U.S. Biomass Energy:
An Assessment of Costs & Infrastructure for Alternative Uses of Biomass Energy Crops as an Energy Feedstock

William Russell Morrow, III P.E.

B.S., Mechanical Engineering – Georgia Institute of Technology, Atlanta, GA 1993

M.S., Carnegie Mellon University – Civil and Environmental Engineering, Pittsburgh, PA – 2003

A DISSERTATION
SUBMITTED IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS
FOR THE DEGREE OF

Doctor of Philosophy

in

Civil and Environmental Engineering

Department of Civil and Environmental Engineering
Carnegie Mellon University
Pittsburgh, PA

May, 2006

This Work is Dedicated To:

My Mother
Mary Lola Walker Morrow

My Father
William Russell Morrow, Jr.

And to

My Wife
Cary Anne McQueen Morrow

My Dog
Buddy Winifred Morrow

ACKNOWLEDGEMENTS

This work was funded by a grant from National Science Foundation (NSF), and a grant from Pennsylvania Infrastructure Technology Alliance (PITA). And my wife Cary McQueen Morrow

I would like to thank my primary advisors, Dr. H. Scott Matthews and Dr. Mike Griffin for helping me to conceptualize, plan, write and re-write this dissertation. The combination of Scott and Mike's expertise in this field, coming both from rich academic and industry experience, as well as their commitment to excellence and eye for detail are reflected throughout the pages of this document. You have been excellent advisors and I thank you for all of your time and effort.

I would like to thank the other members of my committee: Dr. Lester Lave and Dr. Chris Hendrickson, for their support throughout this project. Lester's sharp intellect and seemingly boundless expertise were invaluable during various phases of this process, particularly in conceptualizing a method to estimate world crude oil markets. Chris' strong civil and environmental engineering knowledge base helped in the formulation of linear programming methods.

I would also like to thank all the members of the Green Design Institute who have been supportive throughout: Professors: Cliff Davidson, Francis McMichael, Jeremy Michalek; Researchers Gyorgyi Cicas, Deanna Matthews and Eric Williams; and of course my esteemed colleagues and friends: Shahzeen Attari, Troy Hawkins, Cortney Higgins, Paulina Jaramillo, Joe Marriott, Aurora Sharrard, Heather Wakeley, Chris Weber.

I would also like to thank those in the Civil and Environmental Engineering Department who have provided support both academically and personally: Dr. Peter Adams, Dr. Dave Dzombak, Dr. Greg Lowry, Dr. Irving Oppenheim, Dr. Mitchell Small, and Larry Cartwright.

I would also like the thank those in the Engineering and Public Policy Department, and especially the Carnegie Mellon Electricity Industry Research Center with a special thanks to Dr. Jay Apt, Dr. Granger Morgan, Dr. Ed Rubin, and Dr. Paul Fischbeck. Also, I would like to thank fellow CEIC graduate students.

But it is my wife who I would like to thank the most. Her patience, support, and understanding have proven essential to the completion of this work.

Abstract

Reduction of the negative environmental and human health externalities resulting from both the electricity and transportation sectors can be achieved through technologies such as clean coal, natural gas, nuclear, hydro, wind, and solar photovoltaic technologies for electricity; reformulated gasoline and other fossil fuels, hydrogen, and electrical options for transportation. Negative externalities can also be reduced through demand reductions and efficiency improvements in both sectors. However, most of these options come with cost increases for two primary reasons: (1) most environmental and human health consequences have historically and are currently excluded from energy prices; (2) fossil energy markets have been optimizing costs for over 100 years and thus have achieved dramatic cost savings over time. Comparing the benefits and costs of alternatives requires understanding of the tradeoffs associated with competing technology and lifestyle choices.

Bioenergy advocates propose its use as an alternative energy resource for electricity generation and transportation fuel production, primarily focusing on ethanol. These advocates argue that bioenergy offers environmental and economic benefits over current fossil energy use in each of these two sectors as well as in the U.S. agriculture sector. However, estimates of bioenergy resource reveal that bioenergy is only capable of offsetting a portion of current fossil consumption in each sector. As bioenergy is proposed as a large-scale feedstock within the United States, a question of "best use" of bioenergy becomes important. Unfortunately, bioenergy research has offered very few comparisons of these two alternative uses. This thesis helps fill this gap.

This thesis compares the economics of bioenergy utilization by a method for estimating total financial costs for each proposed bioenergy use. Locations for potential feedstocks and bio-processing facilities (co-firing switchgrass and coal in existing coal fired power plants and new ethanol refineries) are estimated and linear programs are developed to estimate large-scale transportation infrastructure costs for each sector. Each linear program minimizes required bioenergy distribution and infrastructure costs. Truck and rail are the only two transportation modes allowed as they are the most likely bioenergy transportation modes. Switchgrass is chosen as a single bioenergy feedstock. All resulting costs are presented in units which reflect current energy markets price norms (¢/kWh, $/gal). The use of a common metric, carbon-dioxide emissions, allows a comparison of the two proposed uses. Additional analysis is provided to address aspects of each proposed use which are not reflected by a carbon-dioxide reduction metric.

Using switchgrass as an electricity generation feedstock offers more than twice the amount of carbon-dioxide emission reductions as using switchgrass as an ethanol feedstock (370 versus 160 million short tons per year respectively; representing 14% and 12% of electricity and transportation sector annual CO_2 emissions). Total costs, including capital, labor, feedstock, and transportation, is more certain for electricity production than for ethanol; 20 - 45 $/ton CO_2 mitigated versus free - 80 $/ton CO_2 mitigated respectively. In both cases, mitigation cost is a variable of fossil energy costs. Coal price are very stable as compared to crude oil prices and therefore, more risk is inherent in ethanol economics than in electricity economics.

Additional analysis comparing life-cycle benefits and burdens though full-cost accounting methods also favors bioenergy for electricity production. Agricultural impacts are neutral, while criteria pollutants increase with ethanol use and decrease with bioenergy electricity production. Moreover, ethanol use could cause an increase in groundwater toxicity, a risk that is not associated with electricity production.

Considering other available alternative technologies, switchgrass co-firing in existing coal power plants is the least costs retrofitting option available to existing coal fired power plants wishing to lower their carbon emissions. Plug hybrids offer increased system efficiencies over current gasoline-propulsion systems, thereby lowering criteria pollutants and greenhouse gas emissions all at a cost less than or comparable to ethanol. However, shifting transportation energy demands into the United States' antiquated electrical grid will require large-scale electricity infrastructure investments. The economic impact of a large-scale transfer of energy from petroleum to electricity should be a topic of future research.

Table of Contents

Table of Figures

Table of Tables

Chapter 1 Introduction

1.1 Bioenergy Research Context

Anthropogenic carbon emissions generate increased atmospheric carbon concentrations that will affect the global climate [*168*]. It is uncertain to what degree the global climate will change, exactly how it will change, and what effect it will have on the biota [*108*] [*120*]. Because researchers are devoting more attention to studies of climate change, the effects of climate change are becoming more certain, indicating, for instance, that ecosystems are exhibiting changes consistent with climate change predictions [*174*] [*10*] [*41*]. Within the United States, climate change will likely affect environmental ecosystems and, at least, the sectors of our economy that interact with natural resources and land use [*109*].

Developed society's reliance on fossilized carbon energy, known as fossil fuel, is the primary source of anthropogenic carbon emissions [*79*]. The United Nations has agreed that in the pursuit of lifestyle improvements, such as health and education, all sovereign nations, including nations that do not have a history of fossil energy consumption, have the right to exploit resources such as fossil fuels [*157*]. In the absence of less carbon-intensive energy options – and recognizing that developed nations have raised their living standard coincident with rapid increases in fossil fuel consumption – it is clear that anthropogenic carbon emission rates will continue to increase [*40*] [*149*]. Thus the development of less carbon-intensive energy resources and less energy demanding lifestyle options is of paramount importance [*23*] [*26*] [*81*].

Atmospheric carbon stabilization strategies strive to minimize energy related carbon emissions while sacrificing a minimal amount of the lifestyle privileges that fossil energy provides [*130*]. However, the magnitude at which fossilized energy is consumed in order to sustain the current developed-nation lifestyle is considerable; to stabilize atmospheric carbon, technological evolutions are required and should be pursued in unison with conservation measures [*149*]. As of 2006, the United States Government has not chosen to restrict carbon emissions or to participate in international carbon emissions reduction agreements because of legislators' concern over possible economic hardships [*153*] [*15*]. As the world experiences global environmental perturbations congruent with climate change predictions, efforts to stabilize atmospheric carbon concentrations could increase, and political interests may eventually support United States Federal carbon mitigation policies [*9*] [*155*] [*156*].

It appears unlikely that a single technology, fuel resource, or policy measure can provide all the emissions reductions required to stabilize atmospheric carbon levels [*179*]. The most commonly proposed policy measure, the adoption of a carbon tax, could affect multiple technologies and fuel resources by inviting alternative fuel and technology adoptions, efficiency increases, and more R&D for future low-carbon technologies [*60*] [*182*]. A national carbon tax could instead be an international trading mechanism with modest actual carbon emission reductions [*170*]. Even with a carbon emissions restricting carbon tax, additional research will be required at a public level to develop next-generation low-carbon energy technologies able to reach the deep carbon reduction required for a low-carbon emission society [*139*].

The U.S. Department of Energy (DOE) funds research on wide range of carbon reducing technologies and fuels which can be categorized by the energy consuming sectors they serve [*164*]. For example, advanced nuclear, clean coal, and renewable electricity technologies offer carbon reductions for the electricity sector which serves residential, commercial, and industrial energy consumers. Similarly, alternative transportation fuels can offer carbon reductions for transportation, the fourth large energy consuming sector. Some U.S. DOE researched technologies could affect several energy consuming sectors.

DOE's Renewable Energy Biomass Program (REBP) proposes the use of domestic biomass energy, or bioenergy, to provide the U.S. with transportation fuel, electric power, and chemicals [*165*]. Bio-refineries are capable of producing an array of chemicals, electricity, and transportation fuels using bioenergy feedstocks [*181*] [*127*]. Currently, it is possible to produce an ethanol transportation fuel from grain or woody bioenergy (cellulose) feedstocks, the latter conversion process providing more energy efficiency but greater expense [*102*] [*154*]. The goal of the REBP is to facilitate the paradigm shift towards renewable, sustainable energy and chemicals [*117*].

Within the U.S., a relatively small amount of grain-based ethanol is produced annually[1], and no cellulose ethanol is produced at a commercial level. Also, a small amount of electricity is generated from biomass-based resources such as saw-mill wastes, municipal solid wastes, forest residues, and pulp and paper residues [*54*][2]. Despite the

---

[1] 3.4 billion gallons in 2004, all produced from corn grain [*129*]. 2004, total U.S. gasoline consumption was 140 billion gallons [*46*].

[2] Total biomass electricity was 60GWh in 2004 or 1.5% of U.S. total electricity generation (3.97 TWh) [*54*] [*46*]

current modest bioenergy contribution to U.S. total energy consumption[3], REBP proposes an aggressive increase in bioenergy feedstock use by 2030[4] [*117*]. Oak Ridge National Laboratory and the U.S. Department of Agriculture believes that enough bioenergy resources exist to reach this goal [*124*].

Increased U.S. bioenergy feedstock production scenarios typically propose changes within the U. S. agriculture sector for the production of energy crops, with switchgrass specifically identified as a favorable energy crop [*43*]. Tests indicate that switchgrass is a suitable energy resource[5] [*101*] [*141*]. Researchers argue that the production of switchgrass could have multiple benefits for the environment, for agriculture sector economics, and for the U.S. federal budget [*66*] [*36*]. Presently, however, switchgrass is not a large-scale U.S. bioenergy resource because, according to the perspective of current U.S. policies, it is cost prohibitive to produce. Nevertheless, if the U.S. were to adopt carbon emission reduction policies and/or petroleum import reduction policies, bioenergy could become a large-scale energy resource with switchgrass contributing roughly one third of the estimated one billion tons of bioenergy resources [*124*].

A transition away from today's infrastructure, which is focused almost exclusively on fossil resource exploitation, towards a future infrastructure focused on a combination of fossil/bioenergy resource exploitation, will certainly have its costs. Bioenergy economists estimate bioenergy quantity and prices ranging from 0[6], to \$6.00/MMBtu [*63, 99*] [*71*]. A cellulosic-based ethanol production facility generating approximately 70

[3] In 2004, 2.8 quads of biomass energy was consumed or roughly 3% of U.S. total energy consumption (100 quads) [*54*].
[4] 5% of U.S. electricity and 30% of current petroleum consumption
[5] Switchgrass contains comparable energy content to that of wood but with less inherent moisture content, ash, and alkali minerals. Additionally switchgrass has proven to be very suitable substrate and produces high ethanol yield using current simultaneous saccharification and fermentation (SSF) technology
[6] Current electricity sector bioenergy feedstocks are close to zero cost.

million gallons per year would cost roughly 200 million dollars, or 2.85$/gal of capacity [*2*]. The least capital intensive electricity generation option for bioenergy is the conversion of existing coal-fired electricity generation power plants to accept bioenergy feedstocks. Conversion cost estimates range from 50 - 300 $/kW of bioenergy capacity [*78*]. Transportation between farms and processing plants are typically estimated at roughly 10 $/ton of biomass [*2*], with some estimates as low as 4.50 - 8.50 $/ton biomass [*65*]. Small-scale ethanol distribution costs have been estimated between 0.006 - 0.009 $/gal of ethanol [*131*]. Ethanol distribution costs have been ignored for large-scale production scenarios.

Because bioenergy cannot replace all of the U.S. fossil energy consumed by the transportation and electricity generation sectors, a comparison between its ability to affect each of the two is germane. Although researchers debate the degree to which transportation bioenergy consumption offsets transportation fossil energy consumption [*126*] [*111*], it is generally agreed that its use does result in a reduction in fossil energy consumption [*69*] [*58*] [*19*] [*84*]. Likewise, there is little doubt that consumption of bioenergy for electricity production does result in fossil energy reductions, especially when bioenergy consumption offsets coal consumption directly [*113*] [*11*]. Although studies comparing the benefits and costs between bioenergy-based electricity and transportation fuels have been rare, recent research does indicate that the carbon emissions associated with bioenergy use as a transportation fuel would be roughly half that of its use for electricity production [*171*].

1.2 Thesis Research Contribution

This thesis contributes to a growing body of bioenergy research by offering a better understanding of the costs and benefits of switchgrass use through a comparison between two alternative uses: the production of transportation fuels and the generation of electricity. I have singled out switchgrass from other bioenergy resources because of the rich data sets available. Oak Ridge National Laboratory has performed extensive research into potential production yields and economics, and it has produced geographically detailed estimates of switchgrass availability [*67*] [*35*] [*173*] [*172*]. This research specifically models transportation and infrastructure costs required for switchgrass use as an energy feedstock. An estimate of the amount of carbon emission reductions expected from the respective switchgrass uses allows comparisons to be made for the alternative uses.

This research is unique in its transportation and infrastructure modeling of large-scale[7] switchgrass use for both ethanol and electricity production. Prior research on ethanol has neglected to produce estimates of likely cellulosic ethanol conversion plant locations and the resulting transportation required to deliver ethanol to current gasoline consumption areas. Likewise, previous electricity research has failed to estimate transportation required for switchgrass delivery to existing coal-fired power plants and respective power plant modifications required for switchgrass fuel consumption. The transportation models that I have constructed for this research consist of transportation distribution linear programs optimizing for least-cost ethanol or switchgrass distribution. This thesis

[7] Large-scale means the consumption of all forecasted switchgrass capacity to the limit estimated by Oak Ridge National Laboratories' POLYSIS model (roughly 250 million tons per year at 50 $/ton). See Appendix A for the POLYSIS dataset used in this research.

calculates infrastructure costs with the use of supporting literature. With this research project's contribution of transportation cost estimations, a full cost to consumers can be estimated for the large-scale respective alternative uses of switchgrass feedstock resources.

1.3 Thesis Research Boundary

One significant benefit in using bioenergy is the mitigation of environmental and social externalities associated with fossil energy consumption [*89*] [*107*]. Fossil energy consumption results in multiple negative externalities such as the emission of criteria air pollution, release of harmful metal flows through the biota, the creation of human health and environmental damages from resource extraction, dependence on foreign petroleum production, etc. [*118*] [*87*] [*149*]. Likewise, agricultural activities in general result in externalities related to the production of minerals, fertilizers, plant protection substances, machinery, and the depletion of abiotic resources, an increases in toxicity, acidification, and eutrophication, etc. [*18*]. Energy crop production in particular should reduce negative externalities of agriculture [*64*] [*169*].

Life-cycle analysis (LCA) is a method for estimating the quantity of various flows and externalities associated with a product or process [*73*]. Performing LCA requires assumptions to define the boundary for analysis, determine which flows or externalities will be included, and define relationships and value interpretations for the range of externalities [*80*]. Full-cost-accounting is a method for incorporating environmental and social benefits and cost, typically not included in engineering/financial accounting, into comparisons of alternative choices [*27, 33*]. Using a full-cost accounting method requires assumptions to define stakeholders and values to society for chosen externalities [*98*]. Using the two methods, total impact on the environment and society for competing alternative policy or business choices can be compared.

Previous LCAs of bioenergy generally report advantages of bioenergy use over that of fossil energy use. Some of the more salient benefits follow. Agricultural energy crops deliver more energy than their production requires [*72*]. There is concern over water use and soil nutrition when producing bio-based transportation fuels [*128*]. Ethanol transportation fuels result in lower total global warming potential [*91*] [*61*], but at lower blend levels the advantages are reduced [*111*]. The production of electricity from cofiring biomass and coal offers environmental advantages over coal produced electricity [*97*] [*11*] [*44*].

Despite the social awareness for the undesirable fossil energy life-cycle burdens, the current U.S. energy market structure excludes their cost from energy prices [*149*]. Fossil energy markets have been optimized for costs for over 100 years in the United States, and consequently fossil energy is inexpensive when compared to bioenergy. Also despite public awareness of bioenergy's health and environmental advantageous over fossil energy sources, policy has not created sufficient incentives for bioenergy resources use and therefore, bioenergy is rarely less expensive than fossil resources. A public desire to reduce U.S. greenhouse gas emissions and/or to reduce U.S. dependence on foreign petroleum could motivate legislative changes to energy markets however. The most likely legislative policy measure is a carbon tax as measured by cost per carbon emission [*56*] [*110*]. For this reason, I have focused on switchgrass' ability to reduce green-house-gas emissions and crude oil imports.

In this research, the model boundary for measuring carbon emission reductions begins with switchgrass harvested at farms, and continues through the consumption of ethanol or the generation of electricity. In both cases, I demonstrate that fossil resources are offset by the use of switchgrass. Thus, I conclude that the consumption of switchgrass-derived ethanol or the generation of electricity using switchgrass results in carbon emission reductions by offsetting fossil fuel use.

1.4 Additional Analysis Issues

In this thesis, I also provide an analysis of the effect switchgrass consumption could have on fossil energy prices. Because switchgrass energy would substitute for fossil-based energy, a demand reduction would be experienced within respective fossil energy markets. At large scales, a bioenergy market could result in deflated fossil energy market prices. Analysis of this potential is relevant to alternative energy research because as substitutions for status quo fossil energy consumption their economic value is related to fossil energy prices. When fossil energy prices are high, less expensive alternatives are more advantageous. Additionally, a commitment to bioenergy at a time when fossil prices are high must be sustained through times when fossil energy prices are low in order for bioenergy to remain a consistent component of a sustainable energy portfolio.

Lastly, this thesis provides a comparison between bioenergy and other carbon emission reducing technology options. Because more carbon reduction options are available for the electricity sector, bioenergy carbon reduction costs can be easily compared with other technological options such as retrofitting existing power plants with carbon capturing technologies. Comparatively fewer technologies exist for reducing transportation carbon emission, and, for this reason, the thesis compares bio based transportation fuels to changes in transportation efficiency.

1.5 Research Questions

Given the following:

(1) Switchgrass is not currently an alternative energy resource exploited for large-scale resource use.

(2) Switchgrass has been suggested as a large-scale alternative energy.

(3) Energy derived from switchgrass will require substantial infrastructure investments.

(4) Two separate energy consuming sectors are capable of utilizing switchgrass: electricity and transportation.

(5) Switchgrass can not provide enough energy to satisfy current demand in either of the two competing sectors.

I seek to answer the following questions:

(1) What are the likely costs and likely carbon mitigating benefits of using switchgrass as a bioenergy feedstock on a large-scale within the two energy sectors?

(2) Moreover, what relevant issues, other than carbon mitigation, affect switchgrass use as bioenergy feedstock?

1.6 Research Methodology

In this thesis, I address the former question through a comparison of a single metric common to both energy sectors: the cost of carbon emissions reduction, or cost of mitigation (COM).

I address the latter question through a comparison of switchgrass bioenergy cost of mitigation to other competing technologies within both the transportation and the electricity energy sectors.

Chapter 2 Relevant Literature Review

2.1 Switchgrass

This research estimates the benefits and costs associated with a future large-scale switchgrass energy crop production within the U.S. Therefore, this literature review will exclusively focus on switchgrass. Other biomass feedstocks are available for ethanol production. The simplest process can convert sugars derived from sugarcane, sugar beets, molasses, and fruits into ethanol directly through fermentation. Starches from corn grains, cassava, potatoes, and root crops are more difficult feedstocks because they must first be hydrolyzed to fermentable sugars before conversion by fermentation to ethanol. The most difficult feedstocks are cellulose and hemi cellulose (cellulosics) from wood, agricultural residues, municipal solid wastes, waste sulfate liquors from pulp and paper production, and dedicated energy crops. These must be must be converted to fermentable sugars generally by the actions of mineral acids and enzymes for conversion to ethanol [*94*]. Alternatively, many of these can also be co-fired with coal. Previous literature has presented assumptions and capacities for all bioenergy production within the U.S. [*124*]. Researcher's publishing this report believe that one billion tons of bioenergy resources could be available annually within the by the year 2030.

Switchgrass is a herbaceous biomass plant that can be grown in most regions within the United States. It offers high yields, high nutrient use efficiency, is a perennial (so requires no soil tilling), supports multiple harvest schedules every year, and can be grown in virtually every state east of the Rocky Mountains/High Plains areas with no irrigation required [*17*]. Switchgrass is an active participant in the biosphere; it is a perennial plant that absorbs solar radiation while capturing carbon from the air, offering carbon sequestration into the soil as its root systems grow [*93*]. Switchgrass used for energy is considered renewable energy and is an opportunity for the United States to reduce its carbon emissions. Switchgrass offers carbon emission reductions not only by sequestering carbon within its root, but also providing energy services that otherwise would be provided by fossil energy resources. The true net greenhouse gas emissions from biosphere carbon sequestration in soils it not yet agreed upon [*102*] [*176*] [*106*].

At modest prices for energy crops[8] and marginal distortion of other agricultural food product prices[9], there is an estimated 2.92 Quads[10] of primary energy potential available from energy crops[11] [*172*]. The authors estimate that this could supply 7.3 percent of the total U.S. annual electrical demand[12], and increase annual farming revenues by nearly $6 billion. It has been suggested that large-scale biomass and coal co-firing depends heavily on a reduction in costs of large scale switchgrass production [*99*]. Current research indicates that switchgrass yields can be improved by up to 50% from 4.75 to 7.1 tons per acre resulting in larger annual energy crop supplies and reductions in cost (reduction of 25%, or roughly $8/ton) [*100*] [*28*].

Switchgrass can be used as an energy feedstock by several different methods, producing a range of benefits. Most directly, switchgrass can be burned and the thermal energy released captured by steam, and used to make electricity. Co-firing switchgrass with coal can also make electricity and does not require extensive investment in new

[8] $2.72 per million BTU ($40 per ton; $44 per Mg)
[9] Traditional crops such as corn, wheat, soybeans, cotton, rice, sorghum, and oats are estimated to increase by 9 - 14% over base case prices.
[10] 1 Quad = 1 billion MMBtus
[11] The US consumed 20.5 Quads of coal in 2004 [*46*]
[12] Authors assume biomass gasification coupled with combined cycle electricity generation technology to give a 36% efficiency, and assume 80% capacity factor.

capital equipment relying on existing coal fired power plant. Switchgrass can be converted to a producer gas through a thermo-chemical gasification process, but the resulting gas contains roughly 20% of the energy content of natural gas [*149*]. Additionally, switchgrass can be gasified through anaerobic digestion. This bacterial driven process is very sensitive to a long list of parameters, making gas production difficult [*149*]. Fermentation offers yet another conversion process whereby switchgrass can be converted into ethanol, a transportation fuel.

Currently, switchgrass does none of these on a large-scale, but there is growing hopes that switchgrass will one day be a U.S. energy feedstock [*100*] [*82*]. Much of this interest is for the production of ethanol or the construction of a bio-refinery seeking to offset crude oil dominance in the U.S economy [*107*] [*20*] [*129*] [*95*]. Gasifying biomass on a large scale can be done, but appears to be less likely than other technology options mostly because there is extensive debate regarding the use of gasification technologies [*133*]. Burning switchgrass to produce electricity appears to be a likely use for switchgrass. Extensive research has been performed to understand the affects of co-firing switchgrass and coal in existing coal power plants, and has been published by NETL [*183*], by EPRI [*160*] [*78, 78*], and by peer reviewed research journals [*138*] [*39*] [*39, 142, 142*]. Co-firing switchgrass in existing coal plants offers low cost capital expenses and simple procedures that other biomass electricity technologies such as gasifiers, digesters, and thermochemical and biological hydrogen processes can not offer [*113*].

2.2 Biomass combustion effects on existing power plants; the science and experience[13]

In general, researchers conclude that combustion, or fireside issues, associated with co-firing biomass and coal will conform to the following guidelines. NO_x emissions will not be effected by interaction between the gaseous releases from biomass and coal co-combustion. NO_x emissions will likely be lowered when co-firing due to the overall lower nitrogen content is biomass fuels. The large volatile materials found in biomass fuels can be used to further lower NO_x emissions when co-firing through known stoichiometric methods. Low ash, low alkali, low chlorine biomass fuels such as woods will decrease ash deposits when co-firing. The opposite is true for high ash, high alkali, high chlorine biomass fuels such as herbaceous plants. Ash deposition depends strongly on interaction between biomass and coal fuels. Residual carbon increases as does tendencies for incomplete combustion, or burnout as biomass fuel size increases. Ideally, biomass fuel particle size should be no greater than 0.125 inch. This size is reduced if biomass moisture increases above 40%. Chlorine levels should be kept as low as possible and tube surfaces should be maintained at as low a temperature as possible. Sulfur in coal will react with the chlorine in biomass and reduce the presence of both in depositions [*183*].

2.2.1 Biomass Properties

Sponsored by the United States Department of Energy through the National Energy Technology Laboratory, researchers performed a literature review of plant mineral uptake

[13] This literature review is dependent on the review of furnace & boiler combinations presented in Appendix D, titled "A brief discussion of types and boiler design considerations."

and the general inorganic elements contained within biomass [*183*]. Biomass fuels derived from plant matter (as opposed to municipal wastes, and land fill gas), will contain, to varying degrees depending on the plant, the following eighteen inorganic elements: Non-metals: carbon (C), hydrogen (H), oxygen (O), nitrogen (N), phosphorus (P), sulfur (S), boron (B), chlorine (Cl), alkali metals: potassium (K), alkali earth metals: calcium (Ca), magnesium (Mg), metals: zinc (Zn), copper (Cu), iron (Fe), manganese (Mn), molybdenum (Mo), sodium (Na), and silicon (Si). Some elements such as K, Ca, N, P, and Cl are incorporated in the structure of plants and are required for the transportation of nutrients. Of these, K, and Ca are the predominant and will be important constituent of all plant derived biomass fuels. The other elements are less critical for the growth of the plant. Their presence is dependent on their availability in soils which varies between seasons and across regions.

Sponsored by the United States Department of Energy through the Energy Efficiency and Renewable Energy Office, and the Biomass Power Program a detailed chemical analysis was performed on eleven biomass fuels [*104*]. Ignoring the main biomass constituents of carbon, hydrogen, and oxygen, the minor elements of biomass are of more interest to understanding potential hazards when combusting biomass fuels. The minor elements that very in concentration among fuels are nitrogen, sulfur, and chlorine. Nitrogen is important to plant growth, and is often more prevalent in the portion of plants which grow the quickest. Nitrate in plants is converted to ammonia which is then converted to amino acids. Amino acids are prevalent in all plants. It is observed however, that nitrogen varies from plant to plant, and is thought to be ultimately controlled by nutrient levels in soils. Biomass nitrogen is more volatile than coal nitrogen but less concentrated.

Sulfur is absorbed through roots and from atmospheric SO_2. Sulfur can exist either as organic sulfur or as sulfate. Reported data showed that sulfur concentrations do not correlate strongly with nitrogen concentrations in the plant but do with soil concentrations of sulfur. Chlorine serves to balance charges within plants, and is primarily in the form of chloride ion. Its concentration also closely correlates to soil concentration. Other mineral and element presence such as silica and potassium are critical biomass ash minerals. Silicon is incorporated as silicic acid soil solutions and is present in most plants. Its concentration is highest when silicon concentrations in the nutrient solution are lowest. Potassium occurs in plants as an ion and is highly mobile. It is useful to plants for metabolic activities and is largely found in parts of the plant which experience the most rapid growth.

In addition to inorganic property differences between biomass and coal, volatile matter to fixed carbon ratios differ as well. Volatile matter is the matter which vaporizes at low temperatures and pressures. Fixed carbon is the matter which remains when volatile matter, moisture, and ash are removed from a fuel. Because solid-gas (carbon and oxygen) reactions are much slower than gas-gas (vaporized matter and oxygen), a higher fixed carbon results in longer residence time for combustion. All fuels are comprised of moisture, volatile matter, carbon, hydrogen, trace minerals, etc. each of the components represents a fraction of the fuel weight. Typically, coals have a volatile to fixed carbon ratio less than 1.0, meaning that the fuel is comprised of more fixed carbon than volatile material. As coal quality, or rank, increases, coals become less reactive. Biomass has volatile to fix carbon ratios of 4 to 5 meaning that several times more volatile matter is present than fixed carbon. Therefore, biomass fuels will always be more reactive than coals. The inorganic materials present in biomass are typically more reactive than those in coals as well. The alkali minerals in general, and sodium and potassium, in particular are more reactive in biomass fuels. Higher reactivity causes ash issues to be different between biomass and coal fuels [*159*]. For this reason alone, existing coal fired power plants considering modifying their plant to co-fire biomass with coal are advised to consult their boiler's manufacture for recommendations of modification required for the adequate handling of different ash ashes [*7*].

Each co-firing application requires changes in the combustion operation to accommodate the different fuel properties introduced with biomass fuels. For example, time required for the release of volatile material is dependent on particle size and temperature. Smaller particles have more surface area, and higher temperatures vaporize volatiles more quickly. In cyclone boilers, small particles can cause premature volatility and combustion prior to reaching the optimal combustion location. Therefore, the primary, secondary, and tertiary air will require adjustments in order to place volatile release in the desired location. For wall-fired and tangentially-fired PC boilers, biomass can be injected into the combustion zone at strategic locations. Co-fire rate, particle size, injection location selection, and control of stoichiometric air affects boiler NO_x emissions [*159*].

2.2.2 Switchgrass Properties

Miles et al. found that combusting annually harvested herbaceous fuels such as grasses, straws, and agriculture wastes caused rapid fouling of heat transfer surfaces, furnace slagging, and agglomeration of fluidized beds [*104*]. The major harmful alkali mineral was potassium instead of sodium (as is the case with coals). The fuels are also typically rich in chlorine, silicon, and sulfur. When the combination is combusted, potassium reacts with chlorine and is transported the to heat transfer surfaces where it is deposited and reacts with sulfur to form potassium sulfate. The deposit forms a sticky coating that then catches more ash. When present, potassium along with alkaline earth metals like calcium can react with silicates to form a form a sintered glassy slag fouling.

Subsequent DOE researchers question the switchgrass samples used by Miles et al., and consequently the conclusion that switchgrass is an inappropriate combustion fuel [*101*]. DOE tests found switchgrass alkali concentrations roughly half those of Miles et al. They estimate alkali content to be at or below the recommended 0.40 lbs per MMBtus.

National Energy Technology Laboratory researchers analyzed switchgrass samples from different regions within Iowa [*183*]. Analysis results showed that switchgrass has low to moderate ash, low sulfur, acceptable heat content and relatively low moisture. Mineral content shows a correlation with season, and geography. In late March to early April, the ideal harvesting time, switchgrass exhibits high heat content, despite moisture presence, and low alkali and chlorine content. These properties can result in a higher viscosity ash that is particularly important for PC furnace ash control. Geographically, higher elevations and dryer conditions produce highest energy densities and lowest potassium concentrations. Both of which can benefit co-firing.

2.3 General biomass combustion effects on existing boilers & power plant equipment

2.3.1 Dedicated Biomass Combustion

Research conducted by the Department of Energy's National Renewable Technology Laboratory investigated the impact of biomass combustion on dedicated biomass furnaces and boilers [*103*]. The research was conducted by Sandia National Laboratories, Bureau of Mines, University of California Davis, Foster Wheeler Development Corporation, and T.R. Miles Consultants. They concluded that the alkali content of all biomass fuels is sufficient enough to cause server boiler fouling. The alkali gasses released when combusted, lowered the ash fusion temperature of biomass ash to below the flue gas temperature resulting in increased ash tackiness leading to ash deposition through impaction on tubes, and through condensation on cooled furnace wall surfaces. Analysis showed ash to be heavy in potassium, sulfur and chlorine. Deposition chemistry could not be explained through fuel analysis although slagging tendency correlated with fuel composition and concentration of alkali, sulfur, chlorine, and silica. A list of advice to interested biomass combustion personnel was provide with the strongest advice being the careful discrimination of fuels based on alkali content (choose fuels with alkali contents below 0.40 lb/MMBtus.

This same research team, sponsored by DOE's Energy Efficiency and Renewable Energy Office's Biomass Power Program performed an investigation of alkali deposits in biomass-fired electricity power boilers [*104*]. Bench and commercial scale tests were performed for a wide variety of biomass fuels and biomass boiler designs. Detailed chemical analysis was performed on eleven biomass fuels. Research concluded that alkali reacts with silica to form alkali silicates which exhibit low ash fusion temperatures. Alkali also reacts with sulfur to form alkali sulfates on heat exchanger surfaces. Biologically occurring alkali, primarily potassium, is highly mobile meaning that it easily comes in contact with other materials. This mobilization is facilitated by the presence of chlorine and as potassium chloride is a stable gas at high temperatures. Often, the chlorine acts as a transport mechanism for the potassium to reach the heat transfer surfaces where potassium chloride salts condense and is available for reaction with sulfur oxides to form potassium sulfates. In the absence of chlorine, alkali hydroxides provide the same service. A conceptual framework for ash deposition was presented and the authors concluded that the depositions are related to both boiler design and fuel properties. Of the biomass fuels tested, seasonally harvested biomass such as agriculture wastes and herbaceous grasses exhibited worse fouling than woody biomass fuels. This is consistent with the theoretical expectation based on the lower presence of alkali and chlorine in woody biomass compared to herbaceous biomass. Lastly, the research found consistent ash performance between the bench scale and commercial scale test and concluded that theoretical explanations are validated by industrial experience.

The research performed by Miles et al. and discussed above was performed using dedicated biomass boilers or using blends of biomass [*103*] [*104*]. This research is important to co-firing biomass and coal research because of the insight into the extreme co-firing cases, biomass-only firing in existing boilers.

2.3.2 Biomass and Coal Co-firing

2.3.2.1 Initial DOE-TVA-EPRI biomass co-firing program

In the late 1980s and early 1990s, utilities had somewhat unsuccessfully experimented with blending dissimilar coals. Some utilities were testing alternative fuels such as refuse derived fuels with limited success. Others were testing sunflower seeds, railroad ties, wood product wastes (sawdust), ground tree trimmings, bark, whole tree chips, and tire-derived fuels. At the time, the Electricity Power Research Institute (EPRI) recognized a need for an organized testing structure and in 1992 EPRI established a program with the goal to commercialize biomass and coal co-firing. With Tennessee Valley Authority (TVA) and DOE's Energy Efficiency and Renewable Energy support, the mission of this program was to provide utilities with a fuel which reduces greenhouse gas, sulfur, and NO_x emissions and to provide a means to develop energy crop friendly infrastructure by promoting biomass combustion in large, high pressure (2,500 - 3,500 psi), high efficiency boilers. This program initialized testing projects with the goal of addressing critical issues through understanding biomass and coal co-firing effects on existing coal fired power plant performance. The evaluation included direct and co-firing producer gas (gas produced from a gasification process using biomass) in a combined cycle combustion turbine [*77, 160*]. This review focuses only on biomass and coal co-firing results.

The first plant tested, the Allen Fossil Plant, was successful up to 20% mass basis (10% energy basis), and showed that because biomass particle size affect release of volatile gases it can impact NO_x emissions. If the particles are small enough all of their nitrogen is released as volatile matter and in a fuel rich combustion zone, this reduces the formation of NO_x. The second, Kingston Fossil Plant, experienced co-fire rate limitation (below 4.6 mass basis) because of pulverizer limitations. Though tests were limited they indicated a reduction in carbon combustion and thus carbon dioxide emissions with very little impact on efficiency or temperature distribution [*77*] [*160*].

2.3.2.2 GPU- Genco & FETC

Motivated by concern over CO_2 emissions, in 1995 GPU-Genco with support from the Federal Energy Technology Center (now NETL) evaluated three small plants: Seward, Shawville, and Warren, all located in Pennsylvania. Evaluations focused on biomass fuel availability within a 50 mile radius of the plant, plant layout, and ability to integrate co-firing into the plant operations. Initial engineering feasibility concluded that tests should be performed at the Shawville Generation Station, and a set of testing issues concerning off-site fuel blending, biomass fuel types (tree trimmings and hybrid poplars), pulverizer impacts, and low NO_x burner effects were established. Tested in two of its 130 MWe wall-fired PC furnaces, blends of 3% by weight caused undesirable effects. The Shawville plant, at the time of testing, was fired to coal feed system capacity, which was over capacity on boiler ratings. When biomass was introduced, one of the existing pulverizer mills experienced a reduction in speed and the another a reduction in exit temperature. These reductions decreased boiler capacity up to 6% and 3% respectively. In addition, pulverizer mill amps increased reducing the overall plant efficiency. With a mill exit temperature reduction, fuel injection nozzles experienced dangerous moisture condensation levels which ultimately could lead to nozzle plugging and boiler shutdown.

No noticeable NO_x emissions were recorded, but SO_2 emissions reduced in proportion the blended fuel.

The conclusion of the Shawville test was the PC boiler co-firing is best served by separate feed systems [*77, 160*].

2.3.2.3 The EPRI & USDOE Cooperative agreement

In 1996, EPRI, with support of significant utility partners, and USDOE's Federal Energy Technology Center (Now NETL), and Office of Energy Efficiency and Renewable Energy established a cooperative agreement to further the commercialization of biomass and coal co-firing. The agreement led to testing, demonstrations, and special studies for biomass and coal co-firing in wall-fired PC boilers, tangentially fired PC boilers, and cyclone boilers. The initiative also provided analysis of institutional issues such as new source review, deregulation on utility investments, various state RPS legislations, and federal production tax credits [*77*] [*160*].

2.3.2.3.1 Wall-Fired PC Boiler Tests

The first demonstration projects took place at the Colbert Fossil Plant of TVA, Seward Generation Plant of GPU Genco, and Blount St. Station of Madison Gas and Electric. The Blount St. Station tested switchgrass as the biomass fuel, and will therefore be review below under the section titled "Specific switchgrass combustion effects on existing boilers & power plant equipment".

In 1997, Colbert Fossil Plant (~1,300 MWe generating station; 4 – 190 MW boilers, and 1 – 550 MW boiler; Located in Colbert Co. AL) was co-fired at 4% using wood waste and coal. A pole barn was erected, and a trommel screen feed the wood waste directly onto the coal feed belts where the mixture was bunkered and feed into the pulverizers. The pulverizers were not operated at capacity and handle the wood adequately, although they did experience an 8% mill amp increase. No boiler efficiency reduction was experienced, and there were no noticeable impacts on NO_x emissions or opacity.

In 1996 & 1997, the Seward Generation Station (~62 MWe) located in Indiana County Pennsylvania co-fired sawdust in one of its two wall fired PC boiler. The three unused top burners were equipped with a separate metering auger, lock hopper, and blower, each capable of delivering 2 tons/hr biomass, or 10% co-firing by energy. Positive results from the initial tests lead to the installation of a demonstration facility consisting of a trommel screen, silo, and weigh belt feeder. Capacity was not reduced, and efficiency looses were modest until co-firing exceeded 12% by mass (~6.6% energy). There were not problems with opacity, unburned carbon, or CO emissions. NO_x emissions were reduced in proportion with biomass co-firing rates. Due to unfavorable heat rates and NO_x emissions, deregulation economics forced the plant ownership to change twice and co-firing equipment was relocated to the Albright Generating Station.

2.3.2.3.2 Tangentially-Fired PC Boiler Tests

EPRI and USDOE also tested and demonstrated co-firing in tangentially fired boilers at the Greenidge Station in Dresden New York, Plant Gadsden in Gadsden Alabama, and

Albright Generation Station in Preston County West Virginia. As is the case with the Blount St. Station tests, switchgrass was the tested fuel co-fired with coal at Plant Gadsden, and a review of this test is presented in “Specific switchgrass combustion effects on existing boilers & power plant equipment” below.

The Greenidge plant successfully co-fired its 108 MWe tangentially fired PC boiler using a separate pulverizer and fuel injection. NO_x and SO_2 reduction were experienced.

The biomass material handling equipment was removed from the Seward Generation Station and installed at the Albright Generating Station (2 – 70 MWe wall-fired PS Boilers, and 1 – 140 MWe Tangentially fired PC Boiler). The tangentially fired boiler test already had a separated overfire air system for NO_x control and the demonstration proved that co-firing sawdust further lowered NO_x emissions. Additionally, SO_2 emissions where reduced in proportion to the quantity of biomass fired.

2.3.2.3.3 Cyclone Boiler Tests

NIPSCO, a utility with a significant number of cyclone boilers, performed tests in two of their cyclone boilers: Michigan City Generating Station located in La Porte County Indiana, and Bailly Generating Station located in Porter County Indiana.

Michigan City Station tests were designed to test co-firing in large (>400MWe), supercritical (>3,500 psig) boilers, with flue gas recirculation and firing with low sulfur Powder River Basin blended coals. Operationally, the tests were successful. The boiler operated stably, although the boiler experienced a predictable minor reduction in power output (1%). Wood wastes were co-fired up to 10% by weight (6% by energy). SO_2 and NO_x emissions were reduced as well as opacity.

At Bailly Generation Station (160 MWe boiler was tested), a triburn concept consisting of coal, petroleum coke and biomass was used to test the use on a renewable fuel that does not reduce boiler efficiency or fuel costs. A pole barn housed a 20 ton/hr trommel screen. Once biomass was screened, it was blended with petroleum coke and the two blended with coal. The most favorable blends were 2:1 and 3:1 petroleum coke to biomass. These blends resulted in no reduction of boiler efficiency, capacity, or operability. NO_x emissions as well as other trace metals such as mercury and lead were reduced although SO_x emissions increased.

2.3.2.4 NETL Tests

NETL researchers tested biomass effects on pulverized coal preparation and feed equipment, and fouling and corrosive effects of biomass and coal combustion ash for three candidate biomass feedstocks: wheat straw, alfalfa stems, and hybrid poplars [*183*]. The three were all co-fired in a pulverized coal furnace with an Illinois bituminous and an Absaloka subbituminous at 20% by weight, and ash deposit rates and composition were measured and analyzed. Their tests showed that the fuels fed smoothly through the PC fuel prep and injection nozzles, and experienced complete combustion. In general fouling grew rapidly, but was weaker than when the biomass or coal fuels were burned by them selves. Analysis of ash and fouling analysis conclude that differences between fuel and ash composition exist for different biomass fuels. Chlorine was strong in the wheat straw fuel, but not in it's co-fired ash. It was weak in the poplar and alfalfa stem fuels, but strong in their ash. For the straw, silicon and potassium were strong in the fuel and in the ash.

2.4 Specific switchgrass combustion effects on existing boilers & power plant equipment

In 1996, as part of the EPRI and USDOE cooperative agreement, the first parametric tests using switchgrass and coal co-fired in a utility boiler took place at the Blount St. Station in Madison Wisconsin. The 26 tons/hr of coal 50 MWe non-reheat boiler was co-fired from 4% to 10% on an energy basis. Switchgrass was run, in series, through a hammermill and a tube grinder, before being bunkered in surge hoppers and feed into the boiler through separate injection ports. The boiler efficiency was reduced by 1% during tests, but NO_x was reduced by 31% [*77*] [*160*].

Testing at Southern Company's Plant Gadsden (2 – 60 MWe non-reheat T-fired boilers) was originally designed to co-pulverize biomass and coal. Initial bunkering test suggested possible operation difficulties and a separate injection system was added. Switchgrass, stored outside, was feed through tub grinders into hoppers and pneumatically conveyed into the boilers at opposite corners. For these tests, NO_x increased. It is speculated that the increase was a result of harvesting and storage practices rather than the properties of the switchgrass itself. SO_2 emissions were reduced [*77, 160*] [*14*].

Ottumwa Generating Station located in Ottumwa IA, successfully demonstrated switchgrass co-firing with PRB (powder river basin) coal, in a large (726 MWe) twin furnace tangentially fired boiler [*4*]. During the tests sulfur emissions decreases while

NO_x emissions increases slightly. It was speculated that the NO_x increases were due to upsets in the feed systems and differences in the boiler load. Plans are moving forward for a long-term switchgrass and coal co-firing test burn scheduled for winter and spring 2006 [*29*].

A catalytic deactivation test was conducted by Southern Company and Alabama Power, together with Southern Research Institute and EPRI, at Alabama Power's Plant Gadsden. The experiment involved exposing catalyst material installed in identical probes to flue gas as switchgrass was co-fired with coal. After 263 hours of biomass ash exposure, no changes in catalyst activity were detected; however, further testing is required to determine the feasibility of selective catalytic reduction (SCR) NO_x reduction technology implementation in a biomass co-fired power plant [*59*].

2.5 Cellulose Ethanol Production

In contrast to the foregone co-firing literature review, this ethanol literature review focuses on primarily on ethanol production economic forecasts. The large body of knowledge specific to technologies, processes, barriers, or current research focuses is not covered except for the instances considered directly relevant to the goals of this thesis. Lin and Tanaka provide a current review of basic technology topics excluded from this literature review such as biomass resources and the associated technology and micro-organisms required for their conversion to ethanol [*94*].

Current U.S. ethanol production is based on corn. This thesis is concerned with switchgrass derived energy, and for this reason, a review of corn processing techniques, technologies, and economics will be excluded other than the following. U.S. Department of Agriculture (USDA) economists surveyed the then existing corn ethanol industry (year 2000) and concluded that the average variable cost of producing corn ethanol was $0.94 per gallon, with feedstock costs accounting for roughly half of this cost [*144*]. These averages exclude capital debt service. An earlier joint USDA and Department of Energy's National Renewable Energy Laboratory (NREL) published a corn ethanol total plant gate estimate (including debt service) of roughly $0.90 per gallon [*177*].

Department of Energy's National Renewable Energy Laboratory (NREL) has published several evaluations of cellulose based ethanol production processes and economics and, as their research work continues, future publications are anticipated [*166*]. The earliest report, published in 1993, created and compared an input output inventory for three fuels: reformulated gasoline (RFG), E10, and E95[14] [*161*]. Researchers concluded that E10 fuel cycles produce less CO, CO_2, and SO2 emissions, but greater volatile organic compounds (VOC), particulate mater, and NO_x. E95 fuels cycles produce 90% fewer CO_2, 67% less SO2, and 14% less VOC when compared to RFG fuel cycles. No economics process forecasting was provided.

NREL published a process design and economic model for a biomass based ethanol process using co-current dilute acid prehydrolysis with simultaneous saccharification and co-fermentation and cellulosic enzyme production [*178*]. The economic estimations for several time-periods of cellulose ethanol plant vintages were presented. The first, based on a what would be a then current constructed plant if one were constructed, is followed by anticipated process improvements through the year 2015. Their economic projection suggested a plant gate ethanol price ranging from $0.76 to $1.44 per gallon of ethanol in

[14] EXX refers to an ethanol and gasoline blend where the XX indicates the relative % of ethanol on a volume basis.

1999 dollars. This is based on a $25 per ton biomass feedstocks, and the range reflects anticipated process improvement. As capital costs decrease and production efficiency increase, capital costs decline from $4.24 to $1.60 per gallon capacity.

Continued research resulted in revised cost estimation [*177*]. For a 25 million gallon per year ethanol plant, a plant gate cost of $1.50 per gallon is forecasted. This cost is based on $35 per ton corn stover, a yield of 72 gallons per ton of feedstock, and ¢2.77 per kWh of electricity generated and sold to the surrounding power grid. Capital costs, which are included in the plant gate price, are roughly $5.44 per gallon capacity.

