The Welfare Costs of GHG Reduction with Renewable Energy Policies in the US

Madhu Khanna and Anthony Oliver

***Corresponding Author**
Dr. Madhu Khanna
Professor, Department of Agricultural and Consumer Economics
301A Mumford Hall
University of Illinois at Urbana-Champaign
1301 W Gregory Drive, Urbana, IL 61801
Email: khanna1@illinois.edu
Phone # 217-333-5176
Fax # 217-244-3637

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Abstract: A range of policies have been implemented in the agricultural, transportation, and electric power sectors, which comprise the majority of GHG emissions in the US. Two prominent policy sets are the national RFS and state-level RPSs. The purpose of this research is to examine the GHG implications of the state RPSs and their welfare costs of mitigating GHG emissions. We also analyze the interactions between the RFS and state RPS policies and the extent to which these policies create competition or complementarity in their use of biomass for meeting the standards since the production of cellulosic biofuels also generating renewable electricity as a co-product that can substitute for fossil fuel based grid electricity and contribute to meeting the RPS. We compare the cost effectiveness of these policies implemented jointly to a carbon tax policy that achieves the same level of GHG emissions. We find that while a carbon tax increases social welfare, the RPS imposes a welfare cost on the economy. However, the implementation of the RFS does reduce the welfare costs of the RPSs by substituting co-product electricity for costly biomass electricity and providing a terms of trade benefit in the agricultural and fuel sectors. We find that the RPSs cause an increase in renewable energy based generation, which primarily offsets natural gas based generation rather than coal and increases total electricity consumption. The joint implementation of RFS and RPSs results in reduction in the use of co-firing and dedicated biomass. Coal based generation increases relative to the RPSs only scenario, while natural gas generation decreases relative to the RPSs only scenario. The implication of this is that the effects of jointly implementing the RFS and RPSs on GHG emissions are not additive.

The Welfare Costs of GHG Reduction with Renewable Energy Policies in the US

1. Introduction

The electricity sector and the transportation sector in the US currently account for over 70% of the greenhouse gas emissions in the US with the majority of those emissions being from the electricity sector in 2011[1]. A range of policies have been implemented in both sectors to encourage a switch to renewable fuels, motivated in part by the objectives of increasing energy security, reducing dependence on fossil fuels and mitigating climate change. In the transportation sector, this has primarily been through the implementation of the Renewable Fuels Standard (RFS) following the Energy Independence and Security Act of 2007 that established volumetric standards for the different types of biofuels, including conventional, advanced and cellulosic biofuels from feedstocks like crop residues, energy crops and forest biomass, to be blended with liquid fossil fuels.[2] In the electricity sector, various states have implemented Renewable Portfolio Standards (RPSs) that set state specific standards for renewable electricity generated from state specific renewable resources.

It has been argued that the implementation of the RFS that mandates the use of at least 60 B liters of cellulosic biofuels may conflict with efforts to reduce US GHG emissions over the next two decades because it will divert a constrained supply of biomass from displacing coal based electricity generation to displacing the less carbon intensive gasoline; the RFS would

[1] http://www.epa.gov/climatechange/ghgemissions/sources/transportation.html

[2] The three categories of renewable fuels are defined based on their specific lifecycle GHG emission intensity threshold relative to conventional gasoline in 2005. Conventional biofuels are those produced from corn starch and should achieve a GHG intensity that is at least 20% lower than that of conventional gasoline. Advanced biofuels are those obtained from feedstocks other than corn starch with a lifecycle GHG emission displacement of 50% compared to conventional gasoline. Cellulosic biofuels are those derived from 'renewable biomass' and achieving a lifecycle GHG emission displacement of 60% compared to conventional gasoline.

therefore result in a “crowding out” of biomass used to generate electricity (Fraas and Johansson 2009). This analysis could be flawed for several reasons; it assumes limited scope to increase the supply of biomass which is not necessarily the case at levels required by the RFS (Khanna, Chen, et al. 2011). More importantly, it disregards the potential for the production of cellulosic biofuels also generating renewable electricity as a co-product that can substitute for fossil fuel based grid electricity and contribute to meeting the RPS. Additionally, it assumes that under an RPS, all biomass would be co-fired with coal and displace coal-based generation and not natural gas based generation.

The RFS and the RPS policies will interact with each other for several reasons. The RFS is a nested standard that sets a minimum requirement for cellulosic biofuels but allows the mix of feedstocks used to meet them to be endogenously determined; moreover it allows the potential for the volume of cellulosic biofuels to exceed the minimum mandated if they can compete with advanced and conventional biofuels. Thus, the mix of different types of biofuels and the mix of various types of cellulosic feedstocks will depend on their relative costs and can be expected to vary regionally due to heterogeneity in availability and costs of production. Since the RFS is a federal mandate, it provides the flexibility to use the lowest cost sources of feedstocks nationally, irrespective of which region they are located in. This is in contrast to the state RPSs which will place demands for renewable resources for electricity generation that are region-specific. Thus, the joint implementation of the state RPSs in the presence of the RFS has the potential to affect the mix of feedstocks and their regional production pattern to produce biofuels as well as the regional mix of renewable electricity generation. This will also affect the costs of meeting the RPSs and the RFS and the GHG emissions savings likely to be achieved by these policies.

An RPS can be expected to affect GHG emissions in two ways; first by implicitly penalizing fossil fuel based electricity and implicitly subsidizing renewable electricity it will create incentives to reduce fossil fuel generation and increase renewable generation. Fischer (2010) shows that an RPS may increase or decrease the price of electricity depending on the impact that reduced demand for fossil fuels lowers the cost of using them as an input for electricity generation; if it lowers the price of electricity then that may offset some of the reduction achieved by displacing fossil fuel based electricity with renewable generation. In addition to this, when there are multiple types of fossil fuels and renewables, the effect of the RPS on GHG emissions will depend on its impact on the mix of fossil fuel sources for electricity and on the mix of renewable sources induced. The effectiveness of the RPS will be larger if renewable sources displace coal rather than natural gas since coal is about 2 times more GHG intensive than natural gas based electricity.[3] However, since the RPS provides uniform incentives to displace all fossil fuel generation, this will not be the case if natural gas based electricity continues to be more expensive than coal based electricity. It is therefore important to examine not only the mix of renewable fuels induced but also the extent to which various fossil sources, such coal and natural gas based electricity are displaced.

The purpose of this research is to examine the GHG implications of the state RPSs and their welfare costs of mitigating GHG emissions. We also analyze the interactions between the RFS and state RPS policies and the extent to which these policies create competition or complementarity in their use of biomass for meeting the standards. We focus specifically on determining endogenously the shares of wind energy and bio-electricity (from co-fired power plants, dedicated biomass electricity generating plants and as a co-product from biorefineries) to

[3] Calculated from the Egrid database (USEPA 2010).

meet the state RPSs as well as the mix of feedstocks and biofuels used to meet the RFS when these policies are implemented individually and simultaneously. Since biomass is a potential input in both the transportation and electricity sectors, these renewable energy policies create a two-way interaction between these sectors and the agricultural sector; bioenergy production has the potential to compete with food and feed production and affect food/feed prices and at the same time the costs of bioenergy will depend on land rents in the agricultural sector. We therefore develop an integrated framework that analyzes the implications of these renewable energy policies on all three sectors. We use this to examine the cost-effectiveness of these policies implemented by themselves and jointly at reducing GHG emissions and their distributional effects on consumers and producers of the transportation, electricity and agricultural sectors.

Additionally, we compare the cost effectiveness of these technology standards for the electricity and transportation sectors with that of a carbon tax on both sectors that achieve the same level of GHG emissions as technology standards on each sector. A carbon tax would achieve reductions not only by inducing renewable energy consumptions but also by reducing the use of fossil fuels, depending on which is more cost effective. Moreover, the carbon tax would allocate reductions in emissions across the transportation and electricity sectors to equate the marginal costs of abatement across the two sectors.

