Biomass Allocation Model

DOE/NETL-2008/1302

Comparing Alternative Uses of Scarce Biomass Energy Resources through Estimations of Future Biomass Use for Liquid Fuels and Electricity

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Abstract

As the United States Congress contemplates the creation of legislation to mitigate CO_2 and other greenhouse gas emissions and as state legislators continue to push for renewable and alternative fuels for the transportation and electricity sectors, energy derived from biomass feedstocks continues to be a promising carbon-neutral renewable resource.

The goal of this research, culminating in this report, is to model and discuss alternative uses of scarce biomass energy resources, assuming that these resources reduce energy sector carbon emissions and can produce non-petroleum-based liquid transportation fuels.

This research explores future scenarios in which the transportation and electricity sectors of the U.S. economy both look to biomass feedstocks as a means of fulfilling the respective goals of reducing motor gasoline use and reducing CO_2 emissions associated with electricity generated from coal. The research concentrates on each sector's demand for biomass resources and demonstrates potential synergies and conflicts between these two largely mutually exclusive goals. In this respect, future biomass allocation trends are explored through several general scenarios. Two technology pathways for biomass energy are modeled and presented in the report: cellulosic ethanol production for alternative liquid transportation fuels and biomass and coal co-firing in existing coal-fired power plants. Because cellulosic ethanol is not in commercial production at the time of this research but significant amounts of corn-based ethanol is in commercial production, a corn-based ethanol forecast model is also developed and presented. It is not the intention to focus on corn-based ethanol however but, instead, to include this ethanol in the sum of potential future alternative transportation fuels.

A linear program (LP) has been developed which forecasts the future demands for biomass resources in the transportation sector (motor gasoline) and the electricity sector (coal-fired power plants) through 2020. Within the LP, three modules have been developed: a corn ethanol module, a cellulosic ethanol module, and a biomass and coal cofiring module. The LP estimates biomass allocations to ethanol production and existing coal-fired power plants simultaneously through estimations of respective market demand potential for biomass feedstocks.

Although the future of biomass energy use is uncertain, it is observed that given certain market conditions and policy choices, biomass energy feedstocks will be demanded by each sector simultaneously. In this case, each sector's ability to utilize scarce biomass resources will be diminished as biomass is allocated between competing alternative demands. Resulting allocations roughly depend on future oil prices, future progress in cellulosic ethanol production technology, and society's desire to mitigate CO_2 emissions from existing coal-fired power plants.

It is possible that demands for biomass energy from pathways not modeled in this report, such as biomass and coal co-gasification, could also compete with the two modeled pathways. In this respect this report is intended to serve as a policy analysis report rather than an exhaustive exploration of all biomass penetration options into future energy markets.

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Introduction

Reducing U.S. dependence on global oil markets and promoting resources and technologies that reduce greenhouse gas emissions are two energy and environmental policy objectives dominating current United States energy debates. In his 2007 State of the Union address, President George W. Bush proposed reducing the United States' annual anticipated gasoline consumption by 15 percent by 2017 through the use of approximately 35 billion gallons of renewable or alternative fuels [1]. Concerns about global warming have prompted the U.S. Congress to consider several bill proposals that would limit, and eventually reduce, carbon dioxide emissions associated with energy consumption, the primary source of greenhouse gas emissions in the U.S. For example, the Climate Stewardship and Innovation bill of 2007, calls for a reduction of U.S. greenhouse gas emissions to 1990 levels by the year 2030 [2]. Existing coal-fired power plants, as a group, are currently the largest source of CO_2 emissions in the U.S. [3]. For this reason, reducing existing coal-fired power plant CO_2 emissions is an area where future CO_2 mitigation policies will likely focus.

It has been suggested that biomass could, as an energy feedstock, play a role in achieving these two energy policy goals for the electricity and transportation sectors [4]. In most cases, however, biomass energy feedstocks are more expensive than fossil energy feedstocks, and therefore, biomass only supplied approximately 3.3% of total U.S. energy consumption in 2006 [5]. The majority of biomass energy use is a byproduct of the pulp and paper industry, with biomass waste energy (e.g., municipal solid waste and land-fill gas based electricity) and corn-based ethanol accounting for roughly 20% of biomass energy use, each [5]. Between 2000 and 2006, corn-based ethanol production capacity grew from 1.7 to 5.5 billion gallons per year (bgy) representing the highest growth of biomass energy use over that timeframe [6]. Producing 5.5 bgy of corn-based ethanol consumed 14% of U.S. corn production in 2006 [7]. Given high oil price assumptions (between 85% and 90% of EIA's Annual Energy Outlook 2007's high price case oil prices [8]) and extended federal excise tax incentives for ethanol use, the USDA has suggested that corn-based ethanol production could exceed 12 bgy by the year 2015 [9]. At 12 bgy, corn ethanol production would consume an estimated 31% of U.S. corn production [7]. Within the context of future high oil prices, researchers at Iowa State have anticipated that corn-based ethanol production could become much larger than the USDA forecast (approximately 30 bgy by 2015) which would have price-distorting consequences for the entire U.S. agriculture sector, and to some degree, world agricultural markets [10].

Although most researchers agree that, given the entire "wells-to-wheels" life cycle, corn-based ethanol does provide a positive return for its total fossil energy investment, corn-based ethanol has been criticized for a poor reduction of net fossil energy consumption [11] [12] [13]. For these reasons, wood, agricultural residues, and other herbaceous biomass resources, which together offers a much larger potential feedstock supply than corn does, have been suggested as desirable feedstocks to augment, or perhaps eventually replace, corn-based ethanol production [14] [15] [16]. Moreover, it has been suggested that utilizing this non-corn biomass as an energy feedstock could increase rural economic development [17]. Although corn-based ethanol production is forecasted, this report is concerned with future uses of non-corn based biomass energy resources. From this point forward, “biomass” is defined as “non-corn-based biomass energy feedstocks.”

Converting renewable solar energy into a useful and dispatchable form that is consistent with current consumer preferences and established technologies can be accomplished using photosynthesis to produce biomass energy feedstocks for conversion to liquid fuels or electricity [18]. Consuming liquid transportation fuels derived from biomass energy feedstocks can offer a renewable energy resource for the transportation sector and serve as an alternative to crude oil imports [19]. In addition, biomass growth uses carbon taken from the atmosphere and, when used as an energy feedstock, provides a largely carbon-neutral energy resource which may be desirable in a carbon-constrained future [20]. Biomass feedstocks can be converted to liquid transportation fuels or electricity through several different technological pathways, including direct and cellulosic fermentation processes for ethanol, gasification/digestion processes leading to liquid fuels and/or electricity, and direct combustion for thermal-electricity generation [21]. Currently, conversion of biomass into ethanol for use as a transportation fuel is anticipated [1]. It has also been proposed that biomass could be co-gasified with coal to make liquid transportation fuels with a net carbon footprint at or below current petroleum-based fuels [22]. Moreover, biomass has been proposed as a carbon mitigation strategy for the electricity sector by displacing coal-based carbon emissions with a largely carbon-neutral resource [23] [24] [25].

Several agriculture sector economic models have generated U.S. biomass feedstock forecasts, and all concur that not enough biomass exists to displace fossil fuel use in either the transportation or the electricity sectors [26] [27] [28] [29]. This report first presents a methodology for modeling tradeoffs between alternative uses of scarce biomass energy resources using a linear program (LP) designed to estimate concurrent biomass allocations to the transportation and electricity market sectors. The LP model is called the Biomass Allocation Model. Second, this report presents biomass allocation results of this methodology and discusses the ethanol production and carbon mitigating potential of biomass allocations along with relevant sensitivities to significant model parameters.

This report is structured with a general presentation of the model structure followed by a presentation of sensitivity scenario results. Model details are presented as appendices.

Methodology

A general presentation of the entire Biomass Allocation Model is presented in this section of the report. This presentation provides model overview for understanding the model results and analysis presented in the next section, titled "Analysis and Allocation Forecasts." Mathematical details of the model, as well as discussions of model structure and references, are presented in respective appendices. Appendix A contains all of the nomenclature used in this report. Appendix B provides a mathematical explanation of the LP formulation, including the time-step methodology employed for capturing biomass allocations changes over time. Appendix C presents the methodology and assumptions used in estimating the ethanol industry performance and costs, and Appendix D presents the methodology and assumptions used in estimating cofiring performance and costs. Appendix E presents a brief overview of the biomass supply forecast dataset that this research is predicated on. Refer to the appendices when more detail is desired than is presented in the general methodology discussion.

Biomass Allocation Model

The Biomass Allocation Model contains three biomass-to-energy industry modules: a corn ethanol industry module, a cellulosic ethanol industry module, and a cofiring biomass with coal in existing U.S. coal-fired power plants module. Each module has been developed so an estimation of respective biomass-based techno-economic performance in both the motor gasoline transportation fuel and electricity generation sectors allows opportunity cost comparisons with traditional fossil energy resources and technologies in both sectors simultaneously.

Two separate LPs are employed in the Biomass Allocation Model: the corn allocation LP and the biomass allocation LP. The corn allocation LP estimates the cost of producing ethanol from corn and results in a corn ethanol supply curve. The biomass allocation LP is designed to maximize the total revenue possible given the two opportunity cost comparisons in the transportation fuels and electricity sector modules. Total revenue is estimated by combining revenue projections of selling ethanol (both corn- and cellulosic-based) to the transportation fuel sector and of selling biomass feedstocks to a carbon-constrained coal-fired power plant sector. Because the two revenue estimations are contained within the same profit maximization equation, the result is an allocation forecast for biomass resource use within the two sectors.

Biomass resource supply forecasts are contained in a biomass supply forecast dataset.

Biomass Supply Forecast Dataset

The Biomass Allocation Model uses a dataset for corn and biomass resources supplies. The dataset was produced by the University of Tennessee's POLYSYS model in the fall of 2006 for the U.S. Department of Energy, Energy Information Administration [30]. The POLYSYS model, an agriculture economics model, has been developed as a tool for estimating the U.S. agricultural sector's ability to produce and supply biomass energy feedstocks [31]. The biomass supply forecast dataset models the U.S. agriculture sector using 305 regions which cover the entire U.S., excluding Alaska and Hawaii. The dataset provides feedstock quantity and price data for all 305 regions. Not all regions are forecasted to produce biomass feedstocks, some are forecasted to produce certain feedstocks only, and feedstock quantities change with biomass prices, corn ethanol production, and time. The corn and biomass feedstock supply dataset contains corn, soybean, and several other biomass energy feedstock production forecasts as a function of price under various corn ethanol production levels and agricultural production yield assumptions through the year 2030. See Appendix E for depictions of biomass supply geography within the U.S. and supply curves derived from this dataset.

The biomass dataset contains two yield assumptions: base case and high yield. The base case extrapolates historical agricultural crop yield trends (based on USDA estimations), and the high yield case assumes much higher crop yields. Thus, the high yield scenarios aggregate to significantly larger annual supply forecasts (roughly double the base case scenario by 2030). However, only the base case supply forecast is presented and analyzed in this report. Therefore, the biomass supply curves presented below are smaller and more conservative than some supply curves published in other biomass supply research reports.

For this report, "biomass energy feedstocks", or "biomass" refers to the wheat straw, corn stover, switchgrass, forest trimmings and residues portions of the dataset. Although woody feedstocks could be used as a cellulosic ethanol and cofiring feedstock, wheat straw, corn stover, and switchgrass feedstocks are more commonly proposed for ethanol plant designs. It is assumed that these feedstocks could be used interchangeably within a single cellulosic ethanol plant and also within a single cofiring power plant. Therefore, we chose to limit our analysis to this subset of biomass (wheat straw, corn stover, and switchgrass) within the dataset. Thus, the results presented in this report are based only on forecasts of these feedstocks given the base case yield assumption.

Biomass supplies are a function of petroleum energy price. POLYSYS is a separate model and is not incorporated in the Biomass Allocation Model. Moreover, the Biomass Allocation Model does not alter the dataset and must accept all assumptions inherent in the POLYSYS model, including that of petroleum price, and the dataset used in this analysis does not have a specific parameter for petroleum fuel prices. Because the POLYSYS model is not a part of this LP, it is assumed that biomass supply is independent of petroleum price for simplification[1].

The Biomass Allocation Model pulls data from the biomass supply forecast dataset based on year and corn ethanol allocated by the biomass allocation LP. Thus, corn prices are estimated first, and this, in turn, identifies which set of supply curves will be used for the biomass supply estimations. Corn prices are estimated by the Corn Allocation LP and Corn Ethanol Industry Module.

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[1] This is recognized as a shortcoming of the Biomass Allocation Model; however, it was not the goal of this research to reproduce an agriculture sector supply model. Instead, the POLYSYS dataset serves as a surrogate.

Corn Allocation LP and Corn Ethanol Industry Module

The corn allocation LP allocates corn from corn-producing counties to existing, currently under construction, or future expanded corn ethanol plants. The LP seeks to minimize the total aggregated cost of producing all corn-based ethanol and is constrained so all facilities receive enough corn to operate at full capacity over 96% of the year. The LP model estimates allocations based on state-specific corn prices and quantities, transportation costs between farms and corn ethanol plants, and individual corn ethanol plant production cost estimations. Individual production cost estimations are functions of plant size and state-specific energy costs (assume natural gas for thermal energy). Existing corn ethanol plant locations are well documented, and transportation costs are estimated by a simple assumption that corn production is located in the center of a state. This simplification assumption drastically reduces the size of the LP model and error estimations concluded that corn ethanol production forecasts are relatively insensitive to this aggregation assumption. The corn allocation LP produces an upwardly sloping corn ethanol supply curve, which is then used in the biomass allocation LP.

The corn ethanol industry module is intended to capture economic potential. The module does not seek to capture market-distorting policy goals affecting future ethanol plant locations such as regional tax incentives and/or blending regulations.

Cellulosic Ethanol Industry Module

Cellulosic ethanol production is assumed to begin on a particular date (which is a model variable) and then experience process and design improvements as more plants are built over time. Thus, cellulosic ethanol plant gate prices are assumed to decline over time. Because it is unclear when the first plant will be constructed, how quickly subsequent plants will be constructed, and at what rate process improvements and cost reductions will actually take place, future cellulosic ethanol plant gate price is a model variable and price forecasts are predicated on assumptions. For all cases presented in this report, it is assumed that the first cellulosic ethanol plant is built in the year 2010. The rate that process improvements take place over time is varied in a sensitivity analysis.

For each year analyzed, an estimation of cellulosic ethanol capacity and plant gate price is made for each region. Each region's plant gate price is estimated using an economy of scale equation which reflects each region's quantity of potential biomass feedstock supply. For example, if a region can produce enough biomass feedstock to support a 100 million gallon per year plant, then the plant gate price for ethanol produced in that region would be lower than in a region which could only produce enough biomass to support a 5 million gallon per year plant. It is assumed that ethanol production capacity is developed in the geographical center of each region. A few regions are forecasted to produce enough biomass feedstocks to support multiple large capacity plants (100 million gallons per year or more). For these regions, it is assumed that multiple 100 million gallons per year plants are built within the region. Biomass feedstock supply could come from any location within a region, and therefore, the average shipping distance between biomass-producing farms and cellulosic ethanol plants will be the average distance of all land within the region.

To reduce the LP solution time, the number of decision variables within the biomass allocation LP is reduced by aggregating cellulosic ethanol production from regional to state levels. A state's capacity is simply the sum of all its regional capacity estimations. Ethanol plant gate price aggregation is achieved by averaging regional plant gate prices weighted by regional capacities. States that do not posses biomass supply resources in the biomass supply forecast dataset are not home to any cellulosic ethanol production capacity. Thus a cellulosic supply curve can be created by rank ordering the estimated U.S. cellulosic ethanol capacity plant gate costs and production forecasts.

Biomass and Coal Cofiring Module

Biomass and coal cofiring in existing coal-fired power plants on a large scale is only economical if CO_2 emissions are valued through a CO_2 price mechanism such as a cost per quantity of CO_2 emitted [32] [33]. The biomass and coal cofiring module assumes that a market exists and that the CO_2 emissions are valued by a variable cost per ton CO_2. Thus, mitigating CO_2 emissions by offsetting coal consumption with a carbon neutral biomass feedstock will provide a benefit to the power plant of not being penalized for mitigated emissions.

Existing power plant historic data is taken from eGRID 2006 [34]. Cost and power plant performance effects from cofiring biomass with coal reference the extensive cofiring analysis work performed by the U.S. Department of Energy. Capital costs increase as a function of cofiring rates because more equipment is required as cofire rates increase. An efficiency penalty is assumed for the biomass consumption which is made-up for by increasing coal consumption such that power plants are not de-rated when cofiring. Cofiring plants receive a co-benefit from biomass and coal cofiring through the reduction of SO_2 and NO_x emissions, and very general prices are assumed for these co-benefits.

Biomass Allocation LP

The biomass allocation LP allocates energy to the motor gasoline markets and to coal-fired power plants simultaneously. Biomass energy, in the form of Btus, is allocated directly to existing coal-fired power plants. However, a conversion factor is employed to allocate biomass energy to the transportation fuels sector; the cellulosic ethanol industry module converts biomass to ethanol and then equates ethanol to a gasoline-equivalent-based Btu. Corn-based ethanol is also converted to gasoline-equivalent Btus. Therefore, the biomass allocation LP uses a common unit of Btus for both sectors. Because a price is given for the biomass itself and is estimated for ethanol plant gate prices, a price per Btu can be calculated as it applies to each demand for biomass resources.

In order to limit LP decision variables and consequently model solution time, motor gasoline demands are modeled at state levels. Demand quantities are taken from the U.S. Department of Transportation highway statistics for the year 2005 and, as a simplifying assumption, are assumed to grow at 1% per year [35]. To estimate ethanol transportation costs, state motor gasoline demands are assumed to be located in the geographical center of each state. The model estimates ethanol shipments from ethanol production to the center of states in order to meet state transportation fuel demands. When the model is solved for existing corn ethanol plants alone, the average shipping distance of corn ethanol is 134 miles. Because new corn ethanol production, cellulosic ethanol production, and ethanol demand are all assumed to be located at the geographical center of states, a transportation distance of 134 miles is assigned to intrastate shipments from these forecasted ethanol production capacities. Similarly, biomass quantities are aggregated to state levels and are assumed to reside at the geographic center of each state. Because power plants are modeled individually, biomass transportation costs between fields and power plants are estimated by the distance between individual power plants and state geographical centers.

The LP is constrained by several assumptions. Biomass allocations can only displace 20% of a power plant's coal energy consumption, and ethanol allocations cannot be greater than 85% of motor gasoline energy demand. This limits ethanol allocations to be equal to, or below, a complete E85 blend in any particular state, and does not allow cofiring to be beyond a reasonable range. Allowing blends up to E85 implies that flex fuel vehicles have fully penetrated the U.S. fleet which is improbable by 2020 and thus allowing blends up to 85% is a simplifying assumption. In addition, allocation conservation constraints are also applied such that a ton of biomass can only be used once.

The biomass supply dataset is reflective of a non-linear corn supply curve. However, a linear program requires linear equations and, as a result, the non-linear corn supply curve is modeled through a set of assumptions and constraints. It is first assumed that corn prices are perfectly elastic and that an increase in corn used for ethanol does not increase corn prices. The corn allocation LP does contain relative price differences between states and uses shipping distances to minimize total corn delivery costs to ethanol plants, but does not bid-up corn prices. Because existing corn ethanol plants are of different sizes and distances from existing corn production areas, the corn allocation LP produces a corn ethanol supply curve. Corn ethanol production is fixed exogenously at the point where marginal corn ethanol producers have zero profit. In reality, though, corn prices are not perfectly elastic and large demands for corn use at corn ethanol plants will bid-up corn prices. If "too much" corn is used for ethanol production, all corn ethanol producers will experience a rise in corn prices, causing a negative or "upward" shift in the entire corn ethanol supply curve (i.e., less quantity supplied at every price). Continued such movement of the corn ethanol production supply curve is therefore limited by the said exogenous constraint, so that corn ethanol production is not allowed to bid-up corn prices beyond a level that allows most corn ethanol producers to earn a profit. Corn prices and corn ethanol capacity expansions are related to oil prices because higher oil prices result in larger corn-based ethanol profit margins, thus, creating incentives for investors to invest in corn-based ethanol capacity expansions, which, in turn, bid-up corn prices.

Within the biomass supply dataset, agricultural practices adjust to price signals, and greater corn prices lead to more corn production in following years. As more corn is available in future years, new corn ethanol capacity potential exists in all states where corn is grown, and for this reason, the exogenous corn ethanol production constraint is loosened over time as more corn becomes available. If enough corn is not produced within a state to build a new plant at a profitable economy of scale, or if the state is a high marginal corn price state, then its potential corn ethanol capacity might not be allocated through the biomass allocation LP. In this case, the state has un-materialized potential ethanol growth capacity.

For existing ethanol production capacity, plant gate prices (e.g., $/gal) are estimated using a short-term marginal cost method which excludes capital cost. For these plants, capital costs are either already depreciated or the decision to produce and sell ethanol is independent of capital cost, or capital cost debt payments. Therefore, it is assumed that the plant gate price is purely a function of variable, or short-term, costs.

New ethanol plant gate prices are estimated using a long-term marginal cost method and assume a relatively high investor hurdle rate. For new corn ethanol capacity, a high investor hurdle rate is justified as corn ethanol production growth is bound by short-term inelasticity in corn prices. New cellulosic ethanol plant gate prices as well as cofiring cost estimations are also estimated using a long-term marginal cost method and equally high investor hurdle rates. If new ethanol capacity potential is allocated by the biomass allocation LP, or an existing coal-fired power plant converts to cofiring, then during the next time-step period these plants are assumed to be "existing" and plant gate prices and cofiring costs are estimated using a short-term marginal cost method. Thus, in subsequent years, existing ethanol plants and power plants converted to cofiring get preferential biomass allocation due to their lower cost estimations relative to new capacity or non-cofiring power plants.

Biomass Allocation LP Parameters and General Assumptions

Crucial variables determining biomass allocations to the transportation and electricity markets are crude oil prices, CO_2 market prices, Volumetric Ethanol Excise Tax Credit (VEETC) continuation, cellulosic ethanol process improvements and capital cost reduction, and inflation of the cost of capital intensive infrastructure projects. All of these critical variables are held constant exogenously during LP solution runs, and sensitivity analysis is performed by varying each individually. When the VEETC is applied to ethanol prices, the $0.51/gal of ethanol is assumed to grow with inflation, so its real value remains at $0.51/gal for all forecasted years. All prices referenced from earlier reports are converted into 2007 dollars, and a constant inflation rate of 2.2% is assumed when projecting 2007 prices into future real dollars. Fossil energy prices and electricity prices are taken from EIA's Annual Energy Outlook 2007, and the model is constructed to be solved assuming the Annual Energy Outlook's Reference Case or High Price Case [8]. Various CO_2 market prices, expiration dates for the VEETC, cellulosic ethanol process improvement targets, capital cost inflation rates, and cellulosic ethanol's CO_2 mitigation credits are assumed throughout the analysis. In all scenarios, it is assumed that corn ethanol production will expand at a rate allowable by the corn market and crude oil prices. In general, the corn ethanol production forecast is similar to current capacity expansion and USDA corn ethanol production forecasts [6] [7].

The quantity of biomass energy's carbon footprint is a topic of much debate with some research concluding negative life-cycle carbon emissions and other research concluding positive net life-cycle carbon emissions when producing biomass energy feedstocks. This analysis does not incorporate life-cycle carbon benefits from biomass energy use such as soil root carbon sequestration, nor does it include life-cycle carbon emissions from biomass energy use such as farming equipment and fertilizer use. As a simplification, this analysis assumes that the carbon benefit from using biomass is equal only to the fossil carbon directly displaced when biomass is used as a fossil energy alternative. Thus, cellulosic ethanol is assumed to be carbon neutral, and therefore, when cellulosic ethanol displaces gasoline use, a carbon emission reduction benefit is achieved. Only the carbon displaced from gasoline use is used as the carbon mitigation benefit of cellulosic ethanol use. This assumption follows through cofiring biomass with coal in existing coal-fired power plants as well. The model assumes that the mechanism driving biomass use over fossil energy use is the value of this carbon. This assumption will likely be the subject of much political debate if United States legislators enact carbon mitigation policies in the future.

When cellulosic ethanol receives a financial credit for this benefit, as is the case with the reference case, it is assumed that the financial credit is equal to electricity sector CO_2 values (e.g., \$/ton CO_2). We assume approximately 19 lbs of CO_2 are mitigated when a gallon of gasoline is displaced with cellulosic ethanol. This results in approximately \$0.29/gal at \$30/ton CO_2.

Analysis and Allocation Forecasts

A reference case scenario is presented first followed by several sensitivity analysis cases. The reference case is not a forecast, per se, but a set of assumptions regarding modeled variables. The reference case provides a backdrop against which model parameter sensitivities can be compared and trends associated with key variable assumptions discussed through sensitivity cases. Thus, sensitivity cases explore changes in biomass allocations compared to the reference case. Key model variables, representing sensitivity cases, are future oil prices, future CO_2 prices, cellulosic ethanol process improvements and cost reductions over time, higher infrastructure costs, and whether cellulosic ethanol receives CO_2 monetary credit.

Reference Case

Key variable assumptions

The key variables in the Biomass Allocation Model are future oil prices, future CO_2 prices, cellulosic ethanol process improvements and cost reductions over time, higher infrastructure costs, and whether cellulosic ethanol receives CO_2 monetary credit. The reference case assumes future oil prices are equal to EIA's AEO 2007 high price case estimations. It is assumed that the first cellulosic ethanol plant is built in 2010 and all anticipated cellulosic ethanol production improvements and cost reductions take place along the timeframe presented in Appendix C and that future cellulosic ethanol processes improvements and production cost reduction goals, as detailed in Appendix C, are achieved. Infrastructure cost are assumed to grow no faster than inflation, and it is assumed that cellulosic ethanol, but not corn ethanol, receives monetary credit for CO_2 emissions reductions from displaced gasoline use. It is also assumed that the Volumetric Ethanol Excise Tax Credit (VEETC) is continued through 2020 with a consistent real value of $0.51/gal of ethanol.

Within the Biomass Allocation Model, CO_2 prices are determined by biomass prices and cofiring costs for existing coal-fired power plants choosing to cofire biomass and coal. Within the biomass supply forecast dataset, $20/dry short ton is the lowest price at which farmers would produce biomass energy feedstocks. At this price, however, only a very small quantity of feedstock would be supplied from the agriculture sector (see Figure E 4 in Appendix E). Without a CO_2 value, existing coal-fired power plants cannot afford biomass resources. At approximately $10/ton CO_2, a few power plants could pay $20/dry short ton for biomass feedstocks assuming that they are located near those few farmers producing feedstocks at $20/dry short ton. Therefore, higher CO_2 prices are required before existing coal-fired power plants could demand biomass feedstocks on a large-scale basis. For the reference case, CO_2 prices are set at $30/ton CO_2 in 2010, rise to $35/ton CO_2 by 2015, and remain at $35/ton CO_2 through 2020.

Cellulosic ethanol process and cost improvement assumption leads to low cellulosic ethanol production costs in the year 2020. Assuming EIA's high price scenario, motor gasoline prices will be high enough to provide a large profit to cellulosic ethanol producers. If the VEETC is extended through 2020, even larger profits for cellulosic ethanol producers will result.

Large cellulosic ethanol profits would likely result in rapid development of the cellulosic ethanol industry. A rapidly expanding cellulosic ethanol industry bids biomass prices to the highest point on the biomass supply curve and a larger portion of cellulosic ethanol profits pass to the agricultural sector. Thus, driven by high motor gasoline prices and relatively cheap cellulosic ethanol production, biomass prices rise to \$100/dry short ton by 2020. At this biomass price, CO_2 prices would have to be approximately \$70 to \$80/ton CO_2 before power plants could compete with cellulosic ethanol producers for biomass feedstocks. Because other carbon mitigating options become available to existing coal-fired power plants far below \$70 to \$80/ton CO_2, carbon prices are left at \$35/ton CO_2 for 2020.

Table 1 presents the key parameter assumptions for the reference case.

