Approaches to Reducing the Social Cost of Biofuel Production, Distribution, and Consumption

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Executive Summary

Biofuels, and specifically next-generation biofuels such as cellulosic ethanol, have the potential to create economic, environmental, and energy security benefits relative to the fossil fuels that currently power the transportation sector in the United States. However, issues involving ethanol production cost, emissions resulting from land use change, and infrastructure requirements may incur significant social costs. This dissertation examines social costs from different aspects of biofuel production, distribution, and consumption in an effort to inform policies that could reduce these costs.

This dissertation contains seven research chapters that examine social costs of ethanol at different points along the supply chain. This work begins by examining some impacts of cellulosic feedstock production. Land use change, especially indirect land use change, has been the most controversial topic within the biofuel research community in recent years, with some findings indicating that biofuels could be more carbon-intensive than gasoline. However, cost reductions from cellulosic ethanol could be used to more than offset the increased emissions if policies are in place to balance the impacts. Ethanol production from forest thinnings, on the other hand, could result in a positive externality by reducing wildfire damage while also providing funds for additional fuel treatments.

Decisions regarding cellulosic ethanol facility size and location can have significant impacts on production cost. Cellulosic ethanol refinery investments over the next 12 years are expected to be on the order of $100 billion, so these decisions could be costly if made sub-optimally.

The rest of the thesis examines costs and impacts of ethanol distribution, promoting a regional fuel strategy that would have ethanol consumed in high-level blends (such as E85) in regions where it can be produced (mainly the Midwest and Southeast) rather than in low-level blends throughout the country. Regional distribution would save billions of dollars per year in shipping costs and reduce shipping loads and congestion costs along the rail freight network. Imports of sugarcane ethanol produced in Brazil could be part of this regional fuel strategy, but costs for shipping the fuel from plants to ports within Brazil could be substantial. A key component of this regional fuel strategy is the penetration of both flex-fuel vehicles and E85 infrastructure throughout ethanol producing regions, but these costs are generally less than the savings from reduced shipping costs.

Next-generation biofuels such as cellulosic ethanol will play an increasing role in meeting transportation energy demand in the near future. This research will hopefully help shape policies that will allow cellulosic ethanol to meet demand while limiting social cost.

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1. Introduction

1.1. Motivation

In 2007, the United States consumed over 100 quadrillion BTUs of primary energy, representing over 20% of world energy consumption (EIA 2008). Within the United States, the transportation sector was responsible for over 28% of primary energy consumption, with over 97% of transportation energy demand being met by petroleum (BTS 2010). Gasoline consumption by the United States' light-duty fleet alone amounted to 140 billion gallons, representing 3.5% of all energy consumed by the world in 2007 (BTS 2010).

The massive energy consumption of the light-duty fleet within the United States and its almost exclusive reliance on petroleum have recently become problematic for a number of reasons. Petroleum prices, which have historically remained low, have seen a recent increase in both mean and volatility, with national average retail gasoline prices exceeding $4 per gallon in 2008 (EIA 2010a). Greenhouse gas (GHG) emissions resulting from petroleum use by the transportation sector exceeded 1,900 million metric tons CO_2-equivalent in 2008, representing one-third of all U.S. GHG emissions (EIA 2009a). United States petroleum imports in 2008 amounted to 57% of petroleum consumption, with 30% of petroleum consumption being imported from OPEC countries (EIA 2009b), countries frequently characterized by political instability and strained relationships with western nations. Given that United States gasoline consumption has increased by 10% in the past ten years (EIA 2009c), continued petroleum dependence by the transportation sector could exacerbate the economic, environmental, and energy security problems that have recently emerged.

The transportation sector's almost exclusive reliance on petroleum could be reduced by the production and consumption of biofuels. Biofuels refer to fuels produced from renewable biological feedstocks, and include ethanol, biodiesel, and (potentially) other fuels. (Biomass can be gasified to produce syngas, which can be converted into a variety of fuels, any of which could therefore be considered a biofuel.) Ethanol, which is currently produced from corn and sugarcane at the commercial scale and from cellulosic biomass feedstocks at the pilot scale, can be blended with gasoline and combusted in current light-duty fleet engines, while biodiesel is compatible with current diesel engines. Because current levels of ethanol production (Koh 2009), projected volumes of ethanol demand (EIA 2010b), and ethanol production mandates (EISA 2007) are an order of magnitude greater than commensurate values for biodiesel or any other biofuel within the United States, the bulk of this work focuses on the production and consumption impacts of ethanol.

Biofuels have the potential to reduce greenhouse gas (GHG) emissions, reduce cost, and increase energy security compared to fossil fuels. Theoretically, biofuels could provide major GHG reductions compared to petroleum-based gasoline. All of the carbon released during the combustion of biofuels was originally extracted from the atmosphere during the growth of the feedstock. In addition, substantial amounts of carbon can be deposited into the soil during feedstock growth, giving biofuels the potential to be carbon-negative

(Tilman 2006). Though feedstock production, including accompanying land use change, the use of fertilizer and fossil energy for farm equipment, as well as transportation of feedstocks to conversion plants, conversion processes, and transport to end users can have significant GHG costs, biofuels "done right" can result in large GHG reductions relative to fossil fuels (Tilman 2009).

Biofuels also have the potential to reduce costs compared to fossil fuels, especially in light of recent fossil fuel price fluctuations. Biofuels produced efficiently from inexpensive feedstocks could provide a fuel that features the high energy density valued in the transportation sector at price lower than recent gasoline prices faced by U.S. consumers. Significant cost reductions must still be achieved in order for advanced biofuels (such as cellulosic ethanol) to compete with fossil energy, but some long-term biofuel cost estimates fall below $1.00 per gallon of gasoline-equivalent energy (Wyman 2007, Hamelinck 2005).

Domestic production of ethanol from corn has increased dramatically in recent years, growing from 1.8 billion gallons in 2001 to 9 billion gallons in 2008 (RFA 2010b). In 2010, corn ethanol plants within the United States had a collective production capacity of 13.5 billion gallons with another 1.2 billion gallons of capacity under construction (RFA 2010a). Despite this dramatic growth, domestic corn ethanol production accounted for only about 4% of the total transportation energy used by the light-duty fleet within the United States in 2008. Furthermore, the boom in domestic corn ethanol production, which was fueled by subsidies designed with oil prices near $20 per barrel in mind (Tyner 2008), brought many problems associated with corn ethanol to light, including elevated food prices, emissions from land use change, and loss of biodiversity (Keeney 2009).

Expanding the percentage of transportation energy demand met by biofuels could be accomplished through the development of next-generation biofuels like cellulosic ethanol. A review of alternative transportation fuels, including hydrogen, compressed natural gas, and electricity, found that cellulosic ethanol produced from biomass is the most attractive near-term option based on its environmental benefits, compatibility with current vehicles, and potential production costs (MacLean 2004). Cellulosic ethanol can be produced from a variety of sources, including switchgrass, a perennial warm-season grass that can be grown in the United States and has been the subject of considerable work regarding its production (McLaughlin 2005, Schmer 2008). Cellulosic ethanol could also be produced from waste streams (such as agricultural and forest residues) that could avoid the negative impacts associated with current corn- and sugarcane-based biofuels (Koh 2009) and positively impact energy security, GHG emissions, biodiversity, and the sustainability of food supply (Tilman 2009). While cellulosic ethanol is not currently economically viable, advances in pretreatment and funding for commercialization could push production costs well below current fossil fuel prices (Wyman 2007). Integrating cellulosic ethanol production with high-value biomaterial production at biorefineries, potentially using genetically engineered agro-energy feedstocks, would further improve the efficiency and cost-effectiveness of the fuel (Ragauskas 2006). Cellulosic ethanol may avoid many of the problems associated with corn ethanol, such as high fertilizer and input energy requirement, food versus fuel impacts, and, if grown on marginal land, land use change emissions.

In an effort to encourage the domestic production of biofuels (and specifically next-generation biofuels like cellulosic ethanol) and reduce oil consumption, the Energy Independence and Security Act of 2007 established a Renewable Fuel Standard that set domestic biofuel production targets through 2022 (EISA 2007). Figure 1-1 displays these domestic biofuel production targets alongside historical estimates of corn ethanol production. Two curves are shown for the RFS production targets, one for corn ethanol (shown in red) and one representing production of all biofuels (shown in green), where the difference between the curves represents production of advanced biofuels including cellulosic ethanol. The production target for corn ethanol levels off at 15 billion gallons per year in 2015, while the total production target of 36 billion gallons represents close to 20% of total annual gasoline energy consumption by the United States (EIA 2010a).

Corn ethanol production should have little difficulty meeting the EISA goal. While the production target for corn ethanol is an order of magnitude greater than production levels from 1990 to 2000, it represents only a marginal increase over current and planned corn ethanol production capacity thanks to the explosive growth of the industry in recent years (RFA 2010b). The production target for advanced biofuels, on the other hand, is considerably more ambitious. Cellulosic ethanol is not currently produced on a commercial scale, yet meeting the EISA target will require a rate of expansion similar to that experienced by corn ethanol since 2000 sustained over the next 12 years.

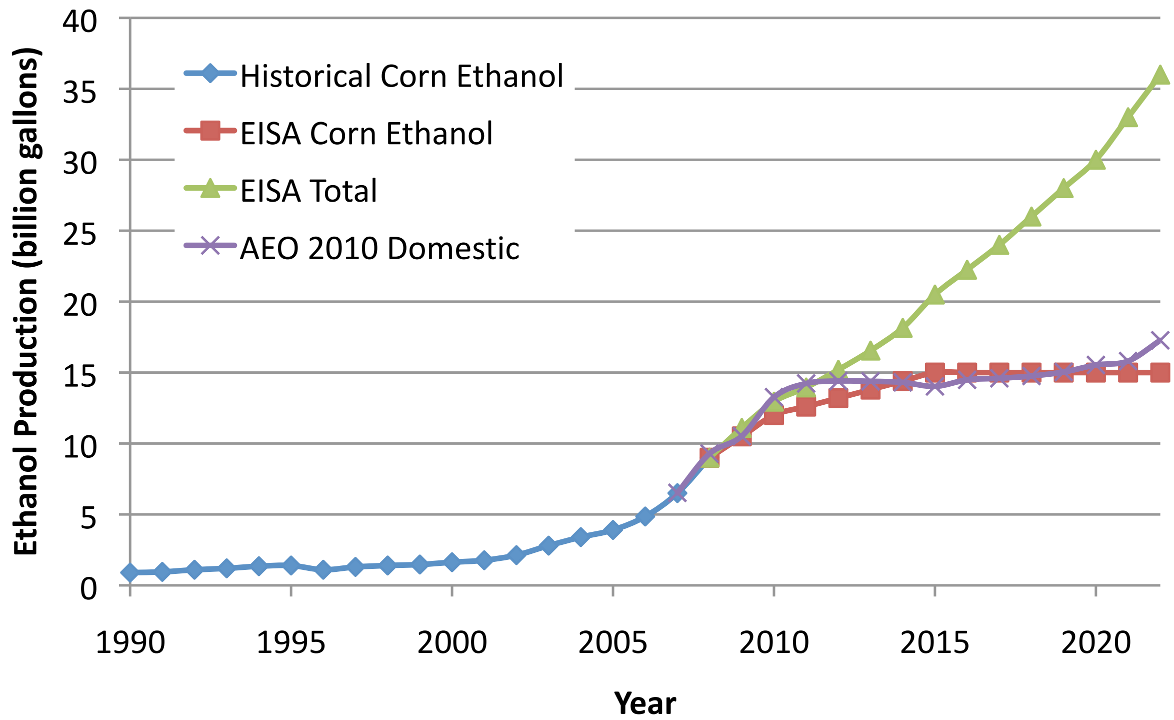

Figure 1-1. Historical domestic production of corn ethanol (RFA 1), biofuel production targets (EISA 2007), and biofuel consumption projections through 2022 (EIA 3).

There are some obstacles cellulosic ethanol must overcome before it can come close to meeting the EISA target and gain widespread use. First and foremost, cellulosic ethanol must begin to approach the low production costs anticipated for a mature industry. But even if production costs fall substantially, a number of challenges remain, including land use requirements, uncertainty regarding emissions, industry inexperience, and competition from other fuels (MacLean 2004). Infrastructure requirements also pose a major obstacle. Ethanol is largely compatible with the current fuel infrastructure, but cannot be transported in petroleum production pipelines due to the presence of water in those pipelines. Thus, ethanol distribution must either rely on existing highway and rail freight networks or necessitate capital investment in infrastructure.

Collectively, these challenges are substantial. The Energy Information Administration, for one, is not particularly optimistic about the near-term contributions of cellulosic ethanol. Projections from the 2010 Annual Energy Outlook (EIA 2010b) for consumption of domestically produced biofuels (shown in purple in Figure 1-1) hover around the 15 billion gallon corn ethanol plateau from 2010 to 2020, indicating a strong skepticism that cellulosic ethanol will meet the EISA goal. But the chances of cellulosic ethanol contributing positively to meeting transportation energy demand can be improved by crafting policies designed to lessen the costs, both private and social, of cellulosic ethanol production, distribution, and consumption.

In contrast to national biofuel production policies, biofuel consumption policies are left individually to states. A number of states, shown in Figure 1-2, have embraced biofuels and enacted legislation to encourage their consumption, but the currently decentralized nature of biofuel consumption policies may be problematic. The combination of "optimal" state-level ethanol consumption policies may not be optimal from a national perspective, especially if states incapable of producing biofuel feedstocks locally are required to import biofuels from distant states in order to meet demand.

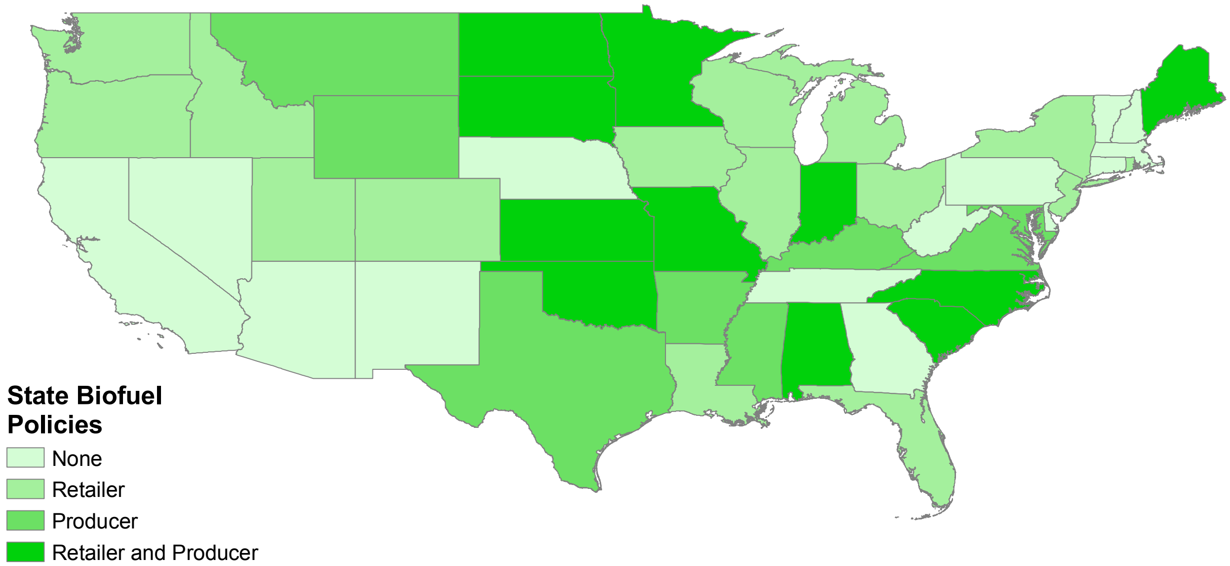

Figure 1-2. State-level biofuel consumption incentives for producers and retailers (RFA 2010c).

Examining and informing national-level biofuel production, consumption, and distribution policy is the main goal of this study. National ethanol distribution and consumption policies are important; the EISA target of 36 billion gallons by 2022 represents 20% of the total gasoline energy consumed by the transportation sector, so inefficient distribution policies may lead to large costs. National biofuel distribution policies are also nontrivial. Ethanol feedstocks, such as corn and cellulosic crops, can be grown most easily in the Midwest and parts of the Southeast, while 80% of U.S. population is found along the coasts. Thus, national distribution of a low level ethanol blend that can be used by conventional vehicles would lead to large volumes of ethanol being shipped long distances. Use of higher level ethanol blends is possible, since ethanol can be blended with gasoline at levels up to E85 (85% ethanol, 15% gasoline by volume) and used to power flex-fueled vehicles (FFVs), but those vehicles would need to be prevalent throughout certain regions for a high level blend to work. Given that the 7.3 million light-duty FFVs in operation in the United States in 2008 (NREL 2008) represent 3% of the entire light-duty fleet, policies may be required to encourage levels of FFV penetration required to enable regional distribution of high-level ethanol blends.

Furthermore, ethanol cannot be shipped in petroleum pipelines, so policies should consider whether or not to invest in distribution infrastructure. And alternative ethanol feedstocks have different economic, environmental, and spatial characteristics, making the decisions of which ethanol feedstock to use and how the resulting fuel should be distributed interconnected. This work considers these factors in an effort to inform effective ethanol production, distribution, and consumption policy.

1.2. Dissertation Overview and Research Questions

The layout of this dissertation follows the ethanol supply chain, moving from impacts of biofuel feedstocks to ethanol refinery decisions, and finally to issues involving the distribution and consumption of biofuels. The following questions are addressed in this research:

1. Given the uncertainty surrounding fossil fuel prices, biofuel production costs, and carbon emissions resulting from biofuel production, what role (if any) should biofuels play in meeting future energy demand? Under which scenarios are biofuels socially beneficial?

Biofuels have traditionally been viewed as a low-carbon alternative to fossil fuels. However, biofuels can have drastically different environmental and economic impacts based on the feedstocks from which they are produced. Ethanol produced from corn has very different (and less favorable) environmental impacts than ethanol produced from cellulosic crop residues. Even a single feedstock, such as switchgrass, may result in ethanol with life cycle carbon emissions significantly greater or less than those of gasoline based on whether or not it induces land use change.

Furthermore, the use of feedstocks for biofuel production can have other social impacts, both positive and negative. The use of corn as a feedstock for ethanol production could lead to an increase in food prices, while producing ethanol from excess or waste biomass such as forest thinnings may provide revenue to help offset removal and disposal costs.

Two specific questions are addressed in this work:

a. Assuming that recent findings regarding the land-use change impacts of biofuel production are true, what role should biofuels play in future (carbon-constrained) energy policy?
b. What are the benefits of using untraditional cellulosic feedstocks (such as urban waste and excess forest biomass) compared to energy crops for cellulosic ethanol production? Could forest thinnings be used cost-effectively

as a cellulosic ethanol feedstock? Could revenue generated by forest thinning-derived cellulosic ethanol significantly offset thinning costs?

2. Given the substantial investments to be made in ethanol production in the near future, what are the impacts of facility investment decisions and how can policies potentially impact those decisions?

   Future investments in ethanol production infrastructure are likely to be massive. Large cellulosic ethanol facilities (having capacities greater than 50 Mgal per year) are expected to have a capital cost of $5 - $6 per gallon capacity in the short-term (Hamelinck 2005) implying that, the EISA target of 21 billion gallons of cellulosic ethanol production by 2022 will necessitate over $100 billion in capital investment. Ethanol refinery investments will also have positive impacts on local economies, and perverse incentives may be enacted to influence facility siting decisions.

   a. What are the impacts of ethanol refinery size and location on ethanol production cost? How significant are these impacts, and what policies could help encourage infrastructure investments that lower cost?

3. As ethanol production increases, how will current infrastructure networks respond to the additional load of ethanol production and distribution? What are the potential social costs of ethanol production and distribution, and what policies can help reduce or avoid these costs?

Domestic production of corn ethanol reached 9 billion gallons in 2008 and the Renewable Fuels Standard found in the EISA 2007 establishes a biofuel production target of 36 billion gallons per year by 2022. Ethanol cannot be shipped concurrently with petroleum products, so as biofuel production increases, rail and highway transportation networks may experience additional loads. Increased ethanol shipments may lead to congestion along these networks, specifically if ethanol travels long distances from production centers in the Midwest to large metropolitan areas along the coasts.

Three specific questions are addressed here:

a. If the current ethanol shipping profile remains unchanged, how will additional ethanol shipments impact rail and highway freight networks? Do rail and highway freight networks have sufficient capacity to accommodate increased ethanol shipments, or will these added loads lead to significant congestion costs?
b. What are the anticipated ethanol shipping costs and loads for different distribution scenarios? How do costs for regional and national ethanol distribution change as total ethanol production changes?
c. Ethanol production from sugarcane within Brazil is also expected to increase dramatically in the near future. How will costs an emissions of sugarcane

ethanol produced in Brazil and exported to the United States change as a result of this expansion?

4. Using a combination of current transportation fuels and biofuels, how can the energy demand for the light-duty fleet be met in a way that minimizes social cost? How should corn ethanol, cellulosic ethanol, and imported sugarcane ethanol be used to meet demand, how does regional variation in fuel availability impact fuel distribution, and how will policies impact optimal fuel distribution?

2. Relevant Literature Review

2.1. Ethanol Production Processes

2.1.1. Corn Ethanol

The primary process used to convert corn starch into ethanol is fermentation, but there are a number of steps required to prepare the starch before fermentation and to separate the resulting mixture into fuel-grade ethanol and other co-products. To begin the dry milling process, incoming corn feedstock is first cleaned and ground into a powder. The corn meal is mixed with water and enzymes, heated to kill any bacteria, and then cooled in a process called liquefaction. Following liquefaction, a secondary enzyme is added during saccharification to convert starch into fermentable sugars, which are combined with yeast during fermentation. The resulting solution, which contains roughly 10% alcohol, is distilled to a solution containing roughly 95% alcohol and 5% water, and the remaining water is removed using molecular sieves. The resulting fuel is denatured by adding gasoline, while a centrifuge separates distillers' grains and solubles that were removed from the solution during distillation. For more details on the corn ethanol production process, see, for instance, Eidman (2007).

2.1.2. Cellulosic Ethanol

Production of cellulosic ethanol is more complex than production of ethanol from corn. There are three major components of cellulosic biomass: cellulose, hemicellulose, and lignin. For biological conversion, cellulose and hemicellulose are converted into fermentable sugars through the pretreatment process. Typical pretreatment involves acid or enzymatic hydrolysis and a physical pretreatment step (such as grinding) to release the cellulose and hemicellulose. Following this process, enzymes are used to break cellulose down into sugars that can then be fermented. The pretreatment process usually results in the co-product, lignin, which is often burned to generate process heat or electricity for these systems. Ethanol can then be produced from the sugars using fermentation and distillation processes similar to the ones used to produce corn ethanol. For more detail, see Aden (2002).

Cellulosic ethanol can also be produced from biomass via thermochemical conversion. Incoming biomass is dried then fed into a gasifier, producing a mixture of syngas, tars, and char. Syngas is separated from the rest of the solution and synthesized into alcohol, which is condensed away from the unreacted syngas. The alcohol stream is dehydrated to separate the ethanol and higher alcohols. For more a more detailed description, see Phillips (2007). Ethanol yields for thermochemical conversion are estimated to be lower than those for cellulosic ethanol, but with co-production of higher alcohols (instead of electricity from burning lignin in biological conversion), the total alcohol yield may be higher (Foust 2009).

2.2. Energy Ratio

2.2.1. Corn Ethanol

With the exception of a few outliers, the energy balance of corn ethanol has generally been found to be slightly positive, indicating that the energy contained in corn ethanol is greater than the input energy required throughout the production process. In a USDA study that surveyed and synthesized values from previous reports on corn ethanol to inform their analysis, the energy ratio[1] of corn ethanol was estimated to be 1.24, indicating that 1.24 MJ of energy are produced for every 1 MJ of input energy in the corn ethanol production process (Shapouri 1995). A subsequent update to that study saw the estimate increase to 1.34, with ethanol produced by dry milling (1.37) performing slightly better than ethanol produced by wet milling (1.30) (Shapouri 2002). In a study that examined corn ethanol alongside biodiesel, Hill (2006) estimated a value of 1.25 for corn ethanol's energy ratio. Wang (2007) examined 12 corn ethanol production scenarios, comparing current ethanol plants to new plants powered by natural gas, coal, and biomass with and without distiller grains co-production and combined heat and power systems. Resulting fossil energy ratio estimates for coal and natural gas-powered corn ethanol plants ranged from 1.2 for basic coal-powered production to 1.7 for production of corn ethanol and distiller grains powered by natural gas. Should biomass be used to power the ethanol refinery, the fossil energy ratio could climb as high as 2.9 (Wang 2007). Comparing corn and sugarcane ethanol production, Dias de Oliveira (2008) estimated an energy ratio of 1.1 for corn ethanol, well below the ratio of 3.7 estimated for ethanol produced from sugarcane in Brazil.

In contrast to the studies summarized above, Pimentel and collaborators have consistently found the energy ratio of corn ethanol to be less than one, arriving at values ranging from 0.77 to 0.84 (Pimentel 2003, 2005, 2009). However, the work of Pimentel has criticized

[1] In different studies, the terms 'energy balance', 'net energy balance', 'energy ratio', 'net energy balance ratio', and other permutations of those terms are used to represent the ratio of output energy (contained in corn ethanol) to input energy used in the production process.

based on the use of pessimistic assumptions, outdated technologies, lack of co-product allocation, and poor documentation (Shapouri 2002, Farrell 2006).

Literature reviews of corn ethanol studies have resulted in ranges of values consistent with those summarized above. Farrell (2006) surveyed a number of corn ethanol studies and normalized their analyses (adjusting some values when both necessary and possible), finding values for the energy ratio of corn ethanol ranging from roughly 0.8 to 1.7. Original calculations from the Farrell (2006) study estimated the value to be near 1.2. Similarly, Hammerschlag (2006) found energy ratio values from 0.84 – 1.65. For both reviews, values less than one were attributed to the work of Pimentel. A third review (Von Blottnitz 2007) settled on an average value of 1.3, consistent with many of the results discussed above.

2.2.2. Cellulosic Ethanol

Estimating the performance and impacts of cellulosic ethanol production is more difficult than estimating commensurate values for corn ethanol for a couple of reasons. First, cellulosic ethanol is not produced on a commercial scale, so models of cellulosic ethanol production are based on techno-economic analyses or results from pilot-scale operations scaled up to the commercial level. Second, cellulosic ethanol can be produced from a variety of feedstocks. Ethanol produced from dedicated energy crops will likely have a different environmental impact than ethanol produced from forest or crop residues, making it difficult to agree upon a single value or compare results across studies of ethanol produced from different feedstocks.

With those caveats in mind, research on the energy ratio of cellulosic ethanol has generally arrived at values significantly greater than those estimated for corn ethanol. Sheehan (2004) examined production of cellulosic ethanol from corn stover and found an energy ratio of 4.4. Schmer (2008) estimated an energy ratio of 5.4 for switchgrass, while Vadas (2008) estimated the energy ratio of switchgrass-derived cellulosic ethanol to be 10.8 to 11.3. Vadas (2008) also estimated that adding cellulosic ethanol produced from corn stover to a system producing ethanol from corn would move the overall system's energy ratio from 1.4 to 2.2. A survey of cellulosic ethanol studies found energy ratios ranging from 4.4 to 6.1 (Hammerschlag 2006), with the exception of a value of 0.7 estimated by Pimentel (2005). Von Blottnitz (2007) estimated values of 5.2 for ethanol produced from either corn stover or wheat straw.

2.3. Cost Estimates

2.3.1. Corn Ethanol

A detailed techno-economic assessment of corn ethanol production by NREL estimated the total production cost to be only $0.88 per gallon (McAloon 2000). At $0.68 per gallon, feedstock cost was easily the largest component, with capital cost contributing only $0.11 per gallon and credits for co-production of distillers' dried grains decreasing the production cost by $0.29 per gallon. A USDA survey of 21 dry mill corn ethanol plants taken in 2002 estimated capital costs of $1 to $3 per gallon capacity for initial construction, and $0.20 to $1 per gallon for capacity expansion. Variable ethanol production costs averaged $0.96 per gallon, while average ethanol yields were 2.66 gallons per bushel (Shapouri 2005).

Gallagher (2006) compared historical corn ethanol production costs to the historical production costs of ethanol produced in Brazil, finding that the cost advantage of producing ethanol from corn in the United States has a strong cyclical component that represents about 70% of the cost advantage variation. Dry mill corn ethanol plant could reduce their production cost from $1.05 per gallon to $0.92 per gallon by using corn with an enhanced starch content, assuming a feedstock price of $2.35 per bushel (Gallagher 2006). Gallagher (2005) found economies of scale resulting from increasing plant size, but that the estimated scaling factor of 0.836 was significantly higher than the 0.6 generally assumed for capital investments. They estimated that unit capital costs decreased from around $2 to $1.08 per gallon capacity as facility size increased from 5 to 65 million gallons per year. Hill (2006) estimated an average ethanol production cost of $1.74 per gallon gasoline-equivalent energy in 2005, a production cost close to wholesale gasoline prices before subsidies were taken into account.

While these cost estimates indicate that corn ethanol is economically competitive with gasoline even after adjusting for the difference in energy content, corn ethanol cost is highly sensitive to feedstock cost. The cost estimates referenced above are generally based on a corn price near $2 per bushel, a price that was representative of market conditions through 2006. However, prices of corn contracts have risen sharply since then, with monthly averages peaking around $5.50 per bushel in the summer of 2008 and settling around $3.50 per bushel in April 2010 (Gould 2010). Assuming an ethanol yield of 2.65 per gallon, an increase in corn price of $1/bushel corresponds to an increase in ethanol cost of

$0.38 per gallon, meaning that an increase in feedstock price from $2 to $3.50 per bushel adds almost $0.60 per gallon to the production cost.

2.3.2. Cellulosic Ethanol

Cellulosic ethanol production cost estimates are generally based on techno-economic analyses. These analyses indicate that, for a mature cellulosic ethanol industry, production costs for cellulosic ethanol may be less than those for corn ethanol and may make cellulosic ethanol cost-competitive with fossil fuels. However, current production costs in a nascent cellulosic ethanol industry are considerably higher than costs for either fossil fuels or corn ethanol.

Inexpensive cellulosic biomass feedstocks are necessary for cellulosic ethanol to achieve the low production costs anticipating from a mature industry, and significant research has investigated the costs and resource potential of cellulosic feedstocks such as switchgrass, agricultural residues, and forest residues. McLaughlin (2005) summarizes advances made to production of switchgrass as an energy crop during a ten-year Department of Energy research program, and estimates that farm gate price of $44 and $52 per tonne would result in the production of switchgrass on 16.8 and 21.3 million hectares, respectively, throughout the United States. With projected yields of 9 tonnes per hectare, switchgrass could account for over 150 million tons of cellulosic feedstock per year at prices near $50 per tonne. Graham (2007) estimates that roughly 60 million tonnes of corn stover could be collected annually throughout the United States at a cost of $33 per tonne or less, a cost that includes concerns for erosion, soil moisture, and nutrient replacement costs.

Estimates for the national supply of corn stover climb to 100 million tonnes for universal no-till corn production.

Perlack (2005) examines the entire biomass resource potential for the United States and estimates that over 1.3 billion dry tons of biomass could be available per year, enough to displace more than one-third of all domestic transportation fuel demand. The total resource estimate is comprised of over 350 million dry tons from forest resources (including wood residues and forest thinnings) and 1 billion tons from agricultural resources such as crop residues and perennial energy crops.

Given the availability of low-cost feedstocks, long-term cost estimates indicate that cellulosic ethanol should compete favorably with fossil fuels. A series of techno-economic analyses by NREL around the year 2000 estimated very promising cellulosic ethanol production costs based on a mature industry (Wooley 1999, McAloon 2000, Aden 2002). Wooley (1999) estimated a base case production cost of $1.44 per gallon for cellulosic ethanol produced from wood chips, with production costs dropping as low as $0.76 per gallon in the future due to improvements in ethanol yield and reductions in capital investment requirements. McAloon (2000) calculated a cellulosic ethanol production cost of $1.50 per gallon, roughly $0.60 per gallon higher than the production cost for corn ethanol estimated in that same study due primarily to capital investment requirements roughly five times greater than those for corn ethanol. Aden (2002) expanded the analysis for ethanol from corn stover, producing a base case estimate of $1.07 per gallon and a range of $1.00 to $1.36 per gallon generated through Monte Carlo simulation. All three studies assumed modest feedstock costs around $30 per dry ton. An update to the 2002 report estimates a target ethanol production cost from corn stover of $1.33 per gallon by 2012 and estimates a 2007 production cost of $2.43 per gallon based on pilot-scale operations throughout the industry (Aden 2009).

Other studies estimate promising cellulosic ethanol production costs, though perhaps not quite as low as those initially estimated by NREL. Sheehan (2003) estimated production costs of $1.20 to $1.40 for cellulosic ethanol produced from corn stover in Iowa, with delivered feedstock costs ranging from $45 to $65 per dry ton and a total production of almost 2 billion gallons annually. Hamelinck (2005) examined the development of the cellulosic ethanol industry, estimating costs for short-, middle-, and long-term scenarios. As the industry matures, production costs drop from $2.75 to $1.10 per gallon, thanks to feedstock costs dropping from $75 to $50 per dry tonne and ethanol yields rising from 70 to 95 gallons per tonne. Huang (2009) examined differences in cellulosic ethanol production resulting from corn stover, switchgrass, and wood feedstocks. Production costs ranged from $1.40 per gallon for corn stover to $1.85 per gallon for either switchgrass grown on grassland or hybrid poplar, with much of variation being due to the variation in feedstock prices (which ranged from $64 to $110 per dry tonne) and ethanol yield (which ranged from about 90 gallons per tonne for corn stover and switchgrass but was over 120 gallons per tonne for aspen wood).

In addition to the biological conversion of cellulosic biomass to ethanol modeled by the studies mentioned above, biofuels may also be produced through thermochemical conversion. Phillips (2007) examines production of ethanol from forest biomass using indirect gasification and estimates a production cost of slightly more than $1 per gallon for a mature industry. Foust (2009) compares biological and thermochemical conversion of biomass to ethanol. While thermochemical conversion produces less ethanol per ton of feedstock than biological conversion, thermochemical conversion produces higher alcohols as a co-product, which reduces the thermochemical production cost by an estimated $0.10 per gallon compared to the biological conversion pathway.

Finally, there may be significant advantages to integrating ethanol production with production of either electricity or Fischer-Tropsch fuels. Laser (2009) compared thirteen biomass refining scenarios consisting of combinations of biological production of ethanol, gasification of lignin-rich biomass residues to produce electricity or Fischer-Tropsch fuels, and high quality protein co-products. Scenarios combining biological production of ethanol with thermochemical production of fuels or electricity generally realized the lowest production costs, ranging from $0.96 to $1.24 per gallon gasoline equivalent, compared $1.37 to $2.16 per gallon gasoline equivalent for production of ethanol alone.

2.4. Environmental Impacts

2.4.1. Greenhouse Gas Emissions

Theoretically, corn and cellulosic ethanol could provide major GHG reductions compared to petroleum-based gasoline. All of the carbon released during the combustion of cellulosic-based ethanol was originally extracted from the atmosphere during the growth of the feedstock. In addition, substantial amounts of carbon can be deposited into the soil during feedstock growth, as can happen in the case of perennial grasses. However, feedstock production, including accompanying land use change, the use of fertilizer and fossil energy for farm equipment, as well as transportation of feedstocks to conversion plants, conversion processes, and transport to end users can have significant GHG costs. Thus, GHG emissions of biofuels are generally assessed using life-cycle analysis that accounts for all of the impacts of producing and consuming the fuel.

Life cycle assessments of corn ethanol production have generally found modest but positive reductions in GHG emissions compared to gasoline. Hill (2006) estimated a GHG emission intensity of 85 g CO_2 per MJ, offering a 12% reduction from the 97 g CO_2 per MJ estimated for gasoline. Wang (2007) compared corn ethanol production based on a variety of energy sources used to provide power to the ethanol plant, finding average reductions of 20% compared to gasoline. Production using natural gas could result in reductions of 35% to 40%, while the use of coal could result in higher emissions than those from gasoline.

Farrell (2006) found values for the GHG intensity of corn ethanol production ranging from 60 to 120 g CO_2 per MJ, with the majority of the variation resulting from variation in limestone application rate and farm machinery energy. Their own analysis found modest GHG reductions for current ethanol production, with emissions from CO_2-intensive production exceeding those from gasoline.

Crutzen (2007) warns that emissions of N_2O resulting from fertilizer application could more than offset any GHG benefits of displacing petroleum. Liska (2009a) estimated that improvements in crop production efficiency and biorefinery operations have substantially lessened the environmental impact of corn ethanol production, resulting in ethanol that reduces emissions by 48% to 60% compared to gasoline.

In contrast to corn ethanol, cellulosic ethanol is expected to realize major GHG reductions relative to corn ethanol. Schmer (2008) estimates that cellulosic ethanol produced from switchgrass offers a 94% reduction in GHG emissions relative to gasoline. Tilman (2006) states that life-cycle GHG emissions of biofuel production could even be negative if produced from high-diversity grassland biomass, where carbon sequestered in the soil during feedstock growth is greater than carbon released during biofuel production. Sheehan (2003) comes to a similar conclusion regarding ethanol produced from corn stover. Laser (2009) found GHG emission reductions ranging from roughly 80% to 90% for various biomass-to-bioenergy conversion pathways, while Spatari (2005) found that vehicles running on a fuel blend containing 85 percent cellulosic ethanol and 15 percent gasoline (e.g., flex-fuel vehicles) could reduce GHG emissions by 57 percent to 70 percent compared to equivalent vehicles powered by gasoline alone,

However, the studies discussed above do not include recent estimates of land use change (LUC) impacts that can drastically alter GHG emission profiles. Fargione (2008) examined the losses of soil carbon resulting from the conversion of native ecosystems to agricultural land for the production of biofuel feedstocks. The release of carbon from both the soil and existing vegetation, termed in that study the 'biofuel carbon debt', can be large in comparison to the carbon saved by displacing fossil fuels. Fargione estimated that the time required to repay the carbon debt with displaced fossil fuel emissions ranged from a year or less for biofuels produced from marginal cropland to over 400 years for biofuels produced from converted peatland rainforest. Like Fargione (2008), Gibbs (2008) found carbon payback times on the order of a century for conversion of productive tropical land, and calculated carbon payback times on the order of a year for biofuel production on degraded or previously cultivated cropland.

Around the same time, Searchinger (2008) found that indirect impacts of biofuel production could result in significant GHG emissions. Diverting cropland from the production of food to the production of biofuel feedstocks can increase global prices for crops, and those price changes can lead to conversion of land for agricultural operations. The subsequent conversion of native ecosystems, termed 'indirect land use change' (iLUC), leads to the losses in soil carbon studied by Fargione (2008), which can be significant compared to the GHG benefits of biofuels. Searchinger estimated that, on average, iLUC impacts cause corn and cellulosic ethanol to increase GHG intensity by 93% and 50%, respectively, relative to gasoline.

While these initial results have (justifiably) received considerable attention, initial land use change findings (and specifically iLUC findings) are subject to considerable uncertainty. Gallagher (2008) provides an overview of some criticisms of iLUC findings. Equilibrium models for predicting iLUC impacts rely on accurate forecasts of complex global agricultural markets, forecasts that are impacted by considerable uncertainties on both supply and demand sides. Furthermore, the response of these markets to increased biofuel production needs to be precisely modeled on a spatial level, since land use changes can have drastically different carbon impacts based on the regional characteristics of converted cropland. Future land use requirements also depend heavily on agricultural yields, which may continue to improve, especially for high feedstock prices. Issues involving the allocation of environmental impacts to biofuel co-products (a problem faced by all life cycle analyses of biofuels) are relevant to iLUC analyses as well.

Further research has begun to quantify the sensitivity of iLUC findings to variation in key parameters and assumptions. Keeney (2008) finds that crop yields and bilateral trade agreements have significant impacts on iLUC emissions estimates. Kim (2009) shows that crop management practices can strongly influence life-cycle emissions from biofuel production, with no-tillage and winter coverage crop scenario resulting in 65% greater GHG reductions than plow tillage for grassland conversion and 80% greater GHG reductions than plow tillage for conversion of forestland. O'Hare (2009) discusses how allocating LUC emissions evenly over a period of biofuel production understates their impact, and how properly accounting for the immediacy of LUC emissions increases the biofuel carbon debt.

Liska (2009b) discusses the inherent difficulties in formulating fuel policies while the science behind the estimation of land use change emissions is still in its infancy. Indirect emissions resulting from other activities, such as military infrastructure investment and livestock production, may also be significant, but have not been considered in previous analyses. Liska discusses those sectors not to argue that indirect emissions should be ignored in shaping fuel policy, but to underscore the need for further research regarding indirect emissions as a whole.

2.4.2. Water and Other Impacts

While the GHG emissions from biofuels have been their most studied environmental impact, water consumption from biofuel production may also be a strong deterrent to expanded production. Berndes (2002) provides broad estimates for water consumption from biofuel crop production due to evapotranspiration (a combination of evaporation and transpiration), finding values two orders of magnitude greater than the water used at refineries for ethanol production. While impacts of significantly increasing evapotranspiration through bioenergy production vary greatly from country to country, projected levels of bioenergy production within the United States could result in stressed water supplies.

A National Academy of Sciences report examining water use for biofuel production (Schnoor 2007) outlines the complexities involved in forecasting how bioenergy crops would impact water supplies. While the national water consumption profile may not change drastically in the near future, energy crop production could have large impacts at the regional level. Ethanol refineries may also lead to local water stresses. Corn ethanol refineries are estimated to consume 4 gallons of water per gallon of ethanol, more than double the 1.5 gallons of water per gallon of fuel estimated for petroleum. Estimates for cellulosic ethanol refineries are closer to 10 gallons of water per gallon ethanol, but are expected to drop to a level comparably to that for corn ethanol as the industry matures.

While refinery water consumption estimates are two orders of magnitude less than water consumption for crop production, refinery water demands are highly localized and thus may still be problematic in certain areas. Water consumption estimates for biorefineries from Laser (2009) are consistent with those from NAS, ranging from 6 to 10 gallons per gallon gasoline equivalent for a mature industry.

In addition to straining water consumption, biofuel production may lead to pollution problems for ocean water. Runoff from nitrogen used in the production of biofuel crops contributes to hypoxia in the Gulf of Mexico (Donner 2008). Shifting from corn to cellulosic ethanol could reduce nitrate output by 20%, but the reduction would still fail to meet the EPA hypoxic zone reduction target (Costello 2009). Feedstocks such as switchgrass could potentially be produced without irrigation and with limited fertilizer and pesticide application to ameliorate water quality problems, but policies need to be coordinated to incentivize low-input feedstocks (Dominguez 2009).

The use of crop and forest residues as biofuel feedstocks can potentially have adverse environmental impacts. These biomass sources are generally viewed as waste streams that do not require energy or fertilizer inputs, but they do provide soil benefits such as nutrients, water retention, and protection from soil erosion. Thus, removing crop residues for biofuel production can erase the local soil benefits they provide, potentially leading to soil degradation and future decreases in crop yields (Andrews 2006). Excessive removals of forest residues can result in similar problems (Cram 2007).

3. Indirect Land Use Change and Biofuel Policy

Biofuel debates often focus heavily on carbon impacts, with parties arguing for (or against) biofuels based solely on whether the greenhouse gas emissions of biofuels are less than (or greater than) those of gasoline. In addition to carbon impacts, biofuels could reduce petroleum use, provide energy security benefits if used in appreciable amounts, and, if produced from cellulosic energy crops, accrue positive environmental benefits on the local landscape. If the goal is to avail society of these benefits, we should be addressing ways to mitigate the weaknesses of biofuels instead of relying solely on the plus-minus carbon emissions scorecard to determine energy policy.

An example of such a carbon-focused discussion involves the impacts of global land-use change (LUC) on biofuel emissions. Recent studies by Fargione (2008) and Searchinger (2008) have challenged the net carbon emission benefits of biofuels, traditionally viewed as low-carbon alternatives to gasoline (Farrell 2006). These studies argue that biofuels, including cellulosic ethanol, may actually be more carbon intensive than gasoline due to changes in land use due to two separate phenomena. First, plowing existing vegetation to plant biofuel feedstocks results in a release of soil carbon, incurring a carbon debt that may be large in comparison to the carbon mitigated by displacing gasoline with biofuels. This carbon debt is highly sensitive to the type of land cleared and the type of biofuel crop subsequently planted, but in some cases, the carbon impacts are dramatic; for instance, converting rainforests to biofuel crops may result in a carbon debt that takes hundreds of years of gasoline displacement to repay (Fargione 2008). Second, converting current cropland from food crops to cellulosic biomass may impact global markets in a way that induces agricultural development worldwide, an effect known as indirect land use change (iLUC). Thus, even if current cropland is used to grow biofuel feedstocks and the direct release of soil carbon is small, biofuel crops may still lead to life-cycle carbon emissions significantly greater than those of gasoline, with cellulosic ethanol estimated to increase emissions by roughly 50% due to the impacts of iLUC (Searchinger 2008).

The iLUC findings have sparked a spirited debate. The California Air Resources Board (CARB), charged with developing a Low Carbon Fuel Standard (LCFS) to reduce the carbon intensity of transportation fuels in California by at least 10% by 2020, has received letters from groups of scientists with opposing views. In one letter (Simmons 2008), CARB was urged to ignore iLUC impacts, citing a lack of empirical evidence and validation typically required of scientific findings in order to influence policy. A response (Kammen 2008) defended the recent iLUC findings, stating that the models and methods used to estimate iLUC impacts are widely accepted, and ignoring iLUC impacts in LCFS policy effectively assumes that the carbon impact of iLUC is zero, a value that current research estimates to be very unlikely. CARB has continued to receive letters from parties representing industry, academia, and public policy arguing for and against the inclusion of iLUC carbon impacts in biofuel policy (CARB 2008a). Though important and interesting, the debate will go on for some time, while policy makers need to make decisions now.

There are some drawbacks to the types of economic equilibrium models used to generate the iLUC estimates (Gallagher 2008). Equilibrium models for predicting iLUC impacts rely on accurate forecasts of complex global agricultural markets, forecasts that are impacted by considerable uncertainties on both supply and demand sides. Furthermore, the response of these markets to increased biofuel production needs to be precisely modeled on a spatial level, since land use changes can have drastically different carbon impacts based on the regional characteristics of converted cropland. Future land use requirements also depend heavily on agricultural yields, which may continue to improve, especially for high feedstock prices. Issues involving the allocation of environmental impacts to biofuel co-products (a problem faced by all life cycle analyses of biofuels) are relevant to iLUC analyses as well.

The argument that recent iLUC findings should be ignored due to modeling limitations or uncertainties fails to recognize the goal of employing low-carbon fuels. While accurately estimating iLUC carbon impacts may be difficult, and assigning emissions from iLUC entirely to biofuel production rather than to the agricultural production that occurs on the converted land may be controversial, the ultimate goal of the LCFS is to reduce carbon emissions, and these findings indicate that additional biofuel production may fail to accomplish that goal. Arguments for excluding iLUC emissions in biofuel policy also state that iLUC emissions are rarely considered in life cycle assessments of fossil fuels, so including them only when discussing biofuels in unfair. But fossil fuels have a higher energy density than bioenergy sources and are less likely to displace agricultural production; one preliminary study estimates that land use greenhouse gas emissions for petroleum are 1-2 orders of magnitude less than those estimated for ethanol (Yeh 2010). Certainly, more research toward clarifying iLUC impacts is warranted, but until the scientific community is able to further address the issue, these results must be considered when making biofuel policies.

We argue that a path through the competing arguments is achievable by returning to the various reasons that biofuels are being proposed. Biofuel discussions could be reframed by expanding the argument beyond carbon emissions. Consider cellulosic ethanol as an example. Assuming a feedstock cost of $25 - $50 per dry ton and ethanol yields near 90 gallons per ton, NREL estimates the production cost of cellulosic ethanol using either biological conversion (Aden 2002) or thermochemical conversion (Phillips 2007) to be roughly $1.00 to $1.35 per gallon. After adding distribution costs (estimated to be $0.15 - $0.20 per gallon when shipped primarily by rail (Morrow 2006b)) and adjusting for the difference in energy density between ethanol and gasoline, the cost of cellulosic ethanol could be between $1.75 and $2.25 per gallon of gasoline equivalent energy. Future technological advances, such as enhanced sugar yields from cellulose and hemicellulose, could push these cost estimates lower. For a mature cellulosic ethanol industry in which feedstock costs account for two-thirds of total production costs (a figure in line with other mature commodities), cellulosic ethanol could be produced for as little as $1.00 per gallon gasoline equivalent (Wyman 2007). These cost estimates would make cellulosic ethanol competitive with gasoline, despite the recent drop in petroleum prices resulting from current economic conditions.

Cellulosic ethanol's potential for significant cost reductions compared to gasoline, and partial protection against wild petroleum price fluctuations due to global market forces, should not be ignored when considering biofuel policies. Instead, policy makers should consider the tradeoffs between different impacts of biofuels to decide on policies that are most socially beneficial. Figure 1 provides an example of how to consider both economic and greenhouse gas impacts of cellulosic ethanol relative to gasoline in light of recent LUC research.

Figure 1 compares the social costs of gasoline and cellulosic ethanol as a function of the cost of carbon. Here, the social cost of each fuel is defined as the fuel cost plus the estimated life-cycle CO_2 emissions multiplied by the cost of CO_2. The assumed fuel costs, for illustration, are $2.00 per gallon gasoline equivalent for cellulosic ethanol and $2.50 per gallon for gasoline. The carbon cost, shown along the x-axis in Figure 1, refers to the social cost of an additional ton of CO_2 emitted, and could be represented by the value of a carbon tax, the price of a carbon allowance in a cap and trade system, or simply the estimated social valuation of externalities caused by additional carbon emissions. The social cost for each fuel, shown on the y-axis, is normalized by the amount of energy contained in a gallon of gasoline. Three lines are shown on Figure 1, representing gasoline, cellulosic ethanol without iLUC carbon impacts, and cellulosic ethanol with iLUC carbon impacts taken into account.

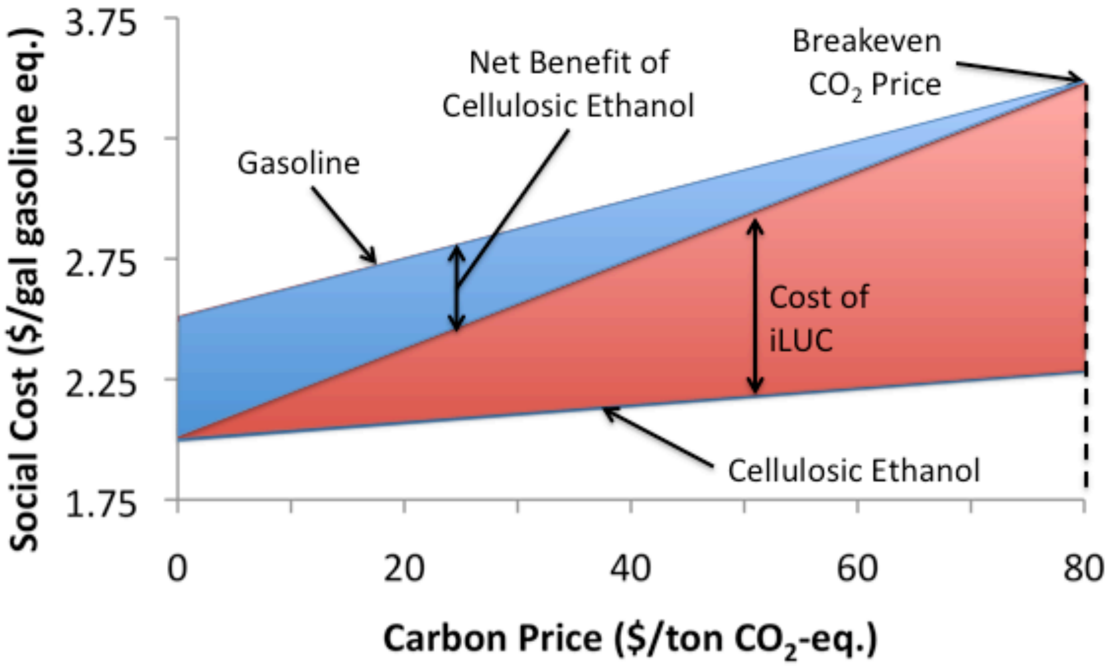

Figure 3-1. Social costs of gasoline and cellulosic ethanol. Cellulosic ethanol can result in substantial net social benefits for modest gasoline prices, even after impacts of indirect land use change (iLUC) are taken into account. Ethanol cost estimates taken from Aden (2002), GHG emissions for both cellulosic ethanol and gasoline as reported in Searchinger (2008).

Life cycle CO_2 emissions used to generate Figure 1 were taken from Searchinger (2008), where iLUC was estimated to shift cellulosic ethanol from a 70% reduction to a 50% increase in greenhouse gas emissions compared to gasoline. Note that this assumption represents a very pessimistic scenario for cellulosic ethanol, where a) cellulosic feedstock production displaces other crops and induces land use change at the rate estimated in Searchinger and b) cellulosic ethanol is held responsible for all of the resulting CO_2 emissions. Since life cycle CO_2 emissions for each fuel are assumed to be positive, each line is upward sloping, with the social costs increasing as the cost of carbon increases.

The colored regions in Figure 1 illustrate the social cost reduction of cellulosic ethanol relative to gasoline. The entire colored region between the (upper) gasoline boundary and the (lower) cellulosic ethanol boundary represents the per-gallon social cost reduction of cellulosic ethanol in the absence of iLUC impacts (or, alternatively, if iLUC impacts were assumed to be zero). The red region represents the portion of this cost reduction consumed by including the current estimates of social costs of carbon resulting from iLUC, and the blue region represents the remaining social cost reduction of cellulosic ethanol.

From this example, for a carbon shadow price of \$80/ton CO_2 or less, cellulosic ethanol results in social cost reductions relative to gasoline, even after subtracting the cost of iLUC soil carbon impacts. As the carbon shadow price increases, the cost reduction steadily decreases, finally disappearing at the 'breakeven' CO_2 price of \$80/ton, where both fuels would have identical social costs. For carbon prices above this breakeven price, cellulosic ethanol would not be socially beneficial, since the increased greenhouse gas emissions resulting from iLUC would outweigh the reductions in fuel cost. (Note that this analysis only explicitly considers the cost and greenhouse gas impacts of cellulosic ethanol and gasoline. Cellulosic ethanol could still benefit society for higher CO_2 prices due to factors such as energy security, increased domestic economic activity, etc.) Though this social cost reduction may seem small on a per-gallon basis, the macro-level impacts are significant. Considering the 16 billion gallons of cellulosic ethanol required per year by 2022 by the Energy Independence and Security Act of 2007, this reduction in social cost would amount to at least \$5 billion per year for carbon prices of \$30/ton CO_2 or less for this particular combination of biomass feedstock and gasoline prices.

The results shown in Figure 1 depend heavily on gasoline and cellulosic biomass prices, and the dramatic changes in gasoline prices in recent years caution against making policies based on narrow predictions of future prices. Additionally, cellulosic ethanol cost estimates are highly sensitive to feedstock costs, and given recent volatility in energy and food prices, cellulosic biomass prices may not be confined in the \$25 - \$50 per dry ton range assumed here. However, even substantial increases in cellulosic feedstock prices do not eliminate the potential for cost savings from cellulosic ethanol. Should feedstock costs rise to \$100 per dry ton, cellulosic ethanol cost estimates would range from \$3.00 - \$3.50 per gallon gasoline equivalent, extrapolating from NREL's results. These production cost estimates are still lower than the \$3.60 pre-tax national average gasoline price at the end of July 2008 (EIA 2010a) despite increasing the price of biomass crops by a factor of 2 – 4 from current estimates. The 2008 gasoline price is notable since it was before the global economic downturn that led to decreases in global production and consumption of oil and price declines.

