466 Tariff schedule with Baltimore as a destination (CSX, January 10th 2009). Prices for Pittsburgh reflect the only scheduled rate from CSX while rates from Chicago reflect an average of the three available rates. The ethanol facility in Clearfield, PA is not yet operational so rates are not available in this schedule. Pittsburgh is used as the point of origin for shipments from Pennsylvania. Chicago is used as the point of origin for ethanol shipments originating from Iowa. These prices do not reflect total transportation costs, but are a proxy for relative location between Iowa and Pennsylvania. The Clearfield, PA plant will likely face lower transport charges than many Iowa plants as it is located at a rail siding removing any trucking cost for the finished product.

Ethanol shipping costs from Pittsburgh are $3,043 per 30,000 gallon tank car when 30-95 cars are loaded. If 96+ cars are used in a unit train the price decreases to $2,413 per car. Shipping costs from Chicago average $3,279.33 per car for 30-95 cars and $2,649.33 per car for 96+ car shipments. These rates are translated into a $/gallon rate based on the 29,400 gallon capacity of ethanol tank cars (Denicoff, 2007). Pittsburgh rates are $0.10/gallon ($0.1035) for 30-95 cars and $0.08/gallon ($0.0821) for 96+ cars. Chicago rates are $0.11/gallon ($0.1115) for 30-95 cars and $0.09/gallon ($0.0901) for 96+ cars. Based on these numbers a plant in Pennsylvania has an annual cost advantage in transportation. Using the 108 mgpy figure the total savings would be $868,151 per year. These estimates are similar to those found by Wakeley et al. who found a shipping cost range of $0.075/gallon and $0.189/gallon (2009). There are several factors left out of this calculation that require discussion.

The first issue to consider is the turnaround time for trains delivering ethanol to East Coast markets. The turnaround time issue is also related to the current relative shortage of available tank cars. Ethanol production has significantly increased the demand for tank cars. The average annual demand for replacement rail cars remained stable at 10,000 cars for ten years prior to 2006 (Jessen, November, 2006). Demand for tank cars after 2006 increased by 50% to approximately 15,000 tank cars per year (Jessen, November, 2006). There are only four major tank car manufacturers (GATX, Trinity, Union and AFT) and orders being placed in 2006 would not be filled until the first quarter 2009 (Ginder, 2006). The backlog of tank car manufacturing is seen in Figure 5.1 taken from Denicoff's Transportation Backgrounder for the USDA (2007). Turnaround times are also a consideration. As facilities invest in

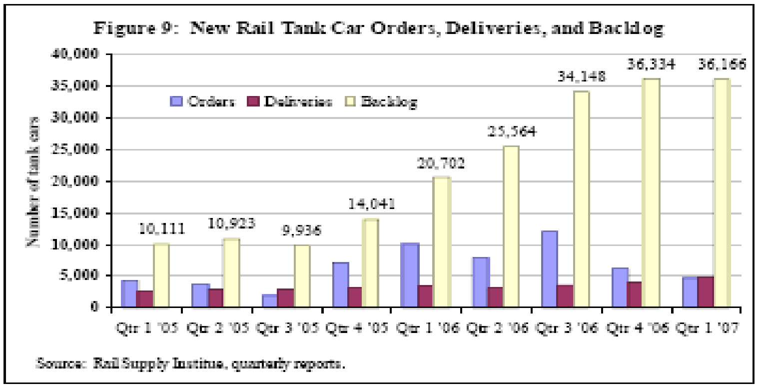


Figure 5.1 – Tank Car Manufacturing Backlog

unit train movements they lose the flexibility that comes from smaller individual car movements, but unit train movements could result in higher utilization rates which decrease unit train costs compared to smaller movements (Ibid.). The ability to increase utilization rates decreases the transportation costs. A plant in Pennsylvania could possibly increase the utilization rate or if the rate is too high the number of cars could be reduced. The shorter distance to market (assuming Baltimore) could significantly reduce transportation costs. A 108 mgpy plant would require 3,674 car loads at 29,400 gallons/car to move all of its ethanol production to market. Using the CSX and BNSF numbers of 96+ cars for a unit train this would require 38.25 train loads at 96 cars or over three train loads a month. The ability to reduce either turnaround time or car requirements by 20% could be a significant cost savings.

Rates for BNSF are taken from BNSF price book 4024 (Burlington Northern, January 15th, 2009). These apply only for Iowa and Illinois as BNSF routes do not go into Pennsylvania. An ethanol shipment from Iowa to Watson, CA is $5,300 for 30-95 cars. From Illinois the shipment would be $5,800 per car for 30-95 cars. It is highly unlikly that any ethanol shipments will travel from Pennsylvania to the West Coast. However, if production east of Iowa (Illinois, Ohio, Indiana, Michigan, Pennsylvania) is sufficient to saturate the East Coast market, producers in Iowa may pursue increasing shipments to the West Coast rather than competing for market share in the East. In this scenario a production facility in Pennsylvania shipping to Baltimore would have a significant transportation savings over an Iowa based facility shipping to the West Coast. Assuming 108mgpy production the difference between the two would be $8,125,200 per year. This could put Iowa production in a position where central location is a detriment to coastal market access.

5.4.2 Corn Transportation Costs

Rates for corn transportation are taken from Norfolk Southern rate authority NSRQ 62508 (Norfolk Southern, November 16th, 2008). The rate is based upon a plant in Pennsylvania purchasing corn on the spot market with prices based on shipment from Chicago. The rate table for Norfolk Southern uses a rail basis mile rate per car. Each car is a 110 ton twin hopper car. Based on a conversion rate of 35.7 bushels of corn per ton (56lbs per bushel) each car can carry approximately 3,927 bushels. The USDA Ethanol Transportation Backgrounder (Denicoff, 2007) states the capacity of a rail car is 3,500 bushels. This number accounts for cars not being loaded to maximum capacity. The 3,500 bushel rate is used to calculate a $/bushel cost. The transit from Chicago is approximately 580 miles and would cost $2,992 per car. This translates into approximately $0.85 per bushel or assuming 2.8 gallons per bushel the cost would be $0.31 per gallon of ethanol. If shipment of corn comes from Ohio as opposed to Pennsylvania the cost is reduced to $2,325 based on a 300 mile shipment. This reduces the cost to $0.66/bushel or $0.24 per gallon. This shipment cost is reflected in the price differential between corn prices in Iowa and Pennsylvania shown in chapter 4. That price differential is smaller than the $0.24 per gallon cost shown here. Having a full $0.24 per gallon reflect in corn prices in chapter 4 would only result if all corn consumed in Pennsylvania was imported.

5.4.3 Transportation Summary

On a per gallon basis the cost to bring corn to Pennsylvania from Ohio is three times greater than the cost to ship ethanol from Pennsylvania to Baltimore. The cost to ship ethanol from Chicago to Baltimore is not significant enough to defray the additional cost of bringing corn to Pennsylvania for ethanol production. The cost to bring corn to Pennsylvania to produce ethanol could add as much as $0.23 per gallon. As seen in Chapter 4 a plant in Pennsylvania could offset the additional cost of corn through fuel switching to coal. On an equal fuel basis a plant in Pennsylvania cannot compete with a plant in Iowa. A production location closer to East Coast markets does not offer an advantage. Pennsylvania cannot competitively produce ethanol based solely on transportation costs.

Chapter 6 : Legislation and Regulation

The recent expansion of ethanol production in the United States is the result of both market forces and policy incentives. These policy incentives are separate from but inextricably interwoven with market forces. Understanding the policy incentives influencing the industry is a critical portion of evaluating the location decision. The legislative and regulation based landscape can sometimes change the balance of a decision. A company financing expansion must understand what policy incentives help or hinder business at the location under consideration. Also, future changes to policies/regulations introduce an element of risk as they could immediately reshape the market and render a previously good location unsuitable. States and regions working to attract industry and economic growth also have a vested interest in understanding and protection these incentives. Attracting industry is a key portion of standard economic development strategies. Protecting and sustaining that industry often requires significant legislative effort. Lastly, the intersection of market forces and diverse policy incentives can be a major factor in explaining patterns in industrial location. The first pieces of the puzzle examined are the laws and regulations enacted at the federal level.

6.1: Overview of Federal Legislation

There are numerous pieces of federal legislation that impact the ethanol production market. These incentives impact at different points in the market and come from different points of origin in the legislative arena. Some originate from energy policies while others are tied to jobs creation programs. Painting the picture of ethanol related policy incentives is a matter of piecing together different policies. Some of the key pieces of federal legislation are the Energy Policy Act of 2005 (EPAct2005), The Energy Independence and Security Act of 2007 (EISA2007), The America Jobs Creation Act of 2004, The Clean Air Act Amendments of 1990 (CAAA1990), the Ethanol Import Tariff of 1980, and the Energy Tax Act of 1978. There are other policy incentives that are important but not directly targeted at ethanol. The most notable of these is the series of Farm Acts with the current version being from 2008. This Act undoubtedly influences the price of corn in the United States and thereby influences the cost of producing ethanol. This analysis focuses on the policy incentives that currently impact ethanol production and the sale of ethanol in the market.

6.1.1 : Energy Tax Act of 1978

The first piece of federal legislation is the Energy Tax Act of 1978. This act came out of the gasoline shortages and Arab oil embargoes from the 1970s. This coincided with the grain embargo after Russia's invasion of Afghanistan which caused a price drop in corn following the 1979 invasion (see corn prices in chapter 4). The legislation served two purposes. It was intended to reduce U.S. dependence on foreign oil and help create a value-added market for U.S. grain. The vehicle for this was a $0.54/gallon tax incentive for ethanol blended into gasoline. This tax incentive encouraged gasoline marketers to blend ethanol by reducing the tax paid on gasoline sold. The unintended consequence of this was to reduce the funds coming into the Highway Trust Fund (Hart, 2004). This resulted from blenders paying $0.54/gallon less in gasoline taxes for every gallon blended. The problem was resolved through the implementation of the Volumetric Ethanol Excise Tax Credit (VEETC) which took the reduction from taxes based on earnings instead. VEETC is discussed further as part of EPAct2005.

6.1.2 : Ethanol Import Tariff

The second piece of legislation was the Ethanol Import Tariff of 1980. This imported ethanol also qualified for the $0.54/gallon tax incentive created under the 1978 Energy Tax Act. The tariff put in place a counterbalancing price increase of $0.54/gallon to directly offset the tax incentive. The tariff remains in place at the enacted level.

