Renewable Energy Policies for the Electricity, Transportation, and Agricultural Sectors: Complements or Substitutes

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Renewable Energy Policies for the Electricity, Transportation, and Agricultural Sectors: Complements or Substitutes

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Abstract: Renewable Portfolio Standards (RPSs) have been enacted in 29 states in the US, in part to encourage an increase in the amount of electricity generated from renewable sources. Biomass can be utilized in a dedicated bio-power plant to generate electricity, co-fired with coal at an existing power plant, or used to produce cellulosic ethanol that also yields co-product electricity. Considering these options along with a detailed national model of agricultural biomass production allows for the simulation of the effect of existing policies on electricity based biomass demand. Using a multi-period, multi-market, price endogenous model of the U.S. agricultural, electricity, and transportation sectors, the effect of existing state-level RPS is evaluated along with the implications for the agriculture sector. It is found that RPSs increase generation from both biomass and wind-based electricity generation, while decreasing the amount of generation from natural gas, and coal. Due to the co-product electricity generation a greater amount of electricity is generated from biomass under the RFS & RPS scenario than the RPS scenario even though biomass prices are higher.

1. Introduction

Concern over externalities associated with the use fossil fuels to generate electricity in the U.S. has increased the desire to generate a greater amount of electricity from renewable energy sources. However, the private costs of utilizing renewable energy sources for the United States' energy requirements tend to be greater than that of conventional sources, and hence renewable energy makes up a relatively small portion of our total energy use. Policy makers at the federal and state level of government, for many reasons, have enacted laws that mandate the use of renewable energy sources, portending a reduction in GHG emissions. Policies that have the potential to contribute significantly to reduction of GHG emissions have been implemented in the electric power, transportation, and agricultural sectors, which combined together comprise the majority of GHG emissions in the US.

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In the transportation sector the Renewable Fuel Standards (RFS), a federal mandate, has been implemented. The Energy Independence and Security Act of 2007 enacted the RFS which mandates that by 2022, 36 billion gallons of renewable fuels must be blended with fossil fuels. Of these 36 billion gallons at least 16 billion gallons must be derived from cellulosic biomass, which includes energy crops such as switchgrass and miscanthus. In the electric power sector Renewable Portfolio Standards (RPSs), which mandate that a certain percentage of the state's electricity consumption be generated from renewable energy sources have been enacted in 29 states, while 7 states have non-binding renewable goals. In general a RPS is a mandate that requires a certain percentage of electricity generated in the state to come from renewable energy sources by a certain target date. In most states that have implemented the RPS, eligible renewable energy sources include: hydroelectric, solar, geothermal, wind, and biomass.

The RFS and RPSs have the potential to lead to a massive increase in the proportion of bioenergy in the US energy portfolio. In order for the RFS mandate to be met there must be a large increase in the amount of bioenergy production, be it through energy crops, crop residues, or forest biomass. The RPSs are more flexible in that they can be satisfied by a number of different renewable energy sources, including biomass. Biomass can be used to generated electricity by co-firing it with coal at a coal power plant or a dedicated biomass power plant. There is also the potential for cellulosic biofuel refineries that use biomass as a feedstock to generate a net positive co-product electricity to be sent to the grid (Humbird et al. 2011).

Renewable energy policies are in effect contemporaneously in the US agriculture, transportation, and electric power sectors. A large amount of biomass will be needed to satisfy the RFS, but the state-level RPSs can also be satisfied by electricity generated from bioenergy sources. This has the potential for these policies to be complements or substitutes for one of the policy goals of reducing GHG emissions. While the RFS applies across the entire country, the RPSs are state by state policies that exhibit spatial heterogeneity. This combined with the spatial heterogeneity of renewable energy resources and co-firing potential across the country suggests that these factors should be taken into consideration to determine the efficiency with which this policy portfolio is able achieve desired goals. This research examines the effects on the agricultural, electricity, and transportation sectors of having these two policies in place contemporaneously, explicitly considering the spatial heterogeneity in the state level policies and renewable energy resources. The outcomes in terms of commodity prices, biomass production, and renewable energy based generation are simulated under scenarios where the RFS and RPS are in effect alone and where they are combined. This gives evidence to assess the complementarity or substitutability of these policies.