NREL's subsequent research estimated total plant gate cost for a 2010 ethanol plant to be $1.07 (+$0.12/-$0.05) per gallon [*2*]. This is for a 70 million gallon per year process, consuming 2,200 short tons of feedstock per day. Electricity generated on site and sold to the surrounding power grid. Discounted over 20 years at 10%, capital costs are $2.85 per gallon. A Monte Carlo sensitivity analysis was also performed and the 90% confidence range for total plant gate cost is bound by $1.06 and $1.26, with a 50% probability of the price being below $1.17 per gallon. Additional analysis provides plant gate cost's sensitivity to plant size, and recommend that 2,000 to 8,000 Metric tons per day is the optimal size range for cellulose ethanol economics.

National Resource Defense Council researchers estimate a plant gate price of $0.39 per gallon for by 2015 [*107*]. This is based on a plant size of 20,000 short tons of biomass per day.

2.6 Full Cost Accounting and Life Cycle Analysis of Co-firing and Ethanol Production

2.6.1 Co-Firing

Department of Energy's National Renewable Energy Laboratory (NREL) researchers Spath and Mann performed a life cycle analysis on a coal-fired power system that co-fires wood residues [*97*]. The analysis was a cradle-to-grave analysis considering processes necessary for plant operation, including raw material extraction, feed preparations, transportation, and waste disposal and recycling. At co-fired rates of 5% and 15%, greenhouse gas emissions where reduced by 5.4 and 18.2% respectively. Criteria pollutants (SO_2, NO_x, non-methane hydrocarbons, particulates, and CO) were also reduced. In addition, total system energy consumption was lower by 3.5% and 12.4% respectively.

Within the state of Iowa, researcher's estimate that the true societal benefits for co-firing 100,000 tons of switchgrass with coal results in a net present value of $22 to $63 million[15] [*151*]. Researchers included all governmental subsidies for coal and switchgrass, environmental expenses from pollutants (criteria and green-house gas emissions), environmental improvements through the conversions of 50,000 acres from cropland to switchgrass production including wildlife habitat impacts. Costs excluded from the analysis are mercury emissions impacts, non-metal toxic emissions impacts,

---

[15] 25 years, discounted at 3%, values are in 2002 dollars

acid mine drainage impacts, coal mining resource impacts. Net present value of private costs to the co-firing utility is estimated to range between $63 and $154 million[16].

Different researchers performing a life-cycle analysis concluded that biomass and coal co-firing was environmentally better than flue gas CO_2 capture [*11*]. Other researchers concluded that wide spread biomass co-generation technology development, instead of fossil energy based expansion pathways, would result in a significant reductions in criteria pollutant and greenhouse gas emissions in Asia and Indochina [*44*]. Just focusing on life-cycle green-house-gas emissions, researches estimated that switchgrass and coal co-firing produces 102 grams CO_2 equivalent for every million joules of switchgrass consumed [*110*]. For comparison, the average for this research is 85 grams CO_2 equivalent for every million joules of switchgrass consumed.

2.6.2 Ethanol

On a Life-Cycle and/or Full Cost Accounting basis, results and conclusions regarding impacts to the environment, stakeholders, and society vary depending on the assumptions used by researchers. Researchers disagree as to the true environmental benefits of ethanol use as an MTBE and/or gasoline substitute. In general though, ethanol can lead to fossil energy consumption reductions and greenhouse gas emissions reductions, but will likely cause other criteria pollutants to increase and may have other undesirable environmental consequences associated with land and water contamination.

NREL researchers performed a peer reviewed life-cycle analysis of corn stover derived ethanol [*145*]. Assuming that all corn stover was produced using no till farming

[16] 25 years, discounted at 3%, values are in 2002 dollars

practices, E85 reduces total energy consumption (coal, oil, and natural gas) by 102%, and greenhouse gas emissions (fossil CO_2, N_2O, CH_4) by 113%. Some air quality pollutants increase (CO, NO_x, and SO_x), while hydrocarbon ozone precursors are reduced.

U.S. Department of Energy's Argonne National Laboratory, the Center for Transportation Research has issued several reports on the environmental performance of automobile use of ethanol derived from both starch (corn), and cellulose feedstocks. The first, estimates the effects on a per-vehicle-mile fuel-cycle petroleum use, greenhouse gas emissions (GHG), and energy use of a mid-size passenger car using ethanol and gasoline blends [*175*]. Their analysis includes petroleum use, energy use, and emissions beginning with biomass farming through to the consumption of fuels for transportation use. They conclude that cellulose ethanol use would result in a 65 to 85% reduction in petroleum use, 6% to 105% reduction in GHG emissions, and a 6% to 86% reduction in fossil energy use. The range in values reflect blend rates (E10 for the previous figures, and E95 for the latter), near-term technologies versus expected future technologies, and cellulose feedstock choices (woody feedstocks offer slightly greater GHG emission reductions, and herbaceous feedstocks (switchgrass) offers slightly greater petroleum use reductions).

The first report, in collaboration with General Motors, was conducted to help inform public and private decision makers regarding the impact of the introduction of advanced fuel/propulsion system pathways within the U.S. from a societal point of view [*136*]. The study estimates wells-to-tank (WTT), tank-to-wheels (TTW), and the combined wells-to-wheel (WTW) energy use and greenhouse gas emissions per unit of distance traveled using a 2010 full size pickup as the benchmark vehicle. Twenty seven fuel/propulsion pathways are analyzed considering low-sulfur gasoline, low-sulfur diesel, crude oil-based naphtha, Fischer Tropsch naphtha, liquid/compressed hydrogen based on five different pathways, compressed natural gas, methanol, and neat and blended (E85) ethanol used by conventional and hybrid electric vehicles with both spark-ignition and compression-ignition engines, as well as hybridized and non-hybridized fuel cell vehicles with and without on board fuel processors all configured to meet the same performance requirements. Three ethanol production paths where analyzed, corn and cellulosic (woody – trees, and herbaceous – grasses) with corn providing the lowest wells-to-tank energy requirements, and herbaceous and woody following in that order. All ethanol wells-to-tank pathways resulted in negative greenhouse gas emissions because of carbon soil sequestration during plant growth, corn being the lowest due to fossil fuel use during farming of corn. Using a GM proprietary vehicle model, tank-to-wheels test estimated an E85 conventional spark ignition vehicle achieved a 16.7% efficiency[17] and the hybrid achieved 20.7% with ethanol fueled fuel cells ranging between 28% and 36% for non-hybrid and hybrids. This translated into 20.2, 24.4, 28.6, and 31.8 miles per gallon of E85 for each propulsion system respectively. The spark-ignition ethanol systems were the lowest efficiency and fuel economies of all systems considered. The reports concludes that while E85 fuel/propulsion cycles consume more energy than all other cycles, ethanol energy is significantly renewable as supported by the fact that ethanol cycles offer the lowest greenhouse gas emissions of all pathways considered.

Argonne National Laboratory and General Motors collaborated on a similar study for advanced fuel/propulsion cycles for the European markets [*31*]. This report's

[17] Efficiency = energy output/energy input, where energy output is the total amount of energy required to overcome the rolling resistance, aerodynamics, and inertial (acceleration) over the driving cycle. Energy input is the energy content of the fuel.

conclusions echoed the previous U.S. analysis in general, but specifically included European bioenergy feedstocks (organic wastes, poplar plantations wood, and sugar beets) and overall energy and greenhouse gas emissions were lower for European vehicles because of small European vehicles. This can be an interpreted as an indication of potential benefits resulting from U.S. corporate average fuel economy (CAFE) standard increases.

The most recent report, also in collaboration with General Motors, estimates well-to-wheels energy use and emissions associated with future fuel/propulsion systems and updates the previous U.S. analysis by including criteria pollutants for the chosen systems [*21*]. With respect to ethanol cycles, previous conclusions remain (ethanol reduces fossil energy use and greenhouse gas emissions), but criteria pollutant emissions increase for ethanol as compared to conventional gasoline fuel/propulsion systems (NO_x, VOC, and PM10 emissions increase by roughly 100%, 25%, and 40% respectively).

Pimentel and Patzek argue that switchgrass derived ethanol requires 50% more fossil energy use than is contained in ethanol [*126*]. Their evaluation includes the thermal and electrical energy required for ethanol production in a list of energy derived from fossil sources. Most cellulose ethanol production processes models account for these energy requirements from the portions of bioenergy feedstock that can not be converted to ethanol, lignin combustion. Moreover, most process models estimate excess electricity production that is then sold to the existing electrical grid as electricity derived from renewable resources. Patzek argues in a non-peer reviewed report that corn ethanol requires seven times the work derived from its use in an internal combustion engine to restore the key non-renewable resources [*121*]. In contrast to Pimentel and Patzek, USDA and Argonne lab researchers argued that corn based ethanol offers a 34% reduction in fossil energy with 53% as a best case [*143*].

An Institute for Lifecycle Assessment researcher normalized results from ten published ethanol production energy evaluations of ethanol to determine a range of energy returns on investment defined as the ratio of total energy out to non-renewable energy, or fossil energy in [*69*]. The author argues that gasoline for example, requires 1.31 units of total energy to produce one unit of gasoline energy, resulting in an energy return on investment ratio of 0.76. Thus, if an ethanol's energy return on investment ratio is greater than 0.76 then this indicates that its production consumed less non-renewable energy than gasoline's production does. A ratio greater than one means that ethanol has nominally captured at least some renewable energy. Corn ethanol ranges between 0.84 and 1.65 and cellulose ethanol ranges 4.40 and 6.61. Pimentel and Patzek's ratio is 0.69 and the author concludes it to be outlier. University of California at Berkeley researchers suggest that despite the net energy and greenhouse gas benefits of ethanol, other environmental metrics should be better understood prior to large-scale ethanol use [*58*].

Other research efforts have investigated environmental and health risks other than explicit energy use and greenhouse gas emissions. Niven published a literature review of existing peer reviewed research on ethanol use as a gasoline blended fuel [*111*]. In this publication, three additional environmental aspects of ethanol use are examined: (1) the reduction in air pollutant emissions; (2) potential impact on subsurface soils and groundwater; (3) the overall sustainability of ethanol production. E10, it is argued, offers little advantage in terms of environmental sustainability and would likely increase both human health risks because of increased criteria pollutants and severity of soil and groundwater contamination because of increased corrosiveness of ethanol/gasoline blinds. E85, however, offers significant greenhouse gas benefits although significant criteria pollution emissions will be produced along with substantial risks to biodiversity because of farming practices. The author also argues that E85s impact on ground water contamination and overall sustainability are largely unknown and should be focus of further investigation.

A separate literature review performed by a U.S. Environmental Protection Agency researcher echoes a similar caution [*34*]. A review of forty-five publications (1996-2005) of virtually all ethanol feedstocks in multiple countries (Brazil, Canada, India, the Philippines, South Africa, the United States and several European nations) reviled that acidification, human toxicity and ecological toxicity impacts, mainly occurring during the harvesting and processing of biomass, were often unfavorable for ethanol.

2.7 Cost of Mitigation for Alternative Options

2.7.1 Electricity

Many electricity generation technologies offer carbon mitigation benefits. A list of near term options includes switching to lower carbon content fuel, retro-fitting coal power plants for carbon capture, coal gasification with carbon capture, nuclear, efficiency improvements such as combined heat and power (CHP) processes, and renewable energy technologies such as wind, solar, small hydro, and geothermal.

In a carbon emissions controlled dispatch analysis, it was found that the electricity sector would most likely convert to as much natural gas fired electricity generation as natural gas prices would allow; after which, carbon capture and sequestration technologies would likely allow further carbon reductions [*83*]. In critique of Johnson and Keith's analysis, natural gas prices have since risen outside the natural gas price boundary of their analysis therefore their research conclusions might not still hold.

Carnegie Mellon University researchers estimated the performance and costs for several carbon reduction technology options for existing coal-fired power plants [*30*]. The carbon capturing options investigated were: retrofitting an amine scrubber to capture post combustion CO_2, and retrofitting an Integrated Gasification process with a Carbon Capture option (IGCC). Adding the post combustion capture option adds a parasitic energy load and therefore the power plant is de-rated[18] or the amount of electricity available for sale to the electricity power grid is reduced. To compensate for this, the researchers modeled an option to add a new natural gas fired boiler and turbine (without carbon capture from natural gas combustion). For the IGCC technology, the researchers model two options: (1) replace everything except the existing steam turbines, and (2) replace everything. Estimated costs are: (1) 75 $/ton CO_2 avoided for amine scrubber accepting de-rate, (2) 77 $/ton CO_2 avoided for amine scrubber with the new NG boiler installation[19], (3) 46 $/ton CO_2 avoided for the IGCC option keeping the existing steam turbines, and (4) 51 $/ton CO_2 avoided for the IGCC option replacing everything. These prices include new pipelines, and compression of CO_2 for geological storage. Other researchers have estimated costs for a process which burns coal with oxygen in an environment of flue gas, called O_2/CO_2 recycle combustion. A cost for this retrofitting option is estimated at 35 $ CO_2 avoided [*147*].

[18] De-rated means that the amount of electricity available for sale to the electricity power grid is reduced
[19] $4.7/mcf NG price

New coal gasification with carbon capture (IGCC – Greenfield) is another option for coal-fired electricity sector carbon emissions reduction [*135*]. In this publication, the researchers performed a literature review of existing IGCC economics publications and determined average costs ($/ton CO_2) ranged from $22 to $26. The authors suggest that the recent literature has not adequately characterized realistic ranges and interdependencies of key factors that effect cost comparisons.

Having performed literature reviews of multiple carbon reducing technology options for electricity generation, researchers published a list of costs ranges ($/ton CO_2) for several technologies as compared to new coal constriction without carbon capturing equipment [*146*]. The following is a list of technologies and the published costs in $/ton CO_2: (1) CCGT[20] = $0 - $43, (2) PC + CC retrofit = $43, (3) CCGT + CC = $19 - $45, (4) Nuclear = $-10 - $37, (5) Hydro = $-8 - $35, (6) Wind = $-22 - $37, (7) Biomass IGCC = $-25 - $32, (8) PV = $48 - $380.

2.7.2 Transportation

Several life-cycle analysis evaluations for multiple transportation alternatives have been performed. This review comments on a few and seeks to highlight some additional transportation alternatives to the current gasoline fuel cycle.

Carnegie Mellon University researchers compared six mass market fuel/propulsion combinations to a conventional gasoline fueled automobile using Carnegie Mellon University's Environmental Input-Output Life-Cycle Analysis tool (EIO-LCA [*68*]) [*91*]. Researchers compared life-cycle impacts for the six fuel/propulsion alternatives

[20] Combined Cycle Gas Turbine

(reformulated gasoline, reformulated diesel, compressed natural gas, ethanol from biomass, battery electric vehicles, hybrid electric vehicles, and fuel cell vehicles) by eleven metrics ((A-1) ozone, NO_x, VOC, (A-2) particulate matter, (A-3) air toxics, (B-1) fuel cycle emissions, (B-2) fuel costs, (C-1) range, (C-2) vehicle cost, (D-1) infrastructure cost, (D-2) energy independence, (D-3) global warming, (D-4) fossil fuel depletion) and concluded no unanimously superior alternative. Determining a cost of carbon mitigation for each alternative is not possible because the article only provided costs differences between one of the alternatives (hybrid electric) and then current automobile. For hybrid electric vehicles, perhaps the least costly of the six alternatives, the authors estimate a cost of carbon mitigation ranging from \$808 to \$188 dollars per ton CO_2.

Carnegie Mellon University researchers published an extensive examination of the life cycle implications of a wide range of fuels and propulsion systems that could power cars and light trucks in the US and Canada over the next two to three decades ((1) reformulated gasoline and diesel, (2) compressed natural gas, (3) methanol and ethanol, (4) liquid petroleum gas, (5) liquefied natural gas, (6) Fischer-Tropsch liquids from natural gas, (7) hydrogen, and (8) electricity; (a) spark ignition port injection engines, (b) spark ignition direct injection engines, (c) compression ignition engines, (d) electric motors with battery power, (e) hybrid electric propulsion options, and (f) fuel cells) [*96*]. In this publication, a literature review of then recent studies to evaluate the environmental, performance, and cost characteristics of the alternatives is provided. The authors provide societal and policy critiques which explain perceived barriers to status-quo alternatives. For example, the authors suggest that the search for alternatives fuels and propulsion systems is not a market-driven but instead, strictly a regulatory policy endeavor aimed at addressing concerns over environmental, health and toxicity, foreign policy, and energy sustainability. Moreover, the authors identify that regulatory goals are often contradictory, and suggest that the evaluation of alternatives consider tradeoffs between multiple attributes such as consumer appeal, externalities and secondary effects, cost-benefit analysis applying life-cycle assessments and net social benefit, comparative advantages between command and control versus market regulations, and metric uncertainties. Upon review of literature, no alternative emerged as a clear winner. The authors conclude that society will decided which tradeoffs are of most importance and that the ultimate alternative chosen will largely be market driven with future petroleum prices being of primary influence. For this reason, petroleum fuel will most likely dominate, at least till 2030, due to the historic investments in petroleum based infrastructure and the continued development of the internal combustion engine. The authors do suggest that ethanol could become a dominate fuel if energy independence, sustainability, or greenhouse gas emissions become a large enough concern or if petroleum prices double from the then current crude oil prices of roughly \$18 to \$20 per barrel crushing Oklahoma spot prices. The authors do not provide metrics from which a cost of carbon mitigation can be determined.

Argonne National Laboratory's Center for Transportation Research and General Motor's Global Alternative Propulsion Center collaborated in an evaluation of seventy five fuel pathways and three drivetrains to determine well to wheel energy use and greenhouse gas emissions [*136*]. The results conclude that hydrogen produced from hydroelectric or nuclear electrolysis sources offers the lowest greenhouse gas emissions followed by ethanol. No cost estimates were provided and therefore costs for carbon mitigation can not be determined from this research.

Argonne National Laboratory's Center for Transportation Research, General Motor's Global Alternative Propulsion Center, and several oil companies sponsored a research initiative to determine wells-to-wheels energy and greenhouse gas emissions for advanced fuel/vehicle systems in Europe [*31*]. Thirty two fuel pathways, divided into four categories (crude oil based, natural gas based, electricity based, and biomass based), and twenty two powertrains, divided into three categories (conventional, hybrid, and fuel cells) were analyzed. Conclusions presented in the report suggest that renewably-produced hydrogen/ fuel cell powertrains offer significantly lower greenhouse gas emissions and improved fuel supply diversity. Hydrogen produced from the European electricity mix does not have any benefits over conventional fuels. Biomass-derived fuel supply pathways are more complex than the other alternatives and have a wide range of uncertainty related to how the biomass feedstocks will be grown. No specific cost metrics are provided and therefore a comparative cost of carbon mitigation is not provided.

The most recent of the Argonne National Laboratory and General Motors collaborated wells-to-wheels analysis for the U.S. seeks to include criteria pollutants into the analysis [*21*]. The authors estimate advanced vehicle technologies offer great potential for reducing petroleum use, greenhouse gas emissions and criteria pollutants. Greenhouse gas reductions are greatest for renewably produced hydrogen fuel cell vehicle cycles, followed by ethanol fueled cycles. The authors conclude that fossil fuel related cycles can also lead to greenhouse gas emission reductions through greater fuel economies. For example, natural gas fueled fuel cell vehicles have greater efficiencies when compared to gasoline internal combustion based cycles. Despite quantifying greenhouse gas emissions reductions possible for alternative fuel/propulsion cycles, like the previous two reports, costs are excluded from this report.

Chapter 3 Cost of Carbon Mitigation for Existing United States Coal Fired Power Plants Using Switchgrass as a Co-Firing Feedstock

3.1 Modeling Switchgrass and Coal Co-Firing in Existing Coal Fired Power plants

In this section, a technique is developed for estimating the costs and benefits associated with co-firing switchgrass in existing coal fired power plants. This technique analyzes transportation logistics and individual power plant performances where multiple coal power plants compete for switchgrass feedstock supplies. It is based on the geography of potential switchgrass supplied and existing coal-fired power plants. The model captures the tradeoff between transportation costs and capital investments.

Two regions were chosen for initial analysis in order to explore a range of expected estimations of costs and CO_2 reductions. The first, Pennsylvania, is home to relatively abundant coal fired power plants[21] (112 TWh in 2002) but with limited switchgrass production potential (3.3 million tons/year at 50$/ton). The second, Iowa, is home to relatively limited coal fired power plants[22] (36 TWh in 2002), but has abundant switchgrass growth potential (19.5 million tons/year at 50$/ton). See Appendix D for a ranking of states' ratio of switchgrass growth potential to coal based electricity generation.

[21] 45% of Pennsylvania's 40,000 GW capacity is coal capacity, which generated 55% of Pennsylvania's 204 TWh in 2002

[22] 65% of Iowa's 9,300 GW is coal capacity, which generated 83% of Iowa's 43 TWh in 2002

Linear programming (LP) was chosen as an economic modeling tool for its ability to produce a least cost evaluation of multiple factors affecting total co-firing economics. The LP model used in this research considers switchgrass transportation costs, additional power plant capital equipment investments, additional operation and maintenance costs, and emissions credits for reductions in NO_x, and SO_2. The cost of switchgrass feedstock is external to the LP because the switchgrass dataset does not allow prices to vary between power plants. In the switchgrass dataset, switchgrass quantities are in gross tons available at a given cost. When choosing a quantity, all switchgrass is at the same price. Therefore switchgrass price becomes a constant in a LP model. Using a LP model allows the interplay of regional switchgrass production, coal plant location, and individual coal plant performance features to determine an allocation of switchgrass that results in the lowest possible costs or the maximum possible benefit.

The benefit derived from co-firing switchgrass with coal is the reduction of power plant CO_2 emissions. The LP model yields a minimized total cost in terms of costs per reduction in CO_2 emissions ($/ton CO_2) or cost of carbon mitigation (COM). Alternatively, the LP can yield a minimized total CO_2 emission regardless of costs. Several scenarios which explore the difference between minimizing costs versus minimizing carbon emissions are performed using this modeling technique and their results are reported below.

This research also analyzes the national coal based electricity infrastructure and estimates costs and carbon reduction benefits of using switchgrass as a coal co-firing feedstock at a national level. This research will provide legislators, utility mangers, and the general public with a benchmark from which to better understand state and national level switchgrass electricity benefits and costs.

3.1.1 Nomenclature

Table 1 - eGRID based Data, Nomenclature, and eGRID Reference

Symbol	Description	Units	e-GRID Symbol
W_{ne}	Net Electric Nameplate Capacity	MW	NAMEPCAP
W_{ng}	Net Power Generation	MWh	PLNGENAN
E	Plant Annual Heat Input	MMBtu / Yr	PLHTIAN
HR	Plant Heat Rate	Btus/kWh	PLHTRT
AER_{NOx}	Plant Annual Emissions Rate - NO_x	lb/MMBtu	PLNOXRA
AER_{O3}	Plant Ozone Season Emissions Rate – O_3	lb/MMBtu	PLNOXRO
AER_{SOx}	Plant Annual Emissions Rate - SO_x	lb/MMBtu	PLSO2RA
AER_{CO2}	Plant Annual Emissions Rate – CO_2	lb/MMBtu	PLCO2RA

Table 2 - Additional Nomenclature

Symbol	Description	Units
AC	Annual Cost (negative value)	(-)$ / yr
BEP	Biomass Efficiency Penalty	%
C	Cost (negative value)	(-)$
CF	Cost Factor	
CFR	Co-Fire Rate	%
D_S	Distance (for Shipping)	miles
ED	Energy Density	MMBtus/ton
EI	Emissions Income	(+)$/yr
ER	Emission Reduction	tons/yr lb/yr - Hg
EV	Emission Value	$/ton $/lb - Hg
FR	Freight Rate	$/ton-mile
FIR	Federal Renewable Energy Incentives Rate	$/kWh$_S$

HrOp	Hours of Operation	hr/yr
i%	Amortization Rate (Hurtle Rate)	%
L	Land	acre
kWh	kilowatt hour	*kWh*
M	Mass Flow Rate	ton / yr
MWh	megawatt hour	*MWh*
Opr	Number of Operators	*People*
n	Life of Co-Firing Equipment	yr
PTC	Production tax Credit	$/yr
RC	Reduction Credit	%
SF	Switchgrass Farms	-
Y	Yield	ton / acre / yr
α	Scalar	NA
β, ζ, ψ	Equipment Cost multipliers	$\$/kW_b$
ξ	Co-Fire rate above which a separate biomass feed system is requires	-

Table 3 - Nomenclature Subscripts

Subscripts	Description
a	Annual
b	Biomass
c	Coal
e	Equipment
f	Fuel Cost
ecf	Crop Farm Location
cpp	Unique Coal Fired Power Plant
m	Maintenance
N	Number of Power Plants
o	Operators
p	Plant
s	Switchgrass
t	Transportation
uf	Unit of Fuel

z	Number of Crop Farms
Hg	Mercury
SO_2	Sulfur Dioxide
CO_2	Carbon Dioxide
NO_x	Nitrogen Oxides

3.1.2 Introduction

Modeling will be presented in four distinct sections:

- Disaggregation of existing Oak Ridge National Laboratory switchgrass availability forecast
- Plant level biomass and coal co-firing engineering, environmental performance and economics
- BioTDEOM – Biomass Transportation and Distribution Economic Optimization Model
- Scenario definition

3.1.3 Disaggregation of Existing Oak Ridge National Laboratory Switchgrass Availability Forecast

Two disaggregation procedures are performed. First, the POLYSIS multi-county level dataset is disaggregated to a county level using the Oak Ridge Energy Crop County Level Database (ORECCL), in conjunction with USDA county level farm crop statistics. Second, for the states chosen in the analysis, the county level is further disaggregated based on satellite land use imagery. Preceded by a general discussion of the ORNL POLYSIS Dataset, both disaggregation methods are presented below.

3.1.3.1 POLYSIS Dataset

The POLYSIS model, a US agriculture policy simulation model, was developed by the US Department of Agriculture, at the Oak Ridge National Laboratories, in conjunction with the University of Tennessee's Department of Agricultural Economics, and Okalahoma State University's Great Plains Agricultural Policy Center [*35*]. POLYSIS is a framework which provides policy analysis and research with an analytical toolkit for estimating a variety of impacts in the agriculture sector resulting from economic, policy, or environmental changes [*37*]. POLYSYS aggregates data according to geographical districts (analogous to Agriculture Statistical Districts (ASD)). The districts are comprised of multiple counties, all of which posses similar attributes (soil type, moisture, terrain, etc.) and economic conditions (crop types, incomes, etc.). There are 305 POLYSYS districts containing 2,787 counties.

The POLYSIS model has been specifically used to analyze the costs and availability of biomass energy crops grown within the U.S. agricultural sector [*35*]. The energy crops considered are switchgrass and fast growth trees. The Oak Ridge Energy Crop County Level Database (ORECCL) informed the POLYSIS model of potential yield (tons/acre) on a county basis. ORECCL contains average yield estimations for energy crops based on cropland, pasture land, and conservation reserve land (CRP) for 3,103 counties [*67*]. POLYSIS only considers switchgrass energy crop productivity potential on the hectares within the US where natural rainfall would provide the water required for switchgrass growth. POLYSIS then estimates the amount of land that farmers would likely convert to energy crop production if energy crop commodities were sold at various prices. The model considers farm incomes given traditional farming activities and seeks to balance demand for all agricultural products. Energy crop prices are based on the cost, including profit, required to replace current farming activities (agricultural commodities: crops, livestock, hay, etc.).

In the resulting POLYSIS dataset, switchgrass availability is forecasted as a function of farm gate prices[23] ($/ton) ranging from $25 to $50 per ton. Assuming that switchgrass has an average high heat value of 14.7 MMBtu per ton, the cost of switchgrass energy would range between 1.7 and 3.4 $/MMBtu [*1*]. The quantity of switchgrass estimated varies from district to district based on yield potential (ton / acre) and incomes derived from current land use practices. The data is divided into forecasts for existing crop land, idle land, pasture land and Conservation Reserve Program (CRP) land.

Appendix A presents the POLYSIS data, as well as an ORNL estimate of the impacts a future energy crop market would likely have on existing agricultural crops. The POLYSIS switchgrass data used in this analysis was kindly provided by Lynn Wright of the Oak Ridge National Laboratory.

3.1.3.2 POLYSIS dataset Disaggregation to Farm Resolution

See Appendix B for a detailed discussion of disaggregation procedure. Figure 1 and Figure 2 present the disaggregated results. The small points represent farm locations and the triangles represent existing coal-fired power plants. The triangle size indicates relative power plant thermal output on an annual basis (year 2002) and are labeled by name and capacity (MW).

---

[23] "Farm Gate Price" is the selling price of switchgrass between farms and any interested purchaser. It assumes that switchgrass will be in cut, bailed, and ready for transport. This price covers all production costs, land rent, and profit to the farm and/or farmer.

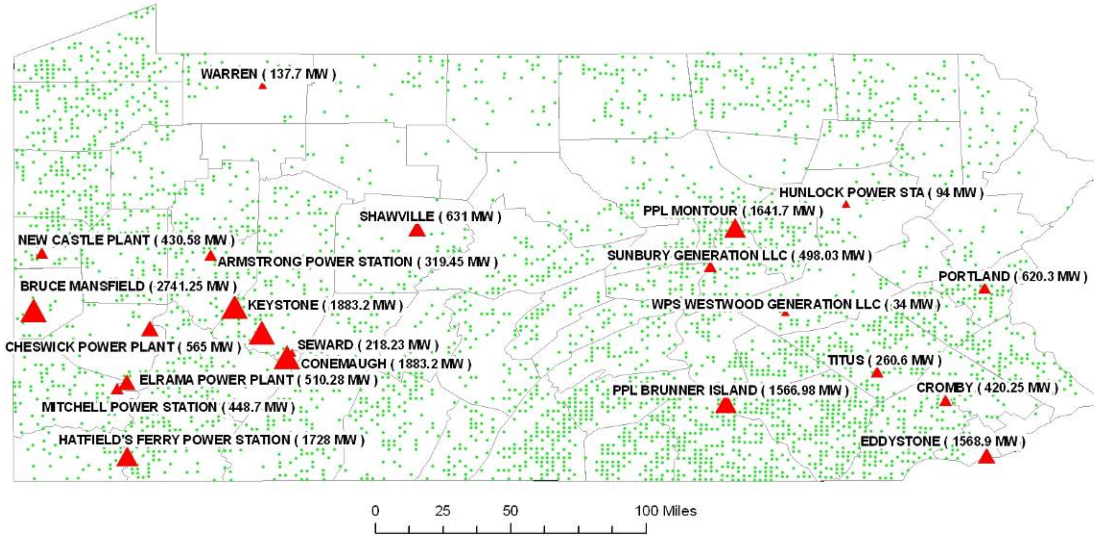

Figure 1 – Pennsylvania: POLYSIS Disaggregated to Farms, & Existing Coal Fired Power plants

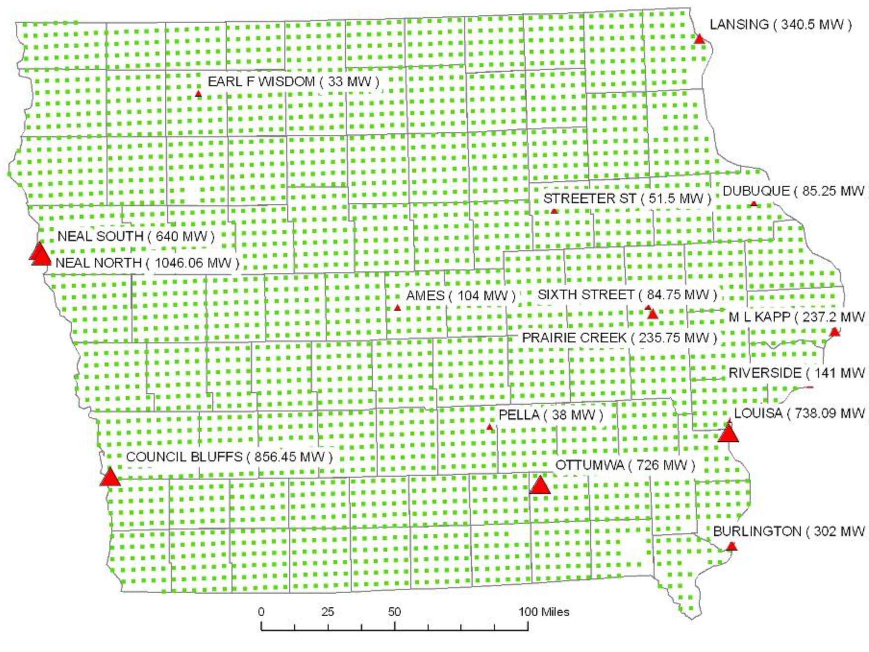

Figure 2 – Iowa: POLYSIS Disaggregated to Farms, & Existing Coal Fired Power plants

3.1.4 Plant Level Biomass and Coal Co-Firing - Engineering, Environmental Performance, & Economics

Power plant co-firing economics modeling is composed of five categorical components:

- Plant Modification
- Fuel Costs & Combustion Performance
- Non-Fuel Plant Variable Costs
- Emission Reductions
- Engineering Economic Parameters

3.1.4.1 Plant Modifications

All co-firing power plants will require some degree of engineering and capital expenditure prior to burning switchgrass. Any power plant considering a transition to switchgrass feedstocks will be wise to consult the original boiler designer and/or manufacturer for possible boiler modification that might be required for successful switchgrass and coal co-firing. For a general discussion of boiler design and specifically, the importance of fuel properties in boiler design, see Appendix C.

The lowest equipment cost alternative would be infrastructure to permit biomass unloading, preparation for combustion, and/or loading onto a boiler feed system. Ideally, combustion preparation should at least consist of coverage[24]. Due to the effect that biomass moisture has on boiler efficiency, coverage should be erected to minimize on-

[24] A barn or some storage which will protect soon to be combusted switchgrass from rain water

site moisture increases [*159*]. In addition to storage and staging, modifications to the fuel feed system may be required. For extreme cases separate boiler feed systems, complete with necessary biomass processing equipment and separate boiler feed nozzles might be required. The degree to which plant modifications are required is dependent the biomass co-firing rate and boiler type.

Boilers can be divided into four general categories[*7*]:

- pulverized coal
- stokers
- fluidized bed
- cyclone

Pulverized coal boilers require very fine powdered coal. The coal is blown into the boiler along with combustion air through nozzles positioned at different locations and heights along the boiler walls. The position and direction of the nozzles are designed to enhance stoichiometric combustion and allow NO_x control during combustion. In contrast, a stoker boiler (an older technology) feeds coal onto a bed upon which combustion takes place. The bed allows continual removal of ash while coal is simultaneously being feed. Fluidized bed boilers are similar to stoker boilers except that air is forced through the bed causing the coal to be suspended. The result is a bubbling mixture of coal and ash that is fluid-like in nature and is similar to boiling water in appearance. Cyclone boilers use tangentially fed combustion air to create a cyclone effect allowing air and coal to mix and form the combustion region. Combusted materials migrate to the boiler walls by means of centrifugal force. At the walls of the boiler temperatures are high enough to keep the combustion ash in a liquid state. A steady state is reached at the wall where gravity drains the slag at the same rate as it is being deposited from the combustion region.

Because of the different combustion mechanics, and feed mechanisms, different coal preparations are required and can be generally categorized by the average particle size of coal after it is processed in preparation for combustion.

- Pulverized Coal (PC) Boilers – fuel size requirement: 70% less than 400 mesh size (≤ 0.00125 inch, or 32.75 microns)
- Stoker Boilers – fuel size requirement: between 1 and 1.25 inch
- Fluidized Bed Boilers – fuel size requirement: 0.25 to 1 inch
- Cyclone Boilers – fuel size requirement: 95% less than 4 mesh (≤ 0.125 inch).

In all four boiler types, if the co-firing rate is low (e.g. below 2% by energy), then the biomass fuel can be fed to the boiler using the existing coal material feed system for transport to, and preparation for firing [*76*]. In the case of PC boilers, when co-firing rates increase above 2%, existing coal pulverizing mills begin to de-rate, or lose their ability to produce the required particle sizes [*159*]. Therefore, above a 2% co-fire rate, PC plants are assumed to invest in a separate feed system. This will typically consist of material conveying equipment between the fuel yard and the boiler including a separate pulverizing mill(s) and injection port(s) into the boiler [*76*]. Because the boiler feeding mechanisms for non-PC boilers are not as particle-size critical, co-firing up to 10% is possible without the addition of a dedicated feed system [*78*].

Capital cost estimations are based on plant biomass consumption rate and incorporate economies of scale. EPRI recommends using \$100/kW_b[25] when in the 2% range, incorporating a 0.7 or 0.8 power law to scale up or down when varying from 2%. When co-firing rates reach 10%, the power law should reverse to 0.8 or 0.7 when scaling up or down using a rate of \$200/kW_b. If low density biomass is used such as switchgrass, then a higher capital cost value of \$300/kW_b will cover the extra capacity required to convey more mass to balance energy equivalence[26] [*78*].

Because a linear program is used for this research, a linear approximation of the power rule is used. Equation 12, presented below, defines the linear cost calculation used. Capital costs rates are estimated for PC and non-PC boilers. For PC boilers, three cost constants correspond to three co-firing rates: below 2%, between 2% and 10%, and above 10%; \$100/kW_b, \$200/kW_b, and \$300/kW_b are used respectively. For non-PC boilers, \$100/kW_b, is used below 10%, above 10%, \$200/kW_b is used.

It is assumed that the capital cost estimate includes design capacity factors implicitly. Therefore, the equipment is designed for optimal performance over a range of desired material feed rates. No additional over design is added.

---

[25] kW_b indicates the portion of the power plants capacity which is derived from switchgrass. If for example, a 1 MW plant co-fires at a rate of 10% based on energy, then its kW_b would be equal to 100.

[26] kWb is defined as the portion of the electricity production that can be assumed to be derived from the combustion of biomass. For example, if a 10 MW capacity plant is co-fired at 10%, then 1MW would be the kWb size.

3.1.4.2 Combustion Performance

Biomass combustion in coal boilers affects combustion efficiency. First, biomass typically contains more moisture than coal[27] does and combustion heat is lost as it is transferred to the moisture as it vaporizes. Second, the least expensive biomass pneumatic feed systems use unheated air to convey biomass to the boiler. The unheated air absorbs latent heat from the energy provided by combustion. Both mechanisms reduce the heat available for transfer to the boiler tubes resulting in de-rating because of boiler efficiency losses.

Efficiency losses are estimated to be on the order of 5 - 15 % for the biomass portion of the blended fuels [*78*]. For this research, the efficiency penalty is kept constant at 10% and is applied to the biomass portion of the energy input. For example, if co-firing 10% biomass and coal the overall boiler efficiency would be reduced by 1%.

See equations 2 & 4 for efficiency penalty calculations.

3.1.4.3 Fuel Costs

Both switchgrass and coal have costs and although co-firing coal with switchgrass will offset coal consumption. It is anticipated that in the near term, switchgrass crops will have higher costs per unit energy than coal. As noted above, energy crop prices in the POLYSIS dataset range between 25 - 50 $/ton equaling $1.7 and $3.4 $/MMBtu,

---

[27] It is recommended that biomass be dried prior to combustion in order to minimize the effects of biomass moisture on boiler efficiency. This can be achieved quite easily because power plants currently exhaust roughly 2/3 of their consumed chemical energy as heat to the atmosphere. This means that more than enough heat exists to remove moisture from biomass feedstocks, even if firing 100% biomass. However, more equipment is required in order to capture this exhausted heat and use it to dry biomass. When retrofitting an existing coal fired power plant, it is unlikely that installing biomass drying machinery will prove cost effective. Therefore, in order to minimize biomass moisture the 100 $/kWb equipment costs is used.

respectively. In 2004, coal costs ranged between 0.75 and 2.25 \$/MMBtu [*48*]. For this research, coal costs are kept constant at 1.24 \$/MMBtu [28]. Of course, a primary concern of this research is the difference in carbon emissions resulting from this premium.

3.1.4.3.1 Fuel Transportation Costs

As presented in "POLYSIS Dataset" above, switchgrass fuel-cost estimates only include revenue required to displace current farm crops, and, therefore, do not include switchgrass transportation costs. The switchgrass transportation cost is estimated by the quantity times distance shipped multiplied by a shipping freight rate (see equation 19). It is assumed that the coal price is a plant gate price and coal transportation costs are included in the price [*52*].

3.1.4.3.1.1 Distance estimation between switchgrass farms and candidate power plants

Using the farm points within each state, GIS software generated latitude and longitude coordinates for all estimated switchgrass farm locations as well as existing coal fired power plant locations. From latitude and longitude coordinates, the great circle radius formula (in Eq. (1) is used to estimate the distances between farm density points and existing power plants.

$$D_{cpp\ ecf} = 3959 \times ArcCOS\begin{pmatrix} SIN\phi \times COS\varphi \times SIN\gamma \times COS\varepsilon \\ +SIN\phi \times SIN\varphi \times SIN\gamma \times SIN\varepsilon \times COS\phi \times COS\gamma \end{pmatrix}$$

Eq. (1)

Where:

[28] 1.24 \$/MMBtu equates the average U.S. historic coal price considering "real" prices for bituminous, sub-bituminous, lignite, and anthracite between the years 1949 through 2004 [*48*].

θ = Latitude_{ecf} (polar) – Energy Crop Farm Latitude

φ = Longitude_{ecf} (polar) – Energy Crop Farm Longitude

ε = Latitude_{ccf} (polar) – Existing Power Plant Latitude

γ = Longitude_{ccf} (polar) – Existing Power Plant Longitude

The resulting distance is a direct distance, and most likely will not be a true highway distance. To compensate for this, a correction assumes that the straight line distance approximates the hypotenuse of an equilateral triangle, the legs of which will more accurately approximate road distances. Assuming this to be valid, all straight-line distances are multiplied by the square root of two, or 1.41 [*6*].

3.1.4.3.1.2 Freight Rates

It is assumed that all switchgrass transportation will be by truck because of the flexibility of the trucking industries to pick up loads virtually anywhere, and the constraint of shipping within a state.

Bureau of Transportation Statistics reports an average truck freight rate of ¢26.6 per ton-mile in the year 2001 [*24*].

3.1.4.4 Non-Fuel Plant Variable Costs

Non-fuel plant variable costs, or O&M costs, consist of additional personnel required to operate and maintain installed equipment as well as maintenance and repair costs for biomass specific mechanical/electrical equipment. The most detailed estimate of additional biomass and coal co-firing O&M costs are presented by EPRI [*78*]. EPRI estimates O&M costs between \$1.50 - \$10 /MWh_S[29] or roughly \$2.00 - \$13.50 per ton switchgrass consumed. This includes additional plant operators ("full cost" at \$70,000 per year per operator) to handle biomass feedstocks and a 5% maintenance factor per year for equipment maintenance. The number of required operators is varied, producing the range of costs presented.

Generally, maintenance costs are weighted towards the end of equipment life, but for simplification, this research considers maintenance costs to be uniform over the equipment life. Following EPRI's recommendation, 5% of original capital equipment expenditures per year for the life of equipment are assumed for maintenance costs. It is assumed that this estimate includes general maintenance material, maintenance labor, and any replacement parts required to maintain equipment (see equation 20).

EPRI's report does not specify a methodology for estimating additional required operators for co-firing. Therefore, an operation cost estimation methodology has been developed for this research. The number of operators is estimated as a function of plant operation hours (capacity factor) and quantity of switchgrass fired. It is assumed that the EPRI laborer cost of \$70,000 per year is valid, and therefore labor cost can be estimated by estimating the quantity of laborers required.

Switchgrass operators' activities will consist of unloading deliveries, storage management, and feeding switchgrass onto material handling equipment along with any switchgrass preparatory requirements. This should be true regardless if switchgrass is co-fed with coal or has its own dedicated material handling equipment. It is assumed that

[29] MWhs are the MWh generated from the switchgrass energy, or simply the co-fire rate on an energy basis times the MWh generated.

labor requirements will also be independent of the type of biomass feed system. It is assumed that switchgrass operators will not handle coal, and that coal operators will not handle switchgrass. Any reduction in coal handling labor is ignored although this might serve to ease switchgrass labor costs. It is also assumed that the annual quantity of switchgrass co-fired is consumed evenly over the entire annual hours of operation[30].

A laborer is assumed to work roughly 2,000 hours per year. Assuming that only one operator is required per hour of operation, a first approximation of labor requirements simply rounds the division of a plant's annual hours of operation by 2,000. For example, a capacity factor of 75% translates to roughly 6,500 hours of operation, or 4.25, rounded to 4, operators. The assumption of only one operator per hour is unlikely at high switchgrass material flow rates, and for this reason, a scalar multiplies the number of operators to reflect more than one employee working in any given hour, as in equation 21. This scalar is represented by α.

A scalar, α, is estimated in two steps. First, an hourly flow rate of switchgrass tons per hour is calculated by dividing annual switchgrass consumption by annual hours of operation. Assuming that switchgrass is delivered in large round bales containing roughly a half ton of dry switchgrass[31], a bales-per-hour handling rate is estimated by multiplying the tons per hour by two. It is assumed that a single operator driving a front-end forklift will not be able to handle a single bale in less than 2 minutes. The second step adds another operator if bales-per-minutes falls below 2 minutes. Using this method,

[30] This might not be true in a power plant diligently seeking to optimize its performance and economics. However, sustaining this assumption simplifies the labor estimation approach.

[31] Switchgrass can be baled into several sizes and geometries, but researchers have determined that the most economical is a large round bale (1.8 m dia x 1.5 m long @ 134 kg/m^3) [*16*]. Although ignored by this research, dry matter losses are expected to be less than 5%[*140*].

the bales-per-minute-per-operator never falls below 3 minutes as in equation 22. Operator costs are estimates by scaling the number of operators and multiplying by \$70,000/operator. See equation 23. Combining the operator labor cost estimate with equipment maintenance cost estimate yields a range between \$1.0 - \$10.6 /MWh_S which is consistent with the high EPRI cost estimate.

3.1.4.4.1 Sulfur Dioxide (SO_2)

Tests have shown that co-firing biomass and coal generally reduces SO_2 emissions in proportion to the amount of biomass fired [*122*]. Switchgrass does contain sulfur however; switchgrass sulfur uptake varies as a function of nitrogen fertilizing, harvest times, and frequency of harvest [*158*]. A laboratory test is required to determine exactly how much sulfur is present in a given switchgrass feedstocks.

For this research it is assumed that switchgrass contains 75% less sulfur than does coal. Switchgrass analyses report switchgrass sulfur content at roughly 0.2 percent by weight, or 95% less sulfur by weight than coal [*13, 159, 183*]. Equalizing for energy lowers this to roughly 90%. Assuming a 75% reduction is therefore a conservative assumption and is the assumed reduction rate used in this research. See equation 7 for emission reduction calculation and equation 26 for emissions value calculation.

A distribution was fit to historic SO_2 market prices. The median value of 230 \$/ton SO_2 was used. The distribution is described by a lognormal distribution with parameters of $\mu = 319.5$, $\sigma = 941.5$, shifted (+) by 126.3. Historic emissions values were provided courtesy of Melissa Gist, Amerex Emissions, Ltd.

3.1.4.4.2 Nitric Oxide & Nitrogen Dioxide (NO_x)

Early co-firing combustion testing focused closely on the production and emission of NO_x [*77*]. The effect biomass co-firing has on existing coal fired power plants' NO_x emissions varies between tests, but a reduction on NO_x emissions can generally be expected. Regressions have fit explanatory parameters to testing results for many different fuels, equipment, and test conditions [*160*]. Combining multiple biomass co-firing tests, which include multiple biomass fuels, a general NO_x reduction estimate is 75% of the biomass to coal co-fire rate [*159*]. This is the reduction rate assumed for this research. See equation 5 for emission reduction calculation, and equation 25 for emissions value calculation.

A distribution was fit to historic NO_x market prices dating between 4/18/2002, and 12/2/2005. The median value of \$3560/ton NO_X was used. The distribution is described by a Weibull distribution with parameters of $\mu = 5.68$, $\sigma = 3545.9$, shifted (+) by 280.46. Historic emissions values were provided courtesy of Melissa Gist, Amerex Emissions, Ltd.

3.1.4.4.3 Mercury (Hg)

Under that Clean Air Act, power plant mercury emissions are required to be reduced by 90% by the year 2008. The U.S. Environmental Protection Agency has estimated mercury emissions reduction costs to be between \$0.003 and \$3.0 per MWh equating to roughly 0.003% - 6% increase in average retail electricity prices[32] [*152*]. The Mercury Action Plan, implemented in the Northeastern U.S. and Canada in 1998, has successfully

[32] 2005 7-month average retail electricity prices: Minimum = \$53.8/MWh (Industrial); Maximum = \$89.4/MWh (Residential)[*51*].

demonstrated the electricity industry's ability to economically reduce its mercury emissions [*150*]. On March 15th, 2005, the U.S. Congress supported the Bush administration's proposal of mercury emission regulation delays when it passed the Clean Air Mercury Rule and the EPA's Clean Air Interstate Rule [*5*]. Under CAMR, power plants will be exempt from mercury controls until 2010. After 2010, a cap and trade mechanism is designed to reduce mercury emissions by 70% by the year 2018.