6.1.3 : Clean Air Act Amendments of 1990

The next piece of legislation was the CAAA1990. These amendments established requirements for oxygenated and reformulated gasoline in certain areas of the country. These requirements came for areas that were failing to meet the National Ambient Air Quality Standards (NAAQS). The oxygenate requirement was later removed by the EPAct2005, but refiners are still required to blend gasoline to meet the EPA emissions requirements in some areas and to upgrade the octane of sub-grade gasoline. The impact of the oxygenate removal is discussed later in conjunction with the multi-state MTBE ban. The CAAA also implemented air quality controls for plant emissions which impacted the industry. Emissions permitting and its impacts on ethanol production are discussed later.

6.1.4 : Energy Policy Act of 1992

The Energy Policy Act of 1992 set the initial stage for what would be more significant future rulings. One key feature of the act was the implementation of a proto Renewable Fuels Standard (RFS). The EPAct1992 set the goal that 10% of total motor fuel consumption by 2000 increasing to 30% by 2010 should be replaced by alternative fuels. These targets were later revised and mandated during EPAct2005. Another piece of this legislation was the requirement for 75% light-duty vehicles owned by federal and state agencies to be alternative fuel vehicles (AFVs). The 1992 act started setting the foundation for a guaranteed market by setting goals for inclusion of biofuels while mandating government use.

6.1.5 : Jobs Creation Act of 2004

The fifth piece of legislation is the Jobs Creation Act of 2004. The impact of this legislation was, as previously discussed, to eliminate the funding reduction occurring to the HTF as a result of the original ethanol tax credit. This act created the VEETC which maintained a $0.51/gallon tax credit for ethanol blended into gasoline. The VEETC set a different level for ethanol blended at an 85% rate. E85 was only credited at $0.4335/gallon. The act also extended the time frame for this credit through 2010. The legislation eliminated the critique that support for ethanol through the tax exemption was significantly reducing the revenue going into the Highway Trust Fund. Another interesting aspect of the

VEETC is that it was enacted a portion of the Jobs Creation Act. This highlights the role of ethanol as not only a liquid fuel but also as an important industry that provides employment for thousands of people.

6.1.6 : Energy Policy Act of 2005

The EPAct2005 was perhaps the most significant piece of legislation. The Renewable Fuels Standard (RFS) that was a portion of this legislation went into effect in 2007 and set new requirements for reporting, registration and compliance requirements for major refiners, blenders and importers (DOE AFDC, 2005). The requirements for biofuels use in the gasoline supply increased to 4 billion in 2006, 6.1 billion in 2009, and 7.5 billion by 2012. It additionally includes the creation of a credit trading system to meet blending requirements. The regulation of federal fleets was also included. AFV vehicles in the fleets are required to fuel using alternative fuels unless a waiver is granted. In 2007 bio-fuel production totaled 3.9 billion gallons of ethanol and only 91 million gallons of biodiesel (DOE EIA, November 2007). The mandated inclusion level for biofuels indicates the government strongly supports the industry.

6.1.7 : Energy Independence and Security Act of 2007

The EISA2007 is the most recent legislation that changed the landscape of policy incentives. The changes made to the Renewable Fuel Standards (RFS) are termed RFS2 where RFS1 were the standards laid out in EPAct2005. The usage for renewable fuels was increased and was mandated at 36 billion gallons by 2022 (Figure 6.1). Of that 36 billion gallons corn ethanol is limited to 15 billion gallons and cellulosic ethanol is required to be 16 billion gallons. The mandate for cellulosic ethanol is of note due to the limited to non-existent production capacity currently in place. In 1980 ethanol production totaled 175 million gallons of corn based ethanol. In 2007 ethanol production was nearly 6.5 billion

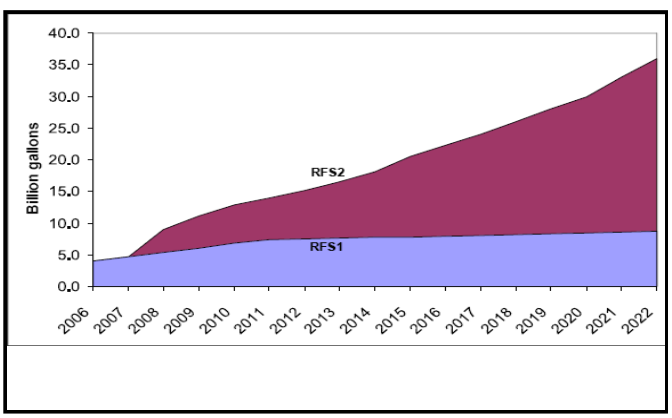


Figure 6.1 – EISA 2007 RFS2 fuel requirements (Argyropoulos, 2008)

gallons. (Renewable Fuels Association, October 24th 2008). The ability of the ethanol industry to grow 16 billion gallons of cellulosic ethanol production by 2022 is highly unlikely. The most controversial portion of EISA2007 in regards to this analysis is the requirement for a 20% reduction in life-cycle Green House Gas (GHG) emissions for biofuels. This requirement uses 2005 as the baseline year for GHG emissions and this would likely exclude plants using coal for process heat. Existing and plants under construction before December, 2007 would be grandfathered in and not required to meet the 20% reduction. Implementation of the overall plan is questionable at best. The issue is that no method currently exists to conduct the full life-cycle analysis as EISA 2007 requires additional requirements that have not previously been used. Additionally, the EPA missed a December 2008 deadline contained in EISA to finalize guidelines for conduct of the life-cycle analysis and the implementation of the RFS. The Life-cycle analysis would now include indirect land use change on an international scale. This requirement means that additional land brought into agricultural production would count against the life-cycle analysis GHG emissions for ethanol. For instance if an additional 5 million acres in Argentina or China are brought into corn production to offset decreasing exports in the U.S. the life-cycle analysis would count these additional GHG emissions from land use change overseas towards ethanol production The future impact of EISA2007 is unclear until the EPA develops and publishes the implementation guidelines.

6.1.8 : Federal Legislation Summary

These separate elements of federal legislation taken together shaped an environment where ethanol was economically supported by a $0.54/gallon import tariff and a $0.51/gallon blender's tax credit. Federal legislation went further and mandated the use of ethanol in the gasoline supply thereby ensuring that a market would exist.

6.2: State Legislation

Federal regulations have a large impact on overall ethanol production. Ethanol receives a tax credit for blending at a rate of $0.51/gallon. Domestic ethanol producers enjoy a tariff of $0.54/gallon helping to protect them from overseas producers using less expensive processes. The federal government has additionally mandated that a market exist through vehicle fleet policy and increasing the RFS. While these federal policy incentives are important, state policy incentives also play an important role. In some cases they influence production locations more significantly because of the variance by state. Additionally, similar actions taken by several states may not alter the location decision as directly, but do influence the size and location of markets.

The first state regulation of concern is one that was enacted by numerous states. Bans on MTBE resulted from groundwater contamination concerns (EPA, November 4th, 2008). Groundwater contamination was detected in the mid to late 1990s but the first ban did not emerge until 2000 (EPA, November 4th, 2008). Iowa was the first state to act and there are now 24 states with at least partial bans as seen in figure 6.2 (EPA, November 4th, 2008). These bans served bolster the market for ethanol as the only ready oxygenate alternative to MTBE ethanol use increased by nearly 140% between 2000 and 2005 (DOE EIA, November 4th, 2008). As discussed the EPAct2005 removed the oxygenate requirement for reformulated gasoline effective in 2006. Ethanol is still used in order for blenders to meet reformulated gasoline performance requirements and as seen in Figure 6.3 use levels have not decreased (DOE EIA, February 14th, 2009).

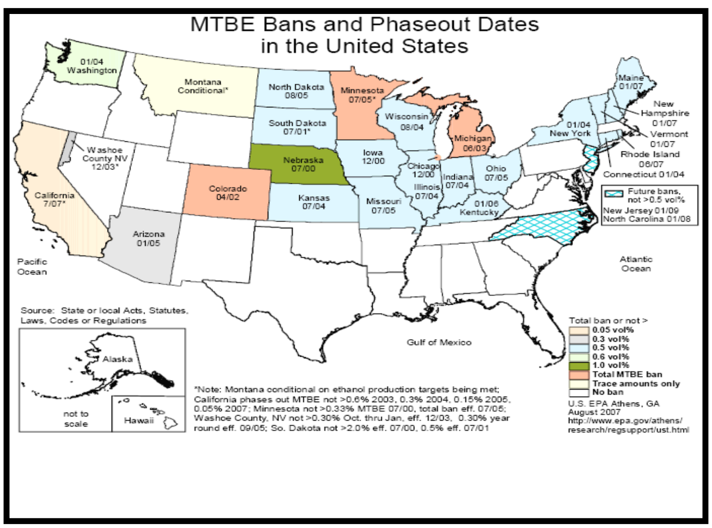


Figure 6.2 - State Level MTBE Bans in the U.S. - EPA

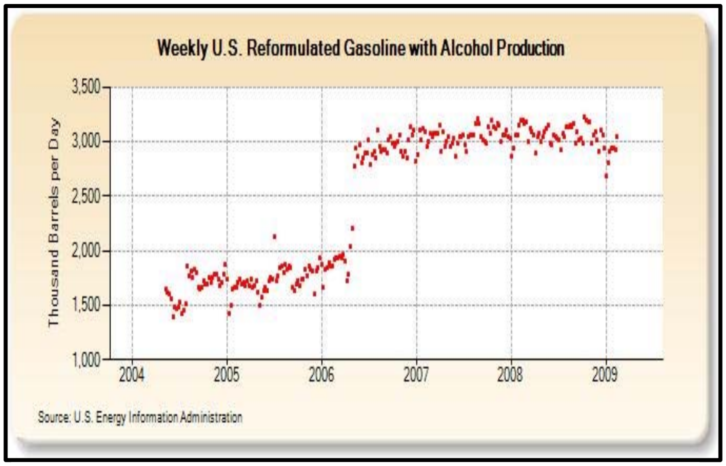


Figure 6.3 - U.S. RFG production 2004-2008 - EIA

The result of the MTBE ban was to provide a substantial advantage to ethanol as well as to create a price increase that helped to fuel the rapid expansion that took place in the industry. The action taken collectively by individual states rapidly reshaped the ethanol market. Individual state laws are also important in the landscape of policy incentives. The impacts of different state laws can be very important in shaping location decisions. A move of only 50 miles could put a plant across a state boundary and either open up or eliminate incentives based on the state programs in place. Figure 6.4 shows the number of programs in place by state (DOE EERE, December 19th, 2008).