2. Literature

The role of bioenergy in the electric power sector to fulfill renewable energy policy requirements has been examined by a few studies. McCarl et al. (2000) examine the economic feasibility of using of biomass fueled power plants to comply with possible greenhouse gas emission regulations. The Forest and Agricultural Sector Optimization Model (FASOM) is used in order to evaluate the competiveness of using biomass fuel for electricity generation compared to coal. In general the results show that biomass is not competitive with coal without subsidies or research innovations. The results show that without technological innovation milling residues will be the primary feedstock with the possibility of some willow and switchgrass, with technological innovation poplar is the primary feedstock used.

The potential for using crop residues for is also examined by Muang and McCarl (2008) using the FASOM. Their results show that the heat content and the production cost of crop residues impacts their feasibility for electricity production, but crop yield improvements have little impact on electricity production. Their results also highlight that co-firing of coal and biomass has greater potential compared to dedicated biomass power plants because of lower feedstock transportation costs and greater heat efficiency of the plants.

A study on the land allocation required to provide a supply of biomass from bioenergy crops for electricity generation in Illinois is done by Dhungana (2007). In this study, a dynamic linear programming framework is used to generate a supply curve of biomass for co-firing in order to examine the statewide land allocation and factors. The model produces from biomass from two different bioenergy crops: miscanthus and switchgrass. Under different co-firing scenarios (5%, 10%, and 25% of Illinois coal electricity generation) the land allocation and bioenergy price is determined. The general results show that the breakeven delivered cost of miscanthus is less than two-thirds of the breakeven price of switchgrass. The author also finds significant spatial variability in the farm-gate price of miscanthus across Illinois' counties. The final bioenergy prices for each of the scenarios ranges from 2 to 4 times the price of coal, indicating that significant policies would be necessary to reach the simulated levels of co-firing.

The effects on local biomass supply and demand when state level RPSs and the RFS mandate are in effect are examined by Dumortier (2012). In this research the location of 398 existing coal-fired power plants are considered, under scenarios where the co-firing of biomass can occur at 15% and 25% ratios. It is found that there is a high potential to collect crop residues in states that have a high level of wheat and corn production, but these states coincide with a low density of coal-fired power plants to co-fire at. There are supply shortages relative to coal-fired capacity in Eastern Ohio, Western Pennsylvania, Illinois, Indiana, and Kentucky.

Considering a renewable energy standard, White et al. (2013) examine the agricultural and forest sector response to different stringencies of this standard. Using FASOM to consider a variety of agricultural and forest crops for biomass production and allowing the renewable energy standard to be met by either co-firing biomass or at dedicated biomass plants they find that biomass is supplied from both the agricultural and forest sectors, but that switchgrass would be the primary feedstock used. It is found that the GHG reduction from a decrease in coal based electricity is about 44 million tonnes CO_2e per year between 2010 and 2020 and 111 million tonnes per year between 2020 and 2035.

A RPS imposes an implicit tax on electricity produced from nonrenewable sources and an implicit subsidy on that produced from renewable sources. A subsidy on renewables will decrease overall price of electricity, while a tax on non-renewables will increase prices; the overall effect depends on which dominates. The direction of the price change depends on the relative slopes of supply curves for renewables and non-renewables, the existing share of renewables, and the stringency of the RPS (Fischer 2010).