The breakeven CO_2 price for cellulosic ethanol is highly sensitive to ethanol costs, gasoline costs, and iLUC emission estimates, but many potential combinations of these parameters result in high breakeven prices. For instance, assuming the same cellulosic ethanol production cost of \$2.00 per gallon gasoline equivalent and the same iLUC emissions as assumed in Figure 1, a gasoline price of \$3.00 per gallon raises the breakeven CO_2 price of cellulosic ethanol to \$160 per ton. Should gasoline prices rise as high as \$3.60 per gallon, cellulosic ethanol's breakeven CO_2 price would reach \$260 per ton. Gasoline prices would have to fall below $2.15 per gallon for the breakeven CO_2 price to fall below $25 per ton. Conversely, should ethanol production costs fall as the industry matures, the breakeven CO_2 price would rise. Assuming $2.50 per gallon gasoline, a cellulosic ethanol production cost of $1.50 per gallon gasoline equivalent equates to a breakeven CO_2 price of $160 per ton, while a production cost of $1.00 per gallon gasoline equivalent (in line with some long-term projections (Hamelinck 2005)) means the breakeven CO_2 price would be over $240 per ton, even with modest gasoline prices. Finally, more conservative estimates of iLUC than those assumed in Figure 1 would also raise the breakeven CO_2 price. If cellulosic ethanol were estimated to be 25% more CO_2 intensive than gasoline (rather than the 50% assumed here), then the breakeven CO_2 price of cellulosic ethanol would rise from $80 to $160 per ton. In order for the breakeven CO_2 price to fall below $25 per ton CO_2 given a $0.50 per gallon price differential, iLUC emissions would have to make cellulosic ethanol 175% more carbon intensive than gasoline.

The potential for very high breakeven CO_2 prices is a promising result for cellulosic ethanol proponents. Since cellulosic ethanol may be a low-cost, high-carbon alternative to gasoline in light of LUC findings, the breakeven CO_2 price is essentially the cost reduction cellulosic ethanol generates in exchange for the release of an additional ton of CO_2. For example, the breakeven CO_2 price of $80/ton indicates that society would be indifferent between cellulosic ethanol and gasoline given a CO_2 price of $80 per ton. In other words, cellulosic ethanol would reduce fuel costs by $80 for every additional ton of CO_2 released, including iLUC emissions.

Put another way, the decision *not* to produce cellulosic ethanol and rely instead on gasoline would result in lower total CO_2 emissions, since, based on assumed emissions estimates, gasoline has lower life-cycle CO_2 emissions than cellulosic ethanol. However, compared to a future scenario with cellulosic ethanol production, using gasoline instead of cellulosic ethanol would represent a very expensive mitigation option, with a cost of mitigation, for this combination of energy prices, of $80/ton CO_2.

Critics argue against the adoption of ethanol as part of a Low Carbon Fuel Standard based solely on the increased carbon emissions. However, such an argument views the social problem of carbon mitigation too narrowly. By taking a society-wide approach to the problem of carbon mitigation, cost reductions from using cellulosic ethanol could be used to fund carbon mitigation alternatives that more than make up for the additional emissions from iLUC, even if current estimates remain unchanged and biofuels are held solely responsible for these emissions. A key ingredient of such an approach is the existence of carbon mitigation technologies or practices available at a cost significantly less than cellulosic ethanol's breakeven cost, estimated to be $80/ton CO_2 in Figure 1. Fortunately, there are many alternatives that meet this requirement. McKinsey & Co. (Grenzeback 2007) suggests that there are 1.3 billion tons per year of potential CO_2 mitigation with negative costs (e.g., conservation activities such as lighting replacements), and another 600 million tons costing less than $30 per ton (such as reforestation). Even large-scale projects such as carbon capture and sequestration from coal-fired power plants could be funded for $30 to $90/ton CO_2 (Metz 2005). These options have long been known but not previously pursued due to lack of centralized funding. If policies are in place to capture part of the $5 billion resulting from reduced fuel costs of cellulosic ethanol, such funding could become available to more than mitigate the 65 million tons of CO_2 added by cellulosic ethanol when iLUC impacts are considered. Thus, if carbon mitigation is the sole objective of LCFS policies, cellulosic ethanol can still play an effective role.

Furthermore, carbon mitigation strategies could be chosen to help ameliorate other negative impacts of biofuels. For instance, biofuel-driven land use change may have detrimental effects on biodiversity. Land use change has been identified as the primary driver impacting biodiversity in terrestrial ecosystems throughout the next century, with significant changes in land use having major impacts on biodiversity across a variety of biomes (Sala 2000). Changes in biodiversity resulting from land-use change may have profound economic impacts on society by altering ecosystem attributes, such as soil quality, water supply, and fire and disease vulnerability (Chapin 2000). These impacts are often costly, if not impossible, to reverse. Though the relationships between biodiversity and ecosystem goods may be non-linear, non-additive, and ultimately difficult to quantify, preserving biodiversity may serve as an insurance policy against drastic ecosystem changes that could otherwise result from changes to the environment. Thus, accelerating global land-use change by producing biofuels could impact biodiversity in ways that, during a time of major climate change, could lead to severe economic consequences. These consequences may be avoided by funding measures such as reforestation (estimated to cost around $30 per ton CO_2 (Grenzeback 2007)) that can both help sequester soil carbon and preserve biodiversity.

Effectively administrating a program that taxes biofuels in order to fund carbon mitigation options would be very challenging. It would be difficult to accurately quantify iLUC emissions from different biofuel feedstocks grown in different regions, a necessary step in determining the size of any biofuel tax. Deciding whether producers or consumers of biofuels are responsible for iLUC could also be difficult (though this issue is already being debated more generally throughout climate change policy). These challenges do not erase the fact that the cost-carbon tradeoff of biofuels may compare favorably to that of gasoline. Though policies designed to balance the carbon and cost impacts of biofuels may not be simple, biofuels should not be excluded from energy policy due solely to iLUC.

This argument has focused primarily on cellulosic ethanol produced from energy crops, but a similar line of reasoning could be applied to other fuels as well. Assuming a corn price of $5/bushel and projecting from the results of a USDA survey (Shapouri 2005), the cost of corn ethanol is $2.00 - $2.25 per gallon. Though corn ethanol could be about twice as CO_2 intensive as gasoline once iLUC carbon impacts are considered (Searchinger 2008), corn ethanol would still be expected to result in social cost reductions for CO_2 costs below $25/ton, assuming a gasoline price of $3.60 per gallon. Fischer-Tropsch fuels produced from coal could cost $1.50 - $1.85 per gallon (Jaramillo 2008), creating the potential for funds to more than mitigate their increased emissions. Cellulosic ethanol produced from sources other than energy crops, or grown on degraded land, looks particularly promising. Growing cellulosic crops on marginal or degraded land results in much lower soil carbon losses than crops grown on forest or grasslands [**Error! Reference source not found.**] and iLUC would be avoided if no agricultural activity were displaced. Using agricultural residues (such as corn stover or wheat straw) or forest residues would avoid land use change entirely. Scenarios with lower land use emissions result in higher breakeven CO_2 prices for cellulosic ethanol and increase the social cost reduction relative to gasoline.

Like so many of the climate and climate mitigation debates, authors argue as if there were only black and white alternatives, when ultimately solutions will be found in the gray areas. Given the rising costs of gasoline, and other externalities such as energy security that may trump iLUC issues, we need to look for alternatives that may not be "optimal" but workable. Here, we suggest using the cost reductions of cellulosic ethanol to balance out the impacts of iLUC as an illustration of ways policies can be used to arrive at workable solutions. As long as parties take a narrow approach and argue for a favorite solution, rather than looking hard for potential compromises, we fear that the scientific community may be unable to provide effective guidance for climate policy in a complex world.

4. Estimating National Costs, Benefits, and Potential of Cellulosic Ethanol Production from Forest Thinnings

4.1. Introduction

From 1960 to 2007, an average of 4.1 million acres of forestland per year has burned due to wildfire in the United States (NIFC 2009). In recent years, wildfires have become significantly more intense, with an average of 9 million acres lost per year from 2004 to 2007 despite no significant increase in the number of wildfires (NIFC 2009). Assuming an average fire suppression cost for large forest fires of $170 per acre (Perlack 2005), forest fires in recent years have resulted in a social cost of at least $1.5 billion per year. This fire suppression cost estimate does not include other important social costs of forest fires, including lost timber, regeneration and rehabilitation costs, and property losses, estimated to be on the order of $3,000 per acre burned (Mason 2006). Based on this larger, more inclusive social cost estimate, forest fires resulted in average annual social costs on the order of $30 billion in recent years.

In an effort to reduce the risk of forest fires, the USDA Forest Service funds forest thinning operations designed to reduce the level of biomass in overcrowded forestland. In 2008, the USDA Forest Service spent $300 million on hazardous fuel reduction, targeting 3 million acres of forestland (USDA FS 2007). Forest thinning options range from prescribed fires to cutting, skidding and chipping biomass for transportation to be used as an energy source, with cost estimates ranging from $35 to over $1500 per acre, depending on treatment method, forest type, and terrain (Rummer 2008). No single thinning strategy is appropriate for all forest types, but a combination of site-specific fuel treatments that includes thinning, surface fuel removal, and prescribed fire has been shown to reduce wildfire risks in forests throughout the western United States (Graham 1999). Unfortunately, with rising fire suppression costs and a budget that declined 8% overall and 4% for hazardous fuel management from 2008 to 2009 (USDA FS 2008), the Forest Service may not be able to expand or even maintain these preventative fuel treatments, despite the fact that current fuel reduction expenditures represent only 1% of estimated annual damages.

Fuel treatment programs could potentially offset some of their costs by offering excess biomass as an alternative energy source (Levan-Green 2001, Rummer 2008, Polagye 2007,Eriksson 2008). Due to concern over the contributions of fossil fuels to climate change, volatile petroleum prices, and a desire for increased energy security, the 2007 Energy Independence and Security Act (EISA) requires that at least 36 billion gallons of ethanol be produced domestically by 2022, with at least 21 billion gallons from advanced biofuels including cellulosic ethanol (EISA 2007). Forest biomass, including forest thinnings, represents a promising feedstock for cellulosic ethanol, an end product whose value could help offset the costs of fuel treatments.

In addition to the decreased wildfire risk that results from their removal, there are a number of other advantages related to the removal and use of forest thinnings as a cellulosic ethanol feedstock. Thinning operations can stimulate forest growth, promote forest health, and improve wildlife habitats. Production of forest thinnings requires no fertilizer or pesticide input, and only requires fossil energy input during the removal phase. They do not compete with food crops for land (avoiding the food versus fuel issue), and their collection results in no land-use change impacts.

The spatial distribution of forest thinnings complements that of other ethanol feedstocks such as corn, crop residues, and switchgrass. These energy crops and crop residues can be produced in large quantities most easily in the Midwest and Southeast portions of the United States, while forest thinnings may be available in the Northeast and along the West Coast. Since the majority of the United States population lives along the coasts, production of ethanol from forest thinnings could provide these dense population centers with ethanol without requiring that it be shipped long distances from the center of the country.

Previous studies have examined the costs of using forest thinnings as an alternative energy source (Rummer 2003, Levan-Green 2001, Rummer 2008, Polagye 2007, Eriksson 2008), often focusing on specific types of thinning operations in specific regions. There are a variety of methods used to estimate forest thinning costs, leading to a wide range of cost estimates (Rummer 2008). Rummer (2003) estimated costs of \$35 - \$85 per dry ton to cut and extract fuel reduction materials from gentle terrain, with costs increasing by about 20% for rolling terrain. Polagye (2007) considered the production of wood pellets, bio-oil, and methanol from thinnings throughout the state of Washington, estimating an average cost of \$10 per ton for cutting and skidding thinned biomass and an additional \$5 - \$7 to load, chip, and debark biomass for use as a biofuel feedstock. Cost estimates in Polagye (2007) are relatively low due to high stand density and favorable terrain throughout the thinned region. Though biofuel revenue would not fully offset biomass removal costs for this scenario due in part to large transportation costs, biofuel production from thinned biomass was economically preferable to landfill disposal. Eriksson (2008) found that stumps and small roundwood produced from thinning operations could be removed at a cost of $65 - $115 per dry ton making these biomass sources cost-competitive with logging residues as a biofuel feedstock in the near future.

In contrast to the studies discussed above, this study models forest thinnings from a higher-level perspective, examining thinned biomass as a bioenergy feedstock on a national level and modeling the entire biofuel supply chain from biomass removal to delivery to biofuel delivery and estimating the social costs and benefits of this fuel production. Producing cellulosic ethanol from forest thinnings could have multiple social benefits. Producing cellulosic ethanol for use as a transportation fuel would displace gasoline, reducing both the carbon intensity of transportation fuels and dependence on foreign oil while providing some insurance against volatile fossil fuel prices, and reducing wildfire risk in overcrowded forests. Additionally, if cellulosic ethanol could be produced for less than the price of gasoline, cost reductions could be used to both reduce consumer fuel prices and provide funds for additional forest thinning treatments. Here, we examine the potential of forest thinning-derived ethanol to achieve these benefits on a national level and discuss policies that would help meet these goals.

4.2. Data Sources and Methods

4.2.1. Biomass Supplies

Availability of biomass from forest thinning operations was estimated using supply curves provided by Oak Ridge National Laboratory. These supply curves estimate woody biomass supplies from a number of sources including forest thinnings on a county-by-county basis for biomass removal costs ranging from $20 to $200 per dry ton. Forest thinning supplies were estimated using the USDA Forest Service Fuel Reduction Cost Simulator model, based on input data from Forest Inventory Analysis plots, aggregated at the county level (Perlack 2008).

For forest thinning supply curves, costs include stumpage cost, harvest cost, skidding cost, and chipping cost, i.e., all costs associated with delivering chipped biomass suitable for use as a bioenergy feedstock to the nearest roadside. Thus, it is assumed that the only additional cost to delivering the biomass in a form that can be used to produce ethanol is the cost to ship the biomass from the roadside to the facility itself. Unit biomass shipping costs for both truck and rail shipping modes were taken from Mahmudi (2006).

4.2.2. Cellulosic Ethanol Production

Cellulosic ethanol is not currently produced on a commercial scale, so future cost estimates are taken from engineering-economic analyses. These analyses indicate that cellulosic ethanol has the potential for low production costs, relative to recent gasoline prices, in the near future. For instance, DOE researchers reported achieving a production cost of $2.25 per gallon in 2006 (Goldemberg 2007), with a goal of producing cellulosic ethanol for close to $1 per gallon by 2012. Huang examined cellulosic ethanol production from corn stover, switchgrass, hybrid poplar, and aspen wood, estimating total operating costs for production of cellulosic ethanol of $1.40 to $1.90 per gallon (Huang 2009). Based on future technological advances, Hamelinck estimated production costs of $1.50 per gallon by 2010 and $0.90 per gallon by 2015 - 2020, falling as low as $0.60 per gallon after 2025 (Hamelinck 2005). For this study, estimates of capital and operating costs were taken from detailed process economic studies of producing cellulosic ethanol authored by Aden (2002) and Phillips (2007). Both studies estimate a cellulosic ethanol production cost of $1.00 to $1.30 per gallon. These cost estimates that lie between the costs already achieved by DOE and long-term cost estimates such as those from Hamelinck.

Since commercial scale cellulosic ethanol plants do not exist, it was necessary to estimate locations of future facilities in proximity to potential biomass sources. Cellulosic ethanol facilities were placed using the clustering algorithm *k*-means. The *k*-means algorithm is a simple, fast heuristic algorithm that attempts to cluster data in a way that minimizes the total intracluster variance. For a more detailed description of *k*-means, see Han (2005). Inputs to the algorithm were county centroids with longitude and latitude coordinates and projected forest thinnings availability. Distances between points and cluster centers were calculated using the great circle equation, with new cluster center coordinates calculated as a weighted average based on biomass supplies. Outputs were *k* partitions of counties, each of which fed biomass to a facility assumed to be located at the cluster center.

The value for *k* was modified to vary facility size, with smaller values of *k* resulting in larger facilities. Larger facilities have increased feedstock transportation costs, but can also take advantage of economies of scale to reduce unit capital investment and operating costs.

Previous studies have estimated the optimal ethanol facility size empirically (Gallagher 2005) (for corn ethanol) and found for both a general bioenergy facility (Nguyen 1996) and a cellulosic ethanol plant (Aden 2002) that costs would be minimized by a facility with a capacity of approximately 70 million gallons per year. While this facility size is larger than 2/3 of corn ethanol plants currently in operation, the largest domestic corn ethanol plants have capacities of twice this value (RFA 2010a), so future cellulosic facilities with this capacity are realistic. Thus, values for k were chosen to result in facilities with approximately this capacity.

4.2.3. Ethanol Demands

Projected ethanol demands were assigned to metropolitan statistical areas (MSAs) throughout the continental United States. Ethanol demand was estimated by assuming that all gasoline consumption is replaced with a fuel blend of 85% ethanol, 15% gasoline by volume (E85). For each MSA, ethanol demand for the year 2020 was estimated based on current gasoline consumption and estimated state-level population growth rates, assuming that transportation energy demand per capita remains constant. Results were insensitive to both lower ethanol blend levels and the target year used to model energy demand.

4.2.4. Ethanol Shipping

Ethanol transportation was modeled using a linear programming (LP) model similar to those employed by Morrow (2006b) and Wakeley (2009). This model assigns ethanol shipments from facilities to demands in such a way that minimizes total transportation cost, subject to constraints on both the facility and demand sites. Since 90% of domestic ethanol shipping occurs via either rail or truck (USDA 2007), only those modes of transportation were modeled. The objective function for this model represents the system-wide transportation cost:

$$Minimize \sum_{i} \sum_{j} \left(f_{ij} + d_{ij} v_{ij} \right) x_{ij}$$

where x_{ij} represents the volume of ethanol shipped from plant *i* to MSA *j*, and d_{ij} represents the great circle distance from plant *i* to MSA *j*. f_{ij} and v_{ij} represent fixed and variable transportation costs, assuming rail shipping if d_{ij} is greater than 180 miles (calculated to be the minimum economic rail shipping distance in Mahmudi (2006)) and truck shipping otherwise.

Constraints ensure that all ethanol is shipped, while no MSA receives more ethanol than it demands:

$$\sum_{j} x_{ij} = S_i$$

$$\sum_{i} x_{ij} \leq D_j$$

where S_i is the total ethanol supplied by plant *i* and D_j is the total ethanol demand for MSA *j*, assuming that all MSAs meet their transportation energy demand with an 85% ethanol blend.

4.2.5. Wildfire Risk Reduction

The reduction in expected fire damage due to the removal of hazardous fuels was estimated based on current volumes of forest biomass, projected biomass removals from thinning operations, and historical fire frequency and severity data.

Expected fire damage was estimated on a state level by examining historical wildfire data. Historical wildfire data was taken from the Monitoring Trends in Burn Severity (MTBS) Fire Occurrence Database (MTBS 2009). The MTBS database contains data on wildfires that have occurred within the United States from 1984 to 2005, including fire dates, number of acres burned, and coordinates of fire centroids. Wildfires larger than 500 acres that occurred in the eastern half of the United States and wildfires larger than 1000 acres in the western half of the United States are stored in the database. For each state, expected annual fire damage was calculated as the average acreage burned annually throughout the state for the years included in the data set.

Wildfire risk reduction from forest thinning was estimated by comparing the amount of biomass removed through thinning operations to the total amount of forest biomass. Total forest biomass estimates on a state level were taken from Forest Resources of the United States, a National Forest Service inventory (Smith 2004).

In the absence of references providing a relationship between biomass density and wildfire severity on a regional level, it was assumed that expected wildfire damage decreases linearly with the volume of forest biomass. For instance, if thinning operations remove 1% of the total estimated forest biomass throughout a state, the expected wildfire damage for that state was assumed to decrease by 1%. Wildfire behavior is often non-linear; for instance, the speed at which a fire must spread in order to remain active increases exponentially as crown bulk density decreases (Graham 1999), so thinning operations that reduce biomass density may have greater than linear benefits in terms of retarding wildfire spread and limiting wildfire severity. Thus, estimates generated in this study for wildfire risk reductions due to thinning operations are likely conservative.

A thinning period of 30 years was assumed (Perlack 2005), corresponding to the assumed lifetime of the ethanol refinery, during which forest biomass would linearly grow back to pre-thinning levels. Thus, thinning operations would reduce the expected number of acres burned throughout the 30 year time period following the operation. For each of the 30 years, wildfire risk reduction benefits were monetized by multiplying the reduction in expected number of acres burned by the per-acre social cost of wildfire estimated by Mason (2006) mentioned in the *Introduction*. Finally, the benefits of thinning operations were estimated by calculating the present value of the annuity represented by reduced wildfire risk, assuming a discount rate of 5%.

4.3. Results and Discussion

4.3.1. Wildfire Risk Estimation and Thinnings Supply

Figure 4-1 provides a map of estimated social benefits of wildfire risk reduction due to forest thinning operations for the lower 48 states. The results shown in Figure 4-1 represent a scenario in which forestland lost due to wildfire has a social cost of about $4,000 per acre, a value estimated in Mason that includes fire suppression costs, value of lost timber and facilities, regeneration and rehabilitation costs, and other negative social impacts (Mason 2006). The values shown in Figure 4-1 refer to the per-ton benefit of removing forest biomass via thinning operations; in other words, a state with a social benefit estimate of $5/ton would see their expected social cost of wildfire decrease by $5 for every ton of biomass removed by thinning operations within that state.

Social benefits are relatively low throughout the eastern United States, with all states east of the Mississippi having benefits of $5/ton or less and many eastern states having no social benefit (a value of $0/ton) due to the infrequency of wildfire. Western states, where wildfires are more frequent and severe, stand to benefit significantly from forest thinning operations, with expected wildfire damage reduced by almost $40/ton for thinnings removed for Nevada and Idaho and over $10/ton for Pacific coast states California and Oregon. For the western states with thinning benefits of at least $10 per ton (California, Oregon, Nevada, Montana, Idaho, and Wyoming), thinning all biomass that can be removed at a cost of $50 per ton or less would create a benefit of over $115 million per year by reducing expected wildfire damage.

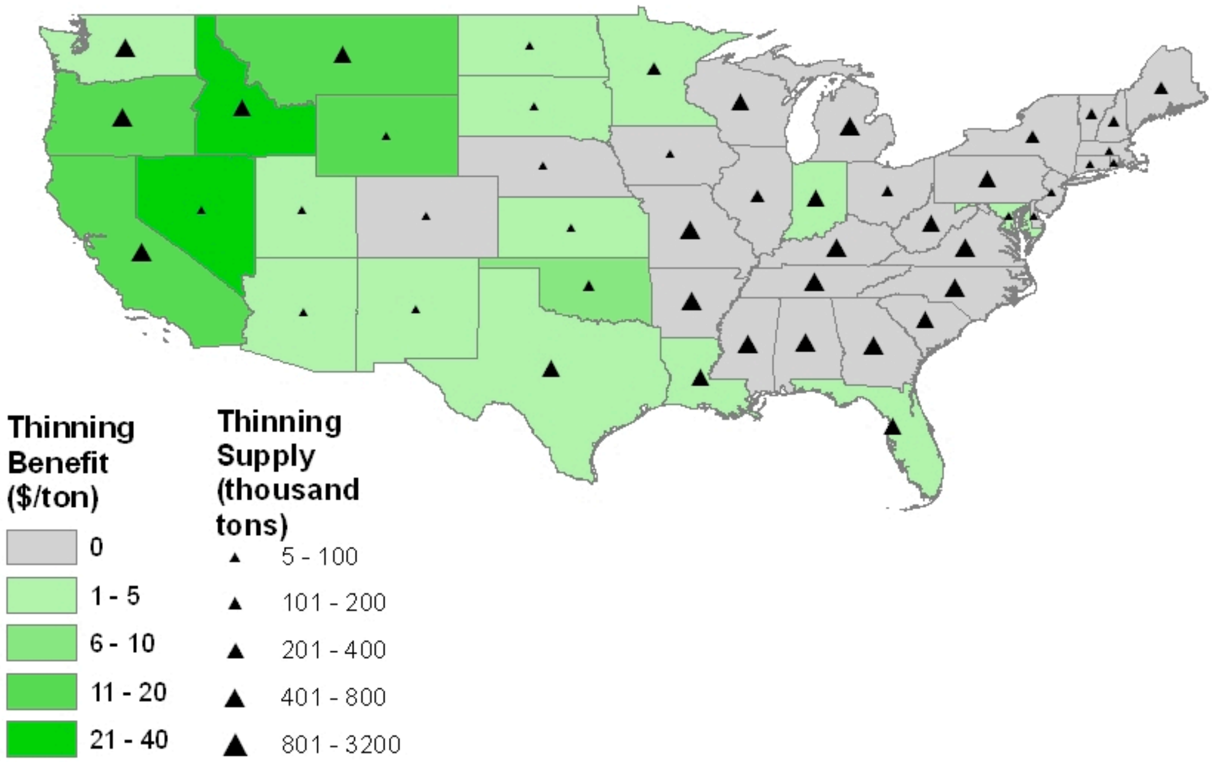

Figure 4-1: Estimated wildfire risk reduction and estimated biomass supplies from forest thinning.

In addition to the estimated benefits of forest thinnings, Figure 4-1 shows estimated forest thinning supplies at state-level aggregation for a feedstock removal cost of $50 per dry ton. Forest thinning supplies were taken from supply curves discussed in Section 2.1 that estimate woody biomass supplies from forest thinnings for biomass removal costs ranging from $20 to $200 per dry ton. The assumed feedstock removal cost of $50 per dry ton is in line with feedstock prices assumed in previous studies of forest biomass (Rummer 2003, Wooley 2000) as an energy feedstock, and is chosen here primarily to illustrate the spatial distribution of estimated thinning supplies. A removal cost of $50 per dry ton is also within the range of estimated energy crop production costs; for instance, switchgrass production is estimated to cost $13 - $80 per dry ton (Cooper 2008). National forest thinning supplies are estimated to be 28 million dry tons per year at a removal cost of $50 per dry ton, an estimate that steadily increases to 45 million dry tons as removal cost increases to $200 per dry ton. The spatial distribution of thinned biomass does not change significantly for higher feedstock costs.

Forest thinnings are projected to be most abundant throughout the southeastern states and those along the Pacific coast. The most promising candidates for producing cellulosic ethanol from forest thinnings are states that have both a high projected supply of forest thinnings and a high estimated thinning benefit. For example, states along the Pacific coast, as well as Idaho and Montana, are excellent candidates for producing ethanol from forest thinnings, since they are projected to provide a significant volume of forest thinnings and have a relatively high thinning benefit in terms of wildfire risk reduction. While Nevada and Colorado have relatively high thinning benefits, forest thinnings available at modest removal costs are limited. Conversely, southeastern states may have abundant forest thinning biomass supplies, but since wildfire risk throughout this region is small, removal of forest thinnings from these states may have a relatively small wildfire risk reduction.

4.3.2. Ethanol Production Cost Estimates

Figure 4-2 shows the county-level spatial configuration for forest thinning-derived cellulosic ethanol production and distribution, assuming a removal cost of $50/dry ton. Cellulosic ethanol plants, placed using the *k*-means algorithm summarized in Section 2.2, are found most abundantly in the Southeast, with some smaller plants located in the Northeast and a few large plants also found in the Pacific Northwest. National ethanol production from forest thinnings is relatively limited in this scenario (totaling less than 3 billion gallons), so in a minimum total cost scenario only MSAs close to ethanol refineries would receive ethanol.

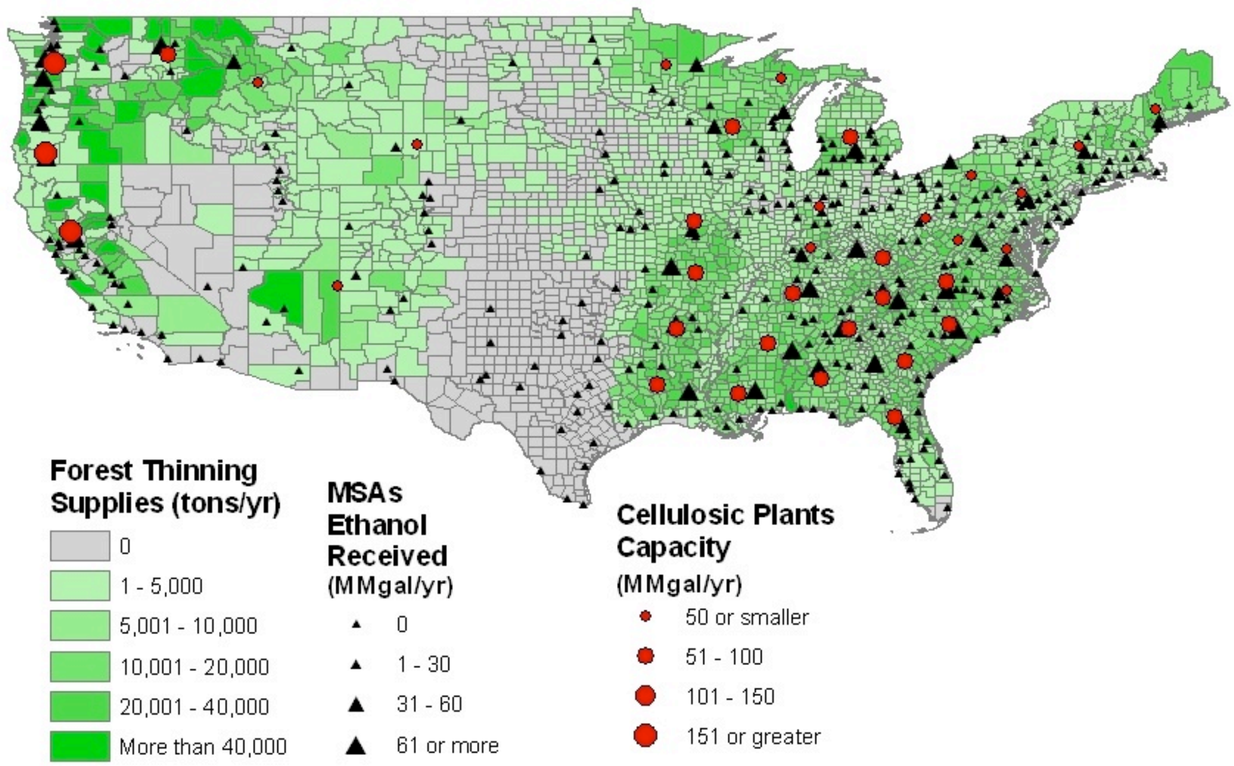

Figure 4-2: Forest thinning supplies, cellulosic ethanol plant locations, and MSAs receiving ethanol, assuming a feedstock cost of $50/dry ton.

Figure 4-3 shows cumulative distribution functions for cost components of cellulosic ethanol produced from forest thinnings throughout the United States. The results shown in Figure 4-3 assume a feedstock cost of $50 per dry ton. Total production cost ranges from a minimum cost of $1.75 to a maximum cost of over $3.00 per gallon gasoline equivalent, with an average cost of $2.10. The considerable variability in total production cost is due to variation in both capital cost and biomass shipping cost. In regions with low forest thinning densities, cellulosic ethanol plants are either built to a smaller capacity (increasing specific capital costs) or are required to draw biomass from a larger area, increasing cost of shipping biomass. Both factors drive costs near $3.00 per gallon gasoline equivalent at the high end of the distribution.

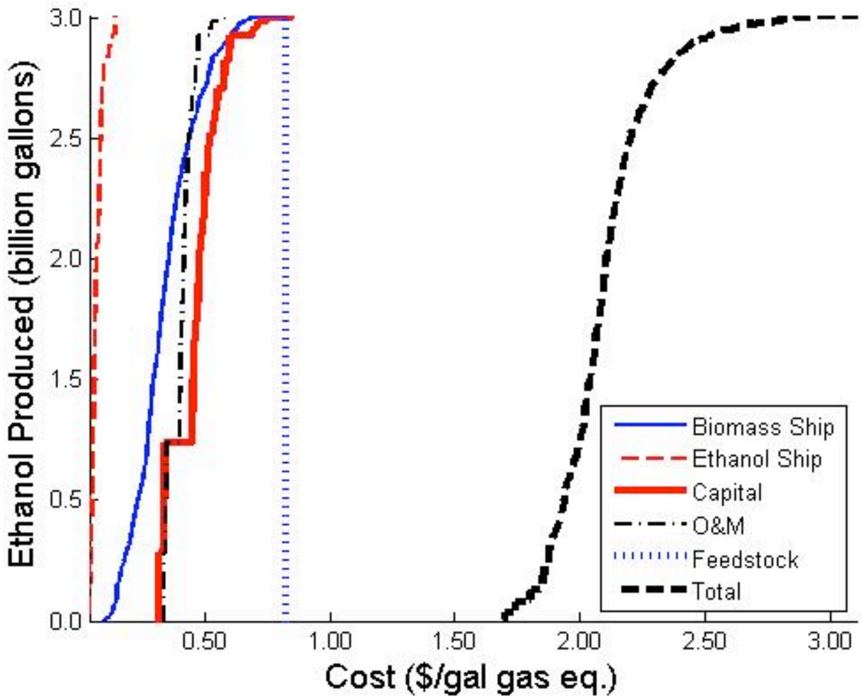

Figure 4-3: Cost components of cellulosic ethanol produced from forest thinnings, assuming a feedstock cost of $50/dry ton.

Figure 4-4 shows the national supply curve for cellulosic ethanol produced from forest thinnings. The supply curve was generated by estimating ethanol production costs and volumes for feedstock costs ranging from $10 to $200 per dry ton. Compared to national demand for transportation fuels, the total potential production of ethanol from forest thinnings is relatively modest; forest thinning-derived ethanol is estimated to max out around 3.5 billion gallons per year, or roughly 10% of the total EISA biofuel mandate required by 2022. However, over half of the total potential is projected to be available at a cost of less than $2 per gallon of gasoline equivalent energy. If cellulosic ethanol facility owners bid up the price of cellulosic feedstocks to the point where the production cost of cellulosic ethanol is equal to the price of gasoline, then the difference between the market price for cellulosic biomass and the removal cost of forest thinnings could generate profits for the forest service. Thus, even for low gasoline prices, cellulosic ethanol from forest thinnings may be competitive with gasoline and may be able to generate profits that could be reinvested to provide funds for additional thinning operations.

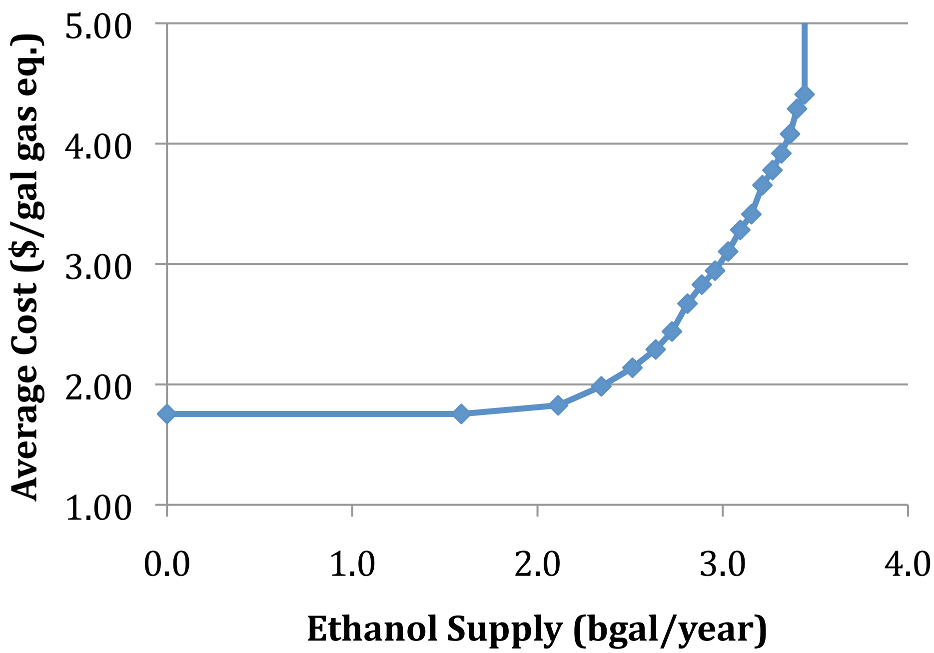

Figure 4-4: National supply curve for cellulosic ethanol produced from forest thinnings.

Figure 4-5 shows components of the production cost of cellulosic ethanol per gallon gasoline equivalent energy, assuming a feedstock price of $50 per ton, for various regions throughout the United States. Figure 4-5 also provides estimated wildfire reduction benefits for cellulosic ethanol produced in those same regions. All regions have an average production cost of between $2 and $2.50 per gallon gasoline equivalent; changes in production cost are due to differences in regional feedstock density. Wildfire benefits from ethanol production are accrued in two regions, the West and Northwest (where wildfires are more common). In these regions, cellulosic ethanol production from forest thinnings is estimated to reduce expected wildfire damage by $0.15 to $0.40 per gallon gasoline equivalent. While ethanol produced in the West region is estimated to have a greater unit wildfire reduction, the total ethanol production potential in these states is relatively limited, compared to the Northwest where the per-gallon benefit is less but the total feedstock availability is greater.

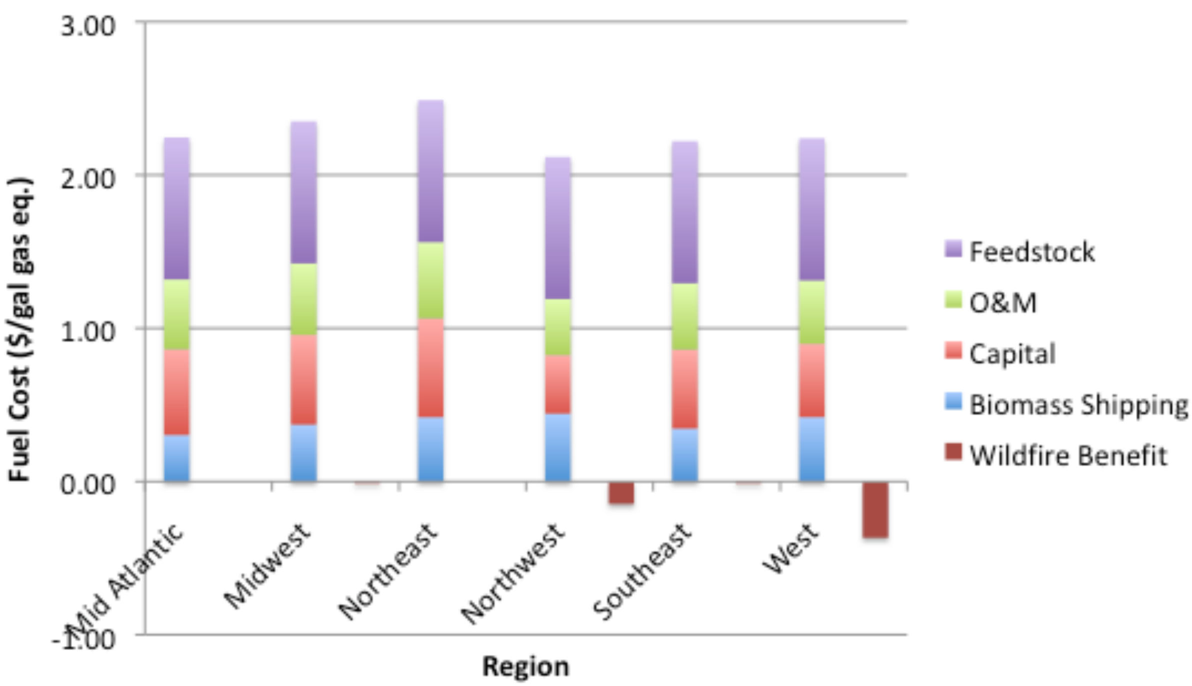

Figure 4-5: Cost components and wildfire reduction benefits for cellulosic ethanol produced in various regions.

Figure 4-6 provides cumulative distribution functions for both biomass and ethanol shipping distances. Figure 4-6 shows that biomass shipping distances are relatively large for the scenario modeled in this study, with 10% of forest thinnings being shipped at least 150 miles, incurring a transportation cost of over $30 per dry ton and contributing a marginal cost of $0.50 or more to the cost of ethanol per gallon gasoline equivalent.

There are two possibilities to reduce biomass transportation costs. The first is to build facilities with smaller capacities. Facilities with capacities smaller than the 70 million gallons per year assumed in this study reduce biomass transportation costs, but they also fail to take advantage of economies of scale and ultimately increase production cost. The second option is to use multiple feedstocks at a single facility. If forest thinnings are used along with other cellulosic feedstocks (such as energy crops, crop residues, or other forest removals such as logging residues which can be used concurrently by a single cellulosic ethanol refinery) to produce ethanol, then relatively large facilities could become more common, leading to shorter shipping distances and production cost reductions. A scenario in which thinnings are used along with these other cellulosic sources results in an average biomass shipping distance of only 20 miles (compared to 95 miles for the thinnings only case), reducing biomass shipping costs by 60%.

Figure 4-6 also provides cumulative distribution functions for two ethanol shipment scenarios, one in which all MSAs demand E10 and one in which they demand E85. (Production cost estimates shown in Figures 3, 4, and 5 were generated based on the assumption that MSAs demand E85.) Figure 4-6 shows that shipping distances are roughly doubled in moving from E85 distribution to E10 distribution; each MSA demands less ethanol, so ethanol plants have to look further for MSAs to consume all of the ethanol they produce. Though ethanol transportation distances may be as high as 250 miles for E10 distribution, the contribution of ethanol shipping to the total production cost of forest thinning-derived ethanol is relatively small, with average shipping costs for E85 near $0.07 per gallon gasoline equivalent.

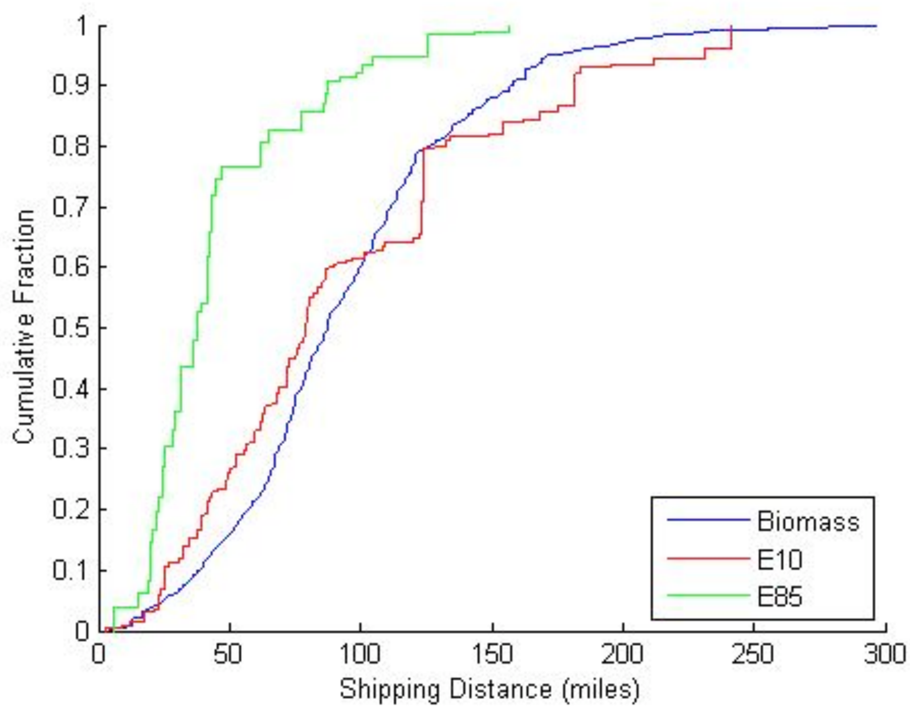

Figure 4-6: Cumulative distribution functions for biomass and ethanol shipping distances.

4.3.3. Forest Thinning Funds

Figure 4-4 shows that a significant quantity of ethanol could be produced from forest thinnings at a cost less than recent gasoline prices. If forest thinning-derived ethanol is cost competitive with gasoline, significant funds may be available for the Forest Service to continue or expand thinning operations.

Figure 4-7 shows how the profit generated by forest thinnings changes as a function of both thinning volumes and gasoline price. Profit is equal to the difference between the equilibrium feedstock price and the cost to the Forest Service to remove thinned biomass, integrated over the national forest thinnings supply curve. Four curves are shown in Figure 4-7, corresponding to feedstock prices of $25, $50, $75, and $100 per dry ton which include biomass transportation to the refinery. Next to each feedstock price label, in parentheses, is the cellulosic ethanol production cost, in dollars per gallon gasoline equivalent, estimated in this study. The results shown in Figure 4-7 assume that the Forest Service does not own cellulosic ethanol plants, but that cellulosic ethanol plant owners bid up feedstock prices until the production cost of cellulosic ethanol is equivalent to the price of gasoline on an energy basis. For instance, if the price of gasoline is $1.79 per gallon, it is assumed that cellulosic ethanol plant owners would be willing to pay $25 per dry ton of cellulosic feedstock.

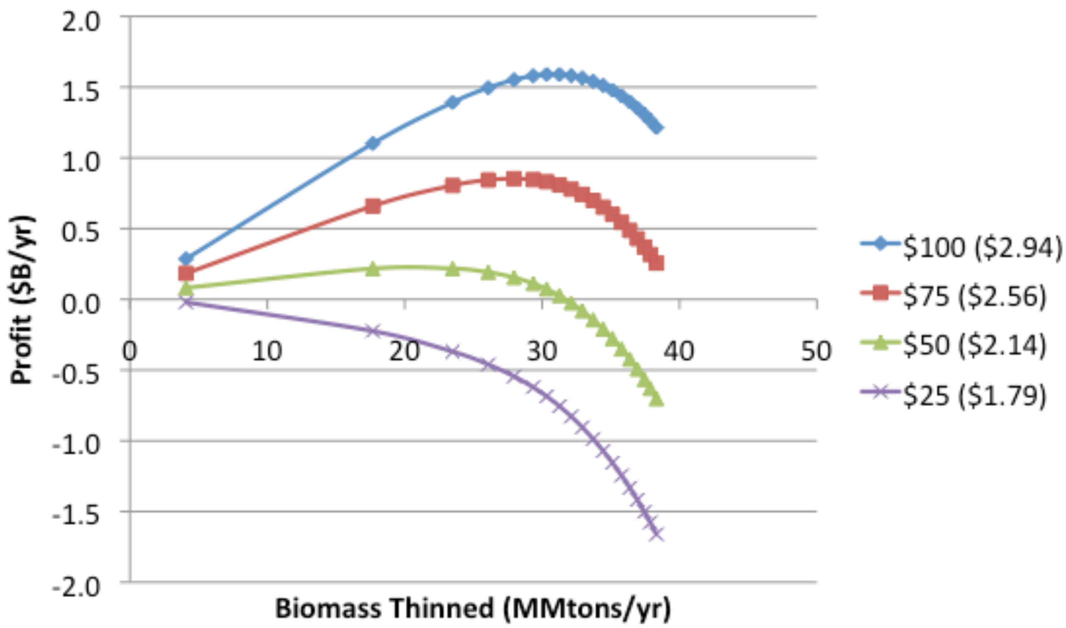

Figure 4-7: Profit generated by forest thinnings for various feedstock prices in $/dry ton (equivalent gasoline prices in $/gallon).

Figure 4-7 shows that forest thinnings have the potential to generate significant profits with feedstock prices of at least $50 per dry ton. If feedstock prices remain near $25 per dry ton, forest thinnings will not be profitable (biomass shipping alone is estimated to cost $20 per dry ton, though this value may fall to $8 per dry ton for a large cellulosic ethanol industry using multiple feedstocks). For a feedstock price of $50 per dry ton, 32 million tons of biomass could be removed from overcrowded forest without incurring a net cost. If plant owners are willing to pay $75 per dry ton or more, almost 40 million tons could be removed while generating a significant profit. For each curve shown in Figure 4-7, the peak represents the point at which the feedstock price is equal to the marginal thinning removal cost plus the biomass transportation cost. If the Forest Service only removes biomass up to the point where the marginal removal cost and transportation cost equal the feedstock price (in order to maximize profit), then a significant quantity of biomass can still be removed, ranging from 20 million tons per year for a feedstock price of $50 per ton to over 30 million tons per year for a price of $100 per ton. The difference between the feedstock price and the forest thinning removal cost could either fund additional fuel treatments, increase cellulosic ethanol producer profits, or reduce fuel prices to consumers.

4.3.4. Electricity Generation

Forest thinnings may also be used as a feedstock for electricity generation. Biomass has been considered as a feedstock for electricity generation both via cofiring with coal (Morrow 2007, Morrow 2008, Tillman 2000, Hughes 2000, Mann 2001) and as a feedstock for gasification (Craig 1996, Haq 2002, Mann 1997, Rhodes 2005). Compared to energy crops such as switchgrass, woody biomass has a lower cellulose fraction and a higher lignin fraction (DOE 2009), making it a better candidate for electricity production, since lignin cannot be converted into ethanol but is instead burned to provide process energy for cellulosic ethanol production. Concerning the electricity vs. ethanol decision, Morrow found that cofiring switchgrass with coal would have a lower cost of GHG mitigation than using it to produce ethanol, though the conclusion depends on volatile fossil fuel prices (Morrow 2006a). Campbell (2009) found that producing electricity from biomass would result in roughly twice as many vehicle miles per hectare as producing ethanol, though some important issues (including economic constraints) were not considered in the analysis.

Figure 4-8 and Figure 4-9 show cost estimates for three forms of forest thinning conversion: ethanol production, cofiring with coal, and dedicated gasification. All cost estimates assume a feedstock cost of $50 per dry ton. For both figures, costs are given in dollars per kilowatt-hour, with cellulosic ethanol costs converted from $gallon^{-1}$ to kWh^{-1} using the higher heating value for ethanol. Cofiring economics were taken from Morrow (2008), and cofiring costs were estimated using a linear program similar to one formulated in that study using power plant locations and operating parameters from eGRID (EPA 2009). Economic parameters for gasification were taken from Rhodes (2005), and gasification plant locations and biomass shipping distances were estimated using methods similar to those used to estimate locations and shipping distances for ethanol plants in this study. Cost estimates shown in Figure 4-8 are for the state of Pennsylvania, chosen to represent a promising region for biomass cofiring due to the widespread use of coal for electricity generation throughout the state.

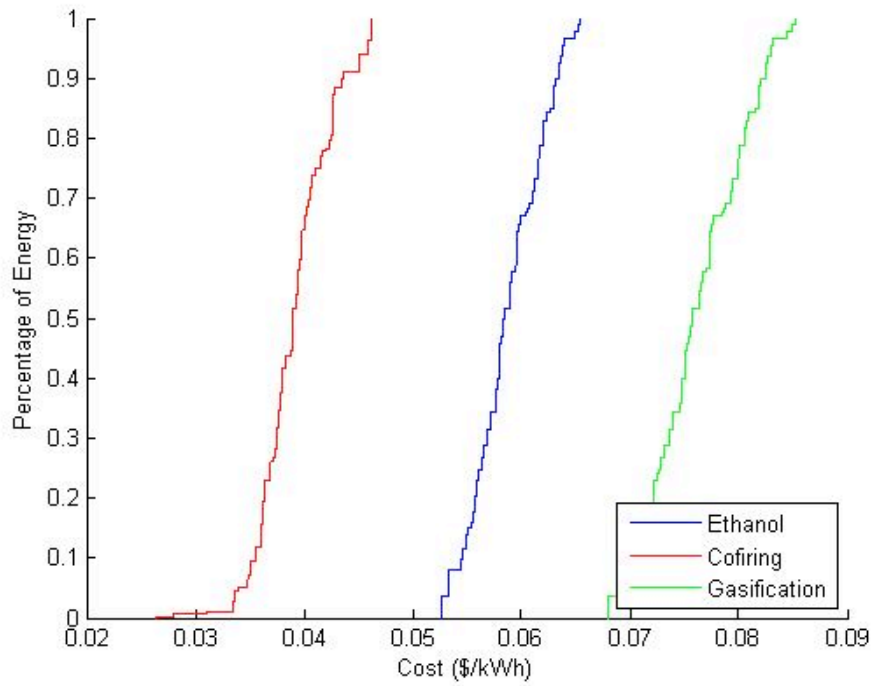

Figure 4-8: Production cost distribution for forest thinning-based bioenergy in Pennsylvania.

Figure 4-8 shows that cofiring dominates both ethanol production and biomass gasification for Pennsylvania. With a large amount of existing coal generation dispersed throughout the state, cofiring forest thinnings in Pennsylvania is characterized by both short biomass shipping distances and low capital costs.

Furthermore, cellulosic ethanol production is significantly less expensive than gasification. Cellulosic ethanol and biomass gasification economics are fairly similar; for instance, capital costs are estimated to be $197 million for a cellulosic ethanol plant with a 2,000 dry tons per day capacity (Aden 2002), and $182 million for a gasification plant with a capacity of 2,100 dry tons per day (Rhodes 2005). Both plants are estimated to have a capital scaling factor of 0.7 (Aden 2002, Rhodes 2005). The primary difference between the two conversion technologies is the conversion efficiency. Biomass gasification is assumed to have a conversion efficiency of 34%, while an ethanol yield of 90 gallons of ethanol per ton of feedstock (assumed based on a mature cellulosic ethanol industry) represents a conversion efficiency of 45%. Gasification conversion efficiency would have to increase to at least 50%, or ethanol yields would have to be 65 gallons per dry ton or lower, to make gasification less expensive than ethanol.

However, cofiring forest thinnings is not always less expensive than using them for ethanol production. Regions with little coal-powered electricity, such as states along the Pacific coast, may not be able to use much biomass for electricity generation before incurring large capital costs. Figure 4-9 shows productions costs for bioenergy produced from forest thinnings in the state of Washington, chosen to represent a region with plentiful forest thinning supplies but little existing electricity generation from coal. For the state of Washington, there are no dominant options, though cellulosic ethanol production is generally the least expensive option. Due to the small amount of coal-fired electricity in this region, cofiring biomass necessitates both high biomass shipping distances and costly capital investments. Costs for ethanol and gasification are similar to those estimated for Pennsylvania.

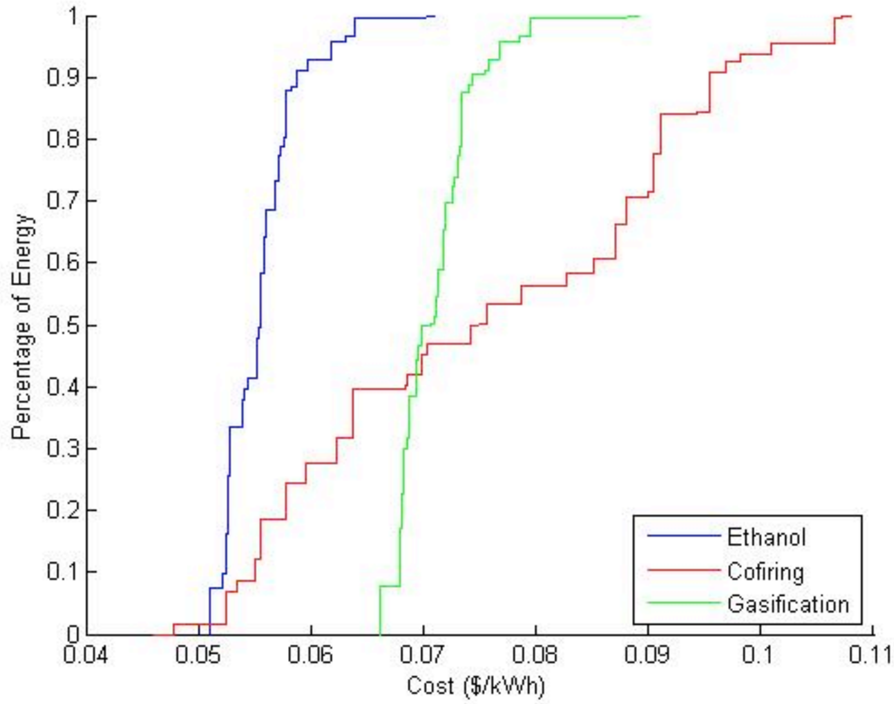

Figure 4-9: Production cost distributions for forest thinning-based bioenergy in Washington.