2. Previous Literature

There has been considerable research analyzing the economic and GHG effects of state and federal RPSs and the RFS that has considered each of these policies in isolation. Several studies have examined the effects of the RPS on electricity prices (Palmer and Burtraw 2005; C. Chen et al. 2009; Fischer 2010; Sullivan et al. 2009) and of the RFS on food and fuel prices (see review in Chen and Khanna 2013). Conceptually, policies that require a percentage share of renewable energy in total energy consumption, like the RPS or a blend mandate like the RFS implicitly tax fossil energy and subsidize the consumption of renewable energy. As a result, Fischer (2010) shows that RPS policies can raise or lower the consumer price of electricity depending on the relative elasticity of the renewable and non-renewable fuel supply curves and the stringency of the RPS target.[4] This finding is similar to that obtained by studies analyzing the effects of the RFS on fuel price for consumers (De Gorter and Just 2009; Chen and Khanna 2013).[5]

Several studies have also examined the cost-effectiveness of a RPS and the RFS in reducing GHG emissions and compared it to the costs of abatement with a cap and trade policy.[6] In general these studies find that the RPS is less effective than a cap and trade policy, because it does not distinguish among technologies based on their carbon intensity; all renewables are treated the same and all non-renewables are treated similarly and the RPS does not incentivize the least cost options for reducing emissions. The RPS also has a small effect on the price of electricity and thus provides inadequate incentives for electricity conservation, unlike a carbon tax. This is particularly the case in the longer run, when the RPS is more likely to underperform

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[4] Studies quantifying the effects of the RPS and RFS on electricity and fuel prices, respectively, find mixed evidence. Palmer and Burtraw (2005) find that a RPS ranging from 5-20% would raise the US electricity price while other studies reviewed in Fischer (2009) estimate that the RPS would lower retail prices. Chen et al. (2009) review a number of studies that have examined the effects of state RPSs in 20 states and project very modest effects of no greater than 1% increase in retail electricity rates. Similarly, Sullivan et al. (2009) find a modest impact of 1-5% increase in the average state level consumer price of electricity.

[5] Studies analysing the effect of the RFS on consumer price of fuel also obtain mixed findings with de Gorter and Drabik (2011)and Rajagopal et al. (2011) finding it will raise consumer price and Chen and Khanna (2012) and Chen et al. (2013) finding it will lower the consumer price of fuel.

[6] Kydes (2007) finds that a federal 20% non-hydropower RPS would promote adoption of renewable energy technologies that would lead to a 6.5% reduction in GHG emissions relative to the reference case in 2020 while raising electricity price by 3%. Chen et al. (2009) review the find that GHG abatement costs vary widely across studies evaluating state RPSs with a median value of $5 per metric ton of CO2. Other studies compare the effects of a RPS with that of a cap and trade policy. Palmer et al. (2010) and Bird et al. (2011) analyze the effects of a 25% RPS with and without the cap and trade policy envisioned by the ACES Act in reducing GHG emissions.

the cap and trade policy because it does not provide the carbon price signals needed to induce sufficient investment in low carbon technologies to lower emissions as demand increases (Bird et al., 2011). These studies find that the impact of the RPS on GHG emissions is largest when the RPS is accompanied by policies to reduce electricity consumption either directly or indirectly by increasing energy efficiency (Sullivan et al., 2009).

Several studies have examined the mix of feedstocks that would be incentivized by federal and state RPSs (see review in White et al. 2013). Sullivan et al. (2009) consider national renewable electricity standards that range from 12% to 22% by the 2020s. The western states were projected to meet their requirement through wind and solar, while the southeastern states were expected to rely on biomass energy. Chen et al. (2009) review a number of studies that have examined the effects of state RPSs in 20 states and project very modest effects of no greater than 1% increase in retail electricity rates with wind generation expected to provide 60% of the incremental capacity expansion and biomass about 11% to meet the RPSs.

A few studies have focused specifically on analyzing the potential contribution of the either the forestry sector or the agricultural sector to bioenergy production and its regional impacts on land use and commodity prices. Some studies find that renewable electricity demands could severely strain state/regional biomass resources and either leads to shortfall of supply or to high prices for biomass products. Abt et al. (2000) analyze the feedstocks needed to meet a 12.5% RPS by 2020 in North Carolina. Assuming given levels of renewable electricity from non-biomass sources and amount of available bioenergy from non-forest biomass, they estimate that more than half of the demand for renewable electricity will be met through forest biomass, specifically pulpwood since forest residues will be insufficient. They project that this will double pulpwood prices and lead to increased planting of forests for pulpwood production.

Other studies find that the impact of demand for bioelectricity on the forestry sector will be modest Ince et al. (2011) assume that forest biomass will meet 33% of the simulated increase in bioelectricity to meet national RPSs but that most of this biomass will be in the form of logging and mill residues and there will be very limited impact on timber product consumption and prices. White et al. (2013) examine the mix of forest and agricultural biomass that would be used to meet exogenously given projections (based on the Annual Energy Outlook) for biomass to meet a federal renewable electricity standard of 10% and 20% by 20%, assuming that targets for cellulosic ethanol are met. They find that the primary feedstock will be switchgrass followed by agricultural and logging residues and there will be some 6 M hectares) from forest sector to agricultural sector but impact on crop prices will be modest.

Dumortier (2012) examines the effects of demand for co-firing biomass by 398 existing coal-fired power plants and biorefineries for cellulosic ethanol and supply of biomass from various agricultural and forestry feedstocks, corn stover, wheat straw, switchgrass, and forest residues. They find that there is sufficient feedstock availability in some regions (Southern Minnesota, Iowa, and Central Illinois) but shortages in other areas including Eastern Ohio, Western Pennsylvania, and the tri-state area of Illinois, Indiana, and Kentucky which are characterized by a high density of coal-fired power plants with high energy output.

A few studies have examined the competitiveness of bio-electricity relative to coal. McCarl et al. (2000) find that biomass-fueled power using short rotation woody crops like poplar or willow is not competitive with coal based generation in the absence of subsidies or without yield enhancements. Similarly, Khanna et al. (2011) find that even with a high yielding energy crop like miscanthus, co-firing of biomass is not economically viable in Illinois in the absence of subsidies or a carbon tax.

A number of studies have also analyzed the effects of the RFS on domestic and global GHG emissions and considered both the direct effects due to displacement of fossil fuels and the offsetting effects of indirect land use change as well as the rebound in domestic and international fuel markets (see reviews in Chen and Khanna 2013; Khanna and Crago 2012).

A few studies have analyzed the effects of overlapping policies in the electricity sector, primarily those that combine an RPS and a cap and trade policy and therefore affect the price of carbon allowances (see review in Fischer and Preonas 2010). These studies show that, as expected, supplementary renewable policies increase the total cost of emissions reduction under an emissions trading policy because they limit the flexibility of the latter at inducing the least cost technologies for emissions reduction. Studies have also examined the effects of combining the RFS with a carbon tax policy and shown its effects on the mix of biofuels and GHG emissions (Huang et al. 2013). None of these studies have analyzed the effects of the RPS with and without the RFS in order to determine the extent to which it changes the renewable electricity mix.

The effects of the RFS and RPS combined could be different from that of each of these policies alone because the production of co-product electricity under the RFS could alter the mix of renewable and non-renewable sources and the costs and GHG intensity of electricity generation. These studies focus only on the electricity sector and consider the supply of alternative renewable technologies, including bioenergy, as exogenously given and do not model the competition for land among alternative types of biomass feedstocks or between biomass and food crops and its effects on the price of land and thus on the cost of bioenergy. Similarly, studies analyzing the RFS have typically not considered competing uses for biomass for electricity generation. To the extent that the RPS creates a demand for bioelectricity, it could raise the cost of biomass for the production of cellulosic biofuels and thus the cost of meeting the mandate. We examine the extent to which this is the case.

3. Policy Background

The RFS sets volumetric targets for different categories of biofuels, based on the type of feedstock used and their GHG intensity relative to fossil fuels.[7] The targets for different categories are nested within the overall target, such that the target for cellulosic biofuels is set as a lower bound while the target for conventional biofuels (principally corn ethanol) is set as an upper bound. This allows for the possibility that cellulosic biofuels could displace conventional biofuels it would occur if their costs of production decreased sufficiently to allow them to be competitive with conventional biofuels. Although the RFS sets quantity targets, it is implemented as a blend mandate. The EPA projects the volume of gasoline that will be consumed the following year and announces the blend rate that will meet the mandated quantity level.

Of the total requirement for 136 billion liters of ethanol equivalent renewable fuel in 2022, 80 billion liters should be advanced biofuels (obtained from feedstocks other than corn starch and with a lifecycle GHG emission displacement of 50% compared to gasoline). Of these 80 billion liters, at least 60 billion should be cellulosic biofuels in the form of cellulosic ethanol or biomass-based diesel derived from ‘renewable biomass’ and achieving a lifecycle GHG emission displacement of 60% compared to gasoline. Biodiesel from soyoil and ethanol from sugarcane

[7] The RFS establishes three categories of renewable fuels each with a separate volumetric mandate and a specific lifecycle GHG emission threshold. The categories are renewable fuel, advanced biofuel, and cellulosic biofuel. Advanced biofuels are those obtained from feedstocks other than corn starch with a lifecycle GHG emission displacement of 50% compared to conventional gasoline in 2005. Cellulosic biofuels are those derived from ‘renewable biomass’ and achieving a lifecycle GHG emission displacement of 60% compared to conventional gasoline in 2005.

are considered to be advanced biofuels, while lignocellulosic ethanol and biomass to liquids (BTL) that reduce emissions by 60% relative to gasoline are considered to be cellulosic biofuels. Since the different types of biofuels considered as meeting the RFS, differ in their energy content, equivalence values were established based on the energy content of the renewable fuel relative to denatured ethanol for gasoline substitutes and relative to biodiesel for biomass-based diesel. Thus, the equivalence value for ethanol is 1.0, for biodiesel is 1.5 and for cellulosic biomass-based diesel is 1.7. To the extent that renewable fuels with volumetric energy content higher than that of ethanol are produced, the actual volumes of renewable fuel needed to meet the RFS could be lower than the volumetric levels specified.