During the summer of 2005, health organizations opposed to the rulings filed law suits against the EPA demanding that the original Clean Air Act mercury reduction goals not be relaxed [*90*]. Despite the lack of federal leadership, states such as Pennsylvania might choose to join Northeastern states in regulating coal power plants' mercury emissions levels within their state [*148*]. No legislation has been passed yet.

Recent research has indicated that gas phase mercury is emitted naturally from ecosystems which would indicate that biomass might possess mercury [*115*]. The researchers suspect, but have not proven, that the gas phase mercury emissions measured from natural sources are most likely from coal combustion. They hypothesize that anthropogenic mercury is cycling through deposition and atmospheric reuptake many times, meaning that elemental mercury is likely remaining active for longer periods than previously suspected before being re-sequestered.

It is unclear when and to what degree the electricity industry will be required to control their mercury emissions. Because there is not a mercury emission regulation currently binding on coal fired power plants, a mercury emissions trading mechanism and market does not exist. Mercury emissions reductions are not included in the economic modeling performed by this research even though emission reduction estimates are possible.

It is assumed that switchgrass energy crops do not possess mercury [*159, 183*]. For this research, net mercury emissions reductions are estimated by scaling existing mercury emissions by the fraction of switchgrass energy co-fired.

See equation 8 for mercury reduction calculation, although no value is placed upon these reductions.

3.1.4.4.4 Particulate Matter (PM-10 & PM 2.5)

Particulate matter is not tracked by eGRID, and therefore is not included in the emissions reduction estimations. There is reason to believe that the production of particulate matter will increase with the combustion of switchgrass, although it is not fully understood how this would affect existing particulate matter emissions controls such as electrostatic precipitators and bag houses [*13*].

3.1.4.5 Engineering Economic Parameters

Purchased equipment is modeled as a capital investment and therefore financing assumptions are made regarding loan interest rates, loan periods, discount rates, and depreciation. It is assumed that the equipment capital costs are entirely financed over a period of 20 years at an interest rate of 15%. The annual cost calculation used in this research is the annual payment required by an amortization schedule for this period of time at this rate. It is assumed that there is no salvage value of the equipment at the end of the 20 year period.

3.1.5 Linear Programming Software & Computer Make and Model

The software used to perform all optimizations in this research is The Large-Scale Linear Program version 6.5 of Solver © produced by Front Line Systems [*62*]. Solver is manufactured as a Microsoft Excel software add-in, and the Large-Scale Linear Program is designed to handle an unlimited number of decision variables and constraints.

An IMB Thinkpad T41 using an Intel Pentium M Processor 1.6 GHz, with 1.5 GB of Ram was used for all processing. Microsoft's Windows XP Professional Version 2002, Service Pack 2 was the operating system.

3.1.6 Biomass and Coal Co-Firing Equations

Following is a presentation of the specific equations that evaluate individual power plants cost and benefits from co-firing switchgrass and coal.

Table 4 - Engineering & Environmental Performance Equations[33]

#	Equation	Description	Units
	Operations & Engineering Equations		
2	$CFR = \frac{E_s}{E_c} = \frac{1}{\frac{W_{ne} \times HR_c}{E_s} - \frac{1}{1+BEP}}$	Co-Fire Rate	%
3	$W_{ng} = \frac{E_s}{HR_s} + \frac{E_c}{HR_c}$	Output Constancy – No New kWh Generation under Co-Fire Scenarios	kWh
4	$E_s = \frac{HR_c \times W_{ne}}{\frac{1}{CFR} + \frac{1}{(1+BEP)}}$	Switchgrass Energy Input Requirement	MMBtu
	Environmental Performance Equations		

[33] See 3.1.1 Nomenclature for variable definitions

5	$ER_{NOx} = \frac{E_s \times AER_{NOx} \times RC_{NOx}}{2,000}$	NO_x Reduction - Annual	tons/yr
6	$ER_{O3} = \frac{E_s \times AER_{O3} \times RC_{O3}}{2,000}$	Ozone Reduction - Annual	tons/yr
7	$ER_{SOx} = \frac{E_s \times AER_{SOx} \times RC_{SOx}}{2,000}$	SO_x Reduction - Annual	tons/yr
8	$ER_{Hg} = \frac{E_s \times AER_{Hg} \times RC_{Hg}}{1,000}$	Mercury Reduction - Annual	lbs/yr
9	$ER_{CO_2} = \frac{E_s \times AER_{CO_2} \times RC_{CO_2}}{2,000}$	CO_2 Reduction - Annual	tons/yr

Table 5 - Co-Firing Economic Equations

#	Equation	Description	Units
		Operations Expenses	
10	$AC_{f\,s} = M_s \times C_{uc_S}$	Switchgrass Fuel Cost	(-) \$/yr
11	$AC_{f_C} = E_s \times C_{uc_C}$	Coal Fuel Cost Savings	(+) \$/yr
12	$C_e = W_{ne} \times CFR \times \begin{cases} \beta \\ \varsigma \\ \psi \end{cases}$	Equipment Cost - Total	(-) \$
13	$\beta = 100$	PC Boiler Capital Cost below and equal to 2% co-fire	$\$/kW_b$
14	$\zeta = 200$	PC Boiler Capital Cost between 2% & 10% co-fire	$\$/kW_b$
15	$\psi = 300$	PC Boiler Capital Cost above 10% co-fire	$\$/kW_b$
16	$\beta = 100$	Stoker, Cyclone, and Fluidized Bed Boiler Capital Cost below and equal to 10% co-fire	$\$/kW_b$

17	$\zeta = 200$	Stoker, Cyclone, and Fluidized Bed Boiler Capital Cost above 10% co-fire	$/kW_b$
18	$AC_e = C_e \times \left(P/_A, i\%, n\right)$	Equipment Cost - Annualized	(-) $/yr
19	$AC_t = FR \times \frac{E_s \times D}{14.682}$	Switchgrass Fuel Transportation Cost	(-) $/yr
20	$AC_m = C_e \times CF_{,m}$	Additional Maintenance Cost	(-) $/yr
21	$Opr = \mathrm{ROUND}\left(\frac{HrOp_a}{2{,}000}\right)$	Number of Operators	People
22	$\alpha_o = \left(1 + ROUND\left(\frac{M_S}{30 \times HrOp_a}\right)\right)$	Additional Operator Scalar	
23	$AC_o = \alpha_o \times Opr \times CF_{,o}$	Additional Operations Cost	(-) $/yr
24	$AC_{total} = AC_{f\,S} + AC_{f\,C} + AC_e + AC_t + AC_m + AC_o$		(-) $/yr
	Monetized Environmental Benefits		
25	$EI_{NOx} = ER_{NOx} \times EV_{NOx}$	NO_x Credit	(+) $/yr
26	$EI_{SOx} = ER_{SOx} \times EV_{SOx}$	SO_x Credit	(+) $/yr
27	$EI_{total} = EI_{NOx} + EI_{SOx}$		(+) $/yr
	Cost of CO_2		
28	$EC_{CO_2} = \frac{ER_{CO_2}}{AC_{total} + EI_{total}}$	Estimation of the expense associated with the reduction of a unit of CO_2 emissions	$/ton-$CO_2$

3.2 Scenarios

Three scenarios are chosen for their respective ability to address different co-firing objectives

- Scenario 1: All coal-fired power plants co-fire switchgrass and coal at their maximum rate before the installation of a separate biomass feed system is required (2% for PC boilers, 10% for non-PC boilers).
- Scenario 2: All available switchgrass[34] is consumed and total cost is minimized.
- Scenario 3: All available switchgrass[35] is consumed and total carbon emissions are minimized regardless of costs.

These three scenarios are chosen for their ability to determine costs at the low end (Scenario 1), determine maximum benefit at minimum cost (Scenario 2), and maximum benefit regardless of cost (Scenario 3).

3.2.1 Scenario Optimization Mathematical Definitions

- Scenario 1 – No installations of separate biomass feed systems

  Objective Function:

$$\min : \sum_{cpp=1}^{n} \left(AC_{Total} + EI_{Total} \right)_{cpp} \qquad \textbf{Equation 29}$$

  Constraints:

$$CFR_{cpp} = \xi \times E_{cpp} \qquad \textbf{Equation 30}$$

$$\sum_{cpp=1}^{n} M_{S,\,ecf,cpp} \leq M_{ecf} \qquad \textbf{Equation 31}$$

Scenario 1's objective function minimizes the sum of all actual costs plus total emission incomes for all coal fired power plants contained in the model. This objective is

[34] All available switchgrass is the amount of available switchgrass at 50$/ton as estimated by the ORNL POLYSIS model.
[35] All available switchgrass is the amount of available switchgrass at 50$/ton as estimated by the ORNL POLYSIS model.

subject to two constraints: (1) that all power plants must co-fire as much switchgrass as they can before a separate biomass feed system is required. (2) Switchgrass farms can not supply more switchgrass than they are estimated to grow.

- Scenario 2 – Minimize Total Costs

  Objective Function:

$$\min : \sum_{cpp=1}^{n} \left(AC_{Total} + EI_{Total} \right)_{cpp} \qquad \textbf{Equation 32}$$

  Constraints:

$$CFR_{cpp} \leq E_{cpp} \qquad \textbf{Equation 33}$$

$$\sum_{cpp=1}^{n} M_{S,\,ecf,cpp} = M_{ecf} \qquad \textbf{Equation 34}$$

Scenario 2's objective function minimizes the sum of all actual costs plus total emission incomes for all coal fired power plants contained in the model. This objective is subject to two constraints: (1) all power plant co-fire rates must be less than or equal to 100%. (2) All switchgrass growth capacity must be used.

- Scenario 3 – Minimize Total CO_2 Emissions

- Objective Function:

$$\max : \sum_{cpp=1}^{n} \left(ER_{CO_2} \right)_{cpp} \qquad \textbf{Equation 35}$$

Constraints:

$$CFR_{cpp} \leq E_{cpp} \qquad \textbf{Equation 36}$$

$$\sum_{cpp=1}^{n} M_{S,\,ecf,cpp} = M_{ecf} \qquad \textbf{Equation 37}$$

Scenario 3's objective function minimizes CO_2 emissions. This is achieved my maximizing the amount reduced. This objective is subject to two constraints: (1) all power plant co-fire rates must be less than or equal to 100%. (2) All switchgrass growth capacity must be used.

3.3 Scenario Results

Cost and benefit estimations for co-firing switchgrass and coal within Pennsylvania and Iowa for the three optimization scenarios are presented in Figure 3 & Figure 4 respectively. For both graphs, the top X – axes are the total CO_2 reduction scales both in tons of CO_2 per year. The innermost bottom X – axes are the reductions scales relative to each state's total CO_2 emissions released by their electricity sectors. The outermost bottom X – axes are the reduction scales relative to the state's total CO_2 emissions released from all sectors. The Y – axes are total cost divided by total CO_2 scales ($/ton CO_2).

In both states, Scenario 1 offers the lowest costs but only a portion of the potential benefits. Scenarios 2 & 3 yield similar results in each state.

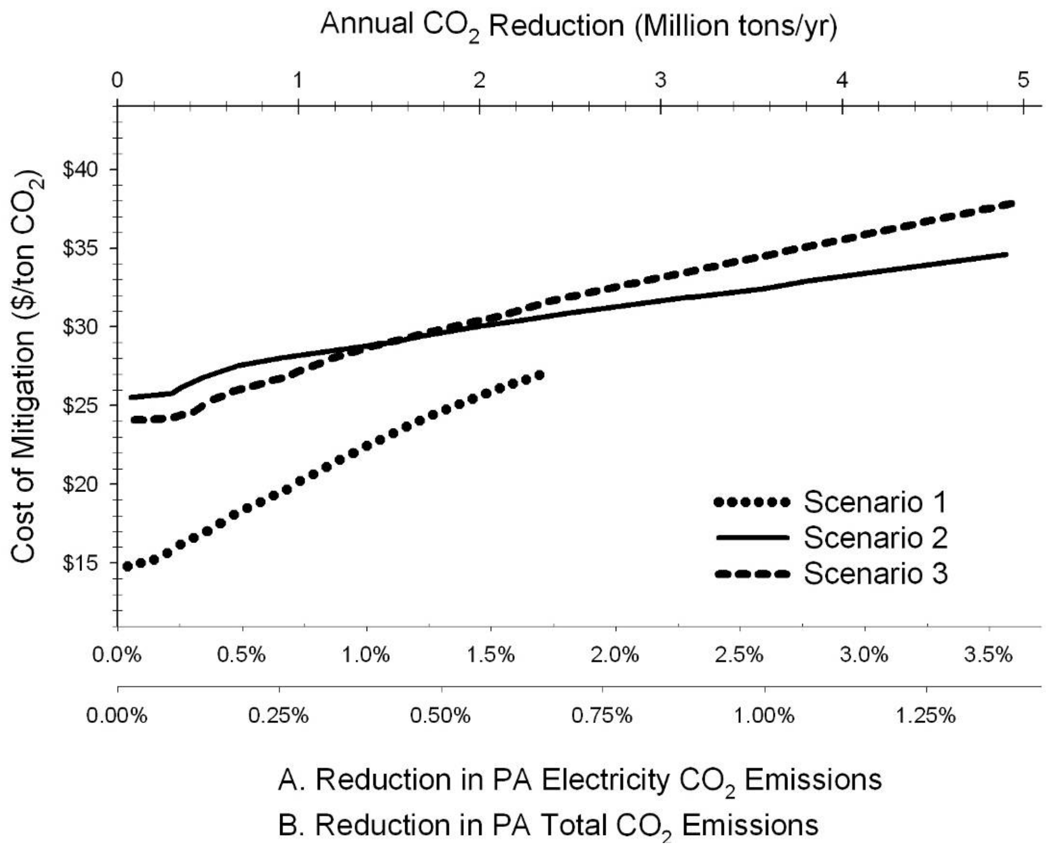

Figure 3 – Pennsylvania Farm Resolution Switchgrass and Coal Co-Firing Optimization Results (Average Costs)

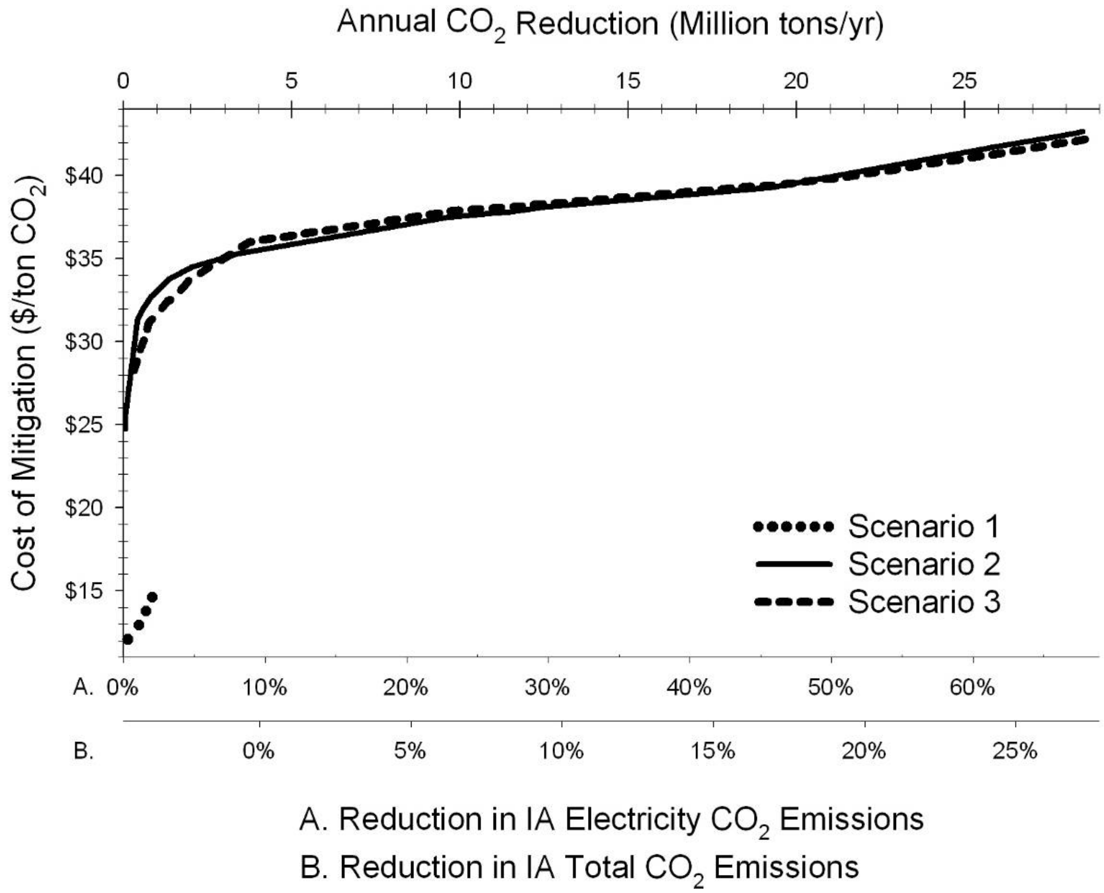

Figure 4 – Iowa Farm Resolution Switchgrass and Coal Co-Firing Optimization Results (Average Costs)

3.3.1 Pennsylvania and Iowa Scenario Results Discussion

The difference between the two state's ratios of switchgrass growth potential to coal based electricity generation[36] is an indication of the difference between the two state's scenario 1 results. Pennsylvania is home to a greater number of large power plants (above 1,000 MW) than Iowa. In addition, Pennsylvania has limited switchgrass growth potential when compared to its quantity of coal electricity generation; Iowa has the opposite. For these reasons, Pennsylvania can consume more switchgrass before its

[36] See Appendix A for state's ratio of switchgrass growth potential coal electricity generation.

power plants require separate biomass feed systems. Iowa can reach its limit while consuming only a fraction of its' potential switchgrass available. Because the total quantity of switchgrass required under this scenario is low in Iowa the switchgrass is relatively inexpensive[37] and typically located nearby the power plant. Pennsylvania, which has much more coal capacity than Iowa does[38], requires more switchgrass to meet scenario 1 constraints. In order to grow enough switchgrass Pennsylvania power plants must pay higher switchgrass prices (35$/ton in PA; 30$/ton in IA). Additionally, Pennsylvania plants have greater shipping distances and costs to meet their supply needs compared to Iowa (average 60 miles in PA, average 1 mile in IA).

When constraining the full consumption of all forecasted switchgrass growth (scenarios 2 and 3), Pennsylvania becomes the more cost effective CO_2 mitigating state. Iowa's switchgrass is located uniformly across the state[39]. The State's power plants are mainly located at the borders on 2 major rivers (the Mississippi and Missouri rivers) resulting in relatively high shipping when large amounts of switchgrass is consumed. On the other hand, Pennsylvania's plants are dispersed more uniformly throughout the State and as the demand for switchgrass increases average shipping distance drops to 46 miles as reflected in scenario 2 and 57 miles in scenario 3. This is much lower than the average shipping distance for Iowa of 74 miles for both scenarios 2 and 3.

For each state the cost and amount of CO_2 mitigation for are similar for Scenarios 2. Plant level CO_2 emissions are exclusively dependent on coal consumption. When coal is

---

[37] Switchgrass prices range from 30$/ton to 50$/ton. Iowa can satisfy scenario 1 with its 30$/ton switchgrass capacity.

[38] Within the optimization models, Pennsylvania has 20,000 MW of coal capacity, generating 106 GWh yr^{-1}. Iowa has 6,000 MW of coal capacity, generating 34 GWh yr^{-1}. See Appendix A for state's coal electricity generation statistics.

[39] See figure 9 in Appendix B for a depiction of switchgrass quantities available at 50 $/ton.

combusted, the quantity of CO_2 created per unit of coal[40] is a property of coal and does not vary widely between coal power plants. The average amount of CO_2 production from coal combustion is 203 lb CO_2/MMBtu of coal, with a standard deviation of 14.5 lb CO_2/MMBtu [*45*]. The LP model is based on energy, so switchgrass displaces coal on an energy basis. One ton of switchgrass displaces 0.68 tons of coal, on average, regardless of which power plant consumes the switchgrass. Therefore, minimizing total costs is very close to minimizing total CO_2 emissions. Figure 4 highlights this fact showing the approach produces very similar results.

Coals mined from different regions have different carbon, hydrogen, and mineral contents. This results in variations in CO_2 emissions when different coals are combusted (thus the 14.5 lb CO_2/MMBtu standard deviation mentioned above). Boilers are designed for a specific range of coal properties and often power plants establish long-term contracts with coal providers resulting in feedstock consistency for long periods[41]. If one power plant fires a higher carbon content coal its CO_2 emissions per MMBtus will be slightly larger than a power plant firing a lower carbon content coal. In scenario 3 for any given state if a power plant has a slightly higher CO_2 emission per energy input rate than the state's average and is one of the state's largest power plants then the model will maximize switchgrass to that particular plant. If a particular power plant is not located near cost competitive switchgrass the transportation costs will increase the co-firing economics of both this individual plant and the state's total.

For Pennsylvania, minimizing CO_2 emission results in higher mitigation costs than it does for Iowa. From the eGRID data, two power plants in Pennsylvania have much

---

[40] Pounds of CO2 emitted per million BTUs consumed (lb CO2/MMBtu)

[41] See Appendix E for a discussion of coal variations and the affect coal properties have on boiler design.

lower than average CO_2 emissions per energy input rate than the other power plants. These two power plants happen to be located near high cost switchgrass located in the southeast corner of the State. Because of the low emissions rate the model forces this switchgrass to be shipped some distance to plants having average lb CO_2/MMBtu ratios (Figure 4).

Iowa has two power plants that have lower than average lb CO_2/MMBtu ratios but these two plants are relatively small and located no closer to switchgrass than any other Iowa power plant. Therefore, reallocating any switchgrass to other plants has only minor impacts. Scenarios 2 and 3 are virtually identical for the state of Iowa.

Scenario 2 stands apart as the most informative scenario. Conclusions regarding the cost of benefits are identical in scenario 2 and 3. Scenario 1 simply provides a result that is somewhere between zero and the results of 2 and 3. For these reasons, it is concluded that scenario 2 provides the conclusive information regarding costs and benefits from wide spread switchgrass and coal co-firing.

3.3.2 Scenario Cost Component Discussion

Figure 5 compares Iowa's and Pennsylvania's respective co-firing cost components. In scenario 2 and 3, all components are lower in Pennsylvania than for Iowa, the opposite of the results from scenario 1. Regardless of state, capital costs, operation and maintenance costs, and transportation costs all very widely within all three scenarios from plant to plant. Although specific causes of variation are different for each cost component an LP model can force wide variations in individual cost components as the model searches for the allocation that results in the most optimum solution (for example, lowest total cost).

Different capacity factors[42] between power plants can affect capital cost variations. Capacity factors for individual plants were taken from the eGRID dataset and are constant for all optimization runs. Equation 12 defines capital equipment costs as the product of the co-firing rate, the plant size, and an equipment cost factor. Equation 2 defines the co-fire rate as the ratio of switchgrass energy to coal energy feed the boiler. When a power plant has a low capacity factor less coal energy is consumed reducing the denominator in equation 2. A relatively small quantity of annual switchgrass consumption will be modeled as a large co-fire rate. Because capital costs vary in direct proportion to co-fire rates, a plant with a low capacity factor will be assigned higher capital costs.

This might not accurately capture all considerations when co-firing. A highly depreciated coal plant that produces relatively expensive electricity and therefore has a high capacity factor would probably not invest in equipment modification capital. It would be more cost effective to allow the coal feed system to de-rate as biomass is feed through it rather than retrofitting a separate feed system. Allowing exemption from retrofitting would result in a less conservative cost estimation and is not allowed in the model.

Equations 20 and 23 define operations and maintenance cost components. Maintenance is modeled using a multiplier of capital equipment cost and operation costs are estimated using an economy of scale variable. Thus as switchgrass consumption

[42] Capacity factor is the portion of the year that a power plant is supplying electricity consumers (also known as the grid). Lots of factors ranging from scheduled and unscheduled maintenance, as well as a host of economic factors can cause capacity factors to vary between plants and between years. In general, a power plant's capacity factor is an indication of its economic ranking amongst other competing power plants within the power pool that its electricity supplies.

increases, operation costs rapidly diminish while maintenance cost increases. Operations are modeled as manpower required to handle switchgrass. If only small amounts of switchgrass are consumed then manpower is idle too often resulting in higher O&M costs per unit of switchgrass.

Equation 19 defines transportation costs as a freight rate times the distance a mass of switchgrass is transported. The further the transport distance, the larger the transportation cost.

The LP model searches all possible distribution possibilities and identifies the most optimal solution. All capital cost, O&M cost, emissions credits, and transportation cost for each power plant contribute to the solution. Increasing switchgrass allocated to one plant in an attempt to lower O&M costs will result in increased capital costs. If this plant is located near switchgrass, the transportation cost would be lower than if the nearby switchgrass where shipped elsewhere. In this manner, all three costs components are optimized by the LP. An optimal solution can mean some plants experience high O&M cost, but low transportation and capital costs. Likewise, high transportation costs can be worth lowering O&M costs. Thus there are the wide ranges in costs components in Figure 5.

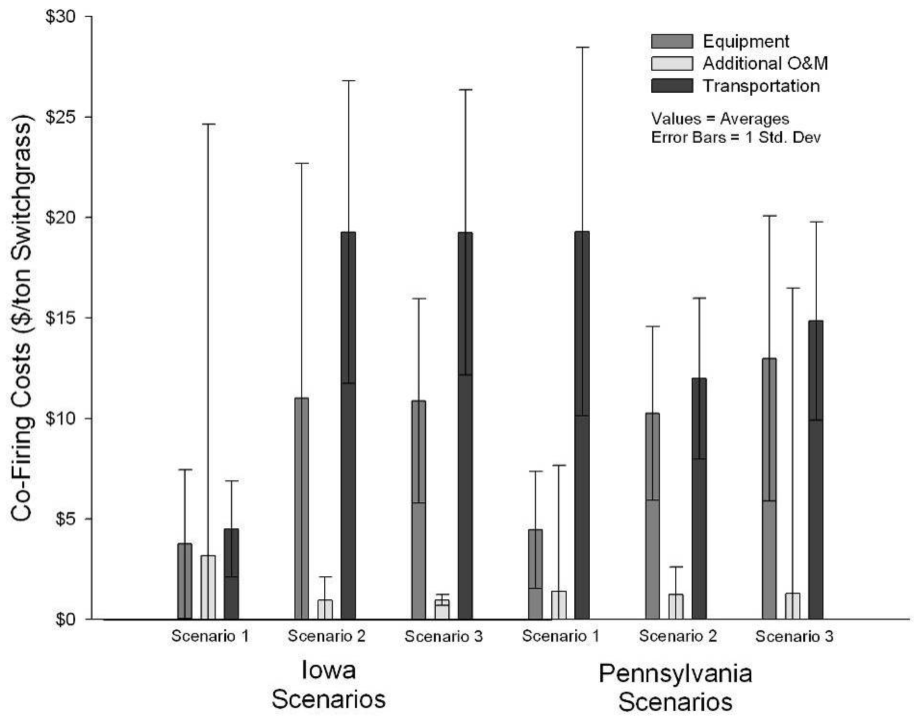

Figure 5 – Relative State Optimization Costs Components

3.3.3 LP Model Simplification

For the goal of accurately capturing transportation distribution options, the POLYSIS dataset was disaggregated from an Agricultural Statistical District (ASD) to the "farm" level. It was theorized that this resolution would result in a more accurate estimation of transportation costs. Approximately 4,000 farm representing nodes where generated from satellite data for each state. Each of the nodes was assigned a portion of the forecasted switchgrass production. The model consisted of roughly 20 power plants and 4,000 farms resulting in 80,000 decision variables.

As presented in Figure 5, shipping costs dominate the non-fuel costs for all scenarios in both states. To determine the accuracy gained by a farm-level model resolution, a coarser geographic resolution model was created and the same optimization scenario 2 applied.

A duplicate model was created based on counties rather than farms. The POLYSIS dataset was only disaggregated to the county level using the same procedure described in Appendix B. All of a county's switchgrass production was assumed to occur at the geographic center of each county and transportation distances were estimated as the distance between county centers and coal power plants. Distances are calculated using the same geometric algorithm as in the farm resolution models[43]. The coarser resolution required 100 county nodes in Iowa, and 67 in Pennsylvania.

As discussed above, only optimization scenario 2 was run for these models, and their results are compared to the farm-level resolution results in Figure 6 and Figure 7.

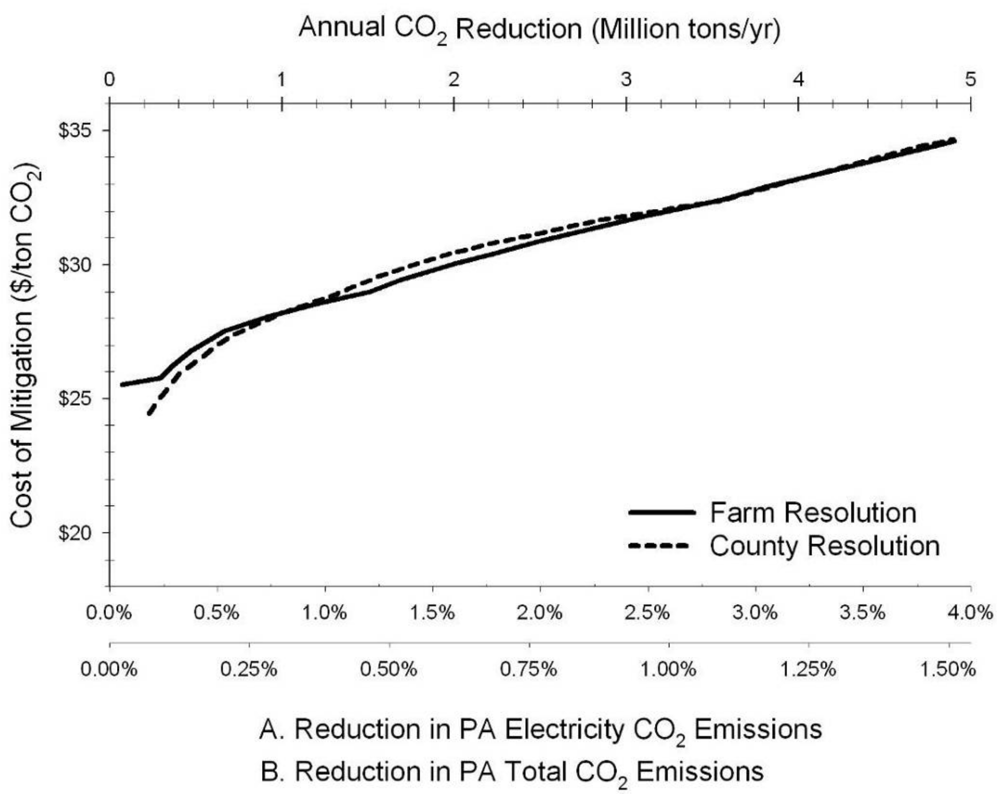

Figure 6 – Pennsylvania Farm and County Resolution Switchgrass and Coal Co-Firing Optimization Results (Average Costs)

[43] Direct distance is calculated using the Great Circle Radius formula.

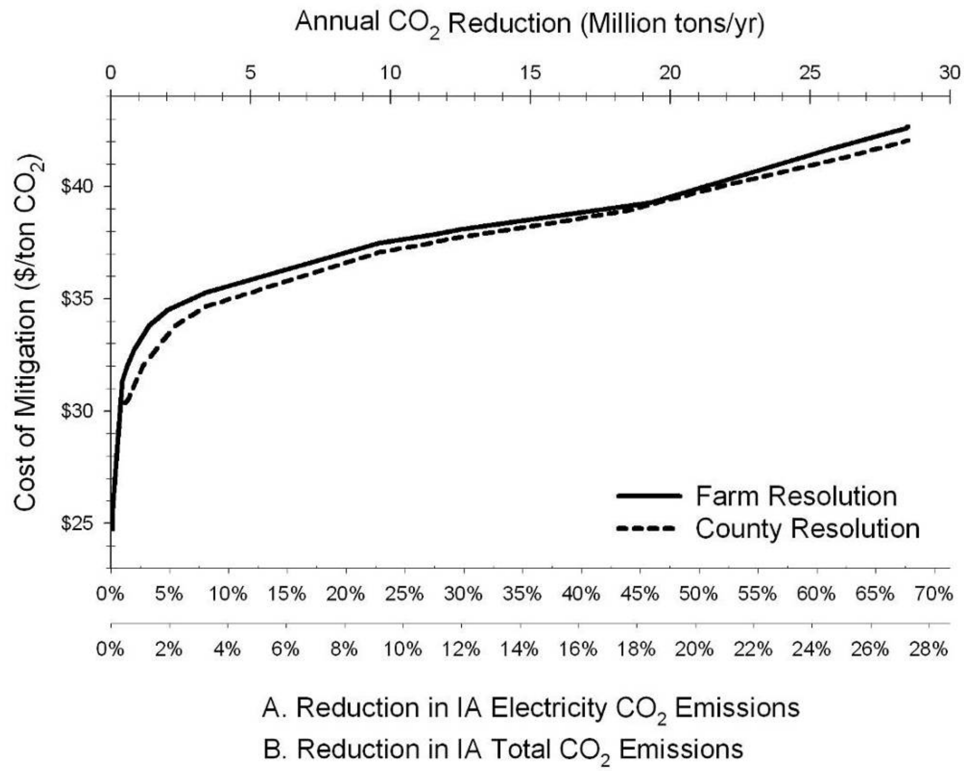

Figure 7 – Iowa Farm and County Resolution Switchgrass and Coal Co-Firing Optimization Results (Average Costs)

The results of the simplified geographical model are consistent with to those based on the farm resolution model. The much simpler resolution resulted in virtually identical results in both Pennsylvania and Iowa. With Pennsylvania and Iowa representing two extremes of switchgrass production capabilities and coal fired power generation capacity the simplification opened the possibility of modeling national or region co-firing.

3.3.4 Large-Scale Switchgrass and Coal Co-Firing Cost of Mitigation

There are 3,532 counties in the POLYSIS dataset that support switchgrass growth and 401 existing coal-fired power plants. The resulting linear program model would equal a little more than 1.4 million decision variables[44]. To limit the size of the model I broke the U.S. into three regions.

The regional boundaries were chosen to include rational groupings such as geographical similarities (for example the Ohio, Mississippi, and Wabash river valleys), however, despite this intension, the boundaries are arbitrarily drawn. Two separate arbitrarily drawn regional groupings were chosen so that comparisons could be made between the two.

The first set of regions, *A*, consists of: (1) A1, containing central states; (2) A2, containing southern states; and (3) A3, contains western states. The second set of regions, *B*, consists of: (1) B1, containing the Mississippi, Ohio, and Wabash River basins; (2) B2, contains all land to the east of B1; and (3) B3, contains all land to the west of B1. The region borders are shown in Figure 8.

The resulting cost and benefit curves are presented in Figure 9

[44] The pervious model were approximately 80,000 decision variables and took roughly an hour to processes.

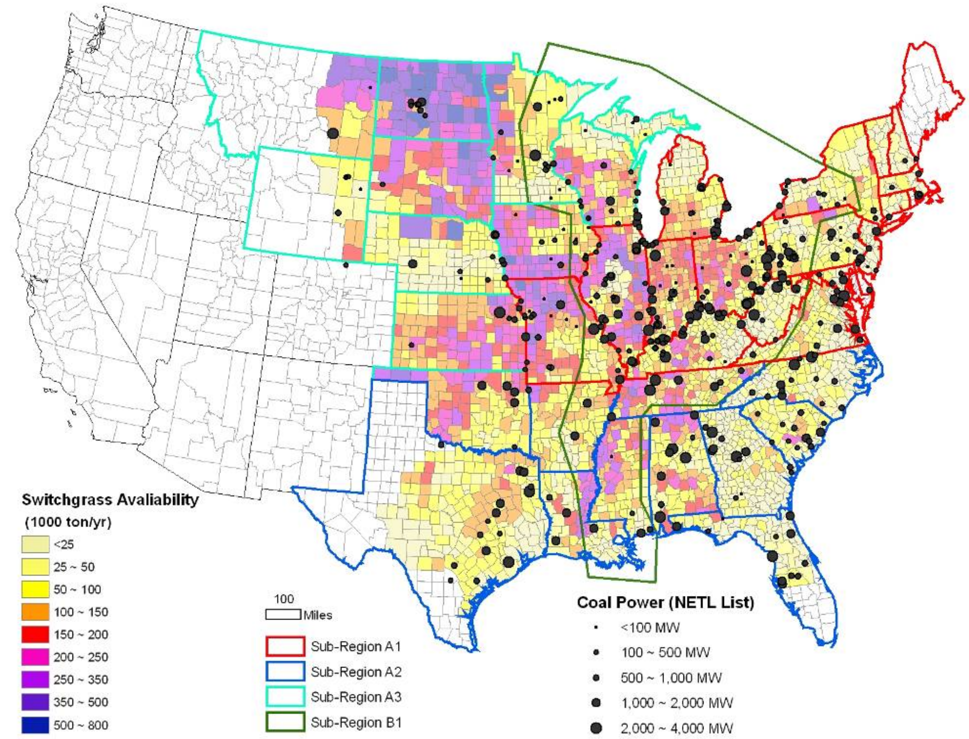

Figure 8 – Sub-Region Groups A & B; Divisions for National Scale Optimization Models.

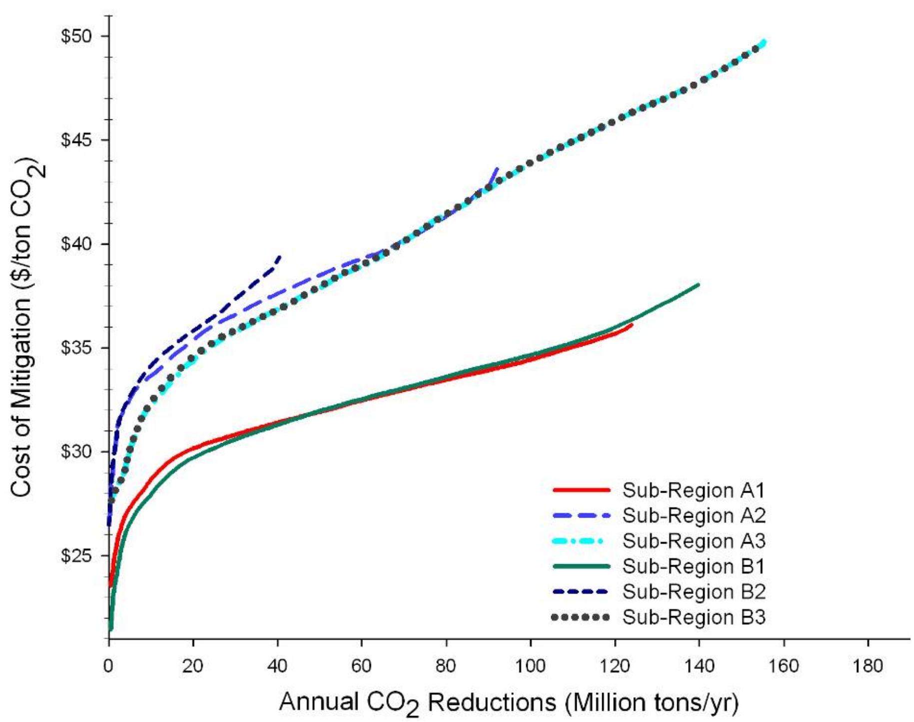

Figure 9 – Sub-Regions A1, A2, A3, B1, B2, & B3 Optimization Model Results (Average Costs)

Figure 10 shows total U.S. cost and benefit curves for the two sub-regional sets.

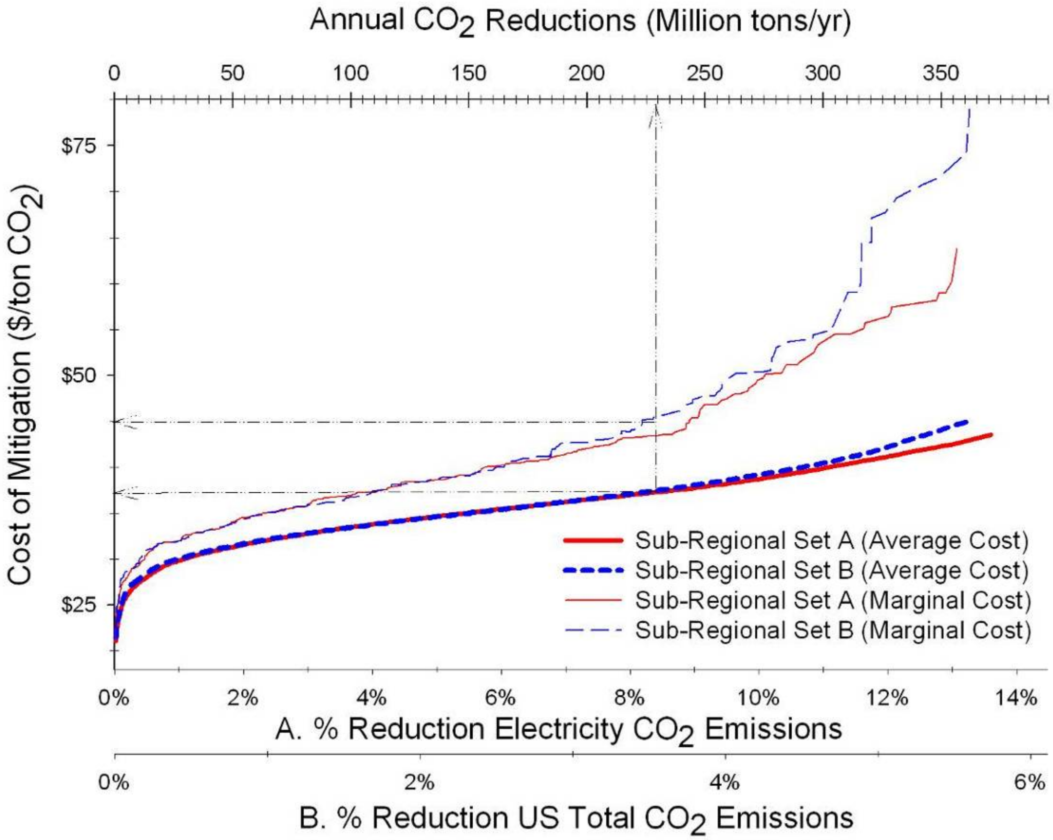

Figure 10 – U.S. Total (Sub-Region Groups A & B) Switchgrass and Coal Co-Firing Cost Curve & % CO_2 reduction

The fact that the total costs curves are relatively consistent indicates that the model produces results that are mostly insensitive to regional boundaries even though experiencing modest marginal cost sensitivities.

The marginal cost curves in Figure 10 indicate that some plant costs are sensitive to regional divisions. For example, regional grouping B resulted in more plants with higher costs than in group A. At approximately 38 \$/ton CO_2 average (45\$/ton CO_2 marginal and 230 million tons of switchgrass consumption) the costs of mitigation increased quickly. Because switchgrass prices are constant the rapid increase in marginal cost at this point results from both the most expensive power plants consuming switchgrass and the most isolated switchgrass being consumed. Comparing the farm models and the regional models indicate that state based modeling arbitrarily creates boundaries that alter cost results. For example, within regional group A, the sum of costs for Pennsylvania is 62% of the costs estimated by the Pennsylvania alone model; Iowa is 112%. Considering the history of both state borders and the location of power plants a consistent theme emerges: rivers. Coal power plants are historically located along rivers so that inexpensive water can be used for cooling by the thermal cycle used to produce electricity. In many states, such as Iowa, state borders are defined by rivers. Modeling a state by itself artificially limits the switchgrass to intrastate production. Cheaper, closer switchgrass might be just on the other side of the boundary river. Regardless of modeling boundary, there will be power plants that are more expensive to co-fire because of their own performance constraints and/or their location relative to switchgrass.

3.3.5 Large-Scale Switchgrass and Coal Co-Firing Cost Components

A general set of estimation parameters, based on the optimization results are presented in Figure 11. The costs components would likely apply when estimating total regional co-firing economics for other biomass feedstock in addition to switchgrass.

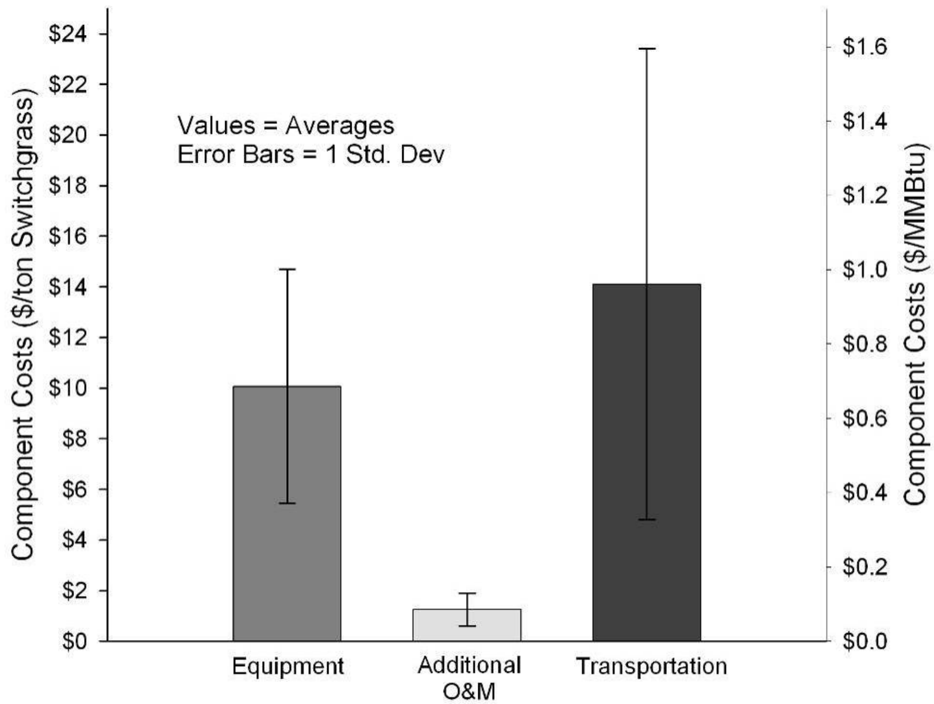

Figure 11 – Region Sub Set A Switchgrass and Coal Co-Firing Cost Components

3.3.5.1.1 Modeling sensitivities

The estimation of co-firing economics is insensitive to geographic model resolution. Modeling switchgrass proximity to existing coal fired power plants using farm locations versus county aggregated locations produces identical economic forecasts. This conclusion means that simple, coarse resolution modeling is sufficient for capturing regional or national co-firing economics.

It is hypothesized that coarse resolution is sufficient in capturing regional transportation economics regardless of the material being shipped.

3.3.5.1.2 Results sensitivities

Co-firing switchgrass with coal in existing coal capacity infrastructure offers modest electricity sector carbon reductions at relatively low costs. .However, switchgrass co-firing is not the only option for existing coal plants. An estimation of CO_2 reductions due to co-firing wood and agricultural suggests that 250 million tons CO_2 per year could be avoided at a price of roughly $20, +/- 10 $/ton CO_2 [*132*]. It is possible that co-firing lower costs feedstocks would affect switchgrass co-firing economics. As demand for biomass feedstocks increase the lower costs feedstocks will naturally be the first consumed. Assuming an existing coal plant has access to and co-fires to its chosen limit with cheaper biomass quantities, higher cost biomass feedstocks such as the switchgrass modeled here would possibly need to be shipped further distances to reach a different power plant, resulting in an increased transportation cost. Therefore, it is anticipated that the results presented here are sensitive to the availability of lower costs biomass feedstocks and are likely lower costs estimates because of this sensitivity.

Figure 12 presents the effect that switchgrass price has on total economics from this modeling. Oakridge's switchgrass availability dataset assumes uniform prices across the entire United States, with regional quantities varying. Varying the price, while assuming the quantity does not change, is essentially moving the average costs curve up and down the Y-axis. The bottom curve in Figure 12 presents the costs of transportation, equipment and additional O&M alone, or the economics excluding switchgrass prices, coal prices, and emissions credits. Moving the price of switchgrass below the bottom curve (roughly 20 $/ton switchgrass at farm gate, or equal price of coal plus emissions credits) will result in some power plants having negative total costs. Once power plants experience negative total costs, that is, profits, new optimization solutions would be available which will alter the general solution presented by the cost curve in Figure 12.