3. Model

3.1. General description

A multi-period multi-market price endogenous non-linear model is used in order to examine the research questions. The multi-market price endogenous framework allows for consumers and producers to make their consumption and production decisions simultaneously, prices being endogenously determined at the intersection of supply and demand curves. This is done by choosing the optimal level production in the agricultural, electricity, and transportation sectors of the economy in a dynamic framework to maximize consumer and producer surpluses in the this sector subject to production functions and technological constraints(McCarl and Spreen 1980 & Takayama and Judge 1971). The solution to this model 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. The multi-period component of the model accounts for the ability of individuals or firms to make decisions that are optimal in the context of future changes to market parameters. The price endogenous model is appropriate for modeling multiple large sectors of the economy, agriculture, electric, and transportation, as a large number of producers are involved in production of these goods and their aggregate output and input demands determine prices endogenously.

This study models markets in the U.S. agricultural, electric power, and transportation fuel sectors of the economy, including international trade with the rest of the world in order to simulate economic outcomes under a baseline, business as usual (BAU) scenario and different policy scenarios. The specific model used is the Biofuel and Environmental Policy Analysis Model (BEPAM). This model is extended with the development of an electricity sector model. This model had been previously developed to examine biofuel policies, such as the renewable fuel standard (Chen et al. 2011) and a low carbon fuel standard (Huang et al. 2012), among other research questions by simulating the U.S. agricultural and transportation fuel sectors[2]. For this study an electric power sector model is developed and integrated with the agricultural and fuel sector model.

[2] The agricultural and transportation fuel sectors of BEPAM are not the primary focus of this paper and are not described in detail here. A full mathematical description of the model of these sectors is available in (Huang et al. 2012).

The electricity sector within the model is depicted as consisting 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 ata 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.

Electricity generated from natural gas is produced by an existing power plant at a CRD level, subject to a power plant capacity constraint, or at 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 power plant pays a fixed operation and maintenance (O&M) cost, a variable O&M cost based on the quantity of generation, and a per unit price for natural gas. The price of natural gas is determined endogenously based on the input demand in the electricity sector and a national supply function. Electricity generated at an existing coal power plant is produced similarly to that at a natural gas power plant; however the coal power plant can choose to co-fire biomass with coal to produce electricity. The quantity of electricity generated is subject to a power plant capacity constraint, where the capacity constraint is the same as it is for natural gas power plants. 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). The coal power plant pays a fixed O&M cost, a variable O&M cost based on the quantity of generation, a per unit price for coal that is exogenously fixed, and an endogenously determined per unit CRD price for biomass.

Electricity generated from wind is produced by existing wind turbines, subject to a capacity constraint, or by new wind capacity built in a region. Electricity generated from existing wind generation capacity incurs an O&M cost. 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. The regional marginal cost of wind based generation is thus determined endogenously in the model.

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 a transmission capacity constraint, that limits inter-regional transmission to historically observed levels. 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 model allows for learning by doing to occur for wind based electricity and dedicated biopower 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 specified technology specific learning rate.

The demand for electricity is at the electricity market region level of aggregation. All electricity market regions have downward sloping linear demand functions for electricity.

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. The electricity sector policies that are considered in this model are state level RPSs and a carbon dioxide tax.

The RPSs are modeled generally as a constraint on the percentage of total electricity generated from renewable sources. It is necessary to adapt the general RPS constraint for the cases of many states that have specifics about how the RPS actually applies to state level generation. These policies have differences pertaining to the sources are eligible for the RPS depending on what date they were built; there are also policy “cut-outs” for specific technologies.

The agricultural and transportation sectors of the model describe agricultural production as occurring at the level of a USDA crop reporting district (CRD). A decision is made at each CRD to utilize its agricultural acres in producing a profit-maximizing portfolio of crops that can include corn, soybeans, wheat, as well as many other crops. These crops are used to satisfy consumer demand as well as input demands from the livestock industry, corn ethanol industry, and the potential cellulosic ethanol industry.