The volumes of second generation biofuels as mandated by EISA are considered unlikely to be achieved by 2022, but to be exceeded by 2035, according to the AEO (2010a). We, therefore, use the AEO projections for the annual volumes of first generation biofuels (corn ethanol, sugarcane ethanol imports, biodiesel produced from vegetable oils) and second generation biofuels (cellulosic ethanol and BTL diesel) to set the achievable biofuel quantities for the period 2007-2035. This implies an upper limit of 57 billion liters of annual production for corn ethanol in 2015 and beyond. We assume that commercial production of cellulosic biofuels will be feasible in 2015, and that total renewable fuel (first and second generation biofuels) production in ethanol equivalent liters will be at least 94 billion liters in 2022 and 179 billion liters in 2035. We follow EISA specifications that renewable fuel must be made from renewable biomass produced on agricultural land or forestland cleared or cultivated prior to December 19, 2009 and actively managed or fallow on that date. Agricultural land is defined to include cropland, pastureland and Conservation Reserve Program (CRP), with land in CRP maintained at the level authorized in the 2008 Farm Bill.

Renewable portfolio standards (RPSs) are implemented in specific forms in most states in the US. Currently 29 states have passed RPS legislation and 7 states have renewable portfolio goals, which are non-binding (DSIRE 2011). RPSs are generally imposed to require that the quantity of retail sales of electricity consists of a minimum proportion of generation be derived from renewable energy sources. In this paper all state level electricity policies are generally referred to as RPSs, however each state's policy differs in its characteristics, levels, and implementation schedule. A state specific policy characteristic that is of importance for this analysis is the whether or not all renewable capacity existing prior to the imposition of a RPS can be used towards achieving the policy goal. In most states that have implemented the RPS, eligible renewable energy sources include: hydroelectric, solar, wind, and biomass. The final target levels state RPSs range from 5% in Minnesota to 33% in California. Initial start dates for the first effective portion of states' RPSs range from 2004 to 2011.[8] State's annual RPS policy stringency also increases at different rates up to the final target level (Table 2). There are 31 states which do not have an RPS. There is a concentration of states lacking a RPS in the south-east, such as Florida and Georgia, as well as in the mountain west and Great Plains such as Utah, Idaho, Nebraska, and the Dakotas.

4. Numerical Model

We simulate the impacts of these policies by applying a multi-market, multi-period, price-endogenous, nonlinear mathematical programming model, BEPAM that integrates the agricultural, transportation fuel, and electric power sectors in the US and incorporates international trade in agricultural commodities, fuel and biofuels with the ROW. Market

[8] Excluding Iowa that has a capacity mandate dating into the 1990s.

equilibrium is achieved by maximizing the sum of consumers' and producers' surpluses in the agricultural, transportation fuels, and electricity sectors subject to various material balance, technological, capacity, and land availability constraints in a dynamic framework for the 2007-2030 time period.[9] The demand for transportation fuels is driven by the demand for VMT that are produced by blending liquid fossil fuels and biofuels. The electricity sector includes generation from coal, oil and natural gas and renewable energy from wind and biomass.to satisfy end-use demand. The transportation fuel sector includes markets for gasoline, diesel and several first- and second- generation biofuels. Biofuel production competes with food and feed production in the agricultural sector and renewable energy demand in the electricity sector. BEPAM includes markets for primary and processed crop commodities, livestock products, and cellulosic biomass from crop residues, perennial energy crops, and forest residues and waste for biofuel production. This multi-market sector model is a constrained optimization problem with an objective function that is the sum of many linear and non-linear functions. The non-linear functions in the objective function are the consumer surplus functions on the demand side and the total cost functions on the supply side. These nonlinear functions are approximated by piecewise defined linear functions so that a linear programming solver can be utilized, which performs better with models of this size. [10]

The perennial nature of energy crops (switchgrass and miscanthus) requires a special treatment of these crops because, instead of annual net returns, farmers would consider a continued income stream over years, which depends on annual variable costs and yields and fixed startup costs of establishing these crops. Furthermore, because we consider a finite horizon

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[9] We choose this time period because it allows us to analyze the effects of the RFS from its year of establishment following the EISA in 2007. According to the Annual Energy Outlook (2010a), the RFS is unlikely to be met by 2022 as mandated by EISA but is likely to be met by 2030.

[10] The model is coded using the General Algebraic Modeling System integrated development environment (GAMSide) software and the linear program itself is solved using the Cplex solver.

in the model, the economic value of a standing biomass crop beyond the terminal year of the planning horizon (i.e., the present value of net returns after the terminal year until the productive life of the energy crop) needs to be taken into account when making production decisions. To address this issue, we use a ten-year rolling horizon where for each year of the 2007–2030 period, the model determines crop production decisions and the corresponding dynamic market equilibrium for the next ten years starting with the year under consideration. After each run, we take the production decisions and the associated market equilibrium for the first year of the ten-year period, and use this information to update some of the key model parameters, such as the overall crop price index and expected prices, land availability in each region, and crop yields for major crops. We then run the model again for another ten-year period starting with the subsequent year and thus have a rolling horizon.

The model specifies demand for transportation using gasoline and diesel blends and the demand for various agricultural commodities at a national level. Demand for electricity is however specified at a regional level due to constraints on transmission and distribution. The model determines several endogenous variables simultaneously, including VMT, fuel and biofuel consumption, imports of gasoline and sugarcane ethanol, mix of biofuels and regional land allocation among different food and fuel crops and livestock over the given time horizon. The solution to this model also endogenously determines electricity generation, the input shares for electricity generation, fossil fuel use in the electricity sector (coal, natural gas, and oil), renewable generation capacity expansion in the electricity sector (wind and biomass), and coal power plants' decisions to co-fire biomass, in addition to regional crop production and bio-fuel production. We now briefly describe the key features and assumptions about transportation, agricultural and electric power sectors.

4.1. Transportation Fuel Sector

BEPAM includes linear demand curves for VMT with four types of vehicles, including conventional gasoline, flex fuel, gasoline-hybrid, and diesel vehicles.[11] The VMT production function considers the energy content of alternative fuels, fuel economy of each type of vehicle and the forthcoming Corporate Average Fuel Economy standards, and technological limits on blending gasoline and ethanol for each of these four types of vehicles, as specified by Energy Information Administration (2010). We exogenously shift demand curves for VMT with each type of vehicles over time as projected by the Annual Energy Outlook (USDOE/EIA 2010a) to capture the growth in demand due to changes in vehicle fleet, income and population.

We include linear supply curves for domestic gasoline and diesel as well as for gasoline supply and demand in the ROW. Exports of gasoline from the ROW to the US are determined by the difference between gasoline demand and supply in the ROW; diesel is assumed to be produced domestically. These supply curves are calibrated for 2007 using data on fuel consumption and production in the US and for the ROW (EIA 2010). The short-run supply elasticity of domestic gasoline in the US is based on (Greene and Ahmad 2005) and is consistent with estimates reported by (Gately 2004; Greene and Ahmad 2000; Huntington 1991). The elasticity of demand for gasoline in the ROW is based on a review of the literature by Hamilton (2009) while the short- run price elasticity of supply of gasoline is based on the review of literature in Leiby (2007). Key assumptions about demand elasticity for VMT and supply elasticities of fuels are reported in are described in Chen et al. (2011).

The biofuel sector includes several first- and second- generation biofuels. First-generation biofuels include domestically produced corn ethanol and imported sugarcane ethanol,

[11] We also include the demand for miles traveled with plug-in and battery electric vehicles (EV), but in the current version of the model its consumption is determined exogenously.

soybean biodiesel, DDGS-derived corn oil and waste grease. Second- generation biofuels included here are cellulosic ethanol and BTL diesel produced using the Fischer-Tropsch process. BTL diesel is a drop-in fuel that can be blended with petroleum diesel without blending constraints and has similar energy content. These biofuels are derived from cellulosic feedstocks, corn stover, wheat straw, forest residues and energy crops (miscanthus and switchgrass).