Table 1 – Key Parameter Assumptions: Reference Case

	Year		
	2010	**2015**	**2020**
Biomass Price	\$40	\$40	\$100
CO2 Market Price	\$30	\$35	\$35
Capital Cost Inflator (100% = 2x capital costs)	0%	0%	0%
% of Cellulosic Ethanol Process & Capital Cost Improvement Targets met	N/A	100%	100%
	N/A	100%	100%
Operating Cost (\$/gal)	\$1.69	\$1.04	\$0.57
Conversion Efficiency (gal/ton biomass)	60	78.2	89.6
Volumetric Ethanol Excise Tax Credit (\$/gal)	\$0.51	\$0.51	\$0.51
Cellulosic Ethanol CO2 Credit?	Yes	Yes	Yes
Fossil Energy Price (EIA's high price case)			
Crude Oil (\$/bl)	\$69.21	\$79.57	\$89.65
Natural Gas (\$/MMbtu)	\$7.03	\$6.50	\$6.61
Electricity (\$/MWh)	\$6.36	\$5.91	\$5.94

Allocation Forecast

In 2010, a small amount of biomass is allocated to cofiring and no biomass is allocated to cellulosic ethanol production. Assuming that the 1st cellulosic ethanol plant is built by 2010, process improvements and cost reductions will not have had enough time to allow profitable cellulosic ethanol; a crude oil price in excess of \$155/bbl (2.25 times higher than EIA's AEO07 High Price Case forecast) would be required before cellulosic ethanol would be competitive with cofiring in 2010. Enough cellulosic ethanol process improvements take place by 2015 such that biomass begins to be allocated to cellulosic ethanol production and biomass allocations split between cofiring and cellulosic ethanol production. By 2020, much of the anticipated cellulosic ethanol process improvements have taken place, and no cofiring is forecasted as most biomass is allocated to cellulosic ethanol production.

Table 2 presents Biomass Allocation Model results for the reference case scenario.

Table 2 – Biomass Allocation Model Forecasts for the Reference Case

	Year		
	2010	**2015**	**2020**
Transportation Market			
Corn Ethanol Allocated (Billion Gal/yr)	10.3	13.2	14.6
Cellulosic Ethanol Allocated (Billion Gal/yr)	0	4.1	29.9
Crude Oil Displacement (Billion barrels/yr)	0.17	0.22	0.73
Cellulosic Ethanol CO_2 Mitigation (Million tons)	0	27	196
Electricity Market			
Coal Displacement (quads)	0.63	1.46	0
Cofiring CO_2 Mitigation (Million tons)	65	153	0
Biomass Allocations			
Biomass Allocated to Cellulosic Ethanol (quads)	0	0.76	4.77
Biomass Allocated to Cofiring (quads)	0.70	1.62	0
Stranded Biomass (quads)	0.69	0.15	0.60

Discussion

Some biomass potential (crop residues, switchgrass, etc.) in the biomass supply dataset is uneconomical to use, and for this report, the measure of the uneconomical biomass potential is designated as "Stranded Biomass." Economy of scale equations are used to estimate cellulosic ethanol production cost; very small plants have high capital costs (see Figure C 3) which translate into high ethanol plant gate prices. If locally available biomass quantities are too small, a cellulosic ethanol production facility cannot be built large enough to produce profitable cellulosic ethanol, and this ethanol does not get allocated by the biomass allocation LP. If this same biomass is located too far from a coal-fired power plant to be cofired at a profit, then the biomass is not allocated at all, or is stranded. Therefore, stranded biomass is biomass growth potential which cannot make it to a coal-fired power plant given the scenario CO_2 price assumptions and which cannot be converted into cellulosic ethanol at a price low enough to be profitable given motor gasoline price and VEETC credit assumptions. Stranded biomass potential is forecasted in all the years analyzed although there is relatively less stranded biomass potential when biomass is allocated to both uses as in 2015.

Sensitivity Cases

The reference case could be thought of as a biomass energy pathway in which biomass is first used by the electricity sector, and ethanol production eventually inherits a matured biomass production market to become the primary biomass energy consumer. However, different assumptions can lead to longer-term cofiring and delayed cellulosic ethanol production or vice versa. The following sensitivity cases explore biomass allocation sensitivity to A) oil prices, B) CO_2 prices, C) cellulosic ethanol process improvements and cost reductions over time, D) higher infrastructure costs, and E) whether cellulosic ethanol receives a CO_2 monetary credit in future CO_2 mitigation legislation.

In general, the biomass allocation forecasts are very sensitive to oil prices. Within the Biomass Allocation Model, ethanol only displaces gasoline if its pump price is equal to or below that of gasoline. Because gasoline prices are largely determined by oil prices, future cellulosic ethanol capacity expansion forecasts, and therefore biomass allocations, are sensitive to future oil prices. All things equal to the reference case, ethanol will not exceed EIA's AEO07 forecasted oil price prior to 2010 (see Figure 1). For this reason, no biomass is allocated to cellulosic ethanol production in 2010. As cellulosic ethanol production processes mature causing plant gate prices to fall, cellulosic ethanol becomes profitable in years 2015 and beyond. For each sensitivity case, biomass allocation sensitivities are only analyzed for years 2015 and 2020.

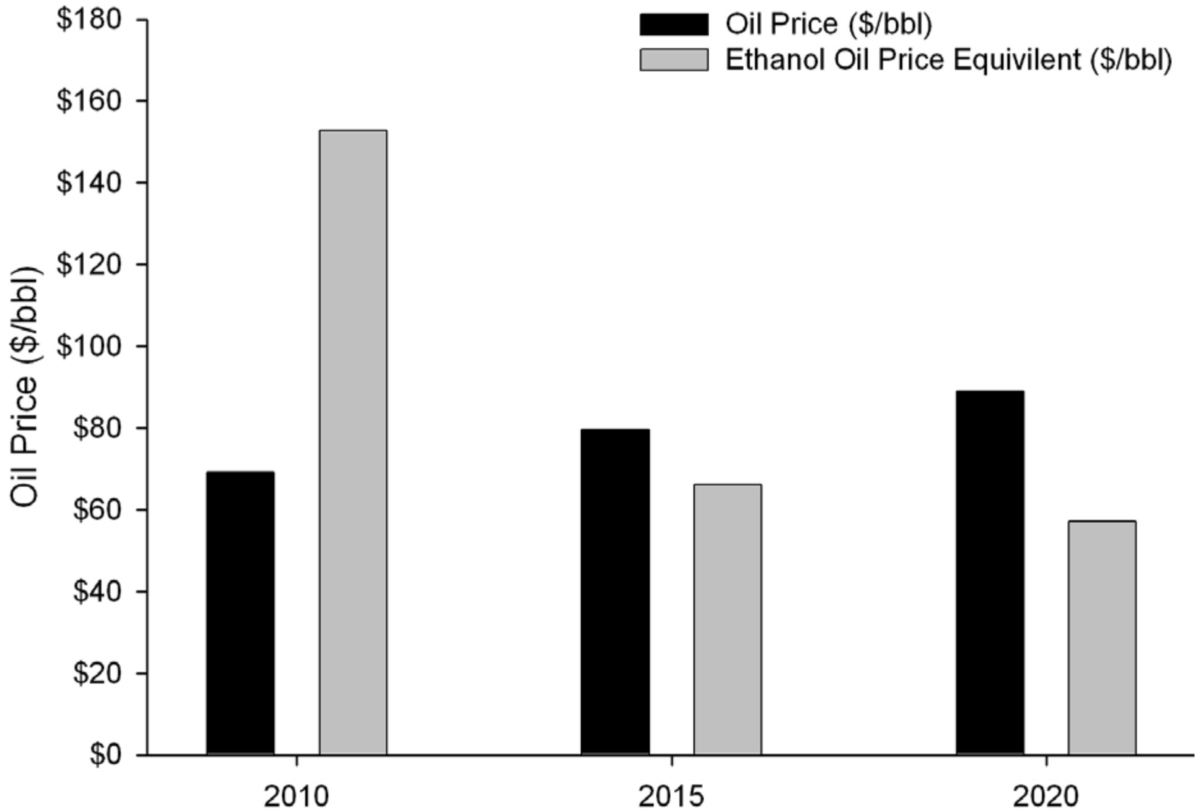

Figure 1 – Cellulosic Ethanol Plant Gate Prices (Oil Price Equivalent) and EIA's AEO07 High Price Case Oil Prices

Sensitivity Case – Oil Price

The first sensitivity case examines biomass allocation results as changes are made to future oil price assumptions. Each year (2015 and 2020) is treated separately, and the future oil price is the only variable adjusted between model LP solutions. The results and a discussion are presented below.

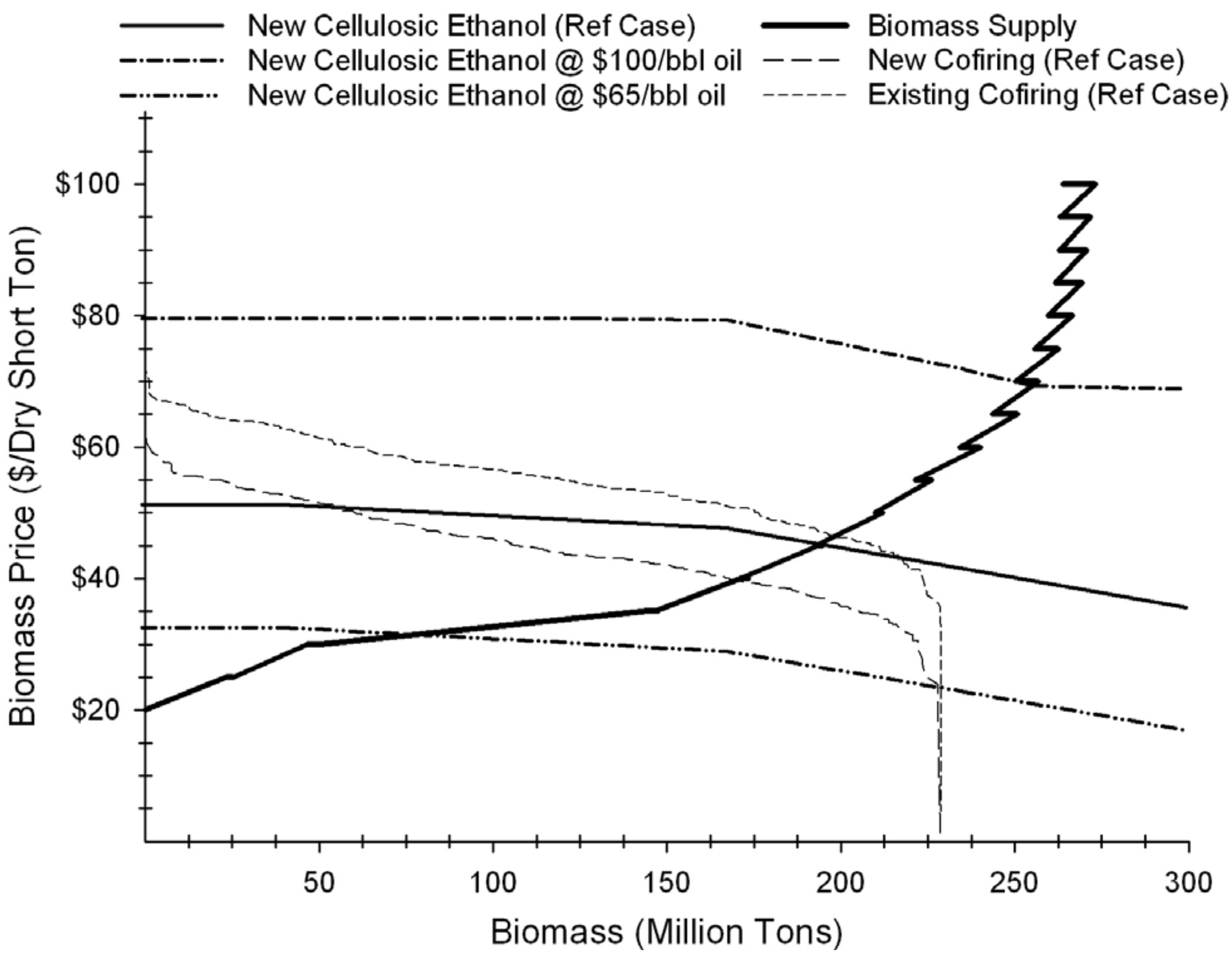

Figure 2 - Oil Price Sensitivity Analysis: Biomass Supply and Demand Curves for Year 2015

Year 2015

A biomass supply curve and cellulosic ethanol and cofiring demand curves for year 2015 are presented in Figure 2. The two cofiring demand curves presented represent demand from new cofiring power plants using a long term marginal costs calculation and from existing cofiring power plants using a short term marginal cost calculation. The cofiring demand curves are derived using the assumption that each coal-fired power plant residing in a state where biomass supplies would be produced cofires at 20% by energy. The demand curve calculation estimates a price that each power plant would be willing to pay for biomass feedstocks, including a general estimation of biomass shipping costs, regardless of the actual amount of biomass available within the state. In the Biomass Allocation Model estimation, a conservation of biomass constrains how many power plants can actually cofire given the quantity of biomass available and biomass shipping costs. If biomass is allocated to a power plant in one year, that power plant is modeled as an existing cofiring plant in all subsequent years, and its demand for biomass is estimated using a short term marginal cost calculation. Because this is an oil sensitivity case, CO_2 prices are the same as in the reference case ($35/ton CO_2). Demand for biomass feedstocks from new cellulosic ethanol production facilities are presented for two oil prices: $65/bbl and $100/bbl. The cellulosic ethanol demand curves are derived assuming that all of a state's demand for motor gasoline is displaced with cellulosic ethanol. The Biomass Allocation Model then determines biomass allocations to cofiring power plants and cellulosic ethanol production based on the previously described total revenue maximizing LP objective function and constraints. Therefore the demand curves provide a general indication of biomass allocations, but actual Biomass Allocation Model solutions present the most optimal biomass allocations between the two alternative demands for scarce biomass resources.

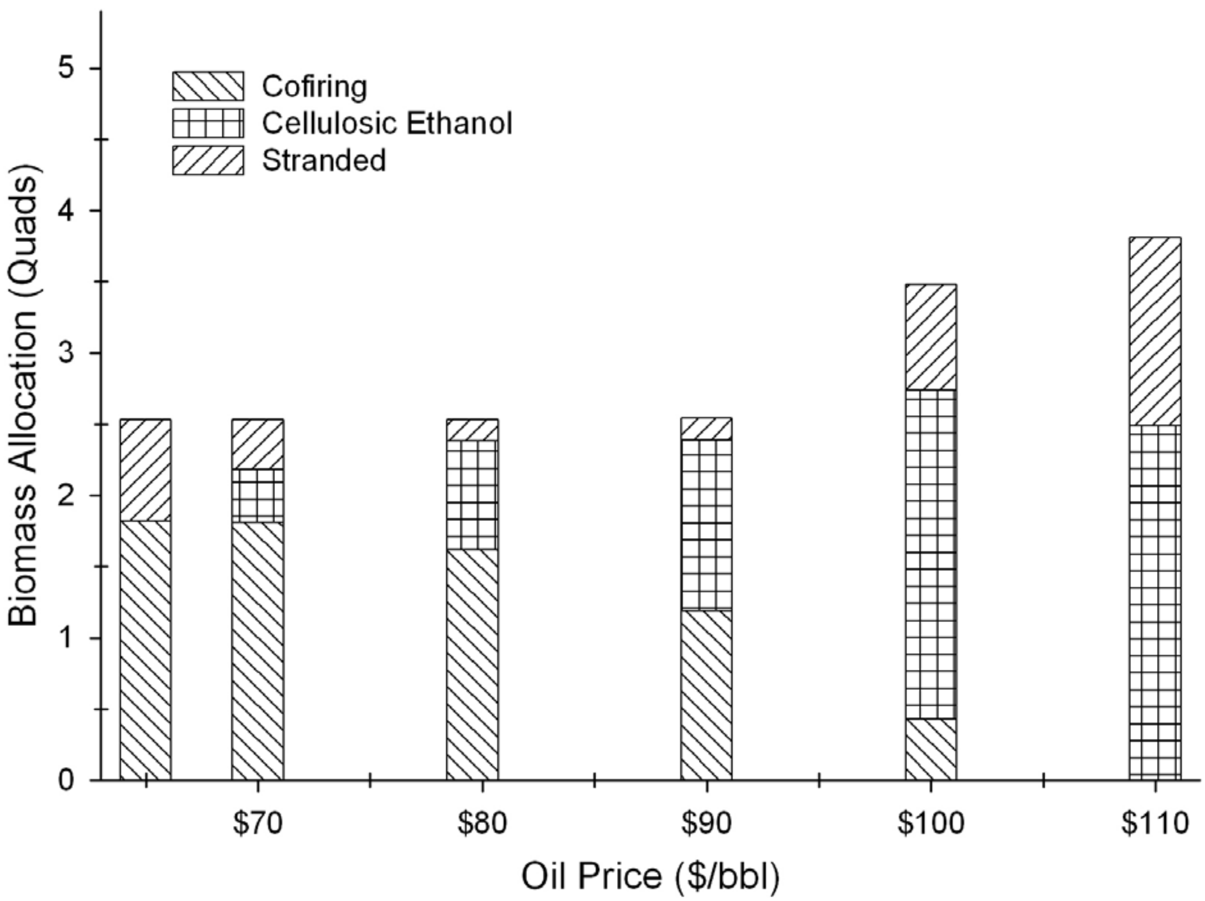

Figure 3 – Oil Price Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2015

Given the 2015 reference case assumptions, biomass allocations are sensitive to oil prices between $70 and $110/bbl (See Figure 3). Assuming a $35/ton CO_2 price, existing cofiring power plants can afford biomass feedstocks at prices between $40 and $70/dry short ton. The $40/dry short ton price from cofiring power plants creates a price floor below which biomass prices do not fall. At a $70/bbl oil price, cellulosic ethanol producers can only afford to pay $35/dry short ton for biomass feedstocks, and therefore, below approximately $70/bbl oil price, cellulosic ethanol production is not forecasted. If oil prices are at EIA AEO07 high price case forecast ($79.57/bbl), then cellulosic ethanol would be profitable and the reference case allocates biomass to cellulosic ethanol production. When oil prices reach $90/bbl, cellulosic ethanol starts bidding up biomass feedstock prices. Holding CO_2 prices at $35/ton CO_2, rising biomass feedstock prices means that fewer existing cofiring power plants can afford biomass and less biomass is allocated to cofiring. Once oil prices exceed $100/bbl, cellulosic ethanol can pay $70/dry short ton for biomass resources. $70/dry short ton allows greater biomass quantities to be available although very few power plants can afford biomass given a $35/ton CO_2 price. Above approximately $110/bbl oil prices, all biomass is allocated to cellulosic ethanol production.

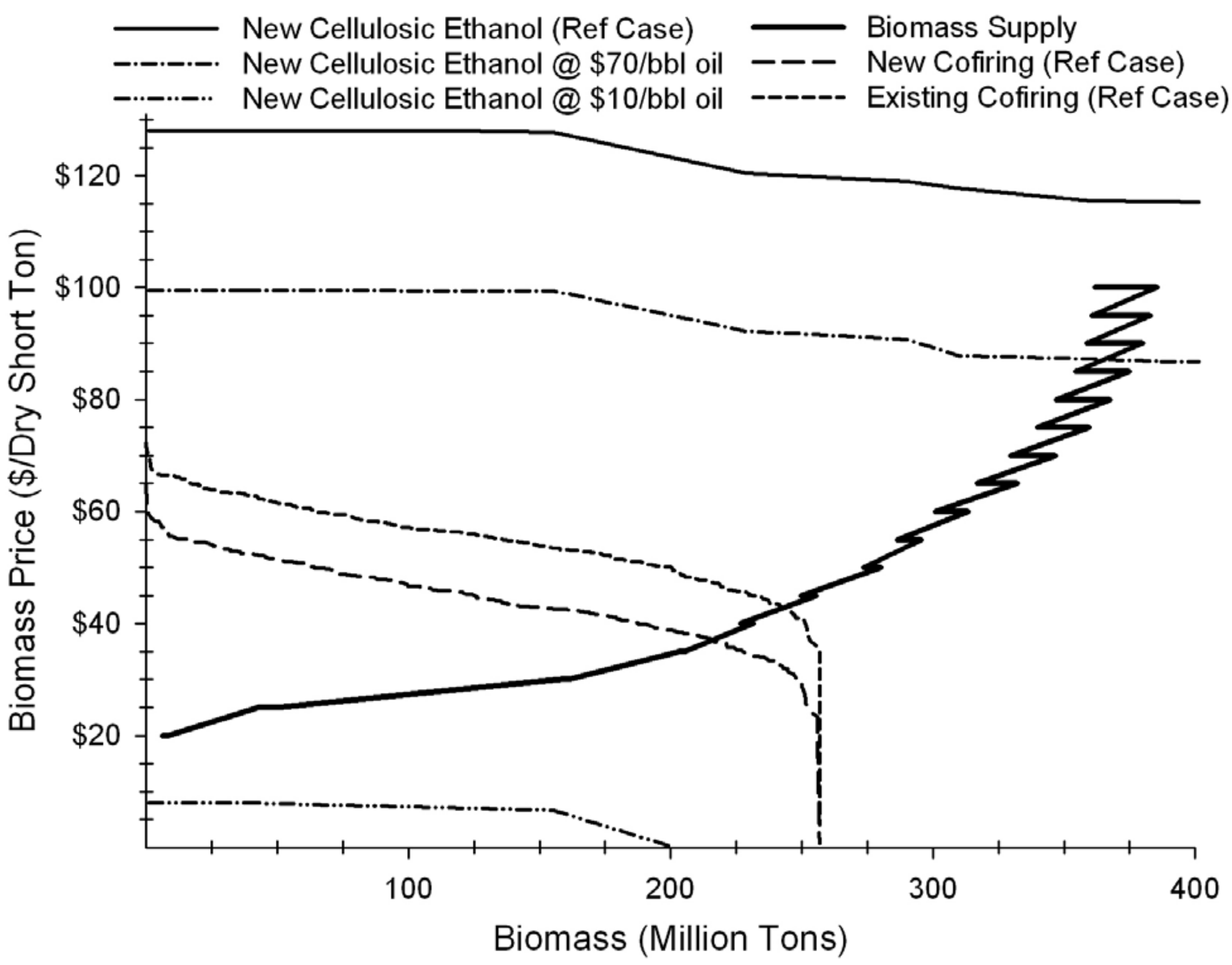

Figure 4 – Oil Price Sensitivity Analysis: Biomass Supply and Demand Curves for Year 2020

Year 2020

Biomass supply and demand curves for 2020 are presented in Figure 4. The supply and demand curves are estimated using the same methodology described above for the supply and demand curves for year 2015.

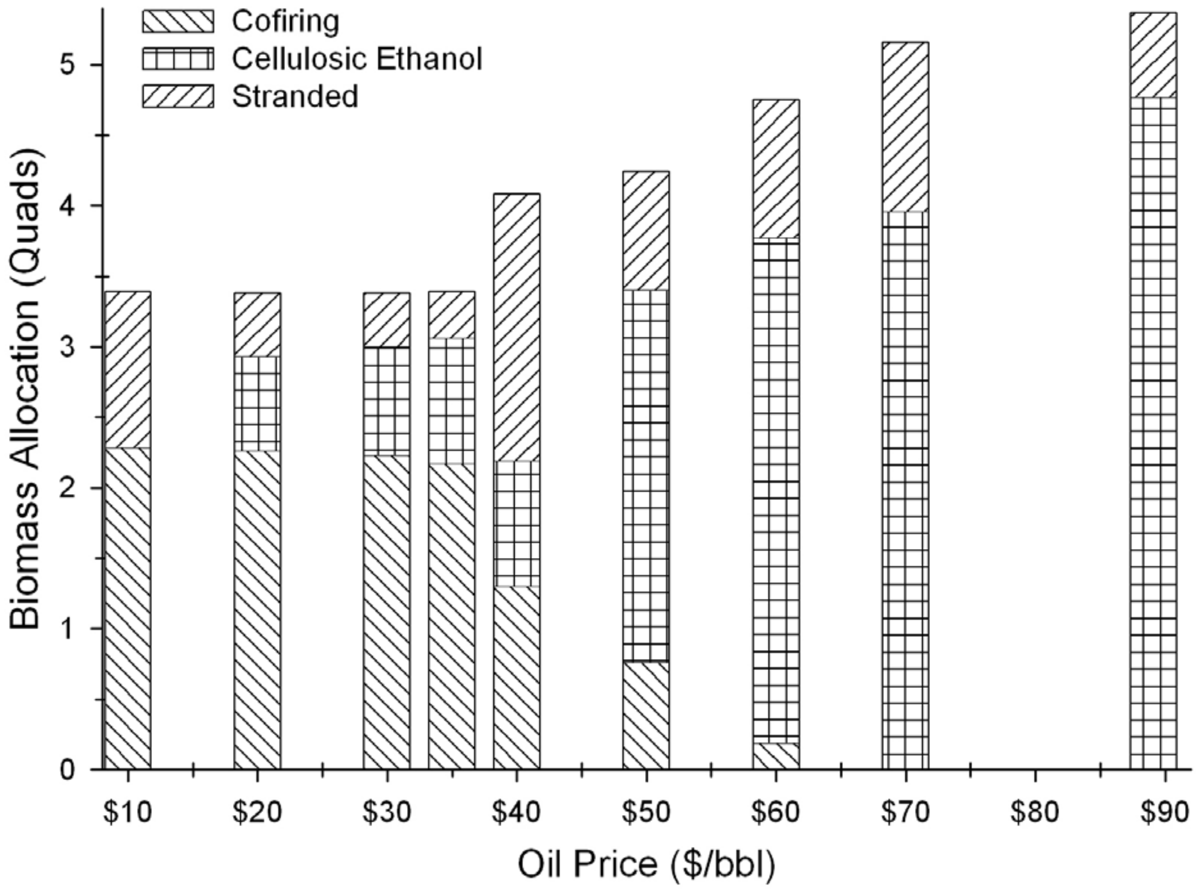

Figure 5 – Oil Price Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2020

Given the reference case assumptions, 2020 biomass allocations are sensitive to oil prices between $10 and $70/bbl (see Figure 5). $70/dry short ton is the highest biomass feedstock price that existing cofiring power plants can afford assuming $35/ton CO_2 price. New cellulosic ethanol producers could afford $70/dry short ton biomass feedstocks at oil prices above approximately $60/bbl. If EIA AEO07 high price case forecast of $89.12/bbl oil price is accurate, then cellulosic ethanol production can afford more than $100/dry short ton biomass feedstock and all biomass is allocated to ethanol production. Between approximately $10 and $60/bbl oil price, biomass allocations split between the two alternative uses; however, between $50 and $60/bbl oil prices, new cellulosic ethanol capacity dominates. Reducing oil prices from $50 to $40/bbl, biomass feedstock prices fall and more existing power plants can afford to cofire.

In this oil price range, marginal cofiring plants and cellulosic ethanol producers keep biomass prices high enough that only a fraction of the potential cellulosic ethanol producers and existing cofiring power plants can afford biomass feedstocks, and a substantial amount of biomass is stranded. An oil price below $40/bbl reduces marginal cellulosic ethanol production allowing biomass price reductions, and greater biomass is allocated to existing cofiring power plants. Existing cofiring power plants keep biomass prices at $40/dry short ton regardless of how low oil prices go. At an oil price of $35/bbl, new cellulosic ethanol production can only afford $35/dry ton biomass feedstocks and therefore, cellulosic ethanol capacity does not expand.

Biomass allocation forecasts for 2020 are sensitive to oil prices in 2020 and 2015. 2020 sensitivity analysis is based upon 2015 reference case forecasts but will be sensitive to 2015 assumptions. For example, if 2015 oil prices do not support any cellulosic ethanol capacity development, then the cellulosic ethanol forecasted at low oil prices in 2020 will not be produced because capacity would not have been built in 2015. Given the reference case assumptions, cellulosic ethanol production expansions developed prior to 2020 will remain profitable in 2020 down to $10/bbl oil prices. However, as oil prices fall below $35/bbl, less cellulosic ethanol is produced at these facilities and slightly more cofiring takes place along with slightly more stranded biomass.