The regional quantities of biomass are based on the quantity of bioenergy crops, crop residues, and forest residues and pulpwood available at a market price. The bioenergy crop supply is derived from the input costs and the opportunity cost of the agricultural land employed for production, which is the benefit of the most profitable crop that can be grown on that land from the set of production possibilities. Crop residues are a byproduct of corn production and are modeled as joint products of corn production; therefore the supply of crop residues depends on the price of corn and the price of ethanol, as well as the price of biomass. Forest residues and pulpwood residues are exogenously given. These endogenous regional biomass quantities interact with the electricity sector portion of the model.

Biomass has a number of interactions within the electricity, agricultural, and transportation sectors. Biomass 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. The production of biomass occurs from dedicated bioenergy crops that take into consideration the profitability of other potential crops that could be grown on a given acre of land, and from crop residues that are a joint product of corn which is used for livestock production, ethanol production, and other end-use demands.

3.2. Algebraic Description

The general model is written algebraically as a constrained optimization problem with an objective function to be maximized by choosing levels of a set of choice variables subject to a set of constraints. The model is an extension of the Biofuel and Environmental Policy Analysis Model (BEPAM), a multi-period, multi-market price endogenous sector model which models the US agricultural and transportation sectors (Chen et al. 2011). The objective function to be maximized is total surplus (1), which is the sum of consumer surplus and producer surplus in the three sectors considered. The definitions of all sets, variables, and parameters in the model are given in Table 3. The total surplus function for the model is written algebraically as:

$$
\begin{aligned}
SW = \sum_t e^{-it} \Bigg\{ & TS_{Ag} + TS_{Trans} + \sum_{er} \int_0^{QE_{er,t}} f_{er,t}\left(\sum_{et} QE_{er,t,et}\right) dQE_{er,t} \\
& - \sum_{r,et} ec_{et} QR_{et,r,t} - \sum_{s,nt} lc_{nt} QS_{s,nt,t} \\
& - \int_0^{NG_{s,t,age}} g_t\left(\sum_{s,age} NG_{s,t,age}\right) dNG_{r,t,age} \\
& - \sum_{ff,r(s)} fp_{ff,s,t} FF_{ff,r,t} - \sum_{r(s),age} np_{s,t} NG_{s,t,age} \\
& - \sum_{er} \int_0^{QW_{er,t}} h_{er}(QW_{er,t}) dQW_{er,t} - \sum_{r_1,r_2} tr_{r_1,r_2} BT_{r_1,r_2,t} \Bigg\}
\end{aligned}
\tag{1}
$$

The first two terms of the first line of the equation (1), TS_{Ag} and TS_{Trans} are the total surplus in the agricultural and transportation fuel sectors respectively.[3] The first integral term in the first line of (1) represent the consumer surplus from consumption of electricity from all sources delivered to electricity market region *er* at time *t*, this consumer surplus is summed across all regions.

The first term in the second line of (1) represents the sum of the O&M cost, and going forward capital cost for existing power plants of technology type *et* in CRD *r* at time *t*. The second term in the second line of (1) represent the sum of the levelized cost of generating electricity at a new power plant of type *nt*, in state *s*, at time *t*.

The integral term on the third line of (1) represents the total cost (area under supply curve) of natural gas used for new or existing natural gas power plants in state *s* at time period *t*. The functions $g_t(.)$ are upward sloping linear supply functions for natural gas used in the electricity sector.

The first term on the fourth line of (1) is the total cost of fossil fuels other than natural gas (coal and fuel oil) used in the electricity sector. These fuel prices are assumed to be constant

[3] The full mathematical description of the objective function and constraints for the agricultural and transportation fuel sectors can be found in (Huang et al. 2012).

in each state *s* at each time period *t*. The second term on the fourth line of (1) represents the state level variation in natural gas cost.

The first term on the fifth line of (1) represents the cost of generating electricity from wind resources in region *er* at time period *t*. The functions $h_{er}(.)$ represent regional supply curves for generation from wind resources in each electricity market region. The second term of the fifth line of (1) is the cost of transporting biomass in the CRD in which it is produced to the CRD in which it is utilized in the electricity sector.