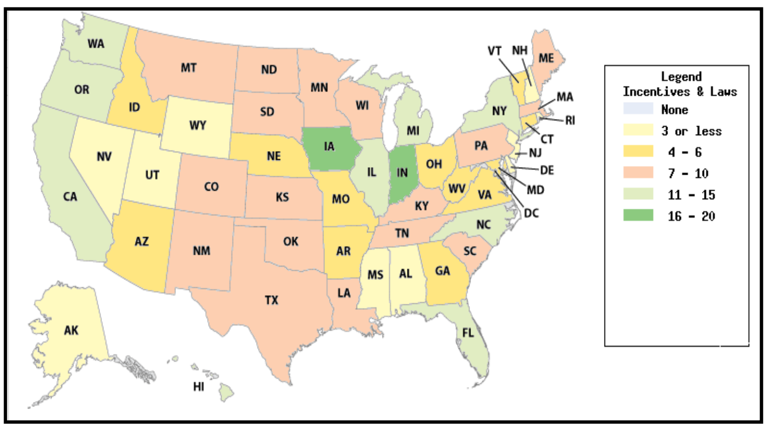


Figure 6.4 - State Ethanol Incentives – DOE

Examining these laws in Pennsylvania and Iowa can help shed light on the current pattern of ethanol production and possibly shed light on expansion of the industry into Pennsylvania.

6.3: Legislation and Laws in Iowa

Iowa has a vested interest in ethanol production. As a state it has more individual ethanol plants than any other state and it has more ethanol production capacity. Iowa and Indiana have more laws in support of ethanol production than any other states. Many of Iowa's programs extend upon federal programs by providing credits and incentives on top of the federal levels. A full description of all

Iowa state incentives is available at the DOE Energy Efficiency and Renewable Energy (EERE) website (DOE EERE, December 19, 2008). The following is a summary of the Iowa incentives from the DOE source.

There are eight incentive based programs in Iowa. The ethanol promotion tax credit provides a $0.065/gallon tax credit to any retailer meeting the RFS2 standards in any given year. The credit is reduced for retailers failing to meet the RFS2 standard by 2% or 4% down to $0.045 and $0.025 respectively. There is also an E85 retailer tax credit that gives stations a $0.25/gallon credit through 2010 which is reduced to $0.10/gallon in 2011. After 2011 it decreases $0.01 per year expiring in 2020. Iowa also has a renewable fuel infrastructure program that gives cost share grants to upgrade and install E85 or biodiesel infrastructure. The Iowa energy center administers the Alternative Energy Revolving Loan Program (AERLP). This program provides no interest loans up to $1 million per facility, or half the cost, for alternative fuels production projects. The Iowa Enterprise Zone Program and the High Quality Job Creation Program offers a variety of state tax incentives. The Iowa Power Fund is a $100 million fund that is designed to educate the public about alternative energy and increase demand for these products.

Iowa also uses a variety of laws and regulations to support ethanol production. Iowa code 323A provides that E85 must be deliverable to a retailer upon request. If a seller cannot provide E85 then the retailer is free to obtain it from any other distributor. The goal of the Iowa renewable fuel standard is to replace 25% of gasoline with biofuels by 2020. Iowa has also entered into a regional promotion plan with Indiana, Kansas, Michigan, Minnesota, Ohio, South Dakota and Wisconsin. This plan establishes shared goals for the Midwest region. Some of the goals include creating common signage as well as collective goals for alternative energy usage and overall fossil fuel use. In Iowa state fleet vehicles may not operate on any fuel other than ethanol blended gasoline. Additionally, by the end of June 2009 60% of the fuel purchased by state vehicles must be E85. Lastly, at least 10% of the vehicles purchased by institutions under the control of the state fleet administrator must be capable of using alternative fuels. This includes groups such as boards of directors of community colleges, state board of regents, commission for the blind, and also the department of corrections.

Iowa has moved to aggressively support its ethanol industry. The state incentives available are a strong indication of why Iowa has 34 production capable facilities, two scheduled for completion in February 2009 and two more under construction (Ethanol Producer Magazine Plant List, November 5th, 2008).

6.4: Legislation and Laws in Pennsylvania

As a newcomer to the ethanol industry Pennsylvania has far fewer incentives than Iowa. With only seven specific current laws it would appear that Pennsylvania has not done enough to incentivize ethanol production. A full description of all Pennsylvania incentives is available at the DOE Energy Efficiency and Renewable Energy (EERE) website (DOE EERE, December 19, 2008). The following is a summary of these various incentives. The Alternative Fuels Incentive Grant (AFIG) program is a wide ranging program that provides money to support alternative fuels. Renewable energy grants administered through the Pennsylvania Energy Development Authority provides grants and loan guarantees for alternative energy projects and research. State laws and regulations are also important in creating a favorable environment for ethanol production. The State's Energy Independence Strategy established in 2006 is called the PennFuels Security Initiative. It seeks to reduce the use of imported transportation fuels. The Renewable fuels mandate in PA does little to address ethanol production. The only requirement in the mandate is that gasoline must contain 10% ethanol by volume one year after production reaches 200 million gallons and increases to 20% at 300 million gallons (PA Department of Agriculture, October 5th, 2008). The state plans on investing $5.3 billion annually in biofuels development through 2011 (PA Department of Agriculture, October 5th, 2008). Additionally, biofuel producers are eligible for a $0.75/gallon subsidy capped at $1.9 million per year (DOE EERE, December 19, 2008).

The Pennsylvania Alternative Energy Portfolio Standard (AEPS) directly impacts the Pennsylvania energy market (McGinty, 2004). Although this legislation is directed at electricity producers it includes waste coal as an alternative energy. The inclusion of waste coal as a tier II alternative energy fuel source will be a benefit to electricity producers who use it as a fuel. An ethanol production facility that fuels with waste coal and is configured as a cogeneration facility could also benefit. Several options exist for how to take advantage of waste coal and co-generation. By co-locating near a facility with waste heat an ethanol plant could reduce energy costs further through use of the waste heat. By building a waste coal fueled ethanol plant that provides waste heat to another facility or community an ethanol plant could take advantage of the lower fuel costs from waste coal. An ethanol plant with cogeneration could also allow the plant to forgo purchasing electricity on market if they elect to include electricity generation. This would serve as a cost savings while also generating Alternative Energy Credits (AECs) which can then be sold through the credit trading program in the state. Eliminating electricity purchases could save a plant in Pennsylvania nearly $10,000,000 in annual electricity charges (see chapter 4). This would be offset in part by increased capital costs for equipment to generate electricity. And it would also be offset by increased fuel costs and operating expenses. It is also unclear what price AECs will sell for in the open market in Pennsylvania. Including waste coal as a Tier II energy source makes coal a more feasible alternative in Pennsylvania but the final cost calculations are not yet known.

The federal and state incentives in place have undoubtedly helped the industry grow over the last 20 years. Midwestern corn producing states had a vested interest in the growth of the industry. With the advent of renewable fuel standard requirements the development of biofuels production is moving beyond its traditional locations. While the Midwest still has a more significant list of incentives other states are developing more robust policy incentive programs. Incentives help spur production and demand but there are other laws and regulations that play an important part. One of the most difficult hurdles for ethanol plants is the emissions permitting process. Changes made by the EPA in 2006 going into effect in 2007 made the permitting process easier for ethanol plants (Ethanol Producer Magazine, May 2006). Changing to coal could make the emissions permitting process more difficult. However, using waste coal could ease the process and also create a secondary by-product through the AEC market.

6.5: Emissions Permitting

In 2007 the EPA changed the classification of ethanol production facilities. Removing ethanol plants from the "chemical processing plants" category increased the maximum level for minor sources from 100 tons per year (tpy) to 250 tpy (EPA, 2006).

This change falls under the Prevention of Significant Deterioration (PSD) guidelines and principally applies to unclassified areas that are in attainment of National Ambient Air Quality Standards (NAAQS) (EPA, 2006). For areas that are not in attainment of NAAQS the New Source Review (NSR) standard would remain at 100tpy. The other impact of the change is by redefining ethanol production and thereby moving many plants into the minor source category the plants do not have to go through the complex permitting process required by Title V of the CAA. This change facilitates the growth of plant size by allowing larger plants to still remain minor sources.

Another benefit exists for an ethanol facility that maintains a CFB fueled with waste coal and set-up as a co-generation or combined heat and power (CHP). These type facilities can be exempted from the SO_X and NO_X emissions requirements under the Clean Air Interstate Rule (CAIR), The CAIR Final Implementation Plan (FIP), and the Clean Air Mercury Rule (CAMR) (Federal Register Vol 72. No 79., April 25, 2007). Co-generation facilities that sell less than 1/3 of potential electric output or less than 219,000 MWh annually, whichever is greater, would be exempt from both CAIR and CAMR (Federal Register Vol 72. No 79., April 25, 2007). Waste coal facilities that are classified as Electricity Generating Units (EGUs) would be required to purchase Title IV allowances from other EGUs as they are not allocated any under the federal or state implementation plans. The use of a waste coal fueled co-generation unit at an ethanol plant would reduce operating costs greatly as these facilities are not required to purchase Title IV allowances.

6.6 : Future Legislation Challenges and Opportunities

The current legislative environment helps define the market and impacts location decisions. Pending and future legislation have an important impact on current investment choices and can change the quality of a location or the attractiveness of the industry as a whole. There are several key pieces of legislation that will play an important part in shaping the future of the ethanol industry. The first, discussed already, is EISA 2007 and its requirement for a life-cycle analysis for GHG emissions. The second is the possible future enactment of CO_2 emissions controls in the form of either a cap and trade system or emissions tax. The possibility for the regulation of CO_2 emissions could substantially change the economics of ethanol production. Regulation of CO_2 introduces a large amount of uncertainty. The level of emissions that will require regulation is the most important question. Do ethanol plants emit sufficient amounts of CO_2 that they will be regulated under future legislation? The answer is unknown, but numbers are available for current emission levels. Ethanol plants emit approximately 1% of total stationary source CO_2 emissions (DOE NETL, 2008). Electricity Generation accounts for 83% of point source emissions and 40% of total emissions (DOE NETL, 2008) (DOE EIA, 2008). The transportation sector itself accounts for 34% of total emissions and is responsible for a large portion of emissions from non-stationary sources (DOE EIA, 2008). The regulation of emissions from ethanol production would have a very minimal impact on overall CO_2 emissions in the United States. The regulation of CO_2 could prove beneficial to the industry though if it can create tradable credits either through emissions reductions or through carbon capture and sequestration.