The feedstock costs of biofuels consist of three components: a cost of producing the feedstock which includes costs of inputs and field operations, a cost of land, and the cost of transportation. Production costs are calculated at county level for each crop and aggregated to a crop reporting district (CRD) level using data and methods described in Chen et al. (2013) while the costs of land are endogenously determined by the shadow price of the land constraint in the model. Transportation costs are based on county to county transportation by highway or rail (Kang et al. 2010) and converted to regional averages.[12] Technological parameters for converting feedstock to different types of biofuel and the industrial costs of processing feedstocks and producing biofuels are described in Chen et al. (2013). These costs are assumed to decline due to learning-by-doing as cumulative production increases using an experience curve approach (X. Chen and Khanna 2013; X. Chen, Khanna, and Yeh 2012). The conversion efficiencies (yield of biofuel per ton of feedstock)[13] are exogenously fixed and based on the estimates in GREET 1.8c for corn ethanol and Humbird et al. (2011) for cellulosic ethanol.

4.2. Agricultural Sector

The agricultural sector includes fifteen conventional crops, eight livestock products, two bioenergy crops, crop residues from the production of corn and wheat, forest residues, various

[12] The conversion to regional averages is found for a given region by finding the average transportation cost of transporting biomass from all counties within that region to all counties within another region.

[13] We use US units throughout the paper; a ton refers to a US short ton.

processed commodities, and co-products from the production of corn ethanol and soybean oil. In the crop and livestock markets, primary crop and livestock commodities are consumed either domestically or traded with the ROW (exported or imported). Primary crop commodities can also be processed or directly fed to various animal categories. Domestic and export demands and import supplies are incorporated by assuming linear price-responsive demand/supply functions. Elasticities used to calibrate domestic and export demand and import supply curves are reported in (X. Chen et al. 2011).The commodity demand functions and export demand functions for tradable row crops and processed commodities are shifted upward over time at exogenously specified rates.

The model considers the 306 CRDs in the 48 contiguous US states as spatial decision units and incorporates the heterogeneity in crop, livestock, and forest residue production across 295 of these CRDs, while the other CRDs only include forest residue production. Production costs and yields of individual crop/livestock activities and resource endowments are specified differently for each CRD based on crop/livestock budgets reported by various agricultural experiment stations and the National Agricultural Statistics Service (NASS) database. Crops can be produced using alternative tillage, rotation, and irrigation practices. Crop yields increase over time at exogenously given rates based on econometrically estimated trends and price responsiveness of crop yields in the US (X. Chen et al. 2011). Following Hertel et al. (2010), we assume that marginal lands have a crop productivity that is two thirds of the average cropland productivity.

Yields and costs of production of crop residues and dedicated energy crops also differ across regions. Corn stover and wheat straw yields for each CRD are obtained based on grain-to-residue ratio of dry matter of crop grain to dry matter of crop residues and the moisture content in the grain reported in Sheehan et al. (2003), Wilcke and Wyatt (2002), and Graham, Nelson and Sheehan (2007). Similar to Malcolm (2008), we assume that 50% of the residue can be removed from fields if no-till or conservation tillage is practiced and 30% can be removed if till or conventional tillage is used. The costs of producing corn stover and wheat straw include the additional cost of fertilizer that needs to be applied to replace the loss of nutrients and soil organic matter due to the removal of the crop residues from the soil, and the costs of harvesting and storage. In the absence of observed yield data for energy crops, we use the simulated biomass yields obtained from MISCANMOD and calculate the costs of producing them over their lifetime (Jain et al. 2010). Yields and costs of production of the bioenergy crops are assumed to be the same on marginal lands and regular croplands, but they vary regionally. The model includes several types of land, namely regular cropland, idle land, cropland pasture, pasture land, and forestland pasture, for each CRD. Cropland availability in each CRD is assumed to change in response to crop prices, using estimated price elasticities of crop-specific and total acreage. Idle land and cropland pasture are assumed to be available to be converted to conventional crop or energy crop production. Other land, including pasture land and forestland pasture are fixed at 2007 levels while land enrolled in the Conservation Reserve Program is fixed at levels authorized by the Farm Bill of 2008.

4.3. Electricity Sector

The electricity sector within the model consists of electricity market regions where consumers demand electricity and producers at varying levels of spatial aggregation generate electricity to meet that demand from renewable and non-renewable energy sources. There is an existing infrastructure of electricity generation capacity that can be utilized for production; the decision can also be made to expand generation capacity that uses natural gas, wind, or biomass as an input. The expansion of biomass capacity can be accomplished by co-firing biomass at an existing coal power plant, generating it at a new dedicated bio-power plant, or generating net co-product electricity from cellulosic ethanol refining. The electricity generated in some electricity market region (EMR) can be transmitted to a geographically adjacent market region to meet demand in that region subject to a transmission capacity constraint.

End-use consumer demand for electricity is represented with linear demand curves for each of the twenty EMRs (Table 1). These demand curves are aggregations of state-level demand curves contained within these regions, which are calibrated based on state annual electricity generation and state residential electricity price in 2007. All regions are assumed to have a -0.25 price elasticity of demand (EIA 2011a).[14] Regional demand increases at annual rate of 0.7% (AEO, 2010). Consumers are indifferent towards the source used to generate the electricity, and hence view electricity generated from different sources as perfect substitutes. Consumers are also indifferent towards electricity generated in adjacent regions, which may be transmitted to their region for consumption.

Electricity generated from existing power plant capacity broadly consists of two different types: power plants that are modeled as using a fuel source as an input and those where a fuel source is not explicitly modeled. The former group consists of existing natural gas, coal, and fuel oil capacity. For these sources of electricity generation, production costs are determined based on fuel cost, as determined by a production function and a state level fuel price, and operation and maintenance (O&M) costs per unit of electricity. The production functions for these power plants are defined by a parameter describing the regional average heat rate (summarized in Tables 3a & 3b) and a variable for the quantity of fuel use. Power plants modeled without an input fuel

[14] Using the elasticity of demand for the commercial sector in the NEMS model.

source including wind, geothermal, solar, waste, and nuclear costs' are determined based on per-unit O&M costs. Regional generation from all existing power plant capacity is constrained to be no greater than the total existing capacity and the regional average capacity factor (summarized in Table 3a).

Electricity can also be generated from new power plant capacity built during the considered time period. This power plant capacity expansion is determined endogenously for natural gas, co-firing, co-product, dedicated biomass power, and wind, while being given exogenously for nuclear, geothermal, and solar.[15] Electricity generated from natural gas is produced at a new power plant at a state level, where the power plant chooses the quantity of annual electricity generation by choosing the quantity of natural gas to use as an input. The marginal cost of generation from new wind turbine capacity is based on supply curves for wind energy resources. Regional supply curves for wind based electricity generation are modeled as linear increase marginal cost curves. These curves are constructed from a baseline generation cost and a long-term multiplier cost step that is in increasing in regional capacity (see Table 3b). The baseline generation cost is $148 per Mwh. The regional marginal cost of wind based generation is thus determined endogenously based on these functions and input demand.

Natural gas supply is modeled with a national natural gas supply curve that is calibrated based on the reference scenario for the electricity sector in AEO (2010) and a price elasticity of 0.8. The increased availability of shale gas is simulated by shifting the supply curve to the right in 2012 which results in a substantial decrease in NG prices (USDOE/EIA 2012).[16] State level delivered natural gas prices the endogenously determined national natural gas prices plus or

[15] Power plant capacity for the endogenously determined sources is modeled directly as generation whereby a capacity factor and/or heat rate is necessary to determine capacity.

[16] The reference scenario price and quantity of natural gas for the electric power sector is used to calibrate the supply curve.

minus a state level adjustment amount, which represents a state's natural gas price deviation from the national average.

The option to expand coal power plant capacity is not considered in this model. This assumption is made due to the EPA's New Sources Performance Standard (NSPS) rule issued in 2012, preventing new power plant capacity with emissions that exceed 1000 lbs./megawatt-hour, effectively prevent future coal capacity expansion (Kotchen and Mansur 2012). This has important implications for the model results, because it causes new fossil fuel based generation to use natural gas as a fuel source. However coal capacity can be used to co-fire biomass and coal. Biomass can be co-fired with coal at up to a 10% biomass to coal ratio, achieving the same efficiency as coal and requiring an additional plant conversion cost of $17.26/Mwh (Table 3b).