CO_2 mitigation in 2015 and 2020

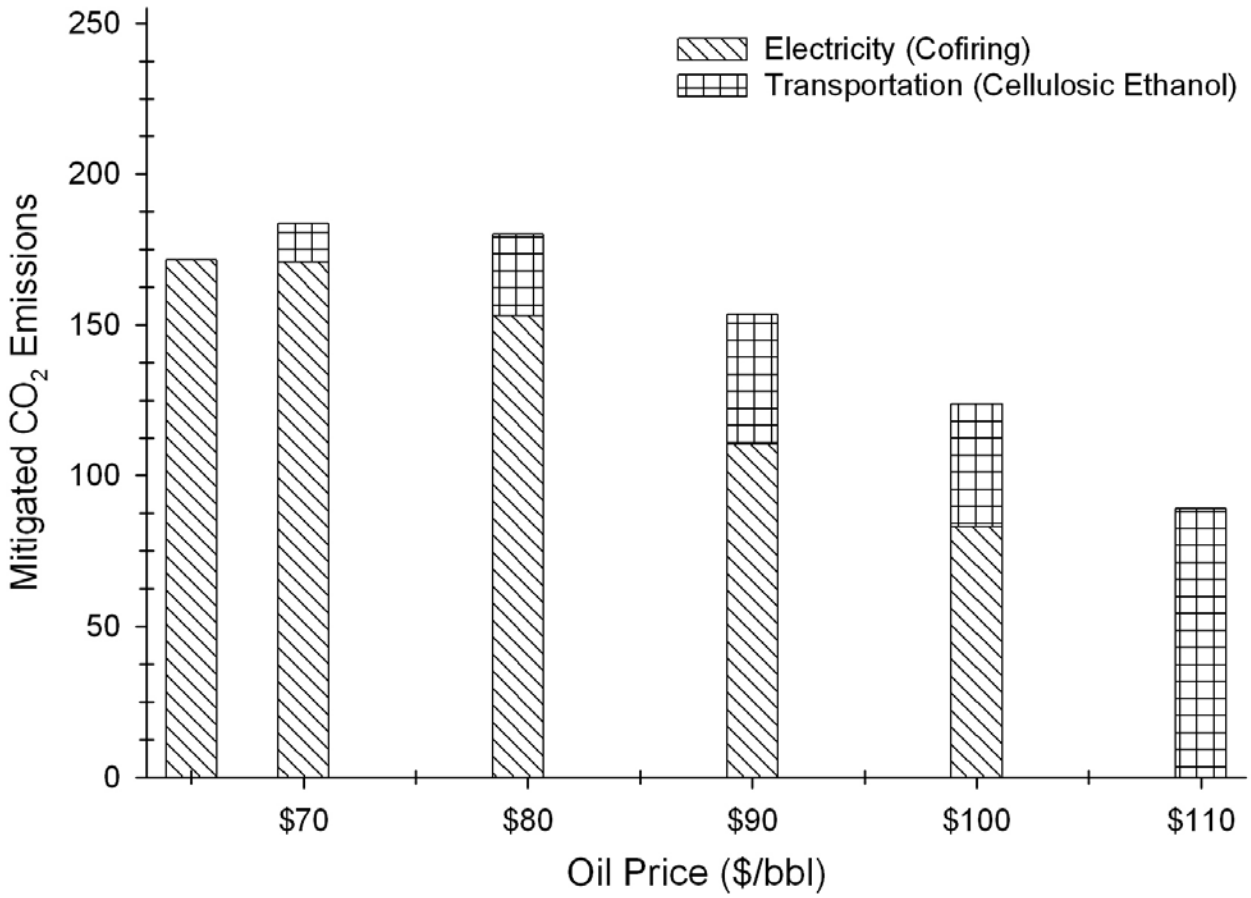

Figure 6 – Oil Price Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2015

Because biomass displaces more CO_2 emissions when cofired than when displacing gasoline, CO_2 mitigation is also sensitive to oil price. Figure 6 and Figure 7 present CO_2 mitigation's oil price sensitivity analysis for 2015 and 2020 respectively. In 2015, the introduction of cellulosic ethanol production at $70/bbl oil price reduces stranded biomass but does not take biomass from cofiring power plants. Above a $70/bbl oil price, biomass allocated to cellulosic ethanol production increases and CO_2 mitigated at coal-fired power plants reduces. Despite more biomass availability with higher oil prices, CO_2 mitigation decreases as oil prices increase. For example, at a $110/bbl oil price, roughly 1/3 more biomass is allocated than at a $90/bbl oil price, but only 1/2 of the CO_2 mitigation is achieved in 2015.

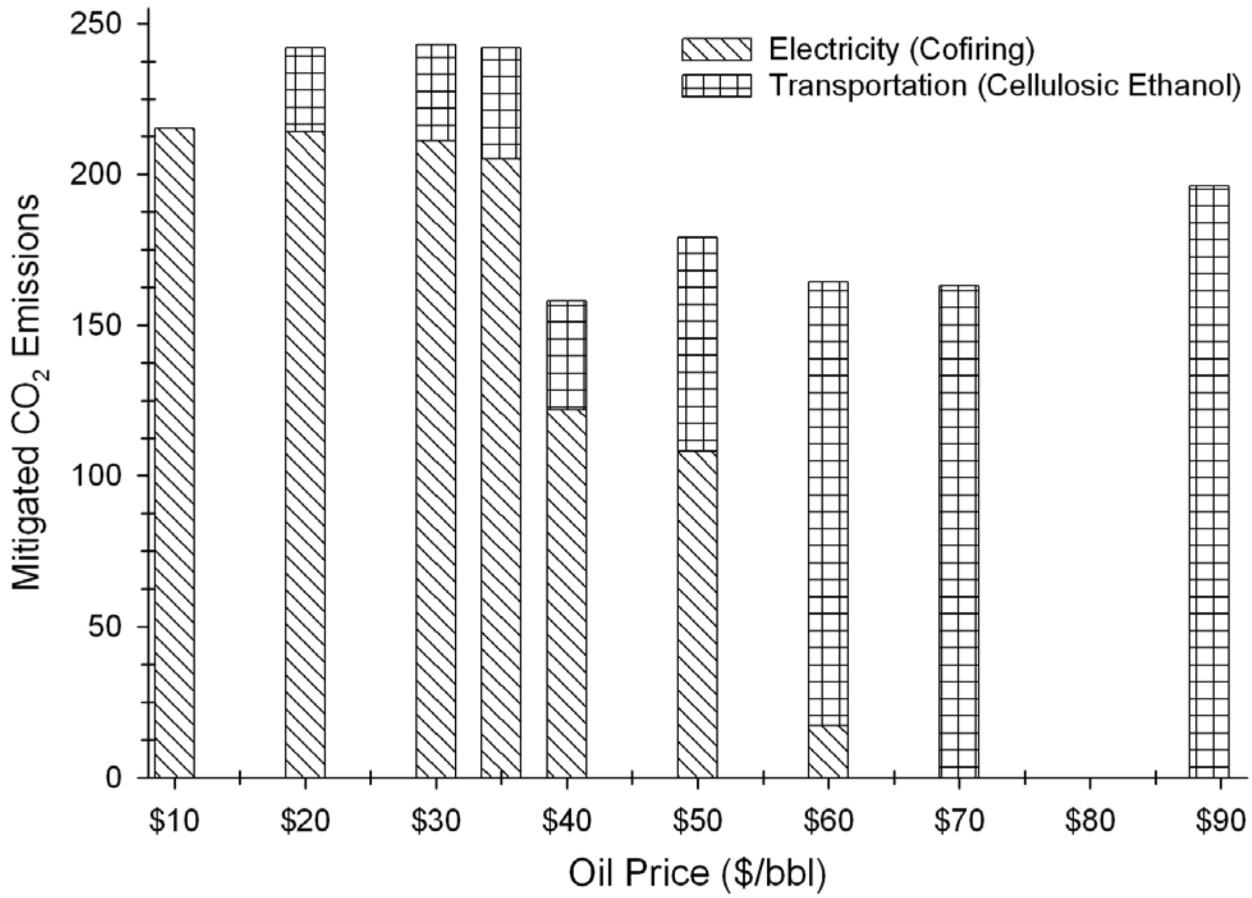

Figure 7 – Oil Price Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2020

Higher oil prices in 2020 allow for substantially more biomass utilization in the production of cellulosic ethanol and mask some of the CO_2 mitigation potential lost when displacing gasoline rather than coal. For reference case assumptions, existing coal-fired power plants will not be able to afford biomass when competing with cellulosic ethanol producers unless CO_2 prices rise above the $35/ton assumption. Holding the CO_2 price consistent with the reference case, oil price would have to fall far below the reference case oil price before the CO_2 mitigation benefits of cofiring are realized. As previously described, lower oil prices translate into lower biomass prices and a smaller biomass supply. The CO_2 mitigation forecast "valley" at $40/bbl oil price is due to the large quantity of stranded biomass as discussed above. Oil prices below $40/bbl allow many more coal-fired power plants access to biomass, and the CO_2 mitigation forecast is highest below $40/bbl oil prices.

Sensitivity Case – CO_2 Price

Both the reference and the previous sensitivity cases assume a single CO_2 price in each year. Because a unit of biomass has the potential to displace approximately two times the CO_2

emissions when it displaces coal (cofired with coal in existing coal-fired power plants) than when it displaces petroleum (as cellulosic ethanol), biomass allocations are sensitive to CO_2 values.

Year 2015

Figure 8 presents supply and demand curves for the year 2015.

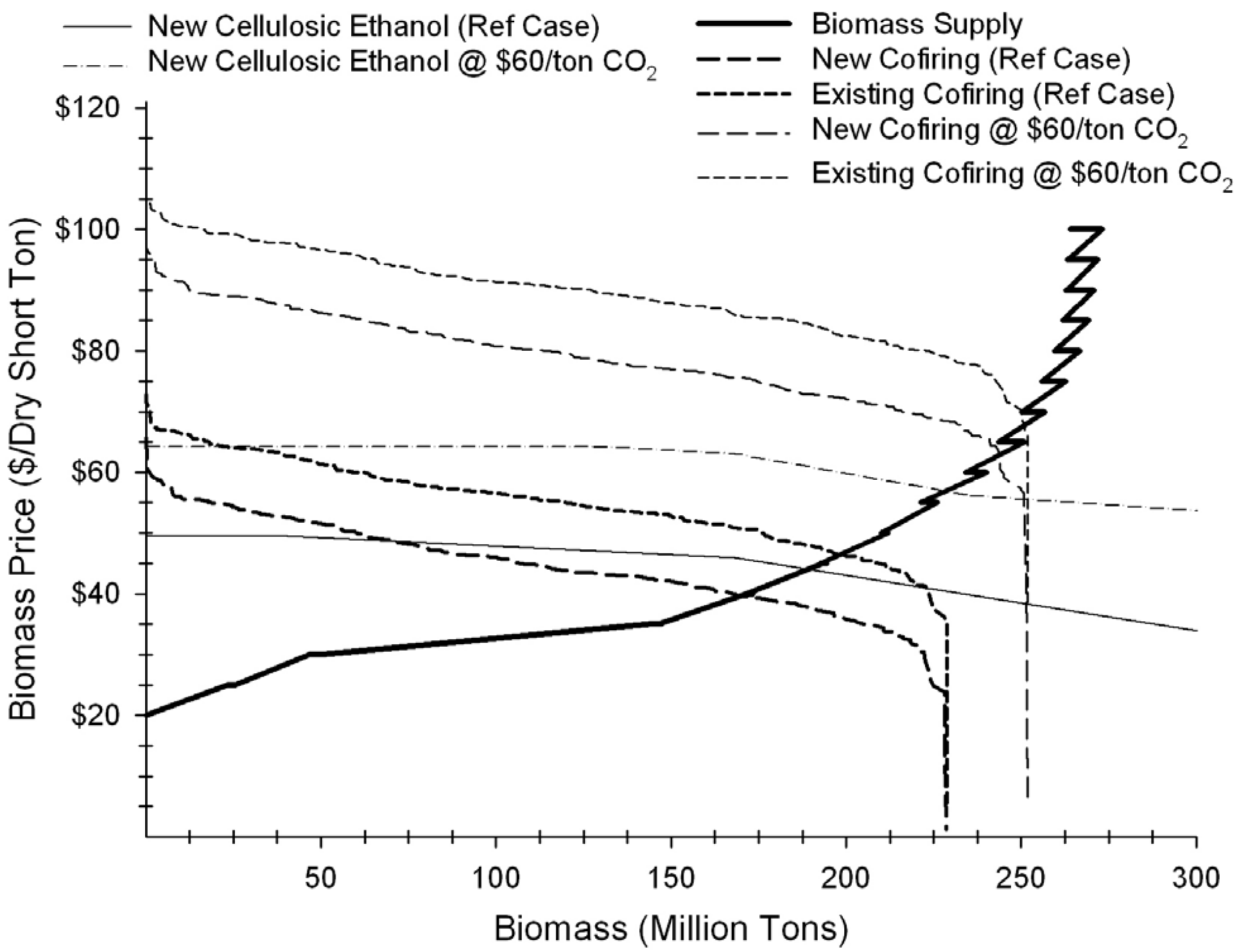

Figure 8 – CO_2 Price Sensitivity Analysis: Biomass Supply and Demand Curves for Year 2015

All things equal to the reference case assumptions, 2015 biomass allocations are sensitive to CO_2 prices between \$10 and \$80/ton CO_2. Cofiring biomass with coal in existing coal-fired power plants is not profitable at any power plants below approximately \$15/ton CO_2. Between \$15 and \$20/ton CO_2, only power plants converted to cofiring in previous years can profitably cofire, and all biomass allocated to cofiring between the prices is allocated to existing cofiring power plants. Above \$20/ton CO_2 prices, some new power plants can afford to cofire, causing more biomass to be allocated to power plants. As CO_2 prices rise, more power plants cofire, and cofiring power plants bid up biomass prices, resulting in more biomass supplied from the agricultural sector. Figure 8 demonstrates that new cellulosic ethanol plants can only afford approximately \$65/dry short ton biomass at \$60/ton CO_2. Above approximately \$60/ton CO_2, cofiring power plants can pay \$65/dry short ton biomass prices, causing less biomass to be allocated to cellulosic ethanol production. At \$80/ton CO_2, cellulosic ethanol producers can only afford \$75/dry short ton biomass, but cofiring plants can afford \$90/dry short ton biomass and virtually all biomass is allocated to cofiring power plants. The allocations are presented in Figure 9.

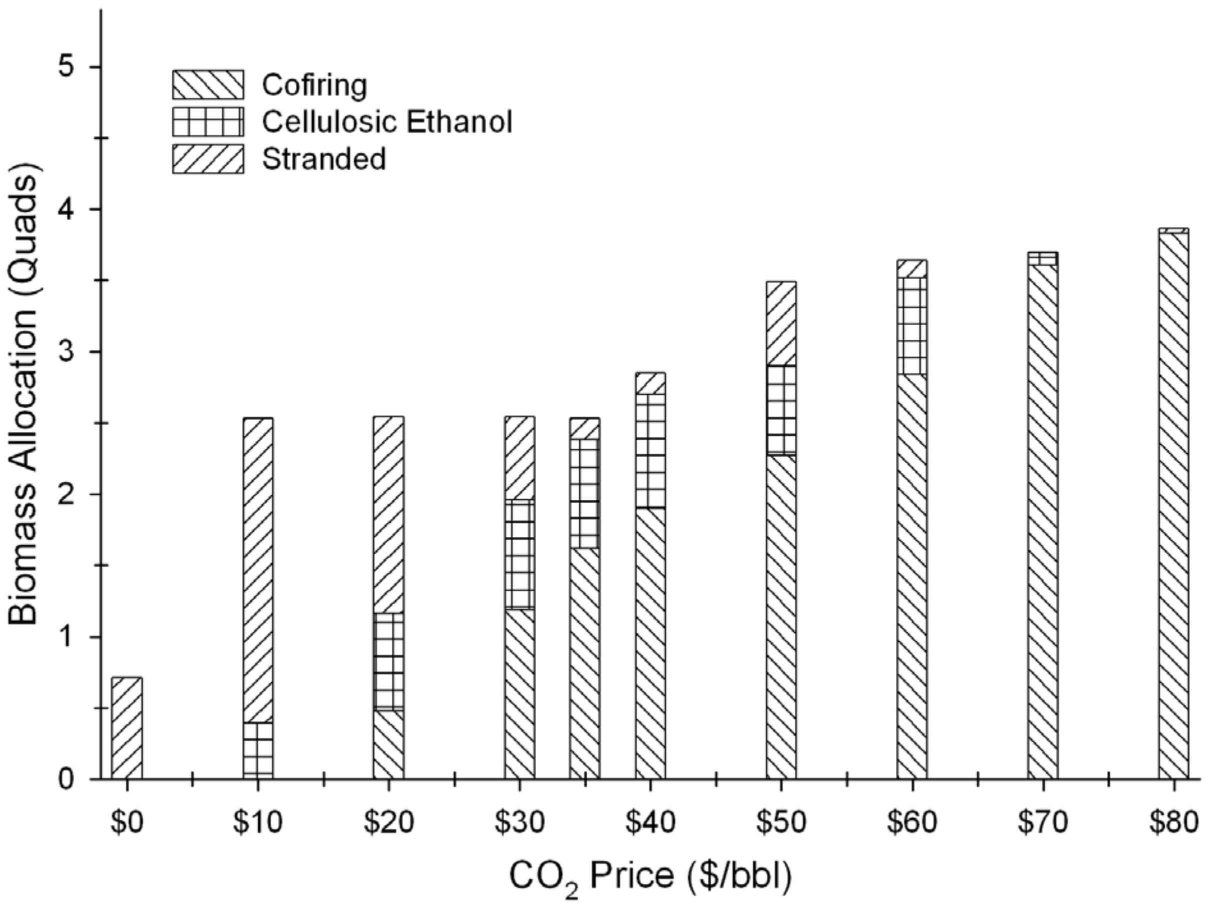

Figure 9 – CO_2 Price Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2015

Displacing gasoline with cellulosic ethanol is a less effective way to mitigate CO_2 than by displacing coal with biomass, and therefore, cellulosic ethanol's market price is less sensitive to changes in CO_2 prices than cofiring profits are. For this reason, higher CO_2 prices attract more biomass to cofiring but low CO_2 prices drastically reduce both cofiring and cellulosic ethanol allocations. Between approximately \$35/ton CO_2 and \$15/ton CO_2, cellulosic ethanol production supports a biomass price floor between \$50 and \$40/dry short ton. As CO_2 prices pass through this region, fewer potentially cofiring power plants can pay biomass prices, thus, lowering biomass allocated to cofiring. Below $15/ton CO_2, biomass prices fall low enough that limited quantities of biomass are available, and most cellulosic ethanol plants become too small to produce price-competitive ethanol. At this point, most of the biomass potential is stranded. At $0/ton CO_2, biomass prices fall to $30/dry short ton, and no cellulosic ethanol is allocated.

Year 2020

Figure 10 presents supply and demand curves for the year 2020.

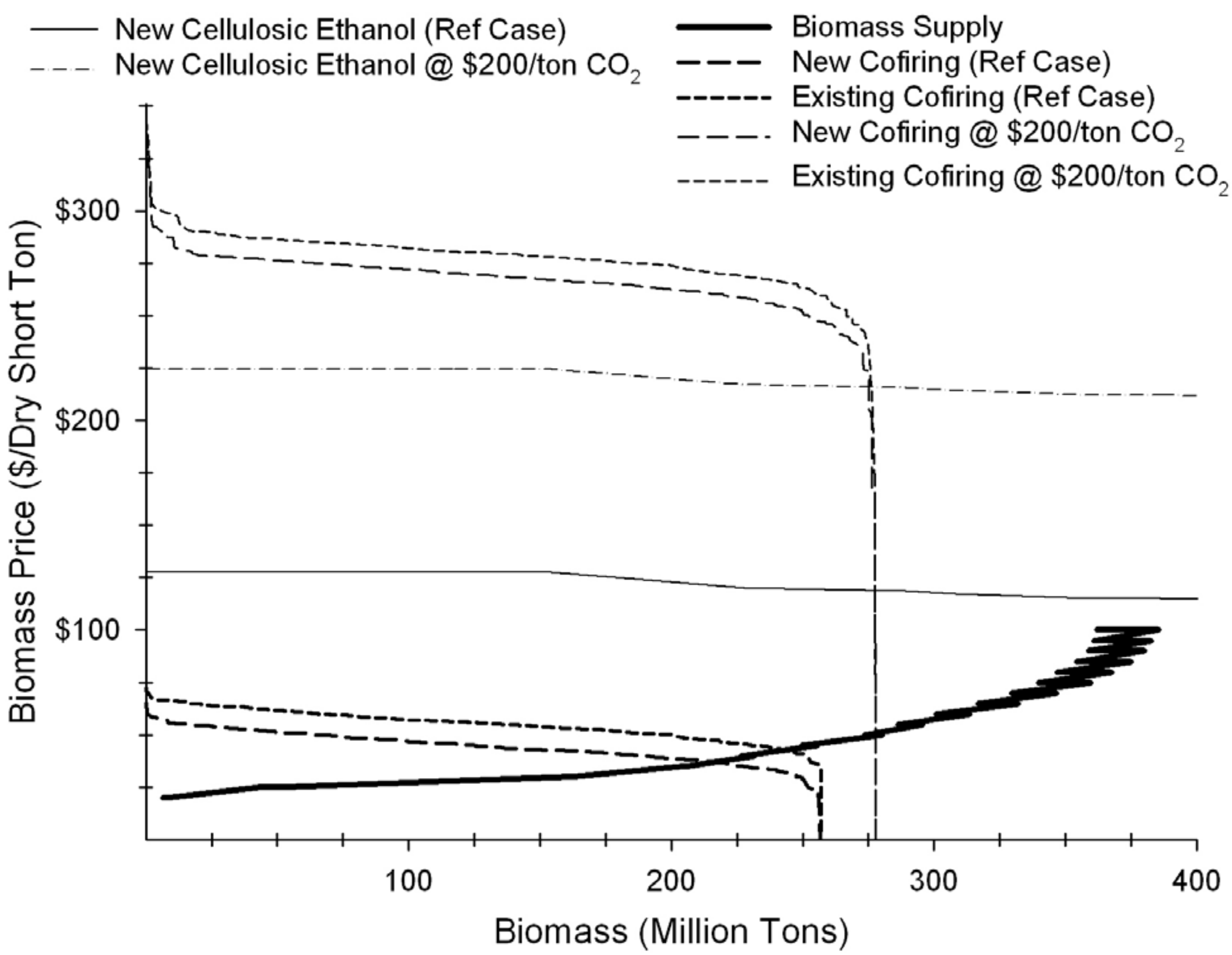

Figure 10 – CO_2 Price Sensitivity Analysis: Biomass Supply and Demand Curves for Year 2020

All things equal in 2020, high CO_2 prices are required to keep the biomass allocation split between the two alternate biomass uses modeled. As presented in Figure 11, CO_2 prices must be near $100/ton before a substantial split in biomass allocations is forecasted. A price of $200/ton CO_2 is required before most biomass is allocated to cofiring.

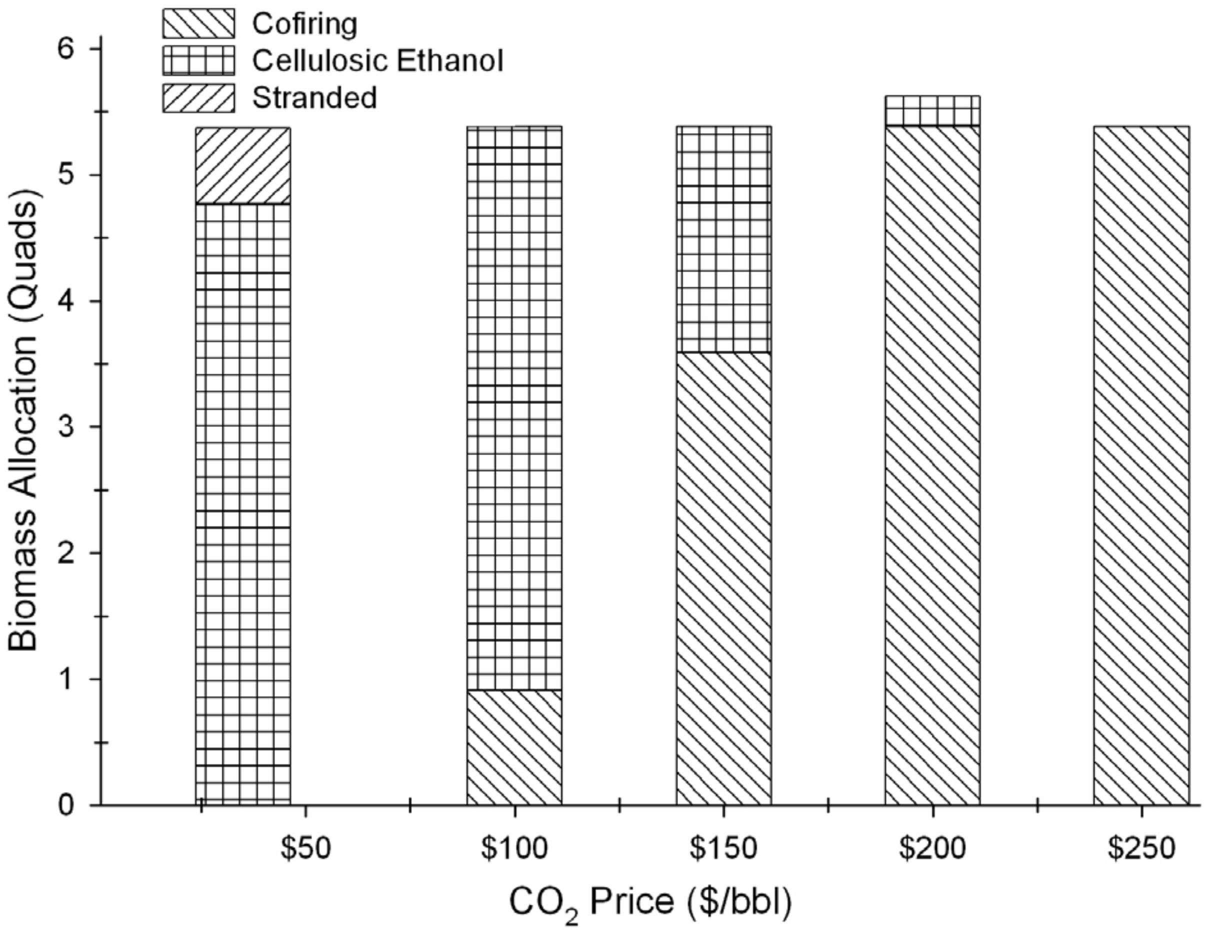

Figure 11 – CO_2 Price Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2020

CO_2 mitigation as a function of CO_2 price is presented in Figure 12 and Figure 13. In both figures, mitigation increases with CO_2 price increases as more biomass is allocated to power plants.