The Regional Greenhouse Gas Initiative (RGGI) is the first mandatory CO_2 permit trading system in the United States. Comprised of ten Northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) RGGI is a cap and trade system. RGGI began holding auctions for permit in Fall 2008. The three auctions held so far have averaged \$3.38 for 2009 permits and the single auction for 2012 permits resulted in a clearing price of \$3.05 (RGGI, March 24th, 2009). These are only initial numbers and do not necessarily indicate what prices would be seen under a mandatory national cap and trade system. They do offer a glimpse into what firms are willing to pay and should indicate what cost is reasonable for emissions abatement. Archer Daniels Midland (ADM) is developing a large scale ethanol sequestration project in Decatur, Illinois (Illinois State Geological Survey, April 6th 2009). The project calls for the injection of approximately 1,000 metric tons of CO_2 daily into the Mount Simon sandstone formation through an 8,000 foot deep well. The CO_2 slated for injection comes from the fermentation process. It does not represent CO_2 emissions from the combustion of fossil fuels required to power the production process. The project costs are difficult to project with major capital outlays including a dehydration/compression facility as well as a 3,200 foot pipeline (Illinois State Geological Survey, April 6th 2009). The project is receiving substantial support with the DOE along contributing \$66.7 million over seven years (Gardner, 2008). The total sequestration potential for CO_2 from ethanol production is still unknown. A study released in the Fall of 2008 found that 50% of existing and 64% of planned plants sit atop geologic formations that are candidates for carbon sequestration (Dahowski and Dooley, 2008). The benefit of using ethanol fermentation CO_2 for sequestration is that it is a relatively pure source of CO_2 that only requires dehydration, to prevent pipeline corrosion, and compression prior to injection (Dahowski and Dooley, 2008). The estimate of cost per ton CO_2 for dehydration and compression is \$6-12 and does not include costs associated with establishing an injection well (Dahowski and Dooley, 2008). This is significantly more expensive than the average \$3.38 price for allowances under RGGI (RGGI, March 24th, 2009). At this point it is uncertain how widely carbon sequestration will be adopted or how sequestration costs will change as projects become more numerous. Ethanol is positioned to benefit from government incentives supporting sequestration as it offers both a pure source of ethanol and a large number of facilities that are located in close proximity to possible sequestration sites. Adoption of a mandatory CO_2 cap and trade system in the United States could prove very beneficial as CO_2 emitters that have a high cost of abatement turn to the ethanol industry as a source of emission reductions allowances.

6.7: Legislation Summary

Numerous federal and state policy decisions are coming together to shape the ethanol industry. The ever changing landscape of policy incentives and regulations can make long term planning difficult. Coal was at one time seen as a likely alternative to natural gas (Bryan, 2004). The increasing cost of natural gas coupled with the low volatility in the coal market made the prospects of coal power appealing. Uncertainty over future carbon dioxide regulation, EPA emissions standards, and other concerns limited the expansion of coal as a fuel choice. The federally mandated, yet uncertain, implementation of life-cycle GHG analysis contained in EISA2007 increases the uncertainty in the future of coal use and corn based ethanol as s whole. Conditions may prove to increase uncertainty enough that coal is only adopted in limited amounts, however, the long term impacts remain to be seen. Plants in areas like western Pennsylvania where coal and waste coal are inexpensive may prove to have a long term cost advantage. Plants that started construction prior to the EISA requirements could find themselves in a situation where further entry into the coal fueled ethanol market is limited to non-existent. These grandfathered plants could be in a situation where low and stable coal prices allow them to produce ethanol at lower costs than any natural gas plant. Additionally, the inclusion of waste coal in Pennsylvania as a Tier II AEC eligible fuel could put a CHP ethanol plant at a distinct advantage in terms of energy costs. Further uncertainty is introduced by the potential for a cap and trade system being implemented to control CO_2 emissions. Such a program could make coal fired plants more expensive to operate, but such a program also creates opportunities as ethanol is a prime source of CO_2 for sequestration projects.

Chapter 7 : Discussion and Findings

Initial results indicate that ethanol production in Pennsylvania can be profitable. Further analysis of these initial findings is needed, but first it is important to discuss several issues with this study and areas that require further study.

7.1 Discussion

There are several considerations that are worth future examination but not included in this study. The first is in reference to the use of waste coal. The second is the ability to transition from corn based to cellulosic ethanol production. The last consideration is public opinion.

This study assumes that waste coal is an available resource and is more or less unlimited. Unlike the more developed markets for standard bituminous coal, waste coal markets vary greatly by region. As a resource it is far from unlimited. In 2003 the Pennsylvania Department of Environmental Protection estimated the PA had 8,529 acres of un-reclaimed coal refuse piles that contained around 258 million tons of waste coal (PA DEP, August 5th, 2008). One the largest users of waste coal in PA is the ARIPPA which was formerly also known as the Anthracite Region Independent Power Producers Association (ARIPPA). ARIPPA estimates that between 1988 and 2003 that waste coal facilities in the state burned 88.5 million tons of coal refuse (PA DEP, August 5th, 2008). The largest scale waste coal project in the world is the Seward 520mW facility run by Reliant Energy in New Florence, PA (Reliant, 2004), (Reuters, September 22nd, 2008). The plant which began operation in 2004 is scheduled to remove between 60 – 100 million tons of waste coal during the plants lifecycle. (DEP, August 5th, 2008), (Reuters, October 2nd, 2008). The plant will draw waste coal from seven surrounding counties (DEP, August 5th, 2008). Identifying the locations of coal refuse around the state is difficult. Project Gob Pile from the Abandoned Mine Reclamation Clearinghouse (AMRC) has documented the location of coal refuse, but only contains data for Westmoreland County. The map of coal refuse is seen in Figure 7.1

(AMRC, December 15th, 2008). The locations of coal refuse piles in Clearfield County are not as well documented. Another location being considered for an ethanol plant is Curwensville, PA. This plant would also use waste coal as a fuel source. Determining the amount and quality of fuel accessible to a chosen plant location requires further study.

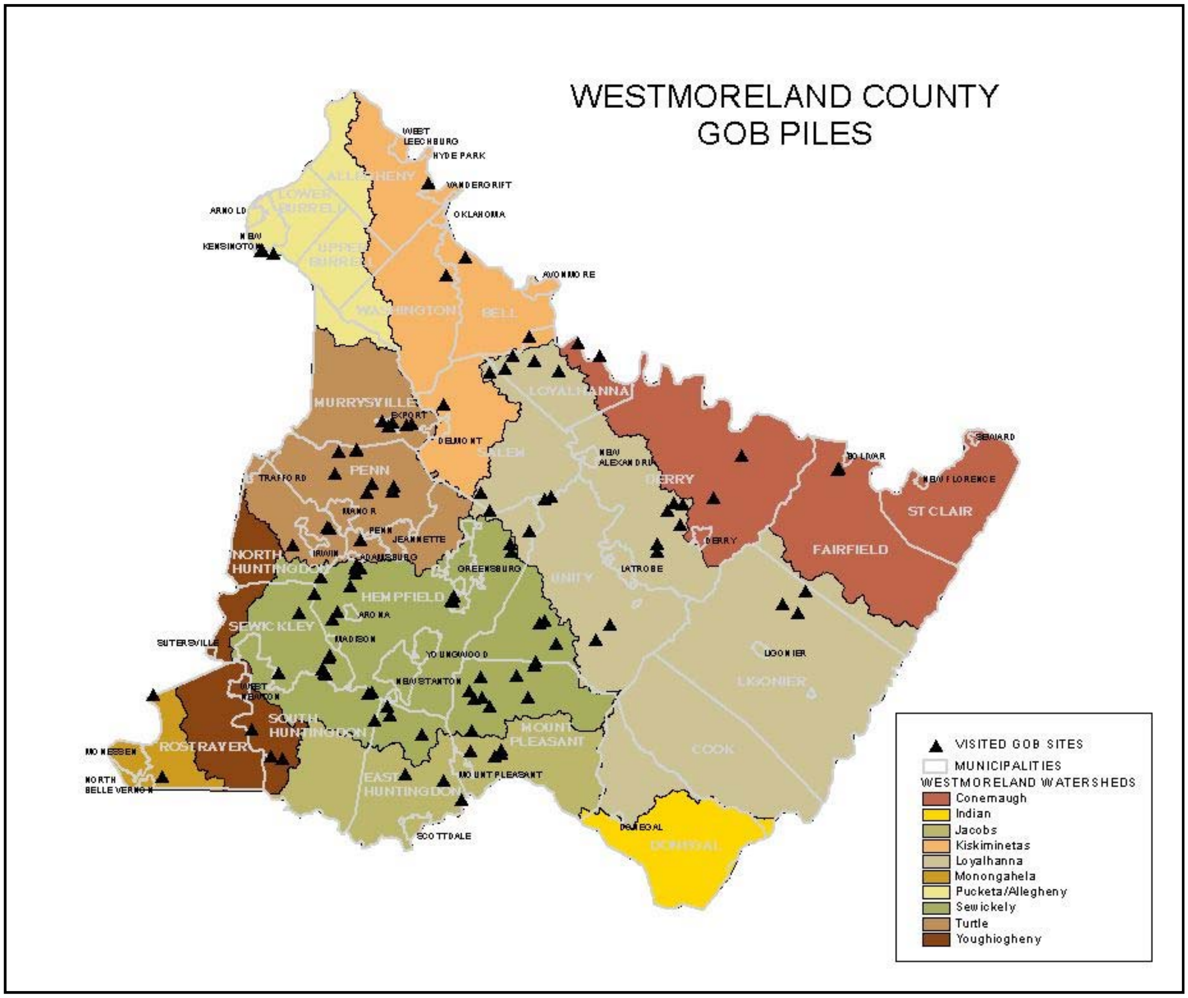


Figure 7.1 – Project Gob Pile – Coal Refuse Locations

The next issue is the ability of the state to transition from corn based ethanol production to cellulosic ethanol production. Governor Rendell is putting support behind cellulosic ethanol production (PA DCNR, December 10th, 2008). The ability of existing plants to transition from one feedstock to another is a concern for the future of the industry. The plant under construction at Clearfield, PA includes a cellulosic pilot plant (BioEnergy LLC, July 14th, 2008). Pennsylvania possesses significant amounts of biomass, but the amount suitable for conversion in a cellulosic plant will not be known until the conversion process is defined. The initial handling of biomass differs significantly from the corn dry-mill process. The handling of the feed stock, receipt of materials process and handling equipment will have to change significantly. The cost of conversion is unknown and is an area that requires further study.