Electricity can be transmitted across electricity market regions. The model allows for electricity to only be transmitted to physically adjacent market regions. This inter-regional transmission is subject to transmission capacity constraints that limit inter-regional transmission to historically observed levels. The levels of these inter-regional transmission constraints are based off of observed inter-regional transmission in 2010 (EIA 2011b). Inter-regional transmission constraints are used to represent real world constraints of transmitted power great on limited transmission capacity as well as transmission loss. From a modeling standpoint they also have the important property of a function of the regional variation in the price of electricity. Without a constraint on electricity transmission, generation from anywhere in the country could be consumed country, this would result in equalization of prices across all regions as the generation will go to wherever the marginal benefit, thus with the constraints in place only a portion of electricity generated in a region can be transmitted with the remaining quantity be utilized within the region, giving heterogeneous electricity prices.

Biomass can be transported from where it is produced to a coal power plant in order to be co-fired. The model allows for biomass produced in any CRD to be transported to another CRD by incurring the specific transportation cost of the quantity of biomass transported. The cost of transportation of biomass from its harvest location to a potential co-firing plant is based on Kang et al. (2010). The transportation costs are estimated using data from the US Bureau of Transportation Statistics, where the centroid of each county is treated as the point of departure and arrival for biomass, and these centroids are connected to their nearest railroad or highway transportation node, considering fixed and variable cost of transportation. The final transportation costs used in this analysis are the minimum of railroad or highway transportation from each county to every other county.

Thus biomass production interacts with the electricity, agricultural, and transportation sectors in several ways. It is demanded as an input for electricity production for co-firing at an existing coal power plant, at a new dedicated biomass plant, or at cellulosic ethanol refinery that provides co-product electricity and for transportation after being converted to a liquid fuel. Its production from dedicated bioenergy crops competes for land with other food crops and with the production of crop residues that are a joint product of corn and wheat.

The model allows for learning- by-doing based on cumulative production with a technology to reduce the costs of production in the case of wind based electricity and dedicated bio-power plants. The quantity of wind based generation or dedicated biomass generation is used to update the cost of generation from these sources based on a technology specific learning rate. The annual learning rate for wind generation is 8% and 1% for dedicated bio-power (McDonald and Schrattenholzer 2001).[17]

[17] The authors assume a conservative 1% rate for learning-by-doing for dedicated biomass power plants.

We use lifecycle analysis to estimate GHG intensity of each type of biofuel, which includes emissions generated during the process of crop production, transportation and conversion to liquid fuel as well as the soil carbon sequestered during the process of crop production as described in Chen et al. (2013). GHG emissions in the electricity sector are considered at the smokestack. These average GHG emission rates for coal are found to be 2,128 lbs./Mwh, 963 lbs./Mwh for natural gas, and 1809 lbs./Mwh for fuel oil.[18]

4.3.1. Policy Constraints

The RPSs are modeled as a constraint on the percentage of total electricity generated from renewable sources in each region.[19] The state level RPSs are transformed to the EMR level using weighted averages in order to be consistent with the spatial modeling approach. The parameters are based on RPS data from the Database of State Incentives for Renewables and Efficiency (DSIRE 2011). In general these parameters represent the RPS for a EMR and are proportions that increase over time until the target percentage is achieved in a target year. As some state's RPS only applies to renewable capacity built after a specific date, we calculate the amount of generation from renewables built before that specified and exclude it from meeting the RPS. We assume the regional RPSs are binding and do not allow for non-compliance and consequent monetary penalties.

We implement the RFS in the model by imposing the annual volumetric targets for biofuels projected by the Annual Energy Outlook (AEO) (USDOE/EIA 2010a) as a mandate. Following the AEO projections, we assume that cellulosic biofuel production commences in 2015. We impose a target of 39.4 B ethanol equivalent gallons of biofuel in 2030 with an upper

[18] Average emission rates is calculated from EGrid database (EPA, 2010) using total generation by fuel source and total emissions by fuel source.

[19] Texas and Iowa have renewable capacity constraints, which are modeled as fixed amount not proportions.

limit of 15 B gallons on corn ethanol. We then iteratively solve the model to find the annual blend rates that need to be mandated to achieve the targeted level of total biofuel production projected annually by the AEO. These blend rates are found to range from 6% in 2007 to 24.5% in 2030

5. Results

The simulation model is validated for the first year of the model 2007 since that year's data is used to calibrate the model under the policy landscape of the corn ethanol mandate, the corn ethanol tax credit and tariff, and state-level RPSs. We compare the simulated prices and quantities for the electricity sector with the observed data used for the model. Table 4 shows the regional validation for electricity generation and price and the national validation for fossil fuel consumption. The simulated generation quantity is within plus or minus ten percent of the observed quantity for all regions. The simulated prices vary correspondingly with generation quantity by four times the amount, thus prices vary between one percent and thirty six percent. The simulated quantity natural gas consumption differs from the observed by 5.8% and the simulated price differs from the observed by 6.9%.[20]

The model is solved for five different scenarios that include a baseline scenario and four policy scenarios. The business as usual (BAU) scenario considers a laissez faire situation where there is no government policy. Scenario (2) is the RPS scenario in which state RPSs are imposed annually over the 2007-2035 period. Scenario (3) is the RFS scenario in which a blend mandate is imposed annually to achieve the volumetric targets considered feasible by the AEO (2010), In Scenario (4) we simultaneously impose the RFS & state RPSs. In Scenario (5) a carbon tax of $33 per metric ton of CO_2 is imposed, with the tax rate determined to achieve the same level of

[20] Observed quantity and price are in the context of the power plant data used in the model; see Table 4.

cumulative GHG emissions over the 2007-2035 period as in the case of the combined RFS & RPS scenario (4).[21] Enforcement of the RPS is at the EMR level and thus varies by state EMR?.

5.1. Effect of Alternative Policy Scenarios on the Electricity Sector

5.1.1. Mix of Energy Sources for Electricity Generation

The resulting energy product mix for different sectors of the economy across the five scenarios considered is shown in Table 5. In the electricity sector generation quantities are shown for renewable and non-renewable energy sources, excluding sources which do not vary across scenarios.[22] Fossil fuel based electricity generation makes up the majority of all generation across all five scenarios. In the BAU scenario coal provides 40% of the electricity generated with natural gas providing 31% with the rest of generation being provided by nuclear, renewables or other sources.

The imposition of the state RPSs, reduces coal based generation by 1% and natural gas based generation by 8.3% in 2030. On the renewables side co-firing increases by 18 million Mwhs, dedicated biomass increases by 21 million Mwhs, and wind increases by 190 million Mwhs. Overall total generation increases by 2%. The reduction of coal based generation is almost equal to the increases in co-firing based generation as coal power plants choose replace some coal fuel with biomass, while leaving the plants operating at nearly the same level of capacity. The dedicated bio-electricity and the new wind based generation displace natural gas based generation and not coal-based generation.

The RFS has indirect effects on the mix of fossil fuels used for electricity generation because it produces co-product electricity and increases the price of biomass feedstock. In 2030,

[21] Only smokestack GHG emissions are considered in the electricity sector.
[22] Nuclear, hydroelectric, solar, geothermal, and other sources do not vary across scenarios and are excluded from Table 5.

the amount of co-product electricity produced is 40 million MWhs which makes approximately 0.9% of total generation. It displaces the most costly source of fossil-fuel based electricity which is natural gas based generation which decreases by 0.9%. Dedicated bio-power plants are not built in this scenario due to the increase in feedstock costs. Low cost forest residues used for electricity generation in the BAU scenario are now diverted to biofuel production. Total electricity generation increases by 0.2% and this is due to the amount of co-product generation being greater than the reduction in natural gas and dedicated biomass based electricity.

With the joint implementation of the RFS and RPSs there is decrease in natural gas based generation by 9.7%, which is larger than under the RPS only scenario. Coal generation decreases by 0.4% relative to the baseline and by a smaller amount than under the RPS only scenario. In this joint scenario the RFS again has the indirect effect of providing co-product generation, however it differs slightly in quantity from the RFS only scenario due to regional heterogeneity in electricity markets and policy, incentivizing a slightly greater amount of co-product generation. Co-firing and dedicated biomass generation is less than is found in the RPSs only scenario, due to the availability co-product generation and the increase in feedstock prices. Wind based generation increases by 203 million Mwhs, which is greater than the increase in RPSs-only scenario. This increase in wind generation relative to the RPS is due to the combination of the effects of the RFS and the regional heterogeneity of RPSs and electricity markets. It occurs because some portion the co-product based electricity is generated in regions which do not have a RPS or their RPS is at a relatively low level; hence this renewable generation cannot all be used to meet the RPS and thus the reduction in biomass based generation (co-firing and dedicated biomass) due to the increase in feedstock price, is offset with an increase in wind generation. This results in a slightly greater overall share of renewable generation (13.66%) than under the RPS alone.