4.4. Conclusions

Since 2004, wildfires throughout the United States have resulted in social costs on the order of $30 billion per year. Fuel treatment activities such as forest thinning have been shown to reduce the severity of wildfires and improve forest health. Forest thinnings represent a promising feedstock for cellulosic ethanol; thinned biomass requires very little input energy, does not compete with food crops for land, and has no land-use change impacts.

Based on cellulosic ethanol production cost estimates and forest thinning cost curves, we estimate that 3 billion gallons of cellulosic ethanol could be produced annually at a cost of

$3 per gallon gasoline equivalent or less. Should gasoline prices rise above $3 per gallon, high cellulosic feedstock prices combined with modest forest thinning removal costs could net the Forest Service over $1 billion per year from the sale of thinned biomass. Removal of all biomass that could be thinned at a cost of $50 or less is also estimated to decrease expected wildfire damage by over $150 million annually, or roughly half of what the Forest Service currently spends on fuel reduction treatments. Cofiring forest thinnings with coal also represents a promising bioenergy conversion pathway, though regional characteristics heavily influence costs. Forest thinnings are an attractive feedstock for cellulosic ethanol, and as the cellulosic ethanol industry matures, the sale of thinned biomass could create a significant source of revenue to fund additional fuel treatment operations.

5. Impacts of Facility Size and Location Decisions on Ethanol Production Cost

5.1. Introduction

A promising alternative to fossil fuel use in transportation is ethanol, and more specifically, cellulosic ethanol. Out of all of the strategies capable of lowering CO_2 emissions and decreasing nonrenewable fuel use, increased production of cellulosic ethanol for transportation energy is the most attractive and closest to being available (MacLean 2004). Cellulosic ethanol can be produced from a variety of sources, including switchgrass, a perennial warm-season grass that can be grown in the United States. Considerable work has been performed in improving switchgrass production processes (McLaughlin 2005). In the past 10 years, switchgrass yields have improved by 50% and nitrogen fertilizer requirements have dropped by 40%, reducing the projected production cost of switchgrass by 25% and creating the opportunity for switchgrass-derived ethanol to compete favorably as a transportation fuel in the near future (McLaughlin 2005). If sugar yields from cellulose and hemicellulose are improved and feedstock costs are reduced, then cellulosic ethanol could be produced at a cost as low as $0.52 per gallon (Wyman 2007).

Employing ethanol as a transportation fuel is not a new concept, but ethanol has yet to contribute substantially to transportation energy in the U.S. Domestic production of corn ethanol has dramatically increased in recent years, growing from about 1.8 billion gallons in 2001 to almost 9 billion gallons in 2008 (RFA 2010b). Despite this dramatic growth, domestic corn ethanol production accounted for only about 4% of the total transportation energy used by the light-duty fleet in 2008.

Expanding the percentage of transportation energy demand met by biofuels could be accomplished through the development of next-generation biofuels like cellulosic ethanol. Cellulosic ethanol has a number of advantages compared to corn ethanol. The net energy ratio of cellulosic ethanol produced from switchgrass is estimated to be 5.4 (Schmer 2008), indicating that 5.4 MJ of energy are produced for every 1 MJ of nonrenewable energy input. (A literature survey finds estimates for this value ranging from 4.4 to 6.6 (Hammerschlag 2006).) Corn ethanol, on the other hand, is estimated to contain only about 1.25 MJ per MJ fossil energy input (Hill 2006), with a range of 0.84 to 1.65 (Hammerschlag 2006). The favorable energy balance of switchgrass-derived ethanol corresponds to significantly lower greenhouse gas emissions than those from corn ethanol (Farrell 2006). Indirect land use change is an important issue challenging the greenhouse gas benefits of all biofuels (Fargione 2008; Searchinger 2008), but cellulosic ethanol can be produced from either high-diversity grassland biomass (Tilman 2006) or switchgrass grown on marginal cropland (Schmer 2008), minimizing and land use and food versus fuel impacts of biofuel production.

However, there are some obstacles cellulosic ethanol must overcome before it can gain widespread use. One of the primary obstacles involves the infrastructure required to produce and distribute it on a large scale. Cellulosic ethanol refineries are capital intensive, with large facilities (having capacities greater than 50 Mgal per year) expected to have a capital cost of $5 - $6 per gallon capacity in the short-term (Hamelinck 2005), falling to around $3 per gallon capacity for a mature industry (Aden 2002; Wooley 2000). These capital cost requirements are significantly larger than those for corn ethanol, estimated to be $1 - $3 per gallon for new construction and around $0.2 - $1 per gallon for capacity expansion (Shapouri 2005; McAloon 2000). These capital costs make it imperative that facility investment and location decisions be made wisely, because suboptimal investment decisions could incur significant costs.

Transportation infrastructure, required for shipment of both biomass feedstocks to the refinery and ethanol from the refinery, may also present a significant challenge. Ethanol is largely compatible with the current fuel infrastructure, but cannot be transported in petroleum production pipelines due to the presence of water and potential corrosion issues (API 2003). Resulting shipping requirements for national ethanol distribution are estimated to be greater than comparable requirements for petroleum (Morrow 2006b), though distribution costs could be reduced through regional ethanol distribution (Wakeley 2009). Furthermore, transporting the feedstocks required to produce 10 billion gallons of ethanol annually (meeting less than 5% of annual fuel demand, by energy) would require the addition of roughly 5,000 trucks to road networks already experiencing congestion problems, or roughly 3,500 rail cars to already stressed rail networks. Thus, infrastructure requirements may prove to be significant obstacles to cellulosic ethanol development and production.

This study examines the importance of cellulosic ethanol refinery investment decisions, addressing the impacts of both facility size and location on the overall cost of cellulosic ethanol. Larger facilities tend to increase transportation costs, since they need to draw feedstocks from a wider area and transport ethanol to more distant locations, but they also take advantage of economies of scale, decreasing the per-gallon capital costs of facilities. These tradeoffs have been studied previously (Aden 2002; Gallagher 2005; Nguyen 1996), but for individual plants without considering ethanol transportation cost. Facility location has been previously modeled using sequential plant-siting algorithms (Aden 2002; Noon 1996; Sheehan 2003), but there may be benefits to coordinating facility location prior to construction. Furthermore, there may be social, political, or other factors influencing individual private facility placement decisions that drive up the production cost of the entire system, and the potential costs of those influences are studied here.

A mixed-integer programming model is developed to optimize cellulosic ethanol infrastructure investments for single and multi-state regions. Cellulosic feedstock availability varies significantly throughout the United States, suggesting that regional fuel policies may have some advantages over a homogeneous national level policy and that regional modeling of biofuel production and distribution can help inform and shape those policies. By identifying facility placement strategies that decrease total cost, and quantifying those benefits, this study can help inform policy decisions regarding the implications of cellulosic ethanol use.

5.2. Model Inputs

5.2.1. Cost Parameters

The cost parameters used in the model involve the cost to refine biomass into ethanol, and the costs to transport biomass to and ethanol from the facility. Given that the optimization model developed in this study requires point estimates for parameters, cost parameters shown in Table 5-1 were used for the base case analysis. The impacts of varying these cost parameters were examined during sensitivity analysis.

Table 5-1: Ethanol facility and transportation cost parameters.

Parameter	Value	Units	Source
Facility capital scaling factor	0.72	(unitless)	Aden 2002; Aden 2009; Foust 2009
Ethanol yield	90	gallons ethanol/ton biomass	
Fixed facility cost	6.5	$M	Derived from Aden 2002; Aden 2009; Foust 2009
Variable facility cost	34	$/ton biomass capacity	
Truck fixed shipping cost: Biomass	4.76	$/ton	Mahmudi 2006
Truck variable shipping cost: Biomass	0.21	$/ton-mile	
Rail fixed shipping cost: Ethanol	20.6	$/ton	Derived from STB 2008
Rail variable shipping cost: Ethanol	0.023	$/ton-mile	
Truck variable shipping cost: Ethanol	0.26	$/ton-mile	BTS 2010

Facility costs were estimated from a process-economic analysis of cellulosic ethanol production from NREL (Aden 2002; Aden 2009; Foust 2009). The NREL studies estimate capital and operating costs for cellulosic ethanol production assuming a mature cellulosic ethanol industry and a cellulosic ethanol refinery with a biomass input of 2000 dry tons per day.

For the purposes of this study, it is necessary to estimate facility costs for facilities with various capacities. Like many capital investments, the NREL studies recommend estimating capital costs as a function of capacity using a scaling factor, estimated to be 0.72 for cellulosic ethanol refineries (Aden 2002; Aden 2009; Foust 2009). In order to retain the linearity of the optimization model used in this study, the total facility cost was estimated using a linear approximation of the total cost estimated using the recommended scaling factor, with the results indicated in Table 5-1 by the fixed and variable facility costs.

Transportation cost parameters were estimated for truck shipping of biomass and for truck and rail shipping of ethanol. Fixed and variable costs of biomass shipping were taken from Mahmudi (2006). Fixed and variable costs of ethanol shipping via rail were estimated from the Surface Transportation Board's (STB) Public Use Waybill Sample, a sample of waybills provided by rail shipping companies to their customers, filtered to include only ethanol shipments (STB 2010). Ethanol shipping cost via truck was assumed to be equal to the national average truck shipping cost (given in dollars per ton-mile), obtained from the Bureau of Transportation Statistics (2010).

5.2.2. Switchgrass Supplies

Spatial supply projections for switchgrass were taken from a data set provided by the Energy Information Administration (EIA) that was generated using the POLYSYS model.

POLYSYS uses interdependent modules for crop supply and demand, livestock, farmer income, and local environmental conditions to predict the availability of various crops (including switchgrass, corn stover, and wheat straw) for 305 Agricultural Statistical Districts (ASDs) throughout the United States (Walsh 2003; University of Tennessee 2009; Ugarte 2000). Figure 5-1, shown below, illustrates the projected distribution of switchgrass availability throughout the United States for the base case. The EIA data set used for this study contains POLYSYS model results for cellulosic biomass prices ranging from $20 to $100 per dry ton, with higher feedstock prices resulting in greater feedstock availability. Because this study estimates distances and costs for shipping biomass to ethanol refineries, feedstock supply estimates were disaggregated from the ASD level to the county level in proportion to the area of cropland found in each county. A feedstock price of $50 per dry ton was used to generate the results shown here, which project widespread switchgrass production in the Southeast and Midwest but very little switchgrass production in the Western states.

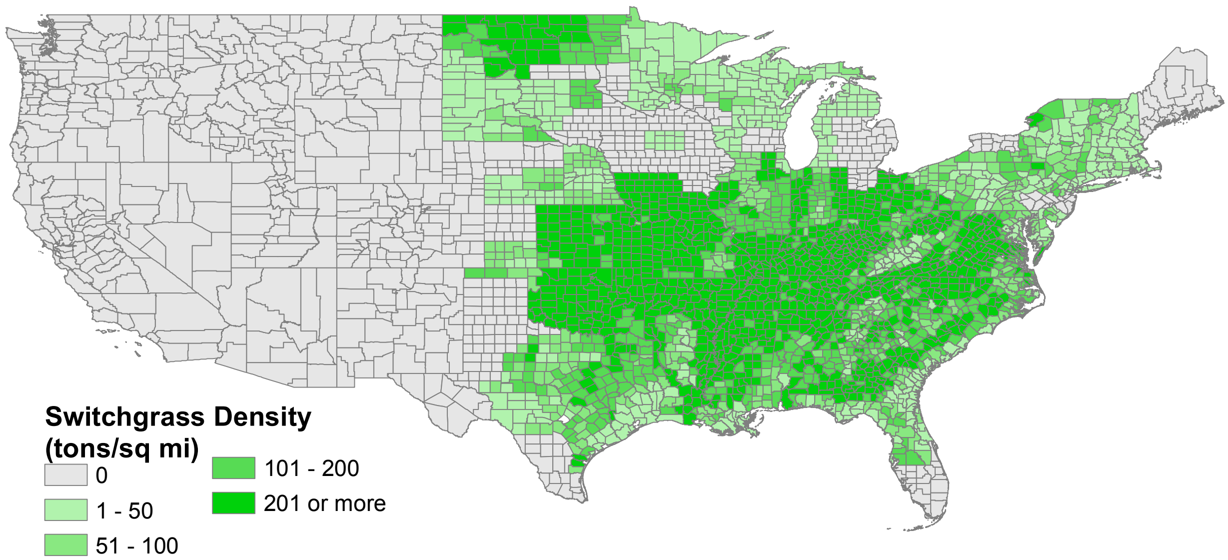

Figure 5-1. Base case switchgrass availability projections.

5.2.3. Ethanol Demands

Ethanol demands were modeled based on locations and population of metropolitan statistical areas (MSAs). For each region studied in the analysis, ethanol supply was allocated to MSAs throughout that region in proportion current population levels and estimated state-level population growth rates.

5.3. Methods

5.3.1. Mixed Integer Programming Model

A mixed integer programming (MIP) model was developed to optimize facility placement and minimize production cost. For the MIP model, switchgrass supplies for each county were assumed to be located at county centroids. Modeling switchgrass availability at county centroids (instead of, for instance, at locations of individual farms) was necessary to limit the model runtime. Ethanol demands were assumed to be located at MSA centroids, and only county centroids were considered as potential facility locations.

The MIP model used in this study is a version of the facility location problem, a classic problem in operations research that has been the subject of considerable research (see Owen (1998) for a review). Because the objective function for the MIP formulated for this study considers both biomass and ethanol shipping costs as well as facility capital and operating costs, and capacity constraints are placed on facility sizes, the model can be more specifically described as a 'multi-commodity capacitated facility location problem' (Pirkul 1998). Facility location problems, and specifically capacitated facility location problems, are frequently difficult to solve on a large scale, leading to the development of heuristic or local search algorithms designed to generate good solutions quickly (Pirkul 1998; Vijay 2001). For this study, the problem was analyzed at a regional level, where a region represents a single state or contiguous group of states. Analyzing the problem at the regional level, rather than at the national level, allows the MIP formulation to solve the model effectively without prohibitively long runtimes.

For the model formulation, let x_{ij} represent the amount of biomass (in tons) shipped from county *i* to county *j* and let f_i be a binary variable representing the existence of a facility (in this case, a biorefinery) at county *i*. Let y_{mn} represent the amount of ethanol (also in tons) shipped from a facility located at county *m* to demand *n*. To represent the total cost, the objective function contains three terms:

1) The biomass shipping cost, represented by the sum over all shipments of the product of biomass shipped (in tons) and the biomass shipping cost (*BSC*), given in dollars per ton.
2) The facility cost, which itself is comprised of two terms: a fixed cost equal to the product of the binary facility variable and the fixed facility cost (*FFC*, given in dollars per facility), and a variable cost, equal to the total processed biomass multiplied by the variable facility cost, *VFC*, given in dollars per ton.
3) The ethanol shipping cost, which, like the biomass shipping cost, is equal to the product of the quantity of ethanol shipped (in tons) and the ethanol shipping cost (*ESC*), given in dollars per ton, summed over all shipment pairs.

$$Minimize \sum_i \sum_j x_{ij} \times BSC_{ij} + \left(\sum_i f_i \times FFC + \sum_i \sum_j x_{ij} \times VFC \right) + \sum_m \sum_n y_{mn} \times ESC_{mn}$$

The constraints shown below ensure that: 1) all biomass is shipped to a facility (where S_i represents the total biomass supply of county *i*); 2) all ethanol demands are met (where D_n represents the total ethanol demand at MSA *n*); 3) biomass cannot be shipped to a county unless there is an existing facility at that location; 4) ethanol shipments from a given site do not exceed the ethanol produced at that site; and 5) facilities capacities do not exceed a predetermined size. In these constraints, *MR* refers to the conversion ratio of tons of biomass to tons of ethanol and $C_{\max}$ represents the maximum facility capacity, in tons of biomass input per year.

$$\sum_j x_{ij} = S_i \tag{1}$$

$$\sum_m y_{mn} = D_n \tag{2}$$

$$x_{ij} \leq f_j \times S_i \tag{3}$$

$$\sum_i x_{ij} \times MR \geq \sum_n y_{jn} \tag{4}$$

$$\sum_i x_{ij} \leq C_{\max} \tag{5}$$

5.3.2. Randomized Facility Placement

Minimizing the production cost of cellulosic ethanol is necessary in order to encourage its short- and long-term adoption as a transportation fuel, and biorefinery location decisions may significantly impact production costs by influencing biomass and ethanol shipping costs. The importance of facility location was examined by comparing the results generated by the MIP optimization model to the total cost estimated for a system with cellulosic ethanol facilities placed randomly. Given a single or multi-state region, random placement results were generated by first assuming a maximum facility capacity, then calculating the number of facilities that would be required to process the total biomass supply. Those facilities were then placed randomly at county centers. Given a set of facility placements, the model discussed in Section 5.1 was then run to minimize the total cost, with the f_i facility decision variables in the MIP model replaced by binary constants representing randomly determined facility locations. The resulting cost estimate based on random facility placements is generally higher than the cost estimated by the MIP optimization model, and the difference in costs is used to quantify the importance of facility location.

5.3.3. Scenarios

Scenarios were run to examine the impacts on total production cost from varying both facility size and size of the region. To examine the impacts of facility size, the maximum facility capacity (represented by $C_{\max}$ in the model formulation) was varied from roughly 750 to 6000 dry tons of biomass input per day, resulting in ethanol production capacities of 25 to 200 million gallons per year per facility.

Regions ranging in size from a single state (Illinois, chosen for its high levels of both projected switchgrass availability and fuel demand) to a contiguous 8-state region containing switchgrass-producing states throughout the Midwest and Southeast were used to study the impacts of facility size and location.

The added cost of random placement was estimated by comparing the optimal solution to a distribution of costs estimated by the random placement model. For each combination of region and maximum facility size studied in this analysis, the random placement algorithm was run 1000 times, creating a distribution of costs resulting from sub-optimal facility placement.

5.4. Results

5.4.1. Optimal Facility Locations

Figure 5-2 displays the spatial inputs to the model for the state of Illinois. Illinois was chosen due to both its projected switchgrass availability and significant in-state fuel demand. Switchgrass availability (displayed in tons per square mile) is greatest in the southern portion of the state as well as part of the western border. Fuel demand is dominated by Chicago (symbolized by the large red circle in the northeast), which represents 86% of the statewide demand. No other MSA represents more than 5% of the total.

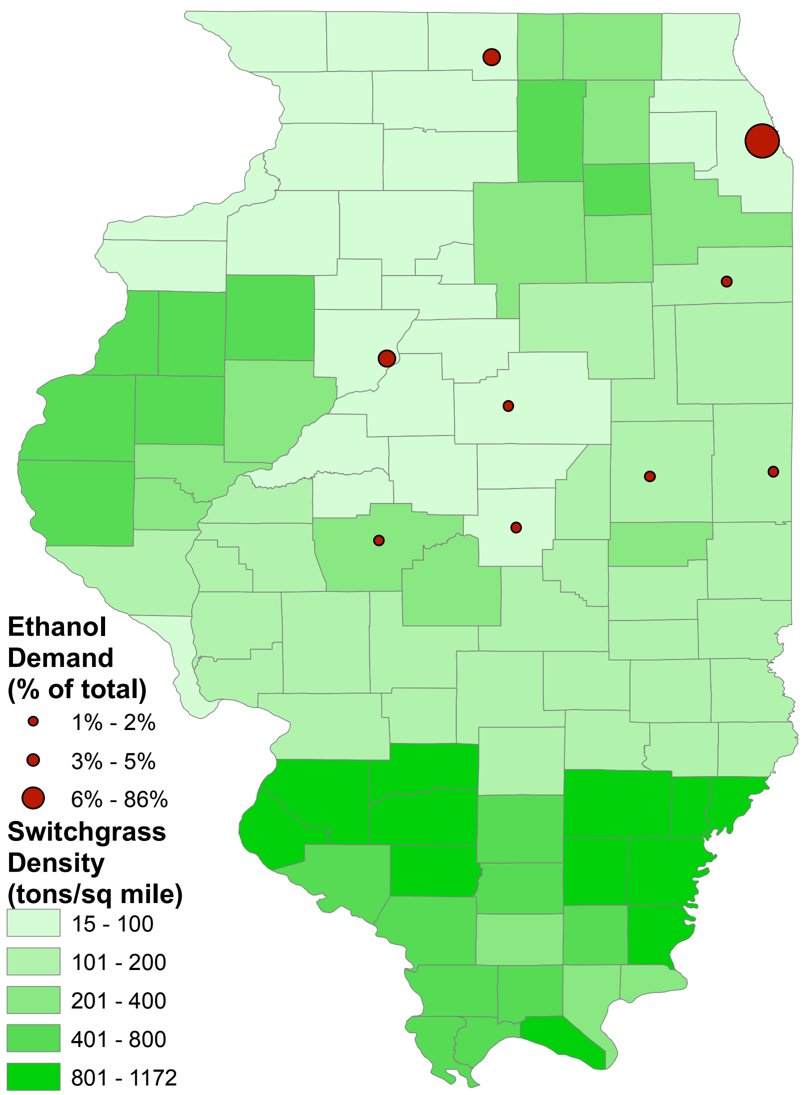

Figure 5-2. Switchgrass densities and fuel demands for Illinois.

Figure 5-3 shows the optimal facility location configuration generated by the MIP model for the state of Illinois. The results shown in Figure 5-3 are based on a maximum facility capacity of 200 Mgal per year, chosen because the total cost (shown later in Figure 5-4) decreases with increasing maximum capacity and 200 Mgal per year was the largest facility size analyzed. Figure 5-3 also plots both biomass and ethanol shipments for the optimal solution. All county centers are symbolized by blue asterisks, county centers chosen to be a facility location are symbolized by red diamonds, and metropolitan statistical areas are symbolized by black squares. Biomass shipments (traveling via truck transportation from county centers to facilities) are indicated by solid blue lines. Ethanol shipments (traveling via either truck or rail transportation from facilities to MSAs) are indicated by dashed green lines. Lines for biomass and ethanol shipment routes represent origins and destinations and only approximate physical shipment routes. Figure 5-3 shows that the optimal solution for Illinois places many ethanol facilities in southern Illinois, where switchgrass availability is high, despite the fact that the majority of the ethanol being produced in those facilities is being shipped north to the greater Chicago area.

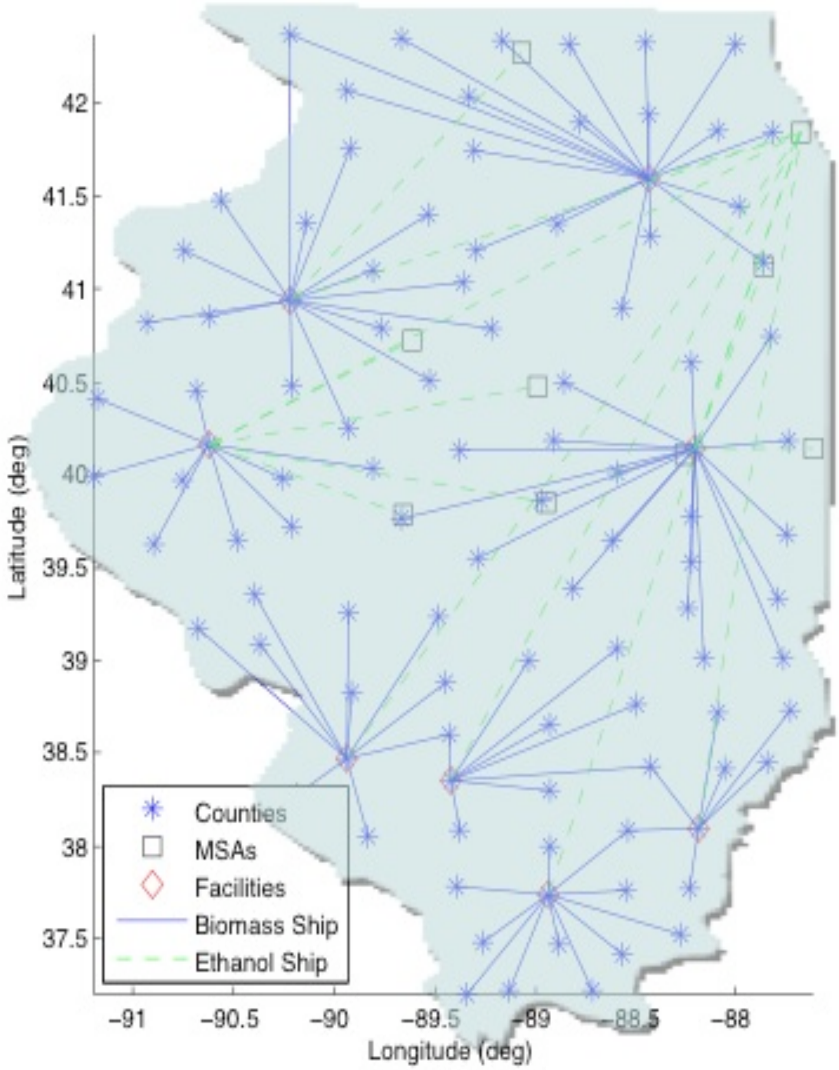

Figure 5-3. Optimal facility placement and shipment solution for the state of Illinois.

A solution that locates facilities close to both biomass supplies and ethanol demands is ideal for lowering shipping costs. However, when biomass supplies and ethanol demands are located relatively far apart, the optimization model must make a choice between placing facilities close to one or the other. The model prefers to locate facilities close to biomass feedstocks because the amount of biomass shipped to each facility is greater than the amount of ethanol shipped from the facility. Three to four tons of biomass are required to produce one ton of ethanol, so long biomass shipping distances are three to four times as costly (per unit ethanol produced) as long ethanol shipping distances. Thus, the optimal solution features facilities located close to feedstocks, sometimes resulting in long ethanol shipping distances.

5.4.2. Facility Size Impacts

Figure 5-4 provides a comparison of the major cost components of cellulosic ethanol production as a function of the maximum allowable facility size, ranging from 25 to 200 Mgal per year. Curves are provided for four cost components (biomass shipping, ethanol shipping, facility [including both capital and operating], and feedstock) as well as the total estimated production cost, each given in dollars per gallon of ethanol.

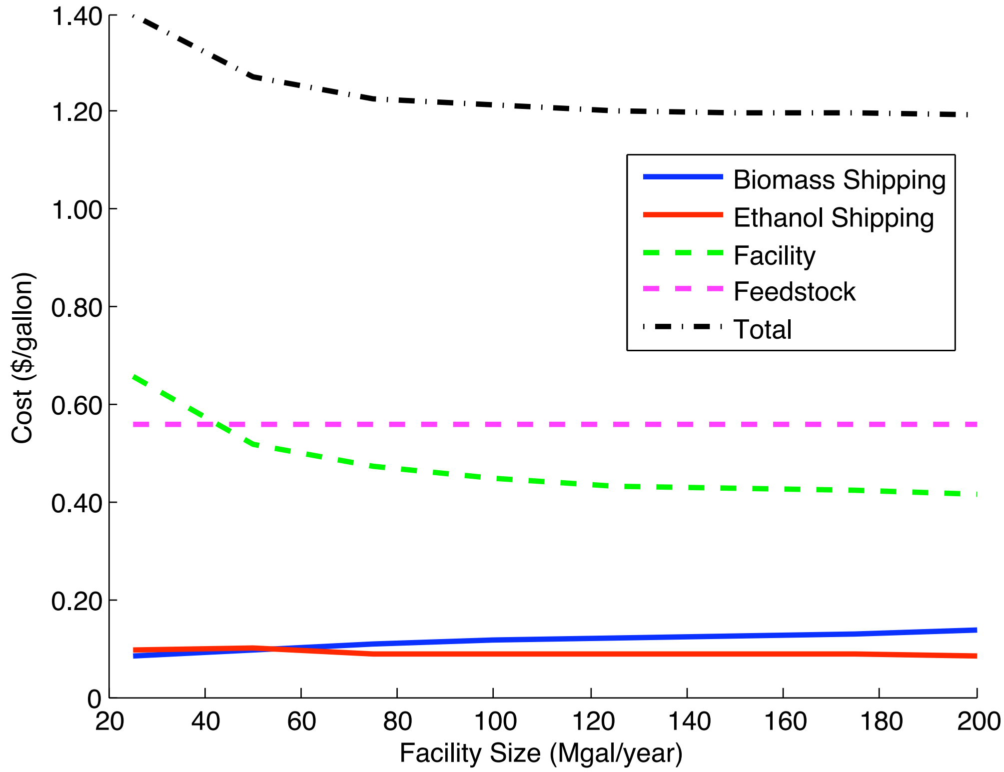

Figure 5-4. Cost components as a function of maximum facility size for the state of Illinois.

Figure 5-4 shows that the total production cost, the cost to provide cellulosic ethanol to MSAs, declines from $1.40 per gallon to less than $1.20 per gallon as the maximum facility size increases. The declining production cost with increasing facility size is driven primarily by economies of scale. As the maximum facility size increases, the per gallon facility cost declines from $0.70 to slightly more than $0.40 per gallon, offsetting the slight increases in biomass and ethanol shipping costs. Feedstock cost, estimated to be $0.55 per gallon, is a significant component of the total cost, but given that both the assumed feedstock price of $50 per dry ton and ethanol yield of 90 gallons per dry ton are fixed for all facility sizes, the feedstock cost is insensitive to maximum facility size. The cost reductions of larger facilities taper off beyond a given size of roughly 125 Mgal/year, beyond which marginal facility cost reductions do not outweigh increased shipping costs.

5.4.3. Facility Location Impacts

The importance of facility placement was examined by comparing results from the MIP optimization model to those generated based on random facility locations. In reality, cellulosic ethanol placement decisions are unlikely to be made truly randomly. Minimizing production cost (which is the objective of the MIP optimization model) will be a major factor. However, there are factors such as firm competition and local public policies that may prevent the configuration of cellulosic ethanol facility placements from resulting in the global optimum.

Like corn ethanol facilities, not all cellulosic ethanol facilities will be owned by a single agent. When a company makes a decision regarding facility placement it will only seek to minimize its own cost, rather than the system cost. Competing facility owners may even be motivated to intentionally increase the production cost for other facilities through their placement decisions, siting facilities in locations that intentionally increase the feedstock cost seen be their competitors.

Cellulosic ethanol facility placement decisions are also be influenced by local public policies. In an effort to attract both the capital investment and job creation resulting from cellulosic ethanol refineries, local governments may create tax breaks or subsidies for cellulosic ethanol facility owners. While locating a facility in a county with favorable policies may lead to the lowest cost for the facility owner, policies that influence facility location could lead to suboptimal placements from a social perspective.

Figure 5-5 shows the impact of facility location on ethanol production cost for the state of Illinois. Four curves are shown in Figure 5-5; the solid blue curve is the average production cost (as a function of maximum facility capacity) estimated by the MIP optimization model, and is identical to the total cost curve shown in Figure 5-5. The other three curves represent results generated by the random facility placement model, one for the mean, one for the 5th percentile, and one for the 95th percentile of the average production cost distribution.

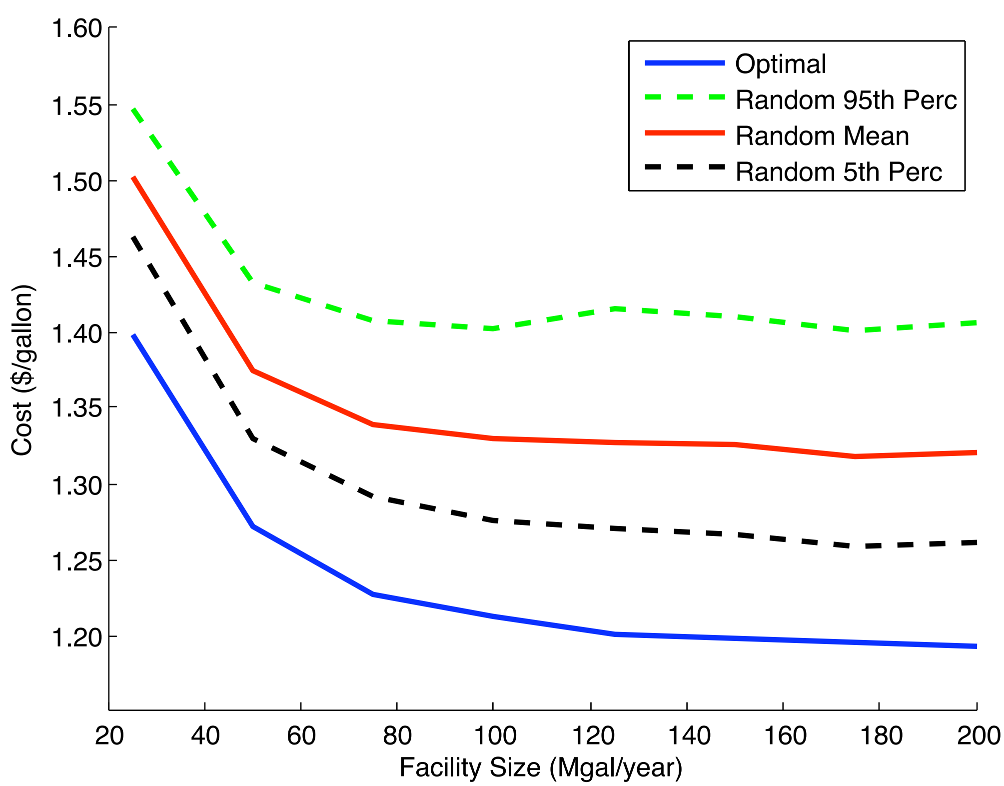

Figure 5-5. Average cost comparison, optimal versus random facility placement.

Random facility placement results in significantly greater production costs than the optimal placement scenario. The mean cost estimates generated by random facility placement are $0.10 to $0.15 per gallon higher than the estimates from the optimal solutions. The 5th percentile of the cost distribution from random placement (i.e., the runs in which the random placement algorithm was 'lucky') add $0.05 to $0.10 to the optimal cost, while the 95th percentile of random placement cost distribution adds $0.15 to $0.25 per gallon to the optimal cost. The cost increases resulting from random facility placement may appear small on a per gallon basis, but the values shown in Figure 5-5 represent average cost estimates and apply to every gallon of gallon produced. Given an estimated cellulosic ethanol production volume of 1.5 billion gallons per year for the state of Illinois, an increase of $0.20 per gallon adds $300 million to the state's annual ethanol production cost.

Figure 5-5 also shows the added cost of random placement increases with increasing facility size, shown here as the difference between the red and blue lines. For a facility capacity of 25 Mgal/year, the production cost for optimal placement is estimated at $1.40 per gallon, while the range of costs estimated from random placement runs from $1.45 to $1.55, adding $0.05 to $0.15 per gallon to the production cost. The added cost of random placement increases significantly as the maximum facility size increases. For a capacity of 200 Mgal/year, the production cost for optimal placement is estimated near $1.20 per gallon, while the range estimated from random placement is $1.25 to $1.45, adding up to $0.25 per gallon compared to the optimal solution.

While random placement leads to significantly higher average production costs, it doesn't simply shift the mean of the production cost distribution, but also increases the variance as shown by the cumulative distribution functions in Figure 5-6. The distribution of costs for optimal placement is relatively narrow; costs range from $1.10 to $1.30 per gallon, resulting in an average cost around $1.18 per gallon. The distribution of costs from random placement, on the other hand, is much larger, ranging from slightly over $1.00 to almost $2.00 per gallon. For randomly placed facilities, 25% of ethanol is estimated to cost more than the most costly ethanol under optimal placement, and 10% is estimated to cost $1.50 or more, an increase of over $0.30 per gallon from the average cost under optimal facility location.

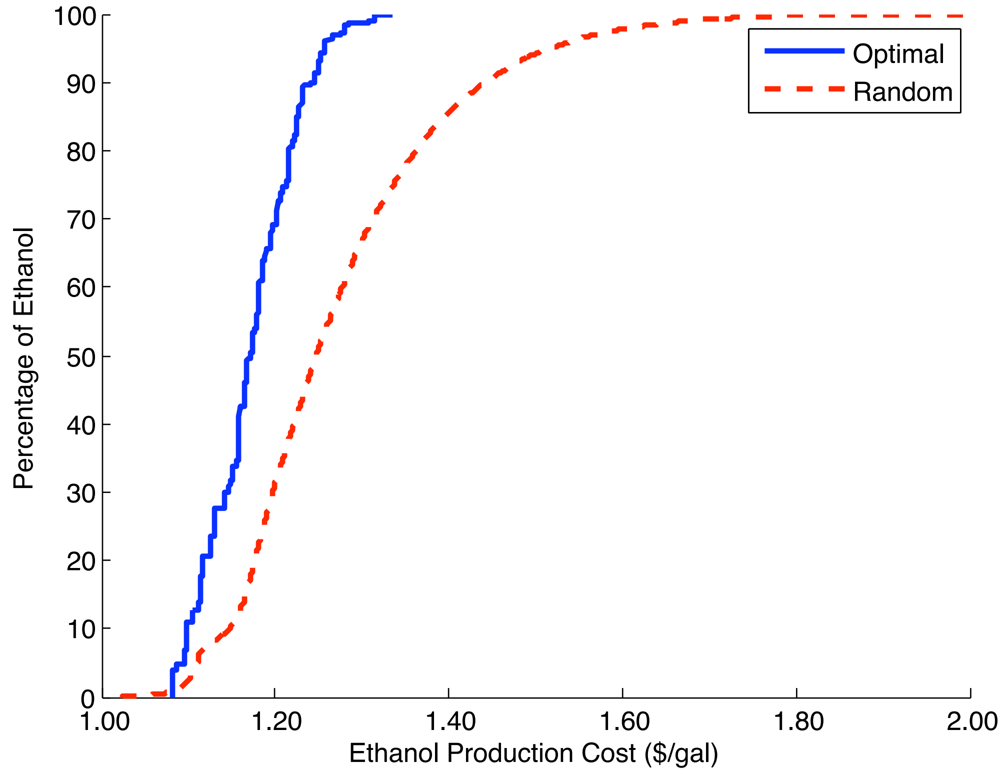

Figure 5-6. Production cost cumulative distribution functions, optimal versus random placement for large facilities in Illinois.

The increased variance from random placement could impact production cost, as well as cellulosic ethanol supply. Facilities producing ethanol at the expensive end of the production cost distribution may be unable to cover operating costs with revenue generated by the sale of their product, resulting in underutilized production capacity and either stranded switchgrass production or unused cropland (both of which would harm the local economy). Investment in ethanol capacity that goes unused due to poor facility placement decisions incurs a social cost without a resulting benefit.

5.4.4. Sensitivity Analysis

Figure 5-7 illustrates how the average total production cost (and the main components of the production cost) estimated by the MIP model change as a function of region size. Regions ranging in size from a single state to an eight-state region containing about 25% of the total national switchgrass availability were examined in the analysis. The region was expanded from one to eight states by beginning with Illinois and consecutively adding adjacent states, with states chosen based on their proximity to Illinois and their projected switchgrass availability. The resulting sequence of states was Illinois, Indiana, Missouri, Kentucky, Ohio, Iowa, Tennessee, and Arkansas. For the results shown below in Figure 5-7, a region of size *n* refers to the first *n* states in the listed sequence. Figure 5-7 shows that the total cost varies from $1.20 to $1.30 per gallon for regions of eight states or less. Most of this variation is due to changes in ethanol shipping cost, which tend to increase as region size increases and ethanol is shipped longer distances. Increasing the size of the region does not have a major impact on facility gate cost estimates.

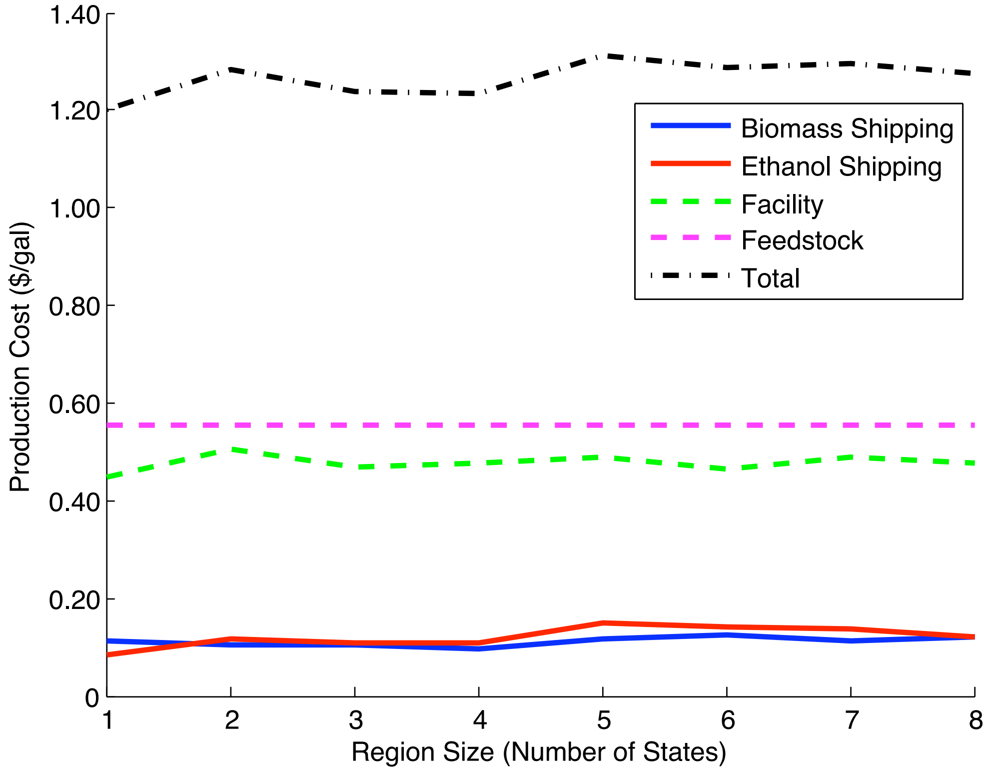

Figure 5-7. Optimal production cost components as a function of region size.

Results generated by the random placement model follow a similar pattern as those for the optimization model shown in Figure 5-7. Cost distributions generated by the random placement model are largely insensitive to region size, adding between $0.10 and $0.30 per gallon to the production cost estimated from optimal facility placement regardless of region size.

The fact that cost estimates generated by both the optimal and random placement models are insensitive to region size for the regions considered in this analysis is not enough to draw firm conclusions regarding the importance of facility size and location at the national level. If nothing else, ethanol transportation costs would likely increase for national ethanol production and distribution (compared to the regional results presented here) given the inclusion of large coastal fuel demands generally located far from cellulosic feedstocks (Morrow 2006; Wakeley 2009). Even if facility placement decisions were largely unaffected by including these ethanol demands, the increased ethanol shipping costs would likely be large enough to noticeably affect the total cost, cautioning against extrapolating regional results to a national scenario.

However, the fact that production costs estimated by both the optimal and random facility placement models are insensitive to region size for those regions considered here at least suggests that impacts of facility size and location are primarily a regional phenomenon. Increasing the size of the modeled region by a factor of approximately eight resulted in only minor changes to estimates of the production costs for optimal and random facility placement. The relationship between the primary cost components was also unaffected by changing region size; the MIP model preferred large facilities placed close to switchgrass supplies in all scenarios. The consistency of these results across various scenarios is enough to suggest that results regarding the regional importance of facility size and location presented in this study may be applicable to a national level cellulosic ethanol production scenario as well.

Figure 5-8 shows cost estimates for optimal and random facility placement generated by varying the ethanol yield, in gallons of ethanol per dry ton of biomass. Three sets of curves are shown in Figure 5-8 providing the estimated cellulosic ethanol production cost assuming ethanol yields of 70, 90, and 110 gallons per dry ton of biomass, with each set containing curves for the cost estimated for optimal facility placement and the mean of the cost distribution estimated for random placement. The estimated ethanol production cost decreases by $0.50 per gallon as ethanol yield increases from 70 to 110 gallons per dry ton, but the added cost of random facility placement (the difference between solid and dashed lines for each color) is not very sensitive to ethanol yield. The suboptimal placement added an average of $0.08 to $0.15 per gallon to production cost under optimal placement regardless of ethanol yield.

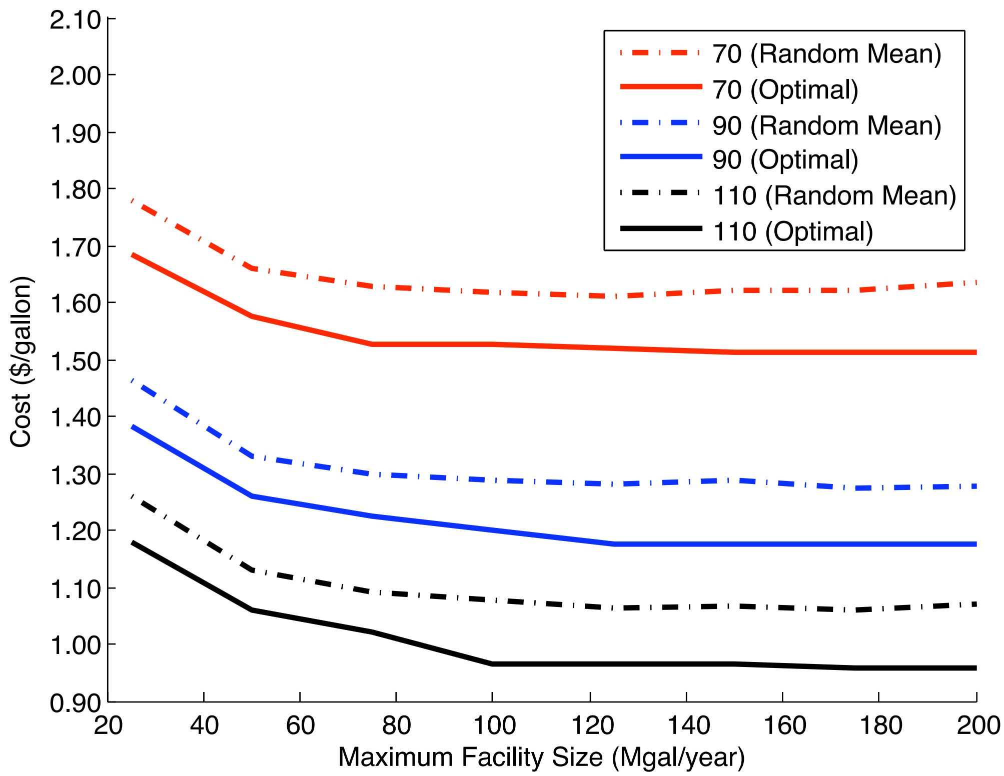

Figure 5-8. Production costs for ethanol yields of 70, 90, and 110 gal/dry ton, optimal versus mean of random placement distribution.

Finally, it is worth noting that facility placement decisions and resulting cost estimates are made based on projections of future cellulosic feedstock supplies and ethanol demands.

These future projections of both cellulosic feedstock availability and ethanol demand are subject to considerable uncertainty. On the cellulosic feedstock supply side, farmers currently have little experience producing dedicated energy crops such as switchgrass, so yields may be significantly higher or lower than those used to generate switchgrass supply estimates used in this study. Availability estimates may also be different from those used for the base case due to varying levels of competition from other crops.

Differences between switchgrass availability projections used in this analysis and actual future feedstock availability could affect these results in multiple ways. For instance, the total switchgrass supply could be similar to that modeled here but with a different spatial distribution. Changes in the spatial distribution of switchgrass production were modeled by beginning with the base case switchgrass supply projections, multiplying the projected switchgrass availability in each ASD by a random number between zero and one, and rescaling the new total switchgrass supply to match the total supply estimated in the base case. Facility locations (optimized for the base case switchgrass distribution) were imported from the MIP model, and switchgrass-to-biorefinery shipments based on the new distribution of feedstock availability were optimized using a linear program. This process was repeated 1000 times, generating distributions for the cost of changes in spatial feedstock production.

The sensitivity of the total cost to changes in the spatial distribution of switchgrass production is summarized in Figure 5-9. Curves are shown for the optimal production cost, along with the mean, 5th, and 95th percentile of the cost generated for randomly distributed switchgrass production. Figure 5-9 shows that the modeled changes in switchgrass distribution can add over $0.10 per gallon to the estimated ethanol production cost, but that the average cost increase of random changes in feedstock distribution is $0.05 per gallon or less, significantly lower than the added cost of random facility placement, estimated to be as large as $0.25 per gallon.

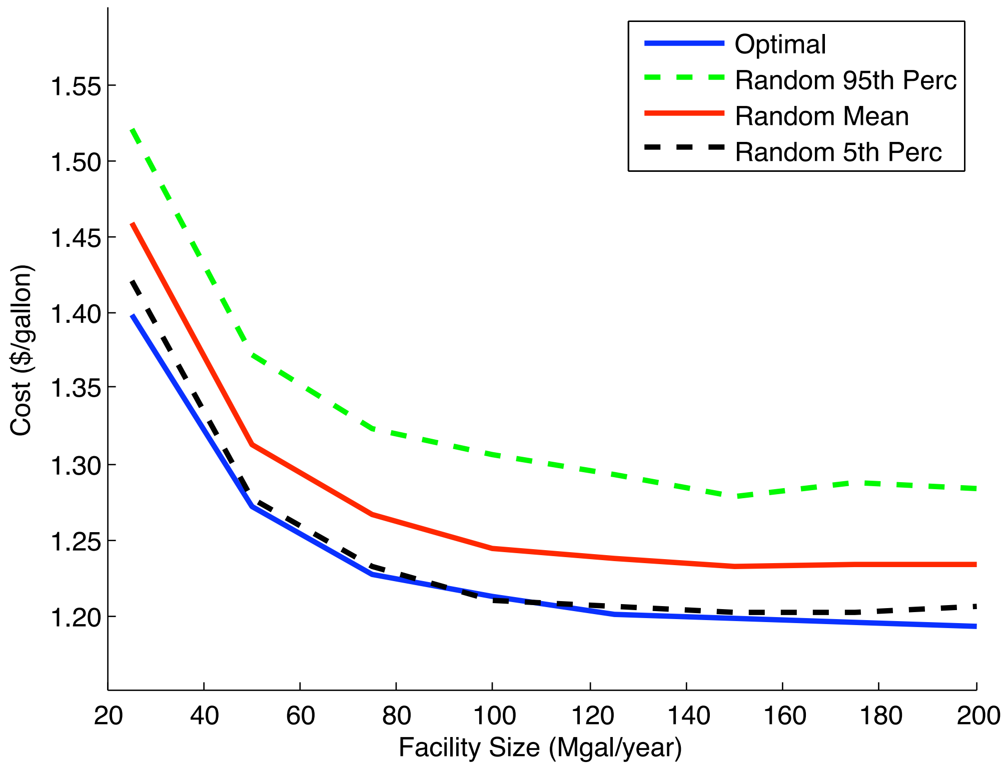

Figure 5-9. Production cost sensitivity to random changes in biomass distribution.

A second scenario, in which the total switchgrass supply is different from that assumed in this study, could also increase ethanol production cost. Suppose that the spatial distribution of switchgrass availability is similar to the distribution assumed in this study, but that the total switchgrass supply is lower, due perhaps to underperforming yields, regional droughts, or competition from food crops. In this scenario, shipping and feedstock costs would be similar to those presented in this study, but the per-gallon facility costs would be significantly higher. The capital cost payment represents 65% - 80% of the total facility cost assumed in this study, and this cost would be incurred regardless of the amount of ethanol produced by the facility. For instance, if switchgrass yields were only half as large as projected yields, the facility cost might rise from $0.50 per gallon to around $0.80 per gallon, adding $0.30 per gallon to the average production cost. If underproduction of switchgrass also resulted in increases in feedstock prices, the added cost would be even larger.

On the ethanol demand side, uncertainties about the nature of future vehicles (regarding both the fuel efficiency and type of fuel used by these vehicles) and the spatial distribution of future population could impact cellulosic ethanol distribution. While ethanol distribution represents a small component of production cost estimates presented here (on the order of $0.10 per gallon), these factors could be influential, especially for a national ethanol distribution scenario that would entail longer shipping distances than those modeled here.

5.5. Discussion

5.5.1. Facility Size

Selecting a smaller number of larger-sized facilities decreases the total cost of ethanol. Thus, from a social perspective, it will be more beneficial for cellulosic ethanol to be produced from larger facilities than from smaller ones. It is not clear, however, that the cellulosic ethanol industry will develop in this manner, especially during its infancy. The early industry will be limited by feedstock availability and investor reticence in investing in an unproven technology. Thus, two approaches will likely occur: retrofitting current corn ethanol plants to accept readily available cellulosic feedstocks, such as corn stover, and the development of greenfield dedicated cellulosic ethanol facilities, minimally sized economically viable plants keeping capital requirement (and project risk) low. Dedicated facilities can use agricultural residues or, in niche areas with low production costs, energy crops. Farmers will likely enter this market cautiously by selling agricultural residues (such as corn stover or wheat straw) before committing to large-scale production of energy crops like switchgrass. From this starting point, as both investor and farmer confidence grow, larger facilities will be constructed, capturing the economies of scale illustrated here. However, facility size may be limited even in a mature industry by large capital investment requirements or by regulations limiting point-source air emissions from a single plant.

The use of smaller facilities has the downside of high overall ethanol cost. It may be possible to scale up the small facilities constructed initially, increasing their capacity and driving total cost down. It is not possible to change the facility location once it is constructed. Thus, the early industry may develop in a way that does not minimize the total cost of ethanol. To reduce the cost of producing cellulosic ethanol, society may wish to create incentives that encourage the construction of larger facilities located near biomass feedstocks. How much society is willing to pay for larger facilities should be a function of the benefit generated by larger facilities in terms of lower ethanol prices.

Based on the cost estimates presented in this study, the greatest benefits from increasing facility size occur for small facilities. Increasing facility capacity from 25 Mgal per year to 50 Mgal per year is estimated to decrease cellulosic ethanol production cost by over $0.10 per gallon. Further increases in facility capacity continue to decrease production cost, but at a much lower rate. For instance, increasing capacity from 50 Mgal per year to 125 Mgal per year or more is also estimated to reduce production cost by $0.10 per gallon. However, increasing capacity from 50 to 125 Mgal per year would require a much larger capital investment than the initial increase from 25 to 50 Mgal per year. Increasing facility capacity from 25 to 50 Mgal per year would increase the capital payment by $7 million per year, while moving from 50 to 125 Mgal per year would add $17 million to the annual capital payment. In terms of facility size, moving from small to medium is more cost-effective than moving from medium to large.

For a mature cellulosic ethanol industry, facilities with capacities of 50 Mgal per year or more may become the norm. In 2009, the average domestic commercial corn ethanol facility had a capacity of approximately 65 Mgal/year (RFA 2010a), and many recently constructed facilities have capacities of 100 Mgal/year or more, indicating that ethanol producers are willing to invest in facilities with relatively large capacities. However, corn ethanol producers rely on a feedstock that has been produced in large quantities for decades and is supported by large subsidies. Cellulosic feedstocks have neither of these advantages, resulting in uncertainty regarding feedstock price and availability and perhaps discouraging investment in biorefineries with large capacities. Thus, it may be socially beneficial to create incentives (such as low-interest loans or tax credits) to encourage investments in larger facility capacity that might otherwise not be made.

5.5.2. Facility Location

Facility location is also an important factor to consider. For larger facilities, the costs of transporting biomass and ethanol can be significant. Locating facilities far from feedstock production and/or product demand can increase the total cost of ethanol by \$0.10 - \$0.25 per gallon.

Companies would not intentionally site facilities far from biomass supplies and ethanol demands. But the proximity of a potential facility site to these locations is not the only factor that determines where facilities are built. For instance, a county may wish to persuade a company to build an ethanol facility within its boundaries, since doing so could provide a boost to the local economy. The local government may then agree to pay a portion of the initial facility construction cost or give the company tax credits in order to attract that company. If the county is located relatively far from biomass supplies and ethanol demands, increased transportation costs will be passed on to consumers, thereby increasing the social cost of using ethanol within that region. Thus, it may be beneficial to determine a minimum effective subsidy value, or a value for the smallest facility construction subsidy that will still decrease the total ethanol cost. For subsidies below the minimum effective value, increased transportation costs will offset the subsidy, resulting in a greater total ethanol cost. This minimum effective subsidy will change based on which county is providing the subsidy; the values given in the table below are simply average values.