The last area of concern is public opinion. The influence the public can exert on a location decision should not be understated. Public opinion's role in the industrial location decision is a difficult topic. The concern, from the perspective of a business, is that a location that offers the lowest production costs can be unsuitable based on public opposition. This opposition is often labeled as the Not In My Backyard (NIMBY) problem. In this case the opposition is derived from a perceived negative impact coming from the proximity to the population. Public opinion has already played a role in the development of ethanol production in Pennsylvania. Sunnyside Ethanol L.L.C. chose a location in Curwensville, PA for an ethanol production facility. The plans for construction were announced in 2003 (Ethanol Producer Magazine, June 12th 2008). However, as of December 2008 only limited construction is underway (Byers, January 4th, 2009). One of the main opposition groups is Citizens for a Clean Curwensville (www.cleancurwensville.com). The group has effectively organized around air quality concerns and the proximity of the project to the local high school has given them extra leverage. Some research suggests that this type of opposition can be avoided through a planning process that includes the community.

In a study of the development of wind power in the Netherlands Wolsink (2000) found that institutional factors were more important than public opposition. Wolsink found that the practice of plan, site, defend led to opposition based on the perception that the public was left out of the decision making process. The opposition existed not as much out of dislike for the project, but as an expression of the desire to retain some form of power in a bargaining relationship. This would indicate that the problem of opposition is addressable if considered early in the process and if key community leaders are integrated into the planning process. One of the key concerns in dealing with public opinion is the public's perception of risk. Judith Petts addresses the complexity of the issue well in her paper "Effective Waste Management: Understanding and Dealing with Public Concerns" (1994). Again she finds that the main source of opposition comes from misperceptions of risk and failure by the planning entity to communicate with the public.

The expansion of ethanol production in Pennsylvania, whether corn based or cellulose based, requires effective management of the location decision process. Attracting sustained economic development is a difficult goal to achieve. Unnecessary public opposition should be avoided through proactive integration of the community in the location decision. Another issue with public opinion is its role in shaping legislation. Ethanol expansion in Pennsylvania requires an affordable fuel source to provide the needed energy. A community that works to bring an ethanol production facility to the area should understand how energy related legislation could impact the future profitability of the plant. This topic is only briefing touched on here. The ability to influence and manage public opinion to maintain critical advantages inherent in a location deserves more attention.

7.2 Findings

Much of the initial findings were discussed in Chapter 4. From that analysis it appears that an ethanol production facility located in Pennsylvania can be price competitive if it is allowed to switch fuels to coal. This analysis of the cost savings is strictly limited to variable costs and then only the two most important of the variable costs. Table 7.1 duplicates information from Chapter 4 for reference here.

Iowa	Pennsylvania	Advantage	2007	2030
Gas	Gas	IA	$27,432,000	$35,105,162
Coal	Coal	IA	$12,944,794	$14,997,235
Coal	Waste Coal	IA	$9,842,688	$11,460,835
Gas	Coal	PA	$9,697,104	$20,875,376
Gas	Waste Coal	PA	$16,571,088	$26,300,536

Table 7.1 – Annual Cost Comparison 2007 & Projected 2030

These results are not designed to stand alone. The cost projections for the different inputs presented in Chapter 4 and seen in Table 4.15 are now put to use. These figures are used in conjunction with the dry-mill ethanol spreadsheet created by Douglas Tiffany from the University of Minnesota. The spreadsheet is featured in Vernon R. Eidman's article "The Evolving Ethanol Industry in the United States" (2007). A copy of the original spreadsheet is contained in Appendix A for reference. This worksheet makes several explicit assumptions about return on investment and capital cost per based on a dollar per gallon basis. These numbers are not changed either from the worksheet or between coal and ethanol. The additional capital costs of a coal fueled ethanol plant are not included and only variable costs are manipulated. The potential profit shown is therefore likely smaller and the focus is more on comparing relative values between price scenarios. Within the worksheet the values for production capacity (cell C4), conversion efficiency (C14), ethanol price (C19), DDGS (C20), corn price (C26), natural gas price (C30), BTU's (C33), electricity price (C35) and kilowatt hours required (C36) are altered. The values for cells C4 (108 million gallons), C14 (2.8 gallons/bushel), C19 ($1.94/gallon) and C20 ($114.88) are initially altered and are then unchanged. The values for C19 and C20 are an average of prices for 2007 taken from the Agricultural Marketing and Research Center (AgMRC) (AgMRC, February 28th, 2009). Using the values from Table

4.15 for 2007 the Actual, High, and Low price scenarios are examined. The results from that analysis are presented in Table 7.2. The results are representative of the changes experienced under the different price scenarios. However, the prices for ethanol and DDGS initially remain constant. This separates these changes from the impacts of changes in product market prices. In limiting the study this way these numbers represent the best that could be expected for a plant in Pennsylvania.

Actual

	Iowa (Gas)		Pennsylvania (Gas)		Pennsylvania (Coal)		Pennsylvania (WC)	
	total	$/gallon	total	$/gallon	total	$/gallon	total	$/gallon
Energy Cost	$49,329,797	$0.3806	$67,010,348	$0.5171	$22,901,930	$0.1767	$19,253,854	$0.1486
Gross Margin	$110,623,757	$0.8536	$98,751,453	$0.7620	$98,751,453	$0.7620	$98,751,453	$0.7620
Processing Cost	$96,301,028	$0.7431	$113,981,579	$0.8795	$69,873,161	$0.5391	$66,225,084	$0.5110
Net Margin	$14,322,729	$0.1105	($15,230,125)	($0.1175)	$28,878,293	$0.2228	$32,526,369	$0.2510
Potential Profit	$14,322,729	$0.11	($15,230,125)	($0.12)	$28,878,293	$0.22	$32,526,369	$0.25

High

	Iowa (Gas)		Pennsylvania (Gas)		Pennsylvania (Coal)		Pennsylvania (WC)	
	total	$/gallon	total	$/gallon	total	$/gallon	total	$/gallon
Energy Cost	$60,074,674	$0.4635	$83,433,001	$0.6438	$25,773,318	$0.1989	$21,710,680	$0.1675
Gross Margin	$19,531,867	($0.1507)	$19,531,867	($0.1507)	$19,531,867	($0.1507)	$19,531,867	($0.1507)
Processing Cost	$107,045,905	$0.8260	$130,404,231	$1.0062	$72,744,549	$0.5613	$29,345,760	$0.2264
Net Margin	($126,577,772)	($0.9767)	($149,936,098)	($1.1569)	($92,276,416)	($0.7120)	($88,213,786)	($0.6807)
Potential Profit	($126,577,772)	($0.98)	($149,936,098)	($1.16)	($92,276,416)	($0.71)	($88,213,786)	($0.68)

Low

	Iowa (Gas)		Pennsylvania (Gas)		Pennsylvania (Coal)		Pennsylvania (WC)	
	total	$/gallon	total	$/gallon	total	$/gallon	total	$/gallon
Energy Cost	$37,212,716	$0.2871	$58,627,301	$0.4524	$20,030,541	$0.1546	$16,797,019	$0.1296
Gross Margin	$156,354,111	$1.2064	$156,354,111	$1.2064	$156,354,111	$1.2064	$156,354,111	$1.2064
Processing Cost	$84,183,947	$0.6496	$105,598,532	$0.8148	$67,001,772	$0.5170	$63,768,250	$0.4920
Net Margin	$72,170,165	$0.5569	$50,755,579	$0.3916	$89,352,339	$0.6894	$92,585,861	$0.7144
Potential Profit	$72,170,165	$0.56	$50,755,579	$0.39	$89,352,339	$0.69	$92,585,861	$0.71

Table 7.2 - Ethanol Production Profit Scenarios

The scenario for actual prices shows that the use of natural gas to produce ethanol in Pennsylvania is not likely a profitable scenario. It also confirms that the use of coal as a fuel source could be a profitable approach. Also shown in the High scenario is the challenges faced by ethanol producers resulting from high corn prices. Under the high price scenario the relatively flat (non-volatile) prices for coal greatly reduces potential losses. This analysis uses static prices for products while varying the input costs. This is an unrealistic assumption and varying related prices alters the outcome.

Coordinated price increases similar to those seen in 2008 change the outcomes, but not significantly. Increasing energy costs (oil and gasoline) drive up the price for commodities (both ethanol and corn). In this type of scenario the higher input costs are slightly offset by the higher prices received for products. This scenario is seen in the left side of Table 7.3. This table eliminates the natural gas and coal columns for Pennsylvania focusing on a natural gas plant in Iowa and a waste coal fueled plant in Pennsylvania. With a High/High price scenario production remains profitable. The second scenario shown in Table 7.3 ethanol producers see a price spike in corn, due to a short harvest perhaps, that does not coincide with higher energy prices. The right side of Table 7.3 uses the highest market prices seen in 2008 for DDGS and MY 2007 for corn. Meanwhile, the energy prices for inputs (coal/natural gas, electricity and ethanol) are changed to the lowest price observed during the same time period.