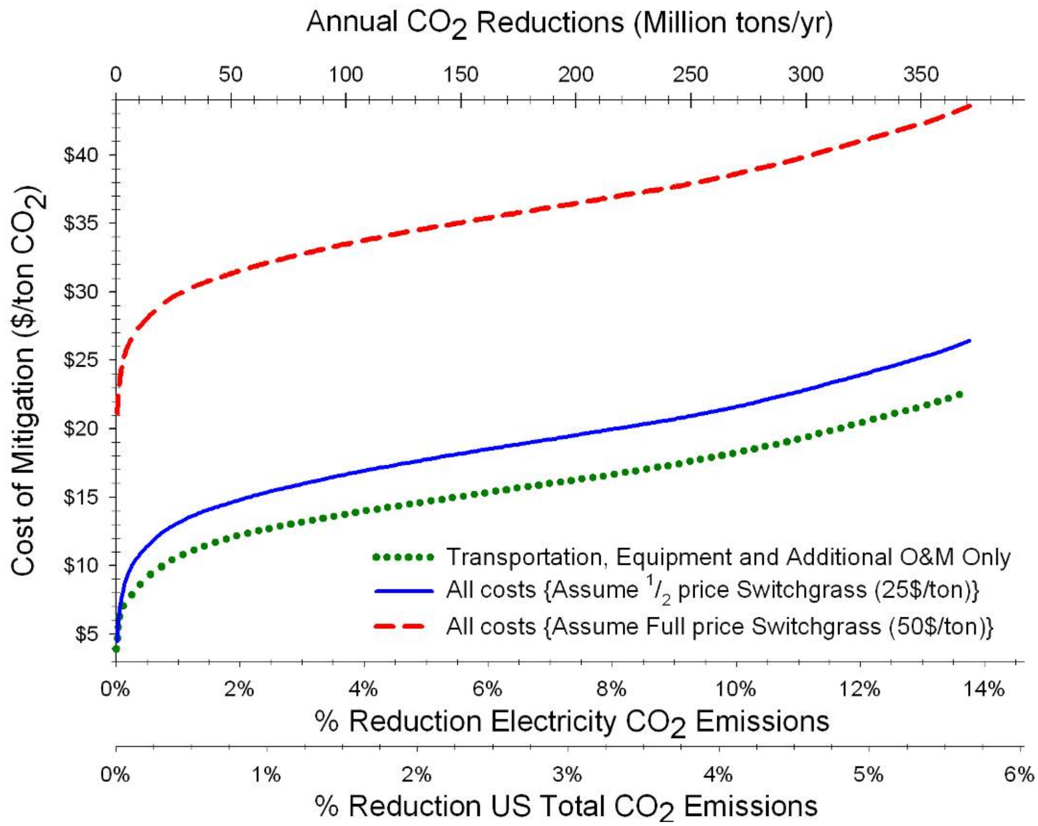

Figure 12 – Sub-Regions A; variable cost of switchgrass feedstocks

3.4 Concluding Comments

Co-firing switchgrass and coal in existing coal-fired power plants does allow existing power plants an option for the reduction of their greenhouse gas emissions. The cost of doing so will vary directly with biomass costs, required biomass transportation, power plant equipment modifications, additional O&M, and power plants' performance characteristics.

If large-scale biomass and coal co-firing is to take place, transportation will cause some biomass resources to be more expensive than others assuming all non-shipping things equal. Some biomass resources would likely be stranded despite large scale biomass electricity production initiatives. For this reason, estimations of social benefits derived from biomass resource utilization must include cost curves. The marginal costs of achieving the most expensive benefits could result in an exclusion of those benefits from ever being realized. Thus the exclusion of costs will mislead the public in their assessment of potential benefits from bioenergy initiatives

Chapter 4 Cost of Carbon Mitigation for Future Cellulose Ethanol Derived from Switchgrass Feedstocks

4.1 Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States

Methodology and resulting estimations for large-scale ethanol transportation distribution costs have been published [*105*]. This paper is reprinted Appendix E – "Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States".

This chapter develops a method for estimating the cost of carbon mitigation using ethanol to displace gasoline. The data used to develop the cost estimation is the same data used in the Morrow et al. article.

4.2 Cost of Mitigation: Cellulosic Ethanol Derived from Switchgrass

4.2.1 Introduction

When ethanol is substituted for gasoline, it is the price difference between gasoline and ethanol that becomes the true cost (or benefit) to consumers. For example, if ethanol can be purchased for the same price as gasoline can be purchased (on an energy basis), then a consumer will experience the same utility (transportation mobility) with no difference in cost. When this is the case, because ethanol (assumed to be carbon neutral) provides the energy for transportation mobility instead of gasoline, the carbon that would have otherwise been emitted to the atmosphere was mitigated for no cost. A unit of carbon mitigation in this case is purchased at the price of 0 \$/ton CO_2. For this reason, mitigating transportation carbon emissions through the use of an alternative energy source will be accounted for according to the following definition: the difference in costs for an equal amount of utility divided by the quantity of carbon reduction, provided carbon emissions are reduced[45].

Estimating a cost of CO_2 mitigation from the transportation sector using cellulosic ethanol requires an estimation of three variables: cellulosic ethanol costs, gasoline costs, and the quantity of CO_2 abated when cellulosic ethanol is substituted for gasoline. For this analysis, cellulosic ethanol and gasoline costs will be pump costs, which include all of the costs required to deliver a unit volume to a consumer at the pump (raw material feedstock, refinery cost, and transportation). We thus ignore taxes and retail costs. The gasoline cost will be subtracted from the ethanol costs. Because gasoline is related to the price of crude oil in the world market, carbon mitigation using ethanol will also be related to the price of crude oil.

4.2.2 Estimating Future Prices

Cellulosic ethanol is not currently produced on a consumer level; production and delivery costs must be estimated. Future production cost estimations range from 1.50 $/gal [*177*], if produced by present technologies, to 1.07$/gal, based on technology advancements anticipated by 2010 [*2*], to 0.39 $/gal by 2015 [*107*]. It must be noted that the 2015 estimate of production cost is based upon a plant size of 20,000 tons of biomass per day, which will be difficult to achieve based on feedstock limitations. Ethanol plants

[45] This definition does not suggested that a money pump is possible, and for this reason, if carbon is not reduced, then no mitigation has taken place, and the accounting will not assume a payment going to the consumer.

at this size will not be common [*105*]. Upstream transportation costs are included in the production cost estimates; however, downstream transportation costs are not[46]. Downstream transportation costs will likely range between 0.12 - 0.45 $/gal ethanol [*105*].

Figure 13 presents imported crude oil prices and U.S. gasoline rack prices[47] between January 1st, 1998 and March 17th 2006 [*46*]. As Figure 13 indicates, gasoline prices roughly follow crude oil prices but the difference between prices is not constant. Crude oil and gasoline are traded in separate markets; the former, in a world market subject to world supply and demand, the latter, strictly in a U.S. market. The U.S. gasoline price varies as it follows both crude oil prices and unique U.S. supply and demand issues. U.S. gasoline supply and demand issues vary based on local factors which crude oil prices are insensitive to, i.e., seasonal and locational gasoline demand variations, previous gasoline reserves, demand for other refinery co-products, natural disasters, etc. [*53*].

---

[46] Upstream transportation is the transportation of raw material (crude oil, or switchgrass) from a well (or farm) to a petroleum (or biomass) refinery. Downstream transportation is the transportation which delivers refined products (gasoline or ethanol) to retail establishments (fuel filling stations).
[47] Rack Price is the refinery gate price, or wholesale gasoline prices.

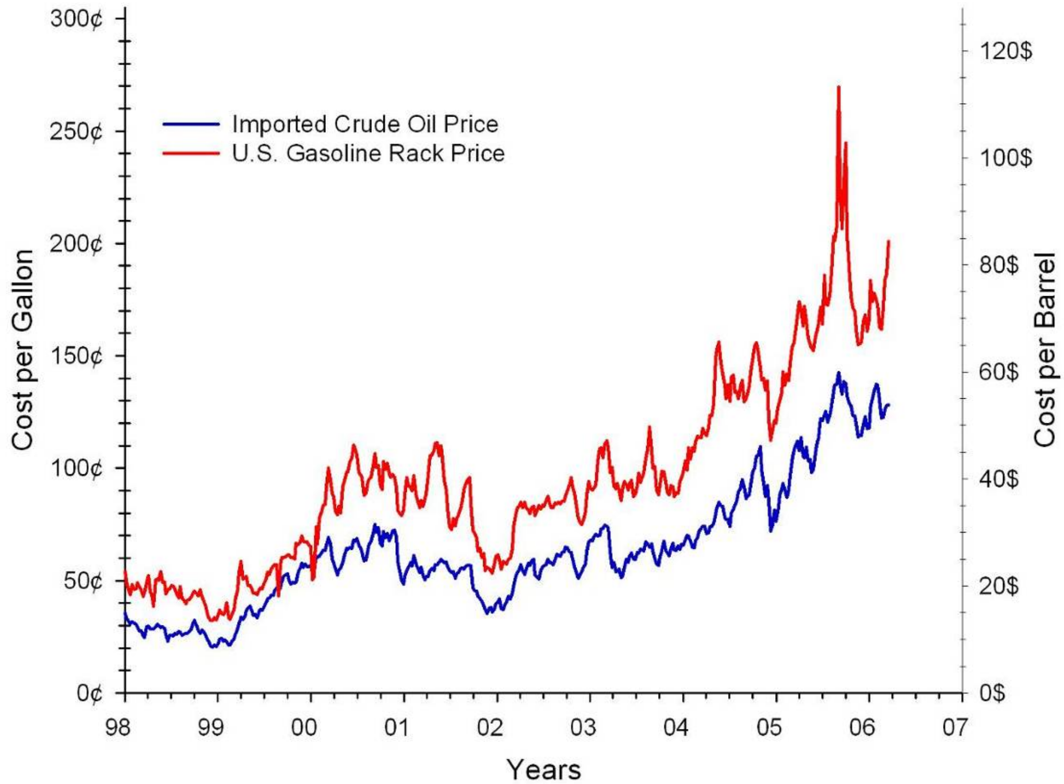

Figure 13 – Weekly Imported Crude Oil Prices and Gasoline Rack Prices
Data Source: EIA – Crude Oil Spot Price: United States Spot Price FOB Weighted by Estimated Import Volume; Gasoline Spot Price: United States Gulf Coast Conventional Gasoline Regulare Spot Price FOB

Figure 14 contains a histogram of the price differences between gasoline and crude oil presented in Figure 13. A probability distribution is fit to the price difference and is also shown in Figure 14. Both the histogram and distribution were generated using @Risk (version 4.5) and BestFit® as part of the DecissionTool Suite (version 4.5) by Palisade Inc. [*119*]. Future gasoline prices will be modeled as equal to future crude oil prices plus this estimation of refinery charges.

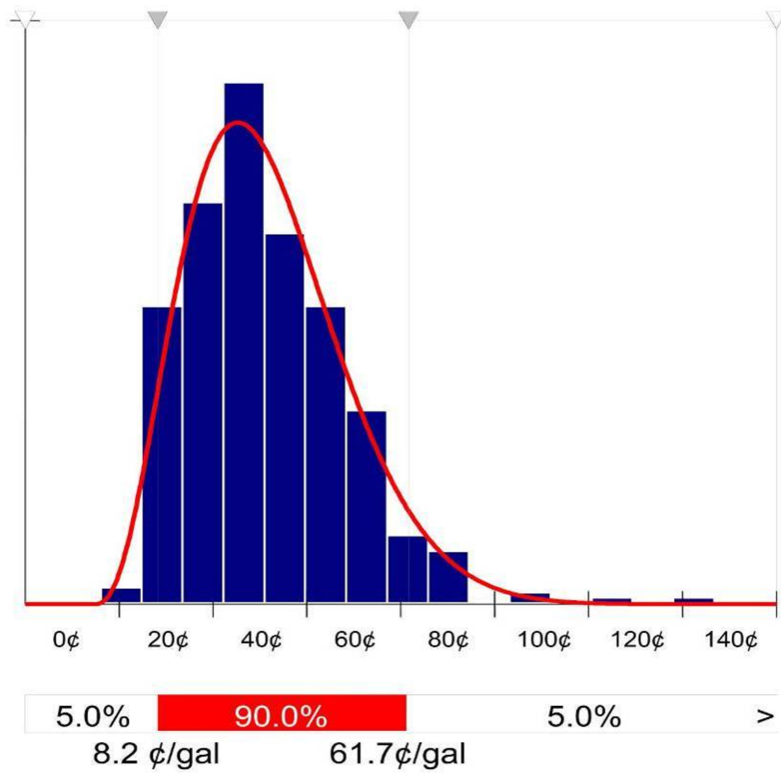

Figure 14 – Histogram and Probability Density Function for Difference between Gasoline Rack Price and Crude Oil Price ($/gal). Distribution Function = Beta General with Parameters α1 = 3.89, α2 =15.31, Min = -5.57, Max = 178.03 The average refinery cost equals 31.6 ¢/gal

Including all historic crude prices between 1861 and 2004, the average crude oil price is roughly 24$/bbl[48] in 2004 dollars. However, during the year 2005, crude oil prices in the U.S. ranged between 40$ and 60$/bbl [*46*]. As of March 24th, 2006, crude oil prices have not fallen below 50$/bbl as of May 2006 [*46*]. Crude oil prices are forecasted to fall to 47$/bbl by 2014, then rising to 57$/bbl by 2030 [*55*]. When considering relevant sensitivities (the accuracy of the United States Geological Surveys' reporting of world oil reserves and differing market share assumptions regarding OPEC and non-OPEC production), the year 2014 price forecast ranges between a low of 34$/bbl and a high of

[48] bbl is short for barrel. 1 bbl = 42 U.S. liquid gallons

76$/bbl. These forecasts are made by the U.S. Department of Energy's Energy Information Administration (EIA). Accurately forecasting future commodity prices is difficult, and EIA has historically made inaccurate forecasts [*86, 114*]. The wider range of future crude oil prices is used in this analysis.

Future gasoline prices are related to future crude oil price, plus the refinery charge.

$$P_{\text{gasoline}} = \frac{P_{\text{Crude Oil}}}{42} + \Phi \qquad \textbf{Equation 38}$$

Where $P_{gasoline}$ is the price of gasoline and in dollars per gallon, $P_{crude\ oil}$ is the price of crude oil in dollars per barrel, and Φ is the refinery charge modeled by the distribution Beta-general (α1=3.98, α2=15.31, Min = -5.57, Max = 170.03).

$$\Delta P = \frac{P_{\text{ethanol}}}{ER_{\text{ethnaol to gasoline}}} - P_{\text{gasoline}} \qquad \textbf{Equation 39}$$

Where $P_{ethnaol}$ and $P_{gasoline}$ are the prices of cellulosic ethanol and gasoline respectively in dollars per gallon, and $ER_{ethanol\ to\ gasoline}$ is the energy ratio between ethanol and gasoline[49].

Figure 15 presents the resulting cumulative distribution function (CDF) curve for the cost difference between ethanol and gasoline as presented by Eq 1 & 2. The CDF curve is generated using a Monte Carlo simulation[50]. Crude oil price is modeled using a triangular distribution with parameters 34$/bbl, 55$/bbl, 76$/bbl to reflect the range of estimates in EIA's forecasts. Ethanol price is modeled using a triangular distribution with parameters (0.39$/gal, 1.07$/gal, 1.50$/gal) based on the literature cited above. Triangular distributions are chosen because they require the least amount of supporting

[49] The HHV of gasoline = 126,000 Btus; HHV for ethanol is 87,000 Btus; the ratio is 0.696.
[50] The Monte Carlo simulation uses a latin hypercube sampling type, with an expected value recalculation setting, and a randomly chosen random seed generator.

assumptions. Triangular distributions assume that the high and low prices are the least likely price, and that the middle price is the most likely. Prices in between the middle and the high or low prices are represented by linear interpolation. Downstream shipping costs are excluded from this calculation, as this calculation only provides a comparison between refinery gate prices for ethanol relative to gasoline. Downstream shipping costs are included later in the analysis when estimating a cost of mitigation for cellulosic ethanol[51].

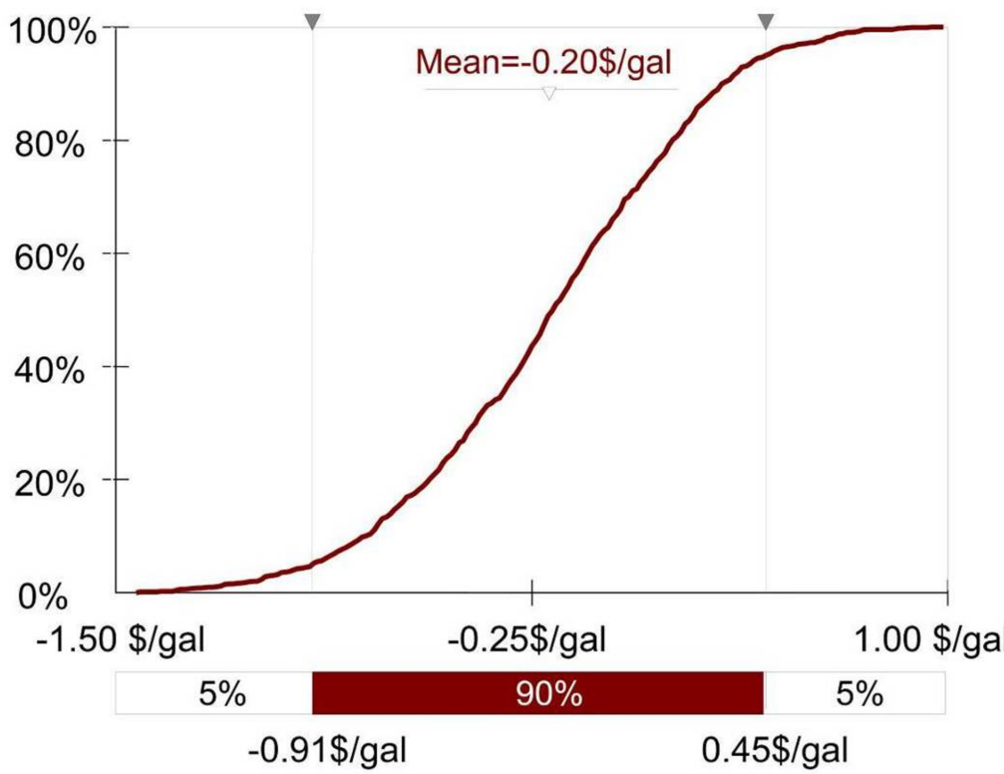

Figure 15 – Cumulative Distribution Curve for the Difference between Cellulosic Ethanol and Gasoline Prices ($/gal)

Interpreting Figure 15, future ethanol will be, on average, 20 ¢/gal cheaper than gasoline. 90% of the time ethanol will be between 91 ¢/gal cheaper and 45 ¢/gal more expensive than gasoline. Belief in the future cost ranges for ethanol production and

[51] Average downstream shipping for gasoline (0.005$/gal) is equal

world crude oil presented in the last paragraph is a pre-requisite for belief in these estimations.

The first cellulosic ethanol plant built will likely produce ethanol at 1.50 $/gal. If crude oil prices are roughly 50 $/bbl, cellulosic ethanol will be equal to gasoline, assuming the average gasoline refinery cost identified in Figure 14 of 31.6 ¢/gal. If crude oil prices are above roughly 50 $/bbl, then cellulosic ethanol will be cheaper than gasoline.

The results presented in Figure 15 are only as valid as the simple relationships presented by Equation 38 & Equation 39 between world crude markets, U.S. gasoline market, and a future U.S. cellulosic ethanol market are valid. It is recognized that a greater level of complexity exists between fossil fuel markets and the future cellulosic ethanol market, but a rigorous economic analysis of actual complexities is not the objective of this engineering research. This general relationship between crude oil, gasoline, and ethanol prices is intentionally left elementary.

Gasoline CO_2 emission rates are calculated using the assumption that all the carbon present in gasoline is completely oxidized to CO_2. The weight of gasoline is 6.5 lb/gal, of which 80%, or 5.2 lbs, is carbon. Assuming that each carbon atom will be combined with two oxygen atoms during combustion, the conversion ratio between carbon and CO_2 weight is 44/12. Thus, one gallon of gasoline is responsible for roughly 19 pounds of CO_2[52].

[52] This is validated by Rubin and Davidson who calculate a stoichiometric conversion of gasoline to CO2 ratio of 352/114. At 739 grams per gallon of gasoline, 19.3 lbs of CO2 is created from stoichiometric combustion of one gallon of gasoline [*134*].

Ethanol's CO_2 emission rate is dependent on the process by which the ethanol is produced. In general, energy derived from a cellulosic feedstock is considered climate neutral because its carbon is taken from the atmosphere and, upon its use, returns to the atmosphere [*17*]. However, because the United States' current corn-based ethanol industry uses fossil energy to power the corn-to-ethanol conversion process, corn ethanol is not considered carbon neutral or sustainable [*58*]. Researchers modeling a cellulosic ethanol process believe that cellulosic feedstocks will not only provide all necessary process energy but will also result in excess electricity that can be sold to the grid. Arguing that this additional electricity, which would also be carbon neutral, will offset electricity sector carbon emissions, researchers assume that consuming cellulosic ethanol will account for a negative CO_2 emission rate of 13% [*2*]. This research is focused on switchgrass derived ethanol, which would be cellulosic ethanol and therefore a negative ethanol carbon emission rate of 13% will be used.

19 lbs of CO_2 are emitted through the combustion of gasoline. Using ethanol, which is carbon neutral, instead of using gasoline, 19 lb of CO_2 plus 13% equals 21.5 lb CO_2 avoided per gallon of gasoline. Ethanol is not as energy dense as gasoline; therefore, a gallon of ethanol only displaces 68.3% of a gallon of gasoline. Thus, each gallon of ethanol only mitigates 14.7 lb/ CO_2. The emission factor for cellulosic ethanol is negative 14.7 lb CO_2/gal of ethanol.

It is noted that additional greenhouse gas emissions associated the gasoline production cycle do exist and are not included in this research. Including life-cycle analysis into the carbon accounting technique widens the boundary envelope. Including the entire carbon economy using an economic life-cycle tool such as Carnegie Mellon University's EIO-

LCA [*68*] is valid, but if used to estimate total fuel related carbon emissions (such as from the production process), then many more items should be included as well (such as the construction of ethanol plants, petroleum refineries, pipelines, new tanker cars & trucks, etc.). While a life-cycle analysis is a valid technique, keeping this analysis as simple as possible provides a basic comparison of alternatives without complex modeling. If the results presented here do warrant additional complexity, then this research should inspire life-cycle analysis of the costs and benefits of the competing technologies analyzed here.

Dividing the cost of ethanol in the cumulative density function of Figure 15 by the quantity of CO_2 displaced by ethanol yields a COM unit cost range. Interpreting Figure 15 in terms of time, near-term costs are likely to be higher than longer-term costs because ethanol production costs are anticipated to decline as processing experience increases. The near/longer timeframe is based on ethanol learning curve forecasted in previous references (through the year 2015). This assumes that crude oil prices remain within the modeled range of 34 to 76 $/bbl as forecasted by the U.S. Department of Energy [*55*]. 90% of the time, the COM will be between negative 123 and positive 61 $/ton CO_2. As stated in this section's introduction (first paragraph), negative costs of COM do not mean that the consumer receives a payment. Instead, negative costs indicate that COM will not only be free, but that this technology option is economical without a carbon value. In terms of costs for benefits, the range will be zero to 61 $/ton CO_2. 66.5% of the time, the cost of carbon mitigation from ethanol use will be free.

4.2.3 Establishing a COM for a Large-Scale Switchgrass Based Ethanol Distribution Scenario

Using a linear program, downstream transportation costs for large-scale ethanol distribution have been estimated and results are presented in the first thesis paper titled "*Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States*" [*105*]. For that analysis, several scenarios of ethanol production were evaluated, and that paper presents transportation cost estimates for varying ethanol production rates, assuming differing transportation modes (rail versus truck). For that body of research, a linear program was developed for the estimation of downstream transportation costs.

Because shipping ethanol from production locations to consumption locations will not be trivial, the carbon emissions required for ethanol distribution will be subtracted from the carbon mitigated by ethanol consumption. The two modes of transportation for ethanol distribution will likely be rail or truck; both are powered largely by diesel fuel . Diesel weighs 7.06 lb/gal, of which 86% is carbon, such that 6.07 lb of carbon exists in a gallon of diesel. Assuming complete combustion, the carbon present in diesel is converted to CO_2 by the ratio 44/12. A gallon of diesel yields 22.25 lb CO_2 upon consumption. In 2003, trucks traveled 138 million miles in the U.S., and 27 million gallons of diesel fuel were consumed, resulting in roughly 5 miles to the gallon [*24*]. Assuming that trucks will return from ethanol deliveries with empty tank trailers, and assuming that very few miles currently traveled by the trucking industry are no-load trips[53], it will be generally assumed that mileage efficiency is doubled (10 miles/gal) for return no-loads. Thus, for every ten miles of ethanol shipping, 3 gallons of diesel fuel are

[53] This assumption implies that 5 mpg is the average price for load trips and does not include no-load trips. Assuming that no-load trips are frequent will require an alteration of the 5 mpg assumption in order to compensate for the higher fuel efficiency when tractors are not pulling a load.

consumed, resulting in 66.75 lb CO_2 emissions. Typical tanker trailers carry 8,000 liquid gallons [*131*]. 8,000 gallons of ethanol is 27.2 tons, equaling 0.11 lb CO_2/ton-mile, or 5.6 x 10^{-5} ton CO_2/ton-mile of ethanol shipped.

Rail cars average 9.3 miles for each gallon consumed [*24*]. As with truck hauls, it will be assumed that returning takers require half the diesel fuel, and thus will be assigned half the carbon emissions. Rail tanker cars carry 30,000 gallons each [*131*]. 30,000 gallons of ethanol equals 99 tons, equaling 0.02 lb CO_2/ton-mile, or 8.3 x 10^{-6} ton CO_2/ton-mile of ethanol shipped. As indicated in the previous section, life-cycle greenhouse gas emissions for both truck and rail are not included in this analysis.

Output from the linear program can be used to determine an average cost of mitigation curve. A cost of mitigation curve is only generated for the maximum ethanol production scenario (E16) modeled during the ethanol transportation and distribution modeling.

Equation 3 describes the COM curve calculation. In this calculation, all demand locations (j) are ranked from least expensive shipping cost to most expensive shipping cost.

$$COM_j = \frac{(\Delta P + R_{\text{mode}}) \times \sum_{j=1}^{m} \sum_{i=1}^{n} (V_{ij} \times D_{ij})}{EF_{ce} \times \sum_{j=1}^{m} \sum_{i=1}^{n} V_{ij} - EF_{trans} \times \varphi \times \sum_{j=1}^{m} \sum_{i=1}^{n} (V_{ij} \times D_{ij})}$$

Equation 40

COM_j is the average cost of mitigation for cellulosic ethanol in dollars per ton CO_2. As ethanol production/consumption rises, COM_j will vary in proportion to the marginal transportation distance required to get ethanol to a consumer. V represents the volume produced at ethanol plant location *i* shipped to consumers located at *j*. D is the distance between *i* and *j*. ΔP is defined by Equation 39. R_{mode} is the freight shipping rate dependent on mode (0.07$/ton-mile rail; 0.22 ton-miles truck) [*105*]. EF_{ce} is the cellulosic ethanol emissions factor presented above (15 lb CO_2/gal ethanol used). EF_{trans} is the shipping specific emissions factor presented

above (0.02 ton CO_2/ton-mile rail; 0.24 ton CO_2/ton-mile truck). φ is a conversion factor for gal-miles to ton-miles (6.8/2000).

$$\Delta P = \frac{P_{\text{ethanol}}}{ER_{\text{ethnaol to gasoline}}} - P_{\text{gasoline}} \qquad \textbf{Equation 41}$$

Where Pgasoline is the price of gasoline and in dollars per gallon, $Pcrude_{oil}$ is the price of crude oil in dollars per barrel, and Φ is the refinery charge modeled by the distribution Beta-general (α1=3.98, α2=15.31, Min = -5.57, Max = 170.03).

Figure 16 presents the cumulative costs associated with carbon mitigation using ethanol derived from switchgrass. The inner X – axes is the quantity mitigated scale in tons of CO_2 per year; the outer X – axis is the percentage of carbon reduced scale benchmarked against the 2004 U.S. gasoline related CO_2 emissions. The Y – axis is the cost of mitigation scale in dollars per unit of emission mitigated. Because of the previously discussed uncertainty regarding the future cost of mitigating the U.S. transportation sector's carbon emissions through the use of ethanol, a range in costs are presented. This range is based on the range presented in Figure 15. Shown are the two 95% confidence boundaries, and the 50% value. For each of these three values, costs associated with truck or rail transport are shown.

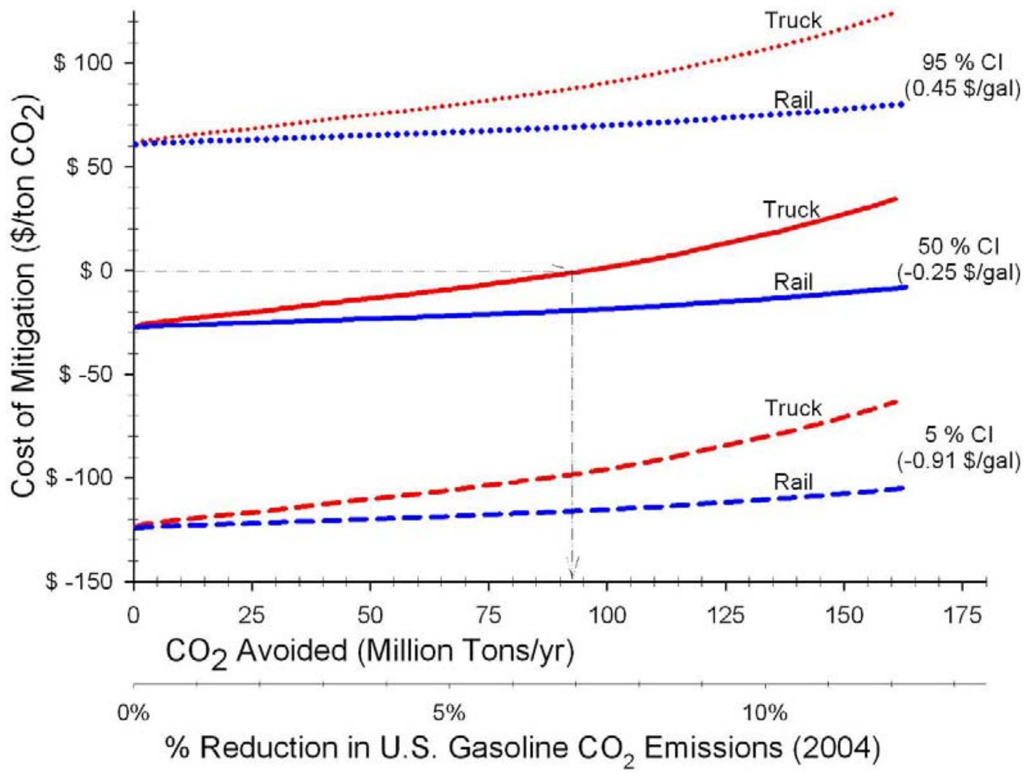

Figure 16 – Cumulative Distribution Curve for Cost of Mitigation (\$/ton CO_2) Estimation using Uncertain Cellulosic Ethanol and Gasoline Prices (\$/gal)

More carbon is abated as more ethanol displaces gasoline. As more gasoline is displaced, more ethanol must be distributed. The optimization modeled in Morrow et al. assumes a uniform blending rate across the lower 48 states, and thus as more carbon is mitigated, the costs per unit of mitigation increase as a reflection of the increase transportation require for the ethanol to reach a consumer. Thus, each curve pair (truck and rail) in Figure 16 indicates the transportation costs associated with ethanol distribution. In each pair, the truck curve mitigates slightly fewer carbon emissions because truck transport is more carbon intensive than rail transport (2.2 million tons CO_2 per year).

The cost range of cellulosic ethanol, as discussed previously, is anticipated to decline as experience in ethanol refining leads to subsequently less expensive processes. Applying time to Figure 16, the most likely near term carbon mitigation from cellulosic ethanol would be the top curve pair. As process costs decline with time, cellulosic ethanol's COM likely pass through the confidence range. Over the time period estimated (through 2015), COM will be free 66.5% of the time resulting in approximately a 93 million tons of transportation carbon reduced for free each year.

Chapter 5 Additional Analysis Issues

5.1 Costs and benefits of using switchgrass to mitigate U.S. carbon emissions

Comparing the carbon mitigation benefits of alternative uses of switchgrass as an energy feedstock is a goal of this research and thesis. Figure 17 summarizes the modeling results. It shows the cost of mitigating carbon emissions with different modeling assumptions. The inner most X – axis is the quantity mitigated scale in tons of CO_2 per year; the middle X – axis is the percentage of carbon reduced scale benchmarked against the 2004 U.S. gasoline related CO_2 emissions and the outer-most X – axis is the percentage of carbon reduced scale benchmarked against the 2004 U.S. electricity CO_2 emissions. The Y – axis is the cost of mitigation scale in dollars per unit of emission mitigated. All X – axis are broken such that the electricity emissions are presented without reducing the ethanol emissions portion of the graph.

Co-firing switchgrass and coal offers over twice the carbon reductions as ethanol production does at more certain costs. Mitigating carbon emissions through the production of ethanol required more risks because ethanol mitigation costs are related to crude oil prices. Electricity mitigation costs are related to coal prices which are much more stable historically than are crude oil prices.

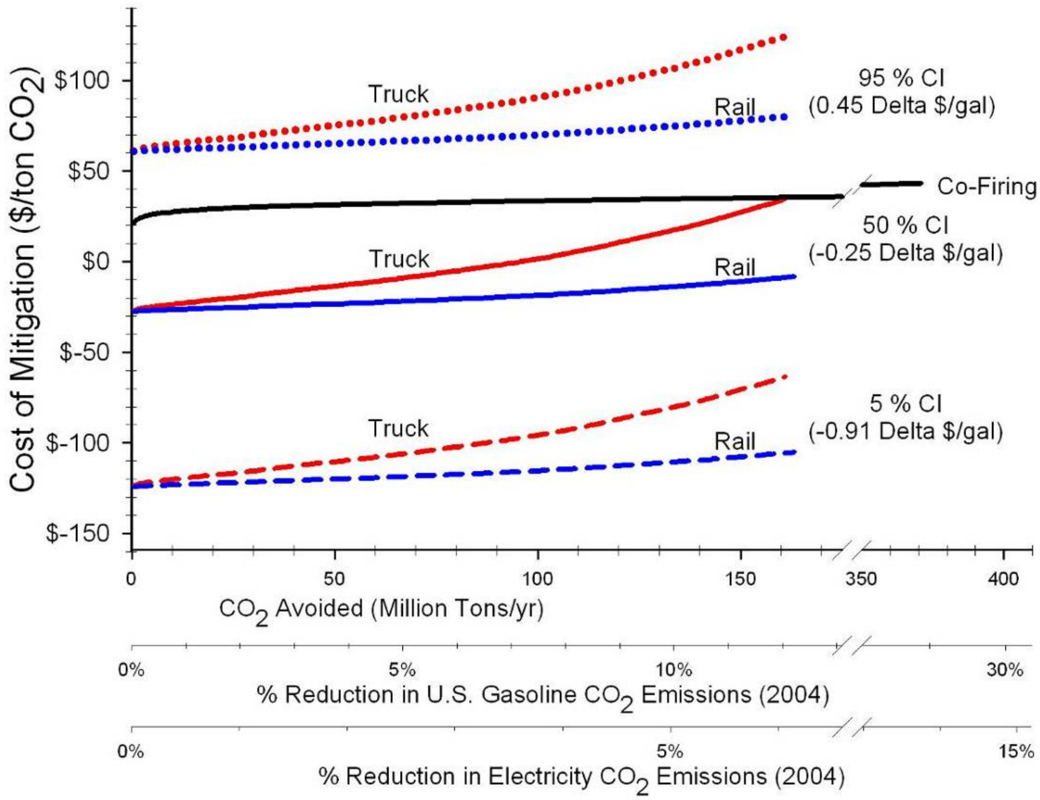

Figure 17 – Cost of Mitigation for Switchgrass Derived Cellulosic Ethanol and Switchgrass and Coal Co-Firing

However, lowering carbon emissions is not the only consideration germane to a choice between these two technologies and how best they can improve U.S. environmental performance. Additional issues relevant to bioenergy use are addressed below in the following sections.

5.2 Comments Regarding Co-Firing, Carbon Capture Retrofitting, or New Plant Construction

5.2.1 Analysis of Federal Renewable Tax Credits and Switchgrass and Coal Co-Firing Economics

The Energy Policy Act of 1992 created a federal renewable tax credit of 1.5 ¢/kWh for each kWh of electricity generated from "closed loop" biomass [*162*]. "closed loop" biomass is defined as an energy crop which would apply to the switchgrass feedstocks used in this research. The Energy Policy Act of 2005 supports the continuation of this tax credit and allows it to be correct for inflation [*163*]. Using the consumer price index, the renewable tax credit for closed loop biomass use should be roughly 1.9 ¢/$kWh_{biomass}$ in 2006. Figure 18 shows three curves, all representing an increase in electricity prices required to compensate switchgrass and coal co-firing power plants.

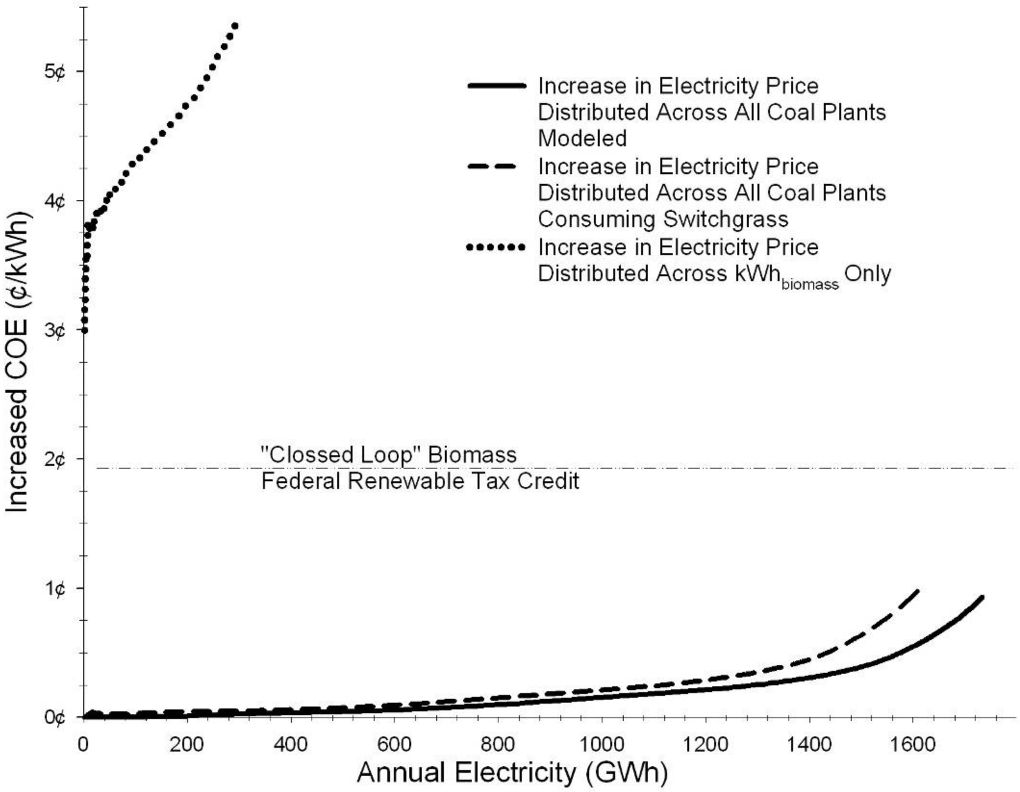

Figure 18 – Switchgrass and Coal Co-Firing Effects on Electricity Prices

The "Increase in Electricity Price Distributed Across All Coal Plants Modeled" curve divides the total cost of producing electricity from switchgrass as presented in Chapter 3 of this research across all the kWh produced by all the coal fired power plants within the model. The "Increase in Electricity Price Distributed Across All Coal Plants Consuming Switchgrass" curve divides the total costs across all the kWh produced only at those power plants which consume switchgrass. Lastly, the "Increase in Electricity Price Distributed Across ¢/kWh$_{biomass}$ Only" curve divides the total costs across all the kWh produced by switchgrass alone. This case "Increase in Electricity Price Distributed Across ¢/kWh$_{biomass}$ Only" are the kWh eligible to receive the federal renewable tax credit. The 1.9 ¢/kWh federal tax credit is roughly one third the price required to co-fire switchgrass and coal as indicated in Figure 18. Thus, it is concluded that the federal renewable tax credit wills not compensate coal-fired power plants the expense of co-firing switchgrass.

5.2.2 Geographic Variations in Co-Firing Economics

Regional differences confound the determination of a federal renewable tax credit for "closed loop" biomass energy production (see Figure 19). Suppose the renewable tax credit is set to compensate electricity producers for their investments in a greenhouse gas reduction strategy, but not so much that a windfall subsidy is created. For example, if the tax is increased 2.5 times its current value (to roughly 5 ¢/$kWh_{biomass}$) only a fraction of Sub-Region A3's available switchgrass would be consumed, while in Sub-Regions A1 and A2 switchgrass and coal co-firing electricity plants would receive substantial revenue increases when exercising this closed loop biomass renewable tax credit.

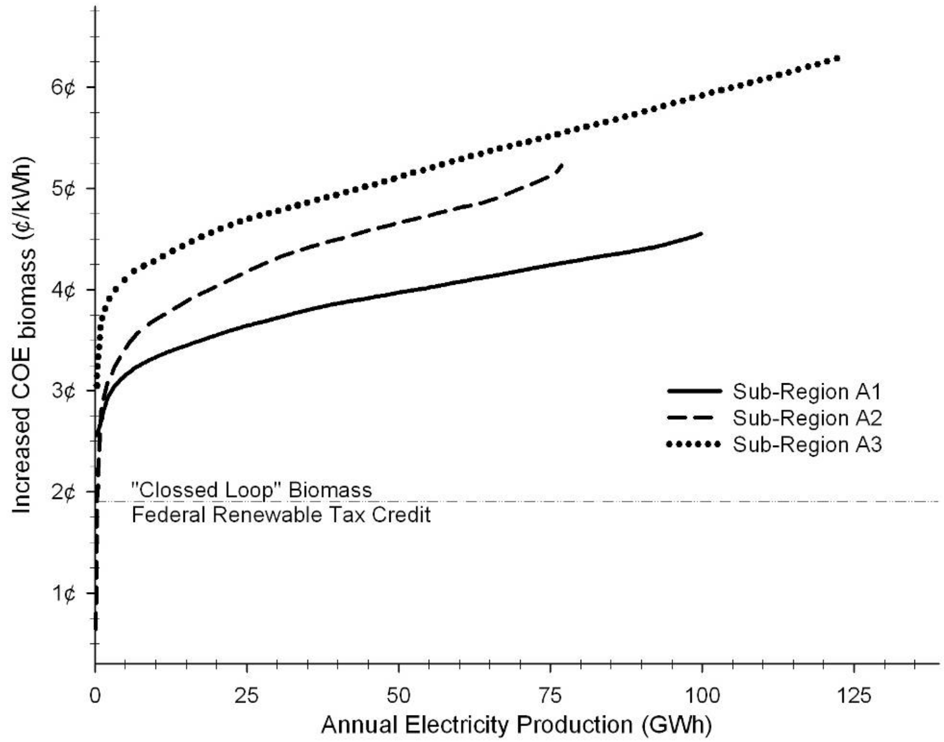

Figure 19 – Regional Switchgrass and Coal Co-Firing Effects on the Price of Electricity Produced from "Closed Loop" Switchgrass

This issue of setting an appropriate tax credit rate is eliminated in a carbon market where carbon value would determine the compensation to coal plants choosing to co-fire. The six optimization cost curves presented in Figure 9, and the three $COE_{biomass}$ curves in Figure 19 highlight the conclusion that the lowest cost switchgrass and coal co-firing will take place in the heavy coal regions of the Mississippi & Ohio River basins. This conclusion is also supported by the lower cost curve for Pennsylvania than for Iowa (presented in Figure 3 & Figure 4). As indicated in Figure 5, the transportation costs are much greater on average in the Midwest states and this is the case in the Southern states also. As illustrated in the United States switchgrass and coal map (Figure 9), Midwest states such as North and South Dakota posses small amounts of coal capacity and large amounts of switchgrass growth potential. The coal capacity within these states is not as dispersed as the switchgrass growth potential , requiring large shipping expenses when shipping from farms to power plants. Some Southern states, such as Alabama, have relatively dispersed power plants yet the larger switchgrass potential counties still require large shipping distances for their switchgrass to reach a coal power plant. Other Southern states (Georgia and Florida) have small switchgrass production forecasts, evenly distributed across the state, but they also require relatively large shipping distances to reach a coal power plant.

5.2.3 Co-Firing, Carbon Capture Retrofitting, or New Plant Construction

All electricity load serving enterprises have their own unique set of financial constraints. Constraints result from choices already made and the choice of goals and strategies for the future. Without specific knowledge of individual enterprises' constraints, making general statements about what they should or should not do with existing coal-fired load serving assets is best kept simple. In general, several policy and technical factors should be considered by owners of existing coal fired power plants including:

1. The timing of carbon constraining legislation or renewable portfolio standards
2. The age and life expectancy of existing coal-fired boilers, turbines, and generators and the anticipated price of carbon emissions
3. New source review status
4. Land and geographical constraints

5.2.3.1 The Timing of Carbon Constraining Legislation or Renewable Portfolio Standards

The time-scale for carbon constraining legislation is not known and any forecast is a guess. The American public is still apprehensive about risks involved with climate change. Only one in three Americans believe that climate change will pose a threat in their lifetime, and climate change ranks eighth in a list of ten environmental issues that Americans worry about [*137*]. Individual states are moving forward with measures to limit or control carbon emissions (see Figure 20). Perhaps the efforts of state legislators will act as forum for carbon mitigation debate and will define legislative measures that are acceptable at a national level [*125*]. Or perhaps, legislative efforts at state levels will not pass and carbon emissions will not be constrained for many years to come.

Renewable Portfolio Standard (RPS) legislation has been enacted in many coal-firing states. In general, RPS's require a certain portion of the electricity produced within a state to be generated from a renewable source such as wind, photovoltaic, or bioenergy [*57*]. Perhaps the most successful program has been in Texas where investments in wind generation capacity allowed renewable targets to be successfully reached.

Until legislation which restricts carbon emissions is enacted, and as long as state RPS's mandates can be achieved, there is no reason to invest in carbon reducing technologies.

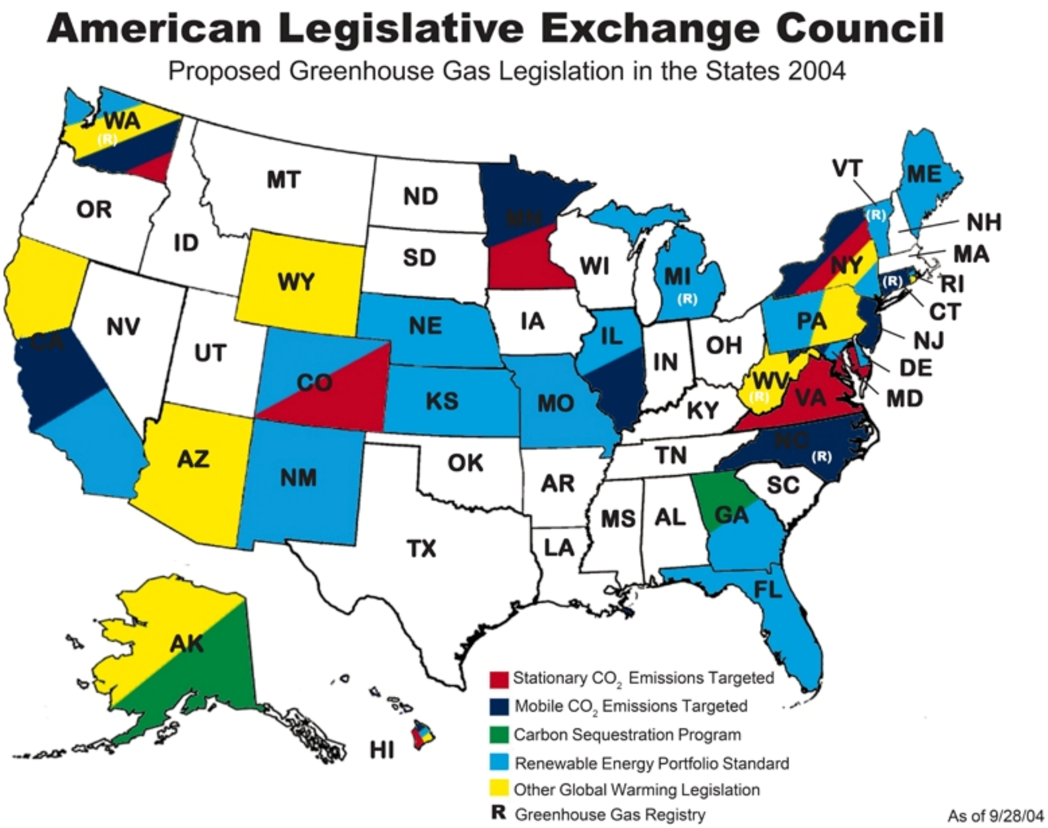

Figure 20 – Status of Carbon emissions related legislation as of 2004
Source: American Legislative Exchange Council [*3*]

5.2.3.2 The Age and Life Expectancy of Existing Coal-Fired Boilers, Turbines, and Generators

If it is believed that carbon mitigation legislation will become effective after the retirement of a coal-firing asset, then no carbon limiting action would take place for a profit maximizing firm. If it is believed that carbon constraints will become binding before retirement of the asset, then a risk analysis should be performed to determine the tipping price of carbon above which investments in carbon reduction technologies becomes advantageous. As presented in this research, the average cost of carbon mitigated by switchgrass and coal co-firing ranges from \$25 to \$50 per ton of CO_2

avoided, with marginal costs up to $75 per ton CO_2. If it is believed that under carbon constraining legislation, carbon price will stay below $25 per ton CO_2, then switchgrass and coal co-firing will cost more than buying permit.