Table 5-2 provides ranges for the minimum effective subsidy for three different plant sizes. For all plant sizes, the costs of random placement can be a significant percentage of the capital cost. For large facilities, random facility location can increase transportation costs by $50M per year, a value that could exceed the capital cost payment for that facility. Therefore, even for very large construction subsidies, transportation costs should always be considered when locating facilities, since getting a "free" facility in a very poor location may actually be more expensive than building a well-located one.

Table 5-2. Costs of random location compared to capital cost payment

Facility Size	Capacity (Mgal/yr)	Added Cost of Random Placement ($/gal)	Minimum Effective Subsidy ($/yr)	Capital Cost Payment ($/yr)	Percentage of Capital Cost
Small	25	$0.05 - $0.15	$1M - $4M	$11M	9% - 36%
Medium	50 – 100	$0.05 - $0.20	$2.5M – $20M	$18M – $30M	14% - 67%
Large	100 – 200	$0.10 - $0.25	$10M - $50M	$30M - $50M	33% - 100%

5.6. Conclusions

Decisions regarding facility size and facility location can have substantial impacts on cellulosic ethanol production cost. For the regions examined in this research, producing ethanol with large facilities can decrease costs by $0.20 - $0.30 compared to small facilities, and placing facilities in a way that minimizes transportation costs can reduce costs by up to $0.25 per gallon compared to random placement. These cost reductions represent 15% to 25% of the total cost to produce cellulosic ethanol, and it makes little sense to ignore these factors while investing billions of dollars into process research with the goal of achieving similar cellulosic ethanol cost reductions. Future cellulosic ethanol policies concerning facility size and location should encourage these low-cost production scenarios.

6. Estimating Costs for Ethanol Distribution Scenarios

6.1. Introduction

Production of corn ethanol within the United States has increased significantly in recent years. From 2001 to 2008, U.S. corn ethanol production increased by 500%, expanding from 1.8 to 9 billion gallons per year (RFA 2010b). Though total domestic ethanol production in 2008 equates to only about 4% of gasoline energy used to fuel the light-duty vehicle fleet within the United States (EIA 2009c), ethanol production will continue to increase significantly in the near future. Due to concerns over the contributions of fossil fuels to climate change, volatile petroleum prices, and a desire for increased energy security, the 2007 Energy Independence and Security Act (EISA) requires that at least 36 billion gallons of ethanol be produced domestically by 2022. Corn ethanol production is capped at 15 billion gallons per year, with advanced biofuels (such as cellulosic ethanol) comprising the remaining 21 billion gallons per year (EISA 2007).

Throughout the United States, supply and demand for ethanol are generally not co-located. Corn and proposed cellulosic ethanol feedstocks such as switchgrass and crop residues are expected to be produced in large quantities throughout the Midwest and portions of the Southeast (Cooper 2008). Unfortunately, 80% of U.S. population lives along coastlines, so transporting ethanol from production facilities to demand centers necessitate long shipping distances and high shipping costs.

Ethanol shipping costs could potentially be decreased by transporting ethanol through pipelines. Unfortunately, ethanol cannot be shipped through pipelines concurrently used for petroleum distribution. Pipelines currently used for petroleum shipping could theoretically be converted to full-time ethanol pipelines, but ethanol is projected to meet only a fraction of total fuel demand (and can only be used by the current fleet when blended with petroleum), so pipeline conversion would make petroleum shipping problematic. Thus, pipeline shipping of ethanol would likely require the construction of new pipelines, a project that could be costly considering the relatively small capacities and dispersed nature of ethanol plants.

In addition to large shipping costs, increased ethanol production could lead to problems finding markets for the fuel. Pure ethanol can be used in vehicles specifically designed for the fuel, and flex-fueled vehicles (FFVs), which can be produced with only minor modifications to conventional vehicles, are capable of running on fuel blends containing up to 85% ethanol (and 15% gasoline), but conventional vehicles are currently limited to running on fuel blends containing 10% ethanol (E10) or less. Barring widespread use of vehicles capable of running on higher blends, the E10 blendwall caps near-term domestic ethanol demand at roughly 15 billion gallons per year, less than half of the EISA ethanol production target for 2022. Given that FFVs have yet to gain widespread use, representing fewer than 10 million of the 250 million currently registered motor vehicles in the United States (NREL 2008), the E10 blendwall may become problematic in the near future.

The large shipping costs and blendwall constraints facing ethanol could be addressed simultaneously through regional distribution of high-level ethanol blends such as E85. Instead of distributing ethanol throughout the country as a low-level blend to be used primarily in conventional vehicles, ethanol could be distributed regionally as E85 throughout areas where the fuel is produced, avoiding the longer shipping distances and high shipping costs associated with transporting the fuel from production centers in the Midwest to coastal demands. Regional distribution of E85 would require widespread use of FFVs throughout these regions, but the minor modifications from conventional vehicle designs can be made at little cost during vehicle production, and incentivizing FFV upgrades could be done for only those states receiving high-level blends. Increasing the number of E85-compatible vehicles on the road would also increase the amount of ethanol that could be consumed domestically, allowing ethanol production to continue to expand beyond the current E10 blendwall constraint.

This work builds off of previous studies that estimated shipping costs for national distribution of ethanol to be used in a low-level blend (Morrow 2006b) and regional distribution of ethanol as E85 (Wakeley 2009). Here, costs are estimated for various levels of domestic ethanol production, generating estimates for the cost savings achievable through regional ethanol distribution for both short- and long-term time horizons. The impacts of state-level ethanol blend policies are also examined in this study, and estimates of cost reductions (or increases) resulting from state-level E85 mandates are generated. Finally, some minor modeling changes were made for this analysis relative to previous work by Morrow and Wakeley, including the use of a more precise cellulosic ethanol facility placement algorithm and shipping cost functions estimated directly from ethanol shipping data.

6.2. Data Sources

To model ethanol distribution, it was necessary to first estimate the locations and quantities of future ethanol supplies and demands. Ethanol production was modeled based on current locations of corn ethanol refineries and projections of future cellulosic feedstock supplies, while ethanol demand was modeled based on the current distribution of motor vehicle fuel consumption, assuming that gasoline is displaced by ethanol according to a given distribution and consumption scenario. Data sources used to model ethanol supplies and demands will now be discussed in more detail.

6.2.1. Ethanol Production

Domestic ethanol supplies were assumed to come from the production of corn and cellulosic ethanol. Locations and capacities of corn ethanol refineries were obtained from the Renewable Fuels Association (RFA 2010a). With a total nameplate capacity of 13.5 billion gallons per year in 2010 (RFA 2010a), corn ethanol production would have to increase by 11% to meet the EISA 2007 target of 15 billion gallons per year (EISA 2007). In lieu of modeling the construction of new facilities, future capacities of corn ethanol plants were estimated by uniformly increasing current capacities by 11%.

Because cellulosic ethanol is not currently produced on a commercial scale, it was necessary to estimate both the locations and capacities of future cellulosic ethanol refineries. In order to accurately model the distribution of future cellulosic refineries, it was necessary to first estimate the locations and volumes of future cellulosic biomass feedstock supplies.

Three primary types of cellulosic biomass were considered as domestic cellulosic ethanol feedstocks: switchgrass, crop residues (corn stover and wheat straw), and forest biomass. Spatial supply projections were taken from a data set provided by the Energy Information Administration (EIA) that was generated using the POLYSYS model. POLYSYS uses interdependent modules for crop supply and demand, livestock, farmer income, and local environmental conditions to predict the availability of various crops (including switchgrass, corn stover, and wheat straw) for 305 Agricultural Statistical Districts (ASDs) throughout the United States (University of Tennessee 2000, De La Torre Ugarte 2000).

Based on these cellulosic feedstock supply projections, the locations of future cellulosic ethanol facilities were estimated. Cellulosic ethanol facilities were placed using the clustering algorithm *k*-means. The *k*-means algorithm is a simple, fast heuristic algorithm that attempts to cluster data in a way that minimizes the total intracluster variance. For a more detailed description of *k*-means, see Han (2005). An ethanol yield of 90 gallons per ton of feedstock was used for the base case (Aden 2002). While cellulosic ethanol production cost is highly sensitive to ethanol yield, estimates of shipping costs for different distribution scenarios do not change significantly for different ethanol yields.

6.2.2. Production Scenarios

Ethanol distribution costs may change as a function of the total ethanol supply. For instance, regional distribution of ethanol to be blended as E85 may become more expensive as ethanol production increases and regional ethanol demand is satiated. Therefore, different ethanol production scenarios (with national ethanol production ranging from 20 to 90 billion gallons per year) were modeled in this analysis to examine the impact of ethanol supply on ethanol distribution cost.

It was assumed that corn ethanol production would be capped at the EISA goal of 15 billion gallons per year (EISA 2007), and that ethanol production beyond this volume would be comprised of cellulosic ethanol. Thus, different ethanol production scenarios were modeled by varying projected cellulosic feedstock availability. The EIA data set used for this study contains separate results for combinations of four input variables: cellulosic production level, energy demand, cellulosic feedstock price, and simulation year. Descriptions and ranges for each of these variables, along with their impact on feedstock availability projections, and summarized in Table 6-1.

Table 6-1. POLYSYS Input Parameters

Parameter	Description	Range	Effect of Parameter Increase on Biomass Availability
Cellulosic Feedstock Price	Farm gate price received by farmers for cellulosic biomass, given in $/dry ton	$20 – $100 per dry ton, in $5 increments	Increase
Year	Year assumed for simulation	2005 – 2030	Increase
Yields and Tillage (Production Level)	Qualitative parameter representing switchgrass	Average/High	Increase

	production advances		
Energy Demand	Demand level for energy (including cellulosic crops) relative to baseline assumed in model	Baseline, Baseline+25%, Baseline+50%, Baseline+87.5%, Baseline+125%	Increase

Combinations of input variables were chosen by first assuming a target cellulosic ethanol production volume, which varied from 5 to 75 billion gallons per year. Based on this production target, the model first searched for the first year in which the amount of cellulosic feedstock required to meet this goal would be available, and then selected the lowest cellulosic price for which the feedstock supply would be sufficient, examining results generated for each combination of production level and energy demand. The resulting POLYSYS input parameters for each scenario are shown below in Table 6-2. For ethanol production targets ranging from 20 to 90 billion gallons per year, Table 6-2 shows the four input parameters selected by the model and the total estimated ethanol production.

Table 6-2. Ethanol Production Scenario Summary

Target Ethanol Production (billion gal)	Production Level	Energy Demand	Cellulosic Price ($/dry ton)	Year	Corn Ethanol Produced (billion gal)	Cellulosic Ethanol Produced (billion gal)
20	Normal	Baseline	30	2007	15	5.5
36 (EISA)	Normal	Baseline	55	2007	15	23.7
50	High	Baseline	70	2013	15	35.2
60	High	Baseline	60	2016	15	46.8
70	High	Baseline	90	2017	15	55.1
80	High	Baseline	95	2021	15	65.7
90	High	Baseline	75	2027	15	75.5

Figure 6-1 further breaks down cellulosic ethanol production for each scenario into the volume of ethanol produced from each feedstock, as a function of the target ethanol production. For relatively low production volumes (near 20 billion gallons per year), cellulosic ethanol is produced primarily from forest residues and thinnings. As the ethanol production increases from 20 to 36 billion gallons per year, corn stover begins to provide a significant volume of ethanol. Production levels higher than 36 billion gallons necessitate the use of switchgrass as a cellulosic feedstock, with roughly half of the 90 billion gallon ethanol target met by ethanol produced from switchgrass.

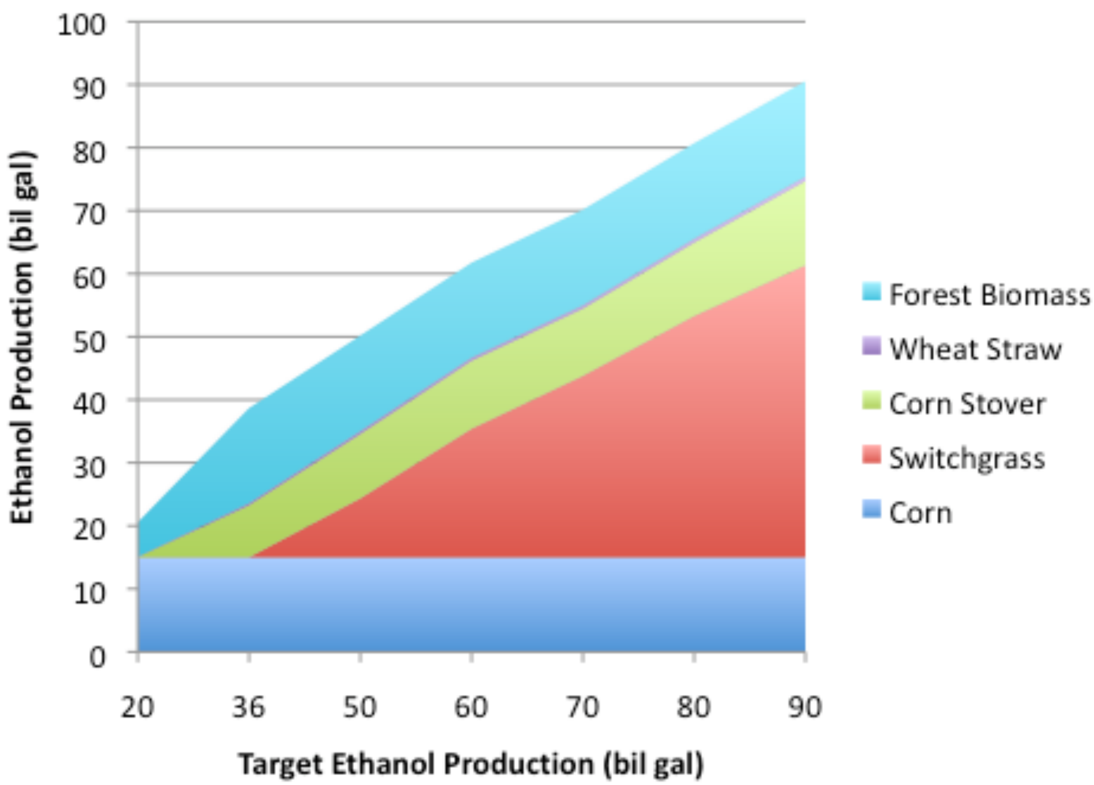

Figure 6-1. Ethanol Production by Feedstock

6.2.3. Ethanol Demand

Ethanol demands were estimated and assigned to metropolitan statistical areas (MSAs) throughout the continental United States by assuming that gasoline consumption was replaced by consumption of a given ethanol blend, which varied for different distribution scenarios (discussed below, in *Ethanol Shipping*). For each MSA, ethanol demand was estimated based on current gasoline consumption, the given ethanol blend level, and estimated state-level population growth rates. The base case analysis assumes that transportation energy demand per capita remains constant; impacts of varying transportation energy demand are examined in the *Sensitivity Analysis* section. Ethanol demands were also estimated assuming that the energy efficiency of motor vehicles is independent of ethanol blend (i.e., a megajoule of E85 is equivalent to a megajoule of gasoline).

Figure 6-2 show the locations of domestic ethanol supplies and fuel demands throughout the United States based on a target ethanol production of 36 billion gallons per year. Corn ethanol plants are shown in yellow, projected cellulosic ethanol plants are shown in green, and MSAs are shown in red, with larger circles symbolizing greater capacities for ethanol plants and larger fuel demands in the case of MSAs. Figure 6-2 illustrates the spatial differences between ethanol plants and fuel demands. The vast majority of corn ethanol capacity is located in the Midwest, primarily in Iowa, Minnesota and Nebraska, and cellulosic ethanol plants are projected to be located throughout the Midwest and Southeast. Large fuel demands, however, are found primarily along the coasts, specifically along the northern portion of the Atlantic Coast and throughout southern California. The lack of spatial agreement between ethanol supplies and demands may lead to large ethanol shipping costs for certain distribution scenarios, highlighting the importance of finding distribution policies that limit ethanol shipping costs.

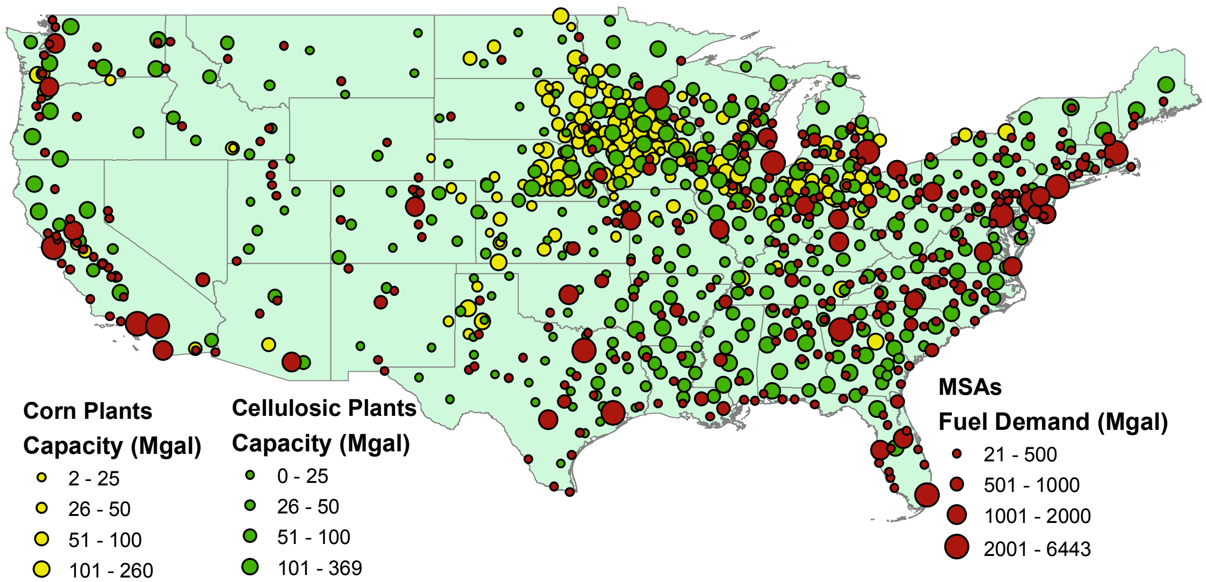

Figure 6-2. Ethanol Production and Demand Locations.

6.2.4. Distribution Scenarios

Three scenarios for ethanol distribution were modeled in this analysis: regional distribution of E85, national distribution of a low-level ethanol blend, and individual state E85 mandates. The first scenario examines the impacts of distributing and consuming ethanol in high-level blends throughout regions capable of producing ethanol locally. Scenario A – Regional E85 assumes that FFVs are widely distributed throughout regions with significant ethanol production capacity, allowing these regions to displace current gasoline consumption with consumption of E85. Although widespread adoption of FFVs would slightly increase vehicle costs, distributing and consuming ethanol in high-level blends throughout these regions generally results in short shipping distances and reduced ethanol shipping costs that may offset the marginal cost of FFV modifications.

The second scenario, on the other hand, models ethanol distribution without the ethanol blend flexibility created by widespread FFV usage. Conventional vehicles are currently limited to running on ethanol blends of E10 or less, though the conventional vehicle blendwall could likely be increased to E20 without causing significant problems (MDA 2008). Thus, in the absence of widespread FFV distribution, ethanol blends would continue to be capped at a relatively low level. Scenario B – National Low-Level Blend assumes that ethanol is distributed throughout the country as a uniform low-level blend with gasoline, where the blend level is near E20 (but may be slightly higher or lower depending on the assumed total ethanol production).

Ethanol consumption policies are currently made at the state level. While the combination of state-level consumption policies may be more expensive than an optimal national-level policy, policies with energy and climate change implications may prove difficult to implement at the federal level, leaving these decisions to individual states. To model the potential impacts of aggressive state-level ethanol consumption policies, a third scenario examines the distribution costs resulting from a single state mandating a high-level ethanol blend. Scenario C – State E85 assumes that all MSAs throughout a given state are supplied with E85 and any remaining ethanol is distributed subject to an E20 blendwall throughout the rest of the country.

State-level E85 mandates implemented by different states could have drastically different impacts. Compared to Scenario B – National Low-Level Blend, an E85 mandate by a Midwestern state with significant local ethanol production capacity would reduce both ethanol shipping distances and ethanol shipping costs. Conversely, an E85 mandate by a state far from ethanol production sites would require a greater volume of ethanol to travel long distances, increasing the overall shipping cost. To study each of these impacts, Scenario C was run for each of the lower 48 states, assuming that each state individually implements an E85 mandate while the other 47 states are limited to E20.

6.3. Methods

6.3.1. Linear Programming Model Formulation

Ethanol transportation was modeled using a linear programming (LP) model similar to those employed by Morrow (2006b) and Wakeley (2009). The ethanol shipping LP is an implementation of the classic shipping problem, assigning ethanol shipments from facilities to demands in such a way that minimizes total transportation cost, subject to constraints on both the facility and demand sites.

It is assumed that ethanol is blended with gasoline at blending stations located near the MSAs that consume the fuel. Because 90% of domestic ethanol shipping occurs via either rail or truck (USDA 2007), only those modes of transportation were modeled.

The objective function for this model represents the system-wide transportation load, given in ton-miles:

$$Minimize \sum_i \sum_j x_{ij} \times d_{ij}$$

where x_{ij} represents the volume of ethanol shipped from plant *i* to MSA *j* and d_{ij} represents the great circle distance from plant *i* to MSA *j.*

Constraints ensure that all ethanol is shipped, while no MSA receives more ethanol than it demands:

$$\sum_j x_{ij} = S_i$$

$$\sum_i x_{ij} \leq D_j$$

where S_i is the ethanol production capacity of plant *i* and D_j is the total ethanol demand for MSA *j*.

Values for D_j, representing the spatial distribution of ethanol demands, varied as a function of the ethanol distribution scenarios discussed in detail above. In Scenario A – Regional E85, all MSAs demand enough ethanol to replace their current gasoline consumption with E85 (a blend of 85% ethanol, 15% gasoline by volume). In this scenario, the total demand for ethanol is 160 billion gallons per year, much higher than the total supply of ethanol estimated for any of the supply scenarios. Because the objective function for the LP represents the system-wide shipping cost, the LP picks those demands that are least expensive to satisfy, and as a result, only the MSAs closest to ethanol supplies receive ethanol under this scenario.

For Scenario B – National Low-Level Blend, the total demand for ethanol is set equal to the total supply, and then allocated to MSAs in proportion to their current gasoline demand. The resulting ethanol blends range from E13 to E36, depending on the production scenario, and all MSAs throughout the continental United States received enough ethanol to satisfy their demand. Because 80% of U.S. population lives along the coasts, approximately 80% of ethanol (by volume) is shipped to coastal areas, often incurring large shipping distances.

The model formulation for Scenario C – State E85 is similar to that for Scenario A in that the total ethanol demand is much greater than the total ethanol supply, and many MSAs do not receive enough ethanol to meet their demand. However, in this scenario, equality constraints were added to the LP to ensure that ethanol demands for MSAs in the state implementing E85 are met before shipping ethanol to other demand locations nationwide.

Each of the three ethanol distribution scenarios are summarized below in Table 6-3, including information on the ethanol blend demanded and the relationship between ethanol supply and demand.

Table 6-3. Ethanol Distribution Scenarios.

Scenario	Description	Ethanol Blend Demanded	Added Constraints or Comments

A	Regional E85	E85	$\sum_i S_i < \sum_j D_j$
B	National Low-Level Blend	E13 to E36, depending on total supply	$\sum_i S_i = \sum_j D_j$
C	State E85	E85 in state with mandate, E20 elsewhere	$\sum_i S_i < \sum_j D_j$ $\sum_i x_{ij} = D_j \forall j \ni D_j \in E85State$

6.3.2. Cost Parameters

Based on the results produced by the LP, ethanol shipping costs were estimated for each scenario. Shipments traveling a distance greater than 250 miles were assumed to travel via rail, with shorter shipments traveling via truck. Truck shipping costs were estimated based on a variable cost from Morrow (2006b), while fixed and variable rail shipping costs were estimated based on data from the 2007 Public Use Waybill Sample (STB 2008).

Table 6-4. Ethanol Shipping Cost Parameters.

Parameter	Value	Units	Source
Truck shipping cost, variable	0.22	$/ton-mile	Morrow (2006b)
Rail shipping cost, fixed	20.6	$/ton	Estimated from STB (2008
Rail shipping cost, variable	0.023	$/ton-mile	Estimated from STB (2008)
Minimum rail shipping distance	250	miles	Shapouri (2005)
Circuity factor, truck	1.23	(unitless)	Wakeley (2009)
Circuity factor, rail	1.52	(unitless)	Wakeley (2009)

6.4. Results and Discussion

6.4.1. Regional and National Ethanol Distribution

Figure 6-3 and Figure 6-4 illustrate the shipment configurations generated by the LP for Scenario A – Regional E85 and Scenario B – National Low-Level Blend, respectively. These figures represent shipment configuration for the EISA 2022 production target of 36 billion gallons. For each figure, counties are represented by blue plus signs, ethanol plants (including both corn and cellulosic plants) are represented by red diamonds, and MSAs are represented by black asterisks. Ethanol shipments traveling a distance less than 250 miles are assumed to travel via truck transportation and are shown in green, while shipments traveling further than 250 miles are assumed to travel via rail and are represented by red lines. Note that shipment connections shown in the figures below do not represent shipments physically traveling along the straight line from one point to another, but rather that shipments travel from origin to destination along existing infrastructure networks.

Figure 6-3 shows that shipments for Scenario A – Regional E85 are generally very short, traveling from plants to nearby MSAs via truck transportation. Corn and cellulosic ethanol produced in the Midwest stays in the Midwest, while cellulosic ethanol produced throughout the Southeast (primarily from forest residues and thinnings) is consumed almost entirely by the MSAs closest to each plant. While some cellulosic ethanol is produced near coastal demand centers, cellulosic production capacity is much less than the transportation energy demand in these regions, which continue to rely heavily on gasoline.

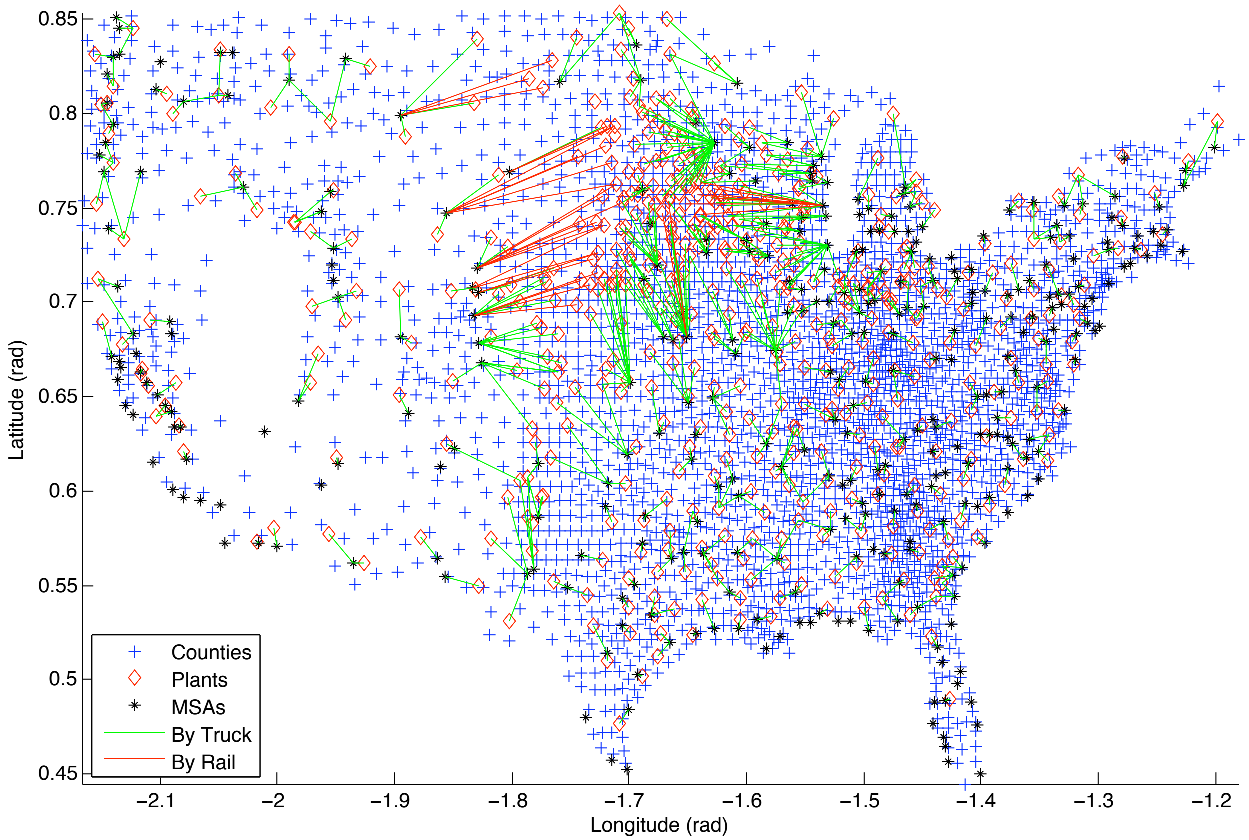

Figure 6-3. Shipping Configuration for Scenario A – Regional E85.

Figure 6-4 shows that ethanol shipments produced by the LP for Scenario B – National Low-Level Blend are dramatically longer than those for regional distribution. For these results, all MSAs replace their gasoline demand with demand for E13, leading to much greater shipping distances than those generated for the regional case. Ethanol shipments via rail, which were almost nonexistent for regional distribution, dominate the shipment configuration as ethanol travels from the Midwest to large coastal demands, primarily in the Northeast and southern California.

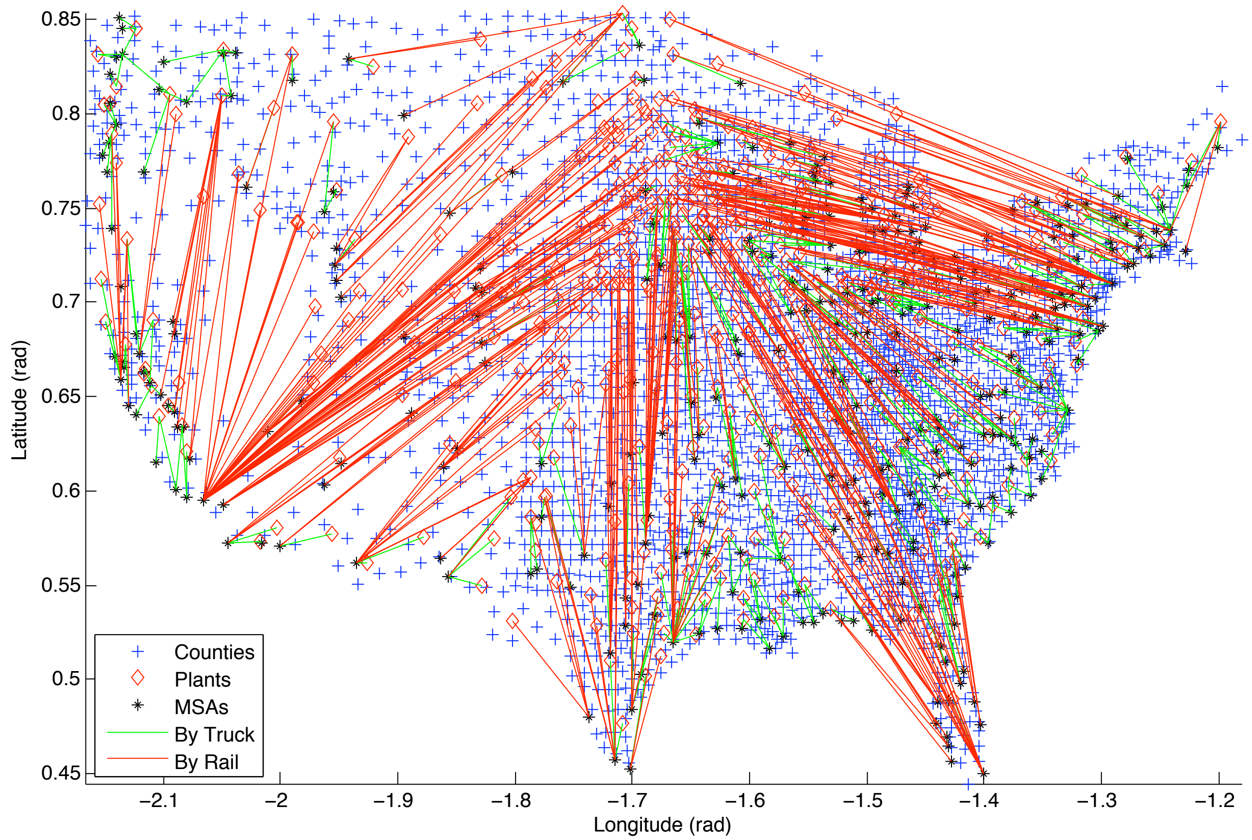

Figure 6-4. Shipping Configuration for Scenario B – National Low-Level Blend.

Figure 6-5 compares the shipping distance distributions for the shipping configurations displayed in Figure 6-3 and Figure 6-4 above, showing that shipping distances for the two scenarios differ drastically. For Scenario A – Regional E85, all ethanol is shipped a distance less than 450 miles, and 50% of ethanol shipments (totaling close to 20 billion gallons) travel less than 55 miles to reach their destination. Scenario B – National Low-Level Blend shows a much larger distribution of shipping distances. Almost 15 billion gallons of ethanol are shipped further than 450 miles (the maximum distance for Scenario A), with a maximum shipping distance of almost 1500 miles. The total shipping load represented by ethanol shipments, which can be viewed as the area between the y-axis and each curve shown in Figure 6-5, are 14 billion ton-miles for Scenario A and 73 billion ton-miles for Scenario B, a increase by a factor of over five in moving from regional to national ethanol shipping.

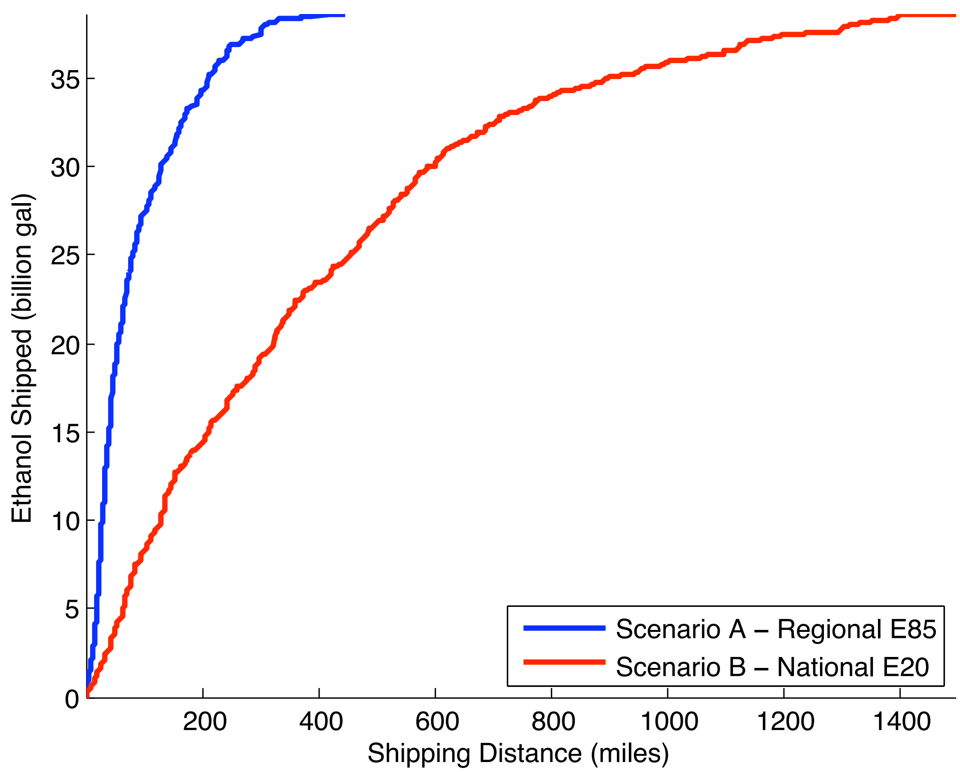

Figure 6-5. Shipping Distance Distributions, Regional E85 and National E20.

Figure 6-6 provides similar curves as those shown in Figure 6-5, but for ethanol shipping costs (given in $ per gallon) instead of shipping distances. Figure 6-6 shows that shipping costs are significantly lower for Scenario A – Regional E85 than for Scenario B – National E20, but that the difference between the two scenarios is not as drastic as the difference in ton-miles between the two scenarios, illustrated in Figure 6-5. The difference in shipping distances for the two scenarios is greater than the difference in cost due to difference in truck and rail shipping costs. It is assumed that ethanol shipments traveling a distance less than 250 miles occur via truck, and that longer shipments travel via rail (USDA 2007). While truck shipping provides increased flexibility relative to rail, it is also more energy intensive and expensive (per ton-mile) than rail transportation. Figure 6-5 shows that, for Scenario A, over 95% of ethanol shipments travel a distance of 250 miles or less and are assumed to travel via truck, while less than half of ethanol shipments for Scenario B are shipped via truck transportation. The shift toward truck transportation in moving from national to regional ethanol distribution results in cost distributions that are more similar than the ton-mile distributions for the two scenarios.

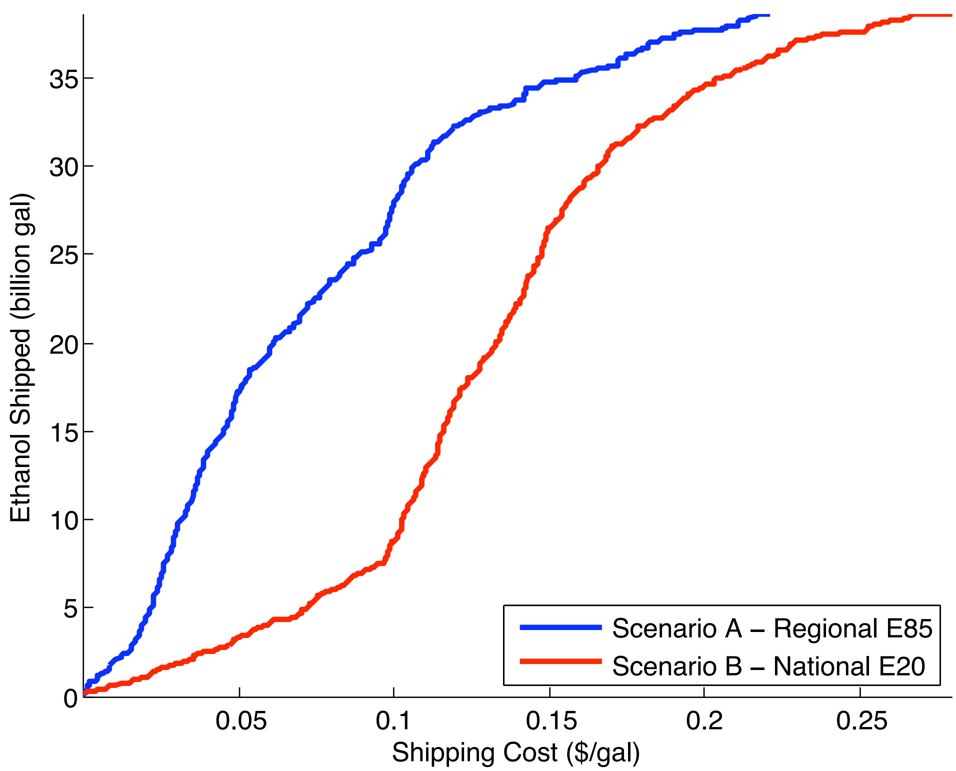

Figure 6-6. Shipping Cost Distributions, Regional E85 and National E20.

Despite the heavier reliance on truck shipping, regional ethanol distribution still results in substantial cost reductions relative to national ethanol distribution. Figure 6-6 shows that for Scenario A, 27 billion gallons of ethanol (representing about 75% of total ethanol production) are shipped to their destination at a cost of less than $0.10 per gallon. For Scenario B, only 9 billion gallons (25% of total ethanol production) reach their destination at a cost of $0.10 or less. Total shipping costs are estimated to be $2.6 billion and $4.8 billion for Scenarios A and B, respectively, indicating that national ethanol distribution would cost about twice as much as regional distribution.

Figure 6-7 displays average ethanol shipping distances (given in miles) for ethanol received by MSAs in each of the lower 48 states for Scenario B – National Low-Level Blend. Average shipping distances are generally short throughout the Midwest and Southeast, with many states receiving ethanol shipped an average of less than 250 miles and virtually all states in these regions receiving ethanol shipped an average of less than 500 miles. Average shipping distances are generally larger for coastal states, with a maximum average shipping distance of 1450 miles for ethanol shipped to California, though some states in both the Northeast and Pacific Northwest are projected meet their modest ethanol demand with cellulosic ethanol produced locally from forest residues and thinnings.

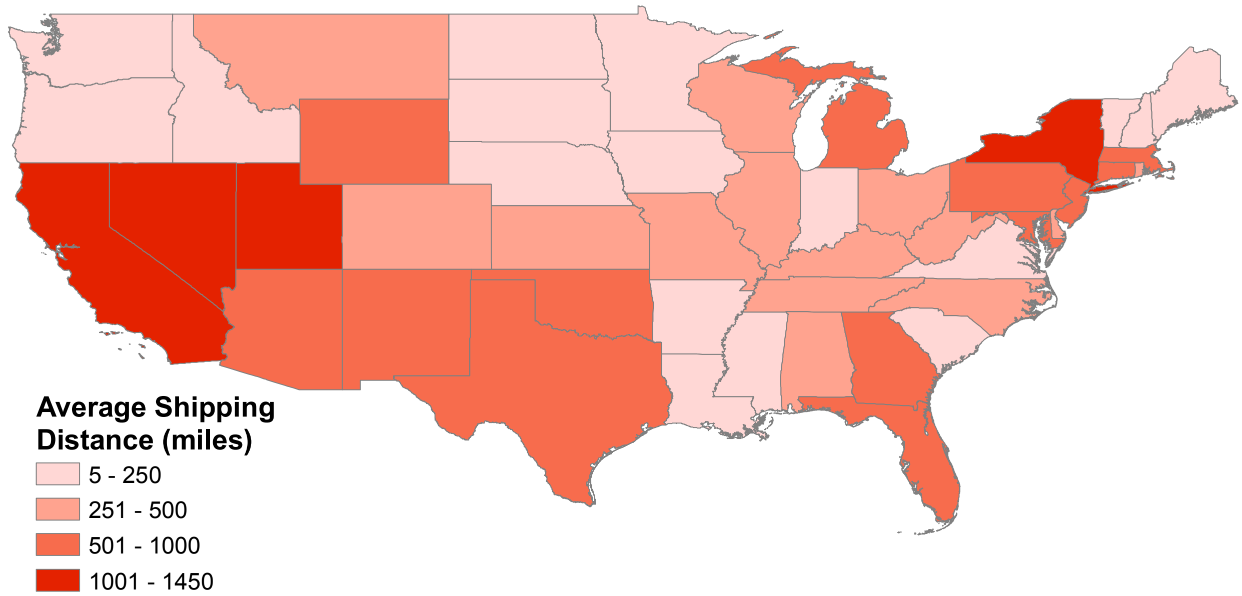

Figure 6-7. Average Ethanol Shipping Distance by Termination State.

Figure 6-8 also illustrates national ethanol shipping results at the state level, but with results indicating the average cost to ship ethanol to MSAs found within each state. The distribution of shipping costs is similar to the distribution of shipping distances shown in Figure 6-7, though some Midwestern states located near ethanol production sites have relatively high shipping costs due to the use of truck shipping to deliver ethanol to MSAs in those states.

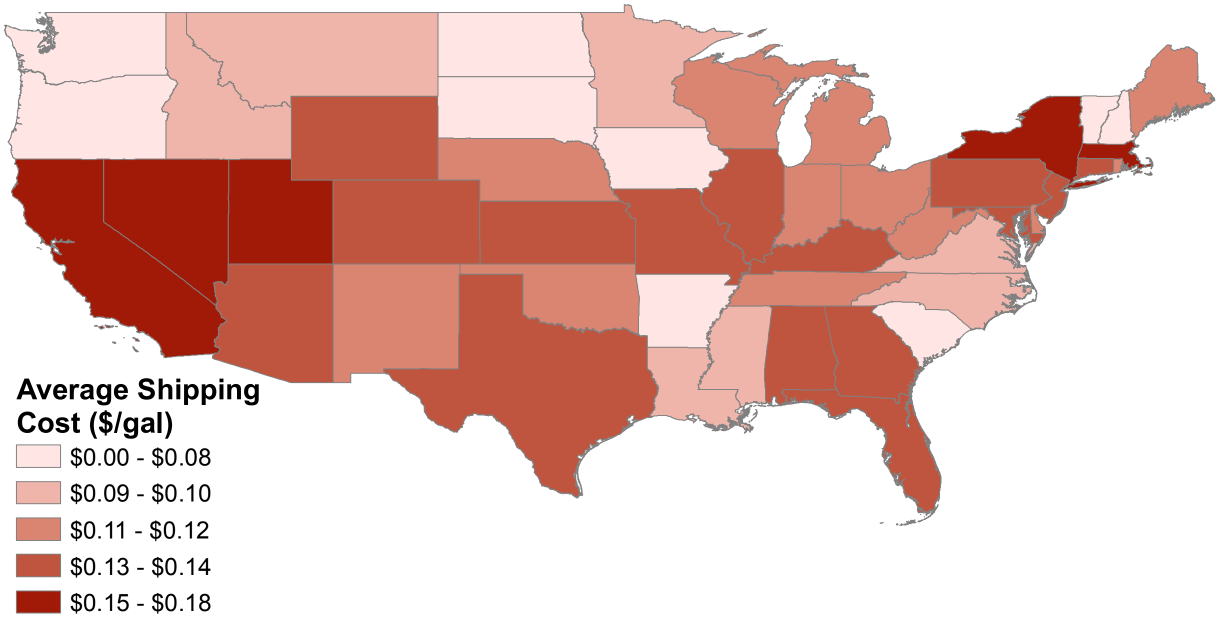

Figure 6-8. Average Ethanol Shipping Cost by Termination State.

Figure 6-9 displays the contribution that ethanol demands in each of the lower 48 states make to the overall ethanol shipping load. Each state in Figure 6-9 is symbolized by ratio of the ton-miles of ethanol terminating at MSAs in that state to the total ton-miles represented by all ethanol shipments. States located far from ethanol production sites containing large populations make the biggest contribution to the total ethanol shipping load, led by Texas and California, which are responsible for 11% and 22% of the total ton-miles from ethanol shipments, respectively.

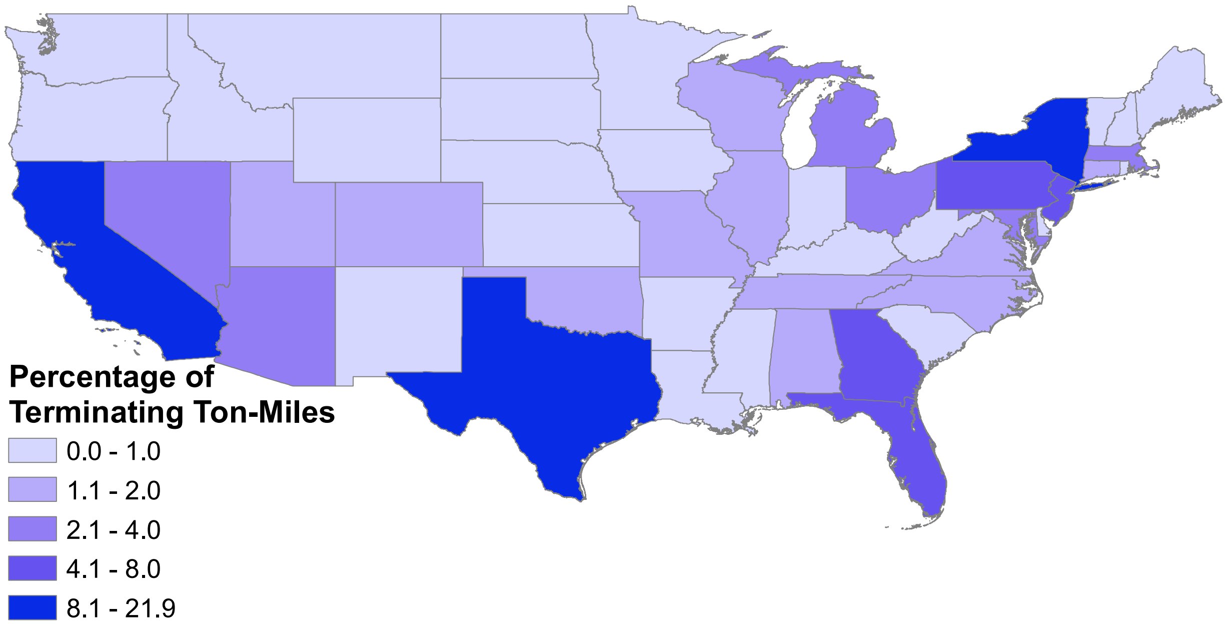

Figure 6-9. Percentage of Total Ton-Miles of Ethanol Shipments by Terminating State, Scenario B - National Low-Level Blend.

Figure 6-10 provides a breakdown of ethanol shipment ton-miles by terminating state, but for regional ethanol distribution rather than the national distribution scenario used to generate Figure 6-9. Figure 6-10 shows that regional distribution shifts ethanol shipments from coastal states to Midwestern ones, with Minnesota, Wisconsin, and Missouri replacing California, Texas, and New York as the state responsible for the greatest percentage of the total ethanol shipping load. Though some Midwestern states are individually responsible for more than 10% of the total ton-miles under regional distribution, regional distribution reduces the total ton-miles of ethanol shipments by a factor of 5 relative to national distribution, so the total ton-miles terminating in Midwestern states are still significantly less than those terminating in population-rich coastal states under national distribution.

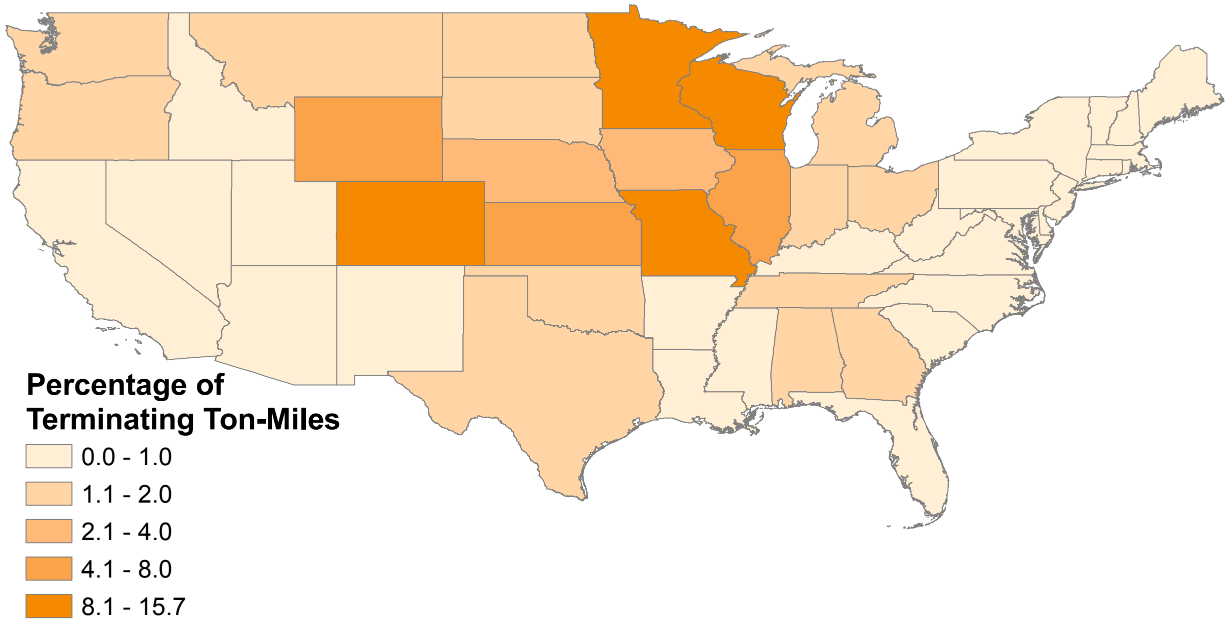

Figure 6-10. Percentage of Total Ton-Miles of Ethanol Shipments by Terminating State, Scenario A – Regional E85.

Should future domestic ethanol production exceed the 36 billion gallon annual target specified by EISA, the estimated costs of different distribution scenarios would change as well. Figure 6-11 displays the total estimated ethanol shipping costs for Scenarios A and B as a function of total domestic ethanol production. Ethanol production ranges from a near-term production level of 20 billion gallons per year (comprised primarily of corn ethanol) to a very long-term production level of 90 billion gallons per year that relies heavily on cellulosic ethanol. Three curves are shown in Figure 6-11, one each for Scenario A – Regional E85 and Scenario B – National Low-Level Blend, as well as a curve representing the cost reduction of Scenario A relative to Scenario B.

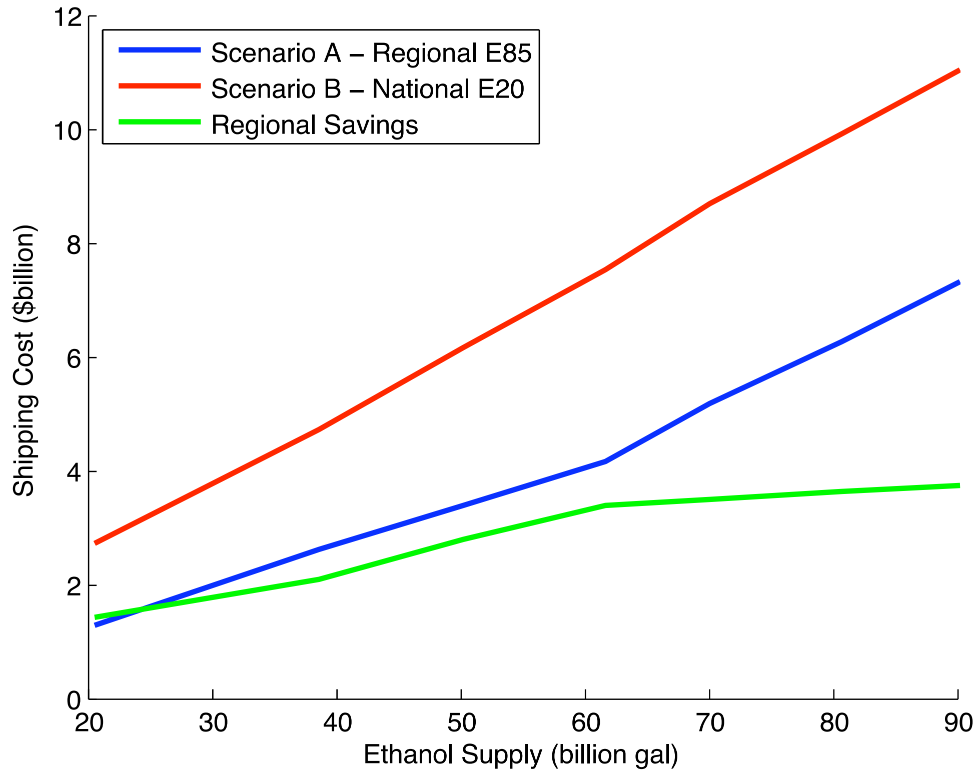

Figure 6-11. Total Shipping Cost as a Function of Ethanol Supply.

Figure 6-11 shows that total ethanol shipping costs for both regional and national ethanol distribution increase as a function of ethanol supply. The total costs of national ethanol distribution increase at a constant rate in moving from an annual ethanol supply of 20 billion gallons to 90 billion gallons; for all production levels, ethanol is distributed proportionally to fuel demand throughout the country, so a marginal gallon of ethanol has the same shipping cost regardless of ethanol supply.

Total costs for regional distribution, on the other hand, show an increasing slope as the annual ethanol supply increases. For regional distribution, ethanol demands near ethanol refineries are met before shipping to distant demands. As ethanol production increases, ethanol demands near refineries are increasingly satiated, forcing the LP to look further for unmet ethanol demand sites. As a result, a marginal gallon of ethanol is shipped significantly further for higher ethanol production volumes, leading to the increasingly slope in the total cost curve for regional ethanol distribution.