Input High/Output High					**Corn High/Energy Low**			
	Iowa (Gas)		**Pennsylvania (WC)**		**Iowa (Gas)**		**Pennsylvania (WC)**	
	total	$/gallon	total	$/gallon	total	$/gallon	total	$/gallon
Energy Cost	$60,074,574	$0.4635	$20,207,328	$0.1559	$37,212,716	$0.2871	$16,797,019	$0.1296
Gross Margin	$124,125,778	$0.9578	$124,125,778	$0.9578	($53,426,222)	($0.4122)	($53,426,222)	($0.4122)
Processing Cost	$107,045,905	$0.8260	$67,178,559	$0.5184	$84,183,947	$0.6496	$63,768,250	$0.4920
Net Margin	$17,079,873	$0.1318	$56,947,219	$0.4394	($137,610,169)	($1.0618)	($117,194,472)	($0.9043)
Potential Profit	$17,079,873	$0.13	$56,947,219	$0.44	($137,610,169)	($1.06)	($117,194,472)	($0.90)

Table 7.3 – Alternative Cost Scenarios for Ethanol Production

Comparing Table 7.3 to Table 7.2 shows that a situation where input and product costs increase together may offset the higher prices seen on the input side. The High/High scenario seen in Table 7.3

shows an increase in potential profit from $0.11/gallon to $0.13/gallon for the Iowa plant. The Pennsylvania plant sees an increase from $0.25/gallon to $0.44/gallon. This scenario highlights the benefit offered by the lower volatility seen in coal prices. The right side of Table 7.3 shows that the benefit of lower energy prices for inputs does offset the loss seen when corn prices are high and ethanol prices are low. While energy prices are important the profitability of the ethanol industry is dominated by corn prices. One issue other issue is the timing of these price increases. This is related to the market structure and timing of purchase and sale contracts. For instance a company that times a purchase of corn at a high price point and then selling ethanol at a lower price, based on market timing, could find the situation even worse. Corn prices continued to rise through the first half of 2008 peaking in July (CME Group, February 9th, 2009). Ethanol prices followed the same trend. A company trying to combat increasing costs could negotiate a large corn purchase in May 2008. This decision would look beneficial through July, but by December prices decreased by around 46% from the levels seen in May. Ethanol made from this large corn purchase and sold in December could likewise see ethanol prices decreasing by 40% from those seen in May when the corn contract was signed. It was conditions similar to this that saw VeraSun declaring bankruptcy in late 2008. The use of waste coal limited these losses somewhat, but the production facility remains exposed to timing issues in volatile markets.

The use of waste coal significantly reduces energy costs. The reduced price volatility seen in the coal market reduces some risk, but corn based ethanol production is still dominated by corn prices. Locating ethanol production in Pennsylvania could compete with ethanol production located in Iowa. This competition requires the use of coal in Pennsylvania while the Iowa plant uses natural gas. The results of the different analysis techniques are summarized in Table 7.4. The first two rows show how potential net margins from the Tiffany spreadsheet compare to each other. The bottom four columns are summarized from Chapter 4. These results confirm that the use of waste coal offers a significant cost advantage. The advantage is pronounced when only energy inputs are examined as seen in row

Pennsylvania Ethanol Production Advantage		
$ comparison	Measure	Time Period
233%	Net Margin	2008 High/High
127%	Net Margin	2008 Actual
161%	Annual Cost	2008 Energy
8%	Annual Cost	2008 Energy & Corn
169%	Annual Cost	2030 Energy
11%	Annual Cost	2030 Energy & Corn

Table 7.4 - PA Cost Advantage in Ethanol Production using Waste Coal

three and five. When corn is included the advantage is markedly decreased as shown in row four and six. The advantage of lower energy costs is again magnified when total processing costs are used to project a net margin. The results indicate that based solely on cost analysis that Pennsylvania can compete in ethanol production if waste coal is used while other plants use natural gas. The results also indicate that coal would be a used extensively in newly constructed plants. It appears that the cost advantage present in the use of coal as a fuel is offset by other factors. Uncertainty surrounding the implications of coal use created by recent federal legislation could explain the failure to adopt coal as a new fuel source. The passage of EISA 2007 increases this uncertainty by mandating a life-cycle greenhouse gas analysis. The GHG reduction targets required in this analysis could be difficult for a coal fueled plant to meet. It is unclear at this time how this future legislation could influence the use of coal as a fuel in Pennsylvania. Until these changes are implemented the use of coal as a fuel source for ethanol production in Pennsylvania will remain profitable.

Chapter 8 : Conclusion

Ethanol production is expanding into Pennsylvania. The production of ethanol in areas that are corn-deficient runs contrary to the forces that have acted to shape the industry in the past. An evaluation of the decision to locate ethanol production in the state is important for several reasons. First, the analysis identifies the features of the specific location and wider region that attracted the new industry. Second, the analysis reveals whether public funds spent to attract economic development have been well spent. Third, the analysis shows how policy incentives shape the industry and how future changes might impact it.

8.1: Methodology

The best approach in understanding the expansion of ethanol production in Pennsylvania is to conduct a critical case study of the expansion. Evaluating the location decision in a critical manner is best done through the use of industrial location theory. The tools available through location theory are simple in practice and very effective when the scope of the study is focused on key factors. In this study the analysis was directed at the two most important input factors—feedstock and energy. In analyzing feedstock and energy costs, the analysis focused on a comparison of regional price variation between Pennsylvania and Iowa. These two factors combined account for more than 95% of variable input costs (Kwiatkowski, 2006). While these two factors are by far the most important in terms of input costs, analyzing the location decision by input cost alone is insufficient. For that reason, the role of market size and location relative to production was also examined. Further, the impacts of both state and federal legislation were considered as a key piece of the location decision. These factors, taken in totality, enable a more thorough analysis of the quality of the location decision.

8.2: Opportunities for Future Studies

This study highlighted several areas that bear further analysis. Three key issues should be examined to determine the long term quality of the decision to locate ethanol production in

Pennsylvania. The first area for further inquiry is the waste coal market. The second is the cost and feasibility of changing a facility built to use corn as a feedstock over to biomass. The third is the potential impacts of EISA 2007 life-cycle GHG emissions standards on ethanol production at both the regional and national levels.

Waste coal is a resource in Pennsylvania and other states with a history of coal mining. In Pennsylvania, waste coal has fueled electricity generation for over 20 years (McGinty, 2004). The planned use of this resource in the future requires a better accounting of it. Waste coal is spread throughout the Anthracite regions where it is referred to as culm, and Bituminous regions where it is referred to as gob or boney pile (McGinty, 2004). It poses environmental and health risks, yet its removal results eventually in needed power generation and land reclamation. According to state estimates, there are 220,000 acres of abandoned mine lands and 8,259 acres of waste coal totaling somewhere around 258 million tons (McGinty, 2004). State classification of these piles by economic viability and environmental threat could more effectively target projects that could utilize waste coal as a process fuel. The area around the Seward Reliant Energy waste coal plant is estimated to contain an additional 10-20 million tons of waste coal in locations that were on a list to be explored and evaluated (PA DEP, 2004). A concerted classification effort would allow the state to focus reclamation funds on environmentally sensitive sites that have little chance of being economically viable as process fuels.

The cost and ability to switch an ethanol plant from dry-mill corn-based ethanol production to biomass-based ethanol production is a critical concern for the Commonwealth of Pennsylvania. In light of the Commonwealth's extensive biomass resources, a process involving biomass feedstock that can be adapted for large-scale production would greatly benefit the state's future ethanol production. Clearly, the ability to transform existing production capacity from corn to biomass is important. Facility transformations that are complex and prohibitively expensive will impede companies from constructing many corn-based facilities in the short term. Transformation that can be accomplished reasonably will mean more corn-based facilities, and may lead Pennsylvania to increase incentives for corn-based facilities before biomass production comes online. These initial facilities could then be easily converted and greatly decrease the lag time in bringing biomass production online, since facilities would not have to be built from scratch.

The last concern and area for further study has to do with the implications and impacts of CO_2 regulation. The first concern comes from of EISA 2007. The life-cycle GHG analysis that is required under this legislation could reshape the ethanol market. Additionally, the reductions in GHG required under EISA 2007 could prove to be prohibitive until cellulosic production becomes a commercially viable option. The use of waste coal and circulating fluidized bed reactor facilities is likely a step in the right direction as biomass can be introduced as a fuel source while coal remains a mainstay. This could help reduce GHG emissions and be beneficial in implementing EISA 2007. Until the EPA publishes the guidelines for implementing this requirement, it will be difficult to assess its impact on the industry. The development of this implementation guideline should be of utmost interest to ethanol producers and regions relying on ethanol production to spur economic development. The second CO_2 regulation concern comes from the potential for a CO_2 cap and trade system being implemented in the United States. Creating a market for CO_2 abatement could prove beneficial to ethanol producers as they produce a relatively pure stream of ethanol that is significantly less expensive to abate than emissions from burning fossil fuels (Dahowski and Dooley, 2008). The new market combined with policy incentives for sequestration projects could bring additional funds to ethanol producers. Plants that emit less CO_2 from their fuel source would stand to benefit more from sequestration funds as they would be less likely to have offsetting abatement costs.

8.3: Key Results

Ethanol production in Pennsylvania that uses coal as an energy source can be price-competitive. The ability to use waste coal in Pennsylvania offers a unique opportunity. Like coal, waste coal does not suffer from the price volatility seen in natural gas. This fuel source also qualifies as a Tier II alternative energy source within the state's Alternative Energy Portfolio Standard. Despite these opportunities, the widespread adoption of coal is unlikely. The added capital expenses, coupled with increased uncertainty based on current emissions permitting and pending regulation changes, make the use of coal less appealing.

A facility that uses waste coal as its fuel source while purchasing electricity off the grid could expect to save over $16 million annually, compared to a plant of the same size in Iowa that uses natural gas as the primary energy source. This figure accounts for the import of all corn required for production from sources outside of Pennsylvania. Based on predictions for corn and energy prices this could increase to more than $26 million by 2030. When analyzed in terms of the entire production process, as seen in chapter 7 the use of waste coal in Pennsylvania could yield an annual profit greater than $18 million annually—more than that realized by a natural gas plant in Iowa.

Input costs were the prime concern within this study but the location and size of critical markets were also key factors. The two markets examined for this study were the market for DDGS that exists around Clearfield County, Pennsylvania. The other was the market for ethanol in the transportation liquid fuels market. The area around Clearfield contains sufficient numbers of livestock to support the plant with a planned capacity of 108 million gallons per year. Probably more important is that Pennsylvania's liquid fuels market is large enough to use all 108 million gallons per year plus many more. Blending ethanol at only a 10% rate within the state would require more than 500 million gallons of ethanol. In contrast with Pennsylvania, Iowa only consumed 5.6% of its total ethanol production and blending. At a 10% rate, Iowa would have an ethanol market of only 370 million gallons. This far exceeds the more than 2 billion gallons of ethanol produced annually. Pennsylvania is also located close to the significant East Coast market. The size of the Pennsylvania market and its proximity to the East Coast minimize transportation costs, but this is not a significant advantage since the transportation of corn to Pennsylvania outweighs the advantage of decreasing shipping distance. It costs approximately three times more when measured on a per-gallon basis to bring corn to Pennsylvania than it does to ship the finished product, ethanol, to the port of Baltimore, Maryland. Transportation costs indicate production should remain in the Midwest. Beyond input costs and market size/location, the next factors considered were legislation and regulation at the state and federal levels.