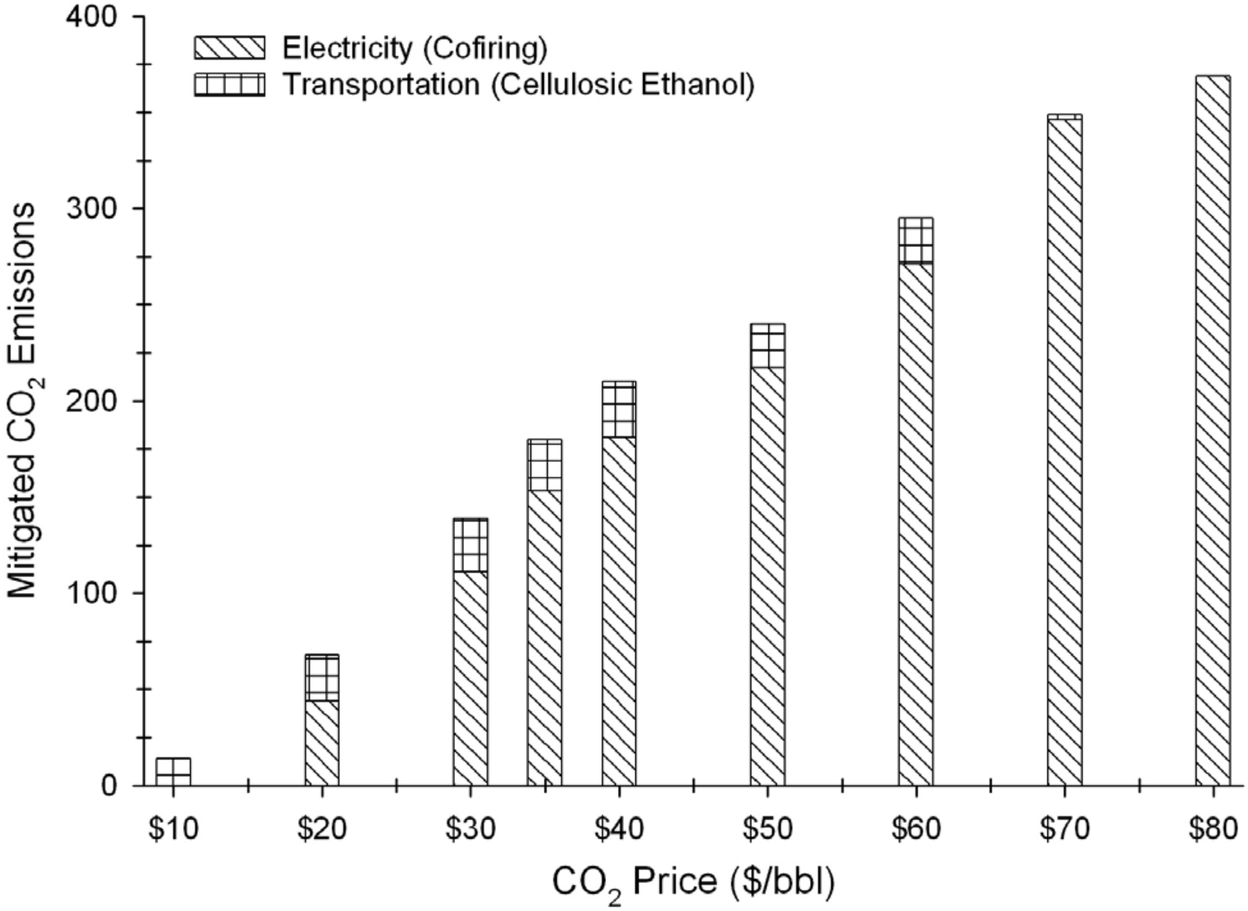

Figure 12 – CO_2 Price Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2015

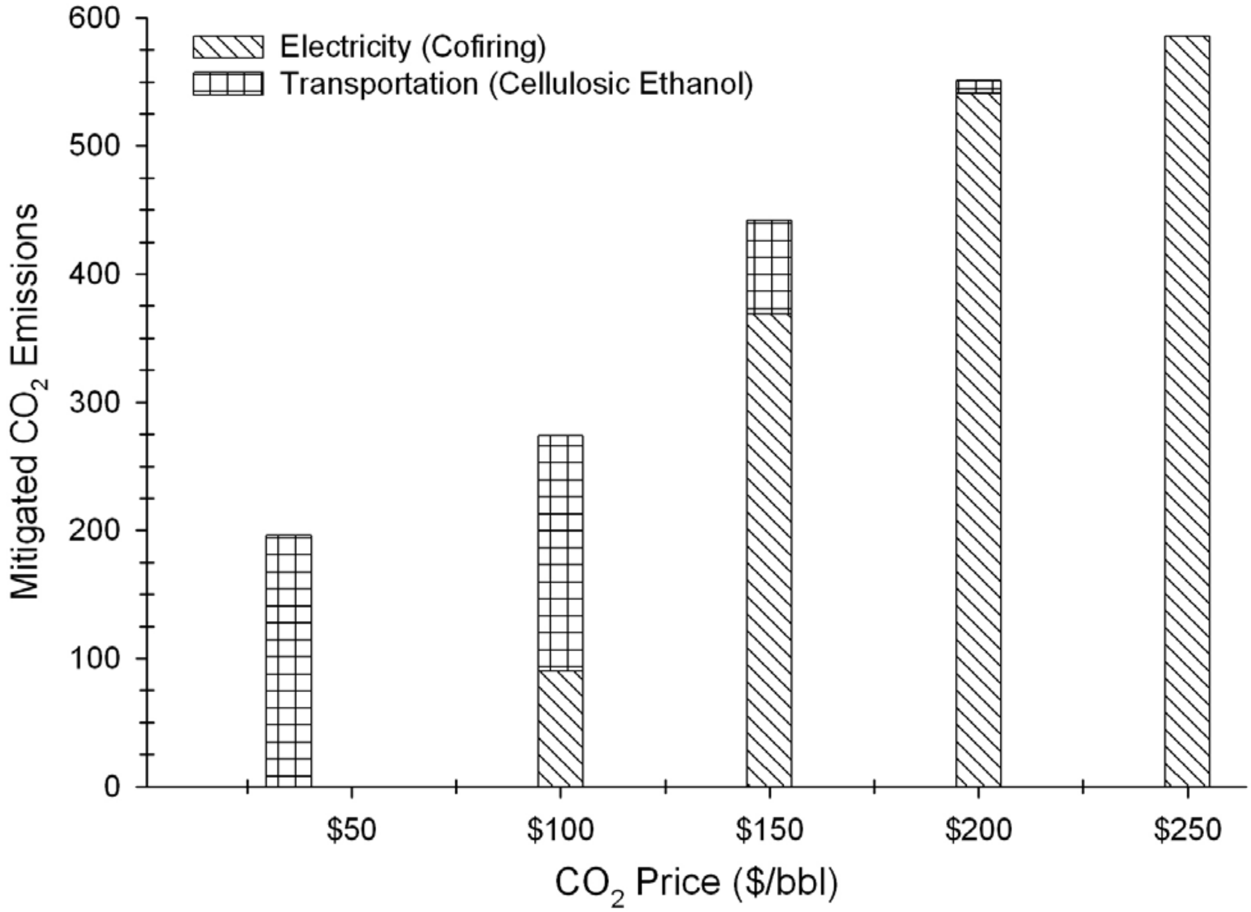

Figure 13 – CO_2 Price Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2020

Other researchers anticipate other technology options being available to existing coal-fired power plants at prices starting around \$50 to \$70 ton CO_2,and new IGCC power plants with CO_2 capture capabilities have anticipated affordability at approximately \$40/ton CO_2 [36] [37]. Therefore, higher CO_2 prices would result in biomass cofiring competing with other technology option within the electricity sector which would reduce the biomass allocations to the electricity sectors presented here.

Sensitivity Case – Cellulosic Ethanol Process Improvements

Excluding future oil and CO_2 prices, the most critical assumption influencing future biomass resource allocations is when anticipated cellulosic ethanol process improvements and cost reductions materialize. The following sensitivity analysis assumes that future cellulosic ethanol process improvements and cost reductions are less than assumed in the reference case. For each year analyzed, the achievement goals assumed in the reference case are reduced iteratively until no biomass is allocated to cellulosic ethanol production at all. Biomass allocation results for year 2015 are presented in Figure 14 and for year 2020 in Figure 15. CO_2 mitigation results for year 2015 are presented in Figure 16 and for year 2020 in Figure 17.

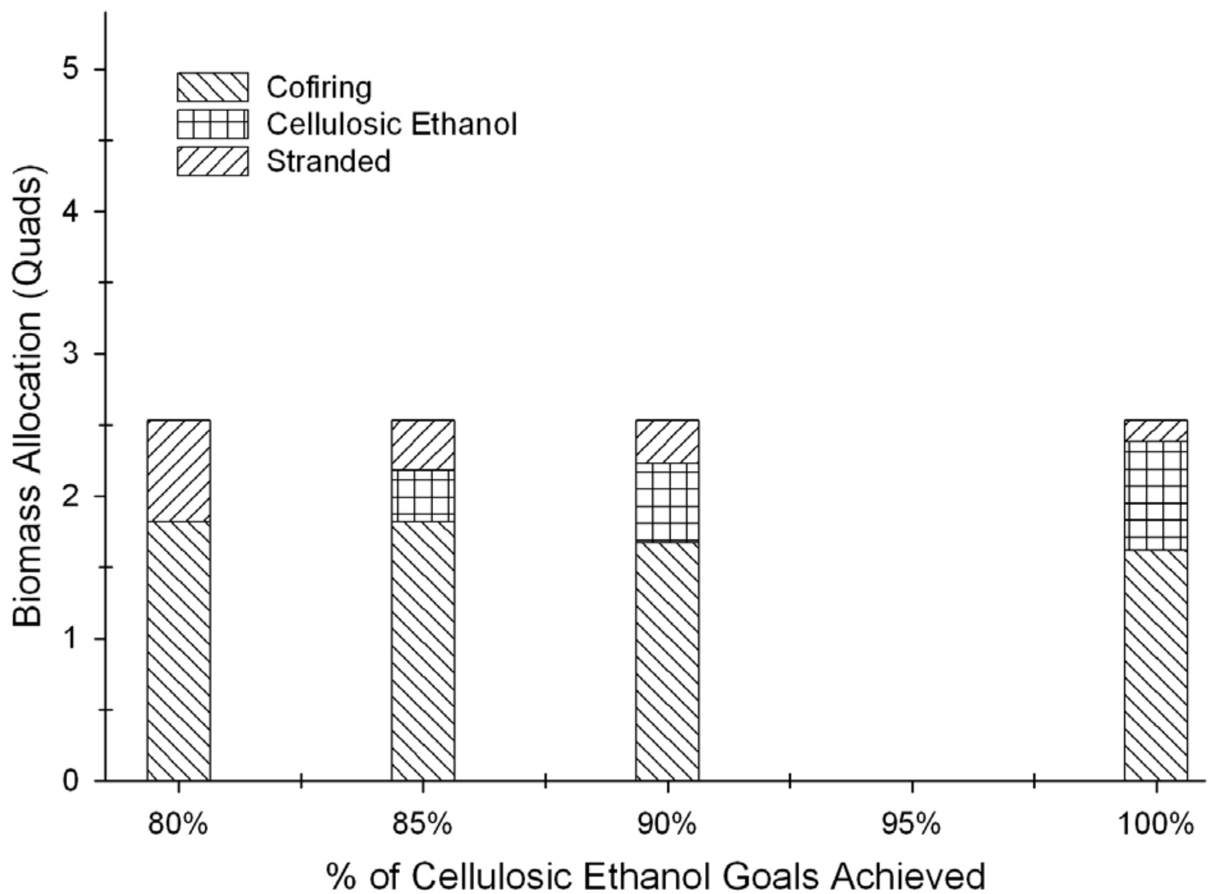

Figure 14 – Cellulosic Ethanol Process Improvement Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2015

Cellulosic ethanol process improvement and cost reductions lower cellulosic ethanol plant gate prices and effectively allow cellulosic ethanol to become more financially attractive when displacing gasoline. If cellulosic ethanol process improvements and cost reductions are not met, the biomass allocation result is very similar to the "higher oil prices" case. The trend presented in Figure 14 in which biomass allocations to ethanol production increase with increasing process and cost improvements is similar to the trend presented in Figure 16 in which biomass allocations to ethanol production increase with increasing oil prices. The comparison can also be made between Figure 15 and Figure 17. Moreover, CO_2 emission mitigation also follows trend parity between process improvement sensitivity and oil price sensitivity.

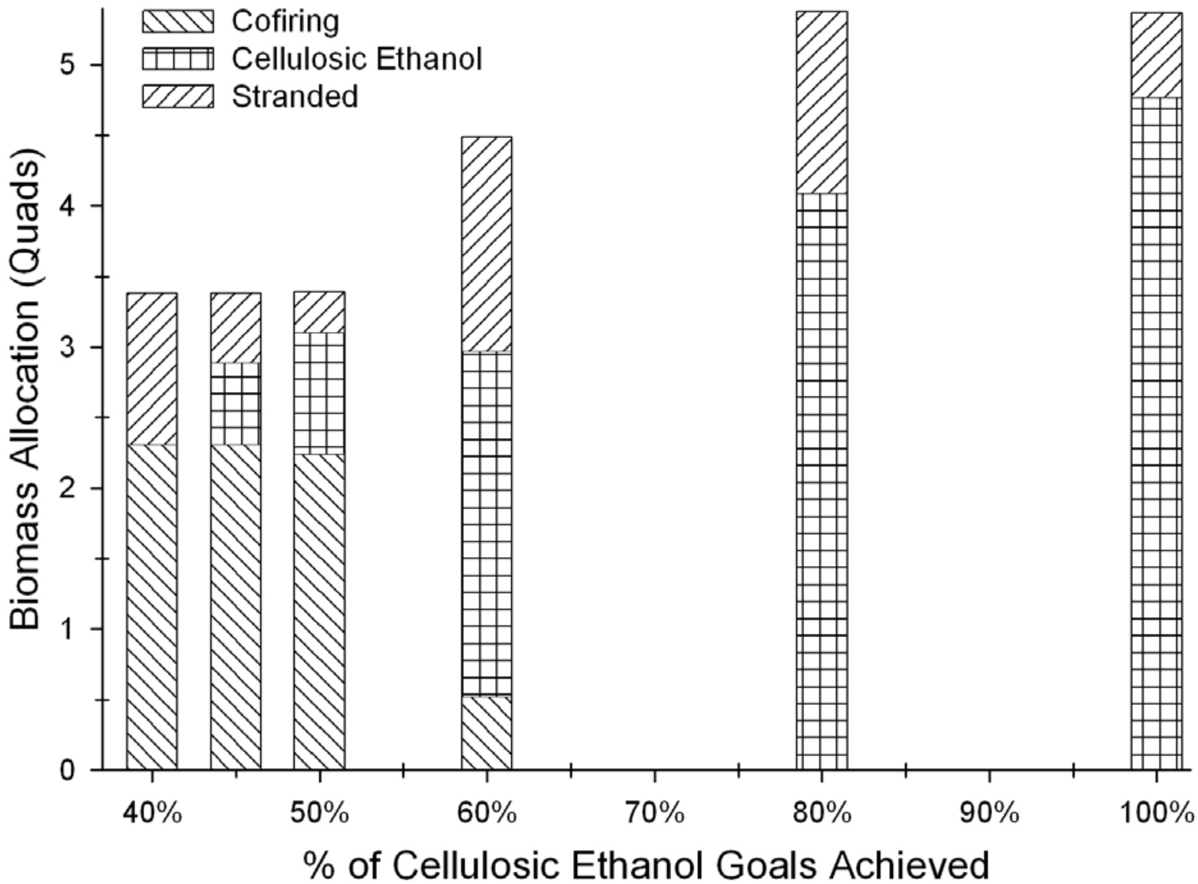

Figure 15 – Cellulosic Ethanol Process Improvement Sensitivity Analysis: Biomass Allocation Model Forecasts for Year 2020

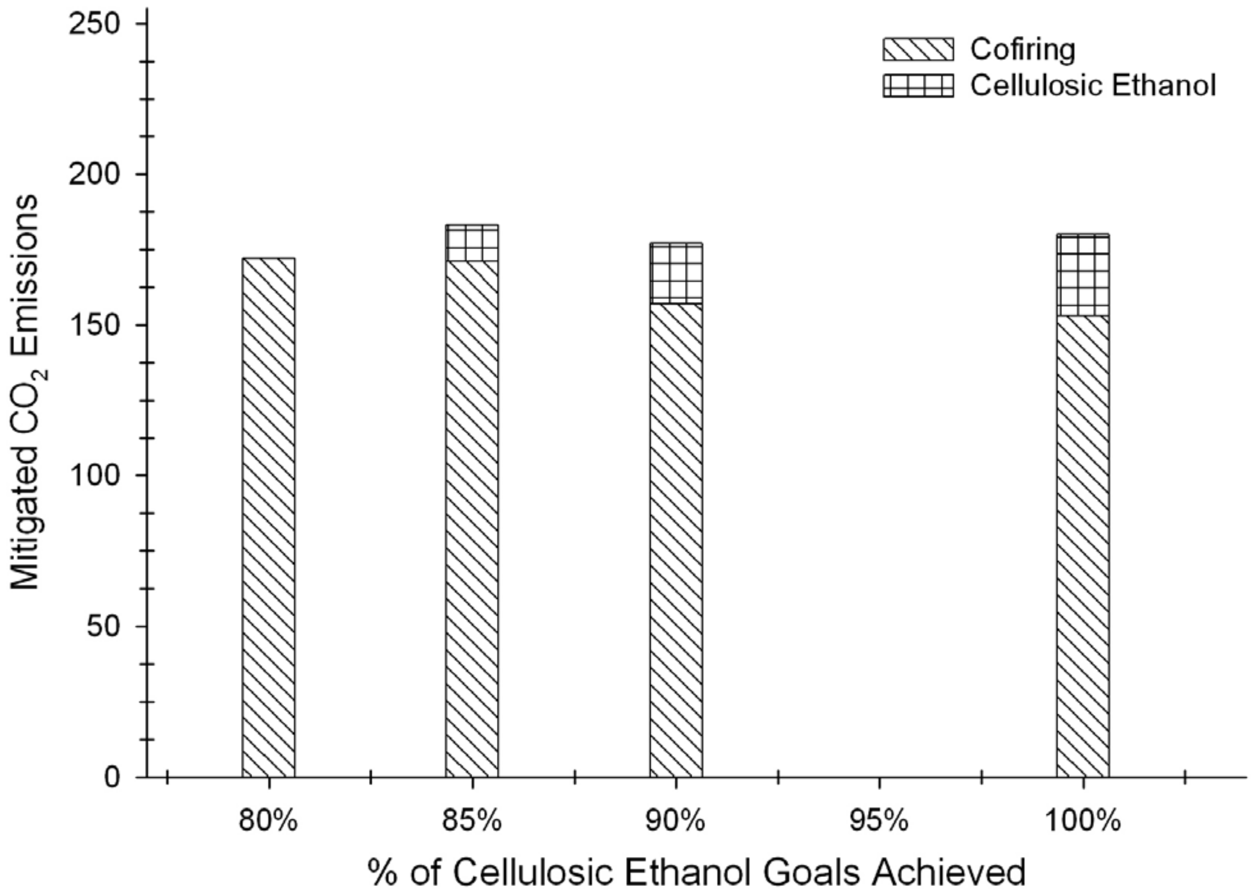

Figure 16 – Cellulosic Ethanol Process Improvement Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2015

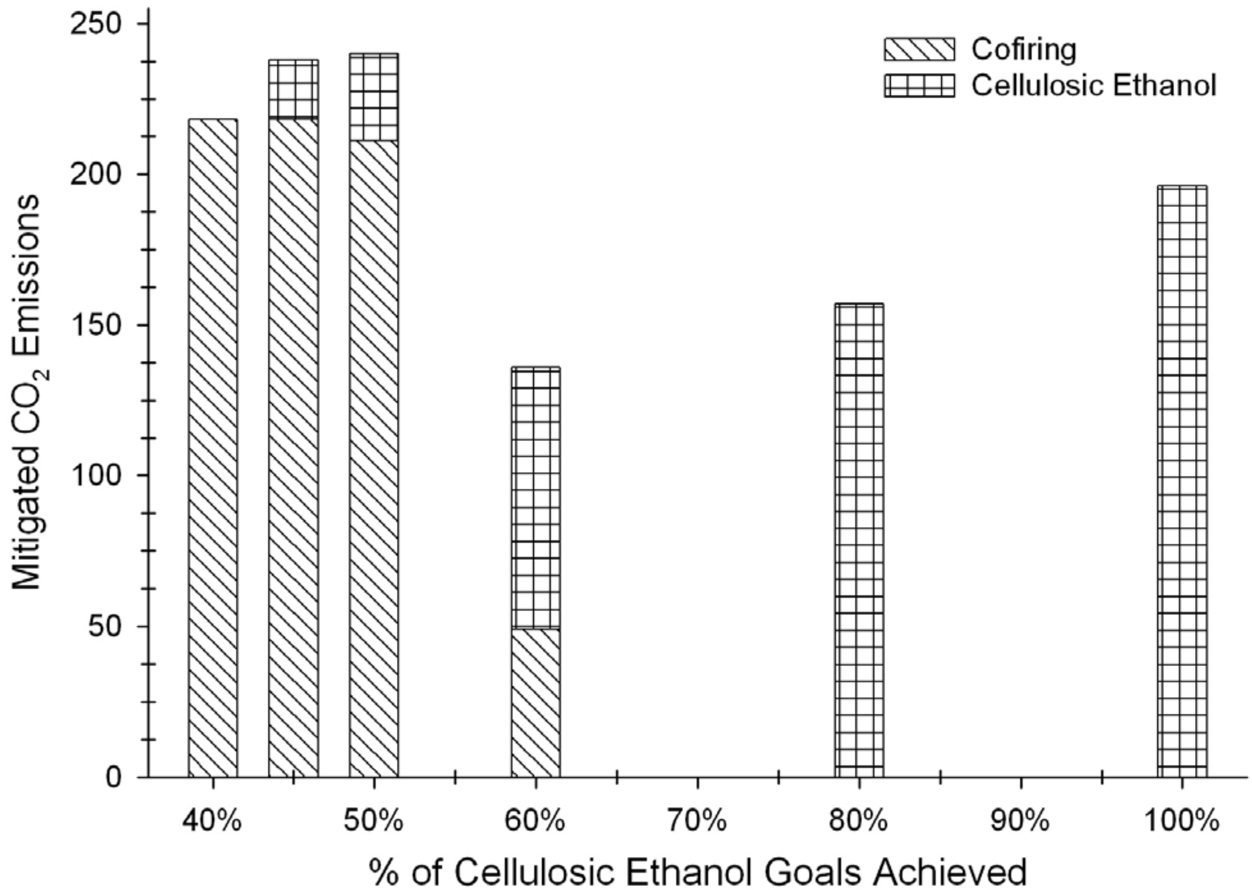

Figure 17 – Cellulosic Ethanol Process Improvement Sensitivity Analysis: Biomass Allocation Model Forecasts for CO_2 Mitigation in Year 2020

Sensitivity Case – Higher Infrastructure Cost

Future costs of capital intensive infrastructure might not follow general inflationary growth but could be higher due to constraints such as scarce global raw material, skilled labor, or permitting processes [38]. The reference case assumes that the inflation of future capital costs increase at 2% per year which is also the general inflation rate assumption. The following sensitivity case explores a future where capital costs are double what they are in the reference case. Doubling capital cost (see Table 3) is an extreme assumption but allows a clear presentation of the effects capital cost escalations would have on biomass allocations. Results are presented in Table 4. Changes relative to the reference case are bold, and the quantity of change is presented in parenthesis.

Table 3 – Key Parameter Assumptions: Higher Infrastructure Costs

	Year		
	2010	**2015**	**2020**
Biomass Price	$40	$40	**$70**
CO_2 Market Price	$30	$35	$35
Capital Cost Inflator (100% = 2x capital costs)	**100%**	**100%**	**100%**
% of Cellulosic Ethanol Process & Capital Cost Improvement Targets met		100%	100%
		100%	100%
Operating Cost ($/gal)	$1.69	$1.04	$0.57
Conversion Efficiency (gal/ton biomass)	60	78.2	89.6
Volumetric Ethanol Excise Tax Credit ($/gal)	$0.51	$0.51	$0.51
Cellulosic Ethanol CO_2 Credit?	Yes	Yes	Yes
Fossil Energy Price (EIA's high price case)			
Crude Oil ($/bl)	$69.21	$79.57	$89.65
Natural Gas ($/MMbtu)	$7.03	$6.50	$6.61
Electricity ($/MWh)	$6.36	$5.91	$5.94

Table 4 – Biomass Allocation Model Forecasts: Higher Infrastructure Costs

	Year		
	2010	**2015**	**2020**
Transportation Market			
Corn Ethanol Allocated (Billion Gal/yr)	10.3	**12.6** (-0.6)	**14.0** (-0.6)
Cellulosic Ethanol Allocated (Billion Gal/yr)	0	**0** (-4.1)	**17.1** (-12.8)
Crude Oil Displacement (Billion barrels/yr)	0.17	**0.21** (-0.01)	**0.51** (-0.22)
Cellulosic Ethanol CO_2 Mitigation (Million tons)	0	**0** (-27)	**168** (-28)
Electricity Market			
Coal Displacement (quads)	**0.2** (-0.43)	**0.81** (-0.65)	0
Cofiring CO_2 Mitigation (Million tons)	**21** (-44)	**84** (-69)	0
Biomass Allocations			
Biomass Allocated to Cellulosic Ethanol (quads)	0	**0** (-0.76)	**2.73** (-0.68)
Biomass Allocated to Cofiring (quads)	**0.22** (-.38)	**0.9** (+0.52)	0
Stranded Biomass (quads)	**1.17** (+0.48)	**1.64** (+1.49)	**2.18** (+1.58)

Doubling capital costs effectively reduces biomass allocations to both the cellulosic ethanol and the cofiring demands leaving greater quantities of stranded biomass. Cellulosic ethanol production is delayed until 2020 as the cost of capital in 2015 would not allow cellulosic ethanol to be competitive with gasoline. Cofiring is reduced in both 2010 and 2015 but, despite higher cellulosic ethanol capital cost in 2020, biomass allocations swing to all cellulosic ethanol as cellulosic ethanol will allow larger profit margins than cofiring will. In each year, however, enough profit is made in either marginal cofiring plants or marginal cellulosic ethanol plants to keep biomass prices high enough to exclude a relatively large quantity of biomass from consumption.

Corn ethanol production remains relatively unaffected by higher future capital costs as a large quantity of forecasted corn ethanol capacity is currently built or is being built and, therefore, modeled using a short-term marginal cost estimation which excludes the cost of capital. Hence, ethanol produced at existing corn ethanol plants is still allocated in the model, but new corn ethanol expansions are not built into the model. Only a relatively small amount of corn ethanol expansion is forecasted without the doubling of capital cost assumption, and thus, the loss of the forecasted capacity expansion because of a doubling of capital cost assumption appears rather small.

Sensitivity Case – No Cellulosic Ethanol CO_2 credit

No CO_2 mitigation legislation exists at the time of this analysis, and therefore, assumptions must be made regarding what a future CO_2 mitigation strategy might be. It is unclear if future motor transportation fuels will be subject to the same CO_2 constraints that the electricity sector is. It is also uncertain if gasoline CO_2 emissions displaced by carbon neutral fuels such as cellulosic ethanol would be valued at the same price ($/ton CO_2) as electricity sector CO_2 emission. For this sensitivity analysis, it is assumed that cellulosic ethanol does not receive a CO_2 credit from displacing CO_2 emissions from motor gasoline use at all. Applying this assumption allows a clear indication of the effect CO_2 credits have on biomass allocations.

Assumption changes are detailed in Table 5, and results are presented in Table 6. Changes relative to the reference case are in bold, and the quantity of change is presented in parenthesis.

Table 5 – Key Parameter Assumptions: No Cellulosic Ethanol CO_2 Credit

	Year		
	2010	**2015**	**2020**
Biomass Price	$40	$40	**$90**
CO_2 Market Price	$30	$35	$35
Capital Cost Inflator (100% = 2x capital costs)	0%	0%	0%
% of Cellulosic Ethanol Process & Capital Cost Improvement Targets met		100%	100%
		100%	100%
Operating Cost ($/gal)	$1.69	$1.04	$0.57
Conversion Efficiency (gal/ton biomass)	60	78.2	89.6
Volumetric Ethanol Excise Tax Credit ($/gal)	$0.51	$0.51	$0.51
Cellulosic Ethanol CO_2 Credit?	**No**	**No**	**No**
Fossil Energy Price (EIA's high price case)			
Crude Oil ($/bl)	$69.21	$79.57	$89.65
Natural Gas ($/MMbtu)	$7.03	$6.50	$6.61
Electricity ($/MWh)	$6.36	$5.91	$5.94

Table 6 – Biomass Allocation Model Forecasts: No Cellulosic Ethanol CO_2 Credit

	Year		
	2010	**2015**	**2020**
Transportation Market			
Corn Ethanol Allocated (Billion Gal/yr)	10.3	13.2	14.6
Cellulosic Ethanol Allocated (Billion Gal/yr)	0	**0** (-4.1)	**25.6** (-4.3)
Crude Oil Displacement (Billion barrels/yr)	0	**0** (-0.29)	**0.66** (-0.07)
Cellulosic Ethanol CO_2 Mitigation (Million tons)	0	**0** (-27)	**168** (-28)
Electricity Market			
Coal Displacement (quads)	0.63	**1.64** (+18)	0
Cofiring Ethanol CO_2 Mitigation (Million tons)	65	**172** (+29)	0
Biomass Allocations			
Biomass Allocated to Cellulosic Ethanol (quads)	0	**0** (-0.76)	**4.09** (-0.68)
Biomass Allocated to Cofiring (quads)	0.70	**1.82** (+0.2)	0
Stranded Biomass (quads)	0.69	**0.71** (+0.56)	**1.22** (+0.62)

Compared to the reference case, 2010 allocation results remain unchanged, but no biomass is allocated to cellulosic ethanol production in 2015, and less ethanol is produced in 2020. In the year 2020, the removal of a CO_2 credit to cellulosic ethanol production translates into a reduction in biomass prices from \$100 to \$90/dry short ton.

These results indicate that a cellulosic ethanol CO_2 credit will not be sufficient to significantly switch allocations of biomass from existing coal-fired power plant to cellulosic ethanol production.