The third curve shown in Figure 6-11, representing the cost reduction of regional distribution relative to national distribution, further illustrates the impact of ethanol supply on distribution costs. Cost reduction of regional ethanol distribution steadily increase from $1.5 billion to $3 billion per year as ethanol production increases from 20 billion to 60 billion gallons, then basically levels off as ethanol production increases from 60 billion to 90 billion gallons. Should ethanol production expand to levels significantly greater than 90 billion gallons per year (a scenario not modeled in this study), the cost reductions from regional ethanol distribution would actually begin to decline, as the cost of shipping a marginal gallon of ethanol regionally would exceed the average cost of national ethanol distribution. Finally, if domestic ethanol production could somehow reach the point where all gasoline demand throughout the United States could be displaced by E85 (a extremely optimistic scenario that would require close to 200 billion gallons of ethanol per year), then national and regional ethanol distribution would be identical, eventually bringing the 'Regional Savings' curve shown in Figure 6-11 down to zero.

6.4.2. State-Level E85 Mandates

For each of the lower 48 states, a separate scenario was run to model ethanol shipments resulting from that state implementing an E85 mandate. Figure 6-12 displays the results generated by the LP for an E85 mandate enacted by California. Ethanol supplies, demands, and shipments are represented using the same symbols used in Figure 6-3 and Figure 6-4. Figure 6-12 shows visually that some state-level mandates could result in significant increases in shipping distances and shipping costs relative to either Scenario A – Regional E85 or Scenario B – National Low-Level Blend. An E85 mandate enacted by the state of California is projected to result in roughly half of the 36 billion gallon EISA target being consumed in California, most of which is produced in the Midwest. The resulting shipment configuration is dominated by ethanol shipments via rail to southern California, traveling long distances and incurring large costs.

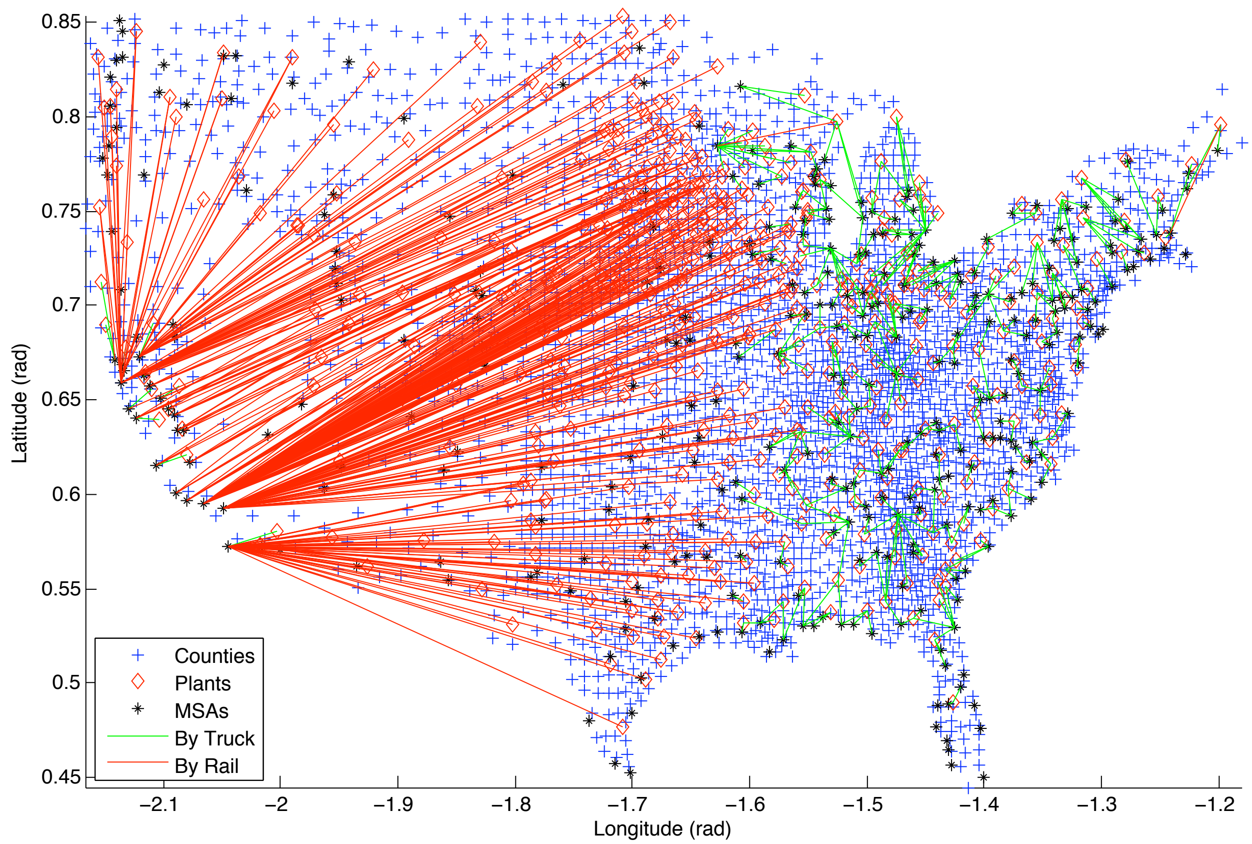

Figure 6-12. Shipping Configuration for Scenario C – State E85 for California.

On the other hand, a state-level E85 mandate could significantly reduce ethanol shipping distances and costs. Figure 6-13 shows the shipping configuration produced by the LP based on an E85 mandate for the state of Illinois, a state with a large population located close to ethanol production sites. Figure 6-13 may not appear drastically different from Figure 6-4, which represents national ethanol distribution, since both figures display large volumes of ethanol traveling from the Midwest to coastal demands. However, with a much larger ethanol supply in the Midwest (resulting from Illinois raising its maximum blend from E20 to E85), the LP does not have to ship ethanol to the MSAs located farthest from production sites. Figure 6-13 shows that MSAs in the ‘corners’ of the United States, and most importantly those large MSAs in southern Florida and southern California, receive little ethanol. In this case, a state level E85 mandate can create distribution flexibility, allowing the LP to avoid shipping ethanol to some of the MSAs that are most expensive to reach.

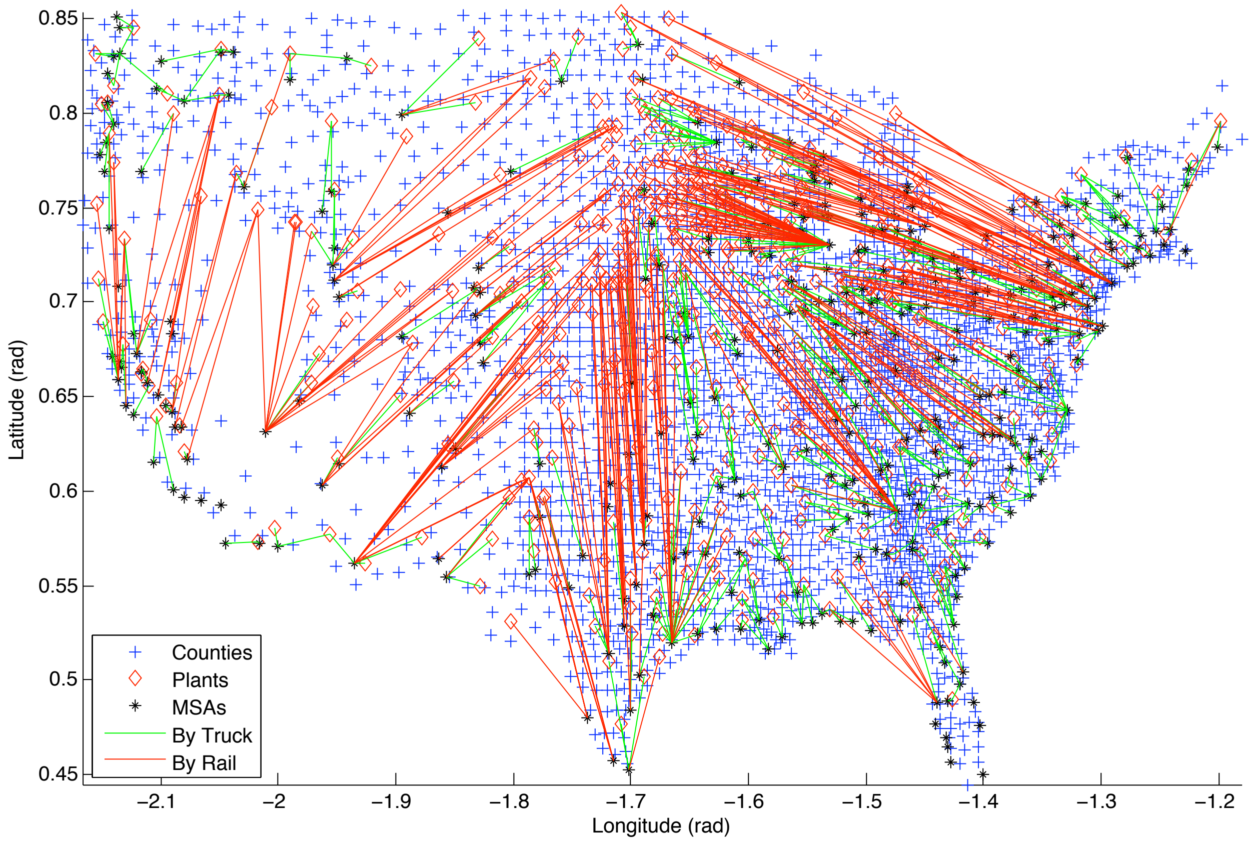

Figure 6-13. Shipping Configuration for Scenario C – State E85 for Illinois.

Figure 6-14 provides average ethanol shipping distances generated for scenarios with state-level E85 mandates compared to the average shipping distance generated for Scenario B – National Low-Level Blend. Values less than zero (symbolized by yellow or green) indicate that a state-level E85 mandate for that state would reduce the average shipping distance relative to Scenario B, while orange and red colored states would increase the average shipping distance by mandating E85.

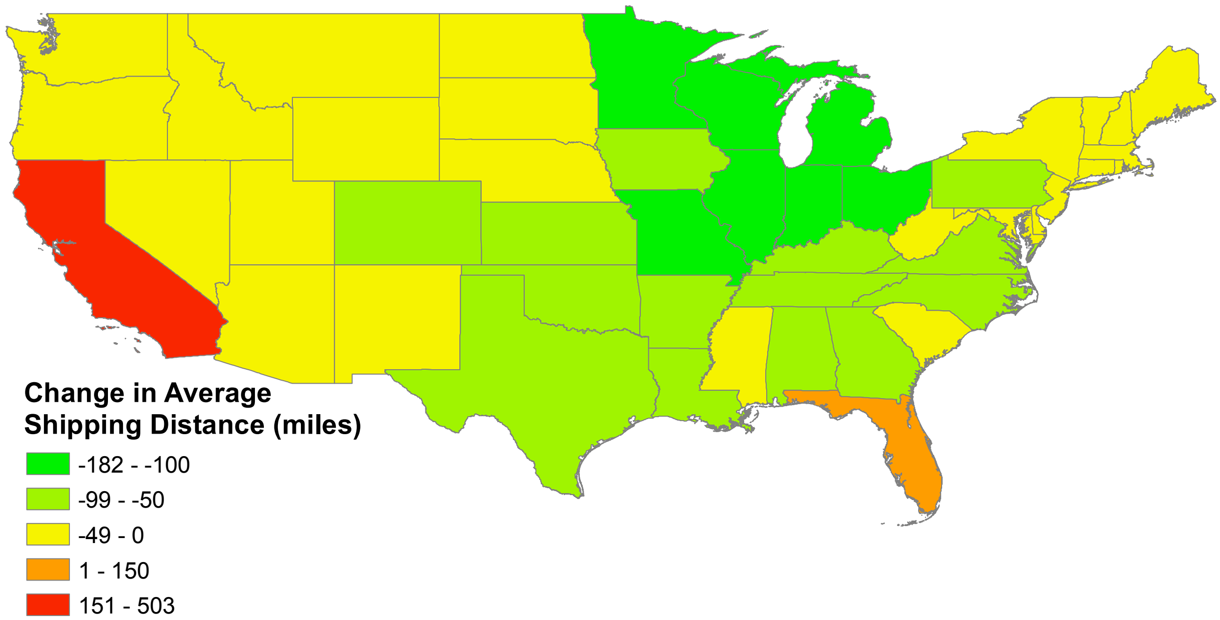

Figure 6-14. Change in Average Shipping Distance between Scenario B – National Low-Level Blend and State-Level E85 Mandate.

Figure 6-14 indicates that only two states, Florida and California, would increase the average shipping distance by mandating E85. All other states would reduce the average shipping distance by enacting an E85 mandate, with the largest reductions coming from E85 mandates by Midwestern states. States located throughout the Midwest could decrease the average shipping distance by up to 180 miles by mandating E85, while an E85 mandate by the state of California would add over 500 miles to the average ethanol shipping distance.

Figure 6-15 provides similar results as those shown in Figure 6-14, but with states symbolized by the difference in total shipping cost rather than the difference in average shipping distance. The distribution of impacts is similar to that shown in Figure 6-14; only

California and Florida increase the overall cost by mandating E85, while states throughout the Midwest would create the greatest benefit by enacting an E85 mandate. Impacts range from a savings of over $500 million in annual shipping cost (for a mandate enacted by Texas) to an addition of over $800 million resulting from an E85 mandate by California.

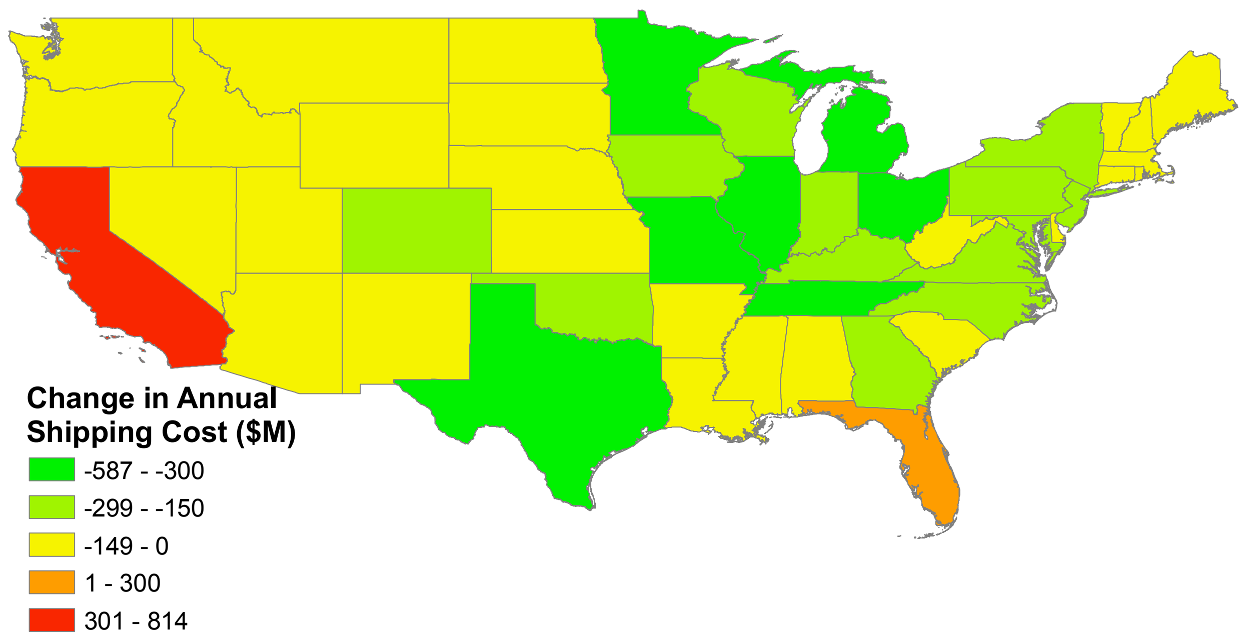

Figure 6-15. Change in Total Shipping Cost between Scenario B – National Low-Level Blend and State-Level E85 Mandate.

Despite having little ethanol production within state boundaries (or in nearby states), states such as Texas, New York, and Pennsylvania could still reduce ethanol shipping costs by enacting E85 mandates. While MSAs in these states are not located in close proximity to ethanol supplies, the large demand for fuel in these states allows the LP to shift a large volume of ethanol shipments away from distant demands. Essentially, these demands are not close to ethanol supplies, but there are not extremely far from supplies either, and by converting their large fuel demand to E85, they create distribution flexibility that can result in significant cost reductions. State-level mandates are generally most effective when enacted by states containing (or located close to) significant ethanol production, but E85 mandates by states with large populations could result in significant cost reductions as well.

Note that the average shipping distance and total cost impacts shown in Figure 6-14 and Figure 6-15 are generated are based on each state individual enacting an E85 mandate while all other states are constrained by an E20 blendwall. Therefore, benefits of multiple states enacting E85 mandates are generally not additive. (For example, the states of Iowa and Missouri are estimated to save $200 million and $300 million, respectively, in annual shipping costs relative to national ethanol distribution by enacting E85 mandates. Both are individually credited for shifting ethanol shipments away from demand located farthest from ethanol production in these estimates, so E85 mandates enacted simultaneously by the two states would likely reduce annual ethanol shipping costs by less than $500 million.)

The optimal combination of state-level E85 mandates is not addressed here, but ethanol distribution under Scenario A – Regional E85 does provide a lower bound for the total shipping cost under any combination of state-level E85 mandates, and therefore an upper bound on the maximum cost reduction relative to the national ethanol distribution baseline. Figure 6-11 indicates that for an ethanol production level of 36 billion gallons per year, the total cost difference between Scenarios A and B amounts to $2 billion per year. While this upper bound is roughly four times greater than any of the individual state E85 mandate cost reductions shown in Figure 6-15, individual states such as Illinois and Texas could save over $500 million by mandating E85. Should a federal ethanol distribution policy or combination of state-level policies prove difficult to enact, these states (as well as some others found throughout the Midwest) could still achieve cost reductions amounting to one-fourth or more of the maximum possible ethanol shipping cost reduction through an individual state-level mandate.

6.5. Sensitivity Analysis

Results presented in this analysis were generated under the assumption that transportation energy consumption per capita would remain constant in the future, and that changes in future transportation fuel demand would be due only to population growth. Due to factors such as fuel price volatility, concerns over the greenhouse gas emissions from fossil fuels, increasing residential density, and a desire to reduce dependence on foreign oil imports, per capita fuel consumption could drop in the near future. Should per capita fuel consumption decrease, a regional fuel distribution strategy could become less effective, because regional fuel demands would be more quickly satisfied, forcing ethanol refineries to look further for MSAs to consume their fuel. Thus, reductions in transportation energy demand per capita could reduce the benefits of regional ethanol distribution estimated in this study.

Figure 6-16 shows the impacts that varying transportation fuel demand has on shipping costs estimated by the LP. Two curves are shown for the total costs of distributing the 2022 EISA target of 36 billion gallons of ethanol, one for regional distribution and one for national distribution. Each curve represents the total shipping cost for that distribution scenario as a function of the energy demand factor, a number that was multiplied by the base case fuel demand estimates for all 347 MSAs to either increase of decrease the estimated fuel demand for that MSA. A value of 1 represents the base case, and value of 0.5 represents a 50% reduction in energy demand for all MSAs, and a value of 1.5 represents a scenario in which all MSAs an increase their energy demand by 50% relative to the base case.

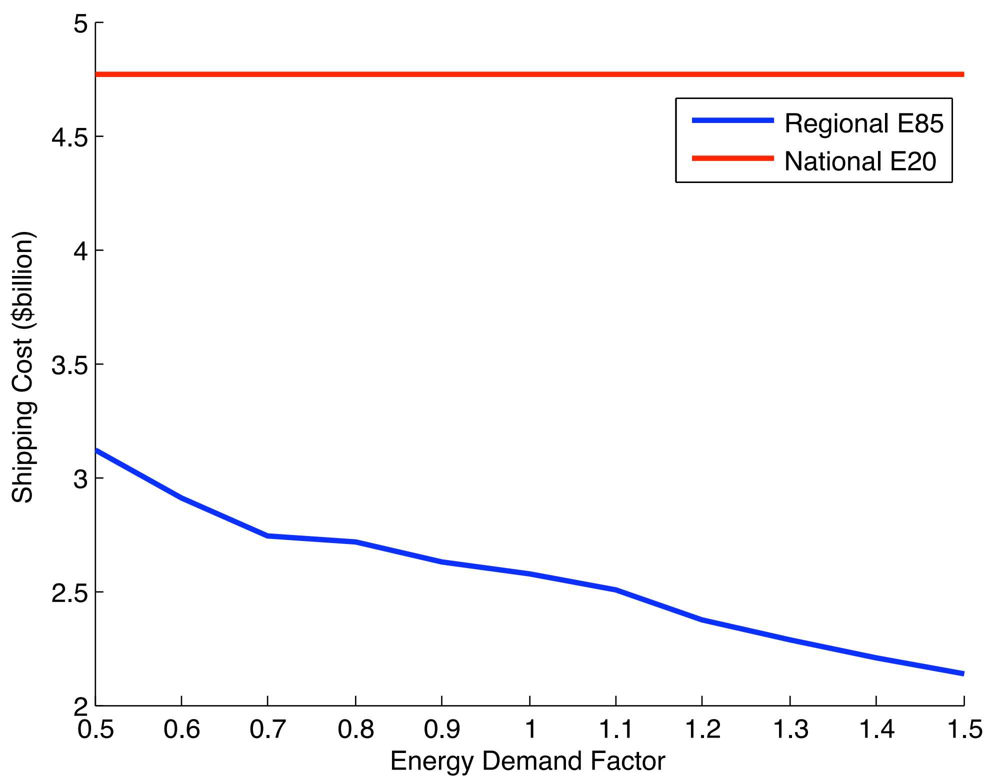

Figure 6-16. Annual Shipping Costs for Regional and National Ethanol Distribution of 36 Billion Gallons as a Function of Relative Gasoline Demand.

Figure 6-16 shows that only national ethanol distribution costs are insensitive to the energy demand factor. For national ethanol distribution, ethanol is distributed in proportion to transportation energy demand, so uniformly scaling demands up or down from the baseline has no impact on fuel distribution costs (though it does impact the ethanol blend used throughout the country). Regional ethanol distribution costs, estimated to be $2.6 billion per year in the base case, increase from $2.1 billion to $3.1 billion as the energy demand factor drops from 1.5 to 0.5. As expected, decreasing per capita fuel demand increases regional distribution costs, but even for a reduction of 50% in per capita fuel demand (to levels not seen since the 1950s), regional distribution is still estimated to save over $1.5 billion in shipping costs compared to national distribution.

Figure 6-17 illustrates the impacts of varying transportation fuel demand as a function of total ethanol production. All four curves shown in Figure 6-17 represent annual shipping costs as a function of ethanol production. Curves labeled 'Regional E85' and 'National Low-Level Blend' are identical to the curves shown in Figure 6-11, while the other two curves represent regional shipping costs estimated for scenarios with fuel demands uniformly increased or decreased by 50%.

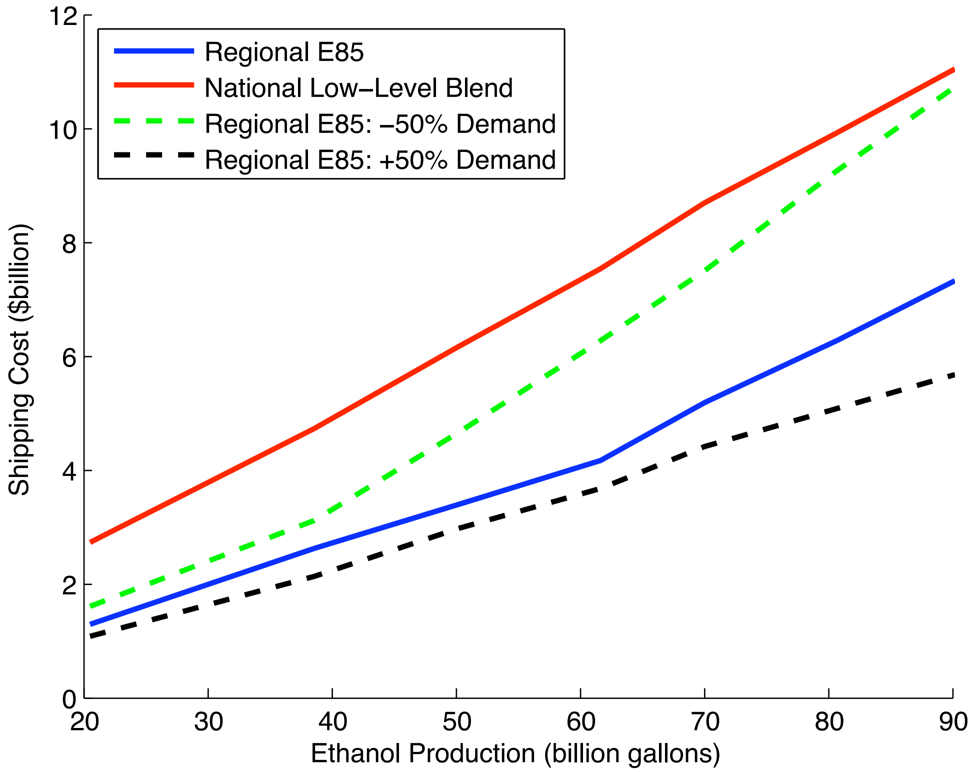

Figure 6-17. Sensitivity of Annual Shipping Costs for Regional Distribution to Energy Demand.

Figure 6-17 shows that changes in energy demand become more important as ethanol production increases. The green dashed line, indicating cost estimates for regional distribution under a 50% reduction from base case demands, is very close to regional distribution costs estimated for the base case at low production volumes, but gradually moves closer to the curve for national distribution as the total volume of ethanol produced increases. Assuming a 50% reduction in transportation fuel demand, 90 billion gallons of ethanol would be almost enough to provide E85 throughout the country, forcing ethanol producers to ship to coastal demands and resulting in costs similar to those estimated for national distribution. However, an annual domestic supply of 90 billion gallons of ethanol and a reduction of 50% in transportation energy demand are each extremely optimistic in the foreseeable future, making a scenario in which regional distribution costs converge to those of national distribution highly unlikely.

6.6. Conclusions

Ethanol production within the United States has increased drastically in recent years, and the Renewable Fuel Standard created by the EISA of 2007 requires domestic ethanol production to continue this upward trend. Domestic ethanol consumption, however, may be limited by both the federal blendwall of E10 for conventional vehicles and the lack of vehicles in the current fleet capable of running on higher-level blends. Demand for ethanol may also be reduced by the relatively high shipping costs required to transport ethanol from production sites in the Midwest to large coastal population centers.

Distributing ethanol as E85 regionally, rather than distributing it nationally as a low-level blend, could help solve problems involving both consumption limits and high shipping costs. Given the EISA's 2022 target of 36 billion gallons of domestic ethanol production, regional distribution of E85 would save almost 60 billion ton-miles of ethanol transportation and over $2 billion per year in shipping costs compared to national distribution of E20. Regional distribution of E85 would require widespread use of flex-fuel vehicles throughout ethanol-producing regions, but incentivizing investment in FFVs at the state or regional level would be either less expensive or easier to implement (or both) than doing so throughout the country.

Should a coordinated regional fuel distribution policy prove difficult to implement, individual state-level E85 mandates could also substantially reduce shipping costs relative to national distribution of a low-level ethanol blend. States either containing or located near large volumes of ethanol production capacity, especially those state with large populations, could reduce annual shipping costs by as much as $500 million compared to national E20 distribution by converting all of their gasoline demand to demand for E85.

Increased production of biofuels could have positive environmental, economic, and energy security impacts for transportation energy used in the United States. Crafting biofuel distribution policies to reduce shipping costs and infrastructure investment requirements, while still creating sufficient demand for the fuel, can help realize those benefits while limiting costs.

7. Estimating Shipping Loads and Congestion Costs for Ethanol Production and Distribution

7.1. Introduction

Production of corn ethanol within the United States has increased significantly in recent years. From 2001 to 2008, U.S. corn ethanol production increased by 500%, expanding from 1.8 to 9 billion gallons per year (RFA 2010b). Though total domestic ethanol production in 2008 equates to only about 4% of gasoline energy used to fuel the light-duty vehicle fleet within the United States (EIA 2009d), ethanol production will continue to increase significantly in the near future. Due to concerns over the contributions of fossil fuels to climate change, volatile petroleum prices, and a desire for increased energy security, the 2007 Energy Independence and Security Act (EISA) requires that at least 36 billion gallons of ethanol be produced domestically by 2022. Corn ethanol production is capped at 15 billion gallons per year, with advanced biofuels (such as cellulosic ethanol) comprising the remaining 21 billion gallons per year (EISA 2007).

Supply and demand for ethanol are generally not co-located. Corn and proposed cellulosic ethanol feedstocks such as switchgrass and crop residues are expected to be produced in large quantities throughout the Midwest and portions of the Southeast (Cooper 2008). Unfortunately, 80% of U.S. population lives along coastlines, so transporting ethanol from production facilities to demand centers necessitate long shipping distances. Currently, the burden of shipping ethanol to coastal demands falls mainly to the rail network. About 60% - 75% of ethanol (by volume) was shipped via rail from 2000 and 2005 (USDA 2007), and the percentage settled to around 65% during 2006 and 2007 (STB 2007, STB 2008). For 2007, the average rail shipping distance for ethanol was 1150 miles (STB 2008), indicating that rail freight networks are already responsible for shipping ethanol literally halfway across the country.

Increasing domestic ethanol production, without investing in transportation infrastructure, could result in congestion on the rail freight network. Assuming that both the percentage of ethanol shipped by rail and the average rail shipping distance for ethanol remain constant, increasing domestic ethanol production from the 11 billion gallons required in 2009 to the 36 billion gallon target for 2022 would add 57 billion ton-miles of freight to the U.S. rail network. This load represents only a 3% increase from the current total rail freight load (BTS 2010), but because shipments would all be originating from the Midwest and traveling to large coastal demands, the added load of ethanol trains could still lead to congestion in certain areas of the rail network.

As ethanol production increases, shipping costs could potentially be decreased by transporting ethanol through pipelines. Unfortunately, ethanol cannot be shipped through pipelines concurrently used for petroleum distribution. Pipelines currently used for petroleum shipping could theoretically be converted to full-time ethanol pipelines, but because ethanol is projected to meet only a fraction of total fuel demand (and can only be used by the current fleet when blended with petroleum), petroleum shipping would be problematic. Thus, pipeline shipping of ethanol would likely require the construction of new pipelines, a project that could be costly considering the relatively small capacities and dispersed nature of ethanol plants.

The purpose of this study is to quantify the impacts that future ethanol shipments could have on the national rail freight network, and to study how those impacts change under different distribution scenarios. Distributing ethanol to be used as E85 (85% ethanol, 15% gasoline by volume) in the regions where corn and cellulosic feedstocks can be grown can both reduce costs and reduce both loads and congestion on the rail freight network compared to national distribution of a low-level ethanol blend.

7.2. Data Sources and Methods

7.2.1. Rail Freight Shipments

Current rail freight shipments were modeled based on data from the Surface Transportation Board's 2007 Public Use Waybill Sample (PUWS) (STB 2008). The PUWS is generated from the Surface Transportation Board's Carload Waybill Sample, a collection of waybill samples required from all major U.S. railroads containing detailed rail shipment information not suitable for public release (STB 2009). The 2007 PUWS contains over 660,000 entries, each representing rail shipments of a given good from one location to another. Each entry within the file contains information on the commodity type, tonnage shipped, freight revenue, and short line rail distance. Some entries also contain geographic information for the origin and destination of the shipments, indicated by one of the 172 Bureau of Economic Analysis (BEA) area codes (with an average of 18 counties per BEA area) that partition the United States.

Only 50% of the tons and 58% of the ton-miles included in the 2007 PUWS have BEA area codes for both the origin and destination of the shipments. Both origin and destination codes are necessary in order to model the flow of freight along the rail network. To account for entries with insufficient origin-destination data, those entries with geographic information for both origin and destination were multiplied by the commodity-specific ratio of total ton-miles within the sample to ton-miles from entries with geographic information. Using this procedure, 97% of tons and 99% of ton-miles in the PUWS were represented within the model. The percentage of rail load accounted for is still less than 1 due to the fact that shipments of some sensitive commodities (such as munitions and hazardous materials) are never given geographic coding in the PUWS and could not be assigned to origin or destination areas.

Sensitivity analysis was performed to determine the impact of alternative projections for national rail freight shipments. Alternative projections for rail freight shipments were taken from the Freight Analysis Framework (FAF), a database estimating freight flows between 114 areas throughout the United States via truck, rail, water, air, and intermodal shipping modes. The FAF database contains projections for freight tonnage and value for commodities at the two-digit STCC code for years ranging from 2010 to 2030 in five-year increments, with projections made based on estimations of regional economic growth rates (FHWA 2010). During sensitivity analysis, baseline rail loads were estimated using 2010 and 2030 FAF projections instead of data from the PUWS, with freight tonnage projections from the FAF database converted into trains using commodity specific estimates for tons per carload (estimated from the PUWS) and carloads per train.

Table 7-1 provides a high-level comparison of the three data sets used to model baseline rail loads, the PUWS and FAF projections for 2010 and 2030. Table 7-1 shows that while estimates for the tons of freight shipped over the rail network are higher for both FAF data sets than for the PUWS, the estimate for ton-miles represented in the PUWS is in between the two FAF projections, indicating that average shipping distances are longer in the PUWS.

Table 7-1. Estimates for tons and ton-miles represented by rail freight shipments.

	PUWS 2007	FAF 2010	FAF 2030
Tons (million)	1740	2080	2960
Ton-Miles (billion)	1830	1580	2440

7.2.2. Ethanol Supplies

Domestic ethanol supplies were assumed to come from the production of corn and cellulosic ethanol. Locations and capacities of corn ethanol refineries were obtained from the Renewable Fuels Association (RFA 2010a). With a total nameplate capacity of 12.7 billion gallons per year (RFA 2010a), corn ethanol production would have to increase by 18% to meet the EISA 2007 target of 15 billion gallons per year (EISA 2007). In lieu of modeling the construction of new facilities, future capacities of corn ethanol plants were estimated by uniformly increasing current capacities by 18%.

Because cellulosic ethanol is not currently produced on a commercial scale, it was necessary to estimate both the locations and capacities of future cellulosic ethanol refineries. In order to accurately model the distribution of future cellulosic refineries, it was necessary to first estimate the locations and volumes of future cellulosic biomass supplies.

Three primary types of cellulosic biomass were considered as domestic cellulosic ethanol feedstocks: switchgrass, crop residues (corn stover and wheat straw), and forest biomass. For switchgrass and crop residues, spatial supply projections were taken from a data set provided by the Energy Information Administration (EIA) that was generated using the POLYSYS model. POLYSYS uses interdependent modules for crop supply and demand, livestock, farmer income, and local environmental conditions to predict the availability of various crops (including switchgrass, corn stover, and wheat straw) for 305 Agricultural Statistical Districts (ASDs) throughout the United States (University of Tennessee 2000, De La Torre Ugarte 2000). The EIA data set used for this study contains POLYSYS model results for cellulosic biomass prices ranging from $20 to $100 per dry ton, with higher feedstock prices resulting in greater feedstock availability.

Biomass supplies from forest removals were estimated using supply curves provided by Oak Ridge National Laboratory (ORNL). These supply curves estimate woody biomass supplies from a number of sources (including logging residues, forest thinnings, and other removals) on a county-by-county basis for cellulosic biomass prices ranging from $10 to $100 per dry ton. Forest thinning supplies were estimated using the USDA Forest Service

Fuel Reduction Cost Simulator model, based on input data from Forest Inventory Analysis plots, aggregated at the county level. Switchgrass and crop residue projections from the POLYSYS model were disaggregated from the ASD level to the county level, and combined with forest biomass estimates to generate total cellulosic biomass availability estimates at the county level.

Feedstock prices were varied in order to model scenarios with different level of cellulosic ethanol production. Estimates of total cellulosic biomass availability ranged from 80 million tons per year up to 600 million tons per year, resulting in total cellulosic ethanol supplies ranging from 7 to 55 billion gallons per year, assuming ethanol yields of 90 gallons per dry ton of biomass (Aden 2002). Combined with the assumed corn ethanol production of 15 billion gallons per year, total ethanol supply estimates ranged from 22 to 70 billion gallons per year.

Based on these cellulosic feedstock supply projections, the locations of future cellulosic ethanol facilities were estimated. Cellulosic ethanol facilities were placed using the clustering algorithm *k*-means. The *k*-means algorithm is a simple, fast heuristic algorithm that attempts to cluster data in a way that minimizes the total intracluster variance. For a more detailed description of *k*-means, see Han (2005).

The value for *k* was modified to vary facility size, with smaller values of *k* resulting in fewer, larger clusters, and therefore larger facilities. For facilities that draw biomass from the surrounding area, larger facilities have increased feedstock transportation costs, but can also take advantage of economies of scale to reduce unit capital investment and operating costs. Previous studies have estimated the optimal ethanol facility size statistically (Gallagher 2005) (for corn ethanol) and theoretically, both for a general bioenergy facility (Nguyen 1996) and specifically for cellulosic ethanol (Aden 2002), finding that costs would be minimized by a facility with a capacity near 70 million gallons per year. While this facility size is larger than 2/3 of corn ethanol plants currently in operation, the largest domestic corn ethanol plants have capacities of twice this value (RFA 2010a), so future cellulosic facilities with this capacity are realistic. Thus, values for k were chosen to result in facilities with capacities of approximately 70 million gallons per year.

7.2.3. Ethanol Demands

Ethanol demands were estimated and assigned to metropolitan statistical areas (MSAs) throughout the continental United States by assuming that gasoline consumption was replaced by consumption of a given ethanol blend, which varied for different distribution scenarios (discussed below, in *Ethanol Shipping*). For each MSA, ethanol demand was estimated based on current gasoline consumption, the given ethanol blend level, and estimated state-level population growth rates, assuming that transportation energy demand per capita remains constant.

7.2.4. Ethanol Shipping

Ethanol transportation was modeled using a linear programming (LP) model similar to those employed by Morrow (2006b) and Wakeley (2009). This model assigns ethanol shipments from facilities to demands in such a way that minimizes total transportation cost, subject to constraints on both the facility and demand sites. It is assumed that ethanol is blended with gasoline at blending stations located near the MSAs that consume the fuel. Because 90% of domestic ethanol shipping occurs via either rail or truck (USDA 2007), only those modes of transportation were modeled. The objective function for this model represents the system-wide transportation cost:

$$Minimize \sum_i \sum_j \left(f_{ij} + d_{ij} v_{ij} \right) x_{ij}$$

where x_{ij} represents the volume of ethanol shipped from plant *i* to MSA *j*, and d_{ij} represents the great circle distance from plant *i* to MSA *j*. f_{ij} and v_{ij} represent fixed and variable transportation costs, assuming truck shipping if d_{ij} is less than 180 miles [the minimum economic rail shipping distance calculated in Mahmudi (2006)] and rail shipping otherwise.

Constraints ensure that all ethanol is shipped, while no MSA receives more ethanol than it demands:

$$\sum_j x_{ij} = S_i$$

$$\sum_i x_{ij} \le D_j$$

where S_i is the total ethanol supplied by plant *i* and D_j is the total ethanol demand for MSA *j*.

Three ethanol distribution scenarios are considered in this analysis. Ethanol distribution scenarios are summarized below in Table 7-2. In Scenario A, all MSAs demand enough ethanol to replace their current gasoline consumption with E85 (a blend of 85% ethanol, 15% gasoline by volume). In this scenario, the total demand for ethanol is 160 billion gallons per year, much higher than the total supply of ethanol estimated for any of the supply scenarios. Because the objective function for the LP represents the system-wide shipping cost, the LP picks those demands that are least expensive to satisfy, and as a result, only the MSAs closest to ethanol supplies receive ethanol under this scenario.

Table 7-2. Description of Ethanol Distribution Scenarios.

Scenario	Description	Ethanol Blend Demanded	Added Constraints or Comments
A	Regional E85	E85	$\sum_i S_i < \sum_j D_j$
B	National Low-Level Blend	E13 to E36, depending on total supply	$\sum_i S_i = \sum_j D_j$
C	California E85	E85	$\sum_i S_i < \sum_j D_j$ $\sum_i x_{ij} = D_j \ \forall \ j \ni D_j \in CA$

Scenario B represents national distribution of a low-level ethanol blend. Here, the total demand for ethanol is set equal to the total supply, then allocated to MSAs in proportion to their current gasoline demand. The resulting ethanol blends range from E13 to E36, depending on the production scenario, and all MSAs throughout the continental United States received enough ethanol to satisfy their demand. Because 80% of U.S. population lives along the coasts, approximately 80% of ethanol (by volume) is shipped to coastal areas, often incurring large shipping distances.

Scenario C represents a case in which all MSAs throughout the state of California are supplied with E85 and any remaining ethanol is distributed regionally to provide E85 to MSAs near ethanol refineries. The California Air Resources Board is currently developing a Low Carbon Fuel Standard (LCFS) to reduce the carbon intensity of transportation fuels used in the state by 10% by 2020 (CARB 2009b). Though the LCFS may be unlikely to mandate statewide use of E85, modest ethanol blends combined with California's large population could result in significant ethanol shipments from the Midwest to the Pacific Coast. By considering statewide use of E85 throughout California, Scenario C is designed to model the worst-case rail loads resulting from ethanol shipment. Like Scenario A, the total ethanol demand is much greater than the total ethanol supply here, and many MSAs do not receive enough ethanol to meet their demand. However, in this scenario, equality constraints were added to the LP to ensure that ethanol demands for MSAs in the state of California are met before shipping ethanol to other demand locations nationwide.

The results of the LP for each scenario were used to determine ethanol shipment routes over the rail network. Only ethanol shipments traveling distances longer than 180 miles were assumed to travel via rail, so only those ethanol refineries that shipped ethanol and MSAs that received ethanol from distances greater than 180 miles were modeled as origins and destinations along the network.

7.2.5. Rail Capacity Estimation

A shapefile for the rail freight network throughout North America was obtained from the Center for Transportation Analysis (CTA) at ORNL (ORNL 2009). The rail network contains all North American rail routes active since 1993. Data for each link in the network includes the number of tracks, miles of track, track control type, and use of the line for passenger service.

Capacities for links throughout the rail network were estimated using data provided in the National Rail Freight Infrastructure Capacity and Investment Study (Grenzeback 2007). It was necessary to estimate capacities in order to determine how the rail network would respond to increases in load due to ethanol shipments, load increases that would be large in certain areas. For a specific link, the practical maximum capacity, in terms of trains per day, was estimated as a function of the number of tracks, type of track control, and existence of different train types using the link. Those estimates were applied to the links within the CTA rail network to generate link capacities, and the results are shown below in Figure 7-1.

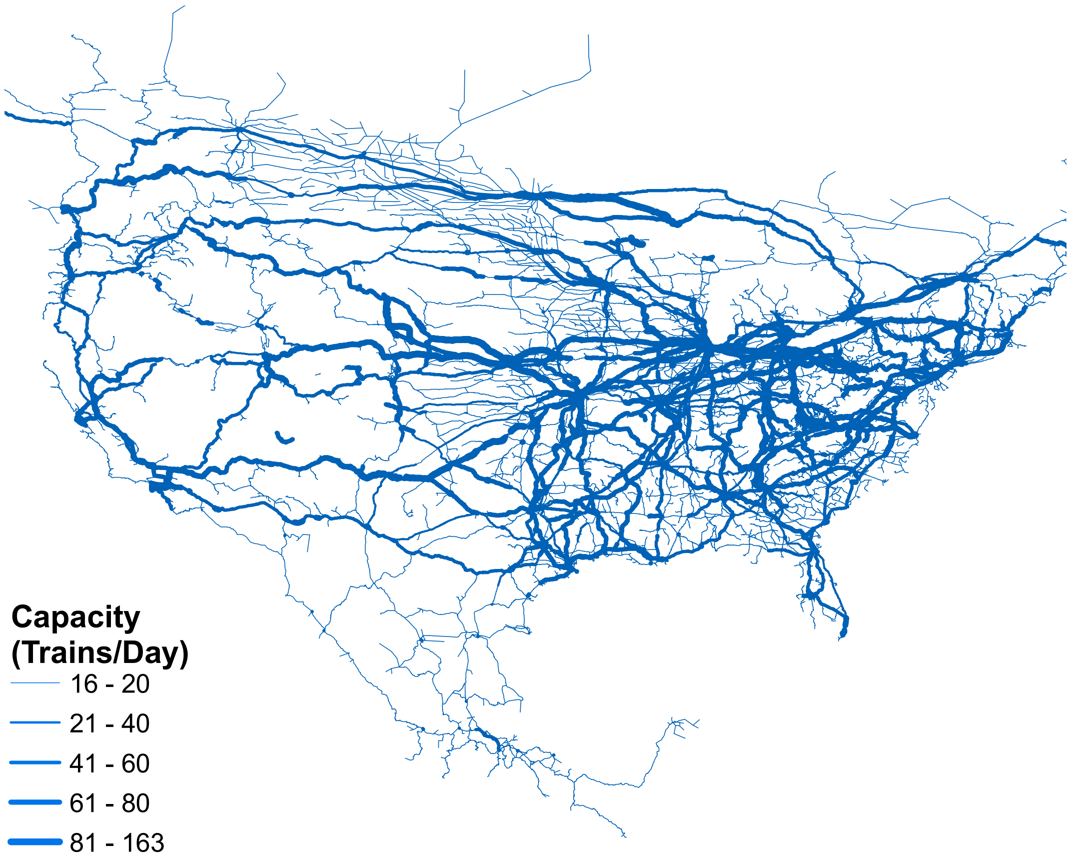

Figure 7-1 Estimated rail link capacities.

In this study, rail capacity is only considered in terms the maximum flow of trains along rail lines. Other factors, such as rail car availability, may also limit future growth in rail freight traffic.

7.2.6. Traffic Assignment Problem Formulation

To model the impacts of additional ethanol shipments on the rail network, current rail shipments and projected ethanol shipments were formulated as a traffic assignment problem. The traffic assignment problem minimizes the total cost of shipping goods across a network, subject to all shipments traveling from their origin to their destination.

For the traffic assignment problem formulation used in this study, let x_{ij} represent the number of trains traveling along the network from node *i* to node *j*. The objective function represents the total congestion-weighted train-miles for all trains traveling across the network:

$$Minimize \sum_i \sum_j x_{ij} \times d_{ij} \times g\left(x_{ij}, C_{ij}\right)$$

where d_{ij} represents the length of the link connecting nodes *i* and *j*, and $g\left(x_{ij}, C_{ij}\right)$ is a congestion multiplier that is a function of both the annual trains (x_{ij}) and the link capacity (C_{ij}).

Constraints ensure that each shipment begins at its origin and arrives at its destination. For all nodes *i* and for all shipments *k:*

$$\sum_j x_{ij}^k - \sum_j x_{ji}^k = O_i^k - T_i^k$$

where O_i^k and T_i^k are nonzero if shipment *k* originates and terminates at node *i*, respectively. The above constraint ensures that, at each node *i* along the network, the total outflow of trains minus the total inflow of trains must equal the difference between the number of trains originating at node *i* and the number terminating at node *i*, causing shipments to travel from their origin to their destination.

The congestion multiplier in the objective function, $g\left(x_{ij}, C_{ij}\right)$, was taken from the M/D/1 queuing model. The M/D/1 model assumes Markovian arrivals and deterministic service, and it can be thought of as a blocking model. The closed-form solution for the expected ratio of congested service time to free-flow service time is given by:

$$g\left(x_{ij}, C_{ij}\right) = 1 + \frac{x_{ij}}{2C_{ij}\left(1 - {x_{ij}}/{C_{ij}}\right)}$$

7.2.7. Traffic Assignment Problem Algorithm

An algorithm was implemented that iteratively uses a least cost routing algorithm to solve the problem based on a model outlined by Newell (1980). The algorithm used here routes all traffic across the network by their least cost paths using Dijkstra's algorithm (Wilson 1996), calculates link costs using the congestion multiplier discussed above, then reroutes a portion of the traffic along the newer least cost paths. The algorithm iterates until the objective converges. For more detail, see Newell (1980).

7.3. Results and Discussion

7.3.1. Ethanol Shipping Results

Figure 7-2 provides estimates of the total ethanol shipping cost for all three scenarios as a function of total ethanol production. Total ethanol production ranges from 22 to 70 billion gallons per year, and unit shipping costs for both truck and rail shipping modes were taken from Mahmudi (2006). Assuming an ethanol production cost of $1.00 per gallon (a figure in line with (Aden 2002, Phillips 2007) or exceeding (Wyman 2007, Hamelinck 2005) long-term production cost estimates), shipping costs range from 5% to 30% of production cost, depending on scenario and total ethanol production.

For all production levels, total shipping costs are lowest for Scenario A, representing regional distribution. Total costs for Scenario A – Regional E85 increase from $1 billion to $4 billion as total production increases from 22 to 70 billion gallons, but costs are always significantly lower than total costs estimated for the other two scenarios.

For Scenario B – National Low Level Blend, total costs increase linearly from $3 billion to $10 billion as ethanol production increases. Scenario B – National Low Level Blend represents national distribution of a low-level ethanol blend, and the specific blend levels were calculated so that the total supply and demand quantities would be equal. Thus, as ethanol production increases, the ethanol blend level increases, but the spatial distribution of ethanol shipments does not change significantly, so total shipping costs are roughly proportional to total ethanol production and the corresponding total cost curve appears linear.

Scenario C – California E85 is the most expensive distribution strategy for an annual ethanol production of 22 billion gallons. To meet its transportation energy demand with E85, the state of California requires about 20 billion gallons of ethanol. Scenario C assumes that California receives its ethanol demand even for relatively low total ethanol supplies, so as ethanol production increases, the high cost of shipping ethanol to California is felt immediately. Ethanol supply in excess of 20 billion gallons is distributed regionally as E85. Because shipping costs for a marginal gallon of ethanol are higher for national distribution than for regional distribution, the gap between Scenarios B and C gradually shrinks until total production exceeds 55 billion gallons per year, beyond which Scenario C represents the less expensive distribution option.

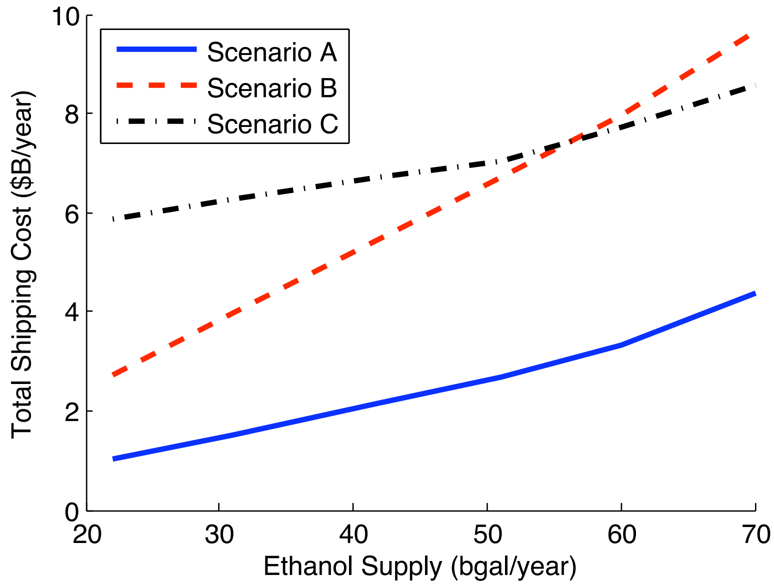

Figure 7-2. Total Ethanol Shipping Costs.

7.3.2. Traffic Assignment Model Results

Figure 7-3 shows the results of the traffic assignment model for the base case without any added ethanol shipments. Rail loads are given as a percentage of the estimated capacity for each link. Figure 7-3 shows that rail lines running into and out of Chicago are heavily loaded; however, this region features many large rail lines, so additional ethanol shipments (if they are required to travel by rail) will likely have access to rail capacity. Rail lines carrying coal from the Powder River Basin are heavily loaded, and lines passing through the Southwest connecting southern California with the Midwest are moderately loaded. Though these areas have low population density and demand little ethanol, ethanol shipments headed to the Pacific coast that pass through these regions may cause congestion problems.

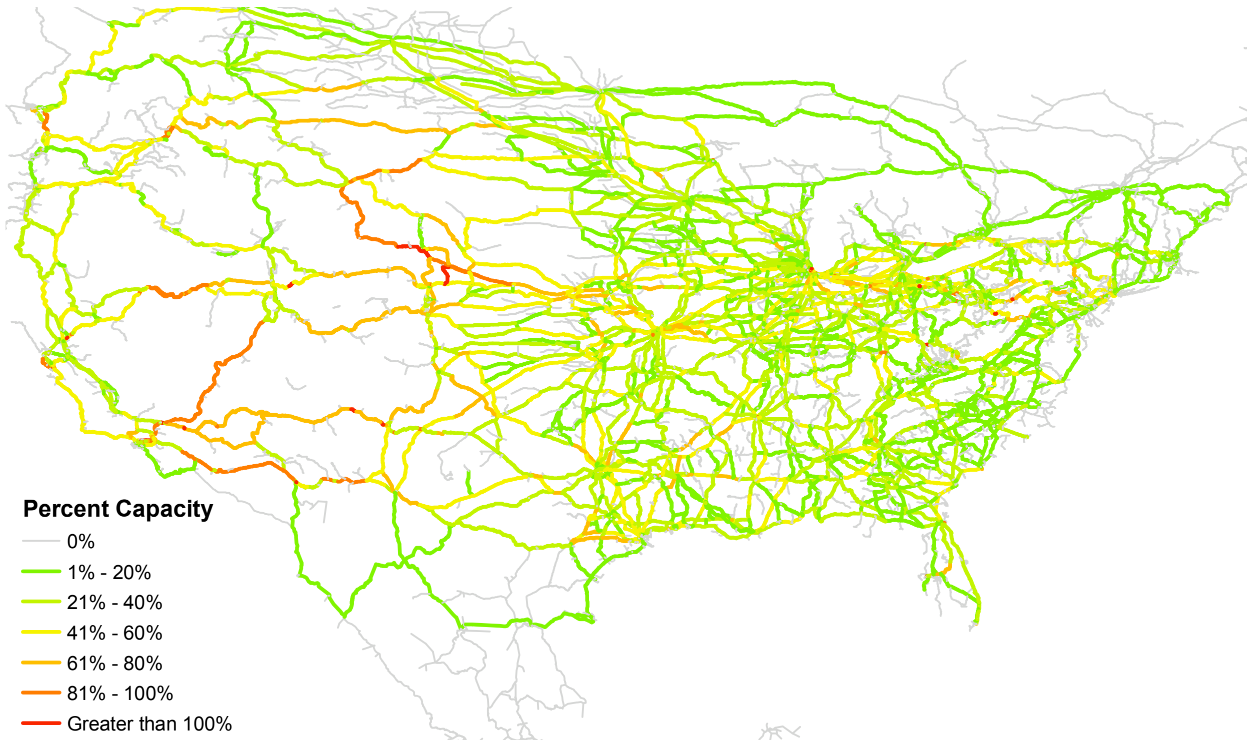

Figure 7-3. Baseline Rail Loads

Figure 7-4, Figure 7-5, and Figure 7-6 illustrate the results of the traffic assignment model for Scenario A – Regional E85, Scenario B – National Low Level Blend, and Scenario C – California E85, respectively. All three figures are based on total ethanol production of 36 billion gallons per year, matching the EISA requirement for 2022. Once again, the 36 billion gallon total supply was chosen for illustrative purposes; the spatial distribution of rail network impacts does not change significantly for other supply levels, although load increases generally become greater at higher production levels. For each figure, results are given in terms of the change in load for each link of the network, where the change in calculated as the difference between the results generated for the base case (shown in Figure 7-3) and the results generated for the given scenario. Changes in load for each link are given as a percentage of the capacity of the link.