The legislation and regulations that support the ethanol industry come from a variety of sources and policy objectives. Large discrepancies between state-level programs could explain some of the spatial variation in the location of ethanol plants. More important are the federal supports, which come principally in the form of the \$0.54/gallon import tariff and the \$0.51 blender's tax credit. Without these supporting policies the ethanol industry could not exist in its current form. The passage of EISA 2007 marks another possible turning point for the ethanol industry. The inclusion of a controversial life-cycle GHG assessment that includes international land use changes could alter the list of fuels counted towards the federally mandated Renewable Fuel Standards. If corn ethanol is found to have emissions that disqualify it as a renewable fuel, the market for ethanol production could change rapidly. The uncertainty surrounding the implementation of this regulation is the most important piece of pending legislation. The structuring and passage timeline for the implementation instructions are of great importance to the industry as a whole.

8.4: Significance

The expansion of the ethanol industry into Pennsylvania provides an opportunity to use industrial location theory to evaluate the location decision. A critical case study of the decision to locate an ethanol production facility in Clearfield, Pennsylvania revealed several benefits. First, this study demonstrated how a focused use of industrial location theory, supported by publicly available data, can provide information that is important to regional economic development planning. Second, this study indicated a significant opportunity for ethanol production in Pennsylvania utilizing waste coal as a fuel source for a co-generation facility that provides heat and power. The savings in energy costs available can offset the additional cost of importing corn. If cellulosic ethanol production becomes viable, Pennsylvania could be uniquely positioned to benefit from its position relative to the East Coast ethanol market and the availability of waste coal as an energy source.

Lastly, this study identified important current and future legislation that is affecting and will affect the ethanol industry. It also shows that EISA 2007 could rapidly reshape the ethanol industry depending on the implementation guidelines forthcoming from the EPA. The lifecycle Green House Gas analysis, including international land use change, could cause certain biofuels to no longer qualify as renewable fuels that states can use to meet their inclusion levels from the RFS. A loss of status as a renewable fuel would be a major blow to the ethanol industry.

8.5: Energy Price Issues

This study was based upon energy prices recorded during 2008. The continued recent volatility in energy prices drastically alters the ability of Pennsylvania-located production to compete with Iowa-based production. Natural gas prices for industrial customers in Iowa have decreased 28% from the price used in this analysis to a current price of $7.94/MBTU. When compared to waste coal prices, natural gas prices in 2008 were on average 469% higher—as of March 2009, they are only 307% higher. In the short term, ethanol production in Pennsylvania could be less competitive. However, if energy prices rise again plants in Pennsylvania could again find themselves in a better position relative to plants in Iowa.

8.6: Summary

The location of ethanol production in Pennsylvania appeared to be contrary to the forces that had previously shaped the industry and concentrated production in the Midwest. The application of industrial location theory to a critical case study enabled an examination of the quality of the location decision. Findings revealed that ethanol production in Pennsylvania fueled by coal or waste coal can compete economically with production in Iowa fueled by natural gas based on 2008 prices. Further opportunities exist through the use of waste coal-fueled CHP facilities to both increase process efficiency and reduce permit requirements. If natural gas prices remain volatile and return to above normal levels, Pennsylvania will be in a position to engage in further ethanol development. However, if natural gas prices remain at current levels and do not return to 2008 prices, expansion could be limited. The future of the ethanol industry as a whole could be called into question by EISA 2007. Pennsylvania is a viable location for ethanol production but the extent of future development remains uncertain. Clearly, volatility in energy prices and the implementation of future legislation and regulation will continue to shape the industry in the future.