With a \$33/MT CO_2 tax the relative costs of fossil fuel based electricity increase relative to those of renewable electricity, with that of coal increasing much more than of natural gas based generation. This results in a decrease in coal-based electricity generation more than in natural gas based generation and an increase in all renewable energy sources. However , this tax rate is not high enough to induce any cellulosic biofuel production and hence there is no co-product electricity generation. Coal based generation decreases by 3.6% and natural gas generation decreases by 7.1%. The increased cost of electricity also cause consumption to decrease resulting in total generation that is lower than the BAU and all other scenarios.

5.1.2. Impact on Electricity Prices

In the electricity sector under the BAU scenario the regional-generation-weighted average price of electricity (hereafter referred to as the electricity price) is \$123.18/Mwh and the delivered price of natural gas in the electricity sector is \$9.42/MBtu (Table 6). The imposition of the RFS causes a decrease in the price of electricity and of natural gas by 0.6% and 1.1% respectively. The small decrease in the price of electricity in the RFS scenario is a direct result of the increased generation from the co-product generation, which does not result in corresponding decrease in other generation sources, which have a lower marginal cost than consumers' willingness to pay, resulting in an increase in total generation and lower electricity prices. Under the RPS, there is a 6% decrease in the price of electricity while the price of natural gas decreases by 9%. The price of electricity decreases by a much greater amount under the RPS scenario and results in a corresponding increase in total generation. The electricity price decreases due to the displacement of natural gas based generation by the increase in co-fired , dedicated biomass, and wind generation, which decrease the price of natural gas based generation. Under the joint RFS and RPS scenario, the price of electricity decreases by 7% and the price of natural gas drops by 11%. The carbon tax scenario leads to a 6% increase in the price of electricity and a corresponding decrease in electricity generation which in turn leads to a decrease in natural gas price by 8%.

5.2. Effect of Alternative Policies on the Transportation Fuel and Agricultural Sector

The RFS and the carbon tax have a major impact on the transportation sector; the former by inducing a significant displacement of gasoline consumption by biofuels and the latter by reducing vehicle miles travelled by gasoline and diesel vehicles. Implementation of the RFS causes ethanol consumption to increase by 125 B liters in 2035 relative to the BAU. Gasoline consumption decreases by 15% and this leads to a 6% decrease in its consumer price while diesel consumption decreases by 2% and its consumer price increases by 3%. The implementation of the state RPSs by themselves in addition to the RFS have a negligible impact on the fuel sector. While they induce some demand for biomass, it is not a large amount and the joint implementation of the RFS and RPS leads to a x% increase in the price of biomass. The benefit of the co-product electricity towards achieving RPSs leads to a slight increase in cellulosic ethanol production and hence a slight increase in gasoline consumption due to the blend rate constraint. The carbon tax causes gasoline consumption to decrease by 1.6% and the price of gasoline to increase by 8% while diesel consumption decreases by 2% and its price increases by 9%.

The agricultural sector is impacted by the increased demand for biomass seen across these scenarios (Table 5). The RPSs' increased use of co-firing and dedicated biomass increase agricultural biomass production by 21.4 MT and forest biomass production 6.8 MT, which corresponds with an increase in regional biomass price of $25/Mg. The RFS requires a large increase in biomass production, resulting in an increase in agriculture biomass of 236 MT and forest biomass of 16.3 MT, the price increases by $20/Mg. The joint implementation of RFS and RPSs resulting in an increase in biomass production that is less than the sum of production of the two policies independently, resulting primarily in the reduction in biomass electricity (co-firing, dedicated biomass) due to the co-product generation provided by the RFS. The RFS and RPS exhibits the highest regional biomass price at $81/Mg. The carbon tax scenario results in a large decrease in coal generation, which is partially offset by an increase in co-firing, therefore resulting in an increase in agriculture biomass by 19.1 MT and an increase in forest biomass of 13.3 relative to the BAU scenario. The carbon tax causes biomass prices to increase by $19.9/Mg.

5.3. Welfare Effects and GHG emissions of Alternative Policies

The differences in production and prices across scenarios as discussed in the preceding also results in differences in welfare (Table 7). The RPSs lead to a decrease in economic surplus of $84.6 billion; after incorporating the value of GHG reductions estimated at $33/MT the decrease in social welfare is $58.6 billion. The RPSs have little effect on producers and consumers in the liquid fuels and agricultural sector; agricultural producers see a relatively small increase in surplus of $0.2 billion and biomass producers see an increase in surplus of $3.39 billion, while agriculture consumers have a decrease in surplus of $0.1 billion. Biomass producers see an increase in surplus as the production of biomass increases relative to the baseline, which is used to generate electricity from co-firing and dedicated biomass power plants, thus increasing the price and quantity of biomass and hence producer surplus. Total electricity generation increases in this scenario, implying a lower consumer price for electricity and an increase in consumer surplus. This increases in electricity consumer surplus comes at the expense of a decrease in producer surplus, as the quantity of fossil fuel generation and natural gas consumption decreases and the quantity of more costly (less profitable) renewables increases. Overall the change in welfare in the electricity sector must decrease. In the electricity sector consumer surplus increases by $211 billion, while producer surplus decreases by $300 billion. These changes result in a decrease of economic surplus by $85 billion due to the state level RPSs. Including the value of the abated GHG emissions social welfare decrease $59 billion.[23]

The RFS results in an increase in economic surplus in the US by $54.2 billion, which corresponds to an increase of $96 billion in social welfare. This total increase in welfare is a function of the distributional changes in welfare for the producers and consumers in the agricultural, transportation, and electricity sectors as well as government revenues. In the liquid fuels markets both consumers and producer see decreases in surplus, with the loss heavily weighted towards producers. This decrease in surplus in the fuels market is more than offset by the increase in producer surplus for agricultural producers and, separately biomass producers. Government revenues increase. There is an overall decrease in welfare in the electricity sector, where producers lose surplus, but consumers gain surplus.

In the joint RFS and RPS scenario there is a combination of the welfare effects seen in the scenarios where the policies are implemented independently. Economic surplus decreases by $29.4 billion, where if the externality reduction is considered social welfare increases by $36.3 billion. This scenario exhibits large distributional changes in welfare for consumers and producers in all sectors. As gasoline miles travelled increase so does the consumer surplus, by

[23] GHG emissions valued at $33/MT as in the carbon tax scenario.

$43.6 billion, an almost equal amount to that in the RFS scenario. Diesel miles travelled decrease, implying a decrease consumer surplus, which amounts to $65.23 billion, slightly greater than the RFS scenario. Gasoline and diesel producers' both have decreases in producer surplus as the quantity demanded decrease, being substituted with ethanol and a decrease in miles travelled. Gasoline producer surplus decreases by $144.5 billion and diesel producer surplus decreases by $55.9 billion. In the agricultural sector consumer surplus decreases by $165.7 billion, while agriculture producer surplus increases by $386.1 billion. This scenario exhibits the largest level of production of biomass as well as the highest prices, thus the greatest increase in biomass producer surplus ($27.2 billion) across the scenarios is seen. Cellulosic ethanol refineries also experience an increase in producer surplus ($6.6 billion) as the national price of ethanol increases, and the value of co-product generation has increased due to the RPSs. In the electricity sector it is apparent again that electricity consumer's welfare increases, by an even greater amount than under just RPSs and electricity generators producer surplus decreases, by an even greater amount than under just RPSs. Electricity sector consumer surplus increases by $227.7 billion and producer surplus decreases by $322.8 billion, resulting in a loss of $95.1 billion in total welfare in the electricity sector. Government revenue increases by $33.6 billion, which is the same amount as in the RFS-only scenario.

The carbon tax policy results in an increase in an economic surplus of $78.6 billion, which becomes an increase in social welfare of $150.4 billion if the reduction in externality cost is considered. The changes to the amount and distribution of welfare differs qualitatively from those in the RFS and RPSs scenarios. In this scenario there are decreases in the welfare in most energy markets, and a large increase in government revenues resulting from the tax. Gasoline and diesel miles consumers experience a large decrease in consumer surplus of $644.6 billion and \$200.9 billion respectively. Gasoline and diesel producers also see a decrease in producer surplus of \$39.1 billion and \$56.9 billion, respectively. Agriculture sector consumer surplus increases by \$2.1 billion, while agriculture producer surplus decreases by \$2.9 billion and biomass producer surplus increases by \$1.5 billion. In the electricity sector both consumers and producers experience the relatively large decreases in consumer surplus of \$496.7 billion and \$765.9 billion, respectively. Government revenues increase by the relatively large amount of \$2.282 trillion. Overall there is an increase in domestic economic surplus of \$78.6 billion.