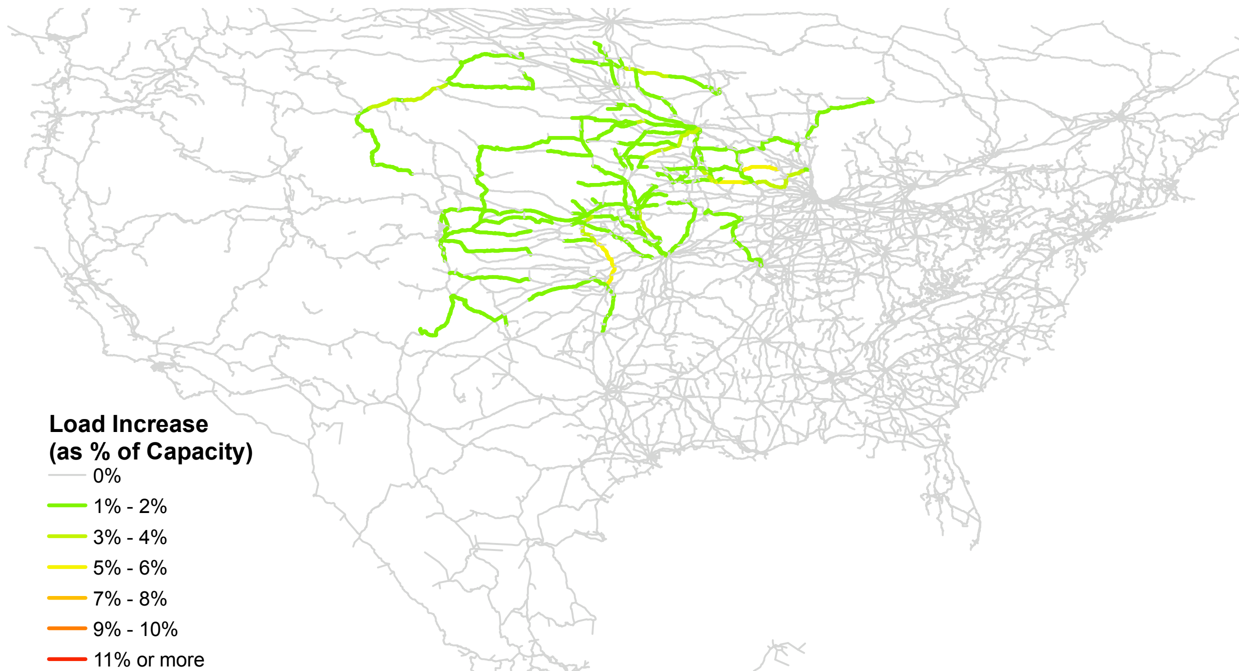

Figure 7-4. Added Rail Loads for Scenario A – Regional E85

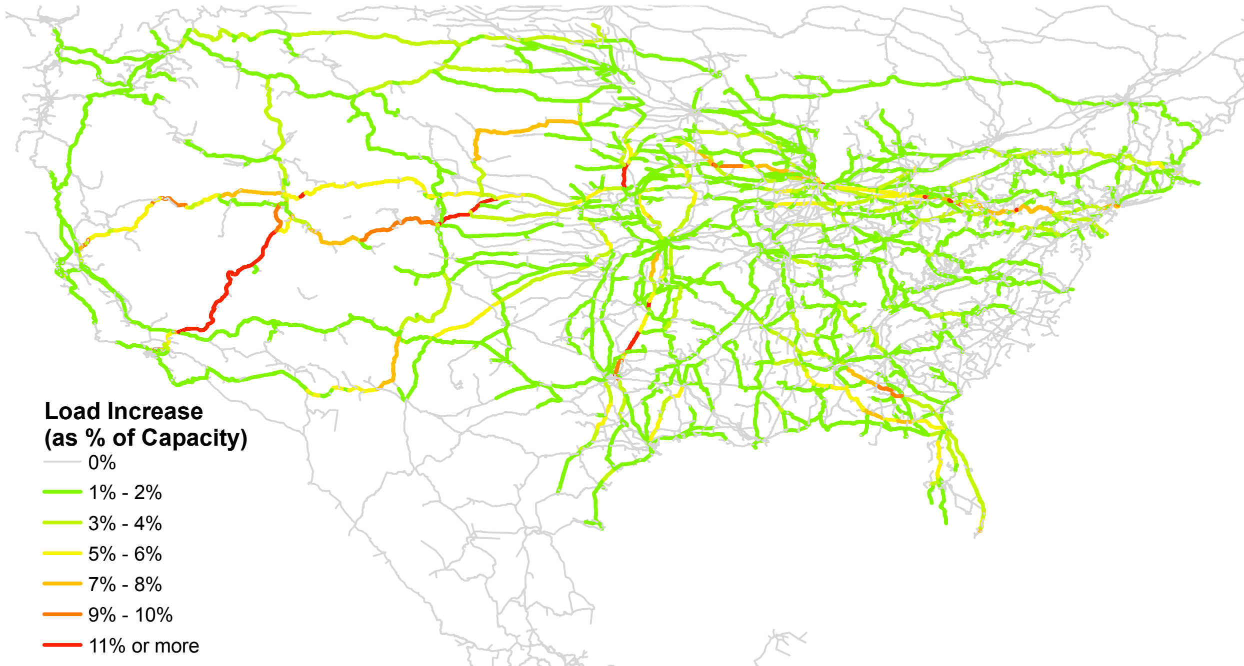

Figure 7-5. Added Rail Loads for Scenario B – National Low Level Blend

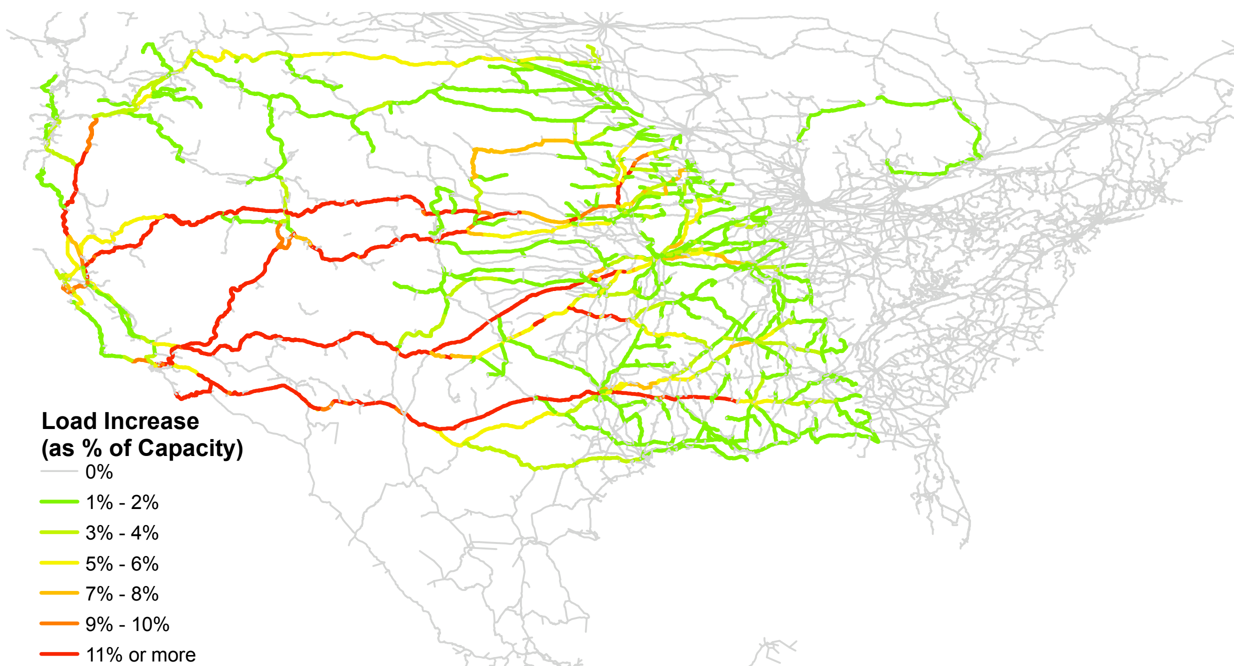

Figure 7-6. Added Rail Loads for Scenario C – California E85

Figure 7-4 shows that rail load impacts of regional ethanol distribution are minimal. In this scenario, only 3% of ethanol is shipped via rail; shipping distances are short enough that the remaining 97% is assumed to travel exclusively by truck. Rail lines on the eastern half of the United States are almost entirely unaffected, while a handful of rail lines on the western half experience slight load increases.

National ethanol distribution, shown in Figure 7-5, has more widespread impacts on the rail network. Most rail lines throughout the country experience load increases of less than 5%, while some rail lines connecting coastal demands to Midwestern production centers experience load increases representing up to 10% of their capacity.

Scenario C – California E85 shows the most drastic impacts. While the eastern half of the country is largely unaffected, main rail lines running from the Midwest to southern California are heavily loaded, experiencing an increase of at least 11% of their capacity.

Figure 7-7 illustrates the ton-miles added to the rail network for all three distribution scenarios as a function of total ethanol production. Ethanol shipments themselves represent most of the added ton-miles, though some of the added load is due to current shipments that must be rerouted (along longer routes) as a result of ethanol trains. The differences between the three scenarios are dramatic. Scenario A – Regional E85 adds very few ton-miles to the network. The added ton-miles for Scenario B – National Low Level

Blend increase linearly from 30 to 120 billion ton-miles as total production increases, representing an increase of 1.5% to 6% from the current total rail freight load. Even for low total ethanol supplies, Scenario C – California E85 would increase total rail load by over 150 billion ton-miles per year, or about 9% of current rail load. Though these increases are all less than 10% of the total current rail freight load, the fact that they generally originate in similar areas (the Midwest) and terminate in similar areas (all coastal regions for Scenario B, California for Scenario C) increases the chances that they lead to severe congestion costs.

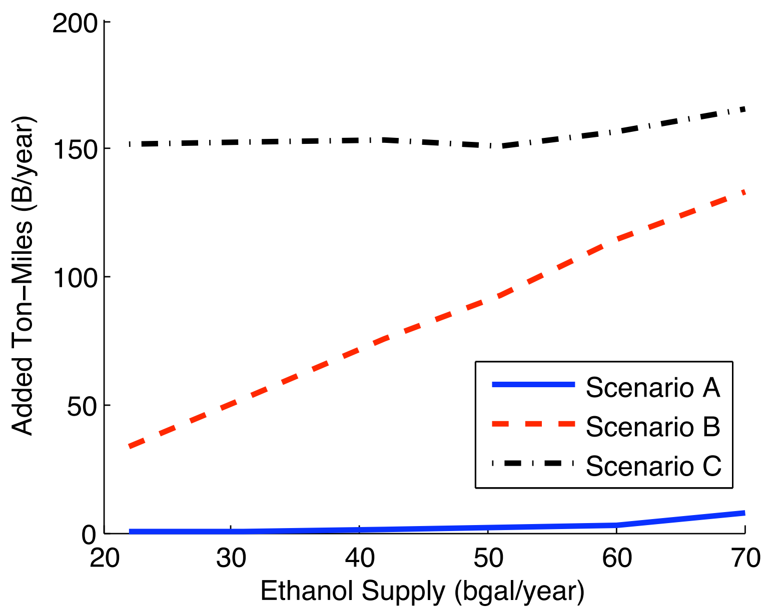

Figure 7-7 Added Ton-Miles for Distribution Scenarios.

Figure 7-8 summarizes rail congestion costs estimates for various combinations of ethanol production and distribution. Costs for nine scenarios are shown, with each scenario representing a combination of one of the distribution scenarios A, B, or C summarized in

Table 7-2 and a total production level of 20, 36, or 90 billion gallons per year. For each combination of ethanol production and distribution, costs are shown for the private ethanol shipping cost and the added congestion cost for all shipments across the network due to added ethanol shipments. Because ethanol shipments are projected to travel along rail links that are already heavily loaded, congestion costs may be on the order of the estimated private costs of ethanol shipping.

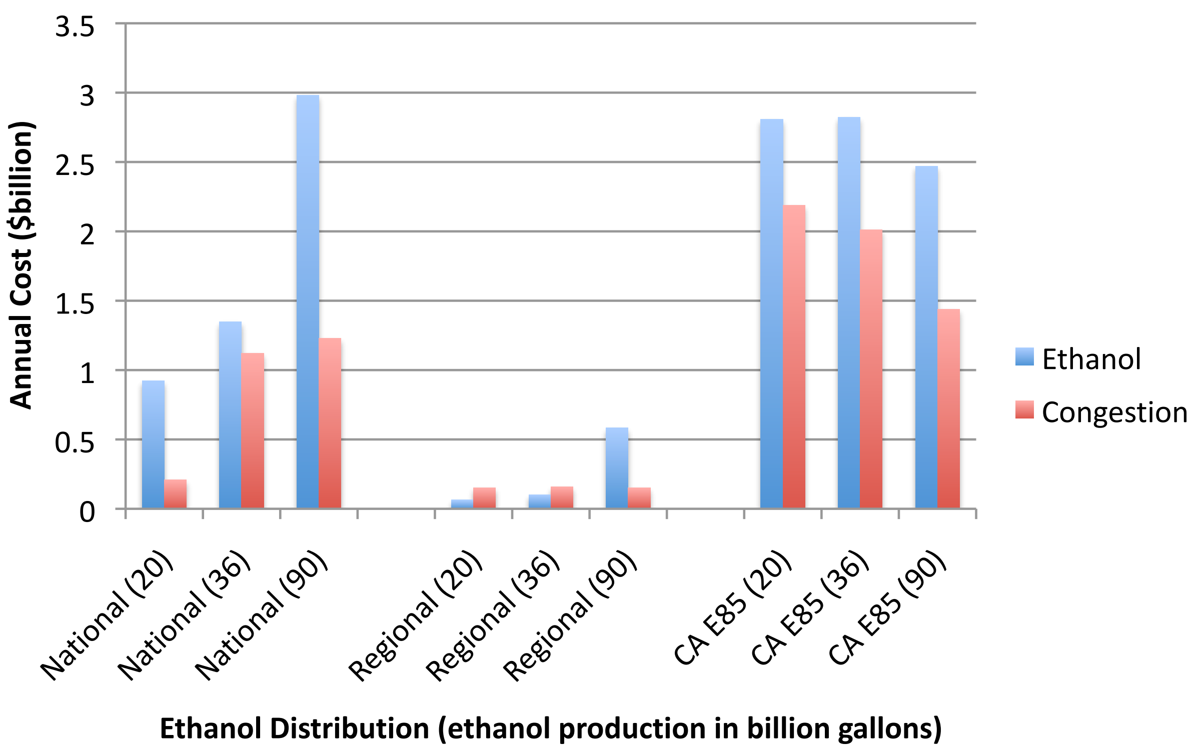

Figure 7-8. Estimated shipping and congestion costs for shipments of ethanol along the rail network.

7.4. Sensitivity Analysis

Figure 7-9 summarizes the results of the sensitivity analysis performed to estimate the impact of changing assumptions about baseline rail loads and existing rail capacity. Nine pairs of costs are shown in Figure 7-9, with the blue bar representing the estimated private cost of ethanol shipping and the red bar representing estimated congestion costs. The first three pairs of bars represent cost estimates generated using the FAF 2010 projections to estimate existing rail shipments. The second three pairs represent costs estimated based on the 2007 PUWS, while the third set represents the FAF 2030 projections. Moving from the leftmost group to the rightmost group indicates increasing the assumed baseline loads.

Within each group, three pairs of bars are shown. The first pair within each group of three shows results from the base case estimates for existing rail line capacity. The second pair assumes that the control systems for all rail freight lines are upgraded to centralized track control, while the third pair of costs are estimated assuming a doubling of base case line capacity estimates. Thus, moving left to right within each group shows the impacts of increasing rail capacity estimates.

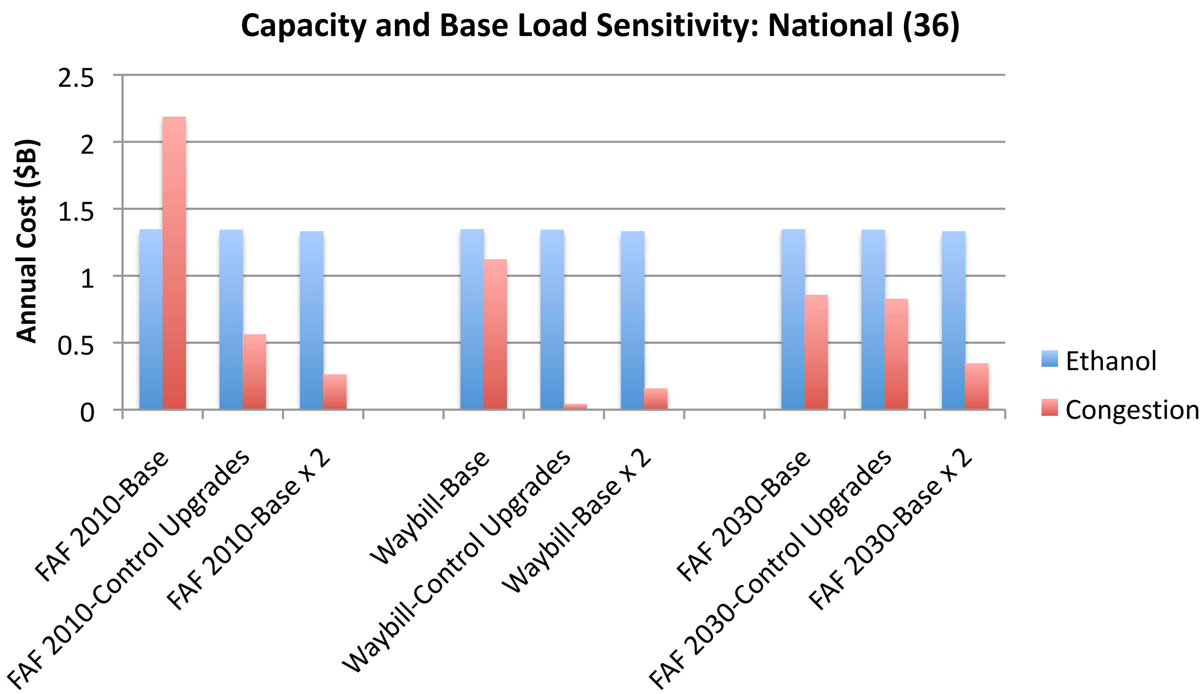

Figure 7-9. Sensitivity of congestion cost estimates to changes in both baseline rail loads and estimates of rail line capacity.

Within each group, it is clear that increasing assumed levels of existing rail line capacity decrease congestion cost estimates. For results generated based on both the FAF 2010 and Waybill Sample, increasing capacity from the base case estimates to a scenario with control upgrades reduces estimates of congestion costs by 75% or more.

The effects of varying the assumed baseline rail loads, on the other hand, do not demonstrate a clear trend. Given the baseline estimate of rail capacity, congestion costs actually decrease as the baseline load estimates increase (demonstrated by examining the red bars in the leftmost pair of each group). This result is due to the fact that the model automatically makes some capacity investments for the baseline loads themselves; thus, for higher baseline loads, some areas of the rail network have already been expanded before the addition of projected ethanol shipments. However, this trend does not hold for other capacity scenarios; implementing control upgrades throughout the rail network, for instance, results in smaller congestion cost estimates for the Waybill scenario than for either FAF projection. Part of this inconsistency may be due to the variance in the spatial distribution of rail loads (in addition to the variance in total rail load) across data sources. Regardless, congestion costs estimated based on each of the data sets are between 50% and 150% of the private ethanol shipping cost, and decline as estimates for rail capacity increase.

7.5. Biomass Shipping Analysis and Results

In addition to the analysis for rail infrastructure impacts resulting from ethanol shipping, this study also modeled the impacts of biomass shipping via truck transportation on highway infrastructure. Because the methods and results for this component of the analysis are similar to but simpler than those used to model rail shipping loads and congestion costs, the data sources and results will be discussed here instead of as a stand-alone chapter.

The goal of this portion of the analysis was to determine whether or not biomass shipments (from production or collection sites to ethanol refineries) could lead to significant negative impacts along roadway infrastructure networks. Between three and four tons of biomass are required to produce a ton of ethanol, so the above finding that ethanol shipments could lead to congestion along rail networks implies that shipments of biomass along road networks could have the same effect. This portion of the analysis also examined pavement deterioration impacts of biomass shipping to better evaluate infrastructure impacts of biomass shipping in relation to other costs along the biofuel production supply chain.

Previous analyses found in this thesis allocated biomass projections to centroids of either Agricultural Statistical Districts or counties. Because this component of the analysis is concerned with largely local road damage and congestion impacts that occur at the county level or below, allocating biomass to centroids was not sufficient. Instead, biomass projections were allocated at the farm-level (or lower) based on spatial coverage data for cropland throughout Pennsylvania.

Data for cropland throughout Pennsylvania were obtained from the U.S. Department of Agriculture (USDA) National Agriculture Statistics Service (NASS). NASS provides cropland coverage data generated from satellite imagery for crop-producing states, with the file for the state of Pennsylvania obtained from the Pennsylvania Geospatial Data Clearinghouse (PASDA 2010). Ground resolution for the data set is 30 meters by 30 meters, resulting in 160 million rasters for the state of Pennsylvania. To make the data set more manageable, it was resampled into 300 meter by 300 meter rasters, a level of resolution that was still detailed enough for the analysis but reduced the size of the data set by a factor of 10 thousand.

The POLYSYS data set contains projections for the spatial availability of switchgrass, corn stover, wood residues, and other cellulosic feedstocks. However, the POLYSYS scenario chosen to model the EISA target of 36 billion gallons only projects forest biomass (including residues from commercial operations and forest thinnings) to be available in large quantities throughout Pennsylvania, with little to no availability of switchgrass or corn stover for that particular scenario. Thus, only forest biomass was modeled as a cellulosic ethanol feedstock in this portion of the analysis, though the methods outlined here could be easily modified to model the shipping of switchgrass and/or corn stover for a different scenario or a different state.

Volumes and locations of forest biomass were modeled by allocating ASD-level forest biomass projections to individual land rasters throughout each region. Tracts of land identified by the NASS cropland coverage file as forestland were assumed to be locations for potential forest biomass supplies. Given that each tract of land represents the same area, the total estimated forest biomass availability for each ASD was divided evenly among all tracts identified as forestland.

A shapefile for the highway network throughout the state of Pennsylvania was obtained from the Pennsylvania Department of Transportation (DOT) via the Pennsylvania Geospatial Data Clearinghouse (PASDA 2010). The shapefile contains over 48,000 miles of highway throughout the state of Pennsylvania, with estimates for the annual average daily traffic (AADT) provided for each highway link. Estimates for AADT for the state of Pennsylvania are shown in Figure 7-10. Taking baseline levels of traffic from the

Pennsylvania DOT is in contrast to the analysis of rail infrastructure impacts of ethanol shipping, where baseline levels of traffic were modeled endogenously based on data for origins and destinations of rail shipments obtained from the Public Use Waybill Sample. Treating baseline levels of traffic exogenously may result in an overestimate of the infrastructure impacts of biomass shipping; because existing traffic is not allowed to adjust to the marginal impacts of biomass shipping, modeled traffic flows do not generally represent a global optimum. However, if the marginal impacts of biomass shipping are small, the subsequent reaction of baseline highway loads would likely be insignificant.

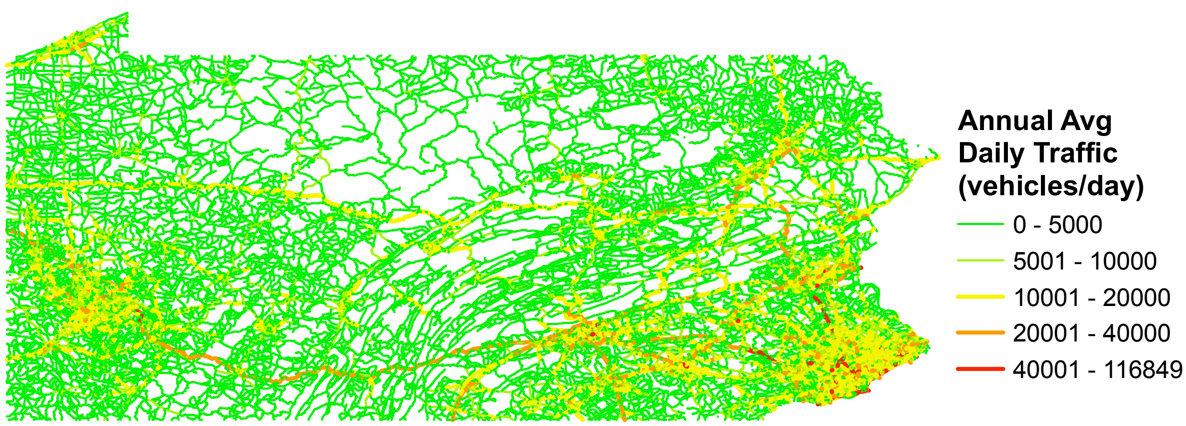

Figure 7-10. Baseline estimates for highway traffic throughout Pennsylvania. Based on data from the Freight Analysis Framework (FAF 1).

To model truck shipments of biomass over the highway network, it was necessary to estimate locations of future cellulosic ethanol refineries. Based on raster-level projections of switchgrass production, cellulosic ethanol facilities were placed using the same *k*-means algorithm that has been used to estimate facility locations in other portions of the analysis. For a detailed description of the algorithm, see Han (2006). Sensitivity analysis examined the impacts of placing facilities at ASD-centroids instead of using *k*-means. While projected facility locations were different, the range of facility sizes and the range of biomass shipping impacts were relatively unchanged.

It was assumed for the base case that a single truck could carry 10 tons of biomass per trip. This estimate is consistent with the truck capacity used in a field trial of corn stover transportation (Glassner 1998), but lower than estimates found in other studies (Mahmudi 2006). Should truck capacities be higher than 10 tons per trip, the results here would overestimate infrastructure impacts of biomass shipping. It was also assumed that trucks carrying biomass would return unloaded to the collection site along the same path that was taken from the collection site to the facility, corresponding to an empty return ratio of 2.0.

Finally, truck shipments of biomass were routed over the highway network from origins (tracts of land used identified as sources of forest biomass) to destinations (cellulosic ethanol refineries) using Dijkstra's algorithm. Routes for all biomass shipments were then superimposed to generate an estimate for the total network load represented by biomass shipments.

Figure 7-11 shows the results generated in this portion of the analysis, displaying both the projected locations of cellulosic ethanol facilities and the estimated highway shipping loads represented by truck shipments of biomass. Cellulosic ethanol refinery capacities range from 18 to 122 million gallons of ethanol per year, with smaller facilities located in the southeast portion of the state where biomass availability is lower. Highways are symbolized by the number of truck shipments of biomass flowing over each link, provided in truck per day, with increasing loads going from green to red.

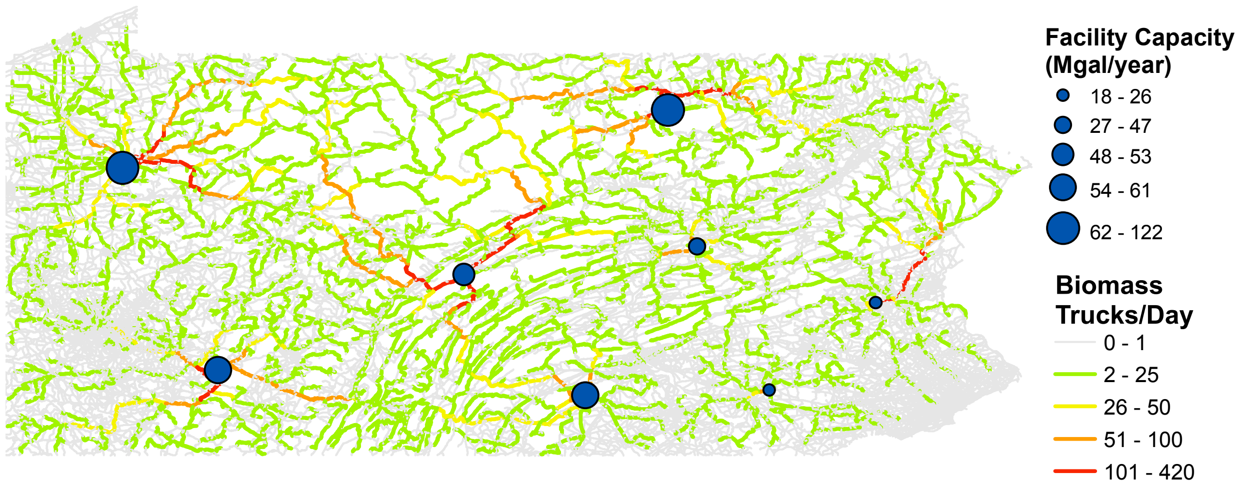

Figure 7-11. Projected cellulosic facilities capacities and locations and additional highway loads resulting from biomass shipping.

Figure 7-11 shows that biomass shipping loads are greatest near ethanol refineries, with loads climbing as high as 420 truck trips per day along highways leading directly to cellulosic biorefineries. In general, the highway loads represented by truck shipments of biomass are significantly less than current levels of estimated traffic. Figure 7-10 shows that highways through and around major cities feature an annual average daily traffic level of 10,000 vehicles or more, two orders of magnitude greater than the heaviest biomass shipping loads.

The fact that current traffic levels on major highways greatly exceed the maximum loads estimated from truck shipping of biomass does not necessarily mean that marginal loads from biomass shipping will not lead to congestion. The heaviest biomass shipping loads tend to be found near large facilities in northern parts of the state, in areas with AADT levels much lower than those estimated around large cities. A comparison of projected biomass shipments to current levels of traffic shows that truck shipments of biomass would increase traffic flows by 10% or more on 290 miles throughout the state of Pennsylvania, and would more than double currently estimated traffic flows on 25 miles of road. The 290 miles experiencing a load increase of 10% or more represent less than 1% of highway miles, but if areas with low traffic flows are also characterized by low levels of roadway capacity, then these impacts could lead to localized congestion problems.

However, it is likely that roadway capacity even in these low-volume rural areas is sufficient to accommodate additional biomass truck traffic. The Federal Highway Administration (FHWA) provides guidelines for estimating highway capacity for roads ranging from freeways to rural one-lane highway (FHWA 2008). The procedures outlined by the FHWA rely on detailed information about roadways, such as lane width, percentage of traffic represented by trucks, and percentage of roadway where passing is not allowed, to generate precise estimates of capacity for specific sections of highway. Though the data required to generate these estimates is not available on a link-by-link basis for the shapefile used here, FHWA guidelines can still be used to create ballpark estimates of highway capacity.

For rural two-lane highways, FHWA guidelines begin with an estimate of 3200 passenger cars per hour, and then adjust that estimate downward based on terrain, percentage of traffic represented by heavy vehicles, and percentage of roadway with passing restrictions. Using values in the middle of the range of numbers provided by FHWA for each of the adjustment parameters generated a best guess capacity estimate of 1350 passenger cars per hour, with a range of 340 to 2800 cars per hour generated by using extreme values for the adjustment factors. Figure 7-11 indicates that the additional loads from truck shipping of biomass can be as high as 420 trucks per day, or roughly 18 trucks per hour. After converting this value into passenger car equivalents, the maximum traffic load represented by biomass shipping represents about 2% of the best guess capacity estimate. For the lowest capacity estimate, an additional 420 trucks per day represents 13% of estimated capacity (where the increase from 2% is due to both decreased capacity and a larger passenger car equivalent conversion factor). While an increase of 13% of capacity could have impacts on local traffic flow, this estimate represents an upper bound generated based on the maximum level of added biomass shipping and very pessimistic assumptions about highway terrain and conditions.

Furthermore, the greatest biomass shipping loads are realized near cellulosic ethanol refineries, rather than near feedstock collection, so congestion could be greatly reduced by siting refineries in areas with ample highway capacity. Siting refineries in areas with an average level of highway capacity would likely push the percentage of highway capacity represented by biomass shipments closer to the best guess of 2%, avoiding any congestion impacts that could result from siting them in areas with poor highway accessibility.

Costs from roadway deterioration are also expected to be relatively small. Transporting cellulosic feedstocks from collection sites to ethanol refineries is estimated to add 160 million ton-miles to highway networks throughout Pennsylvania, with an average shipping distance of 30 miles for the 5.3 million tons of cellulosic feedstock. To estimate the roadway damage resulting from these shipments, FHWA provides estimates for unit costs per payload-mile for a variety of truck type and roadway type combinations (FHWA 2000). For local rural roads that may bear the majority of the feedstock shipping load, pavement costs are as high as $0.38 per thousand ton-miles. (Unit costs are lower for other roadway types, or if trucks with more than three axles are used.) Given the 160 million ton-miles represented by cellulosic feedstock shipments, pavement deterioration costs from cellulosic ethanol shipments amount to $60,000 per year, or about one cent for each of the 5.3 million tons of feedstock used for ethanol production.

The lack of significant congestion or roadway deterioration, however, does not necessarily guarantee that future shipments of cellulosic biomass will not have negative impacts on infrastructure. The volume of cellulosic feedstock required to meet cellulosic ethanol production targets may represent a significant increase from current levels of agricultural production and forest removals, especially at a regional level. Figure 7-12 compares projections of cellulosic feedstock availability required to meet the 21 billion gallon cellulosic ethanol target found in EISA 2022 to current levels of both agricultural production and estimated forest removals. For each of the lower 48 states, Figure 7-12 displays the ratio of projected cellulosic feedstock supply within that state to the total tons represented by both agricultural production (including barley, corn, hay, soybeans, and wheat) and forest biomass removals. Data on crop production were obtained from USDA (NASS 2010) and data on removals of forest biomass were obtained from the National Forest Service (Smith 2004).

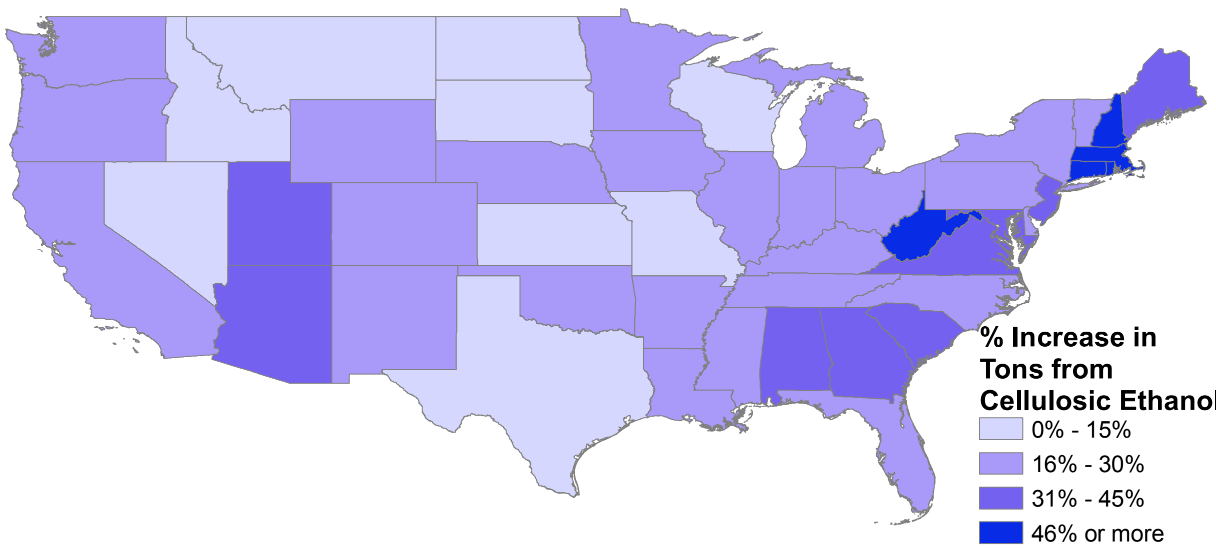

Figure 7-12. Biomass feedstock availability projections as a percentage of current crop production and forest removals.

Figure 7-12 shows that production of cellulosic feedstocks represents a significant increase in agricultural and forestland production. For most states on the eastern half of the United States (where cellulosic feedstocks are expected to be available in large quantities), production of cellulosic feedstocks required to meet the 21 billion gallon ethanol target increase agricultural and forest output by at least 16%, and some states along the Atlantic coast would see their agricultural and forest output increase by 30% or more. Transporting these feedstocks is unlikely to lead to major congestion or pavement deterioration costs for the reasons discussed above, but such a dramatic increase in agricultural and forest output could increase demand for infrastructure required to produce, harvest, collect, and transport feedstocks well beyond existing levels. Future work should investigate whether constraints on the availability of these types of equipment could hinder the production and use of cellulosic biomass as an ethanol feedstock.

7.6. Conclusions

Domestic ethanol production has increased dramatically in recent years and is expected to continue to increase to 36 billion gallons per year by 2022. Distributing ethanol as E85 in regions where the fuel can be produced has advantages over other distribution scenarios. In addition to the shipping cost reductions discussed in Chapter 6, shipping ethanol regionally would avoid adding the 30 to 120 billion ton-miles to the rail network that could result from national distribution, or the 150 billion ton-miles that could result from a scenario in which California runs on E85. These load increases represent increases of 1.5% to 9% of the total current rail freight load, potentially leading to local congestion impacts, especially on rail lines connecting the Midwest to the Pacific coast that already handle significant freight traffic. While estimates for congestion costs resulting from ethanol shipments depend heavily on assumptions about rail line capacity and current levels of freight traffic, some scenarios result in congestion cost estimates on the order of the private cost of ethanol shipping. Although regional distribution of E85 would require investment in flex fuel vehicles and other distribution infrastructure, it would largely erase the rail freight congestion costs of ethanol shipping, lowering the social cost of using biofuels to meet transportation energy demands.

Shipments of biomass over road networks, on the other hand, are unlikely to lead to major congestion impacts. Maximum shipping loads resulting from biomass shipments are at least two orders of magnitude lower than estimates for highway capacity, even around large cellulosic ethanol facilities where the marginal impact of biomass shipments is estimated to be the most intense.

8. Brazilian Ethanol Infrastructure

8.1. Introduction

The Brazilian Alcohol Program was established in 1975 to encourage the production of ethanol from sugarcane within Brazil (Goldemberg 2004). The program was motivated primarily by a desire to reduce oil imports, but also by military concerns about national sovereignty, low sugar prices, and a desire to avoid the bankruptcy of sugar industrialists, and used measures including subsidies and alcohol import tariffs to encourage domestic production (Puppim de Oliveira 2002). In the early stages of the program, production costs for sugarcane-based ethanol were near $100 per barrel, but quickly dropped after 1985 when federal pricing policies changed (Goldemberg 2004), while ethanol production grew to over 10 billion liters by 1990 (UNICA 2010).

Recently, ethanol production within Brazil has surged. Between 1990 and 2005, ethanol production remained between 10 and 15 billion liters per year, but by 2008, production had grown to over 27 billion liters (UNICA 2010). Production of sugarcane ethanol within Brazil is expected to continue to expand rapidly, reaching 47 and 65 billion liters by 2015 and 2020, respectively (USDA 2009).

Ethanol produced from sugarcane in Brazil has a number of advantages ethanol produced in the United States from either corn or cellulosic biomass. Sugarcane produced in Brazil is highly productive, yielding 35 tons per acre, compared to 8.4 tons per acre for corn (Hoffstrand 2009) and 4 to 10 tons per acre for switchgrass grown in the United States

(McLaughlin 2005). Sugarcane ethanol refineries operate at a high level of efficiency, as sugarcane bagasse (or the residue remaining after the sugar has been extracted) can be burned to not only power the refinery but also export energy to the grid. Agricultural operations within Brazil also rely more heavily on manual labor and require less petroleum energy than similar operations in the United States. These factors contribute to sugarcane ethanol's superior energy balance. The net energy ratio, indicating the ratio of output energy to input energy requirements, is estimated to be 8 to 10 for sugarcane ethanol (Macedo 2004), compared to 1.2 to 1.3 for corn ethanol (Farrell 2006, Shapouri 2002, Hill 2006), and 4.4 to 6.1 for cellulosic ethanol produced from switchgrass (Hammerschlag 2006, Schmer 2008).

The superior efficiency of sugarcane ethanol production to ethanol production from corn or cellulosic biomass leads to advantages from economic and environmental standpoints as well. Sugarcane ethanol produced in Brazil and corn ethanol produced in the U.S. have historically had similar production costs (Gallagher 2006), but recent increases in corn feedstock prices have elevated corn ethanol production costs by 50% of more. And while production costs for a mature cellulosic ethanol industry may be at or below those for corn and sugarcane ethanol (Aden 2002, Phillips 2007), near term production costs (Hamelinck 2005) are roughly twice as high as those for sugarcane ethanol.

From an environmental perspective sugarcane ethanol matches the expected greenhouse gas reductions of cellulosic ethanol and far exceeds those from corn ethanol. Life-cycle greenhouse gas emissions for sugarcane ethanol are estimated to be 19 g CO_2–equivalent per megajoule (Macedo 2008), offering a reduction of 80% compared to the carbon intensity of gasoline. On the other hand, corn ethanol as currently produced offers little or no reduction in greenhouse gas emissions compared to gasoline (Farrell 2006), though switching to energy sources such as natural gas or biomass can improve environmental impacts significantly (Wang 2007). Cellulosic ethanol production may actually result in fewer greenhouse gas emissions than sugarcane ethanol, especially if produced from crop residues (Sheehan 2003) or prairie grasses (Tilman 2006), but both fuels offer substantial reductions compared to gasoline.

Due to the economic and environmental advantages sugarcane ethanol has over other biofuels, future environmental goals for transportation energy in the United States may be met most efficiently by importing a substantial volume of the fuel from Brazil. In 2008, the United States imported 400 million gallons of sugarcane-derived ethanol directly from Brazil and another 350 million gallons via Caribbean Basin Initiative countries not required to pay the import tariff (USDA 2009), together representing about 10% of corn ethanol production (RFA 2010b). Despite the $0.54 per gallon tariff currently imposed on ethanol imports, sugarcane ethanol imports may increase substantially in the future, especially if production within Brazil increases to the anticipated levels previously mentioned.

The goal of this analysis is to model distribution of ethanol within Brazil in order to quantify the transportation costs and impacts for Brazilian ethanol exports as production of sugarcane ethanol and exports to the United States expand. By explicitly modeling shipping requirements for transportation Brazilian ethanol to the U.S., this analysis can help clarify the environmental impacts of imported ethanol in an effort to inform policy decisions regarding transportation energy in the United States.

8.2. Data Sources

Data for locations and capacities of ethanol refineries in Brazil were provided by Mirna Ivonne Gaya Scandiffio at the Bioethanol Science and Technology Center in Campinas, Sao Paulo, Brazil. The data set contains information on 281 ethanol plants found throughout the country of Brazil, including plant name, state, and production capacity.

Plant location information was determined at the municipality level, assigning each plant to the centroid of the municipality in which it resides. To put this level of spatial resolution in perspective, the country of Brazil contains roughly 5500 municipalities, while the United States contains roughly 3100 counties. The total land area of Brazil is about 10% less than the area of the United States, so the average municipality is about half as large as the average U.S. county. Because this study is interested in quantifying ethanol shipping distances at the national level, estimating ethanol plant locations based on municipality centroids (rather than coordinates representing the plant themselves) is unlikely to significantly influence the results.

Two types of ethanol demands were modeled in this portion of the analysis: 1) domestic ethanol demand allocated to large Brazilian cities and 2) ethanol for export assigned to major Brazilian ports. Domestic ethanol demands were modeled by allocating Brazil's annual ethanol consumption to the 300 largest cities in Brazil (which account for roughly

50% of the country's total population) in proportion to the population of those cities. It was assumed that ethanol would be shipped first to bulk blending and distribution stations located at these major cities, then distributed from these sites to smaller, rural demands.

Exported ethanol was required to be shipped to one of five major Brazilian ports: Santos, Paranagua, Vitoria, Rio de Janeiro, or Rio Grande. These five ports are located in five different states, providing the model with the flexibility to choose a location close to plants producing ethanol for export.

Figure 8-1 illustrates the distribution of both ethanol production (aggregated at the state level) and population (assigned to the 300 largest cities) throughout Brazil. Figure 8-1 shows that the majority of both ethanol capacity and population are found in the southern portion of the country, primarily in the states of Sao Paulo, Minas Gerais, and Parana.

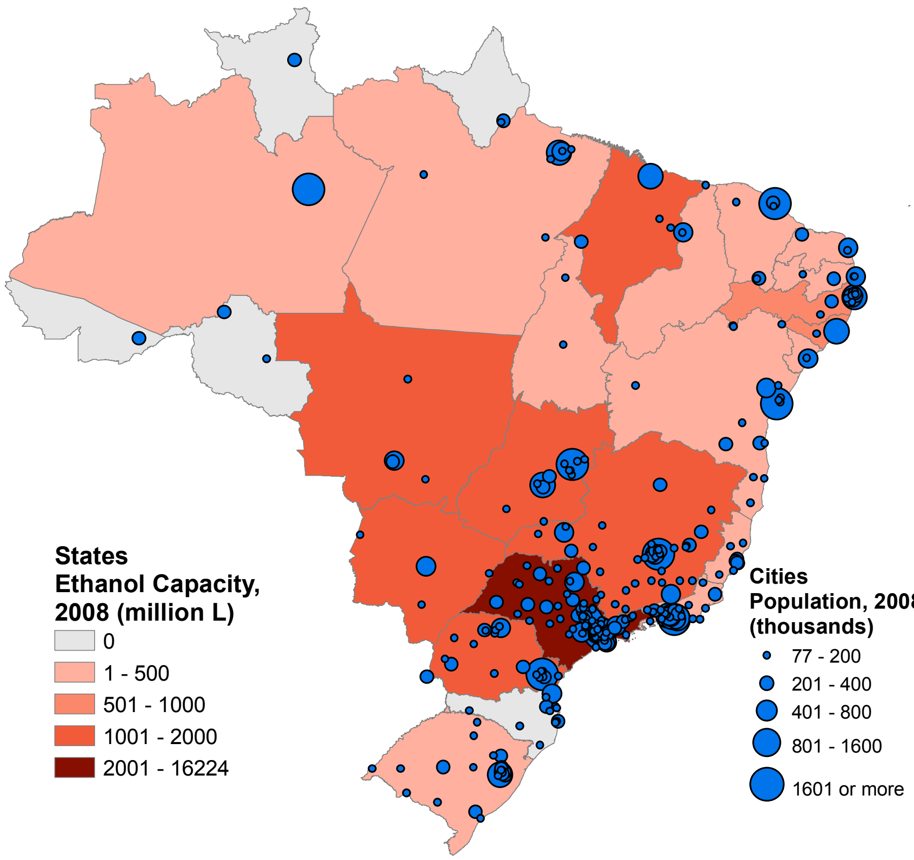

Figure 8-1. Ethanol production and population distributions throughout Brazil.

8.3. Methods

8.3.1. Model Formulation

Ethanol shipments from origins (state centroids) to destinations (cities and ports) were modeled using a linear program (LP) similar to those used to model ethanol shipments within the United States by Morrow (2006b) and Wakeley (2009). The LP formulation used for this analysis is slightly different, however, because the exported ethanol is not assigned to a specific port. Rather, the total ethanol shipped to major Brazilian ports for export is set equal to a given quantity and the LP determines the quantity of ethanol received by each port in such a way that minimizes the objective.

The objective function for the model represents the total ton-miles of ethanol shipped, where x_{ij} (the decision variable) stands for the amount of ethanol shipped from plant i to demand j (in tons) and d_{ij} represents the distance from plant i to demand j.

$$Minimize \sum_i \sum_j x_{ij} \times d_{ij}$$

There are only two constraints for the model. Constraint (1) ensures that all ethanol is shipped from each ethanol plant (where S_i represents the capacity of plant i, in tons of ethanol per year), and (2) ensures that ethanol demand for each Brazilian city is met (where D_j represents the ethanol demand of city j in tons of ethanol per year).

$$\sum_j x_{ij} = S_i \tag{1}$$

$$\sum_i x_{ij} = D_j \forall j \in Cities \tag{2}$$

Two scenarios were run to model future ethanol distribution within Brazil: a near-term scenario that assumed a 10% increase in ethanol production capacity, and a long-term scenario based on a 100% increase in ethanol production capacity. For both scenarios, domestic ethanol demand was estimated based on current levels of ethanol consumption, allocated to Brazilian proportionally to population. As a result, the total ethanol supply is greater than the total ethanol demand $\left(\sum_i S_i > \sum_j D_j\right)$ for both scenarios. However, the set of demands also contains five locations identified as potential sites for export. While none of these ports have explicit demands that must be met by the LP, shipping ethanol not demanded by domestic cities to these ports is the only way the LP can satisfy constraint (1). Thus, the above constraints implicitly require excess ethanol to be shipped to one of the five major ports identified above, with the LP choosing the ports to ship to in such a way that minimizes the objective.

8.3.2. Model Parameters

Ethanol shipping within Brazil may differ significantly from ethanol shipping within the United States, where 60% of ethanol shipping travels via rail, 30% via truck, and the remaining 10% via barge (USDA 2007). First, estimates of the size of the rail freight network throughout Brazil range from 16 to 20 thousand miles (Martins 2008, Shapefile source), and order of magnitude less than the estimated 170 thousand miles of track operated by Class I freight railroads in the U.S. (AAR 2008). Second, truck shipping dominates freight transportation in Brazil, accounting for 82% of the total freight load and 94% of freight shipping expenditure in 1999 (De Castro 2001), compared to 28% and 42% for the percentage of load and revenue represented by truck shipping in the U.S. (BTS 2010). Even within the United States, with a mature, efficient, productive rail freight network, ethanol shipments traveling a distance of 250 miles or less travel via truck due to logistical concerns and the increased flexibility of truck shipping (Shapouri 2005). Thus, it was assumed that all shipments of ethanol from plant to port within Brazil travel via truck shipping.

To accurately model truck shipping within Brazil, a country-specific circuity factor for truck transportation was estimated using distances between pairs of the 300 largest Brazilian cities. For each pair of cities, the great circle distance was first calculated. An algorithm was then run to calculate the shortest path along a network representing primary roads throughout Brazil. The distance of the shortest path was estimated as a function of the great circle distance using a simple linear regression. The results are shown in Figure 8-2, with the estimated truck circuity factor of 1.34 represented by the slope of the linear fit. This estimate is slightly higher than the factor of 1.23 used for truck shipping in the United States (Morrow 2006), an expected result given the higher density of the highway network in the United States. The cost of truck shipping was assumed to be $0.22 per ton-mile (Morrow 2006), while emissions for truck shipping were taken from the environmental input-output life cycle assessment model (GDI 2010).

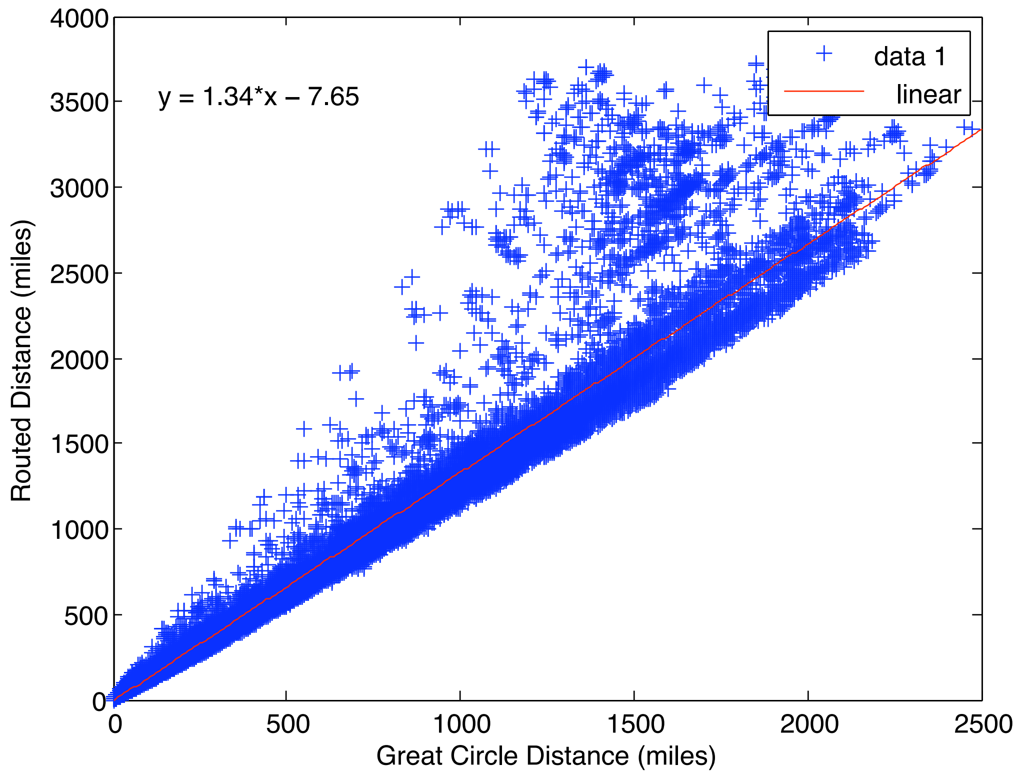

Figure 8-2. Great circle distance vs. routed distance along truck shipping network.

8.4. Results

8.4.1. Shipping Distances

Figure 8-3 provides a plot of the configuration of ethanol shipments produced by the optimization model. The results shown in Figure 8-3, Figure 8-4 and Figure 8-5 are generated for the base case assumption of an increase in ethanol production capacity of 10% from current levels. For the results presented in Figure 8-3, ethanol plant locations are symbolized by blue plus signs. Domestic ethanol demands are represented by red X marks, and major Brazilian ports are symbolized by green asterisks. Shipments of ethanol from plants to domestic demands are shown in blue, while shipments of ethanol to ports for export are shown in green.

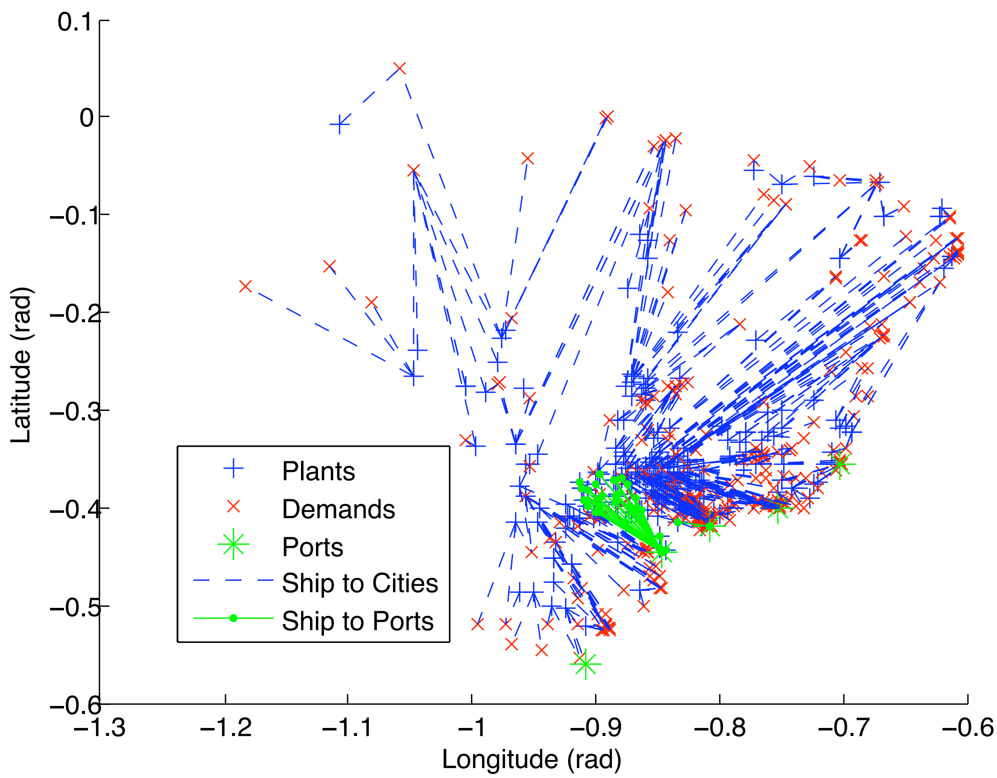

Figure 8-3. Optimal shipping configuration, current production + 10%.