Discussion

As the United States and the global economy move forward, energy and environmental pressures could precipitate rapid evolutionary changes across many sectors of the United States' economy. For example, rising oil prices, U.S. legislators' desire to reduce dependence on imported oil supplies, and concern about the environmental impacts of MTBE use created a market in which U.S. corn-ethanol production has increased more than 600% within 8 years (2000 to 2008). Furthermore, environmental and agricultural market pressures lead analysts and venture capitalists to anticipate rapid cellulosic ethanol production growth at some point in the future. However, many researchers within the electricity and chemical sectors have also expressed interest in biomass energy feedstocks. While it is tempting to believe that biomass energy resources offer unlimited benefits, it would be irresponsible to do so. As demonstrated by the biomass supply dataset used in this analysis, biomass energy resource supply will be inelastic, meaning that biomass resources will grow more expensive, on a per unit basis, as larger quantities of biomass resources are consumed. Although more inelastic in the near-term, long-term resource supply will also likely be limited by many different constraints such as land use, water supply, and rising diesel prices.. To the extent that a future energy or greenhouse gas reducing policy might look to biomass as a large-scale energy feedstock, biomass energy resources will likely be scarce. A holistic research methodology for comparing tradeoffs and benefits of alternative biomass feedstock use has not been fully explored yet, but this research offers a preliminary methodology for capturing and estimating some of the tradeoffs and benefits of utilizing biomass energy resources to achieve divergent energy and environmental policy goals.

The focus of this methodology, and the results of the analysis, is an examination of how biomass might be used given competing technologies and policies within different sectors of the U.S. economy. The two analyzed technologies were chosen because they either appear to be low cost (cofiring compared to biomass gasification combined cycle) or are the current focus of much research (cellulosic ethanol production). Although this methodology could also be adapted to include other technological pathways for the utilization of biomass (e.g., biomass and coal co-gasification, bio-chemical processing, fast paralysis combined with micro-turbine DG, etc.), the conclusions highlighted in this report would still likely be relevant. Therefore, understanding the conclusions presented in this report is a first step in understanding how different market forces could affect the achievement of policy goals. Understanding these affects is important as legislators consider CO2 mitigation and energy independence policies and as investors back technological development pathways.

Given this analysis, three primary variables determine biomass utilization within the electricity and transportation sectors: future oil prices, future CO2 constraints (i.e., the future value of CO2 mitigation [$/ton CO2]), and the date and the degree to which cellulosic ethanol process improvements materialize. The possibility of cellulosic ethanol being granted a CO2 credit, of the VEETC being extended well into the future, or of higher construction costs continuing do not affect biomass allocations to the degree that the previously mentioned items do.

At the time this report was written, oil prices had reached above \$130/bbl, roughly \$50/bbl higher than forecasted for 2008 in EIA's AEO07 High Price Case. If oil prices continue to remain high in the long-term, motivation for lower cost transportation options will only increase, and cellulosic ethanol, if the anticipated breakthroughs materialize, will become a very attractive transportation alternative. However, biomass energy feedstocks can mitigate more CO_2 if used in the electricity sector rather than the transportation sector. As we have demonstrated, lower oil prices, especially in conjunction with a carbon mitigation policy could split biomass allocations between cellulosic ethanol production and electricity production. If the cellulosic ethanol process matures slowly, then more biomass would be available to mitigate greenhouse gas emissions in the electricity sector even if oil returns to its historically lower prices.

It is not our objective to forecast exactly how biomass energy will be utilized but, instead, to contribute an original and cautionary comment to a growing body of biomass energy-focused research with respect to some of the potentially conflicting policy goals facing a biomass energy future. Between now and when a mixture of research and oil prices create a profitable cellulosic ethanol market, climate change policies (e.g., demand for biomass feedstocks from coal-fired power plants as a carbon mitigating option) could provide an opportunity for the U.S. agricultural sector to begin a biomass energy feedstock production transition. Earlier CO_2 legislation could provide an opportunity for a biomass feedstock supply market to develop and mature while cellulosic ethanol research and development continues to lower cellulosic ethanol production costs.

On the cautionary side, high long-term oil prices combined with inexpensive cellulosic ethanol production could bid-up biomass prices higher than expected. As this research demonstrates, several scenarios result in a demand curve that exceeds the biomass supply curve. While this is an artifact stemming from our modeling limitations (i.e., using a biomass dataset rather than a biomass production model), it is easy to see that much higher biomass resource prices should be analyzed by an agricultural research tool such as POLYSYS in order to determine the degree to which very high biomass energy prices affect all other U.S. agricultural prices. Large-scale biomass energy demands could cause tremendous tensions within the U.S. agriculture sector because higher biomass demand could divert land from food production. Upward agricultural pricing pressure could result in which current U.S. trade tariffs restricting ethanol imports will be lifted. However, it is difficult to predict how U.S. legislators might decide to mitigate rapid changes in the agricultural markets through mechanisms such as trade tariffs.

Future policy research should explore "best use" metrics to help guide legislators as to how society and the environment could best be served by future biomass energy policies. A holistic investigation of "best use" metrics could lead to different policy goals with respect to how best to utilize this potentially scarce resource in conjunction with U.S. foreign policy goals and objectives. It is our hope that this report points researchers in that direction.

Appendices

Appendix A contains nomenclature definitions used in this report. Appendix B presents the allocation LP model equations. Appendix C presents ethanol-specific performance and economic estimation equations along with relevant discussions of equations and inherent assumptions. Appendix D presents biomass and coal cofiring performance and economic estimation equations along with relevant discussions of equations and inherent assumptions.

Many assumptions are imbedded in the algorithms and equations used in this report, and the main body of this report explored the effect these assumptions have on capacity growth and biomass allocations. These appendices, therefore, describe the general relationship between biomass-allocating and revenue-estimating LPs, the equation upon which they are built, and when appropriate, imbedded assumptions.

APPENDIX A – Nomenclature

Table A 1 – General Nomenclature

Symbol	Description	Units
AC	Annual Cost (negative value)	(-)$/yr
AEI	Plant Annual Heat Input (from eGRID)	MMBtu
AERCO2	Plant Annual Emissions Rate – CO_2 (from eGRID)	lb/MMBtu
AERNOxHG	Plant Annual Emissions Rate - NO_x (from eGRID)	lb/MMBtu
AERSOx	Plant Annual Emissions Rate - SO_x (from eGRID)	lb/MMBtu
A	Area	Miles2
BEP	Biomass Efficiency Penalty = 10%	%
bgy	Billion gallons per year	
bl	Barrel of Oil = 42 gallons	
bu	Bushel of corn = 56 lb	
C	Cost	(-)$
CapF	Capacity Factor (Hours of Operation per year)	hr/yr (%)
CC	Capital Cost	$/gal Capacity $/kWh Biomass
CFR	Co-Fire Rate	%
CGC	Capacity Growth Constraint	MMgpy
COM	Cost of CO2 Mitigation	$/ton CO2
ConF	Consumption Factor	kWh/gal MMbtu/gal
CostF	Cost Factor	%
D	Distance (for Shipping)	mile
D/E	Debt to Equity Ratio	%
DDB	Double Declining Balance	
DGY	Distiller's Grains Yield	lb/gal
DIR	Dept Interest Rate	%
E	Energy	MMBtu
ECR	Ethanol Conversion Rate	gal/bu or gal/dry short ton
ED	Energy Density Ethanol: 0.087 MMbtu/gal Gasoline: 0.126 MMbtu/gal Biomass: 14.3 MMbtu/ton	
EL	Equipment Life = 10	yr

ENC	Ethanol Nameplate Capacity	MMgpy
$\overline{ENC}$	Ethanol Nameplate Capacity (forecasted as new)	MMgpy
$\hat{E}NC$	Average Ethanol Nameplate Capacity	MMgpy
ER	Emission Reduction	ton/yr
EV	Emission Value	$/ton
FR	Freight Rate Truck: 0.266 $/ton-mile Rail: 0.0244 $/ton-mile For Ethanol, assume 10% truck, 90% rail: FR = 0.0446 For biomass assume 100% trucking	$/ton-mile
IHR	Investor Hurtle Rate	%
kWh	kilowatt hour	kWh
MM$	Million dollars	
MMBtu	Million British Thermal Units (btu)	
MMBu	Million bushels of corn	
MMgpy	Million Gallons per Year	
P	Price	$/bl $/bu $/gal $/MMBtu $/ton
$\overline{P}$	Price for New Capacity	$/gal $/MMBtu
PL	Plant Life = 25	yr
PNC	Power Nameplate Capacity (from eGRID)	MW
PTC	Production Tax Credit = $0.51/gal	$/gal
Q	Quantity	bu, gal tons, MMBtu # ethanol plants
$\hat{Q}$	Average Quantity	bu, gal tons, MMBtu # ethanol plants
R	Revenue	(+)$/yr
RC	Reduction Credit RCCO2 = 100% RCSO2 = 75% RCNOx = 75%	%
TCC	Total Capital Cost	$

TR	Tax Rate	%
UC	Unit Cost	\$/bl \$/bu \$/gal \$/kWh \$/MMBtu
UCRF	Uniform Capital Recovery Factor	%
WACC	Weighted Average Cost of Capital	%
YBP	Number of Years Building Plants	integer
β, ζ, ψ	Equipment Cost Multipliers	\$/kWb
Θ,Ξ,Λ	Equipment Cost Multiplier Thresholds (based on CFR and boiler type)	%

Table A 2 – Nomenclature Subscripts

Subscripts	**Description**
a	Allocated
asd	Agricultural Statistical District
b	Biomass
be	Biomass-Based Ethanol
bep	Number of Biomass-Based Ethanol Plants
c	Corn
ce	Corn-Based Ethanol
cl	Coal
CO2	Carbon Dioxide
cpp	Unique Coal-fired Power Plant
dg	Distiller's Grains
e	Ethanol
el	Electricity
eq	Equipment
f	Fuel Cost
g	Gasoline
i	Individual ethanol production plant
m	Maintenance
n	Number of ethanol plants
N	Number of Power Plants
neoc	Non-energy operating costs
ng	Natural Gas
NOx	Nitrogen Oxides
o	Oil
oc	Operating costs
r	Oil Refinery

SO2	Sulfur Dioxide
sp	Spare (excess)
st	State
t	Transportation
uf	Unit of Fuel
Y	Individual Year Estimation (for time step estimations)
y	year

APPENDIX B – Corn and Biomass Allocation Model LP Definitions

This analysis forecasts corn-based and biomass-based ethanol production expansion along with electricity generated by biomass and coal cofiring in existing coal-fired power-plants. Table B 1 presents the LP equations used to estimate corn allocations to existing corn ethanol plants, and Table B 2 presents the LP equations used to estimate biomass allocations to biomass ethanol plants and candidate cofiring plants as well as ethanol to consumers. Table B 3 presents the equations used for estimating both corn- and biomass-based ethanol capacity expansion, and Table B 4 presents the equations used for estimating biomass and coal cofiring capacity expansion. All four tables reference equations defined in Appendices C and D.

Ethanol Capacity and Biomass Allocation Forecasts

Table B 1 presents the corn allocation LP objective function, decision variables, and constraints. The corn allocation LP objective function (Equation B 1) stipulates that the goal of the LP solution is to determine the lowest cost for all corn-ethanol production. The decision variables are corn quantities allocated to corn-based ethanol plants, and the constraints limit corn allocations to be below the amount of corn grown and specify that all corn-based ethanol capacity demand for corn be satisfied. Corn-based ethanol capacity can expand when corn is available after all existing corn-based ethanol capacity demand for corn has been satisfied (Equations B 14 and B 15). All of the variables used by the corn allocation LP are defined in Appendix C.

Table B 2 presents the corn-based ethanol and biomass allocation LP objective function, decision variables, and constraints. The corn-based ethanol and biomass allocation LP objective function (Equation B 5) stipulates that the solution of the LP is the allocation which results in the largest combined revenue from ethanol sales and carbon emission reduction credits from biomass and coal co-firing in existing coal-fired power-plants. The decision variables are ethanol (measured by btus) allocated from both corn and biomass-based ethanol plants to states for consumption as transportation fuels and biomass (measured in btus) allocated to existing coal-fired power-plants as a carbon mitigation option (Equation B 6). LP constraints limit the quantity of ethanol allocated between ethanol plants and states (Equations B 7 and B 8), the quantity of corn-ethanol produced (Equation B 9), and the quantity of biomass allocated to power-plants and biomass-based ethanol plants (Equation B 10 and B 11). Equation B 9 limits corn-based ethanol production in order to limit corn price escalations.

Corn Allocation LP

Table B 1 – Corn Allocation LP Equations

Eq #	Equation	Description
Objective Function		
B 1	$\text{MIN}: \sum_{i=1}^{n} \left(ENC_i \times P_{ce_i} \right)_i$	Minimize the total cost of producing all corn-based ethanol
Decision Variable		
B 2	$Q_{c_{st,i}}$	Corn grown in each state, allocated to each corn-ethanol plant
Constraints		
B 3	$\sum_{st=1}^{48} Q_{c_{i,st}} = Q_{c_i}$	All corn-based ethanol plants must receive their full capacity of corn
B 4	$\sum_{i}^{n} Q_{c_{st,i}} \le Q_{c_{st}}$	Corn producing states cannot supply more corn than their corn production capacity

Ethanol and Biomass Allocation LP

Table B 2 – Corn-based ethanol and Biomass Allocation LP Equations

Eq #	Equation	Description
Objective Function		
B 5	$\text{MAX}: \sum_{cpp=1}^{N} R_{CO_2\,cpp} + \sum_{i}^{n} R_{e_{i,st}}$	Maximizes the sum of annual revenues from all cofiring plants and all ethanol production facilities
Decision Variable		
B 6	$Q_{ce_{i,st}}, Q_{be_{i,st}}, Q_{b_{st,cpp}}$	Ethanol production at ethanol plants and biomass energy consumed at existing coal-fired power-plants (in MMMMBtu)
Constraints		
B 7	$\sum_{st=1}^{48} Q_{e_{i,st}} \le ENC_i \times CapF_e$	Ethanol allocation from ethanol plants is limited by the plant's rated capacity
B 8	$\sum_{i=1}^{n} Q_{e_{st,i}} \le Q_g \times \frac{ED_g}{ED_e}$	Total ethanol allocation to a state is limited by the state's gasoline consumption
B 9	$\sum_{st=1}^{48} \sum_{i=1}^{n} Q_{ce_{st,i\,y}} \le CGC_{ce_y}$	Sum of corn ethanol production is limited by a capacity growth constraint
B 10	$\sum_{cpp=1}^{N} Q_{b_{st,cpp}} + \sum_{i=1}^{n} Q_{b_{st,i}} \le Q_{b_{st}}$	Biomass allocation to power-plants and ethanol plants to be less than or equal to a state's ability to grow biomass
B 11	$CFR_{cpp} \le 20\%$ (Energy-Basis)	All power-plant cofiring rates are limited by 20% (on an energy basis)

Time-Dependent Estimations

Both ethanol production capacity and cofiring capacity grow over time in accordance with the results of the two allocation LP models presented above. Table B 3 presents the equations governing ethanol capacity growth over time, and Table B 4 presents the equations governing cofiring capacity growth over time.

Ethanol production capacity in year Y (Equation B 12) is the sum of corn-based ethanol production as reported in the Renewable Fuels Associations, Ethanol Industry Outlook 2007 publication (either online, under construction, or planned during 2007) [6] (Equation B 13) plus corn-based ethanol capacity expansion forecast (B 15 and B 16), and biomass-based ethanol capacity expansion forecast (Equations B 22 and B 23). Equation B 13 estimates how much corn remains within each state after existing corn-based ethanol production's corn demand has been satisfied. If enough corn remains within any given state, then that corn can potentially be used for corn-based ethanol production, and a potential plant is estimated to be built to consume this spare corn and to offer additional ethanol for allocation. The size of this forecasted plant is limited to 100 MMgpy (Equation B 15). If this potential capacity is allocated by the ethanol and biomass LP in year Y, then the plant is considered an existing plant for year Y+1 (Equation B 16). Equation B 17 applies a corn-based ethanol capacity growth constraint in order to limit corn prices. The rationale for this constraint is discussed in Appendix E, but Figure B 1 provides an estimate of this constraint over time.

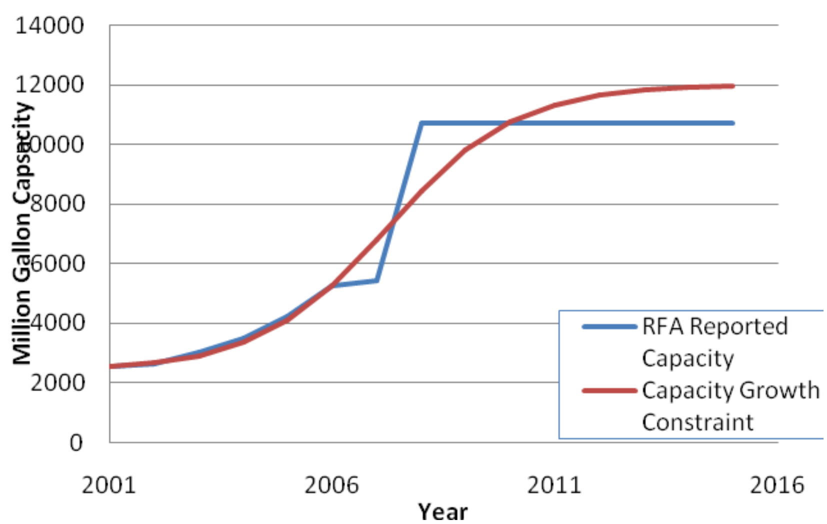

Figure B 1– Corn-based ethanol capacity growth constraint

A similar consideration is applied to biomass when forecasting biomass-based ethanol expansion, although no exogenous limit is placed upon capacity growth. Spare biomass is estimated by Equation B 18, and Equation B 20 estimates how many 100MMgpy biomass-based ethanol plants could be built within each state according to the quantity of biomass available. Similarly to corn-based ethanol, the biomass-based ethanol capacity is considered potential capacity until its ethanol is actually allocated by the ethanol and biomass allocation LP. Once the LP allocates potential ethanol in year Y, the plant is considered an existing plant for year Y+1.

Table B 3 – Ethanol capacity growth

q. #	Equation	Description
12	$\sum_{i=1}^{n} ENC_{Y_i} = \sum_{i=1}^{188} ENC_{Y=2008_i} + \sum_{st=1}^{48} ENC_{ce,Y} + \sum_{st=1}^{48} \overline{ENC}_{ce,a,Y_{st}} + \sum_{i=1}^{48} ENC_{be,Y_{st}} + \sum_{st=1}^{48} \overline{ENC}_{be,a,Y-1_{st}}$	Ethanol capacity in year Y equals capacity built or planned by 2008, plus expanded corn and biomass-based ethanol capacity
13	$\sum_{i=1}^{188} ENC_{y=2008_i} = 11{,}129$	Capacity Existing or Planned by 2008
14	$Q_{c_{sp,st,Y}} = Q_{c_{st,Y}} - \sum_{i=1}^{n} Q_{c_{a,st,Y=1,i}}$	Spare Corn
15	$\overline{ENC}_{ce,Y_{st}} = \begin{cases} \dfrac{Q_{c_{sp,st}} \times ECR_{ce}}{CapF_{ce}} & \text{IF } Q_{c_{sp,st}} \le 34MMbu \\ 100MMgpy & \text{IF } Q_{c_{sp,st}} > 34MMbu \end{cases}$	Corn-Ethanol Expansion Potential
16	$ENC_{ce,Y_{st}} = \overline{ENC}_{ce,a,Y-1_{st}}$	Corn-Ethanol Expanded Capacity
17	$CGC_{ce} = 12{,}000 \times \left(\dfrac{1+30\times e^{-\frac{Y}{1.44}}}{1+150\times e^{-\frac{Y}{1.44}}} \right)$	Capacity Growth Constraint
18	$Q_{b_{sp,st,Y}} = Q_{b_{st,Y}} - \sum_{i=1}^{n} Q_{b_{a,st,Y=1,i}}$	Spare Biomass
19	$\hat{Q}_{b_{st,Y}} = \dfrac{\sum_{st} Q_{b_{asd,Y}}}{CountIF_{st}\left(ASD_{st} > 0\right)}$	State’s Average ASD Biomass Quantity
20	$\hat{ENC}_{be_{st,Y}} = \dfrac{\hat{Q}_{b_{st,Y}} \times ECR_{be_Y}}{CapF_{be}}$	State’s Average Biomass-Ethanol Plant size
21	$Q_{bep_{st}} = Rounddown\left\{ \dfrac{Q_{b_{sp,st,Y}} \times ECR_{be_Y}}{\hat{ENC}_{be_{st,Y}} \times CapF_{be}} \right\}$	Number of New Biomass-Ethanol Plants
22	$\overline{ENC}_{be,Y_{st}} = Q_{bep_{st}} \times \hat{ENC}_{be_{st,Y}}$	Biomass-Ethanol Expansion Potential

23	$ENC_{be,\ Y_{st}} = \overline{ENC}_{be,\ a,Y-1_{st}}$	Biomass-Ethanol Expanded Capacity

Table B 4 – Cofiring capacity growth

Eq. #	Equation	Description
B 24	$AC_{regression_Y} = \overline{AC}_{regression_{a,Y-1}}$	Cofiring capacity expansion

If a power-plant can economically cofire biomass with coal in year Y, then the power plant's cost function switches from a long-term marginal cost estimate (includes capital debt reduction and tax payments) to a short-term marginal cost estimation (excludes capital debt reduction and tax payments). See Equation B 24 above and Equations D 22 and D 23 in APPENDIX D – Biomass and Coal Cofiring in Existing Coal-fired Power-Plants.

APPENDIX C – Ethanol Production & Economic Performance Estimation

Two ethanol production processes are modeled: corn-based and cellulosic-based. Corn-based ethanol process is a mature process, and future processing cost improvements are not expected. Therefore, current process costs are assumed to be a realistic estimation of future corn-based ethanol production costs. By contrast, cellulosic-based ethanol production is a very immature process, and future costs are uncertain. Of this analysis, cellulosic ethanol costs are assumed to fall over time and production yields (amount of ethanol produced from a quantity of feedstock) are expected to improve over time.

For both corn-based and cellulosic-based ethanol production processes, a distinction is made between new and existing plants. For existing plants, ethanol production costs are estimated using a short-term marginal cost estimation, which excludes capital investment payments. New plant economic estimations assume a long-term marginal cost estimation which includes capital investment payments over the life of the plant. Thus, four cases are handled separately in the Biomass Allocation Model and, where appropriate, are discussed separately below.

The following table contains general financial assumption and variable definitions.

Table C 1 – General Ethanol Financial Assumptions

q. #	Equation	Description	Units
1	CapF = 50/52 = 96%	Plant Capacity Factor	%
2	D/E = 50%	Debt to Equity	%
3	IHR = 20%	Investor Hurdle Rate	%
4	DIR = 8%	Debt Interest Rate	%
5	$WACC = (1 - D/E) \times IHR + D/E \times DIR = 14\%$	Weighted Average Cost of Capital	%
6	PL = 25	Plant Life	yr
7	TR = 39	Tax Rate	%

8	$UCRF = \frac{WACC \times (1+WACC)^{PL}}{(1+WACC)^{PL}-1} = 15\%$	Uniform Capital Recovery Factor	%
9	$DDB_i = TCC_i \times \left(\frac{2 \times 100\%}{PL - y} \right)$	Double Declining Balance Depreciation	$

Corn-based ethanol process

Corn-based ethanol production general performance and cost estimation

Corn-based ethanol production in the United States uses either a dry-mill or a wet-mill process. Older corn ethanol plants tend to be wet-mill plants which allow the plant to produce a wider range of corn-based co-products such as sweeteners, corn oil, germ, corn gluten, CO_2, and yeast. These plants tend to be smaller and more expensive than newer dry-mill plants [39]. Between 2002 and 2007, corn ethanol production capacity almost tripled, going from roughly 2 to 5.5 billion gallons per year, and as of 2007, another 6 billion gallons per year of capacity is currently in the design or construction phase [6]. The dry-mill process dominates this recent corn-ethanol capacity expansion because it focuses exclusively on ethanol production, as opposed to a wet-mill's co-product capacity, and is therefore a less capital intensive process. Dry-mill corn-based ethanol production currently makes up 82% of the total corn-based ethanol produced [6]. For simplicity, all ethanol capacity is modeled as a dry-mill process, and the overall process cost estimation is predicated on USDA's 2002 cost of production survey [40].

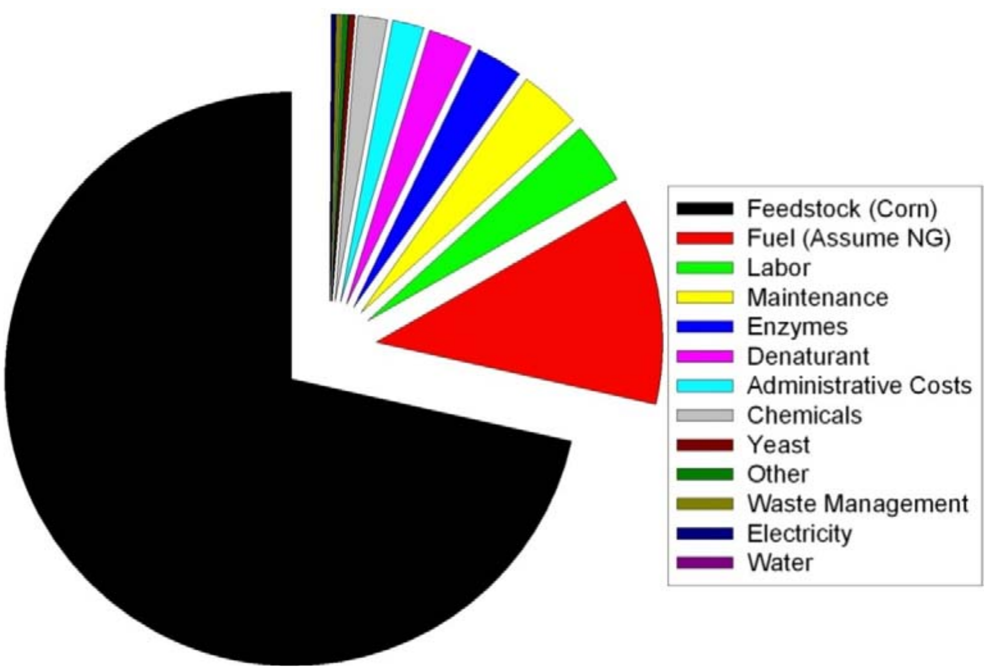

Figure C 1 – Average dry-mill corn ethanol production costs (REF USDA)

Distiller's gains, which are typically sold as a feed for cattle production, provide a single co-product for a dry-mill ethanol production plant. Distiller's grains are the remaining protean after the beer fermentation process converts corn's usable sugars into alcohol. Distiller's grains leave the ethanol process as a wet recovered solid and can either be sold as is, or dried. Wet distiller's grains will spoil unless used within a few days of production; however, dry distiller's grains can last for months after production and can be shipped over large distances. Drying distiller's grain requires more equipment than is accounted for by the USDA cost of production survey, but allows a corn ethanol producer to access markets that are further away. For simplification, it is assumed that additional drying equipment is not purchased and that wet distiller's grains access a market where it receives a market clearing price. This may be an easily critiqued assumption because it is anticipated that the large-scale expansion in dry-mill corn ethanol production capacity will necessitate distiller gain drying in order to reach distant markets (REF ISU). In this analysis, distiller's grain prices are assumed to equal the price forecast by the FAPRI model at the University of Missouri's College of Agriculture, Food, and Natural Resources [41].

Existing corn ethanol plants

The USDA survey report presents costs and incomes for a range of plant capacity sizes. Individual plants sizes are reported in the RFA annual report and regressing costs to plant capacity size provides a means for estimating individual plant production costs. Because they vary regionally, corn, fuel, and electricity cost components presented in Figure B 1 are separated in the corn ethanol plant cost estimate, and all other costs are aggregated into a total non-energy operating cost component. Annual corn demand and plant conversion factors are functions of plant size (equation C 10 and C 11). Electricity and fuel consumption factors are estimated using equations C 12 and C 13, and electricity and fuel unit costs are estimated using equations C 15 and C 16 respectively. Total non-energy operating cost is estimated using equation C 17. Distiller's grain yield is estimated using equation C 14, and revenue from distiller's grain sales is estimated by equation C 18.

Existing plant economic estimations assume a short-term marginal cost which excludes capital investment payments. Thus, for existing corn ethanol facilities, plant gate ethanol price is simply the sum of corn, electricity, and natural gas cost minus distiller's grain revenues (see equation C 21).