The method used to estimate switchgrass and coal co-firing costs assumed no salvage value with a twenty year capital depreciation at fifteen percent annual interest. A coal-firing asset owner should expect a higher COM if co-firing equipment's useful lifetime would be reduced due to boiler, turbine, or generator life expectancies.

5.2.3.3 New Source Review Status

At present it is unclear if modifications to allow switchgrass and coal co-firing will cause the U.S. EPA to re-classify an exempt power plant as a New Source Review status. However, if an existing plant is re-classified, then substantial costs might be incurred to meet the New Source Review standards. Because this is a topic that existing power plants have a history of fighting EPA over [*123*], a plant owner will likely seek legal assistance in the determination of the New Source Review status.

5.2.3.4 Land and Geographic Constraints

As presented in Figure 12, the largest costs for co-firing switchgrass and coal, other than the purchase of switchgrass itself, is the transportation of switchgrass from fields to power plants. An obvious way to reduce this cost is through the establishment of long term contracts securing switchgrass production from the closest farms.

5.3 Cost of Mitigation and Future Fossil Fuel Prices

5.3.1 Future U.S. Ethanol Production and World Crude Oil Prices

Ethanol is a substitute for gasoline, the predominant US transportation fuel. For this reason, both the future costs of ethanol and the future cost of abating transportation carbon emissions by substituting ethanol for gasoline are a function of future crude oil prices. This is demonstrated by Figure 15 and Equation 38 and Equation 39. In a future where ethanol displaces gasoline, crude oil prices could potentially be affected. If ethanol's cost (or value) is a function of crude oil prices, and crude oil prices can be affected by substituting ethanol for gasoline, an economic feedback is possible, which could change the price difference between ethanol and gasoline. For example, if enough ethanol were produced and enough crude oil were displaced that crude oil prices fall, ethanol would become less attractive economically as a result (i.e. the results in Figure 15 would change). Therefore, a brief analysis of ethanol economics and the influence of crude oil prices must explore the degree to which ethanol production could affect crude oil prices.

U.S. ethanol production could lower the world crude oil price if ethanol production displaces enough crude oil that the world market experiences a significant decrease in demand for oil. Current crude oil prices in 2006 are higher than historically normal, largely because the combined world crude oil demand has created a tight market where spare production supply is limited [*49*]. High crude oil prices should attract new capital investments aimed at increasing oil supply. If demand is reduced, especially after investments in production capital are in place, debt service for the capital could force production to continue even though prices are falling. In this sense, investments in additional production capacity can act as a barrier to supply reductions even if supply begins to outpace demand.

Ethanol's ability to affect crude oil prices is most likely if a combination of circumstances developed, all working in concert. First, U.S. ethanol production displaces a large quantity of crude oil. Second, most U.S. displaced crude oil results in a reduction in U.S. crude oil imports. Third, U.S. ethanol production growth rates result in rapid crude oil import reduction. And fourth, current oil producing regions and/or businesses are incapable of stabilizing crude oil prices through supply reduction.

Eventually, consumption will respond to price reductions. If a low cost crude oil market emerged, world demand would respond by investing in lifestyle choices that take advantage of deflated energy prices. For this reason, a low oil cost market would not last indefinitely, although forecasting a timeframe for consumption to expand will not be attempted here. It could, however, last long enough for U.S. consumers to witness falling gasoline prices. Lower gasoline prices could mean that ethanol is no longer economical by comparison. In this sense, pricing feedback will create risk for ethanol industry investments based on ethanol demand.

This analysis is interested in the combinations of U.S. ethanol industry and international crude oil demand growth rates that will result in a negative international crude oil demand. If these growth rates appear unlikely, then confidence in the economic feedback's ability to undermine an ethanol industry should be low. If the circumstances appear likely, then ethanol investors and the lending sector should be aware, allowing interest rates to reflect this risk.

This analysis will first estimate a potential future ethanol capacity. Second, it will compare that capacity with U.S. crude oil demand growth. Lastly, it will analyze growth rates for both the U.S. ethanol industry and world crude oil demand, identifying the rates where supply would be greater than demand.

5.3.2 Future U.S. Ethanol Capacity

In 2005, the corn ethanol industry produced 3.6 billion gallons of ethanol [*129*]. Due to co-product market saturation, it is unlikely that corn-based ethanol production can expand beyond roughly 5 billion gallons per year. For ethanol quantities greater than 5 billion gallons per year, ethanol production based on cellulosic feedstocks such as switchgrass and agricultural residues will be required [*105*].

Agricultural researchers at Oak Ridge National Laboratory estimate that approximately 250 million tons per year of switchgrass could be available at 50$/ton with minor price distortions for other agricultural commodities [*180*]. At similar prices, the U.S. Department of Energy has estimated that 340 million tons per year of agricultural residues are possible without compromising agricultural soil quality [*71*]. Assuming that 590 million tons per year of domestic cellulosic biomass feedstock could be available and assuming that 100 gallons of ethanol can be derived from each ton of cellulosic feedstock, approximately 59 billion gallons of cellulosic ethanol could be produced in the U.S. Adding corn ethanol, 64 billion gallons of ethanol per year could be produced.

In 2004, 141 billion gallons of gasoline were consumed by the U.S. light duty vehicle fleet, and 178.5 billion total within the U.S [*116*]. To supply the refinery industry in 2004, the U.S. imported 3.7 billion barrels of crude oil, and produced another 2 billion barrels domestically [*50*]. Accounting for the lower energy density of ethanol[54], 64 billion gallons of ethanol could displace 45 billion gallons of gasoline. Converting gasoline volume into crude oil volume[55], 45 billion gallons of gasoline translates into roughly 41 billion gallons of crude oil, or roughly 1 billion barrels of oil per year. 1 billion barrels of oil per year represents 27% of 2004 U.S. crude oil imports (13.3% of 2004 total U.S. crude consumption).

Recently, agricultural researchers at Oak Ridge National Laboratory have estimated that 1 billion tons per year of total biomass could be possible by mid-century [*124*]. This includes agricultural residues, forest wastes, municipal wastes, and energy crops. If this occurs, 100 billion gallons of ethanol could be produced per year. The Oak Ridge biomass resource evaluation was performed to support the Department of Energy's Renewable Energy Biomass Program's goal of a 30% reduction in current petroleum consumption by the year 2030 [*117*]. In 2004, 7.5 billion barrels of petroleum was consumed [*50*]; 2.2 billion barrels represents 30%. 100 billion gallons of ethanol per year could replace 1.5 billion barrels of petroleum per year. To displace all 2004 U.S. gasoline consumption, 200 billion gallons per year of ethanol is required[56].

For this research, 64 billion gallons of ethanol is assumed to be the upper level of ethanol production despite the REBP's goal. 64 million is used because it is consistent with previous ethanol assumptions of yields and feedstocks. The following analysis technique can also be applied to the larger petroleum reductions called for my REBP.

---

[54] Ethanol energy density = 87,000 Btu /gal; Gasoline = 125,000 Btu/gal

[55] It is assumed that demanded for non-gasoline refinery products are independent of gasoline demand or production such that crude oil requirements for their production will not be impacted by gasoline demand reductions. It is assumed that gasoline expansion from crude oil offsets refinery processing energy requirements. Crude oil and gasoline volumes are related by energy density. Gasoline = 125,000 Btu/gal; Crude oil = 138,000 Btu/gal; Conversion rate = 0.906

[56] 140 billion gallons of gasoline adjusted for the energy difference between ethanol and gasoline.

5.3.3 U.S. Ethanol Production Growth Rates

While U.S. motor gasoline consumption is forecasted to grow 1.2% annually between 2006 and 2030, domestic crude oil production declines at 0.7% and crude oil imports grow at 1.1% annually, for a total crude oil consumption growth of 0.6% annually [*55*]. Assuming that ethanol production does not grow, Figure 21 presents the Energy Information Administration's forecast of crude oil demand from the transportation sector for motor gasoline through the year 2030. In Figure 21, corn ethanol's maximum of 5 billion gallons per year is presented as the last 5 billion gallons of the forecasted transportation total crude oil demand.

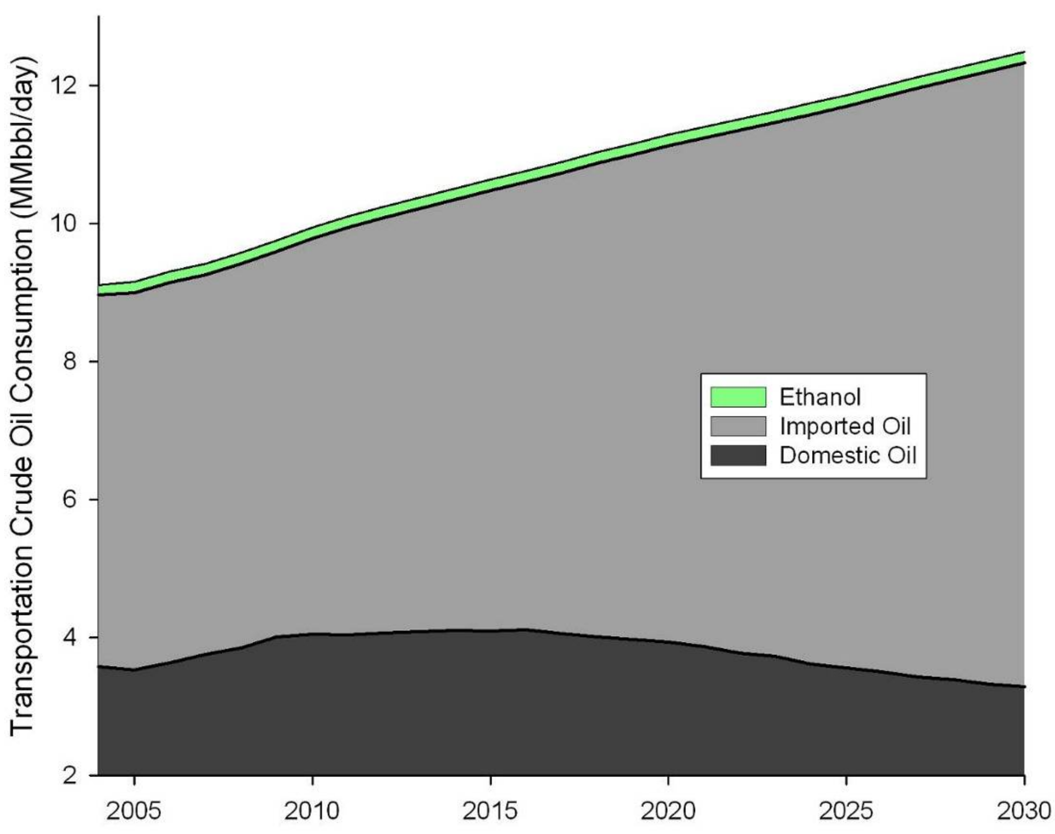

Figure 21 – Future U.S. Crude Oil Demand with Current Ethanol Productivity Subtracted
Data source: EIA [*55*]

Ethanol production in 2005 was 3.6 billion gallons, and in 2006, production is expected to reach 4.3 billion gallons [*129*]. Using a simple growth rate, if the ethanol industry were to reach maximum production rate of 64 billion gallons by the year 2030, an annual growth rate of 12% is required. To reach its maximum within 10 years, the annual rate increases to 28%, with capacity doubling every 3 years. Between the years 2001 and 2005, ethanol production has grown at 23% annually [*129*]. For comparison, the fastest U.S. petroleum refinery capacity growth period was between 1940 and 1960 when capacity grew at an annual rate of roughly 4% [*50*]. Assuming that ethanol production grew at 4% annually, the ethanol industry would not reach its maximum capacity until the year 2090.

Figure 22 illustrates the impact that ethanol production could have on U.S. crude oil imports assuming two different ethanol industry growth rates. In Figure 22, both transportation sector demand for crude oil and domestic crude oil production remain unaltered from Figure 21, and it is assumed that ethanol production will offset crude oil imports exclusively. Ethanol production might not offset imports exclusively; assuming that it will provides the worst case scenarios, however.

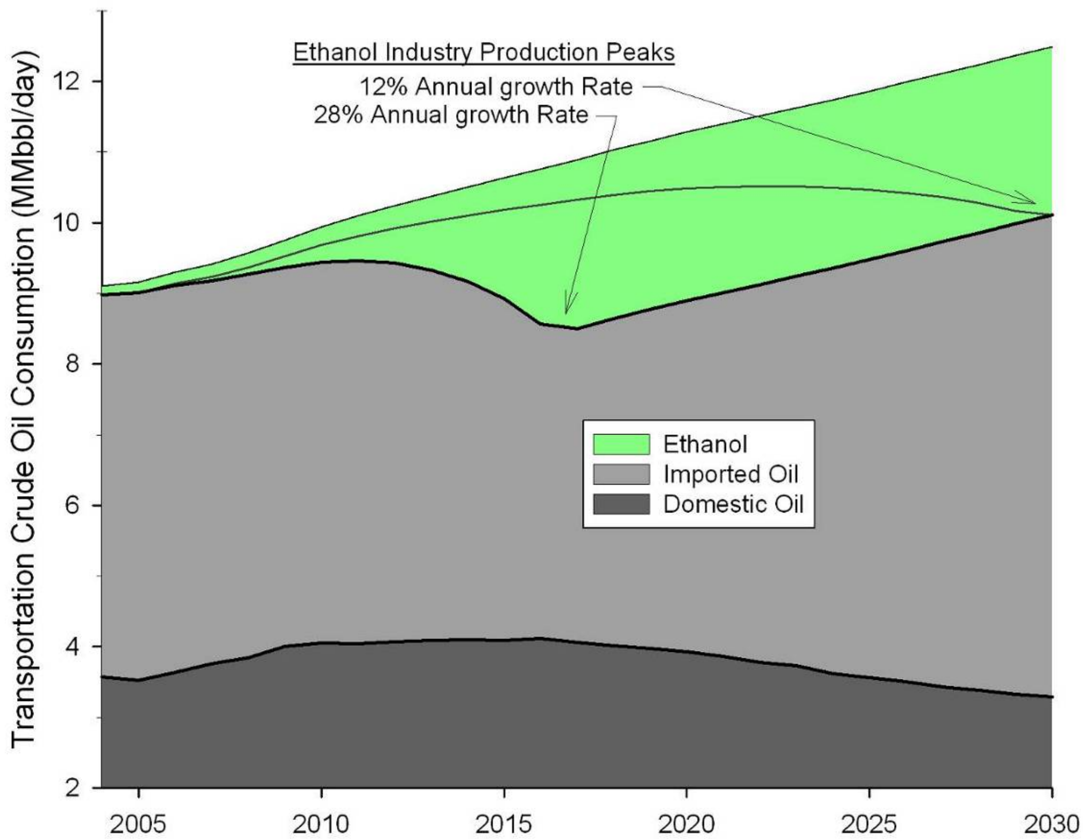

Figure 22 – Forecast of Potential Growth Rates and the Impact that U.S. Ethanol Industry Growth Could Have on U.S. Crude Oil Demand.

Figure 22 does indicate that rapid ethanol industry growth rates could cause a reduction in U.S. crude oil imports. As discussed above, a 28% annual industry growth rate sustained for 10 years would be challenging, but not impossible. If this growth rate does not cause world oversupply, then it is not likely that the U.S. ethanol industry could cause a demand decline in the world crude oil market.

5.3.4 International Crude Oil Consumption and U.S. Ethanol Production Growth Rates

Assuming that the U.S. ethanol industry does grow at 28% annually beginning in 2005 and that U.S. ethanol production does displace crude oil imports exclusively, Figure 23 illustrates projections of world crude oil demand for varying world crude oil demand rates. World demand growth includes all countries consumption of internationally traded crude oil, including the U.S. Four world crude oil growth rates are illustrated: no-growth, 0.25%, 0.5%, and 1% growth. In all five scenarios, U.S. ethanol will affect total world crude oil demand. However, it is only when world demand growth falls below one quarter of one percent (0.25%) that world demand levels could actually decrease.

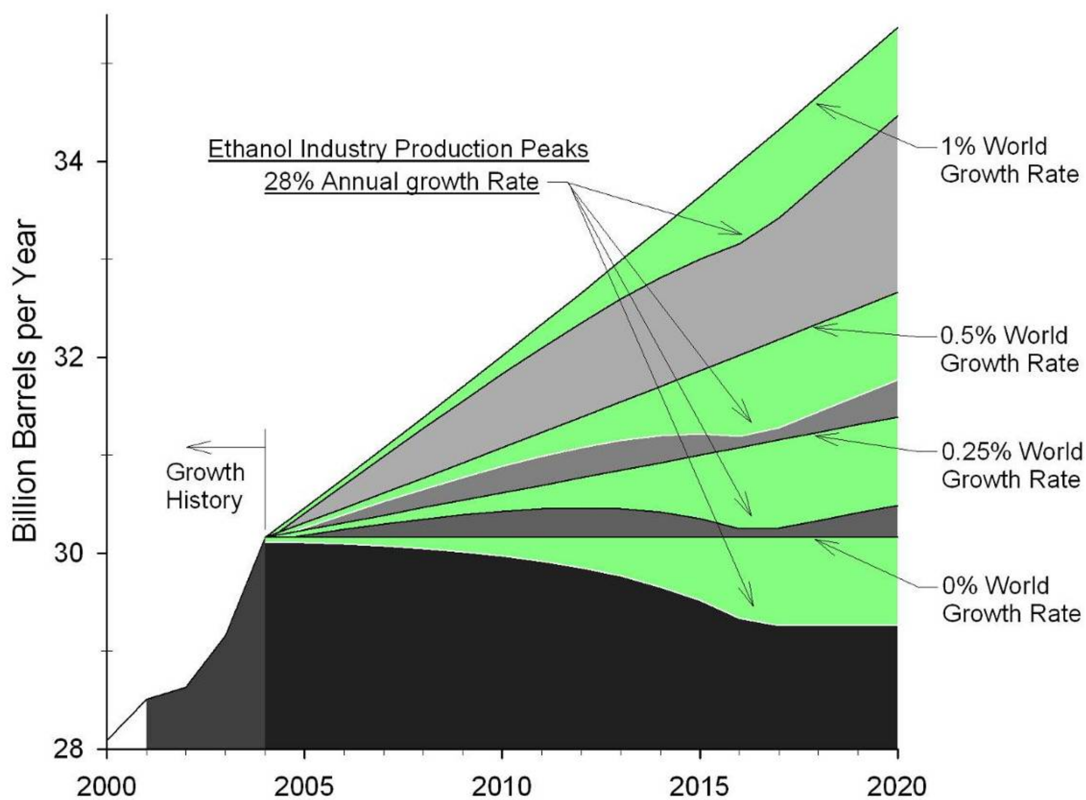

Figure 23 – Forecast of Potential Growth Rates and the Impact that U.S. Ethanol Industry Growth could have on World Crude Oil Demand.

If world crude oil demand grows faster than 0.25%, a 28% or lower annual U.S. ethanol industry expansion would not reduce net crude oil demand at the global level.

The U.S. DOE forecast of world crude oil demand estimates a 1.9% growth rate through 2025 [*49*]. Much of this growth, increasing from 10.5 to 14.8 billion barrels per year, is expected to come from emerging economies such as China and India that are expected to grow 3% annually over this same time period between 2002 and 2010.

If the U.S. did invest heavily in cellulosic ethanol, it is most likely that international crude oil demand would absorb any U.S. demand offsets. For this not to be the case, the world economy will have had to experience a tremendous slowdown.

In summary, even large US ethanol investment rates are unlikely to cause demand reductions in the global crude oil market (that would significantly lower the price of crude oil) given growth in world demand from other countries. Moreover, even rapid U.S. adoption of alternative transportation fuel/propulsion cycles will not likely lower global crude oil prices. Perhaps worries over crude oil production peaks possible affect on crude oil prices should be replaced with a worries over demand expansion. The net global economy is perhaps at a size where any additional growth will always lead to crude oil demand outstripping supply. If this is the case the result will likely be high crude oil price for the near-to-long term.

5.4 Competing Carbon Reduction Technologies within the Transportation and Electricity Generation Sectors

In this section, I present a comparison of this analysis to other carbon reducing options that electricity and transportation fuels have in the near-to-long term. Generally, the electricity sector has many alternative technology options available that can reduce carbon emissions from electricity production; the transportation sector is more limited.

Consideration of broader issues such as foreign policy alternatives, is outside the scope of this thesis research.

5.4.1 Electricity Sector Alternative Options

In competition with energy crop and coal co-firing, other electricity generation technologies offering carbon mitigation benefits include switching to lower carbon content fuel, retrofitting coal power plants for carbon capture, coal gasification with carbon capture, nuclear, CHP, and renewable energy technologies such as wind, solar, small hydro, and geothermal. In a carbon emissions controlled dispatch analysis, it was found that the electricity sector would most likely convert to as much natural gas fired electricity generation as natural gas prices would allow; after which, carbon capture and sequestration technologies would likely allow further carbon reductions [*83*]. In critique of Johnson and Keith's analysis, natural gas prices have since risen outside the natural gas price boundary of their analysis.

Retrofitting existing power plants offers slightly higher carbon mitigation prices as energy crop and coal co-firing [*30*] [*74*] [*147*]. Coal gasification with carbon capture is also competitive with co-firing [*135*]. It will likely remain unclear what new U.S. nuclear electricity will cost until new capacity is actually built, but nuclear projects constructed in other countries are not entirely un-affordable [*88*]. Renewable energy technologies offer modest generation potential but often are accompanied by cost, policy, and research challenges [*92*] [*42*]. Wind is the most economical renewable technology when competing directly with current electricity production cost, but due to intermittence in wind, it requires complex management and backup capacity which is often not included in costs [*38*]. Solar electricity technologies are more expensive than other carbon reducing electricity technologies and, therefore, requires policy subsidies before offering competitive prices [*12*].

The only other technologies available to existing coal fired power plants are technologies which allow carbon capturing retrofits. Therefore the remaining discussion will compare cost for retrofitting existing coal fired power plants for carbon capture to the results presented in Chapter 4 for co-firing.

Adding carbon-capture equipment to existing coal fired power plants can take place as either pre- or post-combustion retrofits, and each has different costs [*30*]. A pre-combustion retrofit requires a gasification unit for carbon removal/reduction from the coal feedstock and power plant re-powering to facilitate the conversion of the gasifier's output gas to electricity. Capital cost estimates for this option range between $1,400 to $1,800 per kW capacity, translating to ¢7 - ¢10 kWh^{-1}, or $60 - $90 ton CO_2^{-1} [*30*]. These costs are for a small-size plant (100 - 500 MW) retrofit. Larger coal plants would require capital costs comparable to new IGCC + CCS[57] costs, which are estimated to translate into a costs range from $18 to $77 ton CO_2^{-1} captured [*74*].

[57] IGCC + CCS = Integrated Gasification Combined Cycle with a Carbon Capture and Sequestration option active

Capturing post combustion carbon is more economical; estimates range from $600 to $900 kW^{-1} capacity, translating into ¢5.75 - ¢7 kWh^{-1}, or $45 - $55 ton CO_2^{-1} captured [*30*], to $35 - $53 ton CO_2^{-1} captured [*147*].

For each of these pre or post combustion retrofits estimates, capturing carbon is only one of the additional costs. Transporting and sequestering the carbon is another. Currently, transportation and sequestration is speculated to cost an additional $10 ton CO_2^{-1} captured. However, for each of the existing coal power plants, finding a suitable location for sequestration could alter this cost [*8*]. Secondly, the effects of increased electricity prices from existing coal plants retrofitted for carbon capture would likely affect their economic rank in a power pool[58]. Researchers using an electric system dispatch model which dispatches the lowest cost carbon technologies considering all available technology options, concluded that retrofitting existing coal plants for carbon capture is not economical below $100 ton CO_2^{-1} captured [*83*]. Below $100 ton CO_2^{-1} captured, other options such as fuel switching to lower carbon fuels is more attractive than retrofitting and will likely provide most of the desired carbon reductions.

Dispatch preference will also influence switchgrass and coal co-firing economics. Although a rigorous analysis of dispatch orders' effect on co-firing economics is outside the scope of this research, a simple comparison between the co-firing economics presented here and Johnson and Keith's retrofitting analysis can provide insight into co-firing economics' possible sensitivity to dispatch order. In their analysis, Johnson and

[58] The United States national electric grid is composed of multiple power generation and transmission regional grouping. While these grouping are all connected to each other, they operate according to regional oversight by a regional transmission organizations (RTO's) which are independent from all generated, but who govern which power plants contribute electricity to their regional grid and when. This regional grid is called a "power pool", and RTO chooses power generators based on their prices and availability.

Keith use a retrofitting cost equivalent to roughly \$25 - \$30 ton CO_2^{-1} captured. Yet their dispatch order analysis forecasts a price of \$100 ton CO_2^{-1} captured before retrofitting becomes economically viable. Thus, in a power pool, the market price at which a retrofitted coal plant is dispatched represents a 300% - 400% premium to CO_2 costs. Assuming that co-firing will experience a similar premium, market CO_2 cost would need to rise to \$90 - \$160 ton CO_2^{-1} captured in order for switchgrass and coal co-firing to become an economical option in a power pool.

Two points in Johnson and Keith's research might offer optimism for co-firing proponents however. First, higher natural gas prices create a push towards retrofitting (in fact, their analysis does not forecast retrofitting to take place unless gas prices are high (4.42 \$/MMBtu)[59]. Second, the dispatch order of a retrofitted plant increases as de-rating[60] decreases. This second point is punctuated by their forecast that hydrogen-fired coal gasification combined cycle (H_2-CGCC), which would not necessarily result in de-rating existing plant electricity production, would be dispatched at 70 \$/ton CO_2 captured. Retrofitting for H_2-CGCC is modeled at 1,500 \$/kW capital costs. By comparison, power plants co-firing biomass with coal experiences roughly a 10% de-rating. This de-rating, however, is scaled by the co-firing rate; if firing 100% biomass, the total de-rating would be 10%, co-firing 50%, yields a de-rating of roughly 5%. Thus, co-firing de-rating is in

---

[59] Natural gas price for electric power production was 11.88 \$/MMBtu at the end of October 2005 [*46*], and are forecasted to remain between 4 - 6 \$/MMBtus through 2030 [*55*].

[60] When a power plant adds carbon capturing technologies, the carbon capturing technologies use energy that otherwise would be sold to the grid (increasing parasitic efficiency losses), and therefore its efficiency (measures by the ratio of energy input to electricity sold) is reduced, or "de-rated". Carbon capturing retrofit equipment is estimated to de-rated a power plant up to 24%. Or, the power plant must increase production up to 31% to sell the same quantity of electric power. This increase in fuel, ancillary products (chemicals, water, waste generation, etc.), and O&M will increase a power plant's cost of electricity (¢/kWh) [*135*].

between carbon capture retrofitting and hydrogen re-powering, or perhaps closer to the 70 \$/ton CO_2 price for dispatch.

5.4.2 Transportation Sector Alternatives

Reducing carbon emissions from the transportation sector will likely prove more challenging because alternative options involving fuel switching and/or propulsion switching are limited and often pose conflicting tradeoffs. For this reason, it appears likely that the internal combustion engine (ICE) propulsion system will remain dominant through 2015 [*91*]. A comparison between current gasoline ICE vehicles (ICEV) and both hybrid electric fossil fuel and hydrogen fuel cell vehicles suggests that greenhouse gas emissions can be lowered with hybrid electric fossil fueled vehicles and substantially lowered with hydrogen fuel cell vehicles [*32*]. However, it is unlikely that hydrogen will become a dominant energy carrier because of economics: fuels cells are very expensive; hydrogen does not exist in a chemically un-bonded state and is costly to crack from water; hydrogen is highly reactive and difficult to store; and hydrogen distribution infrastructure does not exist [*70*]. Hybrid electric vehicles (HEV) can conserve fuel and carbon emissions by their increased fuel economy.

There is anticipation that current HEV technology will advance such that hybrids will eventually plug into the electricity grid [*75*]. The two current technology ideas are straight plug hybrid electric vehicles (PHEV), and vehicle-to-grid (V2G) hybrid electric vehicles. PHEVs are similar to current HEVs except PHEVs will be equipped to use the grid to charge their batteries in addition to charging during breaking as current HEVs do. Once charged, the batteries will provide all power for the car until drained (30 - 40 miles) when the car's on-board ICE takes over until the batteries can be recharged [*25*]. V2Gs are similar to PHEVs except they are designed to feed electricity into the grid during peak grid electricity demand hours [*85*]. How and to what degree shifting the supply of transportation energy from crude oil to the electricity sector will affect the petroleum and electricity generation markets will require further research before conclusions can be offered.

In all likelihood, turnover of existing ICEV fleets for these newer technologies will be slow. For example, demands of current hybrids are strong, but sales are small compared to total car sales. As is demonstrated by the analysis presented above, slow growth rates of alternative technologies would most likely ease the world oil market into a reduction of U.S. demand. However, shifting a large portion of the U.S. transportation energy demand into the coal market might result in higher coal prices, especially if generation mixes and efficiencies remain constant.

PHEV proponents argue that transportation using current ICEV costs roughly 15 ¢/mile and future PHEVs would cost 3 ¢/mile [*112*]. Using the current corporate average fuel economy (CAFE) of 20.2 miles per gallon of gasoline and 125,000 Btus/gallon of gasoline, the average car currently consumes 6,100 Btus/mile. The efficiency of the ICEV, measured by the fraction of fuel energy transferred into propulsion of the vehicle, is roughly 20% [*134*]. Therefore, only 1,220 Btus/mile is required to move the car. Using the 2005 U.S. average residential electricity prices of 9.5 ¢/kWh[61], 3 ¢/mile would be an electricity consumption of 3/9.5 kWh/mile, or 0.32 kWh/mile. 0.32 kWh/mile

[61] [*52*]

equals 1,100 Btus/mile. Assuming that the battery charger efficiency is 85%[62], 935 Btu/mile will be required to propel the vehicle. An equivalent ICEV fuel economy would equal 26.7 mpg gasoline.

Comparing the carbon emissions between the current ICEV, ICEVs at 26.7 mpg, and PHEVs powered by grid electricity allows for an estimation of ethanol to PHEVs. Assuming that 19 lbs CO_2/gallon gasoline the current average fuel economy (20.2 mpg) releases 0.94/lb/mile; at 26.7 mpg, 0.71 lb/mile are released. The 2002 average CO_2 emission from the electricity sector was 1,392 lb CO_2/MWh. At 3 ¢/mile, 0.32 kWh/mile will result in 0.45 lb CO_2/mile. Assuming that the fuel efficiency gain, and therefore the CO_2/mile reduction, will be the result of decreasing car design rather than the PHEV itself, the difference in CO_2 emissions would be 0.26 lb CO_2/mile. Estimating life cycle cost for 150,000 miles, PHEV might be $1,200 lower than for an ICEV [*22*]. Mitigating 0.26 lb CO_2/mile for 150,000 miles will result in 19.5 tons CO_2 mitigated at a cost of $-1,200. This would be equal to -61 $/ton CO_2. Simply switching to PHEV looks promising for net U.S. carbon mitigation strategies, concluding that the transportation sector has attractive technologies in competition with ethanol as well.

Transferring transportation energy into the electricity sector, which is dominated by coal, could cause substantial increases in electricity demands. The effect this could have on coal price is worth investigation. For example, at current consumption rates, the U.S. electricity sector alone will consume the coal reserves present in active coal mines by the year 2018. Beyond 2030, if coal consumption continues to grow at EIA's forecasted rate of 1.9% , which does not include energy for transportation, "estimated recoverable

[62] [*22*]

reserves"[63] will be exhausted by the end of the century. Considerable amounts of coal are estimated to exist within the U.S. beyond the estimated recoverable reserves; however, a prediction of the cost required to access this coal in the future has not been performed here.

5.5 Considering Alternative Evaluation Criteria

5.5.1 Full Cost Accounting Criteria

The life-cycle and full cost accounting literature review provided in section 3.6 revealed that criteria pollutant emissions would likely increase with the use of ethanol, and decrease with biomass co-firing. As this research concludes, twice the carbon emissions can be reduced by co-firing switchgrass as by producing and consuming ethanol. Land use and soil quality impacts are neutral as to the two proposed alternative uses of switchgrass.

The analysis of competing carbon reduction technologies for the electricity and transportation sector provided in Section 7.3 indicates that plug-hybrid cars have the ability to provide CO_2 emission reductions by shifting transportation energy to the grid.

Considering that electricity produced from bioenergy reduces greenhouse gas emissions and criteria pollutants more than ethanol , and that transportation vehicles can be designed to use grid generated electricity, bioenergy should be used to generate electricity rather than transportation fuels.

---

[63] "estimated recoverable reserves" are derived from the demonstrated reserves, adjusting for the demonstrated reserves believed to be accessible, and also believed to be recoverable by surface or underground mining [*47*]

5.5.2 Moving Refineries and/or E-85 in Local Markets

Using a single cost per ton-mile value to estimate both the shipping of switchgrass and ethanol derived from switchgrass, reduces a comparison of upstream and downstream shipping to a comparison of weights. Ethanol weighs 6.5 lbs per gallon [*167*]. Using NREL's estimate of ethanol refinery yield for the first ethanol plant of 72 gallons per ton of feedstock [*177*] means that 1 ton of switchgrass would convert to 468 lb, or less than ½ ton. Therefore optimizing for costs would locate a bio-refinery as close to the location of feedstocks (farms) as possible.

Ethanol refinery gate costs for the first ethanol refinery will be $1.50 per gallon as estimated by NREL [*177*]. As estimated in Section 5.1, downstream transportation cost ranged from $0.45 to $0.49 per gallon of ethanol for truck transport and $0.15 to $0.17 per gallon for rail transport. Correcting for the difference in energy density between ethanol and gasoline, refinery gate cost would rise to $2.00 and downstream transportation would rise to $0.20 to $0.65 per gallon.

Providing E85 in localized markets would potentially result in a $0.17 to $0.55 price difference reduction as compared to evenly spreading ethanol consumption to all markets. This price reduction would be the consequence of not transporting ethanol to all the markets evenly as estimated in Section 5.1. Localized E85 economics would still only be economical as compared to gasoline prices. If for example, ethanol refinery gate costs are lower than gasoline refinery gate costs, then ethanol would be price competitive regardless. In this instance, ethanol's economic advantage would wane as the distance shipped to a consumer increases. Reducing the shipping distance by providing localized E85 would lessen the degree to which ethanol's advantage wanes.

However, if gasoline prices are low enough that ethanol's total economics (production plus distribution) are unfavorable, then lower than E85 blends spreads the price burden across a greater volume thereby reducing the unit price in all markets. The prevalence of historic price differences between gasoline markets, (for example, Georgia versus California) reveals that demand in markets is insensitive to price discrepancies.

Literature Cited

(1) Aabakken J. April 2005, NREL/TP-620-37930 http://www.nrel.gov/analysis/power_databook/

(2) Aden, A.et al. *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*. June 2002, Published By: National Renewable Technology Laboratory. Report ID: NREL/TP-510-32438

(3) American Legislative Exchange Council *American Legislative Exchange Council*. www.alec.org

(4) Amos, W. *Summary of Chariton Valley Switchgrass Co-Fire Testing at the Ottumwa Generating Station in Chillicothe, Iowa*. July 31st, 2002. Report ID: NREL/TP-510-32424

(5) Anon. *Senate Accepts Bush's Plan for Mercury Emissions*. Chemical & Engineering News Sep 19 2005, 83 [38], 26.

(6) Apparicio, P. et al. *The Measure of Distance in a Social Science Policy Context: Advantages and Costs of using Network Distances in Eight Coanadian Metropolitan Areas*. GIDA - Journal og Geographic Information and Decision Analysis 2003, 7 [2], 105-131. http://www.geodec.org/

(7) Babcock & Wilcox. *Steam/ Its Generation and Use - 40th Edition*. June, 1992, Published By: Babcock & Wilcox Company. USA. © 1955.

(8) Bachu, S. and Stewart, S. *Geological Sequestration of Anthropogenic Carbon Dioxide in the Western Canada Sedimentary Basin: Suitability Analysis*. Journal of Canadian Petroleum Technology Feb 2002, 41 [2], 32-40.

(9) Baranzini, A. , Chesney, M., and Morisset, J. *The Impact of Possible Climate Catastrophes on Global Warming Policy*. Energy Policy Jun 2003, 31 [8], 691-701.

(10) Barnett, T.et al. *Detecting and Attributing External Influences on the Climate System: a Review of Recent Advances*. Journal of Climate May 1 2005, 18 [9], 1291-1314.

(11) Benetto, E.et al. *Life Cycle Assessment of Fossil CO_2 Emissions Reduction Scenarios in Coal-Biomass Based Electricity Production*. Energy Conversion and Management Nov 2004, 45 [18-19], 3053-3074.

(12) Black, A. J. *Financial Payback on California Residential Solar Electric Systems*. Solar Energy 2004, 77 [4], 381-388.

(13) Blevins, L. G. and Cauley, T. H. *Fine Particulate Formation During Switchgrass/Coal Cofiring*. Journal of Engineering for Gas Turbines and Power-Transactions of the Asme Jul 2005, 127 [3], 457-463.

(14) Boylan, D., Bush, V., and Bransby, D. I. *Switchgrass Cofiring: Pilot Scale and Field Evaluation*. Biomass & Bioenergy 2000, 19 [6], 411-417.

(15) Brandt, U. S. and Svendsen, G. T. *Hot Air in Kyoto, Cold Air in the Hague - the Failure of Global Climate Negotiations*. Energy Policy Oct 2002, 30 [13], 1191-1199.

(16) Bransby, D. I., Sladden S.E., and Downing M.E. *Yield Effects on Bale Density and Time Required for Commercial Harvesting and Bailing of Switchgrass. BIOENERGY 96 - The seventh National Bioenergy Conference: Partnership to Develop and Apply Biomass Technologies.* Nashville Tennessee, 1996, Published By: ORNL

(17) Bransby David. *Switchgrass Profile*. Published By: Oak Ridge National laboratory http://bioenergy.ornl.gov/papers/misc/switchgrass-profile.html

(18) Brentrup, F. et al. *Environmental Impact Assessment of Agricultural Production Systems Using the Life Cycle Assessment Methodology - I. Theoretical Concept of a LCA Method Tailored to Crop Production*. European Journal of Agronomy Feb 2004, 20 [3], 247-264.

(19) Brentrup, F. et al. *Environmental Impact Assessment of Agricultural Production Systems Using the Life Cycle Assessment (LCA) Methodology - Ii. The Application to N Fertilizer Use in Winter Wheat Production Systems*. European Journal of Agronomy Feb 2004, 20 [3], 265-279.

(20) Bridgwater, A. V. *Renewable Fuels and Chemicals by Thermal Processing of Biomass*. Chemical Engineering Journal Mar 15 2003, 91 [2-3], 87-102.

(21) Brinkmann, N.et al. *Well - to - Wheels Analysis of Advanced Fuel/Vehicle Systems - A north American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions*. May 2005, Published By: Argonne National Laboratory http://www.transportation.anl.gov/software/GREET/publications.html

(22) Browning, L. and Duvall, M. *Advanced Batteries for Electric-Drive Vehicles - A Technology and Cost-Effectiveness Assessment for Battery Electric Vehicles, Power Assist Hybrid Electric Vehicles, and Plug-In Hybrid Electric Vehicles*. May 2004, Published By: Electric Power Research Institute. Concord, CA. Report ID: 000000000001009299
(23) Bruntland, G. H. *Our Common Future: The World Commission on Environment and Development*. April 27th,1987, Published By: Oxford University Press. Oxford, England
(24) BTS. *National Transportation Statistics - 2005*. June 2005, Published By: Department of Transportation. 400 7th Street, SW • Room 3430 • Washington, DC 20590 http://www.bts.gov/publications/national_transportation_statistics/
(25) CalCars *All About Plug-In Hybrids (PHEVs)*. http://www.calcars.org/vehicles.html; Date Accessed: March, 28th, 2006
(26) Caldeira, K. , Jain, A. K., and Hoffert, M. I. *Climate Sensitivity Uncertainty and the Need for Energy Without CO_2 Emission*. Science Mar 28 2003, 299 [5615], 2052-2054.
(27) Carter, D. W., Perruso, L., and Lee, D. J. *Full Cost Accounting in Environmental Decision-Making*. November 2001, Published By: the Department of Food and Resource Economics, University of Florida. Gainesville, FL. Report ID: EDIS - FE 310 http://edis.ifas.ufl.edu/FE310
(28) Cassida, K. A.et al. *Biofuel Component Concentrations and Yields of Switchgrass in South Central Us Environments*. Crop Science Mar-Apr 2005, 45 [2], 682-692.
(29) Chariton Valley RC&D *Chariton Valley Biomass Project: Home Grown Energy*. http://biomass.ecria.com/index.html
(30) Chen, Chao, Rao, Anand B., and Rubin, Edward S. *Comparative Assessment of CO_2 Capture Options for Existing Coal-Firing Power Plants. 2nd Annual DOE Carbon Sequestration Conference.* Alexandria Virginia, Published By. May 7, 2003.
(31) Choudhury, R.et al. *GM Well-to-Wheels Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems - A European Study*. September 27th, 2002, Published By: L - B - Systemtechnik GmbH. Daimlerstrasse 15, 85521 Ottobrunn, Germany http://www.lbst.de/index__e.html?http://www.lbst.de/publications/studies__e/2002gmwtw__e.html
(32) Colella, W. G., Jacobson, M. Z., and Golden, D. M. *Switching to a Us Hydrogen Fuel Cell Vehicle Fleet: the Resultant Change in Emissions, Energy Use, and Greenhouse Gases*. Journal of Power Sources Oct 4 2005, 150, 150-181.
(33) Conway-Schempf, N. *Curriculum and Educational Materials for Environmentally Conscious Green Products and Processes*. *A Course Module on Incorporating Environmental and Social Costs into Traditional Business Accounting Systems*. Published By: Carnegie Mellon University. Pittsburgh, PA http://www.ce.cmu.edu/GreenDesign/
(34) Curran, Mary Ann. *Energy Demand and Other Environmental Impacts across the Life Cycle of Bioethanol Used as Fuel. ASChE, Annual Conference 2005.* Cincinnati, OH, November 4th, 2005,
(35) de la Torre Urgart Daniel and Ray, D. E. *Biomass and Bioenergy Applications of the POLYSIS Modeling Framework*. Biomass & Bioenergy 2000, 18 [4], 291-308.
(36) de la Torre Urgart, D. and Walsh, M. *Synergism Between Agricultural and Energy Policy: The Case of Dedicated Bioenergy Crops*. 2002, Published By: Agricultural Policy Analysis Center. The University of Tennessee; Knoxville, TN 37996-4519
(37) de la Torre Urgart Danielet al. *The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture*. July, 2000,
(38) Decarolis, J. F. and Keith, D. W. *The Economics of Large-Scale Wind Power in a Carbon Constrained World*. Energy Policy Mar 2006, 34 [4], 395-410.
(39) Demirbas, A. *Biomass Co-Firing for Coal-Fired Boilers*. Energy Exploration & Exploitation 2003, 21 [3], 269-278 .
(40) Demirbas, A., Sahin-Demirbas, A., and Demirbas, A. H. *Global Energy Sources, Energy Usage, and Future Developments*. Energy Sources Feb 2004, 26 [3], 191-204.
(41) Dessai, S., Lu, X. F., and Hulme, M. *Limited Sensitivity Analysis of Regional Climate Change Probabilities for the 21st Century*. Journal of Geophysical Research-Atmospheres Oct 8 2005, 110 [D19]
(42) Dobesova, K. , Apt, J., and Lave, L. B. *Are Renewables Portfolio Standards Cost-Effective Emission Abatement Policy?* Environmental Science & Technology Nov 15 2005, 39 [22], 8578-

8583.
(43) Downing, Mark, Walsh, Marie, and McLaughlin, Sandy. *Perennial Grasses for Energy and Conservation: Evaluating some ecological, agricultural, and economic issues. Environmental Enhancement Through Agriculture: Proceedings of a Conference.* Center for Agriculture, Food and Environment, Tufts University, Medford, MA., November 15-17, 1995,
(44) Duval, Y. *Environmental Impact of Modern Biomass Cogeneration in Southeast Asia*. Biomass & Bioenergy 2001, 20 [4], 287-295.
(45) *e-GRID (Emissions & Generation Resources Integrated Database)*. E.H. Pechan & Associates, I. May 2003, Published By: U.S. Environmental Protection Agency Office of Atmospheric Programs
(46) Energy Information Administration *Energy Information Administration - Official Energy Statistic from the U.S. Department of Energy*. http://www.eia.doe.gov/
(47) Energy Information Administration. *EIA Coal Reserves Data*. *U.S. Coal Reserves: 1997 Update*. February 1999, Published By: Energy Information Administration; Office of Integrated Analysis Forecasting; U.S. Department of Energy. Washington, DC 20585. Report ID: DOE/EIA - 0384(2004) http://www.eia.doe.gov/cneaf/coal/reserves/front-1.html
(48) *Electric Power Monthly* . Energy Information Administration. *Table 4.10.B. Average Cost of Coal Delivered for Electricity Generation by State, Year-to-Date through March 2005 and 2004*. July 2005, Published By: Energy Information Administration - Office of Coal, Nuclear, Electric and Alternative Fuels. Washington D.C. http://www.eia.doe.gov/cneaf/electricity/epm/epm.pdf
(49) Energy Information Administration. *International Energy Outlook 2005*. July 2005, Published By: Energy Information Administration; Office of Integrated Analysis Forecasting; U.S. Department of Energy. Washington, DC 20585. Report ID: DOE/EIA - 0484 (2005)
(50) Energy Information Administration. *Annual Energy Review 2004*. August 2005, Published By: Energy Information Administration; Office of Integrated Analysis Forecasting; U.S. Department of Energy. Washington, DC 20585. Report ID: DOE/EIA - 0384(2004)
(51) Energy Information Administration. *October 2005 Monthly Energy Review*. October 26, 2005, Published By: Energy Information Administration
(52) Energy Information Administration. *Electric Power Monthly - December 2005*. March 10th 2006, Published By: Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_tabs.html
(53) Energy Information Administration *A Primer on Gasoline Prices*. http://www.eia.doe.gov/bookshelf/brochures/gasolinepricesprimer/eia1_2005primerM.html; Date Accessed: March 27th 2006
(54) Energy Information Administration *Renewable and Alternative Fuels*. http://www.eia.doe.gov/fuelrenewable.html; Date Accessed: April 19th, 2006
(55) Energy Information Administration. *Annual Energy Outlook 2006 - Overview*. December 2006, Published By: Energy Information Administration; Office of Integrated Analysis Forecasting; U.S. Department of Energy. Washington, DC 20585. Report ID: DOE/EIA - 0573 (2004)
(56) Environmental Protection Agency - NCEE. *The United States Experience with Economic Incentives for Protecting the Environment*. 2001, Published By: Environmental Protection Agency. Washington D.C. Report ID: EPA-240-R-01-001
(57) Espey, S. *Renewables Portfolio Standard: a Means for Trade With Electricity From Renewable Energy Sources?* Energy Policy Jun 2001, 29 [7], 557-566.
(58) Farrell, A. E.et al. *Ethanol Can Contribute to Energy and Environmental Goals*. Science Jan 27 2006, 311 [5760], 506-508.
(59) Felix, J. R. *SCR Catalyst Deactivation due ot Biomass Co-Firing in a Coal-Fired Power Plant - Master's Thesis*. 2004, Published By: The University of Alabama at Birmingham - Mechanical Engineering
(60) Fischer, C. and Newell, R. *Environmental and Technological Policies for Climate Change and Renewable Energy*. April 2004, Published By: Resource for the Future. Washington DC www.rff.org & http://www.rff.org/rff/Documents/RFF-DP-04-05.pdf
(61) Fleming, J. S., Habibi, S., and Maclean, H. L. *Investigating the Sustainability of Lignocellulose-Derived Fuels for Light-Duty Vehicles*. Transportation Research Part D-Transport and Environment Mar 2006, 11 [2], 146-159.
(62) *Premium Solver*. Frontline System Inc. http://www.solver.com/Default.htm
(63) Gallagher, P. W.et al. *Biomass from Crop Residues: Cost and Supply Estimate*. February 2003,