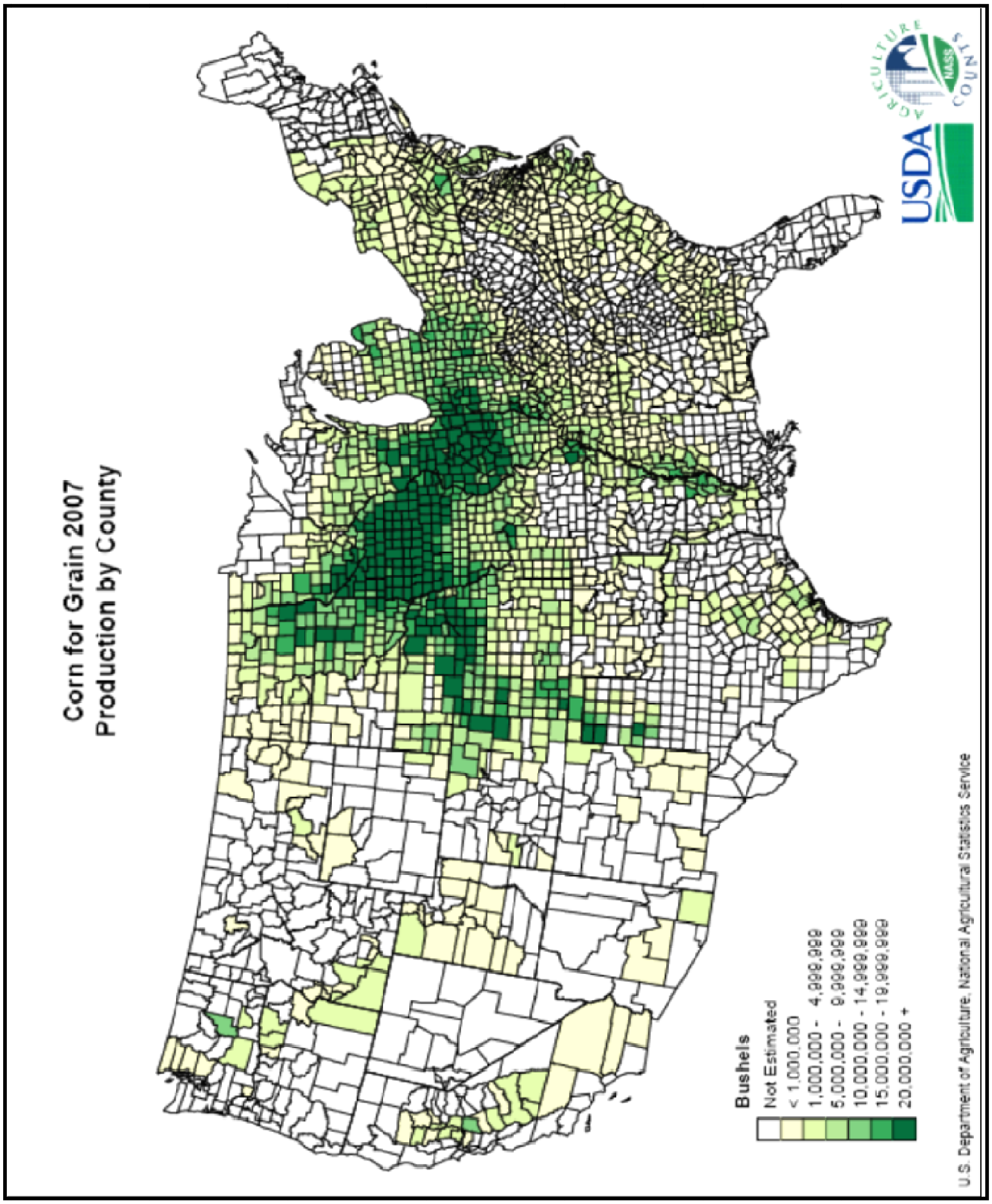
Appendix A: Dry Mill Spreadsheet

1\	B	C	D	E	F	G	H	I
2	**Ethanol Dry Mill Spreadsheet**		by Douglas G. Tiffany, University of Minnesota					
3	23 07 0320 30	**Cost/Denat. Gal. Ethanol**	**Ranges for Column C**					**Plant Totals**
4	**Nameplate Ethanol Prod. (Denat. Gal.)**	**40,000,000**						
5	**Investment per Nameplate Gallon**	**$1.5000**	$1.00-$2.00				**Plant Cost**	**$ 60,000,000**
6	**Factor of Nameplate Capacity**	**1.2000**	(80%- 150%)					
7	**Debt-Equity Assumptions**							
8	Factor of Equity	**0.40**						
9	Factor of Debt	**0.60**					**Initial Debt**	**$ 36,000,000**
10	Interest Rate Charged on Debt	**0.07**						
11	Rateof Return Reqd. by Investors on Equity	**0.12**						
12								
13	**Conversion Efficiency Assumptions**				**Annual Production**			
14	Anhydrous Ethanol Extracted (Gal. per Bu.)	**2.750**	2.5-2.85gal/bu		**Bushels Ground**	**Denat. Gallons**		
15	DDGS per Bushel (lb. per Bu.)	**18**	15-22 lb./bu		**16,581,843**	**48,000,000**		
16	CO2 extracted per Bushel (lb. per Bu.)	**18**	15-22 lb./bu					
17								
18	**Establishment of Gross Margin**	**Price per Unit**			**Revenue/Bu. Ground**		**Revenue/Gal. Denatured Sold**	**Plant Totals**
19	Ethanol Price (denatured price) $/gal.	**$1.15**	$.80 to $1.60		$3.3289		1.1500 $	55,200,000
20	DDGS Price $/T	**$80.00**	$60-$120		$0.7200		0.2487 $	11,938,927
21	CO2 Price ($ per Ton liq. CO2)	**$6.00**	$2- $12 / liq.Ton		$0.0540		0.0187 $	895,420
22	MN Prod. Subsidy/ gal. Denat. Ethanol	**$0.00**			$0.0000		0.0000 $	-
23	Federal Small Producer Subsidy						$	-
24	CCC Bioenergy Credit						$	-
25	Revenue per Unit				$4.1029		$1.4174 **$**	**68,034,347**
26	Corn Price Paid by Processor ($ per bu.)	**$2.20**	$1.70--$3.25		$2.2000		$0.7600 **$**	**36,480,055**
27	Gross Margin				**$1.9029**		**$0.6574 $**	**31,554,292**
28								
29	**Operating Expenses Per Bushel**	**Price per Unit**			**Cost/Bushel Ground**		**Cost/Gal. Denatured Sold**	**Plant Totals**
30	Natural Gas Price ($ 1,000,000 Btu)	**$4.50**	($1.50-$9.00/Dtherm)					
31	LP (Propane) Price ($ per gallon)	**$0.70**	$.55-$.72 / gal.					
32	Factor of Time Operating on Propane	**0.02**	0-.12					
33	BTU's of Heat fr Fuel Req./ Denat. Gal.	**35,000**	28,500-55,000					
34	Combined Heating Cost				$0.4623		$0.1597 $	7,665,569
35	Electricity Price ($ per kWh)	**$0.05**	$.025-$.090/kwh					
36	Kilowatt Hours Required per Denat.Gal.	**1.090**	(.85-1.2 kWh/denat. gal.)					
37	Electrical Cost				$0.1578		$0.0545 $	2,616,000
38	Total BTU's of Fuel and Electricity	45,900						
39	**Total Energy Cost**				**$0.6200**		**$0.2142 $**	**10,281,569**
40		**Cost/Denat. Gal. Ethanol**						
41	Enzymes	**$0.0480**			$0.1389		$0.0480 $	2,304,000
42	Yeasts	**$0.0220**			$0.0637		$0.0220 $	1,056,000
43	Other Proc.Chemicals & Antibiotics	**$0.0200**			$0.0579		$0.0200 $	960,000
44	Boiler & Cooling Tower Chemicals	**$0.0050**			$0.0145		$0.0050 $	240,000
45	Water	**$0.0060**	$.005-.010		$0.0174		$0.0060 $	288,000
46	Denaturant Price per Gal.	**$0.7000**			$0.1013		$0.0350 $	1,679,952
47	**Total Chemical Cost**				**$0.3937**		**$0.1360 $**	**6,527,952**
48								
49	Depreciation based on C49 asset life	**15**	Years		$0.2412		$0.0833 $	4,000,000
50	Maintenance & Repairs	**$0.0125**			$0.0362		$0.0125 $	600,000
51	Interest Expense				$0.1520		$0.0525 $	2,520,000
52	Labor	**$0.0450**	$.04–$.06		$0.1303		$0.0450 $	2,160,000
53	Management & Quality Control	**$0.0136**	$.010-$.022		$0.0394		$0.0136 $	652,800
54	Real Estate Taxes	**$0.0020**			$0.0058		$0.0020 $	96,000
55	Licenses, Fees& Insurance	**$0.0040**	.0030-.0050		$0.0116		$0.0040 $	192,000
56	Miscellaneous Expenses	**$0.0135**	$.01-$.03		$0.0391		$0.0135 $	648,000
57	**Total of Other Processing Costs**				**$0.6555**		**$0.2264 $**	**10,868,800**
58	**Total Processing Costs**				**$1.6692**		**$0.5766 $**	**27,678,321**
59	**Net Margin Achieved Per Unit**				**$0.2337**		**$0.0807 $**	**3,875,971**
60	**Farmer-Investor Reqd. Return on Equity**	12.00%			**$0.1737**		**$0.0600** $	2,880,000
61	**Increment of Success/Failure to Meet Required Return**				**$0.0601**		**$0.0207** $	995,971
62								
63	**Ethanol Plant Profits for Shareholders and Principal Reduction**				**$3,875,971**		**$3,875,971 $**	**3,875,971**

Appendix B: Energy Price Comparison

	Electricity					Coal					Natural Gas				
	cents/kWh					$/million BTU					$/million BTU				
	Nominal	Real				Nominal	Real				Nominal	Real			
1969	1	3.8	Annual	5year	10year			Annual	5year	10year			Annual	5year	10year
1970	1	3.6				0.27	0.97				0.15	0.56			
1971	1.1	3.8	5.56%			0.3	1.05	8.25%			0.16	0.56	0.00%		
1972	1.2	4	5.26%			0.33	1.09	3.81%			0.17	0.57	1.79%		
1973	1.3	4.1	2.50%			0.37	1.15	5.50%			0.2	0.63	10.53%		
1974	1.7	4.9	19.51%			0.69	1.98	72.17%			0.27	0.79	25.40%		
1975	2.1	5.5	12.24%	9.02%		0.85	2.22	12.12%	20.37%		0.4	1.06	34.18%	14.38%	
1976	2.2	5.5	0.00%	7.90%		0.86	2.13	-4.05%	17.91%		0.53	1.32	24.53%	19.28%	
1977	2.5	5.9	7.27%	8.50%		0.88	2.07	-2.82%	16.59%		0.72	1.69	28.03%	24.53%	
1978	2.8	6.1	3.39%	8.48%		0.98	2.15	3.86%	16.26%		0.84	1.83	8.28%	24.08%	
1979	3.1	6.3	3.28%	5.24%	5.90%	1.06	2.14	-0.47%	1.73%	9.84%	1.08	2.18	19.13%	22.66%	15.19%
1980	3.7	6.9	9.52%	4.69%	6.85%	1.1	2.04	-4.67%	-1.63%	9.37%	1.45	2.68	22.94%	20.58%	17.48%
1981	4.3	7.3	5.80%	5.85%	6.88%	1.18	2	-1.96%	-1.21%	8.35%	1.8	3.04	13.43%	18.36%	18.82%
1982	5	8	9.59%	6.32%	7.31%	1.23	1.95	-2.50%	-1.15%	7.72%	2.22	3.54	16.45%	16.05%	20.29%
1983	5	7.7	-3.75%	4.89%	6.69%	1.18	1.81	-7.18%	-3.36%	6.45%	2.32	3.56	0.56%	14.50%	19.29%
1984	4.83	7.14	-7.27%	2.78%	4.01%	1.16	1.72	-4.97%	-4.26%	-1.26%	2.4	3.55	-0.28%	10.62%	16.72%
1985	4.97	7.13	-0.14%	0.84%	2.77%	1.15	1.65	-4.07%	-4.14%	-2.88%	2.26	3.24	-8.73%	4.29%	12.43%
1986	4.93	6.92	-2.95%	-0.90%	2.47%	1.09	1.52	-7.88%	-5.32%	-3.27%	1.75	2.45	-24.38%	-3.28%	7.54%
1987	4.77	6.52	-5.78%	-3.98%	1.17%	1.05	1.44	-5.26%	-5.87%	-3.51%	1.5	2.05	-16.33%	-9.83%	3.11%
1988	4.7	6.21	-4.75%	-4.18%	0.35%	1.01	1.34	-6.94%	-5.83%	-4.59%	1.52	2.01	-1.95%	-10.33%	2.08%
1989	4.72	6.01	-3.22%	-3.37%	-0.30%	1	1.28	-4.48%	-5.73%	-4.99%	1.53	1.94	-3.48%	-10.98%	-0.18%
1990	4.74	5.81	-3.33%	-4.08%	-1.58%	1	1.22	-4.69%	-5.85%	-4.99%	1.55	1.9	-2.06%	-9.64%	-2.68%
1991	4.83	5.72	-1.55%	-3.73%	-2.32%	0.99	1.17	-4.10%	-5.09%	-5.21%	1.48	1.75	-7.89%	-6.34%	-4.81%
1992	4.83	5.59	-2.27%	-3.02%	-3.50%	0.97	1.12	-4.27%	-4.90%	-5.38%	1.57	1.82	4.00%	-2.28%	-6.05%
1993	4.85	5.49	-1.79%	-2.46%	-3.31%	0.93	1.05	-6.25%	-4.76%	-5.29%	1.84	2.09	14.84%	1.08%	-4.63%
1994	4.77	5.28	-3.83%	-2.99%	-2.98%	0.91	1.01	-3.81%	-4.62%	-5.18%	1.67	1.86	-11.00%	-0.43%	-5.70%
1995	4.66	5.06	-4.17%	-2.72%	-3.36%	0.88	0.96	-4.95%	-4.68%	-5.26%	1.4	1.52	-18.28%	-3.67%	-6.65%
1996	4.6	4.9	-3.16%	-3.06%	-3.38%	0.87	0.92	-4.17%	-4.69%	-4.89%	1.96	2.09	37.50%	5.40%	-0.47%
1997	4.53	4.75	-3.06%	-3.20%	-3.11%	0.85	0.89	-3.26%	-4.49%	-4.69%	2.1	2.2	5.26%	5.66%	1.68%
1998	4.48	4.64	-2.32%	-3.30%	-2.87%	0.83	0.86	-3.37%	-3.91%	-4.33%	1.77	1.83	-16.82%	-0.67%	0.21%
1999	4.43	4.53	-2.37%	-3.02%	-2.78%	0.79	0.81	-5.81%	-4.31%	-4.47%	1.98	2.02	10.38%	3.60%	1.59%
2000	4.64	4.64	2.43%	-1.70%	-2.21%	0.8	0.8	-1.23%	-3.57%	-4.12%	3.32	3.32	64.36%	20.14%	8.73%
2001	5.05	4.93	6.25%	0.19%	-1.49%	0.84	0.82	2.50%	-2.24%	-3.46%	3.62	3.54	6.63%	13.98%	9.69%
2002	4.88	4.68	-5.07%	-0.22%	-1.71%	0.87	0.84	2.44%	-1.10%	-2.79%	2.67	2.56	-27.68%	7.37%	6.52%
2003	5.11	4.8	2.56%	0.76%	-1.27%	0.87	0.82	-2.38%	-0.90%	-2.40%	4.41	4.15	62.11%	23.16%	11.25%
2004	5.25	4.8	0.00%	1.23%	-0.89%	0.98	0.89	8.54%	1.97%	-1.17%	4.94	4.51	8.67%	22.82%	13.21%
2005	5.73	5.07	5.63%	1.87%	0.09%	1.16	1.03	15.73%	5.38%	0.90%	6.63	5.87	30.16%	15.98%	18.06%
2006	6.16	5.28	4.14%	1.46%	0.82%	1.24	1.06	2.91%	5.45%	1.61%	5.8	4.98	-15.16%	11.62%	12.79%
2007	6.36	5.31	0.57%	2.58%	1.18%	1.25	1.04	-1.89%	4.58%	1.74%	5.79	4.84	-2.81%	16.58%	11.98%
2008	6.68	5.43													
		2007-1970					2007-1970					2007-1970			
		48%					7%					764%			

Appendix C: Corn Production by County in the United States



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