This objective function is maximized subject to technological and resource constraints. The first constraint described here relates electricity production by source to consumption. The quantity of electricity consumed is equal to the sum of all electricity produced from all sources considered: wind, coal, natural gas, fuel oil, geothermal, biomass, and other sources, including generation at new power plants, plus electricity transmitted from other regions, minus electricity transmitted to other regions:

$$\begin{aligned} QE_{er,t,et} = QW_{er,t} + \sum_{r(er)} \left(QR_{r,t,et} + CF_{r,t}\right) + \sum_{s(er)} QS_{s,t,nt} \\ + \sum_{er_1,at} IT_{er_1,er_2,at,t} - \sum_{er_2,at} IT_{er_1,er_2,at,t} \quad \forall er, t\,. \end{aligned} \tag{2}$$

Electricity is generated or produced according to production functions with a fixed input-output relationship (Leontief production functions). The generation of electricity from existing power plants is described by constraint (3).

$$QR_{r,t,et} \leq hr_{et,r} FF_{ff(et),r,t,\mathrm{old}} \quad \forall r, t \tag{3}$$

The amount of electricity generated from existing power plants in CRD *r*, at time period *t*, from technology *et* is a function of the thermal efficiency of the power plant (heatrate) and the input of fossil fuel of type *ff*.

The co-firing of biomass at existing coal power plants is described by constraint (4), where the coal-energy equivalent quantity of biomass $BC_{r,t}$ is converted to electricity using the coal power plants heatrate.

$$CF_{r,t} \leq hr_{coal,r} BC_{r,t} \quad \forall r, t \tag{4}$$

Co-fired biomass is constrained to be ten percent of less than the amount of coal used at the power plant (eq. 5), on energy equivalent terms.

$$0.1 * FF_{\mathrm{coal},r,t,\mathrm{old}} \geq BC_{r,t} \;\; \forall r, t \tag{5}$$

Generation occurring at new natural gas power plants is described by equation (6). Generation occurs at the state level with a thermal efficiency that is the same for all new power plants regardless of the state they locate in.

$$QS_{s,t,\mathrm{ng}} \leq nr_{\mathrm{ng}} FF_{\mathrm{ng},r(s),t,\mathrm{new}} \quad \forall r(s), t \tag{6}$$

Electricity is generated at new dedicated bio-power plants according to constraint (7). The quantity of generation in state *s* at time period *t* is a function of the amount of biomass utilized at all bio-power plants within that state and a thermal efficiency that is the same for all new plants of that type.

$$QS_{s,t,\mathrm{bio}} \leq \sum_{r(s)} nr_{\mathrm{bio}} BD_{r,t} \quad \forall r(s)\,, t \tag{7}$$

Generation at existing power plants is subject to a capacity constraint. Constraint (8) describes how generation of electricity from technology *et*, in CRD *r*, at time period *t* must not be greater than the nameplate capacity $cap_{et,r}$ times the capacity factor $cf_{et,r}$, converted from megawatts to megawatt-hours.

$$QR_{r,t,et} \leq mw * cf_{et,r} cap_{et,r} \quad \forall r, t, and\ et \in \{ng, oil\} \tag{8}$$

Similarly for coal power plants generation from coal and biomass sources can not be greater than the nameplate capacity times the capacity factor, converted to megawatt-hours.

$$QR_{r,t,\text{coal}} + CF_{r,t} \leq mw * cf_{\text{coal},r}cap_{\text{coal},r} \quad \forall r, t \tag{9}$$

Constraint (10) describes how the biomass that can be utilized to generate electricity is transported from the CRD that it is produced in to the CRD where it is used for electricity generation:

$$\sum_{r_1} BT_{r_1,r_2,t} \geq BD_{r_2,t} + BC_{r_2,t} \;\; \forall r, t. \tag{10}$$