Published By: Office of Energy Policy and New Uses. Washington DC
(64) Goldemberg, J. and Coelho, S. T. *Renewable Energy - Traditional Biomass Vs. Modern Biomass*. Energy Policy Mar 2004, 32 [6], 711-714.
(65) Graham, R. L., English, B. C., and Noon, C. E. *A Geographic Information System-Based Modeling System for Evaluating the Cost of Delivered Energy Crop Feedstock*. Biomass & Bioenergy 2000, 18 [4], 309-329.
(66) Graham R.L. and Walsh M.E. *Evaluating the Economic Costs, Benefits and Tradeoffs of Dedicated Biomass Energy Systems: the Importance of Scale. Second Biomass Conference of the Americas: Energy, Environment, Agriculture, and Industry.* Portland, Oregon, August 21-24, 1995, 207-215. Published By: National Renewable Technology Laboratory. Golden, Colorado.
(67) *The Oak Ridge Energy Crop County Level Database*. Graham, R. L., Allison, L. J., and Becker, D. A. December 20th 1996, Published By: Oak Ridge National Laboratory
(68) Green Design Institute *Environmental Input Output Life-Cycle Analysis*. http://www.eiolca.net/
(69) Hammerschlag, R. *Ethanol's Energy Return on Investment: a Survey of the Literature 1990 - Present*. Environmental Science & Technology Mar 15 2006, 40 [6], 1744-1750.
(70) Hammerschlag, R. and Mazza, P. *Questioning Hydrogen*. Energy Policy Nov 2005, 33 [16], 2039-2043.
(71) Haq, Z. *Biomass for Electricity Generation*. 2002, Published By: Energy Information Administration http://www.eia.doe.gov/oiaf/analysispaper/biomass/
(72) Heller, M. C., Keoleian, G. A., and Volk, T. A. *Life Cycle Assessment of a Willow Bioenergy Cropping System*. Biomass & Bioenergy 2003, 25 [2], 147-165.
(73) Hendrickson, C.et al. *Economic Input-Output Models for Environmental Life-Cycle Assessment*. Environmental Science & Technology Apr 1 1998, 32 [7], 184A-191A.
(74) Herzog, Howard. *CO2 Capture and Storage: Costs and Market Potential. 7th International Conference on Greenhouse Gas Control Technologies.* Vancouver Canada, http://www.ghgt7.ca/programme.html
(75) Huber, P. and Mills, M. P. *Dig More Coal, the Hybrids Are Coming*. Forbes May 24 2004, 173 [11], 106-+.
(76) Hughes, E. *Biomass Cofiring: Economics, Policy and Opportunities* . Biomass & Bioenergy 2000, 19 [6], 457-465.
(77) Hughes, E. Tillman D. *Annual Report on Biomass Cofiring Program 2001*. December 2001, Published By: Electric Power Research Institute. Palo Alto CA. Report ID: 1004601 - 05T084
(78) Hughes, E. and O'Connor D. Tillman D. *Biomass Cofiring Update 2002*. July 2003, Published By: Electric Power Research Institute. Palo Alto CA. Report ID: 1004319 - 05T084
(79) IEA - International Energy Agency. *Key World Energy Statistics 2004*. 2005, Published By: STEDI. France
(80) International Standard Organization - ISO. *ANSI/ISO 14040 - Life Cycle Assessment - Principles and framework*. July 3rd, 1997, http://www.iso-14001.org.uk/index.htm
(81) Jean-Baptiste, P. and Ducroux, R. *Energy Policy and Climate Change*. Energy Policy Jan 2003, 31 [2], 155-166.
(82) Jensen, K.et al. *Tennessee Farmer's View of Producing Switchgrass for Energy*. October 2005, Published By: Bio-Based Energy Analysis Group, Department of Agricultural Economics, University of Tennessee. Knoxville, TN http://beag.ag.utk.edu/
(83) Johnson, T. L. and Keith, D. W. *Fossil Electricity and CO_2 Sequestration: How Natural Gas Prices, Initial Conditions and Retrofits Determine the Cost of Controlling CO_2 Emissions*. Energy Policy Feb 2004, 32 [3], 367-382.
(84) Kemppainen, A. J. and Shonnard, D. R. *Comparative Life-Cycle Assessments for Biomass-to-Ethanol Production From Different Regional Feedstocks*. Biotechnology Progress Jul-Aug 2005, 21 [4], 1075-1084.
(85) Kempton, W. and Tomic, J. *Vehicle-to-Grid Power Fundamentals: Calculating Capacity and Net Revenue*. Journal of Power Sources Jun 1 2005, 144 [1], 268-279.
(86) Kent, C. A. *An Analytical History of EIA*. Government Information Quarterly 1993, 10 [1], 3-24.
(87) Kim, S. and Dale, B. E. *Life Cycle Inventory Information of the United States Electricity System*. International Journal of Life Cycle Assessment Jul 2005, 10 [4], 294-304.
(88) Kozlov, V. V. *Determination of the Highest Possible Capital Costs for the Construction of a Nuclear Power Plant Based on Data From Construction Abroad*. Atomic Energy Nov 2004, 97

[5], 750-756 .
(89) Krotscheck, C., Konig, F., and Obernberger, I. *Ecological Assessment of Integrated Bioenergy Systems Using the Sustainable Process Index*. Biomass & Bioenergy 2000, 18 [4], 341-368.
(90) Kuehn, B. M. *Mercury Rule Challenged*. Jama-Journal of the American Medical Association Sep 14 2005, 294 [10], 1201.
(91) Lave, L.et al. *Life-Cycle Analysis of Alternative Automobile Fuel/Propulsion Technologies*. Environmental Science & Technology Sep 1 2000, 34 [17], 3598-3605.
(92) Leible, L. and Kalber, S. *Renewable Resources for Electricity Production*. Gaia-Ecological Perspectives for Science and Society 2005, 14 [3], 253-261.
(93) Lemus, R. and Lal, R. *Bioenergy Crops and Carbon Sequestration*. Critical Reviews in Plant Sciences 2005, 24 [1], 1-21.
(94) Lin, Y. and Tanaka, S. *Ethanol Fermentation From Biomass Resources: Current State and Prospects*. Applied Microbiology and Biotechnology Feb 2006, 69 [6], 627-642.
(95) Maclean, H. L. *Alternative Transport Fuels for the Future*. International Journal of Vehicle Design 2004, 35 [1-2], 27-49.
(96) Maclean, H. L. and Lave, L. B. *Evaluating Automobile Fuel/Propulsion System Technologies*. Progress in Energy and Combustion Science 2003, 29 [1], 1-69.
(97) Mann, M. K. and Spath Pamela L. *A Life Cycle Assessment of Biomass Cofiring in a Coal-Fired Power Plant*. Clean production Processes June 30th, 2001, 3, 81-91.
(98) Matthews, H. S. and Lave, L. B. *Applications of Environmental Valuation for Determining Externality Costs*. Environmental Science & Technology Apr 15 2000, 34 [8], 1390-1395.
(99) Mc Carl, B. A.et al. *Competitiveness of Biomass-Fueled Electrical Power Plants*. Annals of Operations Research 2000, 94, 37-55.
(100) McLaughlin, S. B. and Kszos, L. A. *Development of Switchgrass (Panicum Virgatum) as a Bioenergy Feedstock in the United States*. Biomass & Bioenergy 2005, 28 [6], 515-535.
(101) McLaughlin, S. B., Samson R., Bransby, D. I., and Wiselogel A. *Evaluating physical, Chemical, and Energetic Properties of Perennial Grasses as Biofuels. BIOENERGY 96 - The seventh National Bioenergy Conference: Partnership to Develop and Apply Biomass Technologies.* Nashville Tennessee, September 15-20, 1996, Published By: Oak Ridge National Laboratory
(102) McLaughlin, S. B. and Walsh, M. E. *Evaluating Environmental Consequences of Producing Herbaceous Crops for Bioenergy*. Biomass & Bioenergy 1998, 14 [4], 317-324.
(103) Miles Thomas Ret al. *Alkali deposits found in biomass power plants - A preliminary investigation of their extent and nature*. April 15th, 1995, Published By: National Renewable Technology Laboratory. Golden Co. Report ID: NREL/TP-433-8142 http://www.trmiles.com/alkali/alkali.htm#EXECUTIVE%20SUMMARY
(104) Miles Thomas Ret al. *Alkali deposits found in biomass boilers - The Behavior of Inorganic Material in Biomass - Fired Power Boilers - Field and Laboratory Experiences*. Febreary 1996, Published By: National Renewable Technology Laboratory. Golden Co. Report ID: NREL/TP-433-8142 SAND96-8225 Vol II http://www.trmiles.com/alkali/alkali.htm#EXECUTIVE%20SUMMARY
(105) Morrow, W. R., Matthews, H. S., and Griffin Mike . *Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States*. Environmental Science and Technology May 1, 2006, 40 [9], 2877-2886.
(106) Mosier, A. R.et al. *Measurement of Net Global Warming Potential in Three Agroecosystems*. Nutrient Cycling in Agroecosystems May 2005, 72 [1], 67-76.
(107) Nathanial Greene. Celik, F. E.et al. *Growing Energy - How biofuels can help end America's Oil Dependence*. December 2004, Published By: National Resource Defense Council http://engineering.dartmouth.edu/other/rbaef/reports/index.shtml
(108) National Assessment Synthesis Team - US Global Change Research Program. *Scenarios for Climate Variability and Change - Chapter 1*. MacCracken Michaelet al. *Climate Change Impacts on the United States - The potential consequences of Climate Variability and Change*. Published By: The Press Syndicate of the University of Cambridge. The Pitt Building, Trumpington Street, Cambridge, United Kingdom http://www.usgcrp.gov/usgcrp/nacc/default.htm
(109) National Assessment Synthesis Team - US Global Change Research Program. *Climate Change Impacts on the United States - The potential consequences of Climate Variability and Change*. 2001, Published By: The Press Syndicate of the University of Cambridge. The Pitt Building,

Trumpington Street, Cambridge, United Kingdom http://www.usgcrp.gov/usgcrp/nacc/default.htm
(110) Ney, R. A. and Schnoor, J. L. *Incremental Life Cycle Analysis: Using Uncertainty Analysis to Frame Greenhouse Gas Balances From Bioenergy Systems for Emission Trading*. Biomass & Bioenergy 2002, 22 [4], 257-269.
(111) Niven, R. K. *Ethanol in Gasoline: Environmental Impacts and Sustainability Review Article*. Renewable & Sustainable Energy Reviews Dec 2005, 9 [6], 535-555.
(112) NREL and National Renewable Energy Laboratory *Hybrid Electric & Fuel Cell Vehicles*. http://www.nrel.gov/vehiclesandfuels/hev/plugins.html; Date Accessed: March 29th 2006
(113) O'Connor, D. *Biomass Resources, Technologies, and Environmental Benefits*. January 2004, Published By: Electric Power Research Institute. Concord, CA. Report ID: 000000000001004602
(114) O'neill, B. C. and Desai, M. *Accuracy of Past Projections of Us Energy Consumption*. Energy Policy May 2005, 33 [8], 979-993.
(115) Obrist, D.et al. *Measurements of Gaseous Elemental Mercury Fluxes Over Intact Tallgrass Prairie Monoliths During One Full Year*. Atmospheric Environment Feb 2005, 39 [5], 957-965.
(116) Office of Highway Policy Information. *Highway Statistics 2004*. 2006, Published By: U.S. Department of Transportation. Washington D.C. http://www.fhwa.dot.gov/policy/ohpi/hss
(117) Office of the Biomass Program. *Multi Year Program Plan; 2007 - 2012* . Agust 31, 2005, Published By: U.S. DOE http://www1.eere.energy.gov/biomass/
(118) Ogden, J. M., Williams, R. H., and Larson, E. D. *Societal Lifecycle Costs of Cars With Alternative Fuels/Engines*. Energy Policy Jan 2004, 32 [1], 7-27.
(119) Palisade *Palisade - Decisions with Vision*. http://www.palisade.com/
(120) Parmesan, C., Root, T. L., and Willig, M. R. *Impacts of Extreme Weather and Climate on Terrestrial Biota*. Bulletin of the American Meteorological Society Mar 2000, 81 [3], 443-450.
(121) Patzek, T. W. *Thermodynamics of the Corn-Ethanol Biofuel Cycle*. Critical Reviews in Plant Sciences 2004, 23 [6], 519-567.
(122) Pedersen, L. S.et al. *Effects on Sox and Nox Emissions by Co-Firing Straw and Pulverized Coal*. Energy & Fuels Mar-Apr 1997, 11 [2], 439-446.
(123) Peltier, R. *Coal Plants Work to Stay Competitive Compliant*. Power Jan-Feb 2003, 147 [1], 35-+.
(124) Perlack, R. D.et al. *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply*. April 2005, Published By: Oak Ridge National Laboratory. Oak Ridge Tennessee. Report ID: DOE/G0-102995-2135 ORNL/TM-2005/66
(125) Peterson, T. D. and Rose, A. Z. *Reducing Conflicts Between Climate Policy and Energy Policy in the Us: the Important Role of the States*. Energy Policy Mar 2006, 34 [5], 619-631.
(126) Pimentel David and Patzek Tad W. *Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower*. Natural Resources Research March 2005, 14 [1], 65-76.
(127) Ragauskas, A. J.et al. *The Path Forward for Biofuels and Biomaterials*. Science Jan 27 2006, 311 [5760], 484-489.
(128) Reijnders, L. *Conditions for the Sustainability of Biomass Based Fuel Use*. Energy Policy May 2006, 34 [7], 863-876.
(129) Renewable Fuels Association. *From Niche to Nation; Ethanol Industry Outlook 2006*. Fenruary 2006, Published By: Renewable Fuels Association. Washington DC
(130) Report of the Steering Committee. *International Symposium on the Stabilization of Greenhouse Gases. International Symposium on the Stabilization of Greenhouse Gases.* Hadley Centre. Met office, Exeter, UK, February 1-3 2005,
(131) Reynolds, R. E. *Infrastructure Requirements for an Expanded Ethanol Industry - Phase II Project Deliverable Report*. January 15, 2002, Published By: Oak Ridge National Laboratory
(132) Robinson, A. L., Rhodes, J. S., and Keith, D. W. *Assessment of Potential Carbon Dioxide Reductions Due to Biomass-Coal Cofiring in the United States*. Environmental Science & Technology Nov 15 2003, 37 [22], 5081-5089.
(133) Rosenberg, W. *"Developing a gasification plant under the 3Party Covenant , utilizing Federal Loan Guarantees and Investment Tax Credits incentives enacted in EPACT 2000"*. February 9th, 2006, http://wpweb2.tepper.cmu.edu/ceic/seminars.htm

(134) Rubin, E. S.and Davidson, C. I. *Introduction to Engineering and the Environment*. 2001, Published By: The McGraw-Hill Companies, Inc. New York NY
(135) Rubin, Edward S., Rao, Anand B, and Chen, Chao. *Comparative Assessment of Fossil Fuel Power Plants with CO_2 Capture and Storage. International Conference on Greenhouse Gas Control Technologies (GHGT-7).* Vancouver, Canada, September 5-9 2004,
(136) Ruselowski, G.et al. *Volume 1 - Well -to -Wheels Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems - North American Analysis*. April 2001, Published By: GM
(137) Saad, L. *Americans still not highly concerned about global warming - Though record numbers say that it is happening*. April 7th, 2006, Published By: The Gallup Poll. Princeton, NJ
(138) Sami M., Annamalai K., and Wooldridge M. *Co-Firing of coal and biomass fuel blends*. Progress in Energy and Combustion Science 2001, 27, 171-214.
(139) Sanden, B. A. and Azar, C. *Near-Term Technology Policies for Long-Term Climate Targets Economy Wide Versus Technology Specific Approaches*. Energy Policy Aug 2005, 33 [12], 1557-1576.
(140) Sanderson, M. A., Egg, R. P., and Wiselogel, A. E. *Biomass Losses During Harvest and Storage of Switchgrass*. Biomass & Bioenergy 1997, 12 [2], 107-114.
(141) Sanderson, M. A.et al. *Switchgrass as a Sustainable Bioenergy Crop*. Bioresource Technology Apr 1996, 56 [1], 83-93.
(142) Savolainen, K. *Co-Firing of Biomass in Coal-Fired Utility Boilers*. Applied Energy Mar-Apr 2003, 74 [3-4], 369-381.
(143) Shapouri, H., Duffield, J. A., and Wang, M. *The Energy Balance of Corn Ethanol Revisited*. Transactions of the ASAE Jul-Aug 2003, 46 [4], 959-968.
(144) Shapouri, H., Gallagher, P., and Graboski, M. S. *USDA's 1998 Ethanol Cost-of-Production Survey*. January 2002, Published By: U.S. Department of Agriculture, Office of the Chief Economist, Office of Energy Policy and New Uses. Washington DC 20036-5831. Report ID: Agricultural Economics Report Number 808
(145) Sheehan Johnet al. *Energy and Environmental Aspects of Using Corn Stover for Fuel Ethanol*. Journal of Industrial Ecology 2004, 7 [3-4], 117-146.
(146) Sims, R. E. H., Rogner, H. H., and Gregory, K. *Carbon Emission and Mitigation Cost Comparisons Between Fossil Fuel, Nuclear and Renewable Energy Resources for Electricity Generation*. Energy Policy Oct 2003, 31 [13], 1315-1326.
(147) Singh, D.et al. *Techno-Economic Study of Co2 Capture From an Existing Coal-Fired Power Plant: Mea Scrubbing Vs. O-2/Co2 Recycle Combustion*. Energy Conversion and Management Nov 2003, 44 [19], 3073-3091.
(148) Sissell, K. *Pennsylvania Proposes Stricter Controls on Mercury Emissions*. Chemical Week Sep 14 2005, 167 [30], 35.
(149) Smil, V. *Energy at the Crossroads; Global Perspectives and Uncertainties*. 2003, Published By: The MIT Press. Cambridge Massachusetts
(150) Smith, C. M. and Trip, L. J. *Mercury Policy and Science in Northeastern North America: the Mercury Action Plan of the New England Governors and Eastern Canadian Premiers*. Ecotoxicology Mar 2005, 14 [1-2], 19-35.
(151) Solow, J. L.et al. *Estimating the Economic Impact of Substituting Switchgrass for Coal for Electric Generation in Iowa*. March 29th, 2005,
(152) Srivastava, R. K., Staudt, J. E., and Jozewicz, W. *Preliminary Estimates of Performance and Cost of Mercury Emission Control Technology Applications on Electric Utility Boilers: an Update*. Environmental Progress Jul 2005, 24 [2], 198-213.
(153) Streets, D. G.et al. *Climate Change and United-States Energy-Policy*. Energy Nov-Dec 1991, 16 [11-12], 1437-1466.
(154) Tembo, G., Epplin, F. M., and Huhnke, R. L. *Integrative Investment Appraisal of a Lignocellulosic Biomass-to-Ethanol Industry*. Journal of Agricultural and Resource Economics Dec 2003, 28 [3], 611-633.
(155) The Economist. *How to think about climate change*. The Economist Dec 8th, 2005, http://www.economist.com/index.html
(156) The Economist. *Pricking the Global Conscience; A UN conference on global warming makes progress, sort of*. The Economist Dec 14th, 2005, http://www.economist.com/index.html
(157) The United Nations. *The 1972 United Nations Conference on the Human Environment (The*

Stockholm Conference). The 1972 United Nations Conference on the Human Environment (The Stockholm Conference). Stockholm Sweden, http://www.unep.org/Documents.multilingual/Default.asp?DocumentID=97&ArticleID=
(158) Thomason, W. E.et al. *Switchgrass Response to Harvest Frequency and Time and Rate of Applied Nitrogen*. Journal of Plant Nutrition 2004, 27 [7], 1199-1226.
(159) Tillman, D. A. *Biomass Cofiring: the Technology, the Experience, the Combustion Consequences*. Biomass & Bioenergy 2000, 19 [6], 365-384.
(160) Tillman, D. A. *Final Report: Electric Power Research Institute - USDOE Cooperative Agreement: Co-Firing Biomass with Coal*. September 2001, Published By: Department of Energy. Report ID: DE-FC22-96PC96252
(161) Tyson, K. S., Riley, C. J., and Humphreys, K. K. *Fuel Cycle Evaluations of Biomass-Ethanol and Reformulated Gasoline*. November 1993, Published By: National Renewable Energy Laboratory. Golden CO. Report ID: NREL/TP-463-4950
(162) U.S. Congress *Energy Policy Act of 1992 (Enrolled as Agreed to or Passed by Both House and Senate) H.R. 776*. http://thomas.loc.gov/home/thomas.html; Date Accessed: September 26th, 2005
(163) U.S. Congress *Energy Policy Act of 2005 (Enrolled as Agreed to or Passed by Both House and Senate) H.R. 6*. http://thomas.loc.gov/home/thomas.html; Date Accessed: September 26th, 2005
(164) U.S. Department of Energy. http://www.energy.gov/
(165) U.S. Department of Energy *Biomass Program*. http://www1.eere.energy.gov/biomass/
(166) U.S. Department of Energy - National Renewable Energy Laboratory. *U.S. Department of Energy Biomass Power Program - Strategic Plan 1996 - 2015*. December 1996, Published By: U.S. Department of Energy. Washington, DC 20585 http://www.nrel.gov/docs/legosti/fy97/22159.pdf
(167) U.S. Department of Energy - National Renewable Energy Laboratory. *Handbook for Handling, Storing, and Dispensing E85*. April 2002, Published By: DOE; Office of Energy Efficiency and Renewable Energy. US www.e85fuel.com/pdf/e85_technical_booklet.pdf
(168) United Nations, United Nations Environment Programme World Meteorological Orginaization *Intergovernmental Panel on Climate Change*. http://www.ipcc.ch/
(169) Updegraff, K., Baughman, M. J., and Taff, S. J. *Environmental Benefits of Cropland Conversion to Hybrid Poplar: Economic and Policy Considerations*. Biomass & Bioenergy 2004, 27 [5], 411-428.
(170) Vehmas, J. *Energy-Related Taxation as an Environmental Policy Tool-the Finnish Experience 1990-2003*. Energy Policy Nov 2005, 33 [17], 2175-2182.
(171) Wahlund, B. , Yan, J. Y., and Westermark, M. *Increasing Biomass Utilization in Energy Systems: a Comparative Study of Co2 Reduction and Cost for Different Bioenergy Processing Options*. Biomass & Bioenergy 2004, 26 [6], 531-544.
(172) Walsh, M. E.et al. *Bioenergy Crop Production in the United States - Potential Quantities, Land Use Changes, and Economic Impacts on the Agricultural Sector*. Environmental & Resource Economics Apr 2003, 24 [4], 313-333.
(173) *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*. Walsh, M.et al. April 30, 1999, Updated January 2000, http://bioenergy.ornl.gov/resourcedata/index.html. Published By. ORNL
(174) Walther, G. R.et al. *Ecological Responses to Recent Climate Change*. Nature Mar 28 2002, 416 [6879], 389-395.
(175) Wang, M., Saricks, C., and Santini, D. *Effects of Fuel Ethanol Use on Fuel-Cycle Energy and Greenhouse Gas Emissions*. January 1999, Published By: Argonne National Laboratory. Center for Transportation Research, Energy Systems Division; 9700 South Cass Avenue, Argonne Illinois 60439. Report ID: ANL/ESD-38
(176) West, T. O. and Marland, G. *A Synthesis of Carbon Sequestration, Carbon Emissions, and Net Carbon Flux in Agriculture: Comparing Tillage Practices in the United States*. Agriculture Ecosystems & Environment Sep 2002, 91 [1-3], 217-232.
(177) Wooley, R.et al. *Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks*. Ocotober 2000, Published By: National Renewable Technology Laboratory. Report ID: NREL/TP-580-28893
(178) Wooley, R.et al. *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios*. July 1999, Published By: National Renewable Technology Laboratory. Report ID: NREL/TP-580-

26157
(179) World Energy Council. *Delivering Sustainability: Challenges and Opportunities for the Energy Industry - Conference Conclusions. 19th World Energy Congress.* Sydney, Australia, Published By: World Energy Council. 5th Floor Regency House, 1-4 Warwick Street, London W1B 5LT, UK. http://www.worldenergy.org/wec-geis/default.asp
(180) Wright, L. L., Walsh, M. A., Downing, M. E., Kszos, L. A., Cushman, J. H., Tuskan G.A. , McLaughlin, S. B., Tolbert, V. R., Scurlock, J., Ehrenshaft, J., and Ehrenshaft, A. R. *Biomass Feedstock Research and Development for Multiple Products in the United States. 1st World Conference and Exhibition on Biomass for Energy and Industry a joint millennium event of the 11th European Conference on Biomass for Energy and Industry and the Biomass Conference of the Americas.* Sevilla, Spain, June 5 - 9, 2000, 2000,
(181) Wyman, C. E. *Potential Synergies and Challenges in Refining Cellulosic Biomass to Fuels, Chemicals, and Power*. Biotechnology Progress Mar-Apr 2003, 19 [2], 254-262.
(182) Zhang, Z. X. and Baranzini, A. *What Do We Know About Carbon Taxes? An Inquiry Into Their Impacts on Competitiveness and Distribution of Income*. Energy Policy Mar 2004, 32 [4], 507-518.
(183) Zygarlicke, C. J.et al. *Task 3.4 - Impacts of Co-firing Biomass with Fossil Fuel*. August 2001, Published By: DOE & NETL. Report ID: 2001 - EERC - 08 - 03

Appendix A – POLYSIS Data

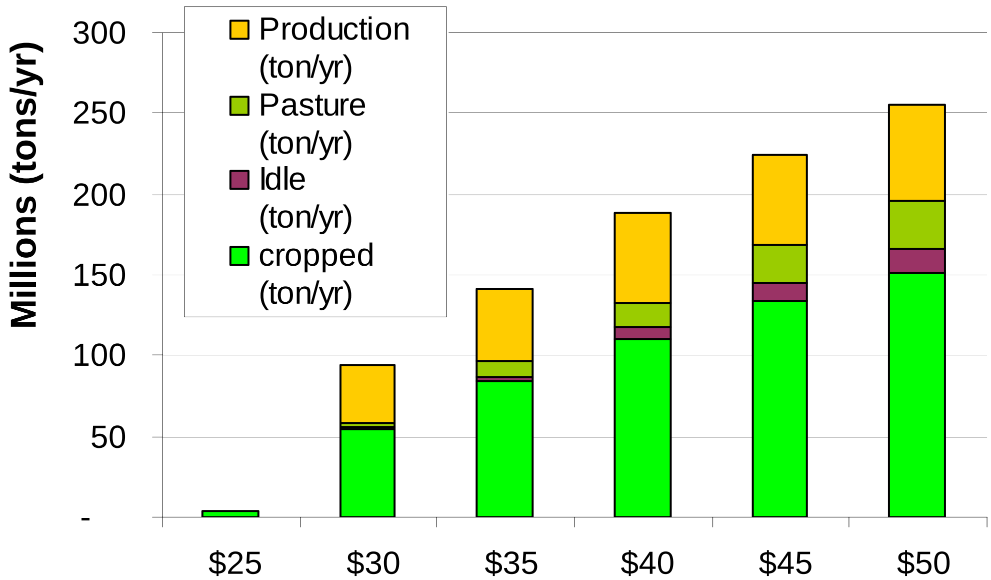

Figure 24 – POLYSIS Estimation of Switchgrass Availability as a Function of Price ($/ton SWG)

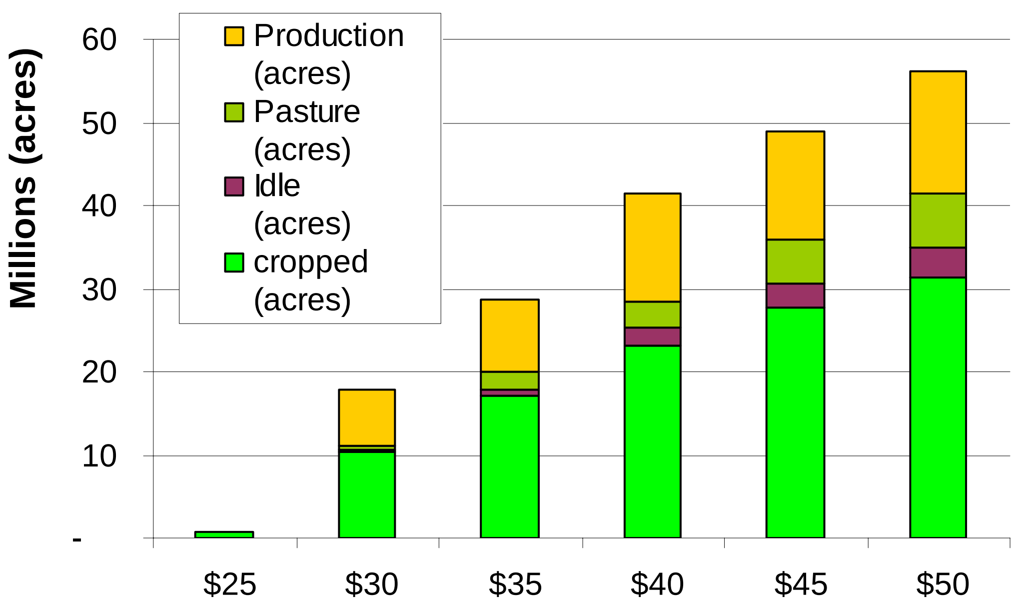

Figure 25 – POLYSIS Estimation of Land Dedicated to Switchgrass as a Function of Price ($/ton SWG)

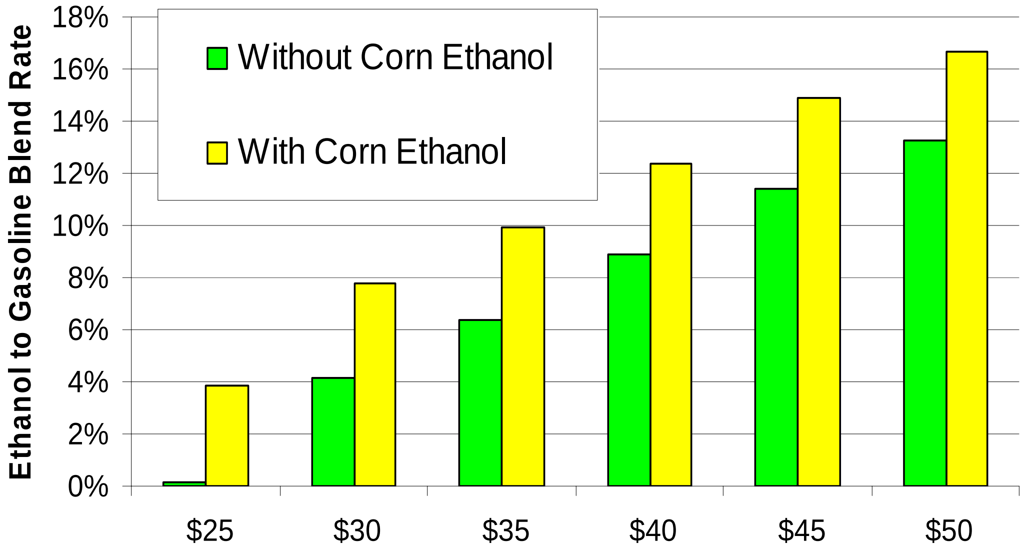

Figure 26 – Estimation of Ethanol Blend Potential based on POLYSIS Forecast of Switchgrass Growth as a Function of Price ($/ton SWG).
Calculations are based on the following assumptions: Gasoline HHV = 126,000 Btu/gal; Ethanol HHV = 84,000 Btu/gal; Year 2001 gasoline consumption (minus Alaska & Hawaii) = 132.5 billion gallons of gasoline; Corn ethanol can be expanded from current 3 to 5 billion gallons per year capacity.

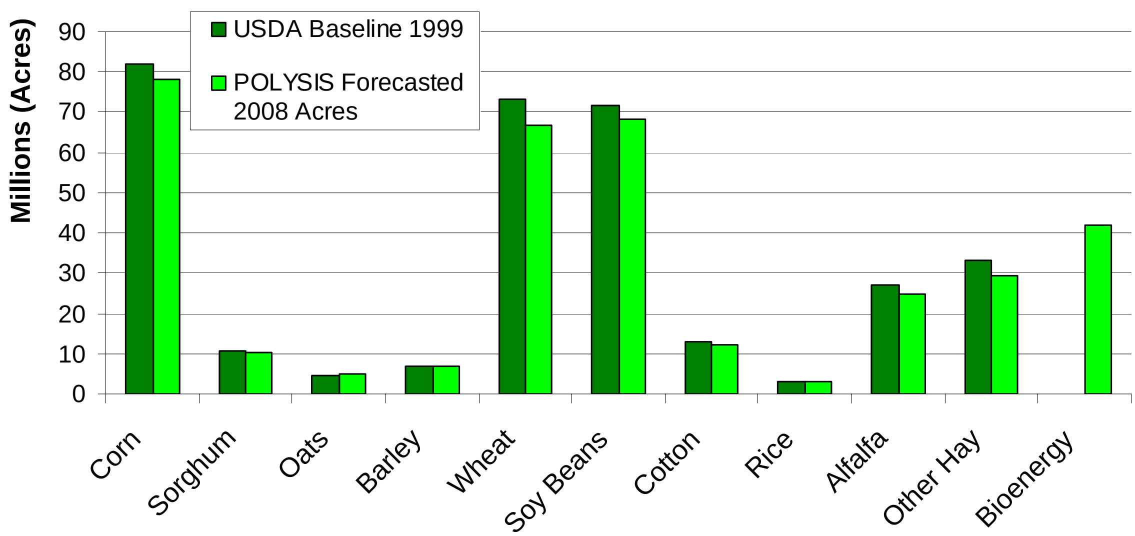

Figure 27 – Estimation of Impacts on Land Dedicated to Specific Crops Under a Bioenergy Growth Forecast at 40 $/ton (2.72 $/MMBtu).
Produced by the POLYSIS model

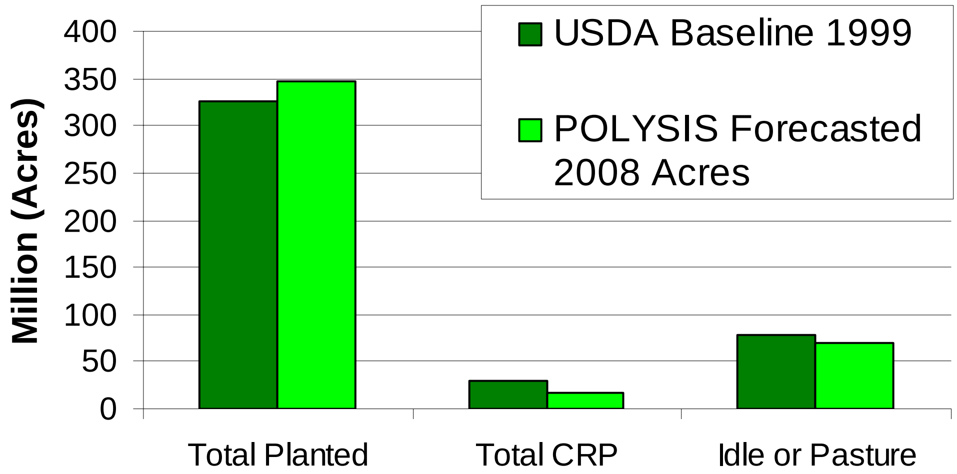

Figure 28 – Estimation of Total Changes in Farmland Use Under a Bioenergy Growth Forecast at 40 $/ton (2.72 $/MMBtu).
Produced by the POLYSIS model

Figure 29 through Figure 32 present the geographical location of POLYSIS forecasted switchgrass growth. Because growth volumes vary with price, the prices relevant to the co-firing research are presented.

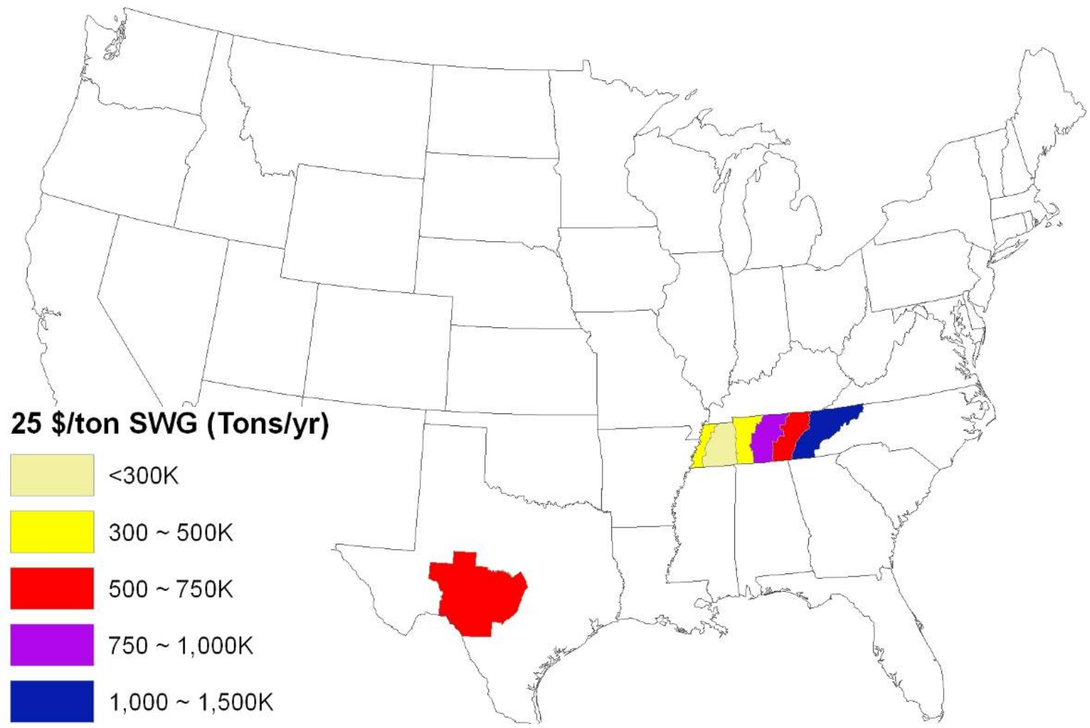

Figure 29 – POLYSIS Forecasted Switchgrass Availability at 25 $/ton (1.70 $/MMBtu).

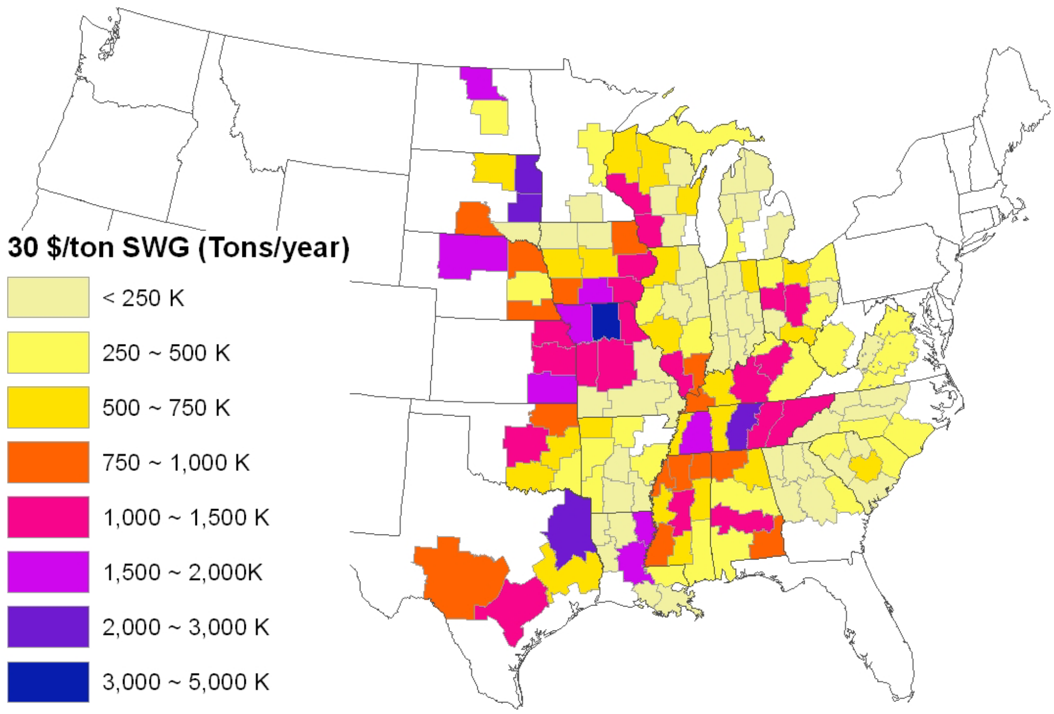

Figure 30 – POLYSIS Forecasted Switchgrass Availability at 30 $/ton (2.04 $/MMBtu).

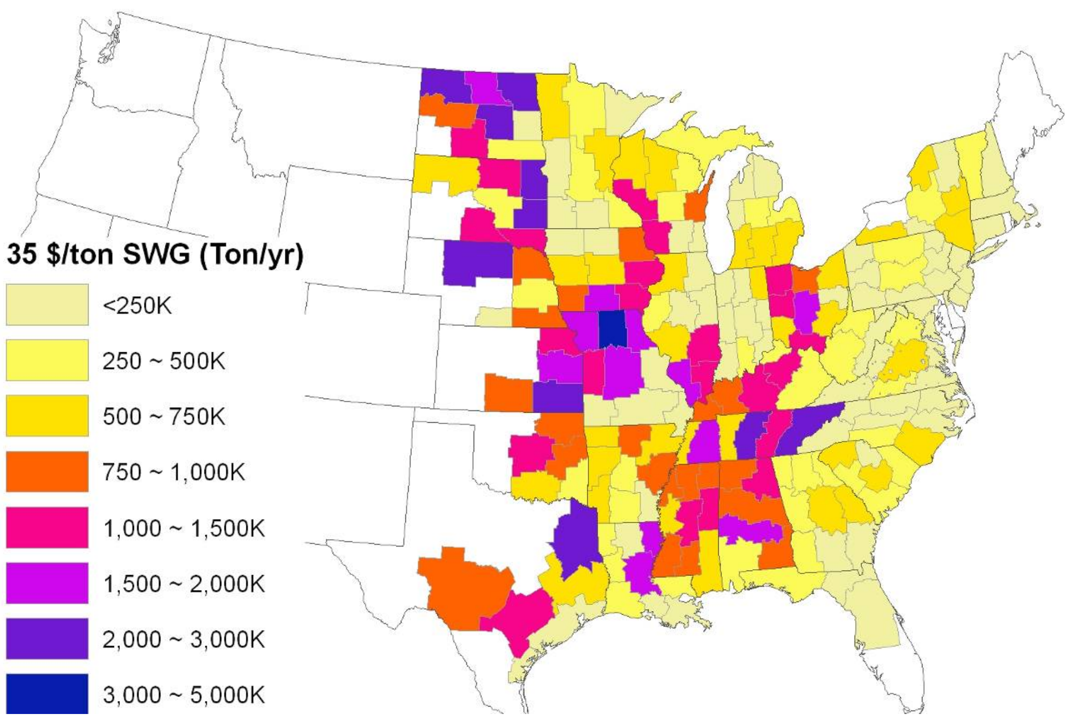

Figure 31 – POLYSIS Forecasted Switchgrass Availability at 35 $/ton (2.38 $/MMBtu).

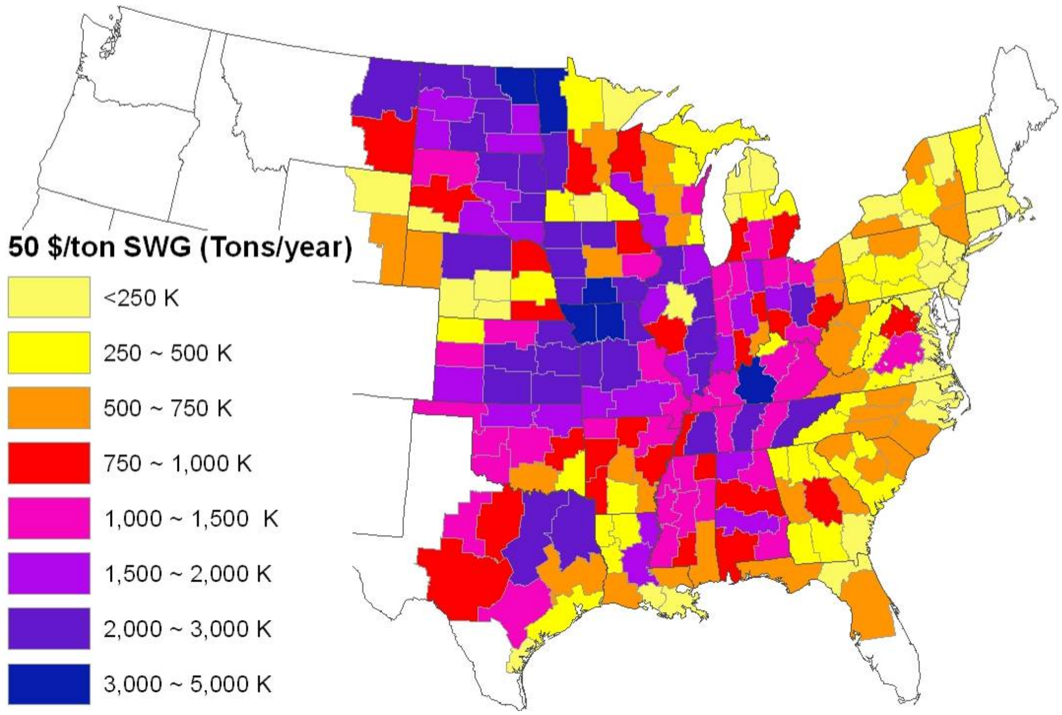

Figure 32 – POLYSIS Forecasted Switchgrass Availability at 50 $/ton (3.40 $/MMBtu).

Appendix B – POLYSIS Data Disaggregation Methodology

POLYSIS dataset Disaggregation to County Level

The POLYSIS data includes estimates of switchgrass production (tons / year). Roughly two thirds of future switchgrass cropland would come from current cropland. The Unites States Department of Agriculture's (USDA) census data of land use includes estimations of acres used for crops, pasture, and CRP for all U.S. counties (*31*). ORECCL provides estimations of expected yield for switchgrass (tons/acre/year) by cropland, pastureland, and CRP land for all U.S. counties (*32*).

Disaggregated of the POLYSIS data from districts to counties is performed according to

$$\dot{M}_{S_j} = \left\{ \frac{\sum_{i=1}^{3} \left(Y_j \times L_j \right)_i}{\sum_{j=1}^{n} \sum_{i=1}^{3} \left(Y_j \times L_j \right)_i} \right\}_k \times \dot{M}_{S_k} \qquad \text{Equation 42.}$$

$$\dot{M}_{S_j} = \left\{ \frac{\sum_{i=1}^{3} \left(Y_j \times L_j \right)_i}{\sum_{j=1}^{n} \sum_{i=1}^{3} \left(Y_j \times L_j \right)_i} \right\}_k \times \dot{M}_{S_k}$$

Equation 42

Where:

M_S = Mass of Switchgrass

Y = Yield (ton/acre)

L = Land (acre)

i = Land Use Category (Crop, Pasture, or CRP)

j = Counties making up a POLYSIS district

k = POLYSIS district

Energy crop potential yields are taken from the ORECCL database, and multiplied by USDA census data for all respective cropland, pastureland, and CRP land for each county. This yields the total potential switchgrass per county assuming that all available land that could growth switchgrass, did grow switchgrass. For each POLYSIS district, a ratio is created for each county by dividing a county's total potential switchgrass growth by the POLYSIS districts total. Each county's ratio is then used to allocated each POLYSIS district's switchgrass forecast into count level forecasts.

Figure 33 and Figure 34 show original 30 $/ton switchgrass POLYSIS districts data and disaggregated county data, respectively. 50 $/ton switchgrass data is shown in Figure 35 and Figure 36.