In general in the carbon tax scenario, the cost of all energy products increases proportional to their carbon intensity. This results in a decrease in the cost of low carbon intensive fuels relative to high carbon intensive fuels and an increase in overall energy costs reducing the quantity demanded. This fact is illustrated in the welfare results for the carbon tax scenario. There are large decreases in welfare for consumer and producers of transportation fuels as the amount of vehicle miles travelled decreases. Electricity consumers and producers see a large decrease in welfare as energy cost rise. These decreases however, are more than offset by the increase in government revenues, implying an increase in total domestic welfare.

The overall changes in the quantities of these energy products relative to the BAU scenario (Table 5) imply changes in the cumulative GHG emissions in the agricultural, electricity, and transportation sectors over the 2007-2030 time period. In the BAU there are 109.56 billion MT of GHG emissions from these sectors. Emissions are reduced to 107.32 billion MT with the implementation of the RFS, while they are to 108.19 billion MT with implementation of the RPS. With the implementation of both the RFS and RPS emissions are reduced to 106.07 billion MT which is marginally less than the sum of the reduction achieved if these policies were implemented by themselves. There are two primary reasons these policies are not perfectly complementary in the reduction of GHG. The increased price of biomass from the RFS results in a share of co-firing than is found in the RPS alone, this capacity that would be used for co-firing is now utilized for coal, increasing emission. When the RPS is added to the RFS the value of co-product generation increases, this causes a marginal increase in the amount of co-product generation, which being a co-product of ethanol implies increased ethanol production, then the blending requirement requires that gasoline consumption increase to blend with the ethanol, finally causing an increase in GHG emissions in the transportation sector.

Comparing the cost-effectiveness of these policies at reducing GHG emissions, using the welfare cost (change in economic surplus) allows for comparison of the relative economic efficiency of the policies (Table 7). The carbon tax policy increases the economic surplus, thus has a negative welfare cost and reduces emissions by an equivalent amount to the RFS and RPS scenario it's cost-effectiveness ratio is -$22.6 billion per billion MT of GHG emissions reduced. The carbon tax is the most beneficial of the policies in absolute terms, but the RFS policy which exhibits a smaller reduction in emission has a better cost-effectiveness ratio of -$24.3 billion per billion MT of GHG emissions reduced. The joint RFS and RPS scenario has an equivalent reduction in GHG emissions to the carbon tax, but has a decrease in economic surplus, resulting in a cost-effectiveness ratio of $8.4 billion per billion MT of GHG emissions reduced. The RPS only scenario has the least reduction in GHG emissions and is the most costly, resulting in the lowest cost-effectiveness ratio of $61.6 billion per billion MT of GHG emissions reduced.

6. Conclusion

Renewable energy policies are being implemented in the agricultural, transportation, and electricity sectors. These policies include the RFS following the Energy Independence and Security Act of 2007 and the twenty nine individual state level RPSs and have the potential to directly and indirectly affect consumers and producers in all three sectors. These policies interact with each other through the potential biomass markets that develop to provide cellulosic ethanol and the electricity markets where ethanol refineries provide co-product generation from the production of ethanol.

We find that the RPSs cause an increase in renewable energy based generation from co-firing, dedicated biomass, and wind. Coal based generation only decreases in response to co-firing. These renewables sources reduce natural gas and lower price of natural gas contributing to lower electricity prices under RPS. We therefore see an increase electricity consumer surplus at the expense of a greater decrease in electricity producer surplus.

The joint implementation of RFS and RPSs results in some co-product generation being used toward RPSs' goals, which diminishes the use of co-firing and dedicated biomass. A higher price of biomass induces more wind generation. But overall electricity consumption increases. Coal generation increases relative to the RPSs only scenario as the amount of co-firing decreases. Natural gas generation is decreased at an even greater rate than in the RPSs only scenario. The substitution of lower carbon biomass based generation with co-product generation and wind generation and the increase in electricity consumption offset some of the GHG benefits of the RFS and RPS. The GHG reduction by the joint policy is therefore less than the sum of the reductions by the individual policies.

The welfare effects of the model show that the carbon tax scenario leads to greatest increase in welfare while reducing the emissions equivalent to the RFS and RPS scenario. The reduction comes primarily from reducing electricity consumption and vehicle miles travelled. The RPSs have a small cost and result in the least reduction in emissions. The RFS has a benefit due the terms of trade effect. The combined RFS and RPS shows that inclusion of RFS lowers the welfare costs of the RPS because the production of electricity as a co-product of biofuel production reduces the need for costly biomass electricity.

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Table 1: States Included in Electricity Market Regions

Electricity Market Region	States Included in Electricity Market Region
AZNM	Arizona, New Mexico
CAMX	California
ERTC	Texas
FRCC	Florida
MORE	Wisconsin
MROW	Montana, Nebraska, North Dakota, South Dakota
NEWE	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
NWPP	Idaho, Nevada, Oregon, Utah, Washington
NY	New York
RFCE	Delaware, Maryland, Pennsylvania
RFCM	Michigan
RFCW	Indiana, New Jersey, Ohio, West Virginia
RMPA	Colorado, Wyoming
SPNO	Kansas
SPSO	Oklahoma
SRMV	Arkansas, Louisiana, Mississippi
SRMW	Illinois, Missouri
SRSO	Alabama, Georgia
SRTV	Kentucky, Tennessee
SRVC	North Carolina, South Carolina, Virginia, District of Columbia

Table 2: Renewable Portfolio Standards in 2030

State	RPS target in 2030
Arizona	10.5%
California	33.0%
Colorado	27.0%
Connecticut	20.0%
Delaware	21.5%
District of Columbia	17.5%
Illinois	18.8%
Kansas	20.0%
Maine	10.0%
Maryland	18.0%
Massachusetts	24.1%
Michigan	10.0%
Minnesota	5.0%
Missouri	14.7%
Montana	15.0%
Nevada	23.5%
New Hampshire	16.0%
New Jersey	17.9%
New Mexico	9.4%
New York	7.6%
North Carolina	11.5%
Ohio	12.0%
Oregon	25.0%
Pennsylvania	7.5%
Rhode Island	14.0%
Washington	15.0%
Wisconsin	9.6%

Table 3a: Technical Parameters and Costs for existing capacity

Generation Technology	Total capacity (Mw)	Average Capacity Factor	Average Heat rate (Mwh/ Mbtu)	O&M or Levelized cost ($/Mwh)	Average Fuel Cost ($/Mwh)	Average Cost ($/Mwh)	References
Existing capacity							
Coal	374067	0.59	0.096	5.50	21.83	27.33	Capacity, capacity factor, and heat rate: EPA (USEPA 2010)[24], O&M costs: UCS (UCS 2013)[25], Fuel price: EIA (USDOE/EIA 2010b).[26]
Geothermal	3181	0.57		32.50		32.50	
Hydroelectric	97031	0.30		5.90		5.90	
Natural Gas	429740	0.16	0.101	5.20	70.85	76.05	
Nuclear	107270	0.88		19.40		19.40	
Fuel Oil	33554	0.04	0.079	3.80	115.38	119.18	
Other	2655	0.41		3.80		3.80	
Solar	448	0.16		6.40		6.40	
Waste	1023	0.55		11.20		11.20	
Wind	15823	0.26		17.60		17.60	

[24] In the model capacity is summed by technology type and CRD, a CRD weighted average heat rate is found by technology type, weighted by 2007 net generation.
[25] Fixed O&M cost that are given in $/Mw are converted to $/Mw hour based on an average capacity factor by technology.
[26] These are delivered fuel prices for the electric power sector by state.

Generation Technology	Total capacity (Mw)	Average Capacity Factor	Average Heat rate (Mwh/ Mbtu)	O&M or Levelized cost ($/Mwh)	Average Fuel Cost ($/Mwh)	Average Cost ($/Mwh)	Learning Rates (%)	References
New capacity								
Natural Gas			0.108	37.80	66.11	103.91		Levelized cost and fuel price: EIA (USDOE/EIA 2010a).[27]
Co-firing	0 - 37406[28]	0.59	0.096[29]	22.76[30]	48.13	70.89		Capacity, capacity factor, and heat rate: EPA (USEPA 2010), Levelized cost: (AEO, 2010).
Co-product			0.008	n/a	n/a			Heat rate: (Humbird et al. 2011)[31]
Dedicated Biomass			0.059	71.90	79.20	151.10	1%	Heat rate: Qin et al. (2006), levelized cost EIA (AEO, 2010)[32]
Wind				148.00		148.00	8%	Levelized cost EIA (AEO, 2010). [33] Data from EIA NEMS.[34]

Table 3b: Technical Parameters and Costs for new generation

[27] The levelized used here is net of estimated fuel costs, and therefore represents capital, O&M, and transmission costs.