Biomass used for dedicated bio-power plants ($BD_{r,t}$) and co-firing at existing coal power plants ($BC_{r,t}$) at CRD *r* must be less than or equal to the quantity of biomass transported to that CRD from all other CRDs. Biomass that is transported to a power plant from where it is produced must not be greater than the amount of biomass produced in that CRD for the electricity sector:

$$\sum_{r_2} BT_{r_1,r_2,t} \leq BE_{r,t} \;\; \forall r, t. \tag{11}$$

The amount of biomass produced for the electricity sector, $BE_{r,t}$ must be less than that amount of biomass produced minus that used for the production of liquid fuels for the transportation sector ($BE_{r,t}$).

Inter-regional transmission of electricity is constrained to only be allowed between adjacent regions and to not exceed historical levels by (12).

$$\sum_{at} IT_{er_1,er_2,at,t} \leq tcap_{er_1,er_2} \;\; \forall er_1, er_2, t \tag{12}$$

The constraint for the regional RPS policy scenarios is modeled as constraint on the proportion of electricity generated from renewable sources that is consumed in the region, thus allowing for inter-regional trading of electricity generated from renewables:

$$rps_{er,t}QE_{er,t,at} \leq QE_{er,t,rt} \;\; \forall er, t. \tag{13}$$

These constraints along with the objective function describe the electric power sector of BEPAM that was developed for this study. This objective function component and constraints are added to the agricultural and transportation fuels sector model that is described in previous literature.

4. Data

4.1. Demand

As described in the model section, one component of social welfare is the area under the inversed demand function for electricity. Each of these demand functions has two parameters: an intercept and a coefficient. These parameters are approximated from data on state electricity retail sales, retail electricity price, and the price elasticity of demand for electricity (USDOE/EIA 2007). Each region is assumed to have a -0.25 elasticity of demand, based on commercial sector demand in the National Energy Modeling System (USDOE/EIA 2012). The data of this model are publically available, but the model itself requires proprietary software to run.

4.2. Supply

Electricity is generated at power plants conditional on each plant's generation capacity. The existing capacity of each power plant at the CRD level is parameterized based on the the Emission and Generation Integrated Database (USEPA 2010). The $cap_{et,r}$ parameter is calculated from the aggregate capacity of all power plants of a specific type within a given county. The total amount of existing power plant capacity is 374 gigawatts for coal, 431 gigawatts for natural gas, and 15,886 megawatts for wind. The capacity factor for each county is calculated based the weighted average on the plant capacity factor (USEPA 2010) of all power plants of a specific type in a given county. The overall average capacity factors are: 0.562 for coal power plants, 0.188 for natural gas plants, and 0.252 for wind turbines.

As described in the model section, new natural gas and biomass based generation can be chosen to increase electricity generation. The cost of a megawatt-hour of electricity generated from natural gas or biomass at a new power plant less fuel costs, is modeled as an annualized cost, called the levelized cost (lc_{nt}). The levelized cost is a per Mwh cost of electricity generation that includes fixed and variable O&M costs, transmission costs, fuel costs, and annualized capital costs (USDOE/EIA 2012). These data are from the from the National Energy Modeling System (NEMS). In order to use these cost data in this model the cost of fuel is subtracted out so that these represent the per-unit of electricity cost of a new power plant minus fuel cost. The levelized cost for a megawatt-hour of natural gas generated electricity less fuel cost is $37.80 and is $71.90 for generation at a bio-power plant less biomass cost.