New corn ethanol plants

New corn ethanol plant performance estimation assumes that all new corn ethanol capacity has a high ethanol conversion rate of 2.8 gallons per bushel of corn [6]. Other than an improved ethanol conversion rate, it is assumed that new corn-ethanol plants operate at the same production costs as existing corn ethanol plants. The plant gate ethanol price estimation of new plants includes capital cost. Plant gate ethanol prices for new corn ethanol plants are estimated by Equation C 24.

Table C 2 – Corn-Based Ethanol Operational Performance & Cost Equations

q. #	Equation	Description	Units
10	$Q_{c_i} = \frac{ENC_i \times CapF}{ECR_{ce_i}}$	Corn Demand	MMBu/yr
11	$ECR_{ce_i} = \begin{cases} 2.65+0.05\times e^{(-0.04*ENC_i)} & Existing \\ 2.8 & New \end{cases}$	Corn-based ethanol conversion rate	Gal/bu
12	$ConF_{el_i} = 0.15+2.5\times e^{(-0.025*ENC_i)}$	Electricity Consumption Factor	kWh/gal
13	$ConF_{ng_i} = 0.025+0.04\times e^{(-0.035*ENC_i)}$	Natural Gas Consumption Factor	MMbtu/gal
14	$DGY_i = 5.4+1.15\times e^{(\frac{ENC_i - 30}{ENC_i + 5})}$	Distiller's Grains Yield	lb/gal
15	$UC_{el_i} = ConF_{el_i} \times P_{el_{st}}$	Electricity Unit Cost	$/gal
16	$UC_{ng_i} = ConF_{ng_i} \times P_{ng_{st}}$	Natural Gas Unit Cost	$/gal
17	$UC_{neoc_i} = 0.225+0.02\times e^{(-0.03*ENC_i)}$	Non-Energy Operating Unit Cost	$/gal
18	$R_{dg_i} = \frac{DGY_i}{2,000} \times P_{dg}$	Distiller's Grains Revenue	$/gal
19	$\hat{P}_{c_i} = \frac{\sum_{st=1}^{48}\left(Q_{c_{i,st}} \times P_{c_{st}}\right)}{\sum_{st=1}^{48} Q_{c_{i,st}}}$	Average corn price at corn ethanol plant	$/bu
20	$\hat{P}_{t_i} = \frac{\sum_{st=1}^{48}\left(Q_{c_{i,st}} \times D_{i,st} \times \frac{56}{2000} \times FR\right)}{\sum_{st=1}^{48} Q_{c_{i,st}}}$	Average price for corn transportation to ethanol plant	$/bu
21	$P_{ce_i} = \frac{\left(\hat{P}_{c_i} + \hat{P}_{t_i}\right)}{ECR_{ce_i}} + UC_{el_i} + UC_{ng_i} + UC_{neoc_i} - R_{dg_i}$	Existing Corn Plant Gate Ethanol Price	$/gal
New Corn-Based Ethanol Plant Capital Cost			
22	$CC_{ce_i} = 3.5 \times ENC_i^{(-0.27)}$	Capital Cost Rate	$/gal Capacity

23	$TCC_{ce_i} = CC_{ce_i} \times ENC_i$	Total Capital Cost	Million $

New Corn-Based Ethanol Plant Break-Even Ethanol Selling Price

C

$$\bar{P}_{ce_i} = \frac{UCRF \times \left(TCC_{ce_i} - DDB_i\left(P/_A, WACC, PL\right) \times TR - ENC_i \times CapF \times P_{ce_i}\left(P/_A, WACC, PL\right) \times (1-TR)\right)}{ENC_i \times CapF \times (1-TR)} \quad (24)$$

Biomass-based ethanol process

Introduction

Cellulosic ethanol process and plant economic performance is speculative in 2007 because, by 2007, no commercial scale cellulosic ethanol plant has been built. The National Renewable Energy Laboratory researchers estimated future cellulosic ethanol processes and have reported estimation for plant performance and costs [42, 43]. Table C 3 presents the performance and cost estimations reported in the first report. In the second report, NREL researchers updated their previous performance and cost estimates and performed sensitivity analysis for a target plant 8 years after the first plant would be built [43]. This target plant is a 70 MMgpy plant, with an ethanol yield factor of 90 gal/ton biomass and a capital cost of roughly $200 million (Capital Cost factor of $2.85/gal). A more recent estimation of first ethanol plant performance and costs suggest yields at 60 gal/ton and total capital costs closer to $3.50/gal capacity [44].

Table C 3 – NREL estimation of future cellulosic ethanol process performance and cost

	1st plant built (1999)	2005 Plant	2010 Plant	2015 Plant
ECR (gal/ton)	68	81	94	99
ENC (MMgpy)	55.2	62.2	72.2	87.5
TCC (Million $)	$234	$169	$156	$159
CC ($/gal Capacity)	$4.24	$2.72	$2.16	$1.82
UC_{OC} ($/gal)	$0.33	$0.25	$0.20	$0.17
$ConF_{el}$ (kWh/gal)	1.76	2.8	1.22	0
P ($/gal)	$1.44	$0.94	$0.82	$0.76

Analysts who are currently updating NREL cellulosic cost estimates suggest first plant cost at roughly $7/gal capacity and a plant size of 30 MMgal/yr. Assuming an ethanol conversion rate of 60 gal/ton biomass, $30/biomass feedstock costs and the other performance and cost assumption previously reported by NREL, the plant gate selling price for biomass-based ethanol will likely be $5/gal which would require $300/bl oil prices before being cost competitive with gasoline. Even if these estimates turn out to be wrong, private investors are not likely to build the first biomass-based ethanol plant. The first plant built will likely require public funding as a necessary R&D step towards developing future domestically-sourced transportation fuels.

As demonstrated by the NREL publications, biomass-based ethanol plant process and economic performance will improve over time. It is uncertain, however, how quickly production performance and costs will improve over time, which creates questions about the relevance of NREL's assumptions to modeling biomass allocations. For example, assuming that biomass-based plants are being built, will process and economic improvements follow the time-based iterative steps presented in Table C 3, or will improvements be a function of capacity, which would most likely take far longer to develop?

For this analysis, it is assumed that process improvements will be a function of time, rather than capacity. Improvements will be modeled based on the timeline presented in Table C 3, and sensitivity scenarios explore biomass allocation assuming alternative timelines.

Biomass-based ethanol process performance and economic modeling

Equations used to estimate the performance and costs of cellulosic ethanol over time are presented in Table C 4.

Table C 4 – Cellulosic-Based Ethanol Operational Performance & Cost Equations

Eq. #	Equation	Description	Units
25	$Q_{b_i} = \frac{ENC_i \times CapF}{ECR_b} \times 1{,}000$	Biomass Demand	1000 tons/yr
26	$ECR_{be} = 56.95 \times YBP_{be}^{\;0.197}$	Biomass-based ethanol conversion rate	Gal/dry ton
27	$UC_{oc} = MIN \begin{cases} \$1.2 \\ MAX \begin{cases} \$1.2 - YBP_{be} \times 0.1075 \\ \$0.34 - YBP_{be} \times 0..007 \end{cases} \end{cases}$	Operating Costs (includes fixed costs, enzyme costs, chemicals and other variable costs	\$/gal
28	$ConF_{el} = \text{-}2.28$	Electricity Consumption Factor	kWh/gal
29	$R_{el} = ConF_{el} \times P_{el_{st}}$	Electricity Unit Cost	\$/gal
30	$P_{t_i} = \frac{\sum_{st} Q_{b,asd} \times \frac{2}{3} \times \sqrt{\frac{A_{asd}}{\pi}} \times CostF_t}{\sum_{st} Q_{b,asd}}$	Biomass to cellulosic ethanol transportation price	\$/ton
31	$P_{be_i} = \frac{\left(P_b + P_{t_i}\right)}{ECR_{be}} + UC_{oc} + R_{el_i}$	Existing Cellulosic Plant Gate Ethanol Price	\$/gal
New Cellulosic-Based Ethanol Plant Capital Cost			

32	$TCC_{be_i} = ENC \times \left(9.221 \times ENC^{-0.28} + 3.333 \times YBP^{-0.41} - 2\right)$	Total Capital Cost	Million \$
New Cellulosic-Based Ethanol Plant Break-Even Ethanol Selling Price			
C 33 $\overline{P}_{ce_i} = \dfrac{UCRF \times \left(TCC_{be_i} - DDB_i \left(P/A, WACC, PL\right) \times TR - ENC_i \times CapF \times P_{ce_i} \left(P/A, WACC, PL\right) \times (1-TR)\right)}{ENC_i \times CapF \times (1-TR)}$			

Biomass demand

Biomass feedstock demand is a function of plants size and conversion rate (see Equation C 25). The maximum plant size is assumed to be 100 MMgpy for this research, though it is likely that plants will be much smaller due to biomass supply restriction. This research however, explores the relative trends of biomass allocations given oil and carbon prices, and therefore, a somewhat crude approximation of biomass-based ethanol production is justified for the basis of this analysis goal. In general, smaller plant sizes will not experience economies of scale and would likely have higher capital cost than those estimated here. Thus, this analysis should be considered optimistic forecasts of biomass-based ethanol production growth forecasts.

Biomass-ethanol conversion rate

Adjusting for the more recent estimations, ethanol conversion rate is estimated by Equation C 26. Figure C 3 presents ethanol plant yield factor changes over time (measured by the number of years of building cellulosic ethanol plants).

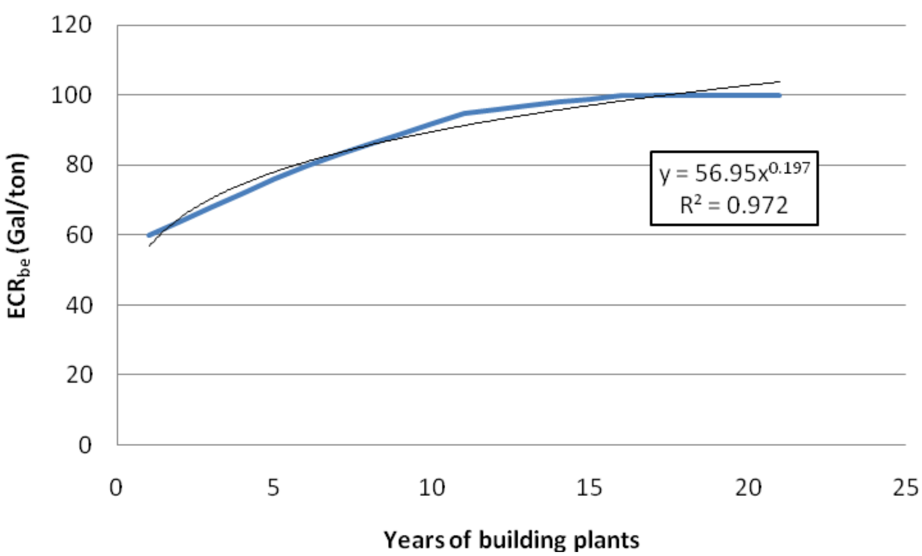

Figure C 2 – Cellulosic-based ethanol plant yield factor improvements over years of building cellulosic ethanol plants

Operating costs

This analysis combines all operating costs, including the cost of enzymes, into one single parameter and then estimates operating cost improvements over time. Operating cost is therefore solely a function of the number of years of building biomass-based ethanol plants (see Equation C 27). The first biomass-based ethanol plant has total operating costs of $1.20/gal [44]. After the first ethanol plant is built, operating price begins to linearly decline over an 8-year period to $0.34/gal [43]. Beyond the initial 8 years of building plants, operation cost continues to decline, but at a much slower rate of $0.007/gal/year. This declining rate is the operating cost decline rate for the last 10 years of building plants in NREL's 15 year time horizon [42]. Operating costs continue declining at this rate until reaching $0.17/gal, the lowest operating cost estimate in NREL's cost forecast [42].

Electricity consumption factor

It is assumed that the process design for all of the biomass-based ethanol plants built over the timeline of this analysis will produce an excess of electricity which will be sold to the electricity grid. Thus, the electricity consumption factor presented in Equation C 28 is a negative value. The price a biomass-based ethanol plant receives for excess electricity is assumed to be equal to the state wholesale electricity prices for the state in which the plant is located. Although NREL's estimate of excess electricity varies over time (see Table C 3), the base case analysis presented in this report assumes a static value over the timeline analyzed. The quantity of electricity available for sale to the grid is then varied as sensitivity analysis cases. Because it essentially varies the electricity revenue stream to biomass-based ethanol plants, this sensitivity is also an indication of the biomass-based ethanol plant's sensitivity to electricity selling prices (assuming that biomass-based ethanol plant-generated electricity sold to the grid is not valued at wholesale prices).

Biomass transportation cost

The biomass-based ethanol economic model uses a transportation cost estimation which is independent of its optimization decision variable. This is in contrast to the cofired power plant economic model which implicitly includes transportation distances between biomass resources and candidate cofiring plants in its optimization decision variable (see APPENDIX D – Biomass and Coal Cofiring in Existing Coal-fired Power-Plants below). The biomass-based ethanol economic model uses ethanol (in energy unites) as a decision variable for the allocation of ethanol between ethanol plants and states (a proxy for consumers). If biomass allocations between farms and ethanol plants were included in addition to ethanol allocations in the linear program, then biomass allocations, which determine each plant's plant-gate price of ethanol, would be multiplied by ethanol allocations (to determine total costs) and would result in a non-linear optimization. Thus, biomass can potentially be used by a local biomass-based ethanol plant or can potentially be allocated to a cofiring power plant.

Although biomass quantities are aggregated to a state level, biomass transportation cost between fields and biomass-based ethanol plants are estimated based on ASDs. The weighted average transportation cost for all biomass in a state is assumed to be a reasonable estimate of biomass shipping cost. Because it is impossible to predict where biomass will be grown or where future ethanol plants will be built, it is assumed that ethanol plants are located in the center of an ASD. The average shipping cost is approximated by assuming that the ASD is a circle and the average distance to all locations within the ASD is the average transportation distance for biomass. Thus, the average biomass to cellulosic ethanol plant transportation price for each state is estimated using Equation C 30.

This estimation method produces transportation estimates that very little from NREL's estimate of biomass transportation costs as presented in the second NREL report on cellulosic ethanol cost estimations [43]. In their report, transportation cost is estimated as a function of daily corn stover feedstock requirements and two land use assumptions. First, it is estimated that 75% of the land near their cellulosic ethanol plant is farmland capable of producing corn stover. Second, it is assumed that corn stover will be removed from only 10% of the corn stover producing land. Thus, only 7.5% of the land surrounding a plant will supply feedstock, and assuming that the ethanol plant is located in the center of all available feedstock, the radius of the area required to supply the plant with feedstock will be an approximation of feedstock transportation distance. Comparing a few cases (similar years, biomass quantities, plant sizes, etc.), the transportation cost in this analysis estimates approximately \$2/dry short ton biomass more than NREL's method.

Total capital cost for biomass-based ethanol

It is assumed that biomass-based ethanol plant capital costs experience economies of scale which is represented by NREL's estimation of a plant's construction and operation economics after approximately 8 years of building plants (see Figure C 3).

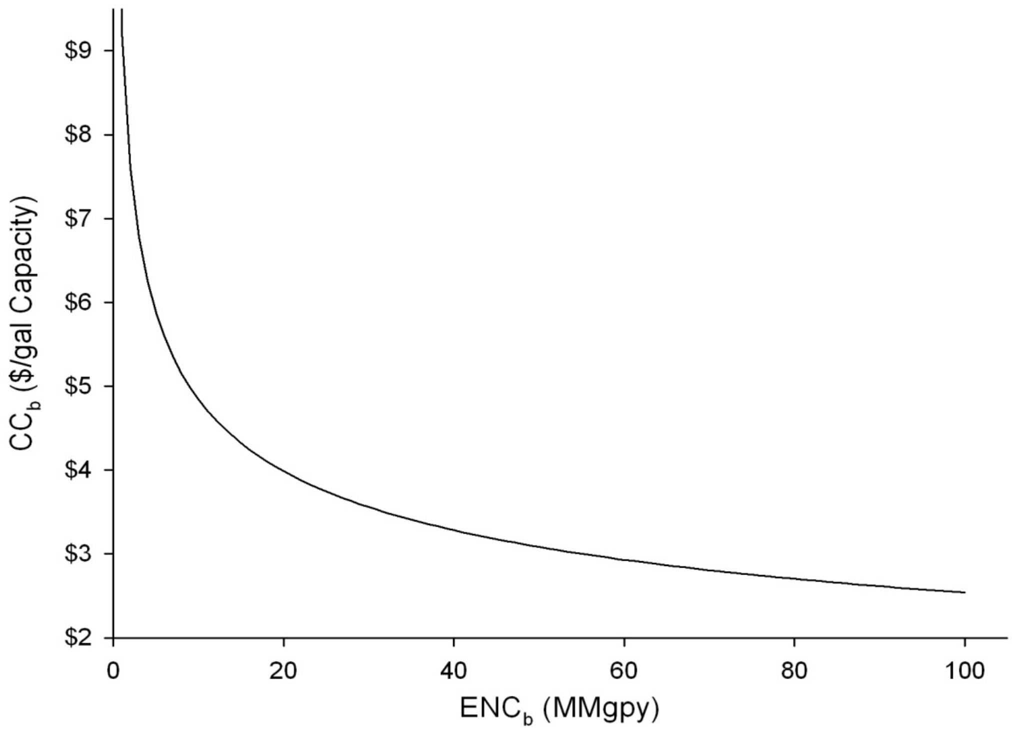

Figure C 3 – Capital cost economy of scale [43]

In addition to economies of scale, it is assumed that capital costs fall over time in accordance with estimates presented in Table C 1. The combination of these two assumptions results in Equation C 32.

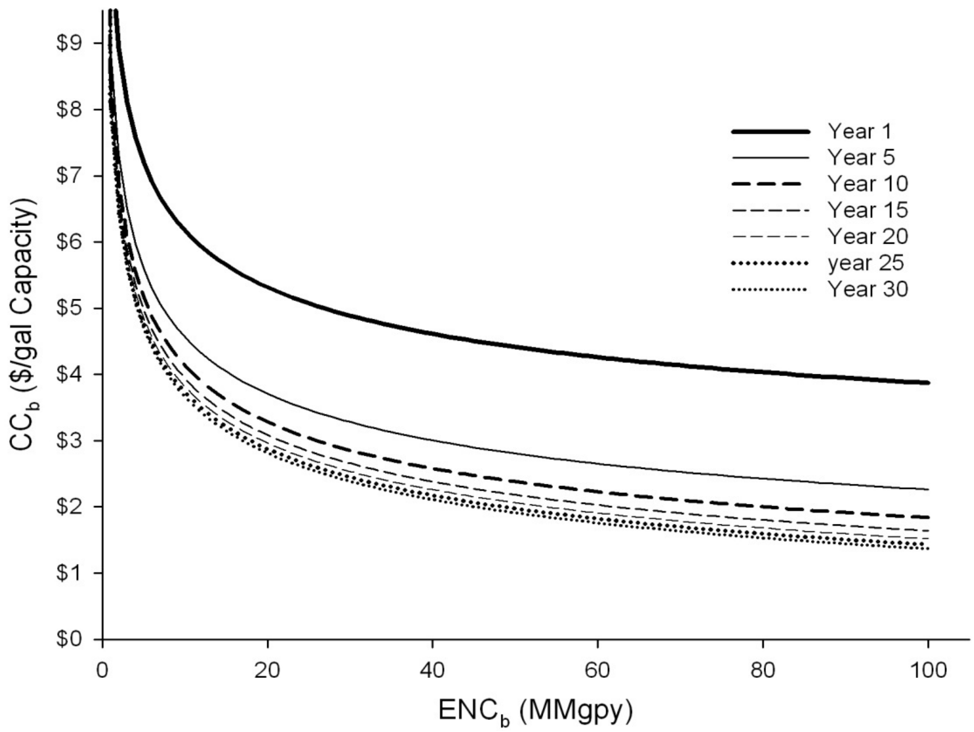

Figure C 4 – Capital cost economies of scale over years of building biomass-based ethanol plants

New versus existing biomass-based ethanol plant gate price

Biomass-based ethanol capacity plant gate price ($/gal) for a potential plant is estimated using a long-term marginal price estimation (see Equation C 33). The long-term marginal price equation is used to represent investor's decision to build an ethanol plant and, therefore, considers the cost of capital and taxes over the life of the plant. If the potential plant's ethanol is profitably allocated to a consumption location in any year, then the potential capacity is considered existing capacity during the next forecast year. Once capacity is considered existing, the plant gate price for ethanol switches to a short-term marginal price estimation (see Equation C 31). The short-term marginal price is used to represent a plant owner's short-term decision to produce ethanol and is, therefore, based on variable costs (operations and feedstock costs) and excludes capital cost and taxes.

Profit for Ethanol Production & Distribution

Table B 5 – Equations for Ethanol Distribution and Profit

Eq. #	**Equation**	**Description**	**Units**
C 34	$Q_{b_i} = \frac{ED_b}{ED_e \times ECR} \times \sum_{st=1}^{48} Q_{be_{i,st}}$	Biomass mass flow through cellulosic ethanol plants	MMbtu
C 35	$UC_{ce_{i,st}} = \frac{\left(\frac{UC_o}{42} + UC_r\right) \times \frac{ED_e}{ED_g} + PTC_e - P_{ce_i} - D_{i,st} \times FR \times \frac{7.2}{2000}}{ED_e}$ $UC_{be_{i,st}} = \frac{\left(\frac{UC_o}{42} + UC_r\right) \times \frac{ED_e}{ED_g} + PTC_e - P_{be_i} - D_{i,st} \times FR \times \frac{7.2}{2000}}{ED_e}$	Unit cost for allocating ethanol from plant i to any state	\$/MMbtu
C 36	$R_{e_i} = \sum_{i=1}^{n}\left(\sum_{st=1}^{48}\left(Q_{ce_{i,st}} \times UC_{ce_{i,st}}\right) + \sum_{st=1}^{48}\left(Q_{be_{i,st}} \times UC_{be_{i,st}}\right)\right)$	Revenue ethanol allocations	\$/yr

APPENDIX D – Biomass and Coal Cofiring in Existing Coal-fired Power-Plants

Power Plant Engineering and Environmental Performance Equations

Table D 1 – Engineering & Environmental Performance Equations

Equation #	**Equation**	**Description**	**Units**
	Operations & Engineering Equations		
D 1	$E_b = Q_b \times ED_b$	Biomass Energy Input	MMBtu
D 2	$CFR = \dfrac{E_b(1-BEP)}{AEI_{co}}$	Co-Fire Rate	%
D 3	$ER_{NOx} = \dfrac{E_b \times AER_{NOx} \times RC_{NOx} \times (1-BEP)}{2,000}$	NOx Reduction - Annual	ton/yr
D 4	$ER_{SOx} = \dfrac{E_b \times AER_{SOx} \times RC_{SOx} \times (1-BEP)}{2,000}$	SOx Reduction - Annual	ton/yr
D 5	$ER_{CO_2} = \dfrac{E_b \times AER_{CO_2} \times RC_{CO_2} \times (1-BEP)}{2,000}$	CO2 Reduction - Annual	ton/yr

Table D 2 – Co-Firing Economic Equations

Equation #	Equation	Description	Units
	Operations Expenses		
D 6	$AC_{f_b} = Q_b \times C_{uf_b}$	Biomass Fuel Cost	(-) \$/yr
D 7	$AC_{f_{cl}} = E_b(1-BEP) \times C_{uf_{cl}}$	Coal Fuel Cost Savings	(+) \$/yr
D 8	$C_{eq} = PNC \times CFR \times \begin{cases} \beta & CFR \le \Theta \\ \varsigma & CFR \le \Xi \\ \psi & CFR \le \Lambda \end{cases}$	Equipment Cost - Total	(-) \$
D 9	$\Theta = 2\%$ $\Xi = 10\%$ $\Lambda = 20\%$	PC Boiler Capital Cost Thresholds	-

D 10	$\Theta = 10\%$ $\Xi = 20\%$ $\Lambda = 20\%$	Non-PC Boiler Capital Cost Thresholds	-
D 11	$\beta = 100$	PC Boiler Capital Cost below and equal to 2% co-fire	$/kWb
D 12	$\zeta = 200$	PC Boiler Capital Cost between 2% & 10% co-fire	$/kWb
D 13	$\psi = 300$	PC Boiler Capital Cost between 10% & 20% co-fire	$/kWb
D 14	$\beta = 100$	Stoker, Cyclone, and Fluidized Bed Boiler Capital Cost below and equal to 10% co-fire	$/kWb
D 15	$\zeta = 200$	Stoker, Cyclone, and Fluidized Bed Boiler Capital Cost between 10% & 20% co-fire	$/kWb
D 16	$AC_{eq} = C_{eq} \times \left(P/A, DIR, EL \right)$	Equipment Cost - Annualized	(-) $/yr
D 17	$AC_t = FR \times \sum_{st=1}^{48} \left(Q_{b_{cpp,st}} \times D_{cpp,st} \right)$	Biomass Fuel Transportation Cost	(-) $/yr
D 18	$AC_m = C_{eq} \times CostF_m$	Additional Maintenance Cost	(-) $/yr
D 19	$AC_o = MAX \begin{cases} 63.5 - 5.9 \times Q_b \\ 5.33 - 0.079 \times Q_b \\ 0.96 - 0.001 \times Q_b \\ 0.71 - 0.00005 \times Q_b \end{cases}$	Additional Operations (Labor) Cost	(-) $/yr
Monetized Environmental Benefits			
D 20	$R_{NOx} = ER_{NOx} \times EV_{NOx}$	NO_x Credit	(+) $/yr
D 21	$R_{SO_2} = ER_{SO_2} \times EV_{SO_2}$	SO_x Credit	(+) $/yr

Regression Equation			
D 22	$\overline{AC}_{regression} = \begin{matrix}\text{Regress over: } E_b : \\ AC_{eq} + AC_m + AC_o + R_{NO_x} + R_{SO_2}\end{matrix}$	New cofiring plants	(-) \$/yr
D 23	$AC_{regression} = \begin{matrix}\text{Regress over: } E_b : \\ AC_m + AC_o + R_{NO_x} + R_{SO_2}\end{matrix}$	Existing cofiring plants	(-) \$/yr
Cost of CO_2 Mitigation (COM)			
D 24	$COM = \dfrac{AC_{regression} \times E_b + AC_{f_b} + AC_{f_{cl}} + AC_t}{ER_{CO_2}}$		\$/ton-CO_2
Power-Plant Profit in CO_2 market			
D 25	$R_{CO_2} = ER_{CO_2} \times \left(EV_{CO_2} - COM\right)$		\$/yr

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

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

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

A simplified estimation of non-feedstock and non-transportation cost are estimated for each individual candidates coal-fired power-plant. It is assumed that no plants will cofire above 20% on an energy basis, and therefore, capital cost estimation is a linear fit of the sum of all plant modification costs, combustion performance, non-fuel plant variable costs, SO_2 and NO_x emission reduction benefits, and engineering economic parameters as a function of biomass feedstock consumption (on a Btu basis). A general discussion of these cost estimates is preceded by a description of regression variable estimates.

Plant Modifications

All co-firing power plants will require some degree of engineering and capital investment depending on their quantity of biomass consumption. Prior to combusting biomass, the original boiler designer and/or manufacturer or an experienced boiler engineer should evaluate boiler(s) and recommend modifications necessary to minimize the risk of corrosion during biomass and coal co-firing. In addition, some amount of capital equipment will be required for biomass receiving, staging, and preparation for combustion and/or loading onto a boiler feed system. Ideally, any stored biomass and the combustion preparation area should be covered from rain as biomass moisture impacts boiler efficiency. In addition, modifications to the fuel feed system may also be required. For larger co-firing rates, separate boiler feed systems, complete with necessary biomass processing equipment and separate boiler feed nozzles, might be required. The degree to which plant modifications are required is dependent on the biomass co-firing rate and boiler type [45] [46].

Boilers can be divided into four general categories [47]:

- pulverized coal
- stokers
- fluidized bed
- cyclone

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

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

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

In all four boiler types, if the co-firing rate is low (e.g. below 2% by energy), then the biomass fuel can be processed and fed to the boiler using the existing coal material feed system [48]. In the case of PC boilers, when co-firing rates increase above 2%, existing coal pulverizing mills begin to de-rate, or lose their ability to produce the required particle sizes [45]. Therefore, above a 2% co-fire rate, PC plants are assumed to invest in a separate feed system. This will typically consist of material-conveying equipment between the fuel yard and the boiler, including a separate pulverizing mill(s) and injection port(s) into the boiler [48]. Because the boiler feeding mechanisms for non-PC boilers are not as particle-size critical, co-firing up to 10% is possible without the addition of a dedicated feed system [46]. Co-firing above 10% in non-PC boilers does require separate biomass feed systems similar to those described for PC boilers.