Figure 8-3 shows qualitatively that not all projected Brazilian ethanol demands are located close to ethanol plants. While the bulk of the ethanol production capacity is located in the southern portion of the country, a considerable amount of population (and assumed ethanol demand) is found the northeast portion of the country, specifically along the northeast coast. Ethanol supplied to these demands, then, is often produced at plants located in the southern portion of the country and is required to travel a large distance to reach its destination.

Figure 8-4 provides the cumulative distribution of estimated ethanol shipping distances within Brazil. While roughly half of all ethanol travels a distance of 250 miles or less, about

10% of ethanol travels a distance greater than 800 miles. These large shipping distances generally result from supplying ethanol to cities in the northern half of the country, located far from ethanol production sites. Shipping distances as high as 1300 miles are required to meet the ethanol demand of all major cities, resulting in an average shipping distance of 280 miles.

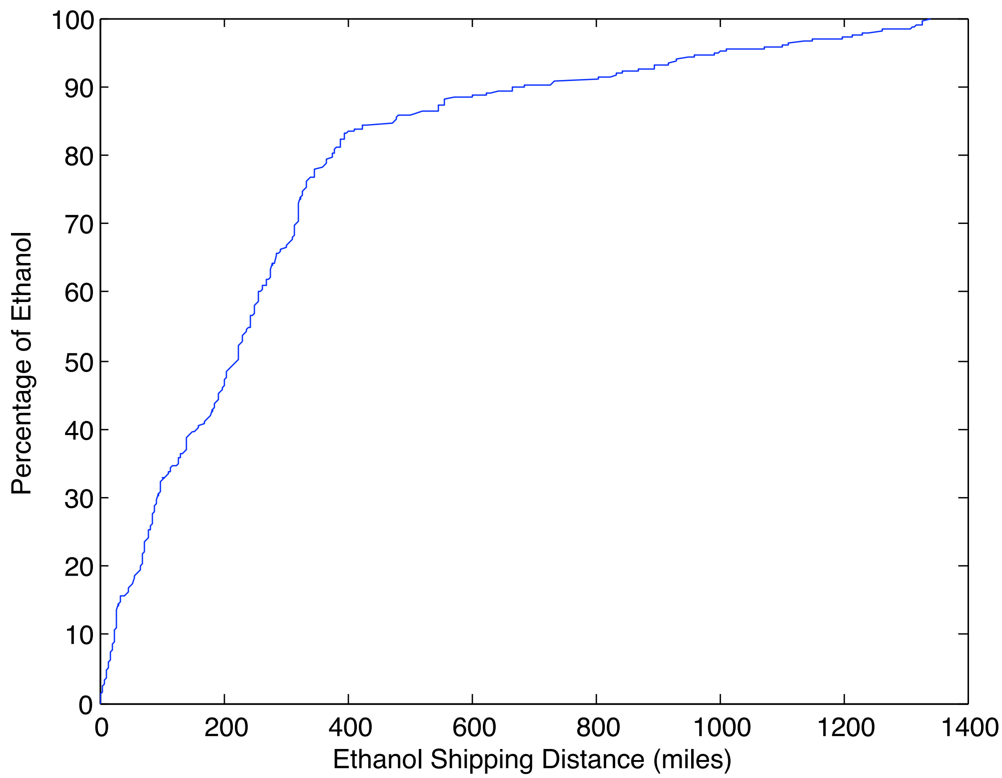

Figure 8-4. Shipping distance CDF, current production + 10%.

Of particular interest to this study are the shipping distances for exported ethanol. Figure 8-3, which illustrates the shipment configuration generated by the optimization model, shows that shipments of ethanol from plants to ports are largely confined to the southern portion of Brazil, beginning in Sao Paulo and ending at the port of Santos. Overall, the green lines symbolizing shipments of ethanol to ports appear noticeably shorter than those connecting ethanol plants to domestic demands, suggesting that shipping distances for exported ethanol may be significantly shorter than those for all Brazilian ethanol. Figure 8-5 provides a cumulative distribution function for the shipping distances (within Brazil) of exported ethanol. Figure 8-5 shows that the range of shipping distance for exported ethanol is much narrower than the range for all ethanol produced in Brazil. The maximum distance for ethanol shipped to ports is less than 400 miles, less than a third of the maximum shipping distance for all ethanol. However, the decreased maximum shipping distance does not necessarily lead to a significant decrease in the average shipping distance. While no exported ethanol travels a very long distance, little exported ethanol travels a very short distance, either. Figure 8-5 shows that only about 20% of exported ethanol is shipped less than 175 miles to port, compared to about 40% of all ethanol shipments that travel 175 miles or less to reach their destination. As a result, the average shipping distance for exported ethanol is about 240 miles, modestly lower than the 280-mile average estimated for all shipments.

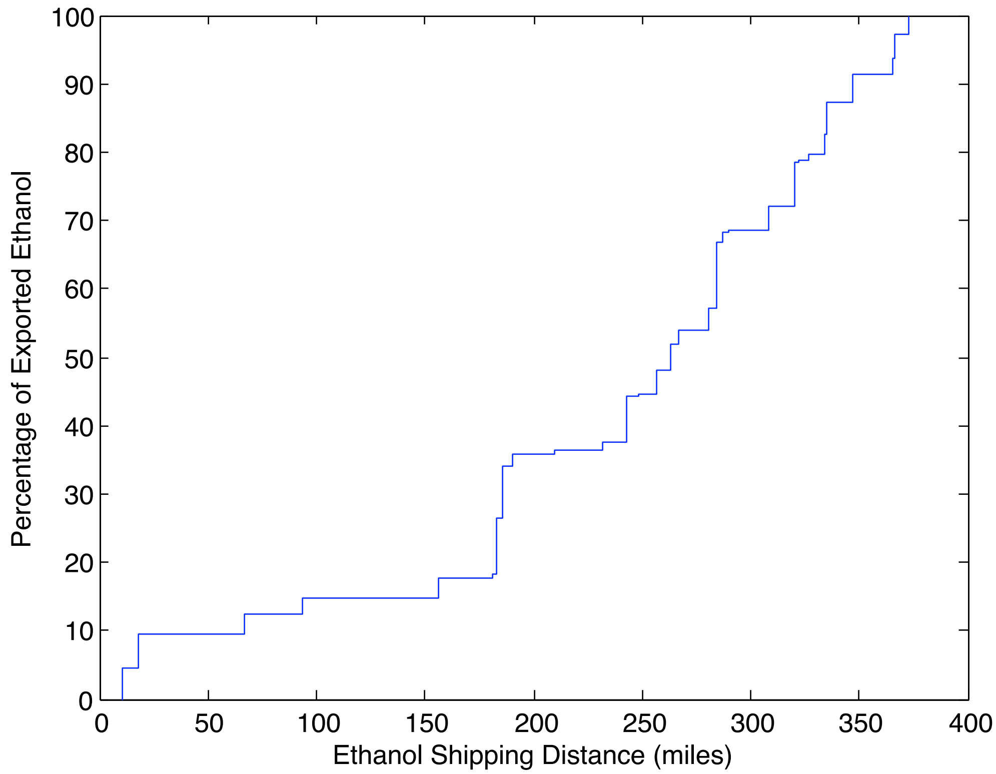

Figure 8-5. Shipping distance CDF, exported ethanol.

Continued increases in ethanol production capacity may result in changes to the shipment configuration and shipping distances modeled in the base case analysis. Therefore, the effects of further capacity expansions were modeled. Figure 8-6 provides the shipment configuration generated by the model assuming an increase in ethanol production capacity of 100%, compared to an increase of 10% for the base case results summarized above. Locations of plants, demands, and ports, as well as shipments of ethanol to demands and ports, are symbolized using the same colors and symbols used in Figure 8-3.

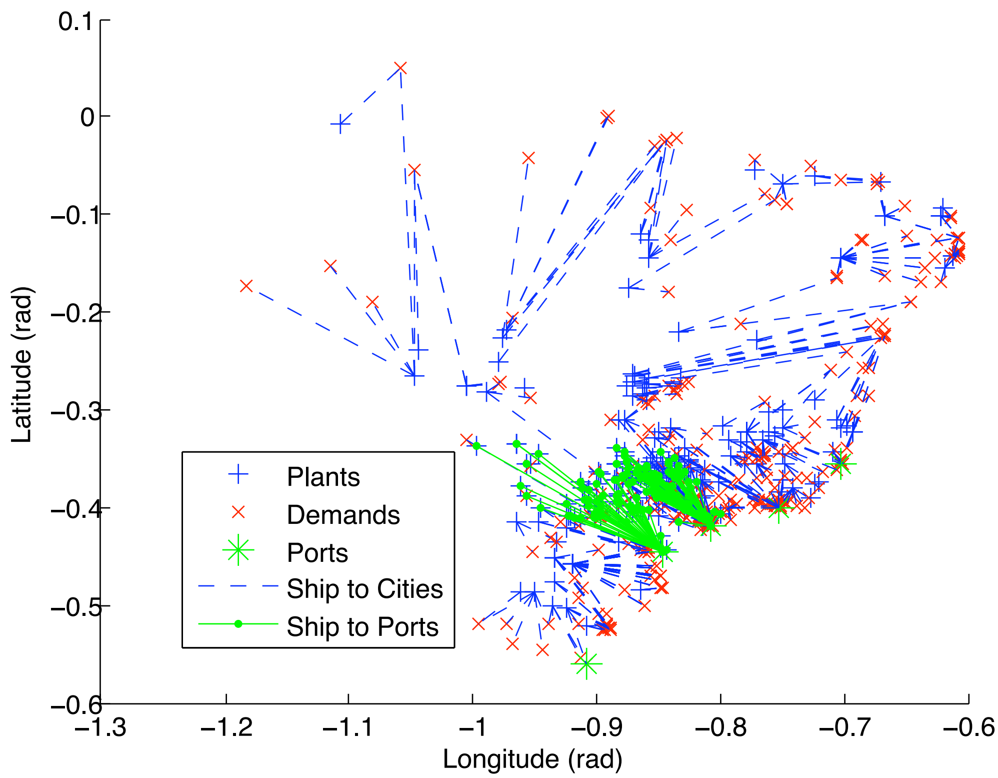

Figure 8-6. Optimal shipping configuration, current production + 100%.

Despite using identical locations for plants, demands, and ports, the shipment configuration generated by assuming a capacity increase of 100% appears substantially different from the base case shipment configuration generated based on an increase of 10%. There appear to be a much greater number of plants shipping ethanol to ports to be exported, shipments represented by green lines in Figure 8-6. Domestic ethanol demand is identical in both Figure 8-3 and Figure 8-6, so changing the added ethanol capacity from 10% to 100% results in a ten-fold increase in the total volume of exported ethanol. There are also far fewer ethanol shipments traveling from plants in the south to demands in north. Figure 8-3, representing the 10% increase assumed in the base case, was marked by a number of ethanol shipments from southern plants to demands along the northern coast. As the total ethanol supply increases, the model is given more flexibility, and is able to meet those northern demands with ethanol produced in the central and northern parts of the country, shifting ethanol produced in the southern regions to ports for export.

Figure 8-7 provides a comparison of the cumulative distribution functions for shipment distance generated by assuming ethanol production increases of 10% and 100%. Figure 8-7 shows that increasing the capacity expansion factor has a significant impact on the distribution of shipment distances. While the two curves are similar for the shortest 50% of ethanol shipping distances (up to about 250 miles), the curve representing a 100% increase in production capacity is greater than the 10% increase curve for greater distances, indicating that increasing production capacity lowers the amount of ethanol shipped long distances. For instance, results generated for the 100% increase case indicate that only 90% of ethanol travels a distance 350 miles, while the corresponding distance for the a 10% increase in capacity is around 750 miles. The reduction in the amount of ethanol shipped these long distances results in a decrease in the average shipping distance to 220 miles, a reduction of over 20% from the base case.

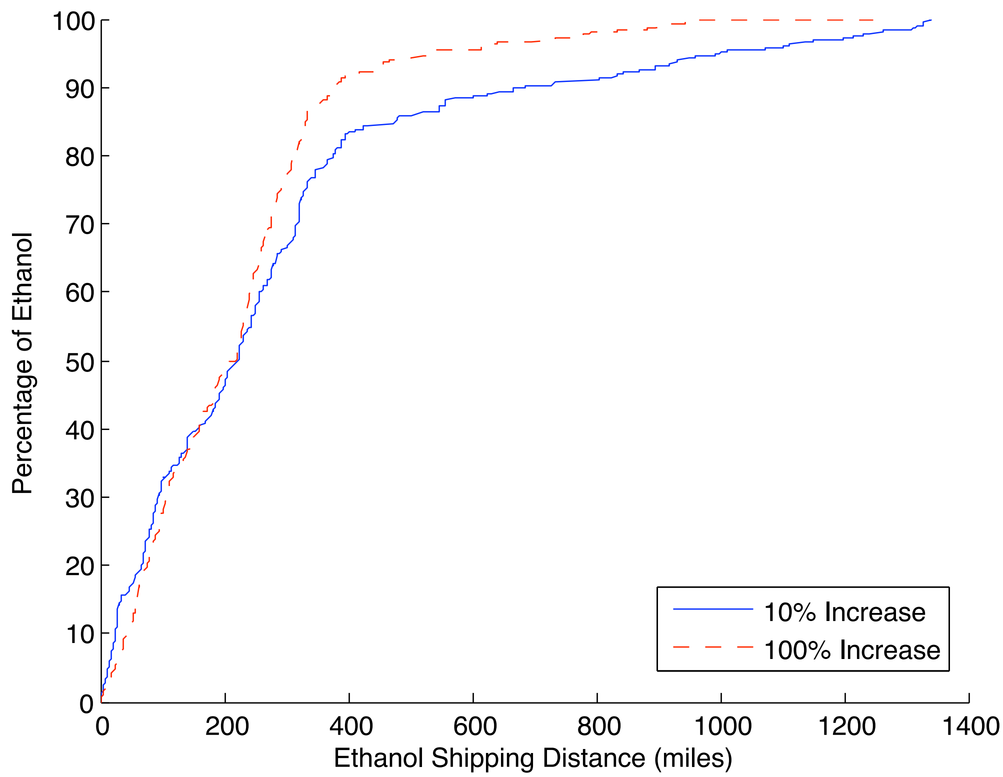

Figure 8-7. Shipping distance CDFs.

Figure 8-8 shows similar curves as those shown in Figure 8-7, but representing only exported ethanol instead of all ethanol produced within Brazil. Figure 8-8 shows that the distribution of shipping distances is somewhat wider for the 100% increase case than for the base case. The maximum shipping distance is also much larger for the 100% capacity increase, reaching almost 700 miles compared to around 375 for the base case. However, only about 5% of ethanol is shipped a distance greater than 450 miles, and the average shipping distance for exported ethanol increases only marginally (to 240 miles) from the base case estimate of 235 miles.

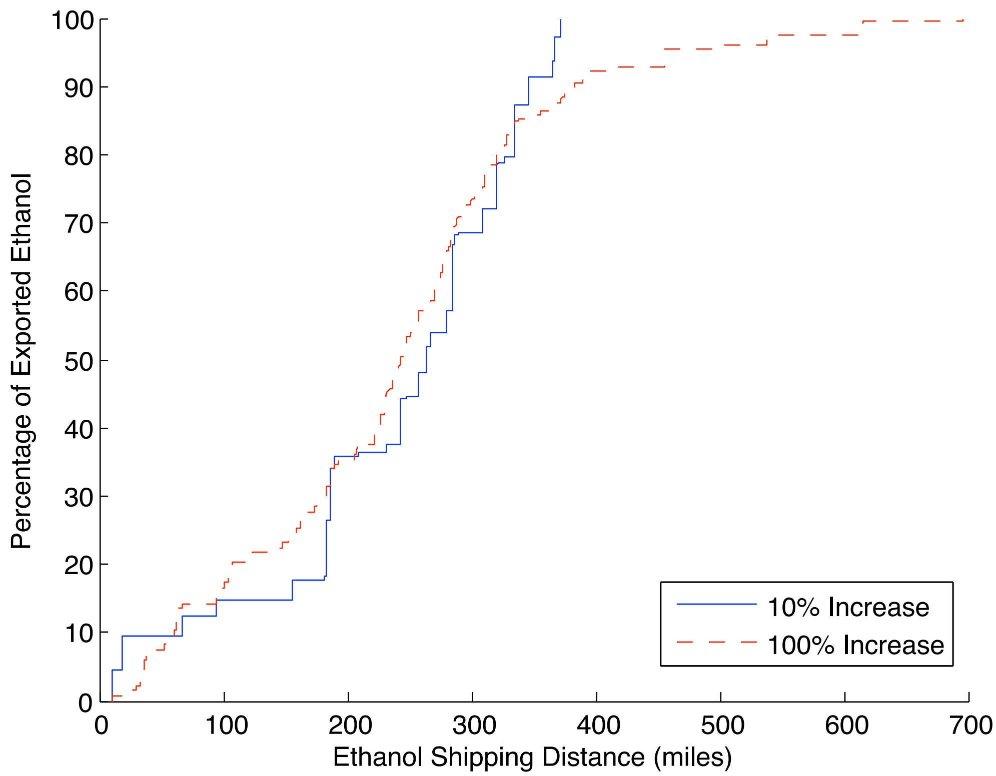

Figure 8-8. Shipping distance CDFs, exported ethanol.

8.4.2. Shipping Costs

Figure 8-9 shows cumulative distribution functions for the estimated cost to ship ethanol from plants to ports for export. Both costs and emissions were estimated as a linear function of shipping distance, so the curves shown in Figure 8-9 and Figure 8-10 have the same shapes as the curves shown in Figure 8-8, but with axes adjusted for the appropriate units. Figure 8-9 shows that for both ethanol export scenarios, roughly half of all ethanol exports incur a shipping cost of $0.25 per gallon or more in traveling from plant to port. While shipping costs for the 10% increase in production are capped around $0.35 per gallon, the more aggressive growth scenario features a longer tail, with the 10% most expensive ethanol costing $0.35 per gallon or more to reach a port.

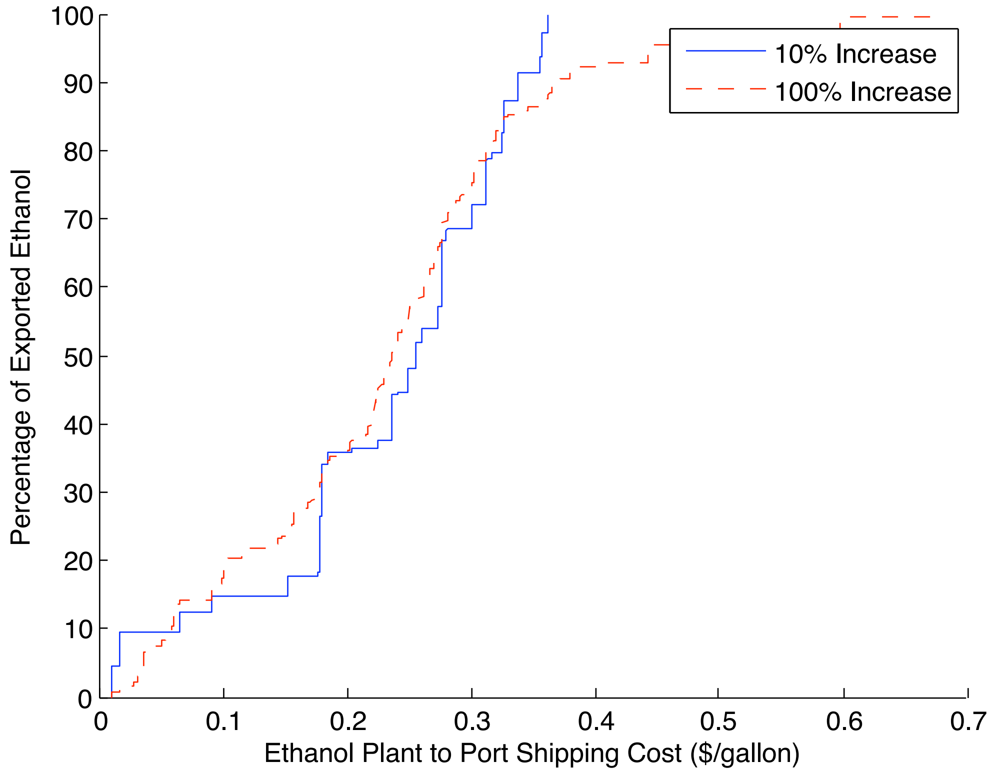

Figure 8-9. Shipping cost CDFs, exported ethanol.

The estimates shown in Figure 8-9 indicate that the cost required to ship ethanol from plants to ports may become significant as ethanol exports increase. Given sugarcane ethanol production cost estimates near $1 per gallon, half of all exported ethanol would see a cost increase of 25% or more due to shipping costs required to transport it within Brazil, hindering the ability of ethanol imports to reduce fuel prices within the United States.

8.4.3. Shipping Emissions

Figure 8-10 shows estimated greenhouse gas emissions for shipping ethanol from plants within Brazil to major ports for export. For both scenarios, shipping within Brazil for half of all exported ethanol adds 350 g CO_2 equivalent or more per gallon to the life-cycle emissions. The impact of transportation to port on total emissions is similar to the impact on total cost: assuming life-cycle greenhouse gas emissions of 19 g CO_2 equivalent per MJ at the facility gate (and therefore 1700 g CO_2-eq. per gallon), transporting ethanol to port would increase emissions by 20% or more for half of all exported ethanol.

Despite the added emissions from transportation, sugarcane ethanol imports would still offer major greenhouse gas emission reductions compared to both petroleum-based fuels and corn ethanol, but if sugarcane-ethanol imports would have to compete with next-generation biofuels, then emissions from shipping within Brazil could become important.

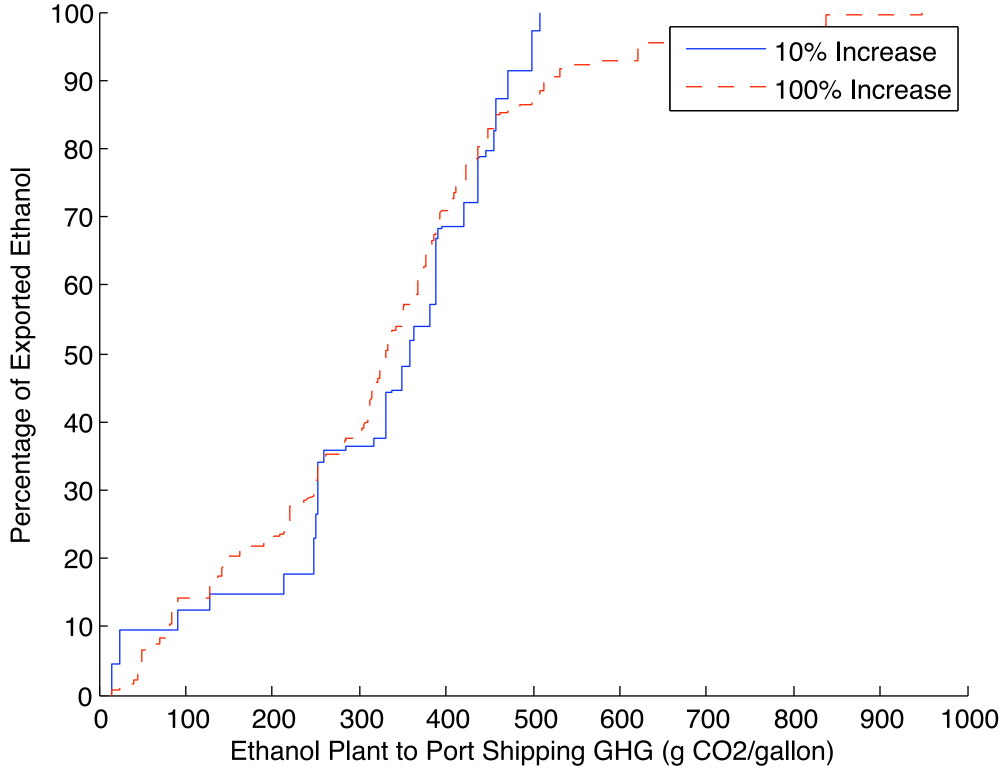

Figure 8-10. Shipping emissions CDFs, exported ethanol.

8.5. Discussion

The results shown above indicate that transporting ethanol from refineries to ports could substantially increase both the cost and life-cycle emissions Brazilian sugarcane ethanol for countries (such as the United States) that wish to import the fuel to help meet economic or environmental targets. There are two assumptions made in this analysis that could significantly impact the results shown in Figure 8-9 and Figure 8-10. The first assumption is that future ethanol production expands spatially in proportion to current ethanol production. If ethanol capacity expansion occurs in areas close to ports, then shipping distances and costs could be significantly less than those estimated in this study. If, on the other hand, future expansion of ethanol production capacity pushes further inland, then shipping costs may actually be underestimated here. The second scenario, in which ethanol production pushes inland, may be more likely. Figure 8-1 shows that existing ethanol production capacity is already heavily concentrated in the state of Sao Paulo, close to major ports; Sao Paulo's current production capacity of over 16 billion liters represents over half of the total production capacity of Brazil. Significant increases in ethanol capacity such as those anticipated in the near future may require expansion into states such as Mato Grosso and Goias. From these states, ethanol is required to travel an upwards of 400 miles to be exported, so increased ethanol production by these states would increase costs relative to those estimated here.

The second assumption that could significantly impact the results estimated here is that all ethanol is shipped from refinery to port via truck. For the reasons discussed in section 8.3.2, it is unclear that Brazil's rail shipping network will be able to handle longer ethanol shipments as effectively as the rail shipping network in the United States. However, if investments are made in rail infrastructure, or barge shipping from plants to ports proves to be both feasible and cost-effective, then the ethanol shipping load within Brazil may shift from truck shipping to other modes. Such a shift would drive the costs and emissions from shipping ethanol to ports lower than the values estimated here.

8.6. Conclusions

Imports of sugarcane ethanol produced in Brazil represent a promising option for meeting transportation energy goals within the United States. Costs and emissions of ethanol produced from sugarcane compare favorably with those for both petroleum and domestic biofuels, and production of sugarcane ethanol is projected to increase significantly in the near future. This study further investigates the impacts of importing Brazilian ethanol by modeling ethanol distribution within Brazil, specifically quantifying shipping distances for ethanol exports. Due to relatively long shipping distances between plants and ports, and the heavy reliance of Brazilian freight transportation on truck shipping, shipping ethanol from plants to ports for export is estimated to add an average of $0.25 and 350 g CO_2 to the cost and emissions of the fuel, respectively. While imports of sugarcane ethanol remain an appealing candidate for meeting the transportation energy demands of the light-duty fleet in the United States, the costs and emissions of the fuel transportation represent significant impacts that should be considered when shaping fuel policy.

9. Optimizing National Motor Vehicle Fuel Distribution

9.1. Introduction

In recent years, ethanol has begun to play a role in meeting transportation energy demand for the light-duty fleet in the United States. Domestic production of ethanol from corn has increased dramatically over the past decade, growing from 1.8 billion gallons in 2001 to 9 billion gallons in 2008 (RFA 2010b). In 2010, corn ethanol plants within the United States had a collective production capacity of 13.5 billion gallons with another 1.2 billion gallons of capacity under construction (RFA 2010a). The recent growth in corn ethanol production may be equaled by future growth in domestic production of cellulosic ethanol. The 2007 Energy Independence and Security Act (EISA) established the second Renewable Fuel Standard (RFS 2) requiring that at least 36 billion gallons of ethanol be produced domestically by 2022. Corn ethanol production is capped at 15 billion gallons per year, with advanced biofuels (such as cellulosic ethanol) comprising the remaining 21 billion gallons per year (EISA 2007).

Ethanol imports may also increase in the future. In 2008, the United States imported 400 million gallons of sugarcane-derived ethanol directly from Brazil and another 350 million gallons via Caribbean Basin Initiative countries not required to pay the import tariff, together representing about 10% of corn ethanol production (USDA 2009). Total production of sugarcane ethanol within Brazil is expected to grow from 27 billion liters in 2008 (UNICA 2010) to 65 billion liters by 2020 (USDA 2009), and with recent legislation explicitly valuing low-carbon fuels such as sugarcane-derived ethanol (CARB 2009b), the United States may be motivated to significantly increase import volumes.

However, vehicles and distribution infrastructure may limit future increases in domestic ethanol consumption (from corn, biomass, or sugarcane). Conventional vehicles are limited to running on fuel blends containing 10% ethanol (E10) or less due to concerns about engine corrosion resulting from fuels containing alcohol. Given the light-duty fleet's annual gasoline consumption of 140 billion gallons, the E10 blendwall limits national ethanol consumption around 15 billion gallons per year, less than half of the 2022 target established by RFS 2.

Should the U.S. wish to increase the role played by ethanol in meet transportation energy demands beyond the E10 blendwall, a few options are available. One option would be simply to raise the blendwall, possibly to E15 or E20. Preliminary tests have indicated that increasing ethanol blends from E10 to E20 would not present problems for current automotive or fuel dispensing equipment and would not negatively impact the performance of engines found in conventional vehicles (MDA 2008). Other investigations have even found fuel efficiency improvements resulting from ethanol blends ranging from E20 to E30 relative to E10 or gasoline (Shockey 2007). Raising the blendwall to E20 would allow domestic consumption to increase to meet the 36 billion gallon 2022 production target without requiring significant vehicle or infrastructure modifications. However, the long-term impacts of E20 in conventional vehicles are still uncertain, and raising the blendwall to E20 would still constrain ethanol demand if future production grows beyond

36 billion gallons or improvements in vehicle efficiency lower the total demand for transportation energy.

A second option to increase domestic demand for ethanol beyond the E10 blendwall involves promoting distribution and consumption of ethanol as E85, a fuel blend containing 85% ethanol and 15% gasoline, at regional levels. In contrast to simply raising the blendwall to E20, promoting regional E85 would require investment in both vehicles and distribution infrastructure. Flex-fuel vehicles (FFVs) are largely identical to conventional vehicles, but with some engine components modified to resist corrosion from exposure to alcohol. While the marginal cost to produce an FFV instead of a conventional vehicle is on the order of $100, an estimated 7.3 million FFVs have been sold in the United States through 2008, representing only 3% of vehicles in the light-duty fleet (NREL 2008). Increasing levels of E85 distribution would also necessitate investments in infrastructure; due primarily to construction of retail storage tanks, capital investment for 100 million gallons of ethanol to be distributed as E85 could total $50 million (Reynolds 2002). Furthermore, these capital investments present a 'chicken-or-the-egg' problem: consumers and vehicle manufacturers may be hesitant to pay for FFVs if E85 is unavailable, while retailers are unlikely to invest in E85 infrastructure before demand for the fuel has developed.

Despite these challenges, regional distribution of E85 has some advantages over national distribution of E10 or E20. Ethanol supply and demand are generally not co-located, so national distribution of a low-level ethanol blend necessitates high shipping distances and costs to transport ethanol from Midwestern production sites to coastal population centers. Regional distribution of E85 could increase amounts of ethanol demanded within the Midwest, decreasing shipping costs and limiting loads on shipping networks resulting from ethanol shipments. Should ethanol production increase beyond the 2022 target of 36 billion gallons, regional distribution of E85 would be better able to accommodate additional supply than a national distribution scenario, which would again be forced to contend with issues involved with raising the blendwall beyond E20.

The goal of this analysis is to model fuel distribution throughout the United States and analyze the impacts of investment in ethanol infrastructure. The model developed for this study considers fuel production costs, volumes, and emissions for gasoline, corn ethanol, cellulosic ethanol, and sugarcane ethanol, as well as projected fuel demands, in making decisions about fuel use by the light-duty fleet in the United States. The model also considers regional variability in these parameters and explicitly models fuel distribution costs in order to make decisions about regional investment in E85 vehicle and distribution infrastructure. By modeling these tradeoffs and identifying infrastructure investments that can lower costs for a variety of future fuel production scenarios, this analysis informs future ethanol distribution policies.

9.2. Data Sources

9.2.1. Corn Ethanol

Locations and capacities of corn ethanol refineries were obtained from the Renewable Fuels Association (RFA 2010a). With a total nameplate capacity of 13.5 billion gallons per year, corn ethanol production would have to increase by 11% to meet the EISA 2007 target of 15 billion gallons per year. In lieu of modeling the construction of new facilities, future capacities of corn ethanol plants were estimated by uniformly increasing current capacities by 11%.

Economics for corn ethanol production were taken from a USDA survey of corn ethanol producers (Shapouri 2005) that found average dry mill production costs of $0.96 per gallon based on an average yield of 2.66 gallons per bushel. Because future corn prices may be significantly different from the $2.00 to $2.50 per bushel that was typical at the time of the survey, production cost estimates from that report were adjusted to account for potential changes in feedstock price.

9.2.2. Cellulosic Ethanol

Cellulosic ethanol is not currently produced on a commercial scale, so the locations and prices of future cellulosic ethanol sources were modeled based on cellulosic feedstock availability projections and production cost analyses.

Three primary types of cellulosic biomass were considered as domestic cellulosic ethanol feedstocks: switchgrass, corn stover, and wood residues. Spatial supply projections for switchgrass, corn stover, and wood residues were taken from a data set provided by the Energy Information Administration (EIA) that was generated using the POLYSYS model. POLYSYS uses interdependent modules for crop supply and demand, livestock, farmer income, and local environmental conditions to predict the availability of various crops for

305 Agricultural Statistical Districts (ASDs) throughout the United States (University of Tennessee 2000, De La Torre Ugarte 2000). The EIA data set used for this study contains POLYSYS model results for cellulosic biomass prices ranging from $20 to $100 per dry ton, with higher feedstock prices resulting in greater feedstock availability. The EIA data set also contains corn prices for different cellulosic production scenarios, and these prices were used to estimate corn ethanol production costs for different scenarios.

Cellulosic ethanol production cost estimates were taken from a techno-economic analysis performed by Hamelinck (2005). That study estimated production costs for short-, intermediate-, and long-term scenarios. Short-term estimates put costs around $2.75 per gallon (in line with what may be currently achievable by industry (Aden 2009)), while long-term estimates are around $1.00 per gallon (like those estimates generated by NREL, assuming a mature cellulosic ethanol industry (Aden 2002, Wooley 1999)). Short-term cost estimates were used in the base case, and the impact of falling production cost was examined during Monte Carlo simulations. Production cost estimates were adjusted for different feedstocks based on a comparative process and economic analysis performed by Huang (2009) that modeled differences in ethanol production processes using switchgrass, corn stover, and woody biomass.

9.2.3. Brazilian Sugarcane Ethanol

Major coastal cities were modeled as potential sources of Brazilian ethanol imports. The cost of importing sugarcane ethanol was calculated as the production cost at the facility gate in Brazil, plus the cost to ship from plants within Brazil to U.S. ports. Production costs ranged from $0.87 per gallon [Trade Matters source] to $1.47 per gallon (USDA 2009). Shipping costs within Brazil were taken to be $0.25 per gallon (the median value of the distribution estimated in Chapter 8) while shipping costs to reach the United States were calculated based on port to port distances and an average tanker shipping cost of $7 per 1000 ton-miles (BTS 2010).

Despite the economic and environmental advantages sugarcane-derived ethanol may have over other both gasoline and other types of ethanol, United States imports may be limited by Brazilian ethanol production capacity, domestic demand within Brazil, and competition on the demand side from other prospective importers. In lieu of attempting to model these market interactions, a range of maximum import quantities was used in the model. Imported ethanol limits were estimated based on projected growth of Brazilian ethanol production. Ethanol production within Brazil is forecast to climb from about 7.5 billion gallons in 2009 to 17.3 billion gallons in 2021 (USDA 2009). Based on this projection, a range of 1.7 to 10 billion gallons of imported ethanol per year was used in the model. The minimum ethanol import limit was calculated by assuming that the United States imports remain at roughly 10% of total ethanol production within Brazil, as was the case in 2008. The maximum ethanol import limit assumes that all non-United States demands remain constant for the next 12 years and that United States imports grow to match all of the added ethanol production during that time period. For the base case analysis, the midpoint of that range was used.

Figure 9-1, shown below, illustrates the geographical distribution of corn, cellulosic, and sugarcane ethanol sources throughout the United States. Corn ethanol plants, shown in yellow, are clustered in the Midwest, primarily throughout Iowa, Nebraska, and southern Minnesota. Cellulosic ethanol sources are more dispersed than corn ethanol, but are still concentrated in the Midwest and portions of the southeast. Large coastal cities, located along the coasts of the Atlantic, Pacific, and Gulf of Mexico, are modeled as potential sources of imported sugarcane ethanol.

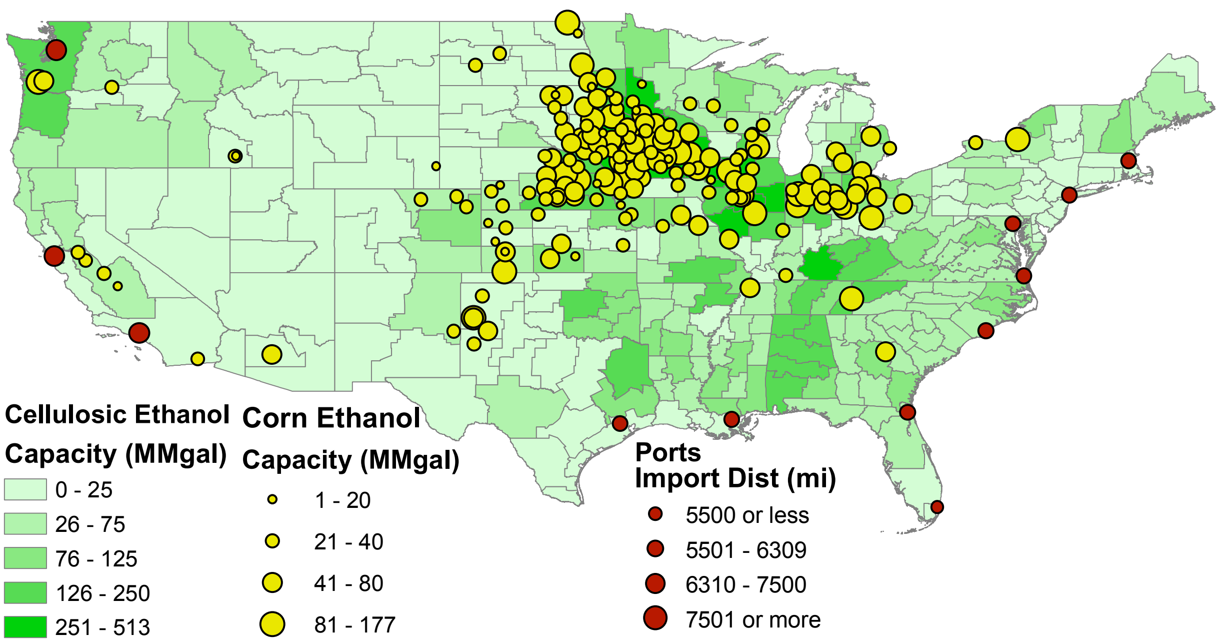

Figure 9-1. Supply locations for corn, cellulosic, and imported sugarcane ethanol.

9.2.4. Gasoline

Supply and distribution of gasoline was modeled based on data for gasoline distribution hubs throughout the United States. Data for the locations and selling prices of 182 domestic gasoline distribution hubs were obtained from Bloomberg. In addition to being the sources of all gasoline supplied to MSAs, these distribution hubs were modeled as blending stations for the blending of ethanol with gasoline. Instead of being shipped directly from plants to MSAs, it was assumed that ethanol would first be transported to one of these hubs, where it would be blended with gasoline before being shipped as a fuel blend to MSAs. Figure 9-2 displays the locations of these distribution hubs along with estimated hub prices, with larger circles corresponding to higher hub prices. Hub prices shown in Figure 9-2 were calculated assuming an oil price of $100 per barrel used for the base case, and were adjusted for different oil prices considered in the analysis.

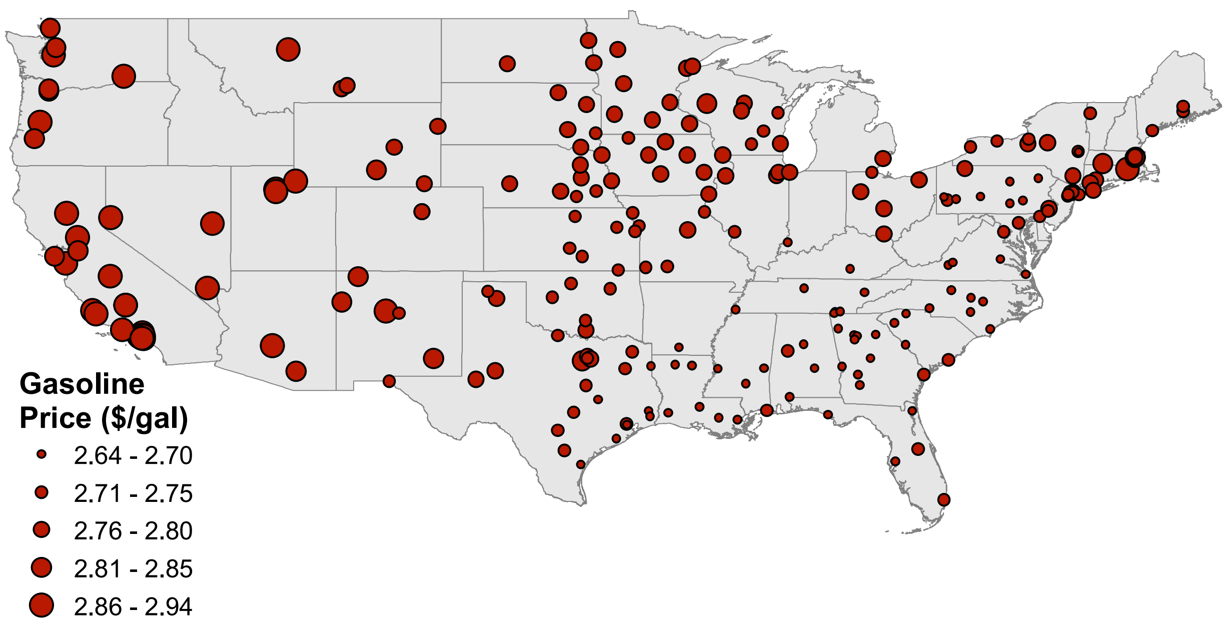

Figure 9-2. Locations and hub prices for distribution hubs throughout the United States. Hub prices calculated assuming $100/barrel oil.

Because the model has the option of displacing significant volumes of gasoline with ethanol, the national average price of gasoline was modeled endogenously as a function of the quantity of gasoline demanded. Displacing gasoline with ethanol is assumed to shift the demand curve for gasoline downward, a shift that results in a lower equilibrium price and quantity than the equilibrium point found before gasoline displacement.

The relationship between gasoline price and quantity demanded was modeled using estimates for the long-run price elasticity of supply for oil. A price elasticity of supply estimate of 0.3 (taken from a meta-analysis of elasticity studies (Espey 1998)) was used in the base case, a value that was varied from 0.1 to 0.5 during the Monte Carlo analysis.

9.2.5. Greenhouse Gas Emissions

For each of the fuels modeled in this study, estimates were obtained for the life-cycle greenhouse gas (GHG) emissions resulting from the production and consumption of the fuel. The cost of GHG emissions was included in the objective function by multiplying the estimated life-cycle GHG emissions of the fuel by a carbon price, used to represent either the value of a carbon tax, the market price for carbon emissions permits, or simply an estimate of the negative externality of carbon emissions.

Table 9-1 provides a comparison of the estimated emissions factors for all six fuel types considered in the model, provided in grams of CO_2 equivalent emissions per megajoule of fuel. For each fuel, three values are provided: one for the non-land use change (LUC) emissions, one for the value of LUC emissions assumed in the base case, and a range of values for LUC emissions used during Monte Carlo analysis. In an attempt to standardize GHG emissions estimates, non-LUC emissions for all fuels except corn stover-derived ethanol were taken from life-cycle analyses performed by the California Air Resources

Board (CARB) used to inform California's Low-Carbon Fuels Standard (CARB 2010). Non-LUC emissions for corn stover-derived ethanol were taken from Sheehan (2004).

For the base case, GHG emissions resulting from LUC were assumed to be equal to 30 g CO_2-eq/MJ, consistent with the estimates from CARB (2010). However, emissions from LUC are highly uncertain, so a wide range of values was used during Monte Carlo simulations. The lower bound is consistent with switchgrass produced on marginal or degraded cropland (where iLUC emissions are negligible), while the upper bound of 100 CO_2-eq/MJ is consistent with results presented in Searchinger (2008). Because corn stover and woody biomass supplies modeled in this study are essentially residues from existing agricultural or forestry operations, no land use emissions were assigned to cellulosic ethanol produced from these feedstocks. Similarly, LUC emissions for gasoline were assumed to be negligible (Yeh 2010).

Table 9-1. Assumed life-cycle greenhouse gas emissions for modeled fuels.

Fuel Type	Non-LUC GHG Emissions (g CO_2-eq./MJ)	GHG Emissions from Land Use Change (g CO_2-eq./MJ)	
	Base Case	Base Case	Monte Carlo Range
Corn Ethanol	65	30	[0, 100]
Cellulosic Ethanol (Corn Stover)	-12	0	0
Cellulosic Ethanol (Switchgrass)	27	30	[0, 100]
Cellulosic Ethanol (Wood Residues)	21	0	0
Sugarcane Ethanol	27	30	[0, 100]
Gasoline	95	0	0

9.2.6. Fuel Demands

Fuel demand was estimated and assigned to metropolitan statistical areas (MSAs) throughout the continental United States. Fuel demand was first estimated on the state level based on current gasoline consumption and state-level population growth rates, assuming transportation energy demand per capita remains constant. Fuel demand was then allocated to MSAs within each state in proportion to their population.

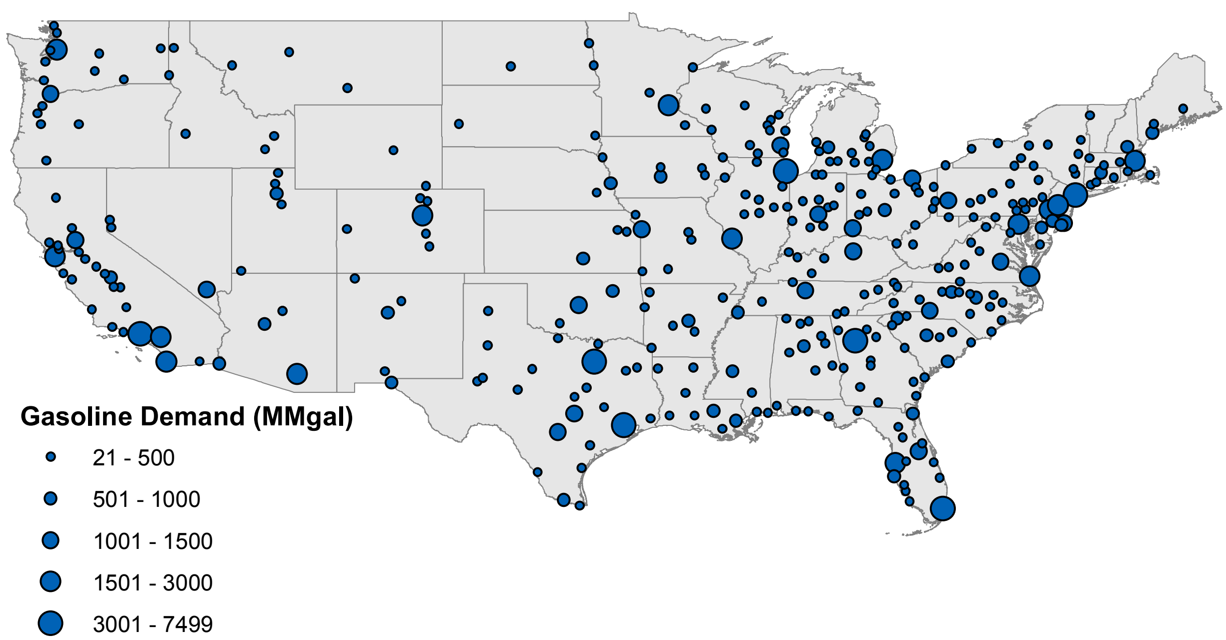

Figure 9-3. Fuel demands throughout the United States, symbolized by annual demand volume in million gallons gasoline equivalent.

It was also assumed that transportation energy demands were independent of the type of fuel (gasoline or ethanol) used to meet that demand. (In other words, gas mileage of the light-duty fleet is proportional the energy content of the fuel.) A gallon of ethanol contains two-thirds as much energy as a gallon of gasoline, so shifting transportation fuel consumption from gasoline to ethanol increases the total volume of fuel required. However, to total energy required was assumed to remain constant. This assumption is consistent with performance of current FFVs. Fuel economy numbers provided by EPA for 96 FFV models manufactured in 2010 indicate that fuel economy when running on E85 drops to 67% to 80% of the estimated fuel economy when running on gasoline, with a simple average across vehicles of 74% (DOE 2010). Because a gallon of E85 contains 72% as much energy as a gallon of gasoline, the simple average drop in fuel economy in moving to E85 is consistent with this assumption. Should the higher octane of ethanol relative to gasoline result in more efficient engine performance (as suggested by the results in Shockey (2007)) and partially offset the decreased energy density of ethanol blended fuels, then the results of this analysis could underestimate the benefits of ethanol.

9.2.7. E85 Infrastructure

In addition to the costs of fuel production and distribution, the model considers some infrastructure investment decisions in minimizing total cost. One of these decisions involves investing in infrastructure required consume E85. This study models two E85 infrastructure components: flex-fueled vehicles (FFVs), vehicles capable of running on fuel blends containing up to 85% ethanol, and retail capacity upgrades specific to E85. By investing in these upgrades throughout a given region, the model can exceed the E10 blendwall imposed on conventional vehicles, allowing for regional ethanol distribution and potential reductions in transportation costs.

The cost of FFV upgrades was modeled as an annual cost at the MSA level equal to the cost to upgrade all new vehicles sold in that MSA from conventional vehicles to FFVs. FFVs represent only minor modification from conventional vehicles, and an FFV upgrade cost of \$100 per vehicle was assumed for the base case (Yost 2006), with a range of \$50 to \$200 per vehicle modeled during the Monte Carlo simulations.

Costs for upgrading retail infrastructure to handle E85 distribution were taken from Reynolds (2002). Reynolds (2002) estimated infrastructure investment costs resulting from expansions in ethanol production, finding that infrastructure costs for low-level ethanol blends (up to E10) were generally less than \$0.01 per gallon, but that investments in retail infrastructure for E85 could cost up to \$0.08 per gallon due primarily to investments in additional storage tanks at retail stations. Reynolds estimated an average cost of \$0.065 per gallon ethanol due to infrastructure requirements, with costs ranging from \$0.04 to \$0.08 per gallon for different scenarios and regions.

9.2.8. Shipping Costs and Emissions

The cost for rail shipping of ethanol was estimated from the Public Use Waybill Sample, a data set representing all shipments traveling across the rail freight network (STB 2008). Regressing the revenue generated by ethanol shipments on respective shipping distance resulted in estimates of \$20 per ton and \$0.023 per ton-mile for the fixed and variable costs, respectively, of ethanol shipping via rail. In the absence of data on the revenue generated by shipments of bulk liquid fuels via other modes, costs for shipping fuels via truck and tanker modes were assumed to be equal to the national average revenue per ton-mile, estimated by the Bureau of Transportation Statistics to be 26.6 and 0.72 cents per ton-mile, respectively (BTS 2010).

Estimates for emissions resulting from truck, rail, and tanker shipping were taken from the EIO-LCA model, an input-output model that estimates sector-level emissions based on economy-wide activities (GDI 2010). Due to an expanded system boundary, emissions estimates from EIO-LCA are often greater than those estimated by process models, but GHG emissions from fuel transportation tend to represent a small percentage of the total emissions resulting from fuel production and consumption. Table 9-2 provides a summary of estimated shipping costs and emissions (both given per 1000 ton-miles) for the modeled transportation modes.

Table 9-2. Assuming shipping costs and GHG emissions for rail, truck, and tanker modes.

Mode	Shipping Cost ($/1000 ton-miles)	GHG Emissions (tons CO2-eq./1000 ton-miles)
Truck	$270	0.38
Rail	$23 (+ $20/ton fixed cost)	0.05
Tanker	$7	0.02

9.3. Methods

9.3.1. Optimization Model Formulation

A linear programming model was formulated to optimize the distribution of fuel for the light-duty motor vehicle fleet throughout the United States. The model considers regional variability in fuel costs, ethanol feedstock production, shipping costs, life-cycle emissions, and vehicle infrastructure in making infrastructure investment and distribution decisions.

The optimization model developed for this portion of the analysis is relatively complex. Therefore, the objective function and constraints shown below will only be discussed qualitatively here.

The objective function for the model seeks to minimize the annual cost of meeting fuel demands throughout the United States, where the annual cost is a function of fuel production, distribution, greenhouse emissions, and infrastructure investment costs:

Minimize:

$$
\begin{aligned}
&\sum_i \sum_h x_i(i,h) \times \left(c_{facility}(i) + c_{ship}(i,h) + c_{ghg}(i)\right) + \\
&\sum_j \sum_{crop} \sum_h x_j(j,crop,h) \times \left(c_{facility}(j,crop) + c_{ship}(j,h) + c_{ghg}(j,crop)\right) + \\
&\sum_k \sum_h x_k(k,h) \times \left(c_{import}(k) + c_{ship}(k,h) + c_{ghg}(k)\right) + \\
&\sum_h \sum_m x_{hg}(h,m) \times \left(c_{facility}(h) + c_{ship}(h,m) + c_{ghg}(h)\right) + \\
&\sum_h \sum_m x_{he}(h,m) \times \left(c_{ship}(h,m)\right) + \\
&\sum_m x_{ffv}(m) \times \left(c_{ffv}(m) + c_{E85Inf}(m)\right) + \\
&\sum_{p_{cell}} x_{p_{corn}}(p_{cell}) \times p_{corn}(p_{cell}) \times q_{corn} + \\
&\sum_{p_{cell}} x_{p_{cell}}(p_{cell}) \times p_{cell} \times q_{cell}(p_{cell}) + \\
&\sum_{p_{oil}} x_{p_{oil}}(p_{oil}) \times p_{oil} \times q(p_{oil})
\end{aligned}
$$

The first three terms of the objective function represent costs for corn, cellulosic, and imported Brazilian sugarcane ethanol, where the costs for each fuel include the costs for fuel production (or import, in the case of Brazilian sugarcane ethanol), ethanol transport to blending and distribution hubs, and life-cycle greenhouse gas emissions. Terms 4 and 5 represent the cost to ship gasoline and ethanol, respectively, from distribution hubs to MSAs. The sixth term represents costs infrastructure investment costs for E85, while the last three terms represent the feedstock costs for corn, cellulosic biomass, and oil, respectively, where the total cost curve for each feedstock is converted into a piecewise-linear approximation.

The following constraints were placed on the model:

$$\sum_{h} x_i(i,h) - \sum_{p_{cell}} x_{p_{corn}}(p_{cell}) \times q_{corn}(i,p_{cell}) \times yield_{corn} \leq 0 \tag{1}$$

$$\sum_{h} x_j(j,crop,h) - \sum_{p_{cell}} x_{p_{cell}}(p_{cell}) \times q_{cell}(j,crop,p_{cell}) \times yield_{cell} \leq 0 \tag{2}$$

$$\sum_{k}\sum_{h} x_k(k,h) \leq S_{Brazil} \tag{3}$$

$$\sum_{i} x_i(i,h) + \sum_{j}\sum_{crop} x_j(j,crop,h) + \sum_{k} x_k(k,h) \geq \sum_{m} x_{he}(h,m) \tag{4}$$

$$\sum_{h} x_{he}(h,m) \times ED_{ethanol} + x_{hg}(h,m) \times ED_{gasoline} \geq D(m) \tag{5}$$

$$\sum_{h} x_{he}(h,m) \times ED_{ethanol} \leq D(m) \times \left(0.1 + 0.75 \times x_{ffv}(m)\right) \tag{6}$$

$$\sum_{h}\sum_{m} x_{hg}(h,m) - \sum_{p_{oil}} x_{p_{oil}}(p_{oil}) \times q_{oil}(p_{oil}) \leq 0 \tag{7}$$

$$x_{p_{cell}}(p_{cell}) - x_{p_{corn}}(p_{cell}) \leq 0 \tag{8}$$

$$\sum_{p_{cell}} x_{p_{cell}}(p_{cell}) \leq 1 \tag{9}$$

$$\sum_{p_{oil}} x_{p_{oil}}\left(p_{oil}\right) \leq 1 \tag{10}$$

$$x_{ffv}\left(m\right) \leq V\left(m\right) \tag{11}$$

The constraints shown above guarantee that: 1) corn ethanol shipments do not exceed plant capacity, 2) cellulosic ethanol shipments do not exceed plant capacity, 3) sugarcane ethanol imports do not exceed the maximum import quantity, 4) ethanol shipments from each hub do not exceed the volume of ethanol shipped to that hub, 5) energy demand for at each MSA is met, 6) ethanol blends are limited to E10 without FFV investment, but increase linearly to E85 as FFV deployment increases to 100%, 7) gasoline price increases with gasoline demand, 8) corn and cellulosic feedstock prices are related according to the results of the POLYSYS model, 9) the model selects a linear combination of cellulosic feedstock production levels, 10) the model selects a single oil price scenario, and 11) FFV penetration is capped at 100%.