The wind energy supply curves are based on data from the NEMS model. The increasing linear marginal cost functions for wind resources ($h_{er}(.)$) are based on data used for the National Energy Modeling System (USDOE/EIA 2012). The marginal cost of generation from new wind turbine capacity is based on supply curves for wind energy resources. The authors were provided by the EIA with intermediate results of the National Energy Modeling System (NEMS), that is used for the AEO, on regional wind resources in terms of capacity. These data are projections of the amount wind capacity that is available by region at multiples of a base price. These capacity values are converted into generation by multiplying by the ratio mwhs/mw per year and a capacity factor of 0.34. The base price used is $148/mwh from the EIA levelized cost. The converted data are now in the form of regional supply functions for mwhs of electricity from wind resources with a function form of a step-function. In order to allow for more variation of the marginal cost of wind-based generation in between these discrete steps, these supply functions are linearized using ordinary least squares.

Production functions are used to describe how electricity is generated from fuel sources. These production functions are parameterized with heat rates. The heat rate is a technical parameter that describes the amount of Btus required to generate a MWh of electricity. The heat rates for coal and natural gas power plants by county are calculated as the weighted average heat rate of all power plants of that type in a given CRD (USEPA 2010). The national average heat rates are: 11,492 for coal and 17,800 for natural gas.

Coal and fuel oil based power plants pay a fixed per-unit price for fossil fuels that varies by state ($fp_{ff,s,t}$). This state price parameter is based on the average state price of coal or natural gas paid by the electricity industry (USDOE/EIA 2010). The average state price for coal for the electric industry was $2.23 per million Btu in 2010 and the average state price for natural gas in the electric industry was $5.06 per million Btu in 2010. National electricity sector natural gas supply functions for each year considered in the model are approximated based Annual Energy Outlook projections for low growth, high growth, and reference case scenarios (USDOE/EIA 2012). All power plants have O&M costs as described in the model. These parameters are based on data from the EIA Annual Energy Outlook (USDOE/EIA 2012).

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.

4.3.Policy

The primary renewable energy policies being examined here are state RPSs. The RPSs is modeled as a constraint on the proportion of electricity consumed in a region that is generated from renewable energy sources, where the parameter $rps_{er,t}$ represents a weighted average of the states' RPS schedule. The parameters are based on RPS data from the Database of State

Incentives for Renewables and Efficiency (DSIRE 2011). In general these parameter represent the RPS for a state and is a proportion that is increasing over time until it reaches its target percentage in a target year.

5. Results

This multi-market sector model is fundamentally 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 require the use of a numerical solver that is able to works with non-linear functions. However, currently commercially available nonlinear programming solvers do not perform well with sector models of this size. For this reason 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. 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.

The dynamic aspect of this model is addressed using the rolling horizon approach, where for each year considered in this paper (2007-2030) the model determines the production and consumptions decisions and the corresponding dynamic market equilibrium for the markets considered, for a 10 year planning period. The solution for the initial year for each 10 year rolling horizon planning period is stored as the final result and used to update some model parameters (such as regional land use, wind and biomass generation for learning by doing) for the next 10 year period.

The simulation model is validated for the first year modeled (2007) under the policy landscape of the corn ethanol mandate, the RFS, and state-level RPSs by comparing the simulated prices and quantities for the electricity sector with the observed data used for the model.[4] Table 4 shows the regional validation for electricity generation and price. The simulated generation quantity is within plus or minus ten percent of the observed quantity for all regions. The inelasticity of demand being -0.25 implies that all simulated prices deviate from the observed prices by four times the amount of the quantity deviation.

The model is solved under 4 different scenarios in order to examine the research questions. (1) A business as usual (BAU) scenario where there is only a corn ethanol mandate in place, neither the RFS or RPSs are considered. (2) A RFS scenario, where the only change from the BAU is the addition of the RFS mandate. (3) A RPS scenario, where the only change from the BAU is that the state-level RPS are in effect. (4) A RFS & RPS scenario, where both the RFS and RPS are in effect contemporaneously. The resulting market equilibria found across these four scenarios are compared in order to come to some conclusions regarding the research questions.