Capital cost estimations are based on plant biomass consumption rates and incorporate economies of scale. EPRI recommends using $100/kW$_b$[2] when in the 2% co-firing range, incorporating a 0.7 or 0.8 power law to scale up or down when varying from 2%. When co-firing rates reach 10%, the power law should reverse to 0.8 or 0.7 when scaling up or down and a rate of $200/kW$_b$ should be used. If low density biomass is used, such as corn stover, then a higher capital cost value of $300/kW$_b$ will cover the extra capacity required to convey more mass to balance energy equivalence[3] [46].

Very little literature exists concerning the affects of larger (greater than 15~20%) co-firing rates. This paragraph presents an expert solicitation on the affects of larger co-firing rates [49]. A boiler's size is determined by ash-handling and corrosion minimizing design parameters, and therefore, boilers are typically designed for a specific range of fuel properties. Deviating from this range, as in the case of larger than 10% cofiring rates, increases potential harm to the boiler. As co-firing rates approach 20% by weight, handling the increased ash and corrosive elements contained in biomass fuels will likely require significant modification to the boiler tube configurations. If cofire ratios exceed 20% by weight, biomass will become the predominate fuel to design for, and existing boilers, designed for coal, should be replaced with boilers designed for biomass. A boiler replacement capital cost factor of 2,000 $/kW was recommended, but for this analysis, a cofiring limit of 20% (by energy) is placed on all candidate cofiring power-plants.

This research incorporates linear programming, and therefore, a linear approximation of the power rule is used. Equation D 8, presented above, defines the linear cost calculation used. Capital costs rates are estimated for PC and non-PC boilers. For PC boilers, three cost constants correspond to three co-firing rates: below 2%, between 2% and 10%, and between 10% and 20%; $100/kW$_b$, $200/kW$_b$, and $300/kW$_b$ are used respectively. For non-PC boilers, $100/kW$_b$ is used below 10%, and above 10%, $200/kW$_b$ is used. The eGRID database contains coal

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[2] kW$_b$ indicates the portion of the power plant's capacity which generates electricity using biomass feedstocks. For example, 1 MW (or 1,000 kW) of capacity co-fired at 10% biomass will represent 100 kW$_b$ of capacity.

[3] Lower mass density fuels tend to also have a lower energy density than a higher mass density fuel will. When measuring co-firing combustion ratios on an energy basis, a lower energy density fuel will require a larger volume feed-rate to compensate for its lower energy density.

energy consumption statistics (e.g., MMBtu/yr), rather than tons of coal consumption. Because a wide range of energy densities exist for coal, converting from coal energy consumption to coal weight consumption is not practical, so cofire rates were measured by energy rather than weight.

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

Combustion Performance

Biomass combustion in coal boilers affects combustion efficiency. First, biomass typically contains more moisture than coal does, and combustion heat is lost as it is transferred to the moisture as the moisture vaporizes. It is recommended that biomass be dried prior to combustion to minimize the negative effects of biomass moisture on boiler efficiency. This can be achieved theoretically because power plants currently exhaust roughly 2/3 of their consumed chemical energy as heat to the atmosphere – more than enough heat exists to remove moisture from biomass feedstocks, even if firing 100% biomass. However, more equipment is required in order to capture this exhausted heat and use it to dry biomass. When retrofitting an existing coal-fired power plant, it is unlikely that installing biomass drying machinery will be cost effective. Second, the least expensive biomass pneumatic feed systems use unheated air to convey biomass to the boiler. The unheated air absorbs latent heat from the energy provided by combustion. Both mechanisms reduce the heat available for transfer to the boiler tubes, resulting in reduced boiler efficiency, also known as boiler de-rating.

This analysis assumes that biomass is dry (i.e., moisture content below 10-15%), and efficiency losses are estimated to be on the order of 5-15 % for the biomass portion of the blended fuels [46]. For this research, the efficiency penalty is kept constant at 10% and is applied to the biomass portion of the energy input. For example, if co-firing 10% biomass and coal, the overall boiler efficiency would be reduced by 1%. This analysis also assumes that the reduction in boiler efficiency is compensated by increasing the coal consumption to make a net zero gain energy balance. See Equation D 2.

Non-Fuel Plant Variable Costs

Labor and Maintenance Cost Estimation

Labor and maintenance cost consists of additional personnel required to operate and maintain biomass feedstock receiving, storing, and conveying, as well as maintenance and repair costs for biomass-specific mechanical/electrical equipment. The Electric Power Research Institute (EPRI) recommends estimating O&M costs between \$1.50 - \$10 /MWh_S[4] or roughly 2.00 - 13.50 \$/dry short ton per ton biomass consumed [46]. This includes additional plant operators ("full cost" at \$70,000 per year per operator) to handle biomass feedstocks and a 5%

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

maintenance factor per year for equipment maintenance. The number of required operators is varied, producing the range of costs presented.

Generally, maintenance costs are weighted towards the end of equipment life, but for simplification, this research considers maintenance costs to be uniform over the equipment life. Following EPRI's recommendation, 5% of original capital equipment expenditures per year for the life of equipment are assumed for maintenance costs. It is assumed that this estimate includes general maintenance material, maintenance labor, and any replacement parts required to maintain equipment (see equation 29).

EPRI's report does not specify a methodology for estimating additional required operators for co-firing. Therefore, an operation cost estimation methodology has been developed for this research. It is assumed that the EPRI laborer cost of $70,000 per year is valid, and, therefore, labor cost can be estimated by estimating the quantity of laborers required to handle the biomass feedstock mass flow. Thus, the number of operators is estimated as a function of quantity of biomass fired.

Biomass operators' activities will consist of truck unloading, storage management, and feeding biomass onto material handling equipment along with any biomass preparatory requirements. Whether biomass is co-fed with coal or has its own dedicated material-handling equipment, and whether biomass is stored as bales in a barn or stored in silos, labor will be required. Therefore, it is assumed that labor requirements will also be independent of the type of biomass feed system. It is assumed that biomass operators will not handle coal and that coal operators will not handle biomass. Any reduction in coal-handling labor is ignored except in the case of boiler replacement. When boilers are replaced (firing above 20% biomass), labor is zero as it is assumed that no new labor or management will be required as labor previously dedicated to coal operations will be freed to assume biomass operation responsibilities. It is also assumed that the annual quantity of biomass co-fired is consumed evenly over the entire annual hours of operation[5].

A laborer is assumed to work 2,000 hours per year and no partial laborers are allowed in the estimation. It is also assumed that handling 1 bail of biomass per laborer minute sets a minimum labor requirement limit. An hourly flow rate of biomass tons per hour is calculated by dividing annual biomass consumption by annual hours of operation. Assuming that biomass is delivered in large round bales containing roughly a half ton of dry biomass[6], a bales-per-hour handling rate is estimated by multiplying the tons-per-hour by two [50]. Although ignored by this research, dry matter losses are expected to be less than 5% [51]. It is assumed that a single operator will not be able to handle a single bale in less than 1 minute. Thus, as biomass feed rates increase, an additional laborer is added if the measurement of bales-per-minute falls below

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[5] This might not be true in as biomass feedstock supplies will likely vary by season at the least and perhaps by other natural/agriculturally based reasons, also. However, sustaining this assumption simplifies the labor estimation approach.

[6] Biomass can be baled into several sizes and geometries, but researchers have determined that the most economical is a large round bale (1.8 m dia x 1.5 m long @ 134 kg/m^3).

1. Using this method, the bales-per-minute-per-operator never falls below 1 minute. Operator costs are estimates by scaling the number of operators and multiplying by $70,000/operator. See Figure D 1 for a graphical presentation of our labor function.

Linear Programming necessitates that the non-linear labor cost function be approximated using linear equations. Four linear equations have been used to approximate the labor cost curve presented in Figure D 1. These four equations are presented in Equation D 19.

Combining the operator-labor-cost estimate with equipment-maintenance-cost estimate yields a range between \$1.75 - \$14.50 /MWh_S which is consistent with the high EPRI cost estimate.

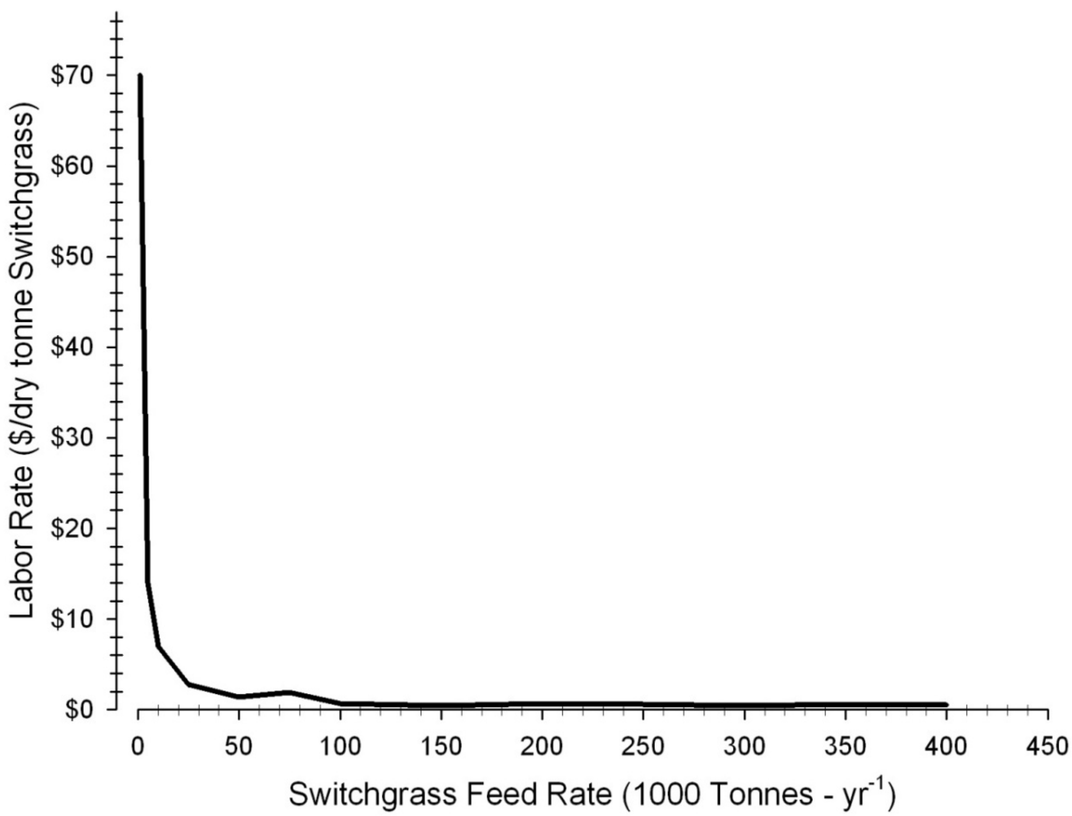

Figure D 1– Labor rate as a function of federates.

Sulfur Dioxide (SO2)

Tests have shown that co-firing biomass and coal generally reduces SO_2 emissions in proportion to the amount of biomass fired [52]. Biomass does contain sulfur, however; biomass sulfur uptake varies as a function of nitrogen fertilizing, harvest times, and frequency of harvest [53]. A laboratory test is required to determine exactly how much sulfur is present in a given biomass feedstock.

For this research, it is assumed that biomass contains 75% less sulfur than coal does. Biomass analyses report biomass sulfur content at roughly 0.2 percent by weight, or 95% less sulfur by weight than coal [45, 54, 55]. Equalizing for energy lowers this to roughly 90%. Assuming a 75% reduction is, therefore, a conservative assumption. See Equation D 4 for emission reduction calculation and Equation D 21 for emissions value calculation.

A distribution describes historic SO_2 market prices. The distribution type and parameters were determined using regression tools provided by @Risk software. The distribution is described by a lognormal distribution with English unit ($/ton) parameters of $\mu = 319.5$, $\sigma = 941.5$, shifted (+) by 126.3. Historic emissions values were provided courtesy of Melissa Gist, Amerex Emissions, Ltd.

Current SO_2 market prices have bounced between $400 and $700/ton SO_2 during the month of July 2007. For this analysis, a price of $550/ton SO_2 is used throughout all forecasted years.

Nitric Oxide & Nitrogen Dioxide (NO_x)

Early co-firing combustion testing primarily focused on the production and emission of NO_x [56]. The affect biomass co-firing has on existing coal-fired power plants' NO_x emissions varies between tests, but a reduction in NO_x emissions can generally be expected. Regression tools have determined explanatory parameters to testing results for many different fuels, equipment, and test conditions [57]. Combining multiple biomass co-firing tests -- which include multiple biomass fuels -- a general NO_x reduction estimate is 75% of the biomass-to-coal co-fire rate [45]. 75% reduction rate is assumed for this research. See equation 12 for emission reduction calculation and equation 32 for emissions value calculation.

Historic NO_x market prices, dating between 4/18/2002 and 12/2/2005, were provided courtesy of Melissa Gist, Amerex Emissions, Ltd. @Risk software regression tools were used to determine a distribution and distribution parameters. The distribution is described by a Weibull distribution with English unit parameters of $\mu = 5.68$, $\sigma = 3545.9$, shifted (+) by 280.46. Current NO_X market prices are much smaller than the historic median value of $3560/ton NO_X and, during the month of July 2007, was $700/ton NO_X. For this analysis, a price of $700/ton NO_X is assumed throughout all forecasted years.

Mercury (Hg)

It is assumed that biomass energy crops do not possess mercury [45, 54]. Research has indicated that gas phase mercury is emitted naturally from ecosystems, which would indicate that biomass might possess mercury [58]. The researchers suspect, but have not proven, that the gas phase mercury emissions measured from natural sources are most likely from coal combustion. They hypothesize that anthropogenic mercury is cycling through deposition and atmospheric reuptake many times, meaning that elemental mercury is likely remaining active for longer periods than previously suspected before being re-sequestered into the Earth's crust.

Mercury emissions reductions are not included in the economic modeling performed by this research because a mercury emission trading mechanism and market do not exist.

Particulate Matter (PM-10 & PM 2.5)

Particulate matter is not tracked by eGRID and, therefore, is not included in the emissions reduction estimations. The production of particulate matter may increase with the combustion of biomass, although it is not fully understood how this would affect existing particulate matter emissions controls such as electrostatic precipitators and bag houses [55].

Engineering Economic Parameters

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

Estimation of Regression Parameters

For each existing coal-fired power-plant, the changes in the sum of capital equipment costs, operations and maintenance costs, and the revenues from a co-beneficial reduction in SO_2 and NO_x emissions are regressed against the quantity of biomass cofired over various cofiring rates. The result is a unique linear approximation of these costs as a function of biomass cofired. Two regressions are performed for each candidate coal-fired power-plant: a long-term marginal cost regression, and a short-term marginal cost regression. The long-term marginal cost regression includes capital debt service and tax payments discounted over time to a net-present-value. See Equations D 8, D 16, and D 22. The short-term marginal cost regression excludes capital debt service and tax to represent the floor below which a power-plant can no longer economically cofire biomass and coal. If revenue from a carbon market will not cover the short-term marginal cost estimate, then the LP will not allocate biomass to this plant and the plant will no longer cofire biomass and coal. Thus, the initial decision to cofire is captured by the long-term marginal cost estimate, and once it is determined that a power- plant can economically cofire biomass given a long-term marginal cost estimate, subsequent year's decision to continue cofiring depend on the short-term marginal cost estimate.

Two independent cofiring LPs were solved, one using the individual cost components described in the previous sections and the other using the regression estimation described in the previous paragraph. Comparisons were made between the two LP solutions, and the regression was adjusted until differences between the two solutions were largely removed. The resulting regression simplifies the capital equipment cost estimate described above in the section titled "”plant modifications.” For PC plants, the two higher equipment cost estimates (cofire rates above 2% use \$200/$kW_{biomass}$ and cofire rates above 10% use \$300/$kW_{biomass}$) are combined into a single cost factor of \$280/$kW_{biomass}$ applied to cofire rates above 2%. For non-PC plants, \$280/$kW_{biomass}$ is applied to cofire rates above 10%.

The resulting regression parameter estimates are unique for each power-plant because each individual power-plant has its own SO_2 and NO_x emissions rates as well as its own capacity factor. Each of these factors, along with access to biomass feedstock, determines a power-plant's unique cofiring cost estimate [59].

Fuel Costs

Both biomass and coal are commodities and will be subject to localized commodity pricing. It is anticipated that in the near term biomass crops will have higher costs per unit energy than coal. Although cofiring biomass with coal will offset coal consumption, combined fuel price will be higher than coal fuel prices will. Biomass prices in the biomass dataset range from \$25/dry short ton to \$100/dry short ton equaling \$1.7/MMBtu and \$6.0 /MMBtu, respectively. In 2004, coal costs ranged between \$0.77/MMBtu and \$2.25 /MMBtu [60]. \$1.24/MMBtu equates the average U.S. historic coal price considering inflation-adjusted prices for bituminous, sub-bituminous, lignite, and anthracite between the years 1949 through 2004 [60]. For this research, coal costs are kept constant at \$1.24/MMBtu.

Fuel Transportation Costs

Biomass fuel cost estimates only reflect farm-gate prices, or revenue required to displace current farm crops; they do not include biomass transportation costs. A biomass transportation cost is estimated by the biomass quantity shipped, multiplied by the distance shipped and a shipping freight rate (see Equation D 18). It is assumed that the coal price is a plant-gate price and coal transportation costs are included in the price [61].

Distance estimation between biomass and candidate power-plants

For simplicity, this analysis assumes that biomass is located at the center of each state in which it is forecasted to be grown. Distances are estimated between state centers and individual power-plant locations using Equation D 26.

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

Equation D 26

Where:

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

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

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

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

To compare the very simply estimate distances to a more spatially disaggregated distance estimation, comparisons were made between solutions taken from an LP using these distances and an LP using more spatially disaggregated distances [33, 59]. Multiplying the coarse distance estimate produced by assuming biomass resides at a state's center by ½ yields a close approximation of the average shipping costs estimated by the finer spatial resolution LPs. Thus, for this research, the distance estimations are multiplied by ½ to approximate shipping distances estimated by a more spatially disaggregated LP model.

Freight Rates

It is assumed that all biomass will be transported by truck because of the flexibility of the trucking industries to pick up loads at fields, a service not offered by rail transportation. If a power plant began co-firing biomass at levels that could justify rail transportation, trucks would likely gather biomass from fields for delivery at rail loading stations [62]. This research does not assume this case although it is recognized that individual power plants could possibly find transportation cost-reduction options, which would lower their transportation costs below those concluded from this research.

Bureau of Transportation Statistics reports an average truck freight rate of 26.6¢ per ton-mile in the year 2001 [63].

APPENDIX E – Biomass Resource Supply Dataset

Introduction and background

In late 2006 through early 2007, the US Department of Energy's Energy Information Administration (EIA) contracted the University of Tennessee's Bio-Based Energy Analysis Group (BEAG) to produce a dataset which forecasts the US agriculture sector's ability to produce energy feedstocks. This dataset will provide a base for EIA to update their projection of biomass energy demands and uses within the NEMS model. EIA kindly supported the development of the Biomass Allocation Model by sharing this dataset.

BEAG developed the dataset using their POLYSYS model. The POLYSYS model, a US agriculture policy simulation model, was developed by the US Department of Agriculture, at the Oak Ridge National Laboratories, in conjunction with the University of Tennessee's Department of Agricultural Economics, and Oklahoma State University's Great Plains Agricultural Policy Center [30]. POLYSYS is currently maintained and utilized by BEAG.

The POLYSYS model is a framework which provides policy analysis and researchers with an analytical toolkit for estimating a variety of impacts in the agriculture sector resulting from economic, policy, or environmental changes [17]. It aggregates data according to geographical districts called POLYSYS districts (analogous to Agriculture Statistical Districts [ASD]). The districts are comprised of multiple counties which posse similar attributes (soil type, moisture, terrain, etc.) and economic conditions (crop types, incomes, etc.). There are 305 POLYSYS districts containing 2,787 counties.

The POLYSIS model has been specifically used to analyze the costs and availability of biomass energy feedstocks produced within the U.S. agricultural sector [31]. The energy crops considered are corn and switchgrass, farming residues (corn stover and wheat straw), and forest trimmings and forest residues. POLYSIS estimates the amount of biomass energy feedstocks available if they were bought at various prices. The model considers farm incomes given traditional farming activities and seeks to balance demand for all agricultural products. Energy crop prices are based on the cost, including profit, required to replace current farming activities (agricultural commodities: crops, livestock, hay, etc.).

The dataset that BEAG produced for EIA consist of two yield scenarios. The first one, titled "Average Production," follows USDA projection of agricultural yields from 2006 through the year 2016 and extrapolates USDA yield changes through the year 2030. "High Production," the second yield scenario, assumes yields are 50% higher than the "Average Production" scenario yields.

Each yield scenario consists of five ethanol demand scenarios. The first, titled "baseline," follows USDA projections of ethanol demand through the year 2016 and extrapolates demand through the year 2030. The additional four scenarios assume that ethanol demand is 25%, 50%, 87.5%, and 125% greater than the baseline projection, respectfully.

Each of the ethanol demand scenarios consists of variable feedstock prices ranging from $20 to $100 per dry ton of biomass energy feedstock. $5 price steps result in seventeen feedstock price assumptions (e.g. 20$/ton, 25$/ton, 30$/ton, etc.). The two yield assumptions, five ethanol demand assumptions, and the seventeen biomass energy feedstock price assumptions result in 170 unique feedstock supply scenario forecasts in the dataset.

Feedstock energy prices are in year-specific nominal dollars following the USDA's estimation of agricultural production through the year 2016 [9]. Between 2016 and 2030, the prices are in 2016 nominal dollars. In this report, the biomass resource supply dataset is presented in its original state, although the results presented are generated after the dataset nominal dollar were converted into year-specific real dollars based on steady inflation.

Each unique feedstock supply forecast results in a unique forecast for each of the 305 agricultural statistical districts (ASD) in the POLYSIS model. For each ASD, seven biomass energy feedstocks are forecasted: corn stover, wheat straw, forest residues, forest thinnings, switchgrass, corn productions, and soybean production. Considering the yearly forecasts, ASDs, and crops considered, the dataset consists of over nine million unique data points. Moreover, an aggregation of each energy feedstock is provided and corn production is broken down by use ("feed," "export," "ethanol production," and "other demands").

Corn price as a function of corn-based ethanol production

Corn prices as a function of corn use is provided in the biomass feedstock dataset. In general, as corn-based ethanol production grows, demand for corn grows. In a given year, corn prices rise in response to higher corn demand, but over multiple years, corn prices can adjust as farming practice may divert land from other uses to corn cultivation [10]. For 2007 and the years immediately following, an unprecedented amount of corn-based ethanol production capacity is planned to come online. During this time period, corn-based ethanol production capacity could demand more corn than farming practices can adjust for and result in very high corn prices. For example, 5.5 bgy of ethanol capacity was online in 2006, but an additional 6 billion is under construction or is in the planning stage [6]. Assuming an average ethanol conversion rate of 2.65 gal/bu of corn, 5.5 bgy demands roughly 2 billion bushels of corn per year. Adding 6 billion gallons more of corn-based ethanol will demand an additional 2.26 billion bushels. Figure E 1 and Figure E 2 present the effect of large-scale corn diversions to ethanol production in the year 2007 from the biomass dataset. Assuming that the quantity of corn used directly for human consumption remains constant, a doubling of corn-ethanol production in a single year would require a reduction in corn feed for livestock and for the U.S. to become a net corn importer (Figure E 1). Moreover, corn prices would rise to roughly $9.00/bu resulting in approximately $4.00/gal ethanol prices. At $4.00/gal, crude oil prices would need to be higher than roughly $233/bl before corn-based ethanol would be cheaper than gasoline[7].

[7] Assumes an energy equivalent basis and a gasoline refinery cost of $0.23/gal

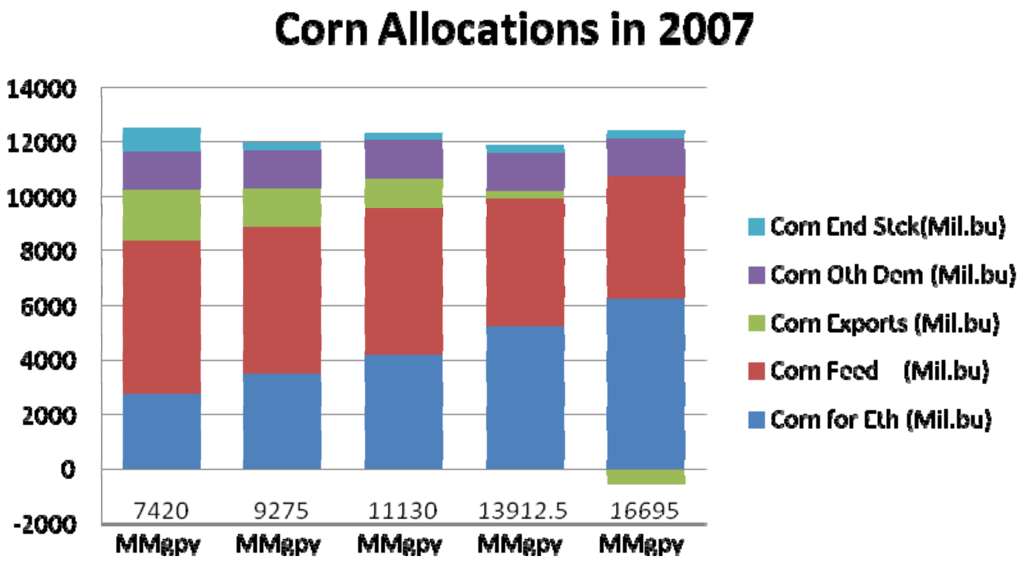

Figure E 1 Corn allocations in 2007 considering a range of corn-based ethanol production (7.4 MMgpy to 16.7 MMgpy)

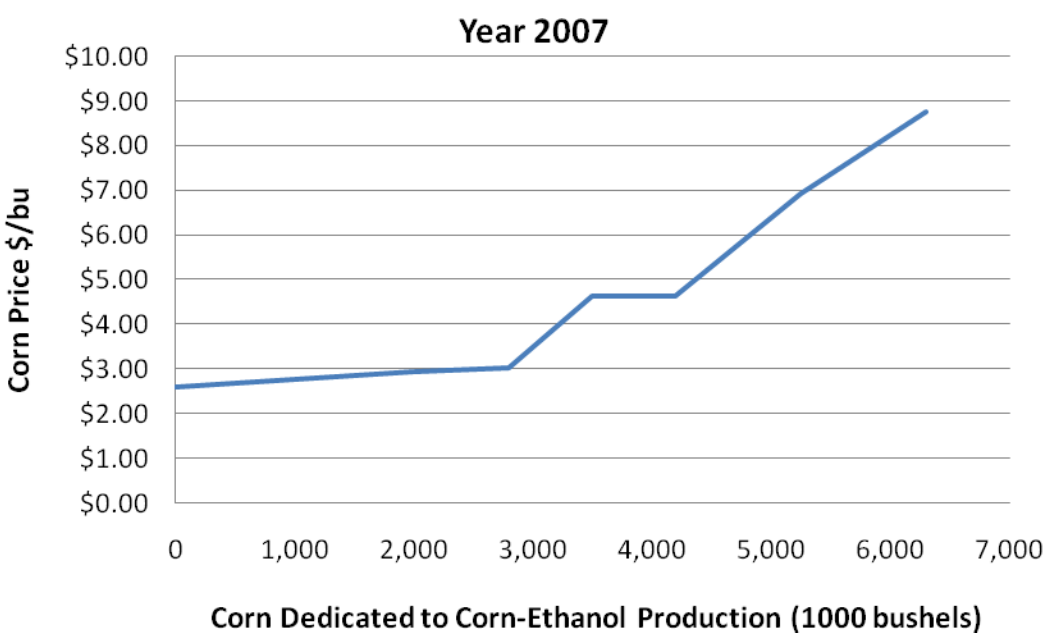

Figure E 2 – Corn prices as a function of corn allocated to corn-based ethanol production in the year 2007

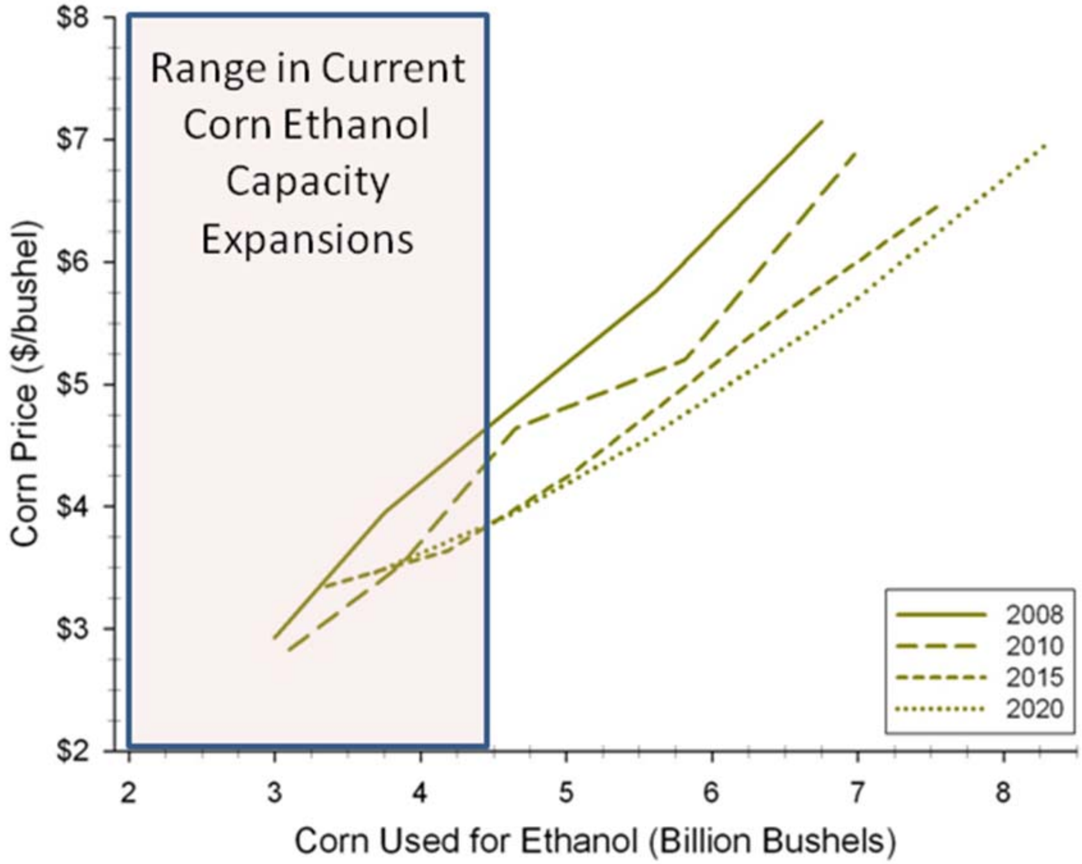

Figure E 3 – Corn supply curves as a function of corn used for ethanol 2008 through 2020. Range in current corn ethanol capacity includes all capacity under construction or planning as of 2007 [6]

Biomass Dataset Aggregation Methodology

The dataset presented above contains estimates of biomass production in tons per year for POLYSYS districts which each contain multiple counties. The data is aggregated to state totals and two biomass categories: grasses (switchgrass, straw, and stover), and wood. “Grasses” covers biomass, wheat straw, and corn stover. Wood is a sum of forest residues and trimmings. Figure E 4 presents grass supply curves assuming USDA yield forecasts.