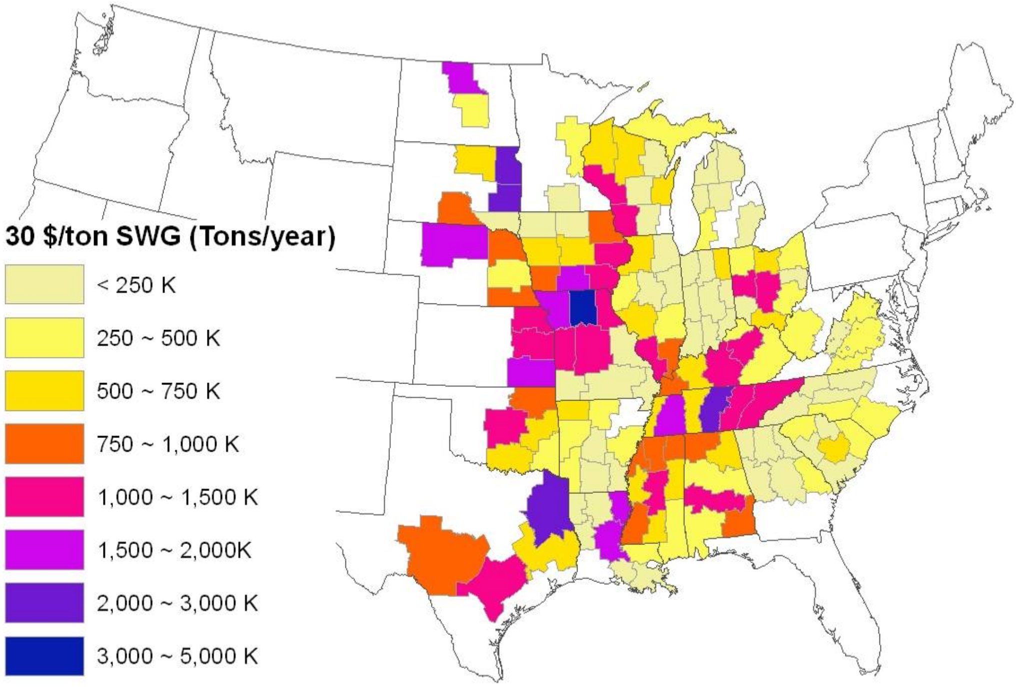

Figure 33 – POLYSIS Estimated Switchgrass Production at $30/ton – POLYSIS Districts

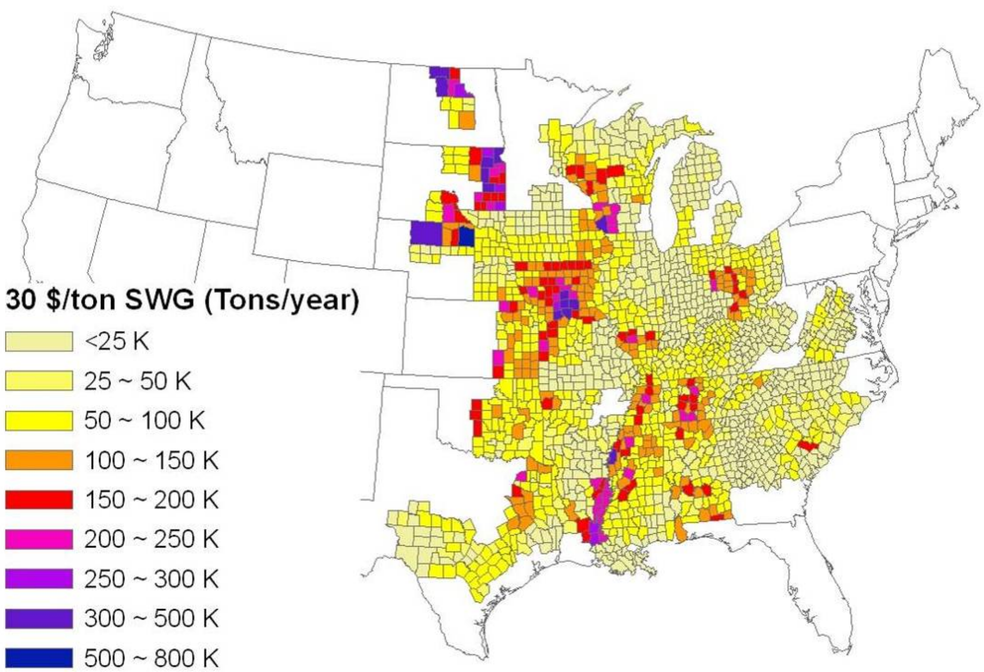

Figure 34 – POLYSIS Estimated Switchgrass Production a $30/ton – Disaggregated to County Level

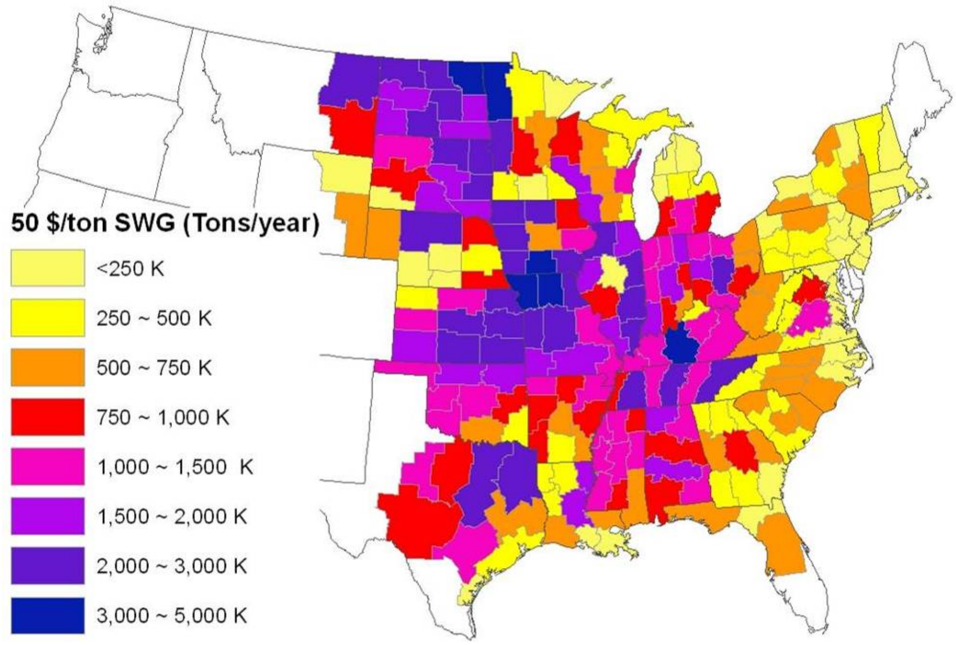

Figure 35 – POLYSIS Estimated Switchgrass Production at $50/ton – POLYSIS Districts

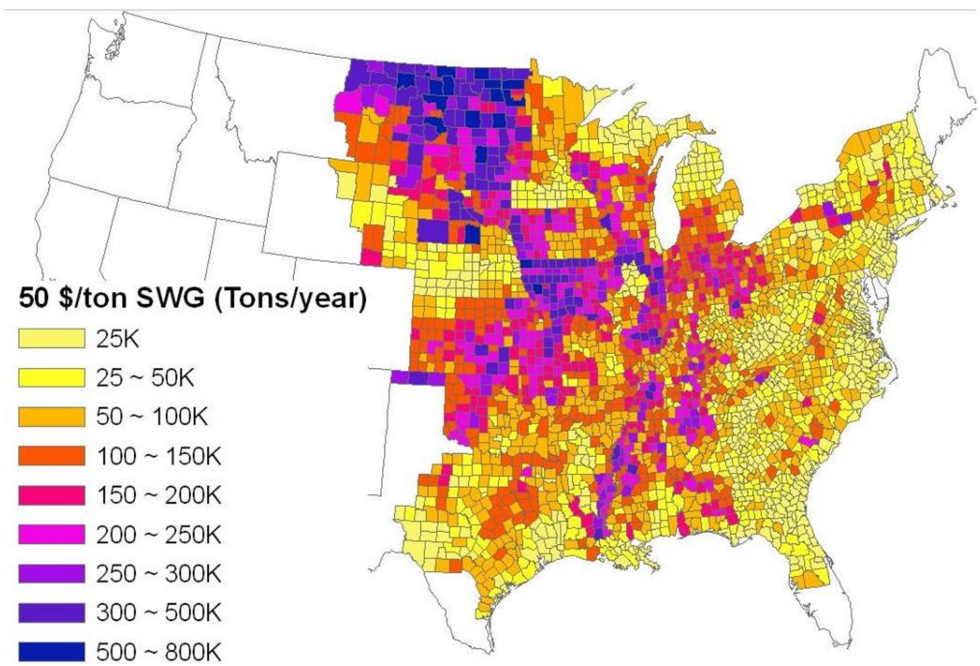

Figure 36 – POLYSIS Estimated Switchgrass Production at $50/ton – Disaggregated to county level

County Level dataset Disaggregation to Farm Level

At 50$/ton, only 56 of the roughly 450 million U.S. farmland acres are estimated as energy crop production acres. The POLYSIS dataset is at the district level resolution, and only provides total production estimates for each entire district.

It is assumed that any non-heterogeneity (soil type, terrain, moisture, etc.) within a district can be accounted for in the differing estimations of energy crop yields. It is recognized that this assumption will not hold were energy crop markets to develop. Farm management, market competition, and a market's tendency to operate under Nash equilibrium would invalidate this simplifying assumption. However, making any other assumptions to aid in the disaggregation of district production levels would be a tedious exercise resulting in less justifiable conclusions.

The disaggregation steps described here, while specific to Pennsylvania, are general enough to be applied to any state provided that a state land use raster image is available. They are also applied to Iowa.

A raster data image depicting land use on a scale of thirty meters square was developed by Penn State researchers from satellite photographs taken between 1999 and 2002 (*33*). Each thirty meter square of land within the state of Pennsylvania is represented by a pixel in the raster image. A color and number is assigned to each pixel according to its land use classification. There are fifteen different land use categories. Since the POLYSYS estimates assume growth on farmland the data used only cropland and Pennsylvania farming land is dominated by row crop land[64] the model only included "row crop". GIS software (ArcGIS) was used to isolate the pixels corresponding land.

With a little over 130 million pixels contained within the land use raster file, row crops account for roughly 2 percent or roughly 26 million pixels. Converted into acres, the land use raster file indicates that roughly 5.8 million acres of row crop farmland exists in Pennsylvania. USDA reports 5.2 million acres (*34*) and is consistent with the GIS estimated data.

Figure 37 shows the location of row crop pixels and county level POLYSIS disaggregated data for the State of Pennsylvania.

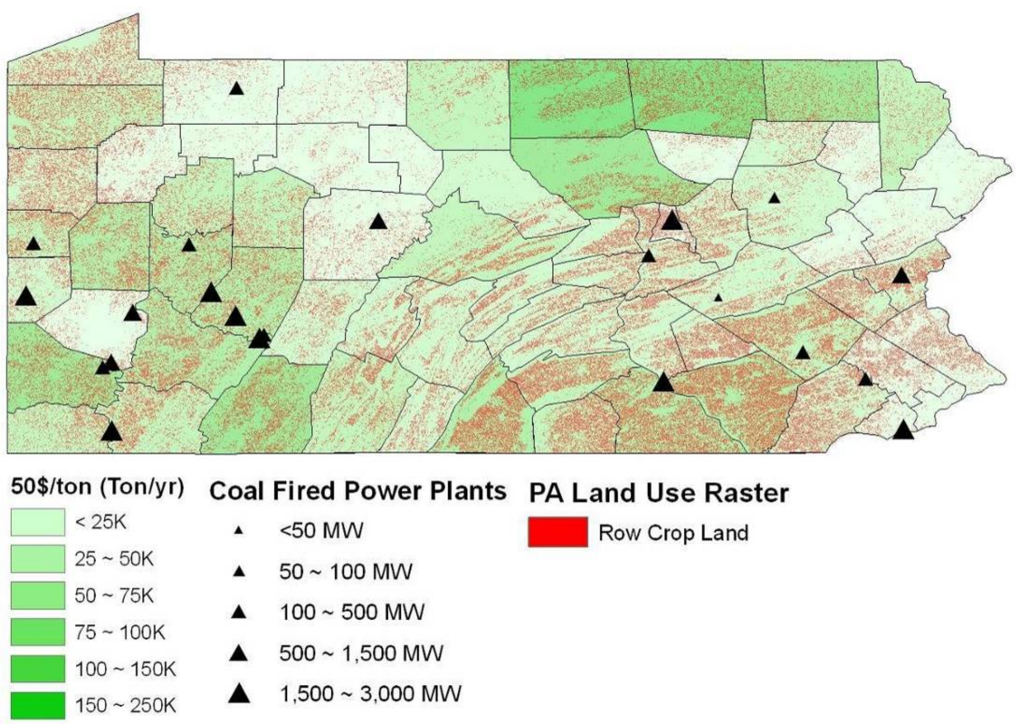

Figure 37 – Pennsylvania – POLYSIS Disaggregated to counties, Land Use Mapping of PA Crop Land, & Existing Coal Fired Power plants

[64] Row crop land ~ 5.2 million acres; pasture land ~ 2.0 million acres; CRP land ~ 190,000 acres.

In this model all crop acres are assume to be equally capable of supporting switchgrass. With 22 utility power plants located within the state and 26 million pixels capable of growing switchgrass more than 600 million possible shipment options are possible within the state[65]. At this resolution a one acre row crop field would be represented by roughly 4 pixels. To reduce the total number of possible shipping routes it was assumed that a farm would consist of at least 100 acres switchgrass with 400 tons of switchgrass.

A point will represent fields, and therefore, it is only necessary to have enough points to capture the relative intensity of farms rather than the actual location of every farm acre. Once the intensity of farms is represented, then biomass production, which was disaggregated from the POLYSIS dataset to a county level dataset, can be allocated to the points. Thus the land use raster image provides a reference for farming intensity rather than specific farms.

Reducing land use raster file resolution

The row crop category in the land use raster file is isolated by transforming the raster pixels into a point feature shapefile using ArcGIS. Once a shapefile, individual points can be manipulated which allows for the isolation of any chosen set of points. Row crop points are isolated and a new raster file is created with the same original resolution resulting in a raster file composed of row crop and empty categorized pixels only.

Next, the "resample" tool in ArcGIS creates a new raster with a new resolution. This tool creates and overlays the grid of the new resolution raster on the old raster. The pixel in the old raster which falls closest to the center of each pixel in the new raster, defines

[65] number of power plants (22) times the number of row crop pixels (~ 26,000,000) = 572 million

the pixel in the new raster. Because the old raster contained only “row crops” and “not row crops”, some of the new pixels will be “row crops” and some will not. The likelihood of a new raster pixel being a “row crop” is proportional to the frequency of “row crop” pixels in the old raster. The resulting new raster is a coarser resolution raster representing the intensity of row crop pixels from the previous raster.

Using this technique, 26 million pixels are reduced to roughly 4,000. 4,000 points representing farms, allows the possible shipment options to fall below 100,000, reducing the decision variables to less than 100,000 in the LP.

The county level switchgrass supply dataset was then allocated to the farm points based on an equal distribution of the available switchgrass within each county. Disaggregated of the POLYSIS data from districts to counties is performed according to

$$\dot{M}_{S_p} = \frac{\dot{M}_{S_j}}{\sum_{p=1}^{l} (SF)_p} \qquad \text{Eq. (43).}$$

$$\dot{M}_{S_p} = \frac{\dot{M}_{S_j}}{\sum_{p=1}^{l} (SF)_p} \qquad \text{Eq. (43)}$$

Where:

M_S = Mass of Switchgrass

SF = Switchgrass Farms

j = Counties making up a POLYSIS district

p = Individual switchgrass farms

l = Number of switchgrass farms in a county j

Figure 38 shows the resulting farm level estimation of switchgrass crop locations.

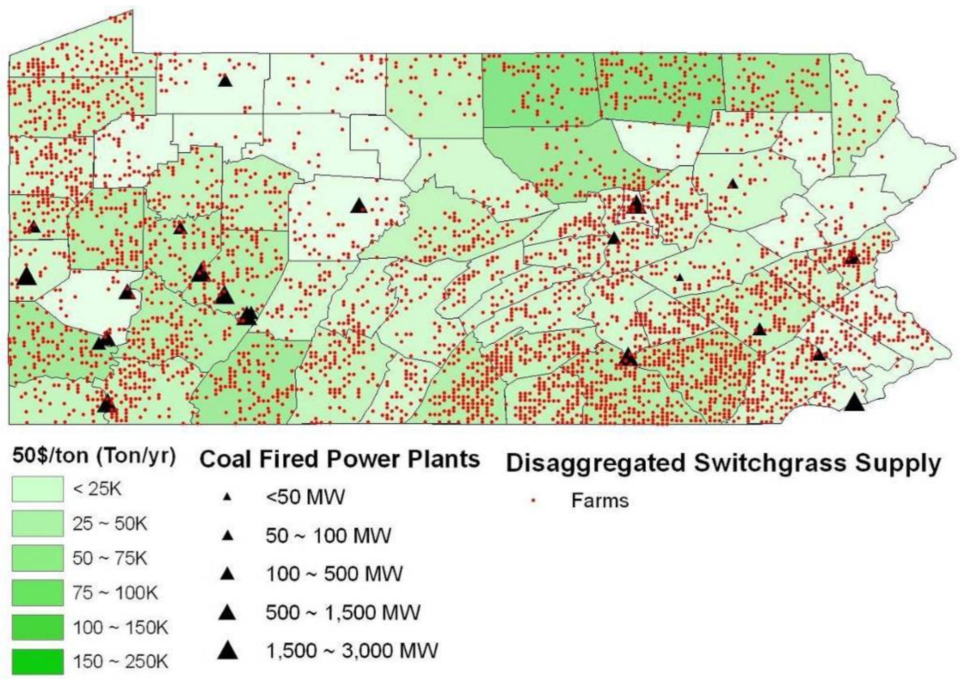

Figure 38 – POLYSIS Dataset Disaggregation to Farm Level - Pennsylvania

This same sequence of procedures is applied to Iowa.

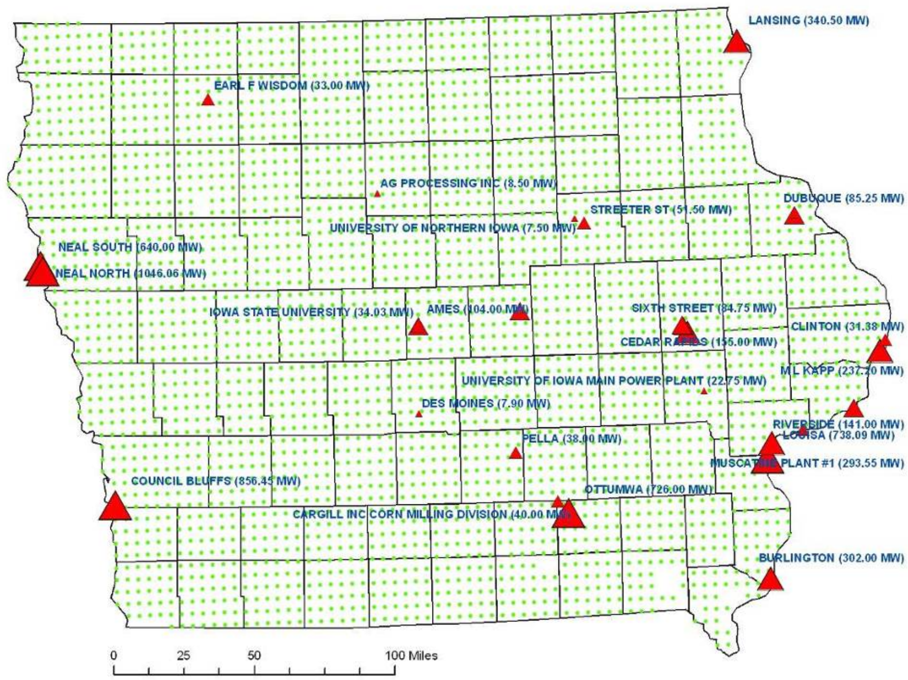

Figure 39 – POLYSIS Dataset Disaggregation to Farm Level - Iowa

Appendix C – A Brief Discussion of Types and Boiler Design Considerations

Coal Fired Steam Generating Boilers, and the Design for Electricity Generation

Each existing furnace boiler combination was designed for and is ideally suited for a specific range of fuels. The three basic overarching design considerations of a steam-generating boiler are the quality and quantity of steam produced and the fuel to be combusted. Working backwards from the purchaser's power generation needs, a specific turbine design will place criteria on the pressure and temperature of steam produced by the boiler. The quantity of steam will largely be proportional to the quantity of desired electricity generation. A boiler manufacturer's engineering team evaluates the types of fuels likely to be combusted over the life of the power plant and, identifying the most problematic fuels, begins the furnace boiler design process. A combination of fuel combustion requirements, steam flow, pressure and temperature ranges, and boiler feedwater conditions define a range of heat transfer performance criteria. Parameters such as furnace combustion strategies, boiler type and size, boiler tube heat exchanger surface area and design are thus constrained to achieve the performance criteria while minimizing foreseen maintenance issues. Long before a power plant is built, the boiler manufacturer's engineers have optimized the furnace-boiler combination specifically for maintaining steam quality and quantity through trouble free combustion. During the life of a power plant, it is the goal of managers and boiler operators to maintain the boiler's ability to perform as designed.

Accepting steam quality and quantity as an extrinsic design constraint, trouble free combustion is completely dependent on the fuel combusted, and the boiler manufacturer's expertise. Oxidizing fuels through combustion provides not only the heat required for steam generation, but also introduces combustion byproducts. During combustion, a wide variance in fuel properties can cause heat transfer difficulties. If these difficulties are not handled or designed properly, a loss of efficiency, down time, and possibly boiler tube failure can result. With a loss of efficiency the ability to control steam pressure and temperature decreases and the cost of generating electricity increases. Decreased steam control can lead to steam turbines operating outside their design specifications, resulting in excessive turbine wear, fatigue, and failure. To ensure the minimization of these risks, coal combusting boilers must be designed for the properties of coal and its ash, or non-coal matter present along with the coal.

Coal, Coal Properties, and Coal Properties Affects on Boiler Design

Coal can be described as organic material in a carbohydrate form (one part carbon, one part oxygen, and two parts hydrogen) that through pressure, temperature, and time below the earth's surface has been transformed into hydrocarbons (simple and complex carbon and hydrogen molecules). Because biological processes rely on non-organic minerals which are absorbed through contact with soils, not all carbohydrate matter is the same chemically. For this reason, coal has different inherent or organically bound non-organic elements. Additionally, spanning between the original carbohydrates timeframe and their transformation to coal, a wide verity of non-organic matter may be deposited and imbedded within the coal at any stage in the transformation. Cracks and fractures which allow water soluble materials to infiltrate can occur within seams all throughout the life of coal. As a result of many pathways, coal is rarely a pure hydrocarbon, but is instead a mixture of hydrocarbons and virtually all common elemental matter. Unfortunately, there is not one simple coal mixture, but instead, properties differ based on coal geography. There are over 300 different types of coal, grouped into 17 ranks, divided by 6 classes. Of the 6 classes (peat, brown coals, lignite, sub-bituminous, bituminous, anthracite), peat and brown coals are generally not used in the U.S.

It is coal's energy content and age that are the primary ranking criteria for classification. Although quantity of volatile matter, fixed carbon, inherent or bed moisture, and oxygen influence class as well, it is the non-hydrocarbon material content that is potential boiler poison and requires much of the attention of boiler manufacturers. Generally 5 to 20% of coal by weight, coal ash--or all the non-hydrocarbon elements--consists primarily of alkalis, shale, pyrite, iron sulfides, and silicates although virtually all other metal and non-metal elements can be found as well. Some impurities can be washed from coal prior to combustion, and coal cleaning is performed quite often. However, due to the manner in which impurities are imbedded, it is not economically practical to clean out all impurities. Many remain and must be treated by the boiler and power plant environmental equipment. **Error! Reference source not found.** presents some of the common coal ash properties

Typical Coal Ash Properties

Mineral	Typical % Composition by weight
Silicon	24 - 60 %
Aluminum	11 - 30%
Iron	4 - 30 %
Calcium	1 - 26 %
Sulfur	1 - 5 %
Magnesium	1 - 4 %
Titanium	1 - 2 %
Potassium	0 - 2 %
Sodium	0 - 1 %
the rest of the periodic table	

Knowing a coal's ash properties, allows a boiler manufacturer to estimate how the ash will act when heated; the properties of coal ash define the temperature at which ash begins to melt, or its ash fusion temperature. Ash fusion temperature is the property most useful when anticipating coal ash transport. Ash begins to deform in the range of 2,000° - 2,400° F. As temperature increases, ash will pass further into its plastic region, becoming fluid at 2,300° - 2,700° F, above which it will exist in a vapor state. Combustion temperatures exceed 3,000° F, and therefore, coal ash is vaporized, and free to travel with the flue gas. Because the goal of a boiler is to extract the thermal energy from the combusted flue gasses, the flue gasses are constantly cooled throughout their residence in the boiler. As gasses cool, they will eventually pass their dew point temperature and condense. Controlling the condensation process is the science and art of an experienced boiler designer, and several methods have proven successful, yielding standard control approaches and boiler furnace designs.

Prior to a discussion of ash control techniques, several terms will be defined. Slag is coal ash in a molten state. The properties of coal ash slag, including melting points, temperature dependent viscosities, and stickiness (sometimes called tackiness), are function of the ash properties. The more silica present, the lower the viscosity at a given temperature; more base to acid increases viscosity. The presence of highly oxidized iron will raise the ash fusion temperatures, but in a non-oxidized state, iron will lower ash fusion temperatures. The more viscose molten ash is, the less likely it is stick to furnace walls and/or boiler tubes.

Fouling is defined when slag begins to stick to heat transferring surfaces such as the furnace walls and the boiler tubes. Slag deposits will fuse on the radiant heat transfer surfaces, such as the furnace walls, and serve as condensing surfaces for minerals. This process enriches the fused slag with mineral. If ash minerals are corrosive to the furnace walls, corrosion can cause furnace wall failure. Ash slag will also condense on and bond to convection heat transfer surfaces. As the ash cools, it provides a sticking surface which attracts more ash to deposit, building until cleaned. Depending on the temperature of deposits, subsequent condensing ash deposits will pass through their ash fusion temperature range. Under this scenario, alkalis minerals (minerals typically corrosive to metal) have a mechanism for physical transport directly to the heat transfer surface, thus increasing concentration at the interface of metal and the ash slag. Increasing concentration exacerbates corrosiveness, deteriorating the heat transfer surface, and eventually resulting in catastrophic failure. Occurring later in flue gasses residence, when flue gas temperatures fall below acid and water vapor dew point temperatures, acid and water condensation will corrode lower temperature heat transfer surfaces such as air pre-heater exchangers.

Experience has led to the conclusion that all coals possess enough impurities to foul and corrode boiler and furnace materials, and that all furnace/boilers must have ash handling strategies. For continuous combustion, coal ash must be removed or successfully handled, and this can define which furnace and boiler type is suitable for a particular type of coal and coal ash. Boiler type is not an arbitrary choice but a design necessity given the plant owner's electricity production needs and the type coal anticipated to be combusted.

Boiler Types and Design

Boilers are basically large heat exchangers coupled with a combustion chamber called a furnace. The two functions of a furnace are to completely combust the fuel and to cool the combustion products (gasses and ash) such that the heat exchange portion of the boiler operates within the desired performance range and can be maintained as designed. Furnace types are typically divided into four designs--stoker, fluidized bed, cyclone, and pulverized coal furnaces--and can be categorized as wet or dry bottom, depending on the condition of ash when it exits the furnace. When ash exists in a liquid state, the furnace has a wet bottom; when ash is solid, a dry bottom.

The primary considerations for which furnace type to employ are categorized in **Error! Reference source not found.**. A discussion of furnace types follows.

Furnace Type	Ideal Coals/Fuels	Ideal Coal Conditions
Stoker	Bituminous Subbituminous Lignite Biomass	Moisture: < 0 - 25% as-fired (Max) Volatile matter: > 18 - 40 % by wt. Fixed Carbon: > 40 - 65 % by wt. (Max) Ash: > 5 - 20 % by wt. (Max) Ash Softening Temperature[66]: 2,000 - 2,500° F
Atmospheric Fluidized Bed	Anthracite Bituminous	Accepting of a large range of conditions

[66] Ash Softening Temperature is the temperature at which the height of a small molten mass of ash slag is equal to half its width.

	Subbituminous Lignite Biomass	
Cyclone	Bituminous Subbituminous Lignite	Viscosity (T_{250})[67]: Bituminous < 2450° F Subbituminous < 2300° F Volatile matter: All coals > 15% by wt. Ash: bituminous > 6% dry basis (Min) sub-bituminous < 4% dry basis (Min) All Coals < 25% dry basis Moisture: < 20 - 40% as-fired
Pulverized Coal	Anthracite Bituminous Subbituminous Lignite	Moisture: < 0 - 40% as-fired (Max)

[67] The T250 value is the temperature at which the ash slag viscosity is 250 centipoises. Below 250 centipoises, slag will flow on a flat surface, above 250, it will not.

A stoker furnace is the oldest furnace design and is typically utilized for small power generation units. Stoker furnaces can typically respond rapidly to changes in steam demand, can turn down quickly, but have lower efficiencies than more modern furnace designs such as fluidized bed, cyclone, and pulverized coal furnaces. Stokers are physically much smaller than cyclone and pulverized coal furnaces, but are capable of handling a large variety of solid combustion fuels with minimal fuel preparation. Many different stoker designs exist, but a stoker furnace generally consists of a bed where fuel is combusted and a removal mechanism for combustion byproducts. Fuel is continually fed either pneumatically or mechanically onto the bed as combustion air is provided from below or above.

Fluidized bed, bubbling fluidized bed, and circulating bed furnaces collectively known as atmospheric fluidized bed combustion (AFBC), follow from stoker furnaces with the exception that air is forced, through the bed from below, creating a suspension of fuel and ash that exhibits a turbulent fluid-like affect. The FBC design was in response to environmental pressures to reduce SO2 and NOx emissions, and FBC furnaces offer better control over these emissions. Although a little more fuel preparation is required for FBC furnaces than stoker furnaces, a fluidized bed operates at lower combustion temperatures allowing for a wider variety of fuels, a reduction in NOx formation, and better SO2 capture. Better fuel combustion control also results in more complete combustion and efficiencies.

Cyclone furnace design grew from a need to reinvent coal combustion such that lower grade coals could be used while reaching higher efficiency. A finer fuel power is pneumatically conveyed into the furnace in a circular pattern creating a cyclone effect. Fuel is completely combusted, releasing high heat rates, and ash is kept in its molten state. The furnace walls are small which results in smaller heat absorption through the furnace walls. Combusting coal and molten ash are held against the furnace wall by centrifugal force, as excess ash flows to the bottom of the furnace where a slag tap removes it. Cyclone furnaces are ideal for the combustion of lower grade coals with higher ash content and low fusion temperatures.

Pulverized coal furnaces (PC) are the most prevalent modern boiler design. There is virtually no limit to their size and they are capable of high efficiencies over a large range of sizes. Coal must be dried and ground to a very fine powder prior to pneumatic injection along with its combustion air. Multiple injection locations are typical which allow greater control of temperature and combustion NOx formation. PC furnaces are appropriate for a wide variety of fuels, and with the addition of specific equipment, low volatility fuels like anthracite coals can also be fired. Because the coal and coal ash is ground so finely, coal ash is carried along with flue gasses through the entire boiler, and collected by particle collecting equipment downstream of the heat exchanger surfaces. Ideally, the fired coal should have high ash fusion temperatures because the flue gas is cooled to below ash fusion temperatures prior to reaching the much cooler boiler tube surfaces. Flue gas cooling is accomplished by a combination of the furnace wall cooling and the addition of cool air downstream of the combustion zone.

Even though furnace types are chosen by their ability to handle certain coals, boiler design further tweaks ash handling. When ash is expected to be troublesome, boiler tubes are designed shallow, with large spacing so that cleaning, when necessary, can be performed quickly. When boiler tubes are designed in such a fashion, the heat transfer surface requirements are not reduced, and, therefore, boiler size must increase. Obviously, capital costs are proportional to boiler size, so boilers are not designed for excess size unless necessary. Many furnaces are equipped with soot blowers which are responsible for maintaining low levels of fouling. The size, quantity, and speed, all of which translate into parasitic electricity loads, are determined by the ash properties as well.

Knowing coal ash properties also allows boiler managers and operators to control for fouling. Strategies aimed at controlling flue gas temperatures are the primary means for controlling fouling, and it is incumbent on the managers and operators to ensure proper maintenance and operation of these controlling mechanisms. If, for instance, the non-cyclone furnace walls are not maintained below ash fusion temperatures, fouling of furnace walls will insulate the combustion region, resulting in increased flue gas temperatures. Increased flue gas temperatures can exceed to the point where post combustion temperature controlling is reduced, and boiler tube fouling grows. In cyclone furnaces, excess air affects slag viscosity as well as the ash properties. A change in slag viscosity can lead to a reduction in slag sticking to the furnace walls causing wall corrosion and erosion. Conversely, an increase in viscosity can result in slag build up. In PC furnaces, the fuel injection ports are designed for a specific coal, with the objective of reducing NOx while maintaining high efficiencies. Changing fuels certainly has the chance of altering the boiler performance and affecting the furnace's ash handling strategy.

Conclusion

Changing the fuels fired at a power plant is cause for a review of firing methods, procedures and perhaps equipment. It is not as simple as just changing the fuel mixture, but instead should be pursued with caution.

Appendix D – Ranking of States' Ratio of Switchgrass Growth Potential to coal Based Electricity Generation

Table 6 – States' Ratio of Switchgrass Growth Potential to Coal Based Electricity Generation

State	% Coal	Total GWh	GWh from Coal	Coal Consumption (ton)	Nameplate Capacity MW	SWG @ 50 DpT (tons)	% SWG to Coal Capacity
Rhode Island	0%	2,883	--	-	-	-	
Vermont	0%	2,968	--	-	-	333,467	
Idaho	1%	6,775	45	25,000	19	-	
California	1%	111,128	1,257	748,000	398	-	
Maine	2%	11,920	226	110,000	102	-	
Oregon	5%	29,544	1,579	936,000	573	-	
Washington	10%	59,302	5,720	3,805,000	1,462	-	
Arizona	37%	61,183	22,911	11,712,000	6,375	-	
Nevada	50%	19,626	9,844	4,586,000	2,784	-	
Colorado	74%	27,594	20,528	11,052,000	5,335	-	
New Mexico	86%	19,009	16,371	9,322,000	4,295	-	
Utah	95%	21,853	20,725	9,537,000	4,773	-	0%
Delaware	60%	4,854	2,933	1,251,000	1,541	1,751	0%
Wyoming	96%	24,935	23,933	14,587,000	6,076	772,433	4%
Maryland	52%	28,891	15,146	6,028,000	8,373	348,562	4%
New Jersey	17%	33,251	5,817	2,458,000	3,326	153,859	4%
West Virginia	97%	53,044	51,696	21,489,000	15,462	1,576,980	5%
Florida	29%	124,206	36,377	15,310,000	14,434	1,386,937	6%
Massachusetts	21%	29,031	6,205	2,558,000	2,702	241,809	6%
Pennsylvania	55%	127,342	69,826	31,395,000	21,922	3,299,201	7%

Connecticut	14%	18,504	2,574	1,249,000	762	177,041	10%
North Carolina	62%	75,974	47,153	19,000,000	14,548	2,994,631	11%
Texas	39%	218,441	85,087	59,483,000	22,077	10,184,041	12%
Georgia	64%	75,549	48,581	22,269,000	15,804	4,418,372	14%
New Hampshire	16%	13,742	2,218	897,000	668	190,811	15%
Michigan	55%	69,115	38,330	19,935,000	15,267	4,749,028	16%
South Carolina	41%	56,898	23,202	9,240,000	7,637	2,859,720	21%
Ohio	88%	85,976	75,856	32,511,000	24,681	10,589,428	22%
Indiana	94%	73,718	69,164	34,070,000	23,251	11,347,691	23%
Kentucky	91%	56,050	51,003	23,113,000	17,217	8,553,804	25%
Alabama	54%	79,118	42,633	19,887,000	14,904	7,611,222	26%
Virginia	43%	47,134	20,132	8,656,000	9,175	3,658,795	29%
Illinois	49%	111,292	54,004	32,151,000	18,838	16,327,048	35%
New York	17%	83,730	14,051	6,161,000	4,265	3,130,096	35%
Montana	63%	15,129	9,602	6,220,000	2,401	3,278,886	36%
Wisconsin	69%	34,681	23,877	14,433,000	7,900	8,231,050	39%
Louisiana	24%	55,787	13,345	8,976,000	5,193	5,750,733	44%
Minnesota	62%	30,671	18,949	11,484,000	6,032	8,331,160	50%
Tennessee	61%	56,466	34,411	14,932,000	12,990	11,180,999	51%
Missouri	87%	49,898	43,457	25,739,000	12,093	19,617,682	52%
Nebraska	61%	18,034	11,046	6,869,000	3,176	5,373,052	53%
Arkansas	48%	29,614	14,103	8,572,000	3,911	6,815,894	54%
Oklahoma	54%	35,255	18,983	11,477,000	6,398	10,207,960	61%
Kansas	73%	27,399	20,092	12,800,000	5,921	16,975,669	91%
North Dakota	94%	18,186	17,018	14,568,000	4,268	19,725,549	93%
Iowa	82%	24,537	20,150	13,226,000	6,547	19,511,372	101%
Mississippi	39%	25,904	10,143	5,702,000	2,498	10,047,030	120%
South Dakota	45%	4,719	2,145	1,382,000	611	14,530,592	719%

Appendix E – Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States

Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the US

William R. Morrow[1], W. Michael Griffin[2,*], and H. Scott Matthews[1,3]
[1]Department of Civil and Environmental Engineering, Carnegie Mellon University, Pittsburgh, PA 15213
[2]Tepper School of Business, Carnegie Mellon University, Pittsburgh, PA 15213
[3]Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213
[*]Corresponding author phone: 412-268-2299; fax 412-268-7357 email: mwg@andrew.cmu.edu

Abstract

Alternative fuels and infrastructure are likely to be important in the future as security and environmental concerns come forward in national priorities. We consider the economic costs of various ethanol fuel blends for transportation scenarios in the US as a substitute for petroleum-based fuel. The current infrastructure in the US for shipping and refining petroleum-based fuels has been highly optimized over time and contributes a relatively small portion of costs (about 3 cents/gal). Our estimates for various ethanol replacement scenarios yield higher cost (2.5 to 9 cents per gallon of ethanol blend for downstream transportation costs only) but remain a relatively small fraction of total fuel cost. If ethanol is to be a competitive option in the long run, more efficient shipment infrastructure will need to be developed, such as pipelines. Unfortunately when using ethanol in low level blends (e.g. E10, 10% ethanol/90% gasoline) existing petroleum and product would still be needed for gasoline based portion of the fuel. Building new pipelines to deliver ethanol would be cost-effective in the short run but if ethanol were to replace gasoline in the long run then pipeline overcapacity would result.

Introduction

Petroleum has many virtues. It has high energy density, is relatively abundant, a feedstock for multiple chemicals, and has low cost. Unfortunately, its production, refining, transport, and combustion cause substantial environmental problems. Assuring a steady supply of imported oil has led to two major wars since 1990 and shapes US foreign policy. The US imports 56% of the 20 million barrels of petroleum per day that is consumed (1). Continued increases in global petroleum consumption will inevitably lead to a shortage and price increases. US fossil fuel use for transportation results in 110 million metric tons of criteria air pollutants emissions (56% of all US emissions), and 1,850 million metric tons of carbon dioxide (CO_2) emissions (32% of the US total) (2,3). Decreasing petroleum consumption by using an alternative – preferably renewable – fuel for use in the light duty (LDV) fleet could address some of these issues.

When made from cellulosic biomass, ethanol can be produced and utilized with no net CO_2 emissions. The production of cellulosic biomass can have many positive impacts in the ecology of agriculture, including increased soil carbon and biodiversity. Engine emissions can be treated with conventional catalytic converter technology. Since ethanol has 1/3 lower energy density than gasoline, a greater volume of fuel is needed for the same range, but the difference is small for blends with 10-20% ethanol (E10-E20). Ethanol is a liquid and for the most part is compatible with our current fueling infrastructure.

Numerous studies have addressed the technical and economic aspects of ethanol production including biomass sources and dedicated growth, biomass conversion to ethanol and to some extent the distribution of ethanol to the retailer (4,5). Lave and co-workers concluded that ethanol is an attractive fuel and has the potential to become an important alternative fuel if it could be produced in quantity and supplied throughout the country (6,7).

In this paper we explore possible costs of shipping cellulosic ethanol from production centers to consumers throughout the US. We assume a robust cellulosic ethanol industry and develop a linear programming model to represent a possible nationwide ethanol distribution system. We consider various levels of ethanol use. In our model only switchgrass is considered as a cellulosic feedstock.

Current Ethanol Infrastructure

Ethanol has a long history of use as an automobile fuel. The US used ethanol as an alternative to gasoline in 1905 (8). Ultimately, the high cost of ethanol, the slow repeal of the alcohol excise tax for fuel ethanol, and the considerable investment of the automotive industry in gasoline engines prevented its large-scale adoption. Ethanol has been used in Brazil since the energy crisis of the 1970's. By 1979, all Brazilian cars ran either on E22 or hydrated ethanol (95% ethanol/5% water) (9,10). Brazilian ethanol use offsets over 200,000 barrels of gasoline per day.

In the US, light-duty vehicles (LDVs) consume about 130 billion gallons of gasoline per year. In 2002, 13% of this volume contained some amount of blended ethanol. However the amount of actual ethanol used by LDVs is small – 1.2% by volume and 0.8% by energy (1).

In the US, there are 96 corn ethanol plants, current or under construction, with an annual production capacity of 4.4 billion gallons of ethanol. The vast majority of this ethanol comes from corn. The industry utilizes 1.6 billion bushels of corn, about 11% of the US corn crop (11). At average US corn yields of 142 bushels/ acre in 2003, approximately 11 million acres of corn is required, mainly in the Midwest (12). Corn is transported to the plants by truck and rail. The ethanol produced is shipped for blending with gasoline mainly via truck across the US.

Importance of cellulosic ethanol

Corn milling produces a variety of co-products depending on the process. In wet milling co-products include starch, sweeteners, gluten feed and meal, along with corn oil. Dry milling produces a primary co-product, distiller's dried grains with solubles (DDGS) used as an animal feed supplement. Both process can produced CO_2 for sale. These co-products off-set some of the ethanol production costs (13).

To fuel the entire US LDV fleet on E10 (10% ethanol/90% gasoline), 13 billion gallons of ethanol would be needed (Table 1). A complete switch to E100, 100% ethanol fuel, would require 193 billion gallons of ethanol, accounting for the energy differences between gasoline and ethanol. Unless other co-product alternatives develop, the corn milling industry could potentially produce an estimated 5 billion gallons of ethanol - 30% more than current capacity- before co-product market saturation makes additional corn ethanol production uncompetitive (14). McAloon et al. (15) indicated that the animal feed markets were showing signs of saturation due to the large reduction in DDGS price from 1996 to 1999. To meet the ethanol requirements for E10, 8 billion gallons of ethanol will need to come from non-corn sources. Thus, other feedstocks, like cellulosics, will be required.

Ethanol from cellulosic feedstocks is a less proven process than producing ethanol from corn. The main differences center around the front-end processes used to convert the feedstock to fermentable sugars. Starch and cellulose are essentially long polymers of sugars. However, in cellulosics the fermentable sugars are found in a complex of cellulose bound with lignin and hemicellulose. This combination requires more intense processing than needed to remove starch from the corn kernel. Pretreatment and hydrolysis are required to separate the lignin from the cellulose and hemicellulose and ultimately convert the carbohydrates into their constitutive C_5 and C_6 sugars. The major pretreatment technologies have been recently reviewed (16). The C_5 and C_6 sugars are converted to ethanol via fermentation.

As an emerging technology, cellulosic ethanol production has been the target of Government funded research. Although no commercial facilities exist, the technology has moved to pilot stage. Assuming continued development and projected cost reductions, cellulosic ethanol provides opportunities for a wider variety of feedstocks for ethanol production including municipal solid wastes, agriculture and food waste, and energy crops. In this study we focus on energy crops, specifically switchgrass.

TABLE 1. Ethanol required to meet various ethanol-gasoline blend levels[1]

Fuel[2]	Required volume of blend	Required ethanol	Ethanol provided from corn	Ethanol required from other sources
		(billion gallons)		
E5[3]	132	7	5	2
E10	134	13	5	8
E20	139	28	5	23
E85	180	152	5	147
E100	193	193	5	188

1 – Base year is 2001, gasoline consumption was 129.7 billion gallons of which 1.5 billion gallons was ethanol

2 – HHV for gasoline (125,000 Btu/gal) and ethanol (84,100 Btu/gal) were used for the calculations

3 – EX where X denotes the percent by volume of ethanol contained in the gasoline/ethanol blend

On average, fuel use increased annually at a rate of 1.9% from 1991 to 2001 (1). This can be expected to continue unless offset by fuel economy savings. Table 2 shows the ethanol required for various increases of fleet fuel economy. Even at a doubling of fleet average miles per gallon (mpg), blends above E10 would likely require ethanol from cellulosic sources. To calibrate the potential for fuel savings via fuel economy improvements, the National Academy of Science's Committee on the Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards found that advanced technologies including direct-injection lean-burn gasoline engines, direct-injection compression-ignition (diesel) engines, and hybrid electric vehicles could improve fuel economy by 20 to 40 percent (17). A fleet with even higher fuel economy would require a change in the vehicle mix, toward smaller, lighter vehicles.

TABLE 2. Ethanol required to meet ethanol-gasoline blend levels with various fuel economies[1]

Fuel[2]	Light duty fleet fuel economy increase			
	10%[3]	25%	50%	100%
	(billion gallons)			
E5[4]	6	5	4	3
E10	12	11	9	7
E20	27	24	20	15
E85	138	122	101	76
E100	174	153	128	96

1 – Base year is 2001, gasoline consumption was 129.7 billion gallons of which 1.5 billion gallons was ethanol

2 – HHV for gasoline (125,000 Btu/gal) and ethanol (84,100 Btu/gal) were used for the calculations.

3 – Base fleet mpg is 20.2 mpg; at 10%, 22 mpg; at 25%, 25 mpg; at 50%, 30 mpg, at 100%, 40 mpg.

4 – EX where X denotes the percent by volume of ethanol contained in the gasoline/ethanol blend

Vision of a cellulosic ethanol infrastructure

Large-scale production of cellulosic ethanol would require significant investment in feedstock distribution systems, production facilities, ethanol distribution systems, and retail stations. Two distinct transportation systems are needed; one bringing biomass to the production facility and the other moving ethanol to the consumer. Estimates for some of the infrastructure components can be made from literature values. If built using current cost estimates of capital for cellulosic ethanol production capacity using E100 to replace all US gasoline consumption range from $337 to $647 billion based on capital costs of $1.82 to $3.49 per gallon (18). For E10 the investment would be from $14 to $30 billion. Assuming the production capacity associated with the lower capital cost case (87.5 million gallon per year), it would take 94 to 2,120 production facilities to supply the required ethanol for E10 or E100, respectively. To put this into perspective, the oil industry has 149 refineries in the US, which at current estimated construction costs would require \$173 to \$260 billion to replace current capacity (19,20). Of course the development of larger cellulosic facilities capturing potential economies of scale could reduce both number of facilities and investment on a per gallon basis. However, even the potential of larger facilities is constrained by the spatial distribution of switchgrass.

Petroleum product pipelines currently move 299 billion ton-miles of refined petroleum products, 60% of petroleum product shipments (21). There were approximately 91,000 miles of petroleum product pipeline in 2003 (22). It would be expected that a mature ethanol production industry providing the majority of the energy required for the LDV would also use pipelines to move product. In such a long-term scenario, some fraction of current petroleum and petroleum product lines could be converted to carry ethanol. Current lines run between gasoline production centers to use centers, which may or may not correspond to the centers of ethanol production. If all pipeline capacity were replaced, using the current industry rule of thumb of a million dollars per mile for construction costs, this would cost \$87 billion. Even at this extreme the cost is 4 to 7 times less than the estimated capital needed for ethanol plant construction. The investment would be incremental as the industry grew and would likely be spread over many years. The majority of petroleum pipeline infrastructure was constructed over 70 years with 75% of the construction occurring from 1940 to 1980 (21).

A transition from gasoline to ethanol would likely be incremental. The first regions of the country to change would be located near current corn mills and new cellulosic mills in areas where biomass could be grown most economically. In these regions, ethanol could be used as a fuel extender in low-level blends (less than E10). As the industry developed and matured, higher levels of ethanol could be incorporated in gasoline nationwide (E10, E20 (20% ethanol/80% gasoline)). With over 1.3 million flexible fuel vehicles in the current LDV fleet (23) and the technology for taking advantage of and treating emissions from ethanol and ethanol blends relatively well known and inexpensive, the transition to higher blend fuels could occur rapidly compared to other technologies. Ultimately the degree of ethanol substitution will be determined by multiple factors including land use, fleet efficiency gains, and the increased energy use related to population growth and increased vehicle miles traveled.

Commissioned by Oak Ridge National Laboratory, Downstream Alternatives Inc (DAI) published a report in 2002 containing estimations of infrastructure and cost requirements associated with an expanded ethanol fuel economy. DAI analyzed two cases, 5.1 and 10 billion gallons per year (BGY) ethanol (24). In the 5.1 BGY case, 89% of the ethanol was provided by corn grain and corn stover. The remaining 11% came from municipal solid waste as the primary feedstock. In the 10 BGY case, 67% was provided from corn grain and stover, 20% by municipal solid waste, and the remaining 13% from other cellulosic feedstocks (e.g. rice wastes, potatoes, forest waste, etc). Their analysis estimated the total costs (including capital costs amortized over the life of equipment) for terminal improvements and retail conversions, new transportation equipment, and freight costs using Chicago as a source. They found that the total transport costs would be approximately \$760 million dollars in the 5.1 BGY case, and \$900 million dollars in the 10 BGY case.

In contrast to DAI, we investigate the implications of a larger scale ethanol program. We assume that ethanol will be used as low-level blends and transition to higher levels blends as more and more cellulosic ethanol becomes available, if possible. For low level blends (e.g. E20) both a considerable ethanol delivery infrastructure and the current infrastructure for petroleum transportation will be needed. Thus, two possibilities exist; one where a duplicate pipeline system will be used for ethanol to capture the most efficient and low cost method of transport or the other where a less than optimal system, truck and rail, would be used in the short run for ethanol transport until the need for the petroleum infrastructure diminishes and can be transformed to ethanol use. We examine the downstream transportation freight costs. Since the cost of transporting biomass is relatively high, ethanol plants will be located close to low cost biomass resources; the ethanol would be shipped via truck or rail to the major centers of US population and fuel consumption. We develop a linear program to estimate the cost of transportation and the modes of transportation needed to meet the shipping requirements for the current ethanol industry with expanded capacity and scenarios with various amounts of switchgrass derived cellulosic ethanol added to the fuel mix of the US light duty fleet.