[28] It is assumed that co-firing may use up to 10% of existing coal capacity, corresponding with an equivalent decrease in coal capacity.

[29] Co-fired biomass is assumed to burn at the same efficiency as the coal at that plant. Qin et al. (2006) finds that co-firing has about a 32% thermal efficiency for firing switchgrass with coal at the 10% level.

[30] Coal plant conversion cost are included here and converted from $120 kw (USDOE/EIA 2010a) to $17.26/Mwh.

[31] Convereted from gallons based on 83 gallons per MT.

[32] The levelized cost used here is net of estimated fuel costs, and therefore represents capital, O&M, and transmission costs.

[33] The levelized cost is used as an initial cost parameter to calibrate the wind supply functions.

[34] Regional wind availability data were provided to the authors by the EIA, which are from intermediate results of the National Energy Modeling System (NEMS). These data are in the form of wind capacity by region available at multiples of a base cost. These data are used to create linear functions using ordinary least squares.

Table 4: Validation 2007

Electricity Market Region	Observed Generation (Quantity)	Simulated Generation (Quantity)	Percentage difference	Observed Price	Simulated Price	Percentage difference
	Total Generation (Million Mwhs)			Retail Price (2007$/Mwh)		
AZNM	92.06	96.85	5.2	101.64	80.5	-20.8
CAMX	207.98	215.47	3.6	138.1	118.21	-14.4
ERTC	404.79	409.65	1.2	130.4	124.14	-4.8
FRCC	219.64	217.99	-0.8	116.5	119.99	3.0
MROE	63.48	61.19	-3.6	115.1	131.67	14.4
MROW	209.68	197.1	-6.0	88.13	109.28	24.0
NEWE	127.09	134.72	6.0	172.49	131.09	-24.0
NWPP	263.19	243.18	-7.6	82.48	107.56	30.4
NY	140.32	153.23	9.2	183	115.66	-36.8
RFCE	277.24	278.34	0.4	117.71	115.83	-1.6
RFCM	114.99	111.62	-2.9	107.5	120.12	11.7
RFCW	437.72	414.81	-5.2	93.48	113.06	20.9
RMPA	99.94	96.34	-3.6	91.36	104.51	14.4
SPNO	46.63	43.83	-6.0	88.8	110.11	24.0
SPSO	76.33	71.14	-6.8	90.9	115.62	27.2
SRMV	260.12	242.43	-6.8	98.08	124.76	27.2
SRMW	290.5	280.05	-3.6	98.82	113.05	14.4
SRSO	282.04	269.63	-4.4	101.68	119.57	17.6
SRTV	188.53	174.1	-7.7	83.79	109.43	30.6
SRVC	298.97	300.68	0.6	96.67	94.46	-2.3
Natural Gas	(Trillion Mbtu)			Electricity Sector Price (2007$/Mbtu)		
US[35]	7,788	8,239	5.8	8.37	8.95	6.9

[35] The supply curve is calibrated based AEO (2010) with a price of $7.14/Mbtu, a quantity of 6,843 T MBtu, which is then used to find observed quantity and price for the model by using weighted average heat rates for all 2007 capacity for the quantity and its corresponding price; see Table 3a.

Table 5: Energy Production in 2030

Energy Source	BAU	RPS	RFS	RFS & RPS	Carbon tax
Fossil Fuels	Quantity	% Change from BAU			
Electricity					
Coal (M Mwhs)	1843.9	-1.0%	0.0%	-0.4%	-3.6%
Natural Gas (M Mwhs)	1430.0	-8.3%	-0.9%	-9.7%	-7.1%
Fuel Oil (M Mwhs)	1.4	-48.9%	0.0%	-49.1%	-49.2%
Total Generation (M MWhs)	4606.1	2.0%	0.2%	2.2%	-1.8%
Transprotation					
US Gas Consumption Total(B l)	504.7	0.0%	-15.4%	-15.3%	-1.6%
US Petro Diesel Consumption (B l)	180.7	0.0%	-1.6%	-1.5%	-1.9%
Gas Miles Consumption Total(B KM)	6621.0	0.0%	1.2%	1.3%	-1.6%
Diesel Miles Consumption (B KM)	725.3	0.0%	-0.5%	-0.4%	-1.7%
Renewable Sources	Quantity	Absolute change from BAU			
Electricity					
Co-firing (M Mwhs)	0.05	17.6	0.0	7.8	66.0
Co-product (M Mwhs)	0.00	0.0	39.8	39.9	0.0
Dedicated biomass (M Mwhs)	16.26	21.0	-16.3	-1.4	-2.8
Wind (M Mwhs)	34.21	190.2	0.0	202.6	19.9
All renewable generation (M MWhs)	393.98	228.8	23.5	248.9	83.0
Share of renewables (%)	8.55	4.7	0.5	5.1	2.0
Biofuels					
Eth Consumption Total(B Liters)	18.30	0.00	125.6	125.8	-0.3
Corn eth(B Liters)	14.60	0.00	42.2	42.2	-0.4
cellulosic ethanol (B Liters)	0.00	0.00	12.8	10.8	0.00
Biomass					
Agriculture Biomass (M MT)	0	21.4	218.3	236.0	19.1
Forest Biomass (M MT)	28.0	6.8	16.3	16.3	13.3

Table 6: Market Prices in 2030 (endogenous)

Product	BAU	RPS	RFS	RFS & RPS	Carbon tax
	Price	% Change from BAU			
Fossil fuels					
US Gasoline Consumer Price($/Liter)	0.96	0.0%	-6.2%	-7.1%	8.4%
US Diesel consumer price($/Liter)	0.98	0.0%	2.5%	2.1%	8.9%
Natural Gas in the electricity sector ($/Mbtu)	9.42	-9.3%	-1.1%	-11.0%	-7.9%
Electricity Markets					
Weighted average electricity price ($/Mwh)	123.18	-6.3%	-0.6%	-7.0%	6.1%
Crops					
Corn ($/MT)	125.89	0.1%	39.5%	39.3%	0.0%
Soybeans ($/MT)	335.66	-0.2%	32.9%	33.3%	-0.9%
Wheat ($/MT)	229.92	0.1%	10.0%	9.6%	0.2%
Land Rent ($/Ha)	502.26	0.2%	33.4%	34.2%	-3.4%
	Price	Absolute change from BAU			
Biofuels					
Ethanol Consumer Price ($/Liter)	0.63	0.00	-0.08	-0.07	0.06
Corn ethanol producer price($/Liter)	0.69	0.00	0.07	0.07	0.03
Sugarcane ethanol producer Price($/Liter)	0.68	0.00	0.12	0.13	0.01
US Diesel consumer price($/Liter)	0.98	0.00	0.02	0.02	0.09
Cellulosic ethanol Producer Price($/Liter)	0.00	0.00	0.80	0.81	0.00
Biomass producer Price ($/Mg)	48.38	24.98	20.09	32.86	19.90

Table 7: Change in Cumulative Welfare and Emissions (2007-2030)

	RPS	**RFS**	**RFS & RPS**	**Carbon tax**
		Change from BAU		
Welfare				
Miles Consumers ($B)	0.0	-17.9	-21.6	-845.5
Gas and Diesel Producers ($B)	0.0	-199.9	-200.4	-96.0
Agricultural Consumers ($B)	-0.1	-165.6	-165.7	2.1
Cellulosic Ethanol Refineries ($B)	0.0	4.8	6.6	0.0
Biomass Producers ($B)	3.4	16.4	27.2	1.5
Agricultural Producers ($B)	0.2	386.1	386.1	-1492.7
Government Revenue ($B)	0.0	33.6	33.6	2282.0
Electricity consumer Surplus ($B)	211.3	19.8	227.7	-496.6
Total producer surplus in Elec sector ($B)	-299.4	-22.9	-322.8	-765.9
Externality Cost ($B)	26.0	41.7	65.6	71.8
Economic Surplus ($B)	-84.6	54.2	-29.4	78.6
	-0.17%	0.11%	-0.06%	0.16%
Social Welfare ($B)	-58.6	96.0	36.3	150.4
	-0.12%	0.20%	0.08%	0.31%
Emissions				
GHG Emissions (B MT)	-1.4	-2.2	-3.5	-3.5
	-1.25%	-2.04%	-3.18%	-3.18%
Cost-Effectiveness				
Cost-Effectiveness ($B/B MT of GHG emissions)	61.6	-24.3	8.4	-22.6