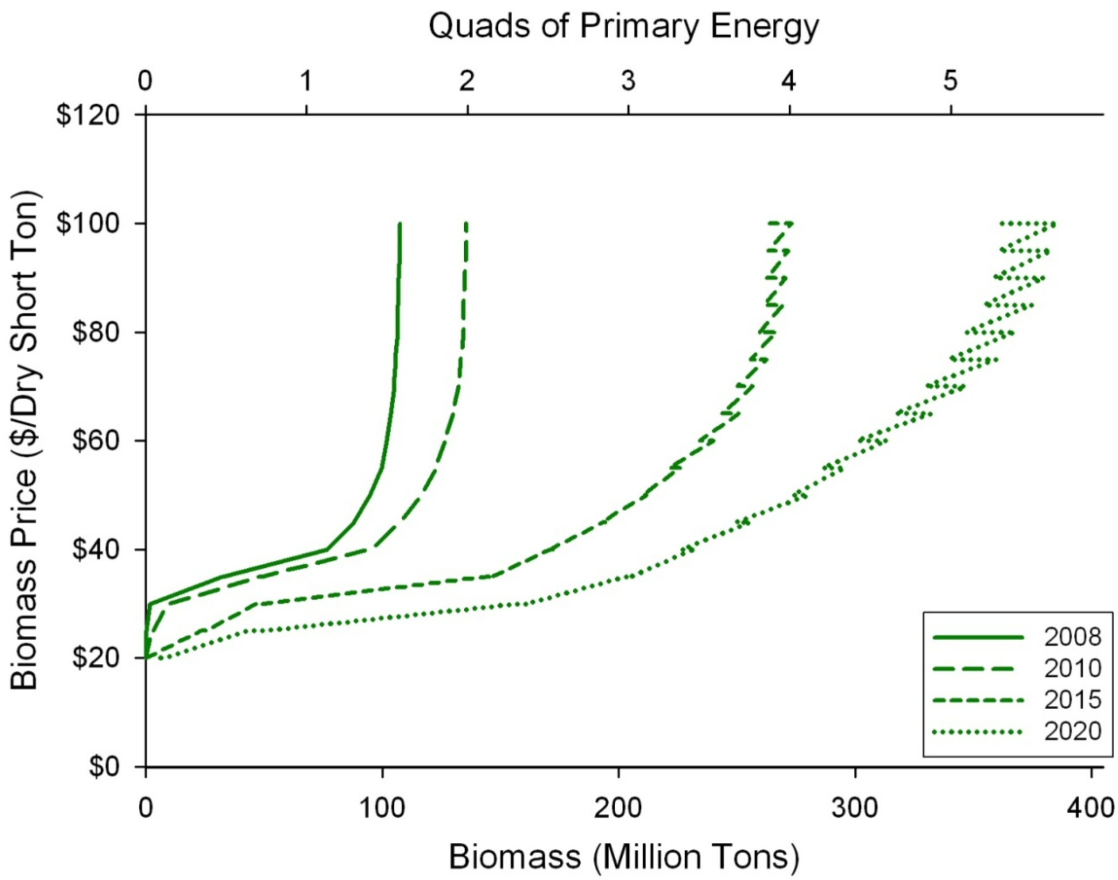

Figure E 4 – Biomass feedstock supply curves for 2008 to 2020. Supply curves are for an aggregation of switchgrass, corn stover, and wheat straw assuming USDA yield forecasts.

Figure E 5 through Figure E 8 present the grasses data on an ASD basis for the year 2008. Figure E 5 presents that grasses data assuming that USDA forecast of ethanol production is correct and that biomass could be bought for $30/dry short ton. Figure E 6 presents the grasses data, assuming the same biomass price, but with ethanol production at 125% greater than that estimated by the USDA. Figure E 7 and Figure E 8 present the grasses data at $100/dry short ton while making the same two USDA ethanol forecast assumptions. Figure E 9 and Figure E 12 present the same ethanol assumptions and biomass selling prices for the year 2030.

For all figures, the increasing intensity of green indicates an increasing production of grasses.

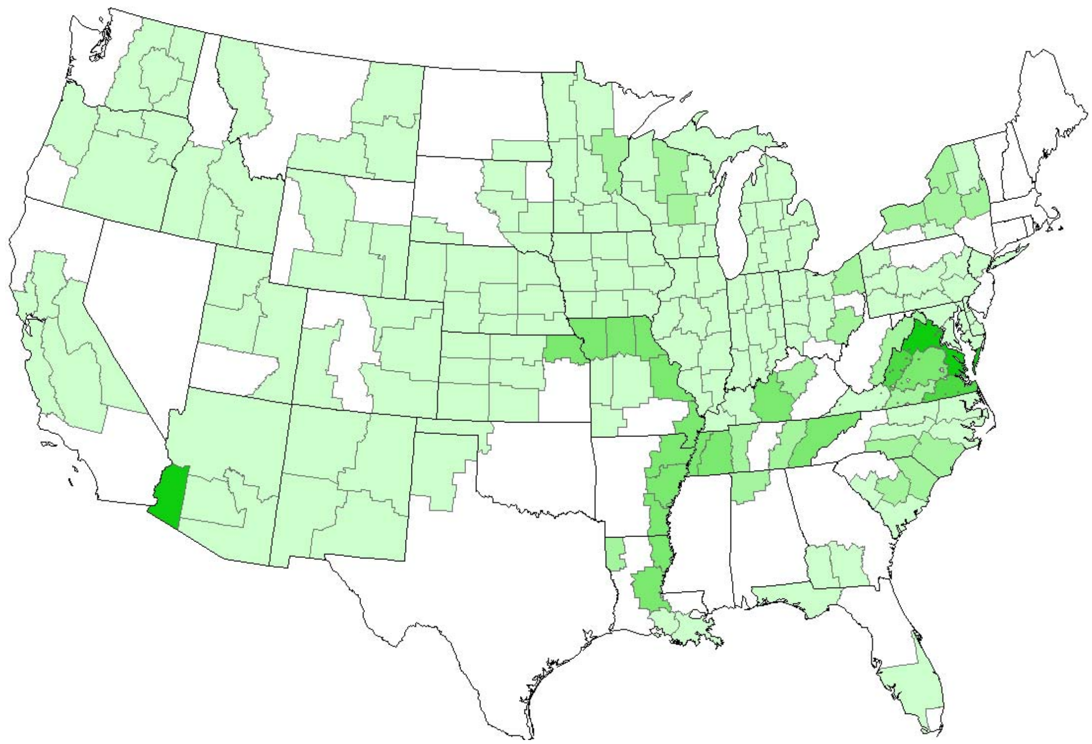

Figure E 5 – Year 2008 grasses at $30/dry short ton assuming USDA ethanol production

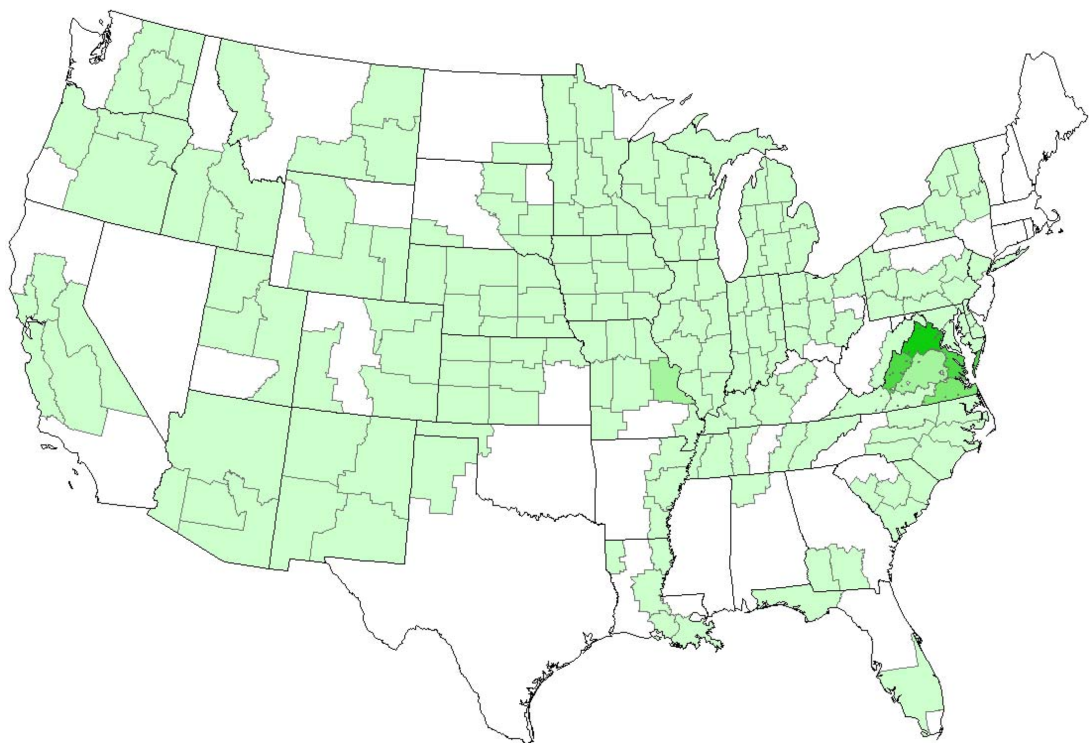

Figure E 6 – Year 2008 grasses at $30/dry short ton assuming a 125% increase over USDA ethanol production

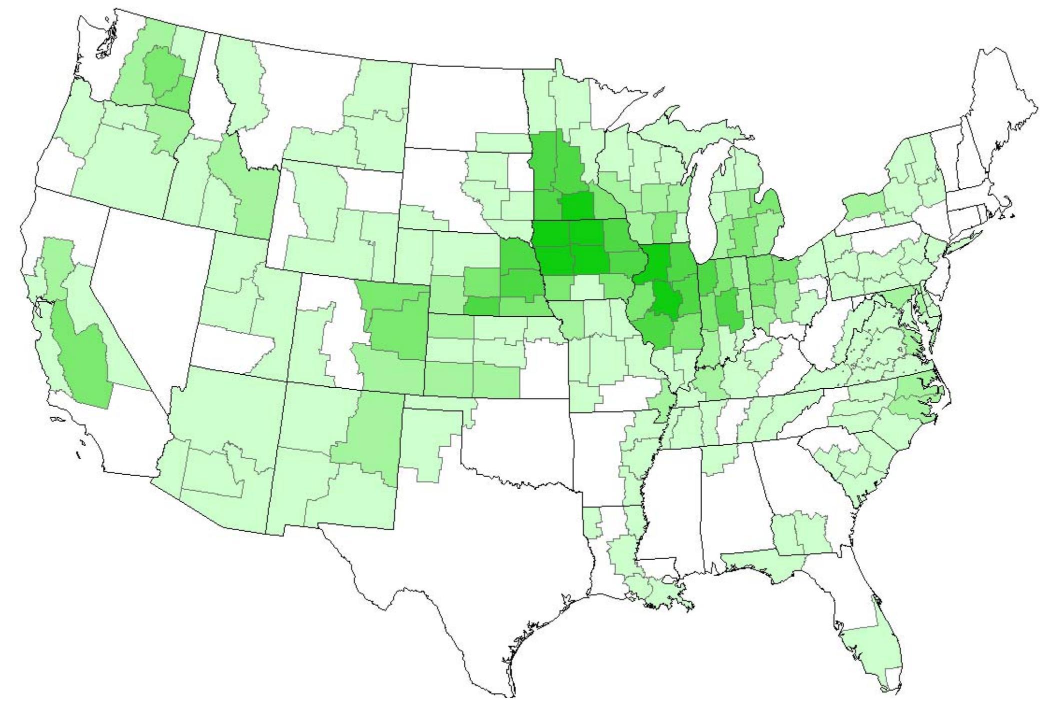

Figure E 7 – Year 2008 grasses at $100/dry short ton assuming USDA ethanol production

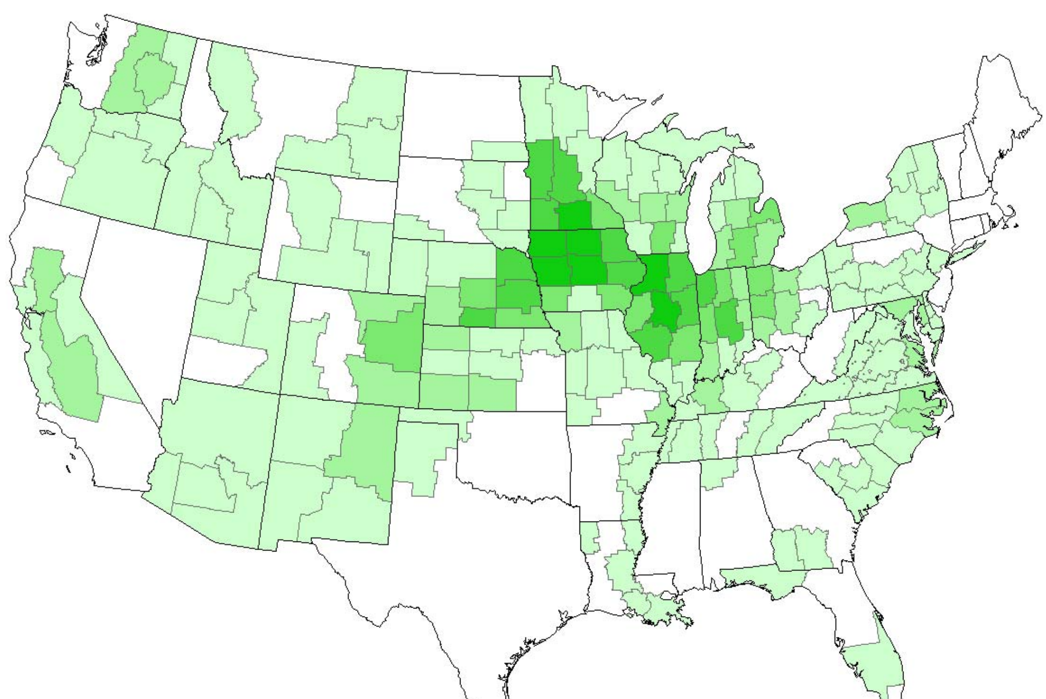

Figure E 8 – Year 2008 grasses at $100/dry short ton assuming a 125% increase over USDA ethanol production

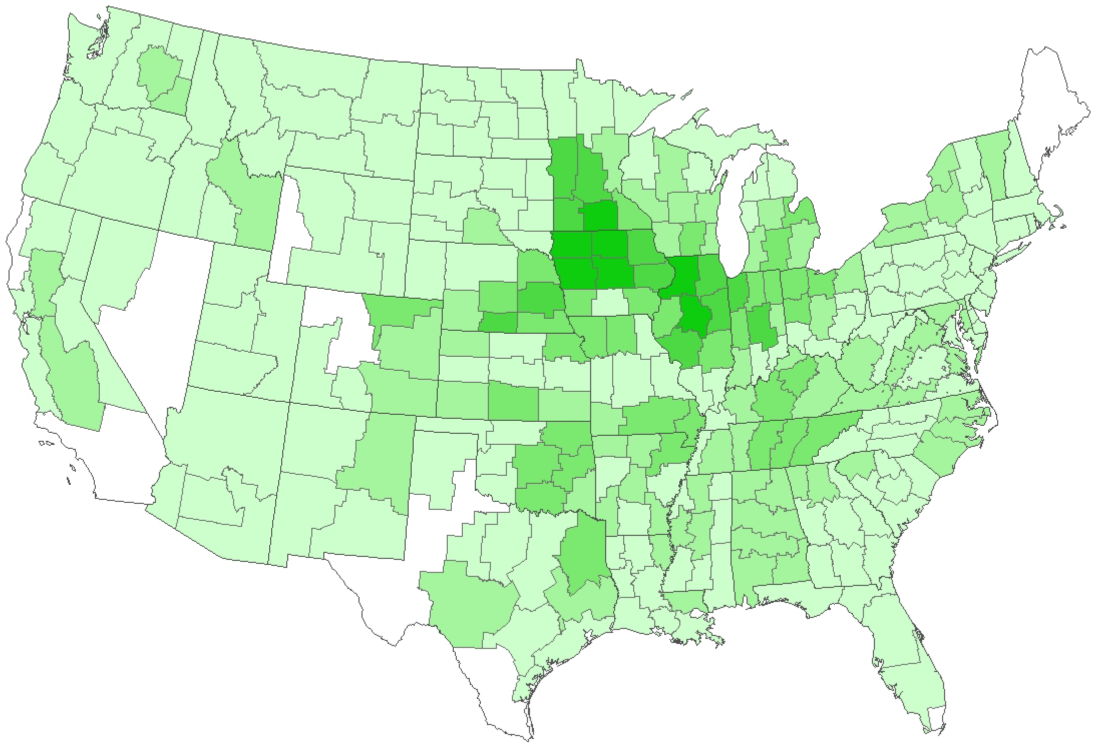

Figure E 9 – Year 2030 grasses at $30/dry short ton assuming USDA ethanol production

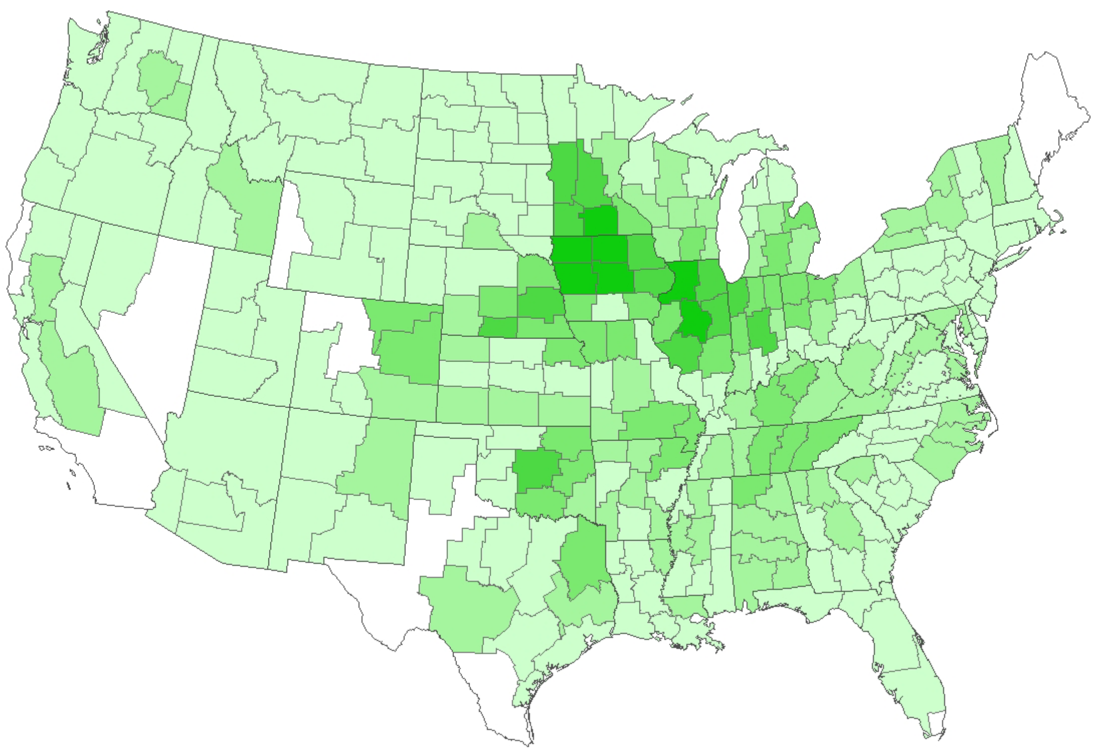

Figure E 10 – Year 2030 grasses at $30/dry short ton assuming a 125% increase over USDA ethanol production

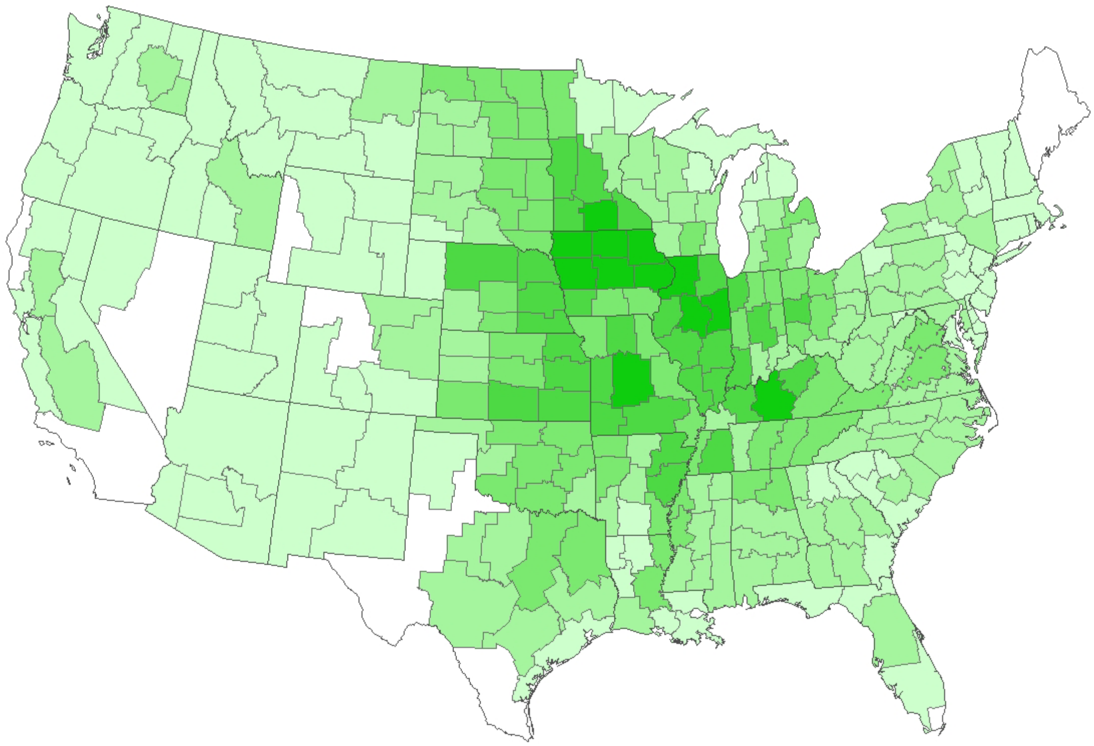

Figure E 11 – Year 2030 grasses at $100/dry short ton assuming USDA ethanol production

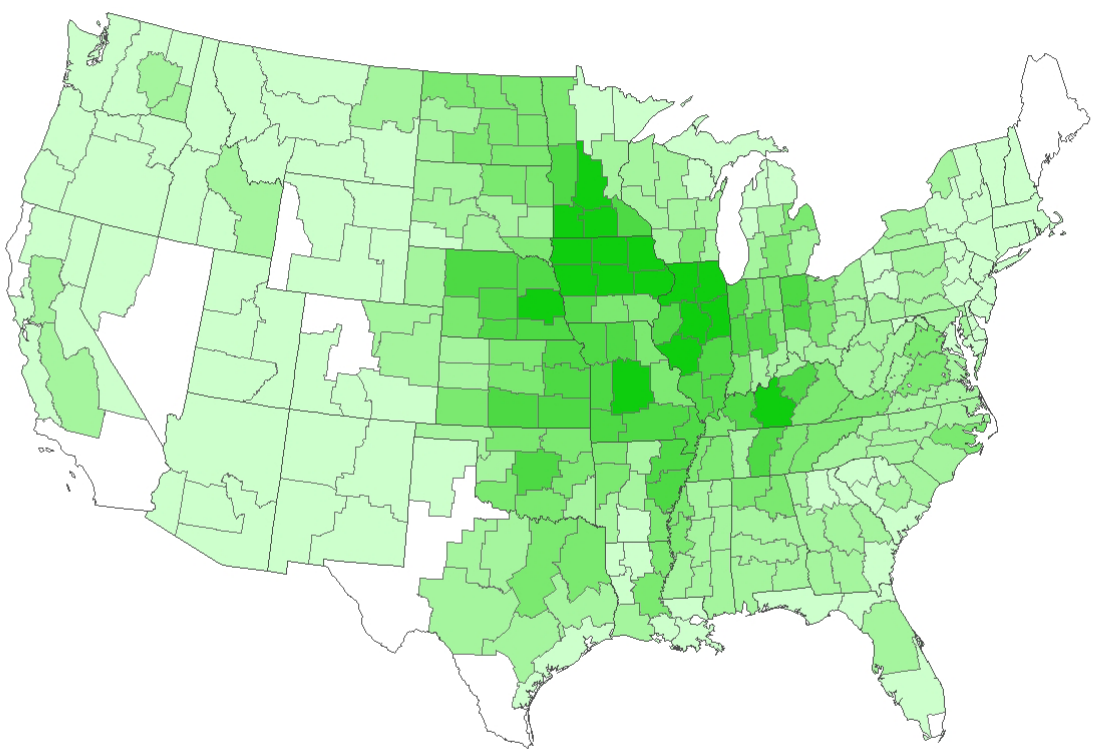

Figure E 12 – Year 2030 grasses at $100/dry short ton assuming a 125% increase over USDA ethanol production

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