9.3.2. Monte Carlo Simulations

Due to significant uncertainties regarding the future costs and emissions associated with transportation fuels, a Monte Carlo analysis was run to model fuel production and distribution for a variety of potential scenarios. For each run, the input parameters shown below in Table 9-3 were randomly sampled, and the optimization model was run to minimize cost. The solutions produced by the optimization model were then used to generate distributions of fuel costs, emissions, and regional fuel consumption decisions.

Table 9-3. Variables and distributions sampled during Monte Carlo simulation.

Parameter	Units	Distribution	Min	Mode	Max
Fuel Demand					
Demand Multiplier	(unitless)	Triangular	0.8	1	1.2
Gasoline					
Oil Price	$/barrel	Triangular	50	100	150
Elasticity of Supply	(unitless)	Triangular	0.1	0.3	0.5
E85 Vehicles and Infrastructure					
FFV Upgrade Cost	$/vehicle	Triangular	50	100	200
E85 Retail Infrastructure Cost	$/gal ethanol	Triangular	0.04	0.065	0.08
Corn Ethanol					
Corn Ethanol Yield	gal/bushel	Triangular	2.65	2.65	3
Cellulosic Ethanol					
Cellulosic Ethanol Yield	gal/ton	Triangular	72.5	72.5	99.4
Cellulosic Ethanol Production Cost (not including feedstock)	$/gal	Triangular	0.55	1.64	1.64
POLYSYS Production Year	(unitless)	Uniform, Integer	2010	-	2030
POLYSYS Production Level	(unitless)	Uniform, Qualitative	Normal	-	High
POLYSYS Energy Demand	(unitless)	Uniform, Qualitative	Baseline	-	Baseline +125%
Sugarcane Ethanol					
Sugarcane Ethanol FOB Price	$/gal	Triangular	0.87	0.98	1.4
Sugarcane Ethanol Imports	bil gal/year	Triangular	1	5.5	10
Carbon Emissions					
iLUC Emissions	g CO_2-eq./MJ	Triangular	0	30	100
Carbon Price	$/ton	Triangular	0	20	100

Most of the terms shown in Table 9-3 are self-explanatory, or were discussed above. The Demand Multiplier term represents a nationwide change in per capita energy consumption for transportation, possibly resulting from changes in energy prices or improvements in vehicle efficiency. Three parameters listed in Table 9-3 referring to the POLYSYS model were used to randomly select a cellulosic feedstock production scenario, with larger values for each parameter leading to greater cellulosic biomass availability. Finally, only the cellulosic ethanol yield and cellulosic ethanol production cost terms were (negatively) correlated; all other terms were sampled independently.

9.4. Results and Discussion

For the base case analysis, all parameters shown in Table 9-3 were assumed to be equal to the modes of their respective distributions, and cellulosic feedstock availability was based on the POLYSYS scenario corresponding to the year 2022 (chosen to match the final year of the RFS 2 biofuel production targets) with normal production level and baseline energy demand.

9.4.1. Base Case Fuel Costs

Figure 9-4 presents average cost components for the four fuels distributed by the model. Costs for each fuel are broken down into fuel cost (representing the cost at the facility gate), shipping cost to transport the fuel to MSAs, and carbon cost (representing life-cycle GHG emissions multiplied by a base case carbon price of \$20/tonne CO_2). All costs are presented in \$ per gallon gasoline equivalent (gge), accounting for the reduced energy density of ethanol.

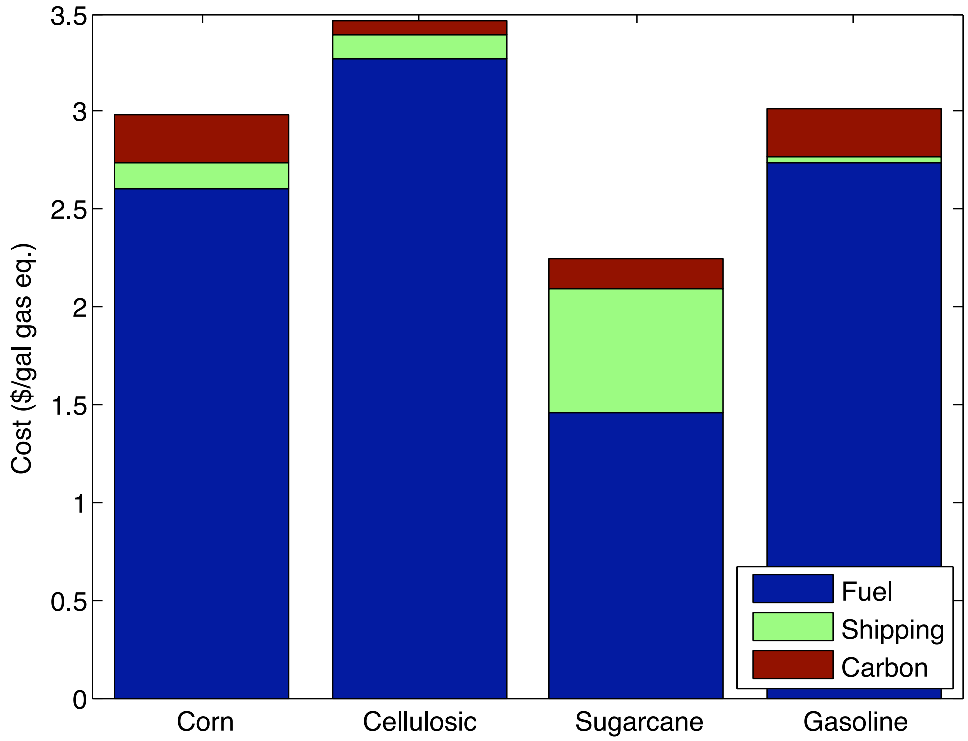

Figure 9-4. Base case average fuel cost components. Shipping costs for ethanol are downstream of refinery; shipping cost for gasoline is downstream of distribution hub.

Figure 9-4 shows that cellulosic ethanol costs are about $0.50 per gge greater than those for gasoline or corn ethanol, while sugarcane ethanol costs are less than $2.50 per gge, even after accounting for over $0.50 per gge in shipping costs. Furthermore, gasoline shipping costs are estimated to be less than $0.05 per gallon, though these costs are not necessarily commensurate with shipping costs shown for ethanol due to modeling assumptions. Given that gasoline distribution hubs were modeled as gasoline sources, the costs to ship crude oil from extraction sites to refineries and gasoline from refineries to distribution hubs are included in the fuel cost rather than the shipping cost.

9.4.2. Regional Fuel Distribution

Figure 9-5 illustrates the regional nature of fuel distribution for the base case solution. For all counties throughout the lower 48 states, colors symbolize the fuel that meets the majority of transportation energy demand. (The optimization model ships fuel to MSAs rather than counties, so to generate Figure 9-5, each county was assigned the fuel mix used by the MSA closest to its centroid.) Counties relying primarily on corn ethanol are shown in yellow, cellulosic ethanol in green, sugarcane ethanol in blue, and gasoline in red.

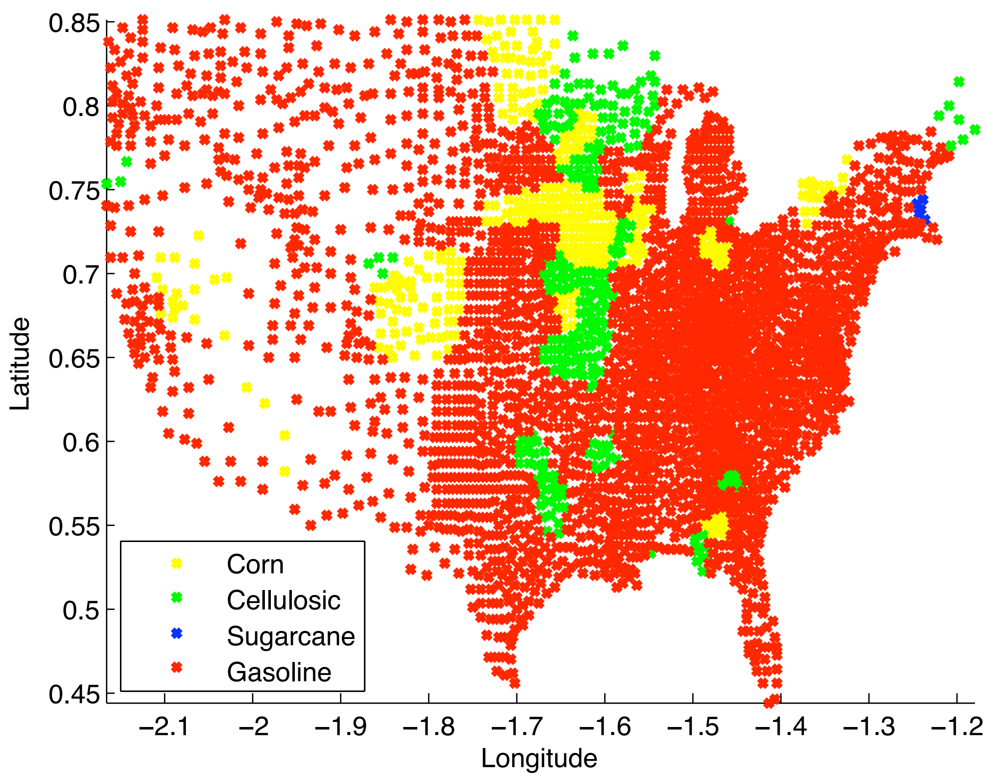

Figure 9-5. Primary fuel used to meet transportation energy demand.

Figure 9-5 shows that ethanol (from both corn and cellulosic sources) is used extensively to meet fuel demands throughout the Midwest and in some isolated packets of counties throughout the rest of the country. Sugarcane ethanol is the only the primary fuel for a few counties around Boston, while gasoline makes up the majority of the transportation fuel blend for the vast majority of the country.

Figure 9-6 further describes the distribution of transportation fuel throughout the United States. For each of the four transportation fuels, maps show counties meeting any of their transportation fuel demand with the respective fuel. While Figure 9-5, displayed counties by the fuel used to meet the majority of their fuel demand, Figure 9-6 displays counties that receive any fuel to provide energy for transportation.

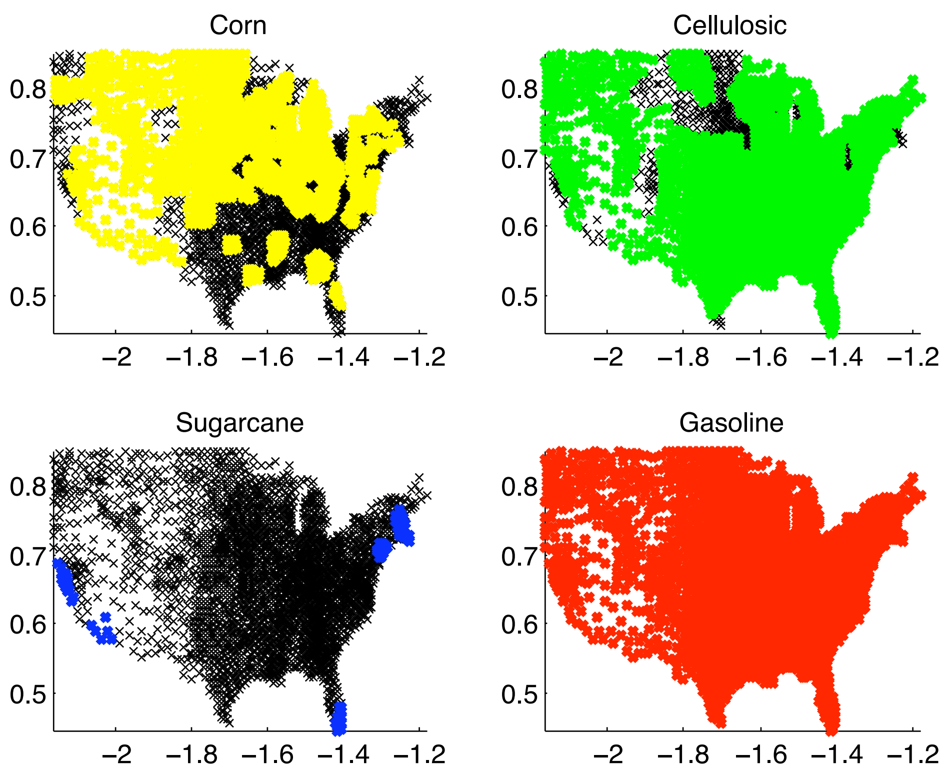

Figure 9-6. Fuel distribution maps for (top to bottom, left to right) corn ethanol, cellulosic ethanol, sugarcane ethanol and gasoline.

Figure 9-6 shows widespread ethanol use throughout the United States. Corn ethanol is distributed primarily in the Midwest, but many counties in the western half of the United States rely on the fuel as well. Cellulosic ethanol is used virtually everywhere except for some corn-ethanol soaked areas around Nebraska and parts of southern California, which, along with southern Florida and some areas in the Northeast, receive imports of sugarcane ethanol from Brazil. Given the maximum ethanol blend of 85%, gasoline is used to meet at least 15% of energy demand in every county.

Regional distribution of ethanol as higher-level blends requires investment in both vehicle and E85 retail infrastructure. Figure 9-7 shows levels of investment in E85 infrastructure throughout the United States. Figure 9-7 shows a similar distribution of results as that shown in Figure 9-5; areas where ethanol represents the primary transportation fuel must have some level of E85 infrastructure investment, and the model does not invest in E85 infrastructure unless ethanol comprised over 10% of the fuel blend. Therefore, E85 infrastructure investment is found primarily throughout the Midwest, along with a few isolated areas in the southeast.

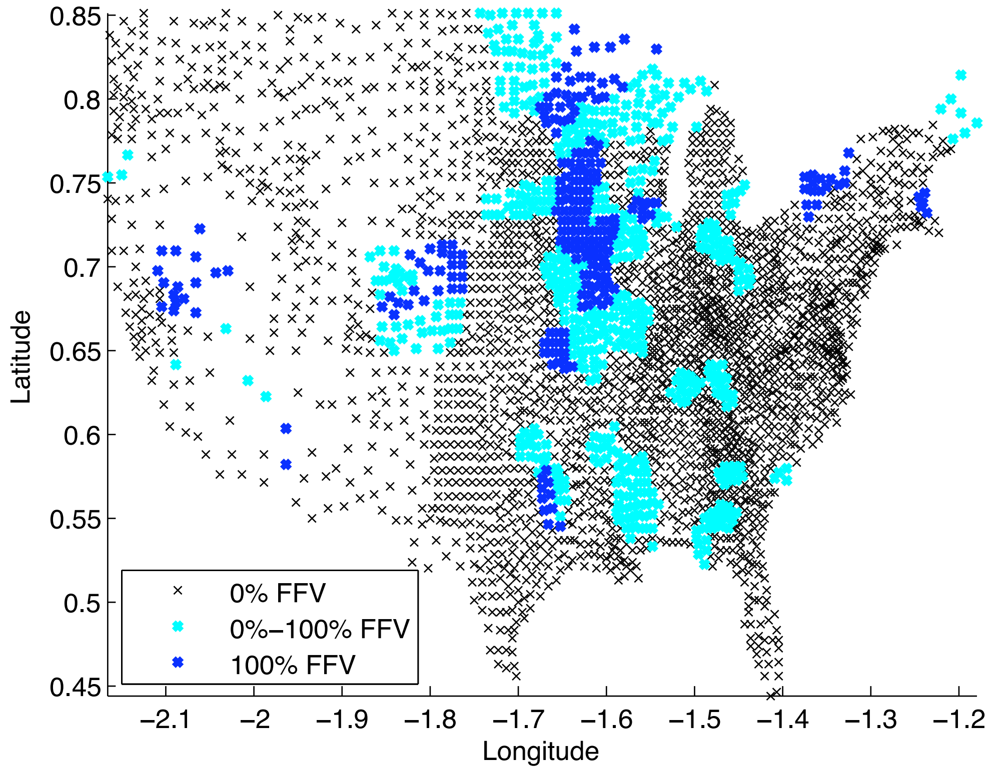

Figure 9-7. Levels of E85 penetration.

9.4.3. Impacts of Ethanol Subsidies and Tariffs

Corn ethanol currently benefits from a $0.45 per gallon blender's credit, cellulosic ethanol receives a subsidy of $1.01 per gallon, while imported ethanol is subject to a tariff of $0.51 per gallon. (Though these ethanol subsidies may be phased out as the cellulosic ethanol industry matures, they may be extended, especially if cellulosic ethanol production costs remain high.) To examine the impacts of these policies, the optimization model was run based on fuel costs adjusted to reflect existing ethanol subsidies and tariffs.

Figure 9-8 provides cost components for the four transportation fuels after subsidies for corn and cellulosic ethanol, and tariffs for sugarcane ethanol imports, are taken into account. Figure 9-8 is similar to Figure 9-4, with subsidy and tariff impacts subtracted from (or, in the case of sugarcane ethanol, added to) the base case average fuel cost component. Figure 9-8 shows that, relative to the base case, existing subsidies and tariffs reverse the order of fuel costs. Sugarcane ethanol, which was previously the cheapest fuel option, is now the most expensive fuel, followed by gasoline, corn ethanol, and cellulosic ethanol.

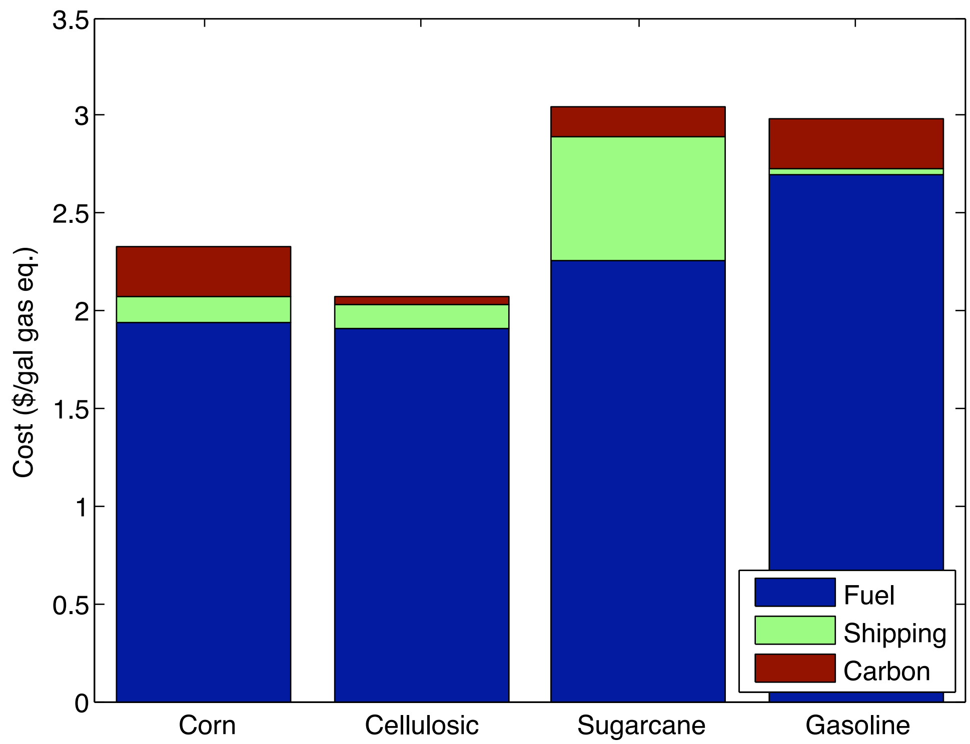

Figure 9-8. Fuel cost components after accounting for current domestic ethanol subsidies and imported ethanol tariffs.

While the costs of ethanol are strongly impacted by existing subsidies and tariffs, the quantities of fuel used by the optimization model do not change significantly. Corn ethanol and sugarcane ethanol remain at 15 and 5.5 billion gallons, respectively, though this result is principally due to modeling limitations that fix the maximum level of fuel supplied at those levels. The volume of cellulosic ethanol used by the model increases from roughly 16 to 22 billion gallons per year as a result of the subsidies, but the distribution of fuels (described in Figure 9-5 and Figure 9-6) does not change significantly once subsidies and tariffs are applied. Because the quantities of fuel chosen by the optimization model do not change significantly, the amount of money required to fund ethanol subsidies (less the funds generated by the ethanol tariff) is roughly equal to the change in the total cost, leading to little net impact at the national level.

However, the fact that the objective function for the model (representing the system-wide cost) and the distribution of transportation fuels do not change significantly as a result of ethanol subsidies and tariffs does not mean that these policies have little impact at the regional level. Figure 9-5 shows that consumption of high-level ethanol blends is concentrated primarily in the Midwest, and areas with greater proportions of their demand met by domestically produced biofuels stand to benefit more from ethanol subsidies. Similarly, coastal areas that rely on sugarcane ethanol imports see their fuels costs increase due to the tariff on ethanol imports. Assuming that funds for ethanol subsidies are collected via a national tax, then, leads to areas that depend primarily on gasoline subsidizing fuel consumption of those relying heavily on ethanol. Figure 9-9 provides estimates for the regional impact of ethanol subsidies and tariffs. As Figure 9-9 shows, existing ethanol subsidies and tariffs result in a net cost for the majority of the population. People living in coastal regions, most of the southeast, and much of the western U.S. incur an annual cost of less than \$100 per person due to ethanol subsidies. (For regions running on E10 or less, the annual cost amounts to roughly \$70 per person.) Coastal regions hit by the imported ethanol tariff see a cost of over \$300 per person. Areas relying on high-level ethanol blends, on the other hand, benefit by over $100 per person per year as a result of these policies, with annual benefits climbing as high as $600 per person for regions fuel by cellulosic E85. Thus, as a result of heavily regional ethanol distribution, ethanol subsidies result in annual transfer payments from coastal regions to Midwestern regions of $100 to $600 per person.

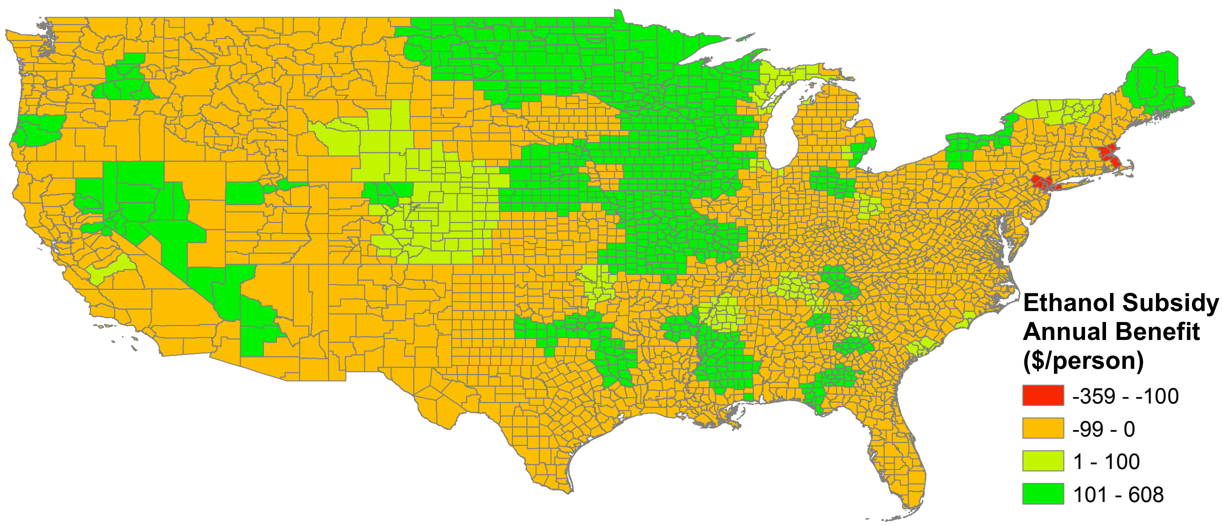

Figure 9-9. Annual benefit (in $ per person at the county level) resulting from ethanol subsidies and tariffs.

9.4.4. Impacts of Raising the Blendwall

As an alternative to investing in infrastructure for regional distribution of E85, raising the blendwall (from E10 to E15 or E20) would allow ethanol consumption to increase beyond current levels. Figure 9-10 and Figure 9-11 illustrate the primary fuel distribution and the spatial distribution of investment in E85 infrastructure, respectively, for a case in which the conventional vehicle blendwall is raised from E10 to E20.

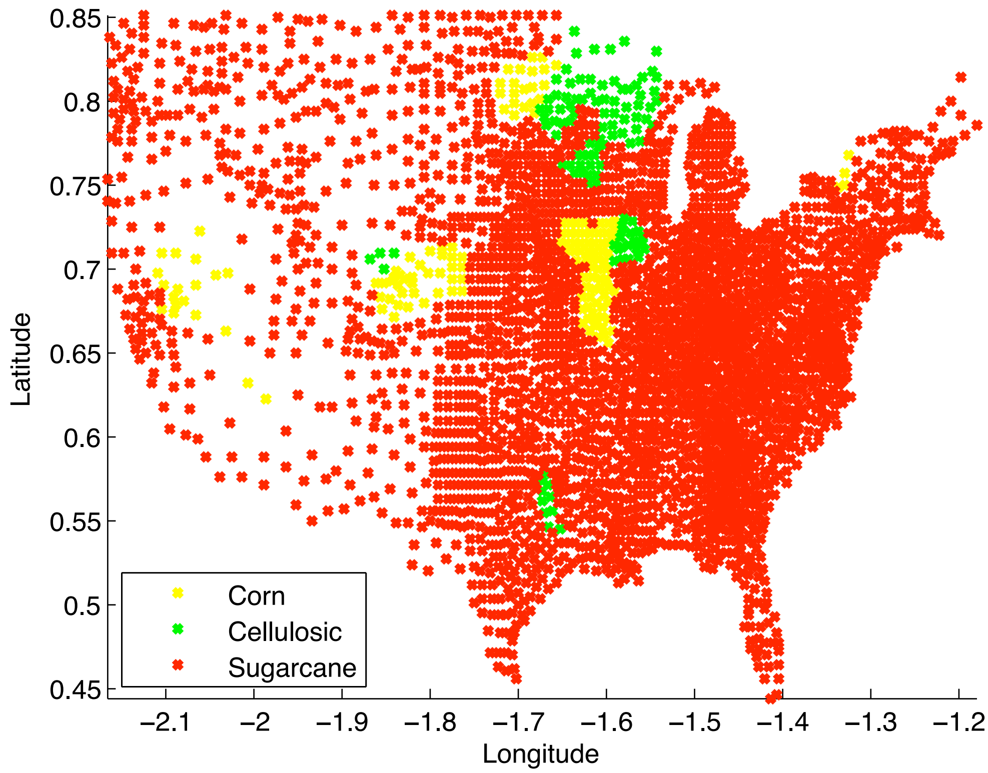

Figure 9-10. Primary fuel map for an E20 blendwall.

Relative to the results for an E10 blendwall (shown in Figure 9-5 and Figure 9-7), the results for an E20 blendwall show that ethanol distribution becomes less regional. The total amount of ethanol used (around 40 billion gallons) is the same for both scenarios, but Figure 9-10 shows that fewer counties rely primarily on ethanol than those for the E10 scenario shown in Figure 9-5. E85 infrastructure investment is similarly decreased in moving to an E20 blendwall.

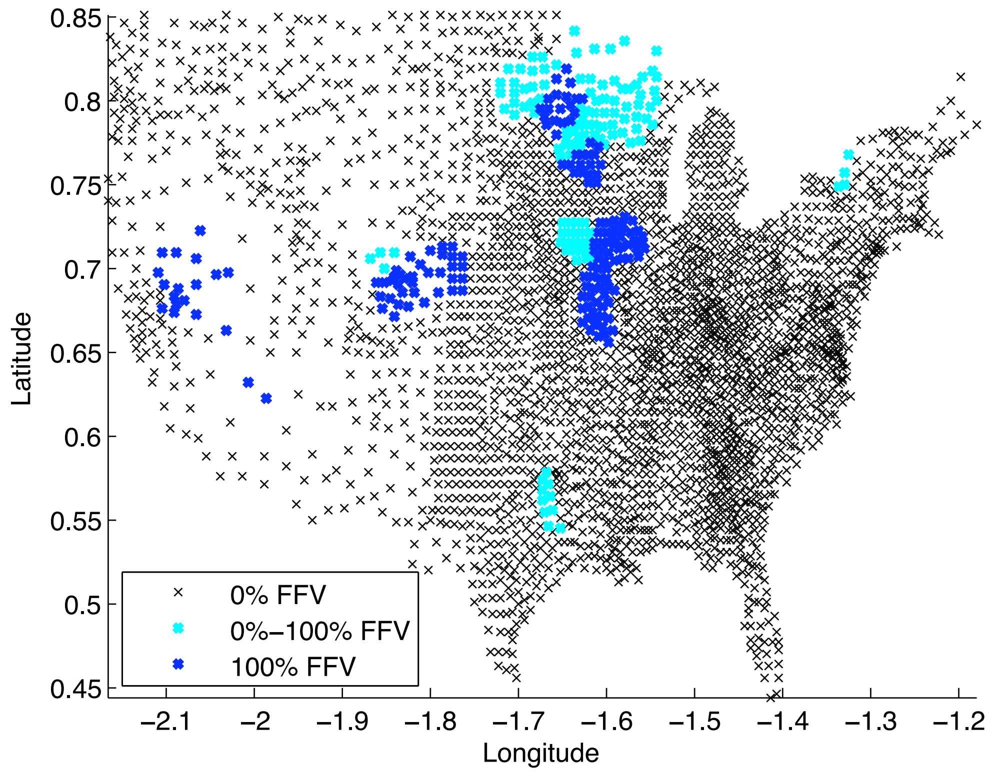

Figure 9-11. E85 Infrastructure Penetration for an E20 blendwall.

However, raising the blendwall to E20 does not eliminate regional distribution altogether. The percentage of ethanol distributed as E85 decreases from 56% for an E10 blendwall to 30% for an E20 blendwall, but does not disappear altogether, despite the fact that nationwide distribution of E20 could consume almost all of the 40 billion gallon ethanol supply. Thus, even for a scenario in which the blendwall is doubled, reductions in shipping cost still outweigh investments in regional E85 infrastructure.

9.4.5. Monte Carlo Simulation Results

Figure 9-12 provides cumulative distribution functions for the volume of each type of transportation fuel used in the optimal solution. Curves are provides for corn, cellulosic, and sugarcane ethanol, as well as gasoline. For 80% of the simulations, consumption of corn ethanol matches the 15 billion gallon per year EISA target; for the remaining 20%, very little corn ethanol is used due to high corn feedstock prices. The volume of cellulosic ethanol ranges from zero to 45 billion gallons, but for 75% of the simulations, cellulosic ethanol consumption is between 20 and 30 billion gallons. Sugarcane ethanol is constrained to 10 billion gallons or less, while gasoline consumption ranges from 100 to 160 billion gallons.

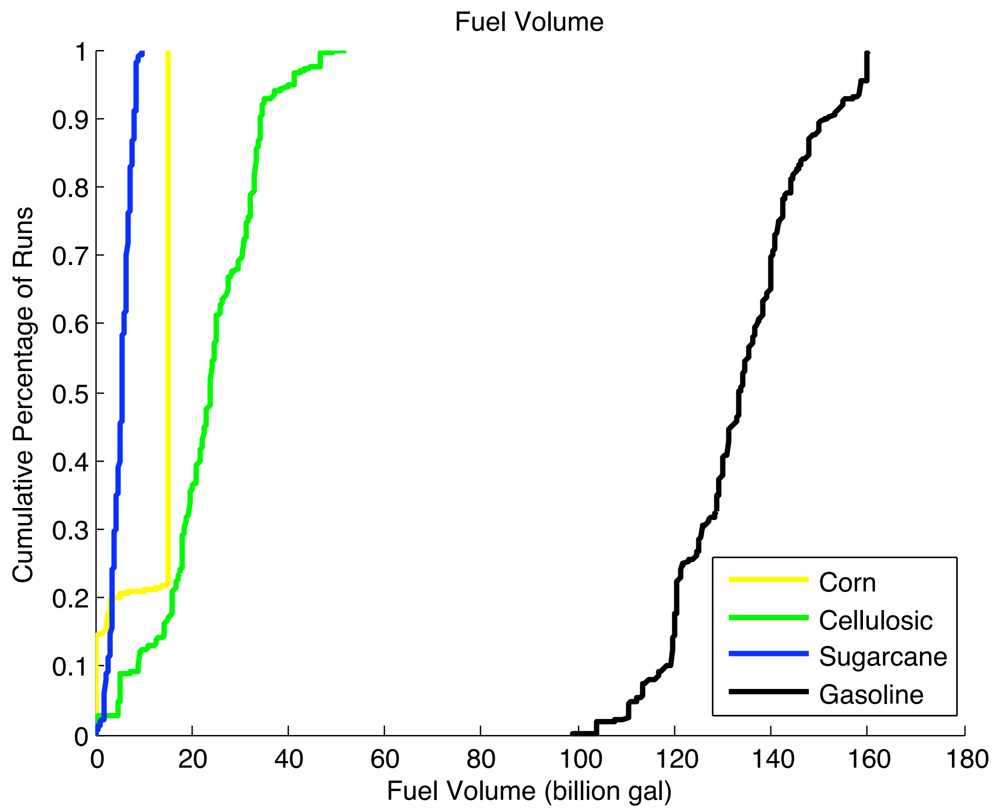

Figure 9-12. Fuel volume cumulative distribution functions for corn ethanol, cellulosic ethanol, imported sugarcane ethanol, and gasoline.

Figure 9-13 provides distribution functions for the fuel cost, given in $ per gallon gasoline equivalent, for the four fuel types. The distribution for gasoline ranges from $2 per gallon to over $4.25 per gallon. The distribution of corn ethanol costs closely follows that of gasoline except at the inexpensive end, where corn ethanol production costs fall below $2 per gge in about 5% of simulations. Cellulosic ethanol production costs range from $2 to $4 per gge, while sugarcane ethanol costs are between $2 and $3.5 per gge. The relationship between the costs of these four fuels is similar to the cost relationship for the base case (shown in Figure 9-4) with the exception of cellulosic ethanol, which was the most expensive fuel in the base case but is, on average, less expensive than gasoline or corn ethanol during Monte Carlo simulations. The base case assumed short-term cellulosic ethanol production costs, which are at the extreme high end of the distribution used during the simulations. As a result, the majority of the simulations result in cellulosic ethanol production costs lower than those assumed in the base case.

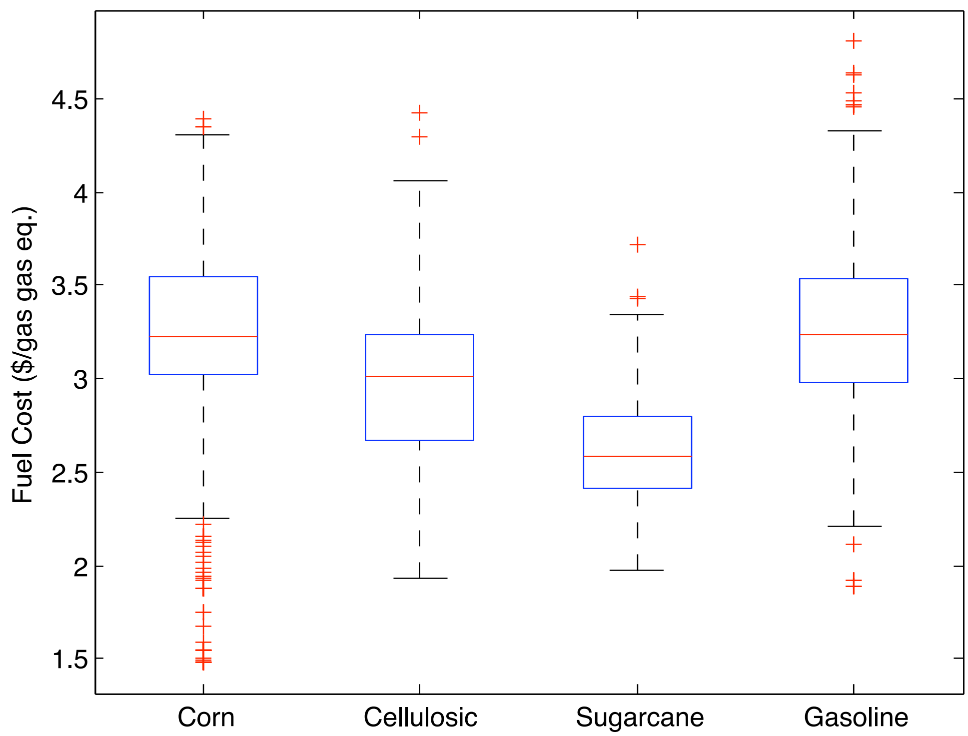

Figure 9-13. Fuel cost (in $ per gallon gasoline equivalent) box and whisker plots for corn ethanol, cellulosic ethanol, imported sugarcane ethanol, and gasoline.

Figure 9-14 provides distributions for the volumes of ethanol blended as E10 and E85, alongside a curve for the total amount of ethanol consumed. For the majority of the simulations, ethanol blended as E10 reaches the national conventional vehicle blendwall (a total volume that varies from about 16 to 19 billion gallons depending on the sampled inputs), while higher levels of ethanol are distributed as E85. However, some simulations in which total ethanol consumption is relatively modest (for instance, between 10 and 15 billion gallons) still show some regional distribution of E85.

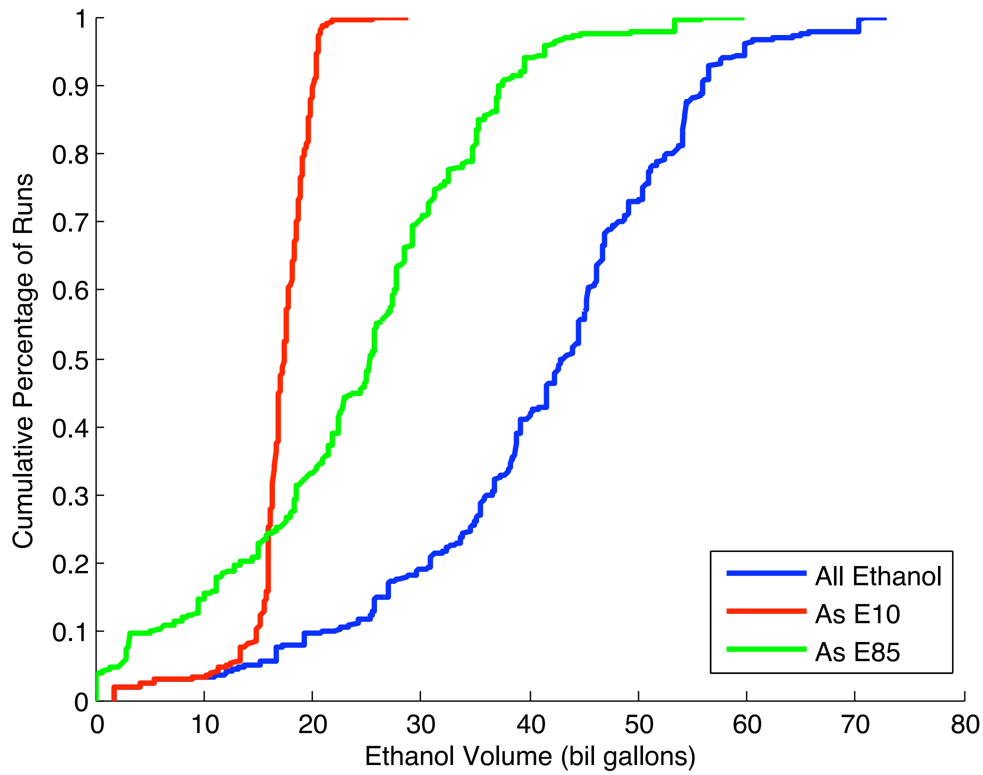

Figure 9-14. Cumulative distribution functions for the volume of ethanol (in billion gallons) distributed as E10, as E85, and in total.

9.5. Conclusions

Domestic ethanol production is rapidly approaching the national E10 blendwall. If consumption of ethanol is to match future expansions in ethanol production, then policies must be in place to either raise the blendwall or encourage consumption of higher-level blends such as E85. Although consumption of E85 requires investments in both vehicle upgrades and distribution infrastructure, the optimization model developed for this study indicates that investing in E85 infrastructure throughout regions capable of producing ethanol consistently results in the lowest cost thanks to significant reductions in ethanol shipping cost. Policies may be required to encourage regional E85 infrastructure investment, because retailers may be hesitant to make capital investments before demand has developed and flex-fuel vehicles may not gain widespread use without reliable E85 supplies. However, if policies can coordinate vehicle and distribution infrastructure investment, then regional distribution of transportation fuels can reduce fuel costs and loads on shipping networks throughout the United States.

10. Conclusions

10.1. Research Questions Revisited

The following research questions were established in the Introduction. In light of the results presented in Chapters 3 through 9, each question is addressed below.

1. Given the uncertainty surrounding fossil fuel prices, biofuel production costs, and carbon emissions resulting from biofuel production, what role (if any) should biofuels play in meeting future energy demand? Under which scenarios are biofuels socially beneficial?

    a. **Assuming that recent findings regarding the land-use change impacts of biofuel production are true, what role should biofuels play in future (carbon-constrained) energy policy?**

    Greenhouse gas emissions from land use change, and specifically indirect land use change, represent a major hurdle for biofuels. Though emissions from indirect land use change are highly uncertain at this point, preliminary results indicate that they may cause biofuels (including cellulosic ethanol, a fuel with an otherwise favorable environmental profile) to be more carbon-intensive than gasoline. While these emissions are of critical importance and should be considered in any biofuel policy, carbon emissions resulting from biofuel production should not be the only factor taken into consideration when formulating fuel policies. Biofuel production and consumption has a number of impacts, and policies should seek to balance these impacts rather than focusing on a single feature of biofuels. Chapter 3 discusses how production costs for a mature cellulosic ethanol industry could fall well below recent gasoline prices, to the point where a portion of the fuel cost reduction could be used to offset emissions resulting from land use change. Like all energy options, biofuels represent an imperfect solution to meeting energy demand, but if policies are in place to balance the positive and negative impacts of biofuels, then they may still be able to make a positive contribution to meeting transportation energy demand.

b. What are the benefits of using untraditional cellulosic feedstocks (such as urban waste and excess forest biomass) compared to energy crops for cellulosic ethanol production? Could forest thinnings be used cost-effectively as a cellulosic ethanol feedstock? Could revenue generated by forest thinning-derived cellulosic ethanol significantly offset thinning costs?

Since 2004, wildfires throughout the United States have resulted in social costs on the order of $30 billion per year. Fuel treatment activities such as forest thinning have been shown to reduce the severity of wildfires and improve forest health. Forest thinnings represent a promising feedstock for cellulosic ethanol; thinned biomass requires very little input energy, does not compete with food crops for land, and has no land-use change impacts.

Based on cellulosic ethanol production cost estimates (for a mature cellulosic ethanol industry) and forest thinning cost curves, Chapter 4 estimates that 3 billion gallons of cellulosic ethanol could be produced annually at a cost of $3 per gallon gasoline equivalent or less. Should gasoline prices rise above $3 per gallon, high cellulosic feedstock prices combined with modest forest thinning removal costs could net the Forest Service over $1 billion per year from the sale of thinned biomass. Removal of all biomass that could be thinned at a cost of $50 or less is also estimated to decrease expected wildfire damage by over $150 million annually, or roughly half of what the Forest Service currently spends on fuel reduction treatments. Cofiring forest thinnings with coal also represents a promising bioenergy conversion pathway, though regional characteristics heavily influence costs. Forest thinnings are an attractive feedstock for cellulosic ethanol, and as the cellulosic ethanol industry matures, the sale of thinned biomass could create a significant source of revenue to fund additional fuel treatment operations.

2. Given the substantial investments to be made in ethanol production in the near future, what are the impacts of facility investment decisions and how can policies potentially impact those decisions?

a. **What are the impacts of ethanol refinery size and location on ethanol production cost? How significant are these impacts, and what policies could help encourage infrastructure investments that lower cost?**

   Decisions regarding facility size and facility location can have substantial impacts on cellulosic ethanol production cost. For the regions examined in Chapter 5, producing ethanol with large facilities can decrease costs by $0.20 to $0.30 per gallon compared to small facilities, and placing facilities in a way that minimizes transportation costs can reduce costs by up to $0.25 per gallon compared to random placement. These cost reductions represent 15% to 25% of the total cost to produce cellulosic ethanol, and it makes little sense to ignore these factors while investing billions of dollars into process research with the goal of achieving similar cellulosic ethanol cost reductions. Future cellulosic ethanol policies concerning facility size and location should encourage these low-cost production scenarios, either by providing low-interest loans for larger facility capacity investments, or, at the very least, prohibiting provincial facility construction subsidies that lead to large biomass shipping costs.

3. As ethanol production increases, how will current infrastructure networks respond to the additional load of ethanol production and distribution? What are the potential social costs of ethanol production and distribution, and what policies can help reduce or avoid these costs?

d. If the current ethanol shipping profile remains unchanged, how will additional ethanol shipments impact rail and highway freight networks? Do rail and highway freight networks have sufficient capacity to accommodate increased ethanol shipments, or will these added loads lead to significant congestion costs?

Domestic ethanol production has increased dramatically in recent years and is expected to continue to increase to 36 billion gallons per year by 2022. National distribution of a low-level ethanol blend is estimated to add 30 to 120 billion ton-miles to the rail network, while providing the state of California with E85 could add 150 billion ton-miles, even for near-term production goals. These load increases represent increases of 1.5% to 9% of the total current rail freight load, potentially leading to local congestion impacts, especially on rail lines connecting the Midwest to the Pacific coast that already handle significant freight traffic. While estimates for congestion costs resulting from ethanol shipments depend heavily on assumptions about rail line capacity and current levels of freight traffic, some scenarios result in congestion cost estimates on the order of the private cost of ethanol shipping. Although regional distribution of E85 would require investment in flex fuel vehicles and other distribution infrastructure, it would largely erase the rail freight congestion costs of ethanol shipping, lowering the social cost of using biofuels to meet transportation energy demands.

Shipments of biomass over road networks, on the other hand, are unlikely to lead to major congestion impacts. Maximum shipping loads resulting from biomass shipments are at least two orders of magnitude lower than estimates for highway capacity, even around large cellulosic ethanol facilities where the marginal impact of biomass shipments is estimated to be the most intense.

e. What are the anticipated ethanol shipping costs and loads for different distribution scenarios? How do costs for regional and national ethanol distribution change as total ethanol production changes?

Ethanol production within the United States has increased drastically in recent years, and the Renewable Fuel Standard created by the EISA of 2007 requires domestic ethanol production to continue this upward trend. Domestic ethanol consumption, however, may be limited by both the federal blendwall of E10 for conventional vehicles and the lack of vehicles in the current fleet capable of running on higher-level blends. Demand for ethanol may also be reduced by the relatively high shipping costs required to transport ethanol from production sites in the Midwest to large coastal population centers.

Distributing ethanol as E85 regionally, rather than distributing it nationally as a low-level blend, could help solve problems involving both consumption limits and high shipping costs. Given the EISA's 2022 target of 36 billion gallons of domestic ethanol production, regional distribution of E85 would save almost 60 billion ton-miles of ethanol transportation and over $2 billion per year in shipping costs compared to national distribution of E20. Should a coordinated regional fuel distribution policy prove difficult to implement at the national level, individual state-level E85 mandates could also substantially reduce shipping costs relative to national distribution of a low-level ethanol blend. States either containing or located near large volumes of ethanol production capacity, especially those state with large populations, could reduce annual shipping costs by as much as $500 million compared to national E20 distribution by converting all of their gasoline demand to demand for E85. Increased production of biofuels could have positive environmental, economic, and energy security impacts for transportation energy used in the United States. Crafting biofuel distribution policies to reduce shipping costs and infrastructure investment requirements, while still creating sufficient demand for the fuel, can help realize those benefits while limiting costs.

f. Ethanol production from sugarcane within Brazil is also expected to increase dramatically in the near future. How will costs and emissions

of sugarcane ethanol produced in Brazil and exported to the United States change as a result of this expansion?

Brazilian sugarcane ethanol compares favorably to ethanol produced domestically from corn or cellulosic biomass from economic and environmental perspectives. Given the anticipated growth in production of sugarcane ethanol within Brazil, and the recent emphasis placed on reducing petroleum imports, the United States may be motivated to meet transportation energy demand by importing sugarcane ethanol from Brazil. However, Chapter 8 shows that transportation requirements for shipping ethanol from production sites within Brazil to domestic demand centers may prove costly. Based on the results of an LP optimization model of ethanol shipping and the current freight transportation profile within Brazil, shipping ethanol from Brazilian ethanol plants to major ports for export is estimated to add an average of $0.25 per gallon and increase estimates of life-cycle GHG emissions by 20%. These costs and emissions may be lessened if sugarcane ethanol expands disproportionately into coastal states or the transportation profile of ethanol shipped from plants to ports differs greatly from the current national profile. However, these results suggest that shipping costs and emissions resulting from transporting fuel from Brazil to the United States may be significant and should be explicitly taken into account when evaluating imports of Brazilian sugarcane ethanol as a light-duty fuel option.

4. **Using a combination of current transportation fuels and biofuels, how can the energy demand for the light-duty fleet be met in a way that minimizes social cost? How should corn ethanol, cellulosic ethanol, and imported sugarcane ethanol be used to meet demand, how does regional variation in fuel availability impact fuel distribution, and how will policies impact optimal fuel distribution?**

Domestic ethanol production is rapidly approaching the national E10 blendwall. If consumption of ethanol is to match future expansions in ethanol production, then policies must be in place to either raise the blendwall or encourage consumption of higher-level blends such as E85. Although consumption of E85 requires investments in both vehicle upgrades and distribution infrastructure, the optimization model developed for this study indicates that investing in E85 infrastructure throughout regions capable of producing ethanol consistently results in the lowest cost thanks to significant reductions in ethanol shipping cost. Policies may be required to encourage regional E85 infrastructure investment, because retailers may be hesitant to make capital investments before demand has developed and flex-fuel vehicles may not gain widespread use without reliable E85 supplies. However, if policies can coordinate vehicle and distribution infrastructure investment, then regional distribution of transportation fuels can reduce fuel costs and loads on shipping networks throughout the United States.

10.2. Discussion

Ethanol, and specifically cellulosic ethanol, has the potential to create economic, environmental, and energy security benefits relative to the gasoline that currently provides transportation energy for the light-duty fleet. It's relatively high energy density, compatibility with conventional vehicles, and potential to be a truly renewable fuel represent advantages it has over other low-carbon transportation fuel candidates.

With that in mind, there are some serious obstacles ethanol must overcome in order to contribute positively to the United States' transportation energy portfolio. This study focuses primarily on obstacles involving ethanol production and distribution infrastructure. These issues are important; analyses discussed in Chapters 5, 6 and 7, for instance, indicate that production and distribution policies such as regional distribution of E85 could save billions of dollars per year in fuel costs. However, infrastructure issues are not the primary obstacles faced by cellulosic ethanol. First, cellulosic ethanol production costs need to begin to drop to the point where the fuel can compete economically with gasoline. Long-term production cost estimates for cellulosic ethanol generally fall below $1.50 per gallon, low enough for cellulosic ethanol to overcome ethanol's reduced energy density. However, production costs achieved by DOE and the private sector have been hovering around $2.50 to $3 per gallon for the past few years, costs that would make it difficult for the fuel to compete without the aid of subsidies. If cellulosic ethanol must rely on subsidies on the order of $1 per gallon (like those currently in place) in order to compete economically with gasoline, then it is highly unlikely that it will be able to displace a significant volume of gasoline without incurring a large social cost. Even if cellulosic ethanol can be produced without land-use change impacts and realize significant emissions reductions compared to petroleum-based fuels, there are many lower cost mitigation options available than heavily-subsidized cellulosic ethanol given current production costs.

As for the aforementioned emissions reductions, uncertainty regarding land-use change impacts represents a second major obstacle for cellulosic ethanol. Cellulosic ethanol has long been thought to offer major greenhouse gas reductions compared to fossil fuels, with the potential to be carbon-negative when produced from agricultural or forest residues or low input grasses. Recent findings on land-use change suggest, however, that competition for cropland resulting from production of energy crops could lead cellulosic ethanol to be more carbon intensive than gasoline. These findings are highly uncertain, and significant research is being undertaken to reduce this uncertainty and validate emissions estimates, but recent findings must be taken into account when making fuel policies, and with recent legislation valuing low-carbon fuels, land-use change emissions could erase a competitive advantage that cellulosic ethanol would otherwise have.

Despite these obstacles, production of cellulosic ethanol is expected to grow to 21 billion gallons by 2022, and many of the infrastructure decisions discussed throughout this report are relevant to policymakers regardless of the production cost or life-cycle emissions of ethanol. If policies are in place to ensure the production of 36 billion gallons of ethanol in 2022, then policies should ensure that the fuel is produced, distributed, and consumed in ways that limit social cost. However, uncertainty in the social cost of cellulosic ethanol is dominated by uncertainty in the production cost and, to a lesser extent, the life-cycle greenhouse gas emission of the fuel, so even the most well-formed ethanol distribution policies are unlikely to make the fuel socially beneficial if those issues are not favorably resolved.

10.3. Deliverables

The deliverables for this research take the form of peer-reviewed publications. Much of the work summarized in this thesis has already made its way into the scientific community. Chapter 3 has been published in *Environmental Research Letters*, while Chapters 4 and 5 have been submitted for publication in peer-reviewed journals (*Biomass Bioenergy* and *Energy Policy*, respectively). The work summarized in Chapter 7 was presented at two international meetings, the INFORMS Annual Meeting in 2009 and the Transportation Research Board Meeting in 2010. Chapters 6, 8, and 9 represent the foundations for journal publications, and work will continue on those topics to further develop the analyses and submit them for publication in the near future.

10.4. Research Contributions

The primary contribution of this research is the identification of options that can reduce the social impacts of ethanol production and distribution, with a focus on the benefits of regional fuel distribution. Chapters 6, 7, and 9 in particular estimate the benefits of regional distribution of transportation fuel, finding savings on the order of billions of dollars per year that could be realized by distributing ethanol in high-level blends near production sites relative to distribution of low-level ethanol blends at the national level.

This work also builds upon previous analyses of ethanol distribution performed within the Green Design Institute at Carnegie Mellon (Morrow 2006b, Wakeley 2009). This analysis examines the impacts of facility size and location, factors that were not modeled in previous studies. Ethanol distribution costs for various production volumes are also examined here instead of basing all analyses on a fixed ethanol production scenario. The optimization model discussed in Chapter 9 explicitly considers costs of E85 infrastructure (for both vehicles and retail stations), as well as variation in gasoline prices, when making fuel distribution decisions.

The explicit modeling of ethanol shipping within Brazil discussed in Chapter 8 also represents a novel contribution for this thesis. Brazilian sugarcane ethanol represents a promising transportation fuel option, but the author is unaware of any existing studies that have modeled fuel transportation requirements within Brazil as sugarcane ethanol production increases.

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