Methods

Our transportation optimization model minimizes the shipping distance of ethanol to the 271 largest metropolitan statistical areas (MSAs) from two sources - current corn based facilities (expanded to meet maximum corn ethanol production) and hypothetical switchgrass cellulosic facilities in the continental US.

Transportation Optimization Equations

Objective Function: Minimize: $$\sum_{i=1}^{n}\sum_{j=1}^{m} V_{ij} \times D_{ij}$$

Where i = Export (Supply) Location (1 to n number of plants)

j = Import (Demand) Location (1 to m number of MSAs)

Constraints:

$$\sum_{i=1}^{n} V_{ij} \le E_i$$

$$\sum_{j=1}^{m} V_{ij} \le I_j$$

Variables:

Let:

I_j = Import (Demand) demanded by location j – (Gallons)

E_i = Export (Supply) available from location i – (Gallons)

D_{ij} = Distance between Locations i & j – (Miles)

V_{ij} = Volume of ethanol transported between locations i & j – (Gallons)

Estimation of the Variables

I_j Import (ethanol demand) demanded by location j:

The model considers 271 of the 273 1997 Metropolitan Statistical Areas (MSAs) in the US, excluding only Anchorage and Honolulu (25). Gasoline demand in these areas is based on the ratio of the MSA's population to all of the MSA populations within the state in which the MSA resides. Using state gasoline consumption statistics (26), each MSA's ratio is used to allocate its demand from the state's fuel consumption. Thus, all of a state's fuel demand is allocated to the MSAs ignoring outlying rural areas. For MSAs crossing state boundaries county level population components (27) of MSAs were used to break the MSAs populations into their respective state components. One hundred percent of the gasoline consumed in the contiguous US state was allocated to the MSAs by this method.

E_i Export (ethanol supply) available from location i

Year 2002 ethanol plant locations and capacities were obtained from the renewable fuels association (28). These 78 plants have a total capacity of 3.2 billion gallons. Increased corn ethanol production could come from increased acreage planted, increased corn yields, or process improvements. We chose to increase the capacity of corn ethanol production to 5 billion gallons by expanding current facilities. Many possibilities exist for such expansion including process improvements, conversion of corn fiber, or simply increased corn utilization. This is a simplifying assumption knowing that expansion will include a combination of new plants and process improvements at current facilities. However, since most current corn mills are distributed regionally in the Midwest and new mills would be generally located in the same area, i.e. corn growing regions. Thus, this simplifying assumption will have little spatial impact on the national optimization model.

The maximum capacity for any expanded wet mill was limited to 250 million gallons per year based on the size of most of the largest facilities operated by the large ethanol players, Archer Daniels Midland and Cargill. Dry mill expansions were limited to 50 million gallons per year based on the observation that only a few plants exceeded this capacity. After extrapolation, the total plant capacity was 5.2 billion gallons.

For ethanol demand beyond 5 billion gallons per year, cellulosic ethanol plants, using a switchgrass feedstock, were modeled. Switchgrass availability data was provided by Lynn Wright of Oak Ridge National Laboratory. The switchgrass data is aggregated on POLYSYS districts (Agriculture Statistical Districts (ASD)). The districts are comprised of counties having similar attributes (soil type, moisture, terrain, etc.) and economic conditions. In the datasets, there are 305 POLYSYS districts, containing 2,787 counties. Our scenarios were based on available switchgrass at biomass costs of $30/ton, $35/ton, and $50/ton.

Ethanol production facilities are assumed to be located where the switchgrass is produced. Plant location and size determination was a two-step process. The first step was to determine if an ASD district could produce enough switchgrass to support a base plant size of 2,200 ton/day. This minimum plant size is based on the work of Wooley et al. (18,29) and Aden et al. (30). Areas that did not meet minimum switchgrass criterion were assumed to produce no ethanol.

In the second step, districts that had more than the minimum amount of switchgrass were assumed to have some combination of base plants and larger plants that permitted use of all of the available switchgrass in that district. However, modeling was based on a single plant having the capacity to utilize all of the switchgrass available in the ASD. ASD's vary in size but the resolution of the switchgrass data was only to the ASD level. This prevented spatial locating plants within the ASD's. Since we were assuming a robust commercially viable industry we assumed whatever the costs of feedstock, including shipping to the facility, permitted the facility to compete in the marketplace.

If an ASD could support at least the base cellulosic ethanol plant feedstock requirement, then a town was chosen within the boundary of the ASD, and all its production capacity was assigned to that town. Even when there was enough capacity to support multiple production facilities within an ASD, only one plant, containing all production, was modeled. Using this method at $50/ton of switchgrass only 137 of the 305 ASDs would support switchgrass based cellulosic ethanol production. At $30/ton, the number drops to 52 ASDs.

At a workshop conducted at Carnegie Mellon University in the summer of 2001, experts agreed that mature process yields would likely be between 80 to 90 gallons per ton of dry switchgrass. We assume the midpoint of that range. At 85 gallons of ethanol per ton of switchgrass and using the switchgrass availability provided by ORNL the cellulosic ethanol production facilities would produce approximately 5.6 billion gallons of cellulosic ethanol per year, at 30$/ton switchgrass. This combined with the 5 billion gallon capacity of the expanded corn ethanol industry would satisfy the capacity requirement of our E5 fuel economy. At $35/ton, 8.6 billion gallons of cellulosic ethanol could be produced. This combined with the maximum amount of corn ethanol could provide enough ethanol to meet LDV demand for E10. At $50/ton, we expect 18.4 billion gallons per year, which would satisfy the requirements for our E16 fuel economy. Higher amounts of ethanol would require higher biomass costs. These data were not available thus, E16 was the highest-level blend that could be modeled.

D_{ij} Distance between locations i & j

Using the online service MapQuest.com®, the distance between existing corn-based and forecasted cellulosic production facilities to each MSA was compiled into a distance matrix. For the few cases when a specific city/state could not be identified, an approximate zip code was used. Distance between each of the 214 production facilities (78 existing corn based ethanol plans as well as 136 forecasted switchgrass based ethanol plants) and the 271 MSAs were calculated.

The distances used above are "highway" distances rather than "rail" distances, but are used for both transport modes. To test how rail and highway distances vary, rail distances were taken from Amtrak schedules for all routes offered by Amtrak. When these distances were compared, the distribution of differences between rail and highway miles shows that rail is more likely to be longer than highway routes. Thus, our model may underestimate rail distances and ultimately rail shipping costs.

V_{ij} Volume of ethanol shipped between locations i & j

V_{ij} is the optimization model decision variable. The optimization software solves for the optimal set of V_{ij}, satisfying the model constraints, yielding the minimum gal-miles shipped throughout the US. This results in a matrix of V_{ij} (which have been solved for the minimum gal-miles) that forecasts ethanol shipments between producers and consumers.

R_{ij} Freight Rates between locations i & j

While not part of the optimization model, we calculated shipping costs for rail and truck based on the model results. We applied the truck and rail transport costs to the optimization results using the following formula;

$$\$ = R_{mode} \times \sum_{i=1}^{n} \sum_{j=1}^{m} (V_{ij} \times D_{ij})$$

where, R_{mode} is cost per gallon-mile for truck and rail.

To estimate the values for R_{mode}, aggregate total dollars spent on rail and truck transport were taken from the US Department of Census Bureau of Economic Analysis “1997 Benchmark Commodity by Industry Direct Requirements” table (31). Quantity of commodities shipped by rail and truck were taken from the 1997 Commodity Flow Survey using “Shipments by Destination and Mode of Transportation” table (32). Using United States Geological Survey data which list the geological center of all of the US states (33), and the online “city distance tool” on geobytes.com® web site to calculate great circle distances, a distance matrix was developed which contains the great circle distances between all the geographic centers of all the 48 continental states.

Using the Commodity Flow Survey “Shipments by Destination and Mode of Transportation” table, for each state to state transport, the ton-miles shipped between individual states was divided by the total ton-miles shipped nationwide. For example, Alabama’s transportation of goods to Arkansas represents 0.0126% of the national total of all good transported in the 48 continental states. Thus a matrix of ratios is calculated which captures each state-to-state transportation’s fraction of the national total of transportations. This ratio is used to divide the national aggregate dollars spent on transport into costs estimates for each respective state-to-state transport. Keeping the same example, an estimated $21.6 million was spent in transporting goods between Alabama and Arkansas. The Commodity Flow Survey also published the tons transported between states. Dividing each state-to-state cost by the tons shipped between states produced a matrix of costs per ton shipped. Knowing the distances between state center points, a linear regression was used to produce an equation for cost per ton as a function of distance where the slope equals the average ton-miles cost.

This procedure was done to estimate the freight rates for both rail and truck. The rates are as follows:

Truck Freight Rate = 21.5¢/ton-mile

Rail Freight Rate = 7.2¢/ton-mile

For comparison, the Bureau of transportation Statistics estimates that in 2001 the truck and class 1 rail freight rates were 26.6 and 2.24 cents per ton-mile, respectively (34).

Scenarios

Figure 1 shows a representation of all of the corn and cellulosic switchgrass ethanol facilities and MSA's used in the following scenarios.

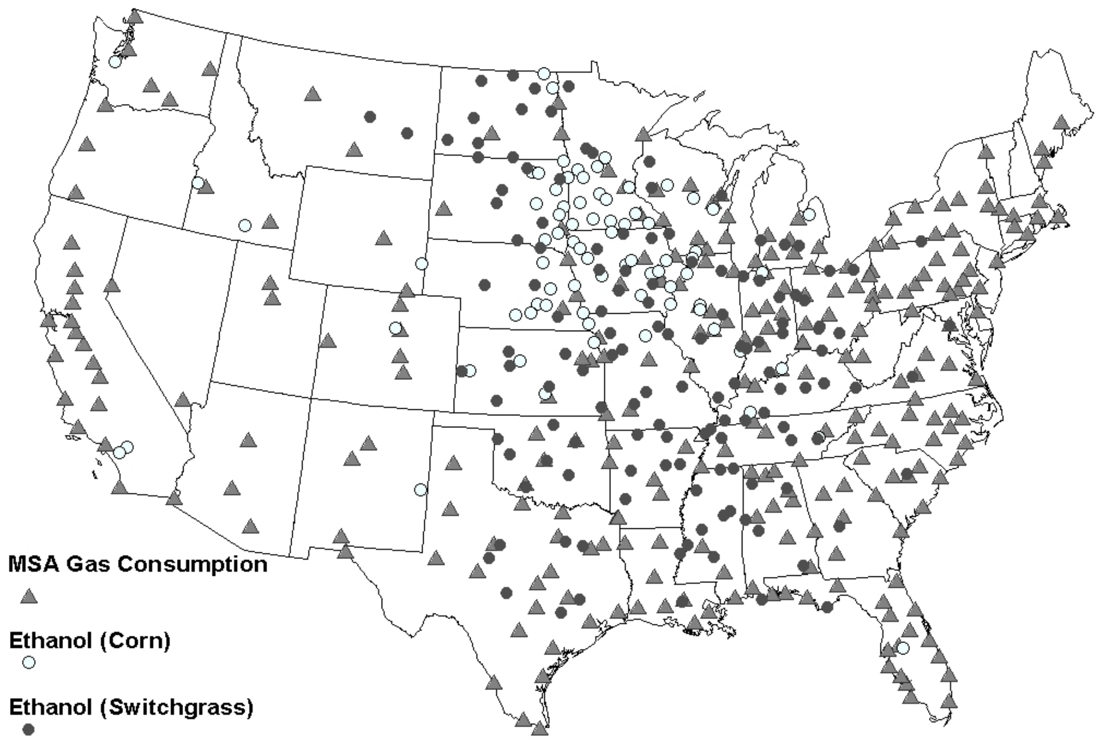

FIGURE 1. Locations of all ethanol production facilities (corn and switchgrass) and MSAs consuming ethanol blended fuels modeled in the study.

As a baseline scenario (Scenario E5 corn) we looked at production of 5 billion gallons of ethanol solely from corn. We model demand in these scenarios as E5. Five billion gallons of ethanol will not meet the requirements for fueling the LDV on E5. Thus not all MSA's would get all of the ethanol required. In this case MSAs closest to the production facilities would get their demands met first.

We also modeled three scenarios using low level blends of ethanol E5, E10 and E16 to fuel the entire light duty fleet, each requiring the use of corn and switchgrass. The availability (spatial and amount) was modeled based on ORNL data for switchgrass costing $30/ton, $35/ton and $50/ton, respectively. The scenarios were labeled Scenario E5 – Corn/Switchgrass, Scenario E10 – Corn/Switchgrass and Scenario E16 – Corn/Switchgrass.

Results

Switchgrass Availability:

Figure 2 shows available acres of switchgrass at farmgate prices from $25 to $50/ton used in this study. At an ethanol yield of 85 gal/ton, switchgrass could provide between 366 million gallons to 25 billion gallons. The higher value is enough ethanol to supply the LDV fleet with E20 and to meet some expanded fuel consumption due to increasing demand and to develop strategies for hedging against catastrophe.

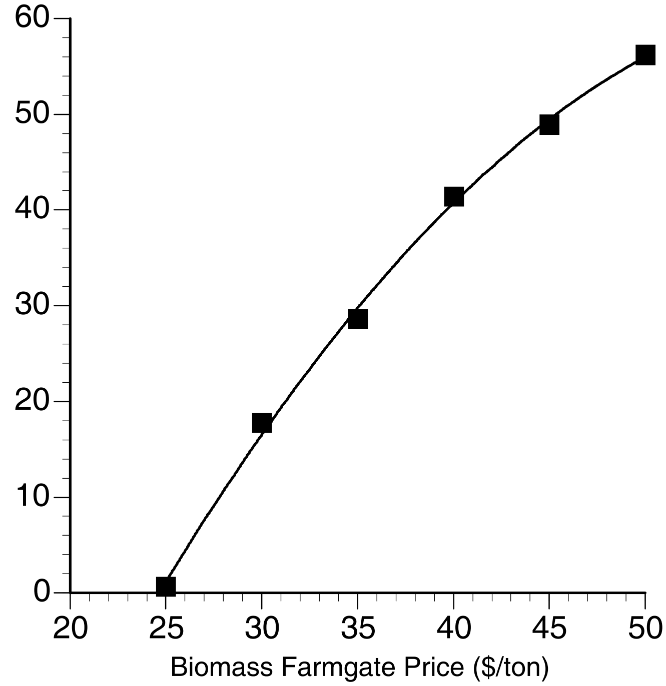

FIGURE 2. Effect of farmgate price on acreage planted.

The estimates of switchgrass availability shown in Figure 2 are sums of the potential switchgrass acreage that could be produced at a given farmgate price. These estimates likely overstate usable switchgrass. For a single plant to be located in any given area, the surrounding land must yield enough switchgrass for its annual needs and be within an economical shipping distance. We determined, for each ASD, if the available switchgrass provided the minimum amount of switchgrass to support an ethanol production facility. Figure 3 shows the results over a range of farmgate switchgrass prices. At lower amounts of switchgrass ($25/ton) the acreage growing switchgrass is widely dispersed and less than half (47%) of the switchgrass is located spatially to supply a facility. At $50/ton, 85% of the switchgrass can be used to supply 2200 ton per day facilities, stranding 15% of the potential switchgrass. Of course, smaller sized plants could capture greater amounts of the available switchgrass.

Plant size is a compromise between increased economies of scale and transportation costs for the feedstock. Lynd et al. (4) suggest larger facilities to take advantage of economies of scale and provide ethanol at prices equivalent to or lower than gasoline on an energy basis.

However, a complete adoption of such a strategy would have the downside of "stranding" ever greater amounts of the biomass limiting further the potential of cellulosic ethanol to displace gasoline.

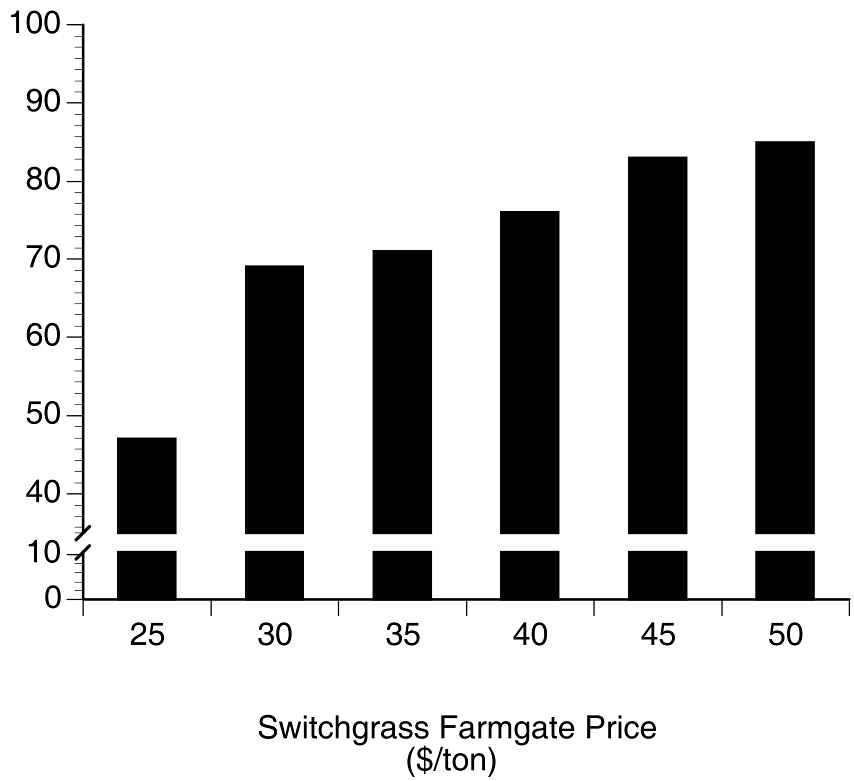

FIGURE 3. Switchgrass availability based on the requirement of 2200 ton/day cellulosic ethanol plant.

Providing 5 billion gallons of ethanol to the MSAs from corn:

We modeled the transportation from the current ethanol plants with an expanded ethanol production of 5 billion gallons to the MSAs whose total demand was based on E5 consumption. The optimization minimizes transportation distance so the closest demand will be met first. Figure 4 shows the MSAs and production locations (corn ethanol facilities) used in Scenario E5-Corn. Most production facilities are located in the upper Midwest, while most demand is located along the coasts (East, West and Gulf), Great Lakes and throughout the Southeast. The optimization results in average shipping distance from these plants to the MSAs of 637 miles (Table 3). The volumetrically weighted shipping distance (accounting for total gallons of ethanol shipped) was 683 miles. The difference suggests that there are some volumes of ethanol being shipped distances greater than the average. In addition, not all demand is met: only 82% of the MSAs receive their desired ethanol amount. In fact 45 of the 271 MSA's receive no ethanol at all, 6 receive partial shipments. These MSA's were all located along the east and west coasts. The centroid of production (the geographical center of all ethanol production facilities), and consumption (the geographical center of all MSAs receiving ethanol in the scenario were located in west-central IA and southeastern MO, along the Mississippi River, respectively.

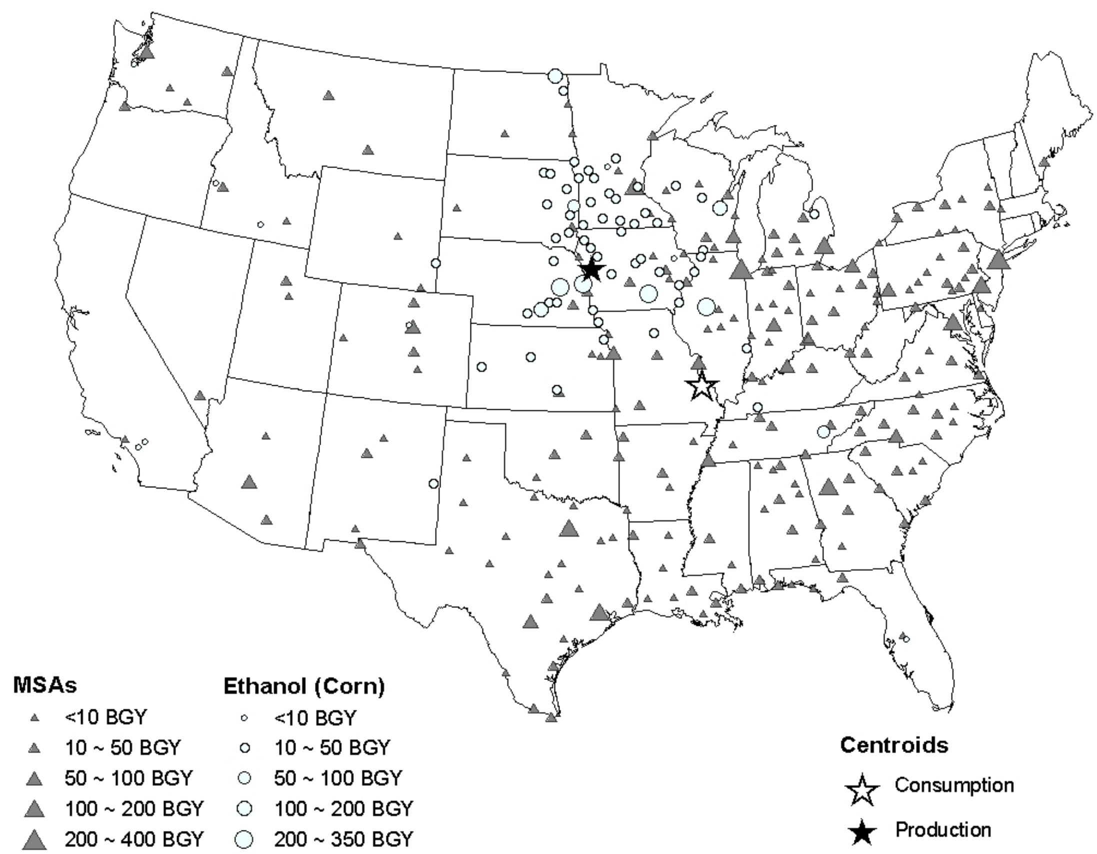

FIGURE 4. Location and size (production or consumption) ethanol production facilities (corn) and MSAs receiving ethanol for scenario E5 – Corn. Note: Geographical centers of consumption and production are included (centroids).

If all the shipments in Scenario E5-Corn were made by truck the average cost would be \$0.50 per gallon. If all shipments were made by rail then the cost would be reduced to \$0.17 per gallon. This would add 2.5 and 0.9 cents/gal of E5 blend at its destination, respectively.

Note that if the corn ethanol industry ultimately produced an amount of ethanol greater than the 5 billion gallons modeled here then the additional ethanol would be shipped to meet the unfulfilled demand in Scenario E5-Corn. The average shipping distances would change if additional plants came on-line to meet this demand. However, these changes would likely be minor since new mills would be generally located in the same geographic region as the current mills.

TABLE 3. Optimization results for supplying E5 to MSAs		
Parameter	Scenario	
	5 billion gallons – <u>*Scenario E5-Corn*</u>	Fleet wide E5 use – <u>*Scenario E5-Corn/Switchgrass*</u>
% MSA's with demands met	81	100
% Overall demand volume met	77	100
Average shipping distance	637	609
Average weighted shipping distance	683	684
Shipping Truck		
Total Costs (billion $)	2.59	3.34
Average Cost ($/gal)	0.50	0.50
Average Cost ($/gal of blend)	0.025	0.025
Shipping Rail		
Total Costs (billion $)	0.87	1.12
$/gal	0.17	0.17
Average Cost ($/gal of blend)	0.0085	0.0085

Providing E5 from corn and switchgrass:

To provide enough ethanol to meet the entire fleet demand for E5, cellulosic ethanol needs to be produced. The addition of 51 cellulosic plants, producing an additional 2 billion gallons of ethanol, was modeled. Figure 5 represents the MSAs and production locations (corn and switchgrass ethanol facilities). All new cellulosic ethanol plants were located in the Southeast. Even though switchgrass could be produced throughout the Midwest the model chose locations that were closest to ethanol demand minimizing shipping distance.

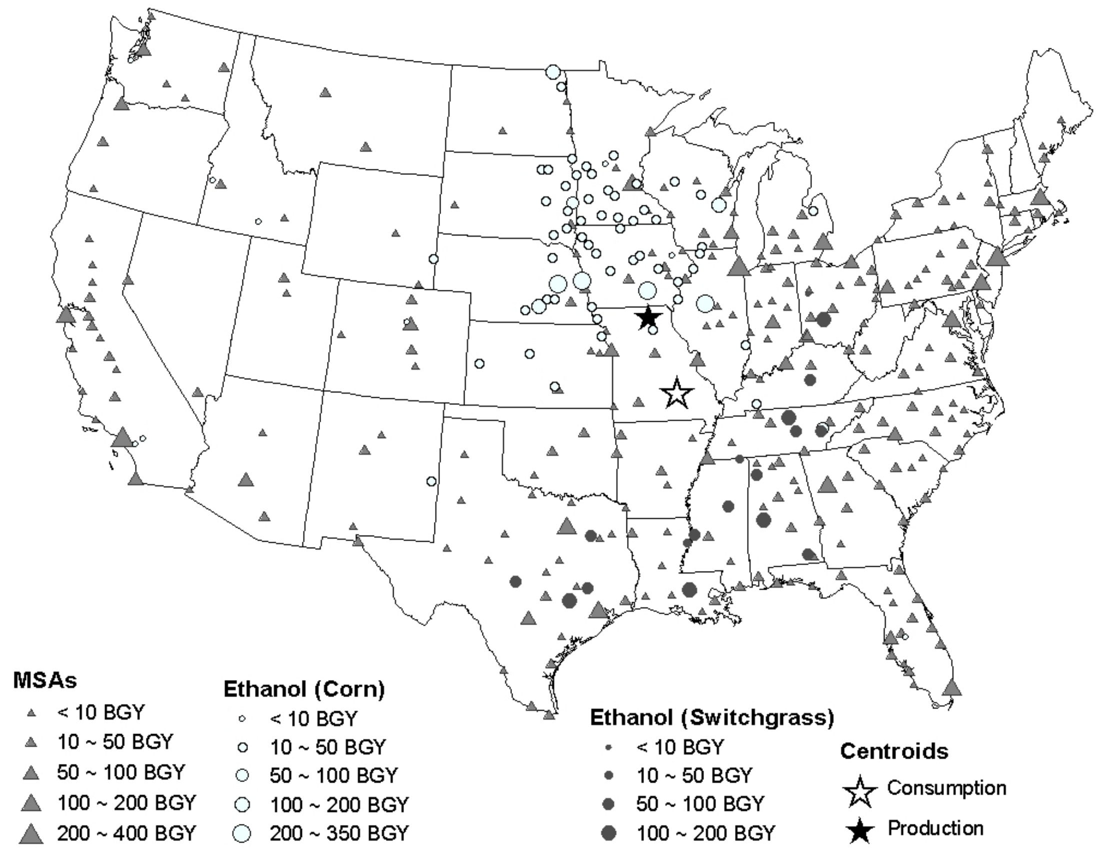

FIGURE 5. Location and size (production or consumption) ethanol production facilities (corn) and MSAs receiving ethanol for scenario E5 – Corn/Switchgrass. Note: Geographical centers of consumption and production are included (centroids).

The summary data for this scenario are also shown in Table 3. In Scenario E5-Corn/Switchgrass all MSA's ethanol demands were met. Compared to Scenario E5-Corn the average distance between MSAs receiving ethanol was reduced by about 4%. However, the volumetrically weighted average remained virtually unchanged. As can been seen in Figure 5 the centroid of production moved into northern Missouri, reflecting the "new" cellulosic ethanol plants located throughout the Southeast while the centroid for consumption shifted only slightly to the southwest. The movement of the center of consumption is reflected in the fact that all MSAs, including those along the coasts that did not receive ethanol in the E5-Corn scenario, received their demanded ethanol, more ethanol was shipped in the E5-Corn/Switchgrass scenario longer distances. The total cost of shipping by rail or truck increased from scenario E5-Corn as expected because of the increase in ethanol production but the cost based on an E5 blend remained essentially unchanged.

Providing E10 and E16 from corn and switchgrass:

Switchgrass has, potentially, a broader geographic growth range than corn, ranging throughout the eastern half of the US. In Scenario E10-Corn/Switchgrass and Scenario

E16-Corn/Switchgrass, switchgrass becomes the major source of ethanol. Figures 6 and 7 show the distribution of switchgrass cellulosic ethanol production facilities and MSAs for each scenario. The data from these optimizations are shown in Table 4. In Scenario E10-Corn/Switchgrass there were 153 "production facilities" compared to 78 and 129 in the previous two scenarios. Comparing Figures 5 and 6 shows the more widely dispersed ethanol production plants in Scenario E10-Corn/Switchgrass compared to Scenario E5-Corn/Switchgrass. The centroid of ethanol production moved slightly northwest and away from the centroid of ethanol consumption. The centroid movement and the wider distribution of the plants are reflected in the increase in the average shipping distance and decrease in the average weighted distance, respectively, compared to the E5-Corn scenario. On a per gallon basis of E10 the transportation costs would increase the total costs by 2 to 5 cents compared to gasoline.

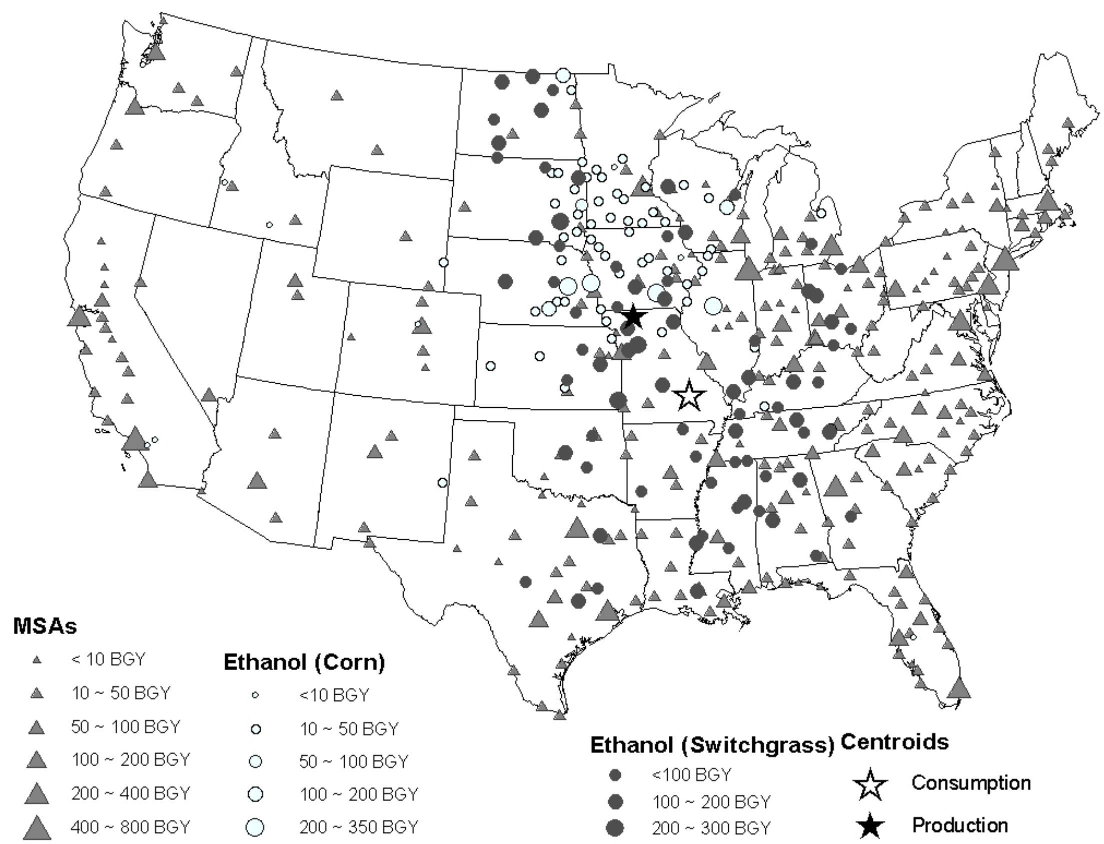

FIGURE 6. Location and size (production or consumption) ethanol production facilities (corn) and MSAs receiving ethanol for scenario E10 – Corn/Switchgrass. Note: Geographical centers of consumption and production are included (centroids).

E16-Corn/Switchgrass (Figure 7 and Table 4) adds an additional 83 cellulosic ethanol production facilities bringing the total to 212 corn and cellulosic ethanol plants. As expected, due to the widest ethanol pant distribution and the closest approach of the two centroids (production and demand) the E16-Corn/Switchgrass provides the lowest shipping distance 580 miles and the lowest weighted shipping distance, 505 miles, of all scenarios. Transportation costs per gallon decreased to $0.45 and 0.15 cents for truck and rail. On a blend basis this would increase the cost of E16 to between 2 to 7 cents per gallon for rail and truck transportation.

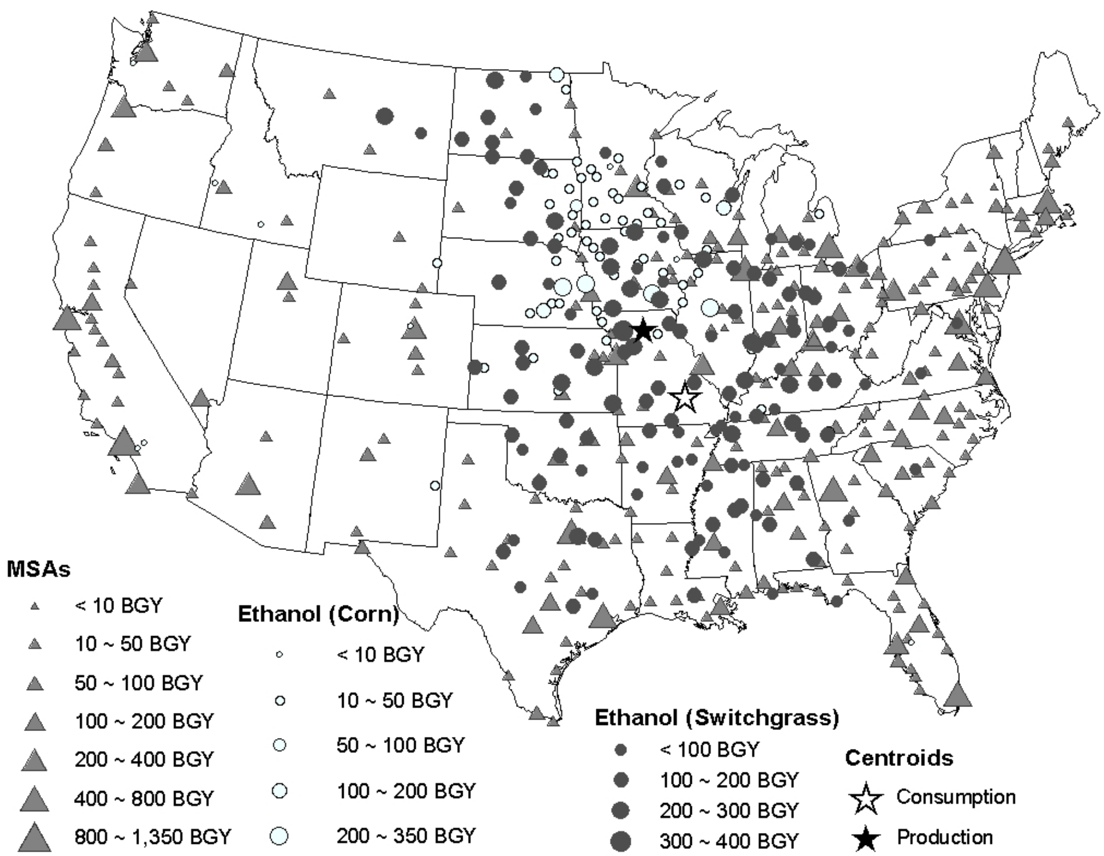

FIGURE 7. Location and size (production or consumption) ethanol production facilities (corn) and MSAs receiving ethanol for scenario E16 – Corn/Switchgrass. Note: Geographical centers of consumption and production are included (centroids).

TABLE 4. Optimization results for supplying E10 and E16 to MSAs		
Parameter	Scenario	
	Scenario E10 – Corn/Switchgrass	*Scenario E16 – Corn/Switchgrass*
MSA's with demands met (% of Total)	100	100
Overall Demand Volume Met (% of Total)	100	100
Average shipping distance	617	580
Average weighted shipping distance	672	620
Shipping Truck		
Total Costs (billion $)	6.68	10.06
Average Cost ($/gal)	0.49	0.45
Average Cost ($/gal of blend)	0.049	0.07
Shipping Rail		
Total Costs (billion $)	2.24	3.38
$/gal	0.17	0.15
Average Cost ($/gal of blend)	0.017	0.024

Discussion

Ethanol transportation:

The oil industry ships 40 million barrels of petroleum and petroleum products each day in the US. Sixty-six percent of these shipments occur by pipeline (21). The remainder is via ship and barge (28%), truck (4%) and rail (2%). There is an extensive pipeline system for moving petroleum and petroleum products comprising 200,000 miles of crude and product lines. Pipelines are the most cost-effective method for shipping liquid products; the cost of shipping a gallon of gasoline from Houston to New York (over 1500 miles) is only 3 cents or 0.6 cents per ton-mile (21). Ideally as the ethanol industry expands, pipelines would become the dominant mode of transportation for finished product. Much of the existing petroleum pipelines could be converted to ethanol transport. However, for ethanol in low level blends, such as E16, there will remain considerable demand for gasoline and its delivery infrastructure, partly due to the lower energy density of ethanol. It is likely, although not certain, that there would be little excess pipeline capacity available for any significant ethanol delivery. In that event, ethanol shipping would be dominated by truck and rail shipments for such low level blends as modeled here. The use of unit trains and inventive designs incorporating a combination of truck and rail use would lower cost below what is shown in this study.

As a comparison, the average cost of shipping crude oil from field to the refinery contributes $0.02/gal to gasoline price (Table 5). The shipping cost of gasoline from refinery to consumer is, on average, $0.01/gal. The total transportation costs is less than 2% of the overall price of a gallon of gasoline. The ethanol transportation costs for E16 on a per gallon of blend basis were estimated above to be as high as $0.07/gal, assuming all transportation from production site to consumer was via the most expensive mode, truck. This is only 4% of the total predicted price ($1.56 per gallon) for E16-- still a low portion of the overall price of fuel.

TABLE 5. Costs components of gasoline and E16.

Component	Gasoline[1]	Cellulosic E16[2]
	($/gal)	
Feedstock (Gasoline/Biomass)	0.64	0.63
Transportation (to refinery)	0.02	0.04
Refining	0.22	0.29
Transportation (to retail)	0.01	0.07
Retail	0.18	0.18
Taxes[3]	0.41	0.39
Total	1.48	1.59

1- Gasoline costs were adapted from Credit Suisse First Boston (35)

2- The cost data is derived from Wooley et al. (18) for 2015 case. The cost of feedstock was changed from the assumed $25 per ton to $50 per ton and transportation cost for biomass from farmgate to refinery gate was assumed to be $5 per ton.

3- Taxes were assumed to be revenue neutral. Since the use of E16 would require greater "gallons" to provide the same energy as gasoline the taxes were decreased to provide taxing authorities constant revenue.

Impact of ethanol use:

Increased use of ethanol could have positive security and environmental impacts. For instance, use of E20 would reduce gasoline consumption by 11 billion gallons per year or about 11% (Table 1). This is equivalent to 709,000 barrels of oil per day or about a 4% reduction in US petroleum use. At the margin, this would lead directly to a reduction in imports of 7%, moderating world petroleum prices.

Wooley (29) estimates the capital costs for the production of a gallon of ethanol to range from $3.49 per gallon to as low as $1.82/gal with future process improvements. Using the low value and the highest level of cellulosic ethanol production we modeled, the 18 billion gallons of cellulosic ethanol for E16 would require $34 billion in cellulosic ethanol plant investments. The expansion of corn based ethanol would add another $2.5 billion dollars the total infrastructure cost. Assuming a plant life of 20 years this would result in an investment of approximately $3 per barrel of oil saved. Plant capital costs are likely to be the largest single cost component of the ethanol supply chain as discussed in the Introduction. For instance even if all transportation of ethanol was accomplished by truck, which is not likely (see below), we estimate the total capital costs using all new tanker trucks would be on the order of $1.6 billion. If ethanol was transported by a duplicate pipeline system, which we did not model, similar to that which is currently in place for petroleum product distribution, the capital cost would be on the order of $23 billion.

Although our study is limited to E16 more switchgrass could be available at higher farmgate prices making higher levels of ethanol possible. We assume, however, that there will be limits to these supplies due to competition with food crops. Additional sources of cellulosic ethanol would likely come from agricultural residues, forest residue, and municipal solid wastes (36). Corn stover alone could provide an additional 23 billion gallons of ethanol. This is an upper bound estimate and assumes 100% utilization, which is unlikely. Also, as we showed with switchgrass, the spatial distribution will probably limit this estimate to a lesser amount. Other options exist to expand the use of ethanol including the import of ethanol from countries such as Brazil.

With the use of ethanol - and cellulosic ethanol in particular - comes a reduction in CO_2 emissions through the replacement of a fossil fuel with a renewable fuel. MacLean and Lave (37) reviewed the life cycle studies addressing this issue from wells to tank. On average gasoline generated 15 to 26 g CO_2 equivalent/ MJ of fuel. Corn and cellulosic derived ethanol produces -19 to 20 and -85 to +14 g CO_2 equivalent/ MJ, respectively. Using the midpoints of these values E16 could reduce CO_2 emission from the light duty fleet by 39%. Going to E85 the reduction would be on the order of 180%.

Summary asked for by reviewer 1 in her final point.*

Acknowledgements:

This material is based upon work supported by the National Science Foundation under Grant No. 0115418. The authors wish to thank Lynn Wright for kindly providing the biomass data used in this study.

References:

(1) Davis, S. C.; Diegel, S. W. Transportation Energy Data Book: Edition 24; Oak Ridge National Laboratory ORNL-6967: Oak Ridge, 2005.
(2) US Environmental Protection Agency, National Emission Inventory Air Pollutant Emissions Trends; http://www.epa.gov/ttn/chief/trends/. (accessed July 2, 2005).
(3) Energy Information Agency, Carbon Dioxide Emissions; http://www.eia.doe.gov/oiaf/1605/gg03rpt/carbon.html (accessed July 2, 2005).
(4) Lynd, L. R.; Elander, R. T.; Wyman, C. E., Likely features and costs of mature biomass ethanol technology. Applied Biochemistry and Biotechnology 1996, 57-8, 741-761.
(5) Wyman, C. E., Biomass ethanol: Technical progress, opportunities, and commercial challenges. Annual Review of Energy and the Environment 1999, 24, 189-226.

(6) Lave, L.; Maclean, H.; Hendrickson, C.; Lankey, R., Life-cycle analysis of alternative automobile fuel/propulsion technologies. Environmental Science & Technology 2000, 34, 3598-3605.
(7) MacLean, H. L.; Lave, L. B., Life cycle assessment of automobile/fuel options. Environmental Science & Technology 2003, 37, 5445-5452.
(8) McCarthy, T., The comming wonder? Foresight and early concerns about the automobile. Environmental History 2001, 6, 46-74.
(9) Moreira, J. R.; Goldemberg, J., The alcohol program. Energy Policy 1999, 27, 229-245.
(10) Rosillo-Calle, F.; Cortez, L. A. B., Towards Proalcool II - A Review of the Brazillian Bioethanol Programme. Biomass & Bioenergy 1998, 14, 115-124.
(11) Renewable Fuels Association, Ethanol Industry Outlook 2005; http://www.ethanolrfa.org/outlook2003.shtml (accessed July 2, 2005).
(12) US Department of Agriculture, US Corn Yield; http://www.usda.gov/nass/pubs/stathigh/2002/graphics/corn.htm (accessed July 2, 2005).
(13) Shapouri, H.; Gallagher, P.; Graboski, M. S. "The USDA 1998 ethanol cost-of-production survey;" Agricultural Economic Report Number 808; U.S. Department of Agriculture, Office of Chief Economist, Office of Energy Policy and New Uses: Washington, 2002.
(14) USDA "Transmittal Letter from Mr. Keith Collins, USDA, Chief Economist/USDA to Senator Bob Kerrey on Sept. 6 responding to request for analysis of the impact if Minumum Average Renewable Fuels Standard on agriculture, farm income, commodity prices and balance of trade.;" 2000.
(15) McAloon, A.; Taylor, F.; Yee, W.; Ibsen, K.; Wooley, R. "Determining the cost of producing ethanol from corn starch and lignocellulosic feedstocks.;" National Renewable Energy laboratory NREL/TP-580-28893: 2000.
(16) Mosier, N.; Wyman, C.; Dale, B.; Elander, R.; Lee, Y. Y.; Holtzapple, M.; Ladisch, M., Features of promising technologies for pretreatment of lignocellulosic biomass. Bioresource Technology 2005, 96, 673-686.
(17) National Academy of Sciences; Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards; National Academy Press: Washington, DC, 2001.
(18) Wooley, R.; Ruth, M.; Sheehan, J.; Ibsen, K.; Majdeski, H.; Galvez, A. "Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios;" National Renewable Energy Laboratory NREL/TP-580-2615: 1999.
(19) Energy Information Agency, Department of Energy, Petroleum Supply Annual Volume 1; http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html (accessed July 2, 2005).
(20) Greene, D. L.; Tishchishyna, N. I. "Costs of Oil Dependence: A 2000 Update, ORNL/TM-2000/152;" Oak Ridge National Laboratory: Oak Ridge, TN, 2000.
(21) Rabinow, R.A, The Liquid Pipeline Industry in the United States: Where It's Been, Where It's Going; http://www.aopl.org/pubs/facts.html (accessed July 2, 2005).
(22) Bureau of Transportation Statistics, US department of Transportation, Table 1-10 - U.S. Oil and Gas Pipeline Mileage (Updated September 2004);

http://www.bts.gov/publications/national_transportation_statistics/2003/index.html (accessed July 2, 2005).
(23) US Department of Transportation, Availability of Alternative Fuel Vehicles; http://www.nhtsa.dot.gov/cars/rules/rulings/CAFE/alternativefuels/availability1.htm (accessed July 2, 2005).
(24) Reynolds, R. E., Downstream Alternatives Inc., Infrastructure requirements for an expanded fuel ethanol industry; www.ethanol-gec.org/information/briefing/18.pdf (accessed July 2, 2005).
(25) US Bureau of Census, US Department of Commerce: "State and Metropolitan Area Data Book (5th Edition.);" 1998.
(26) Federal Highway Administration, US Department of Transportation, Highway Statistics 2001; http://www.fhwa.dot.gov/ohim/hs01/mf33ga.htm (accessed July 2, 2005).
(27) US Census Bureau, US Department of Commerce, Population in Metropolitan and Micropolitan Statistical Areas Sorted Separately and Their Geographic Components in Alphabetical Order and Numerical and Percent Change for the United States and Puerto Rico: 1990 and 2000; http://www.census.gov/population/www/cen2000/phc-t29.html (accessed
(28) Renewable Fuels Association; Ethanol Industry Outlook 2003; Renewable Fuels Association: Washington, 2003.
(29) Wooley, R.; Ruth, M.; Glassner, D.; Sheehan, J., Process design and costing of bioethanol technology: A tool for determining the status and direction of research and development. Biotechnology Progress 1999, 15, 794-803.
(30) Aden, A.; Ruth, M.; Ibsen, K.; Jechura, J.; Neeves, K.; Sheehan, J.; Wallace, B.; Montague, L.; Slayton, A.; Kukas, J. "Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover;" National Renewable Energy Laboratory, NREL/TP-510-32438: Golden, Colorado, 2002.
(31) Bureau of Economic Analysis, Department of Commerce, 1997 Benchmark Commodity by Industry Direct Requirements; http://www.bea.doc.gov/bea/dn2/home/annual_industry.htm (accessed July 2, 2005).
(32) Bureau of Transportation Statistics, US department of Transportation, Table 11 Shipment Characteristics by Destination and Mode of Transportation; http://transtats.bts.gov/Tables.asp?DB_ID=510&DB_Name=Commodity%20Flow%20Survey%20%28CFS%29&DB_Short_Name=CFS (accessed July 2, 2005).
(33) US Geological Survey, Geographical Centers; http://erg.usgs.gov/isb/pubs/booklets/elvadist/elvadist.html#Geographic%20Centers (accessed July 2, 2005).
(34) Bureau of Transportation Stattistics, Table 3-17: Average Freight Revenue per Ton-mile; http://www.bts.gov/publications/national_transportation_statistics/2003/html/table_03_17.html (accessed
(35) Credit Suisse First Boston: "Oil and Gas Primer – Introduction to the Oil and Gas Business;" Boston, 2002.
(36) Perlack, R. D.; Wright, L. L.; Turhollow, A. F.; Graham, R. L.; Stikes, B. J.; Erbach, D. C. "Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The

Technical Feasibility of a Billion-Ton Annual Supply;" ORNL/TM-2005/66; Oak Ridge National Laboratories: Oak Ridge, 2005.
(37) MacLean, H. L.; Lave, L. B., Evaluating automobile fuel/propulsion system technologies. Progress in Energy and Combustion Science 2003, 29, 1-69.