The quantity of electricity generated by each source under the four scenarios in 2030 is shown in Table 5. Under the BAU scenario the vast majority of electricity demand growth is met by expansion of natural gas based generation, coal capacity is nearly fully utilized, and there is a small increase in dedicated biomass based electricity in regions where there is low cost forest biomass available. The scenario where the RFS is in effect realizes a small decrease in quantity of natural gas based generation to 1417 M Mwhs, which is more than offset by the co-product based generation created by RFS mandate, this leads to an overall increase in electricity generation compared to the BAU scenario. The next scenario (RPS) considers the state-level

[4] Only included states where the RPS had actually been in effect in 2007.

RPSs in isolation. In order to achieve the state level mandate the fossil fuel based sources of coal and natural gas are reduced relative to the BAU, while there is an increase in generation from co-firing, dedicated biomass generation, and a relatively large increase in wind generation. Overall the total amount of electricity generated under RPS scenario is greater than the BAU scenario, indicating that the state level RPS actually lead to an increase in electricity generation and consumption compared to if there was no policy. Finally the RFS and state level RPSs are considered together in the fourth scenario. In this scenario overall coal and natural gas based generation are lower than in the BAU case, but coal based generation is actually higher than in the RPS scenario. Coal based generation is greater than in the RPS scenario due to the change in the quantity of co-firing across the two scenarios. The decrease in co-firing from 18 M Mwhs in the RPS scenario to 8 M Mwhs in the RFS & RPS scenario, leads to the capacity to be used for coal generation instead of co-firing. The quantity of co-product generation is approximately equal to what it would be under just the RFS scenario, indicating that while this co-product electricity if in the proper regions can satisfy the RPSs, it would have been generated regardless of the RPSs. Wind generation is also greater than under the RPS. Overall total generation is greatest in the RFS & RPS scenario.

Interestingly the quantity of electricity generated from biomass sources is actually greater in the RFS & RPS scenario than in the RPS, even though the biomass price is greater due to increased demand (Table 7). The reason for this is that the co-product generation is provided regardless of whether or not there are RPSs, this combined with the amount of co-firing and dedicated biomass generation leads to overall greater utilization of biomass for electricity generation. The results indicate that under the two scenarios where RPSs are considered, the quantity of renewable energy generation that is derived from biomass sources is small relative to that which comes from new wind resources. The overall share of electricity generated from renewable energy sources with the RPS is 13.3% compared to 8.6% under the BAU scenario (Table 6).

Biomass production for consumption in the considered sectors is shown in Table 7. Under the BAU scenario relatively little biomass is produced for fuel or electricity generation. There is 36.2 million metric tons of corn produced for ethanol, due to the corn ethanol mandate, there is also 28 million metric tons of low cost forest residues that are produced for electricity generation and biomass pellet export. The production of biomass under the RFS scenario is much larger due to the necessity of satisfying the RFS mandate. In this scenario the total quantity of biomass from energy crops and crops residues is 218 million MT, with the primary feedstocks being corn stover and miscanthus. The quantity of forest residues produced increases to 44.3 in this scenario and corn for ethanol increases significantly to 141 million MT. The production of biomass under the RPS is much less than under the RFS. Total energy crops and crops residues are 21 million MT, with the primary feedstock being corn stover. The production of biomass is greatest under the RFS & RPS scenario. Total energy crops and crop residue production is 236 million MT, which is greater than under the RFS. All energy crop and crop residue feedstock increase under the RFS & RPS compared to the RFS except for switchgrass production which decreases. The quantity of forest residues produced is the same as that in the RFS scenario. Overall biomass production is the greatest in this scenario at 281 million MT.

Table 8 shows commodity prices across the four scenarios and percentage changes from the BAU. Corn, soybeans, and wheat realize large price increases under both the RFS and the RFS & RPS scenarios. The price of corn and wheat increase more under the RFS while the price of soybeans increase more under the RFS & RPS. The price changes for these commodities under the RPS is relatively small. Two different prices are shown for biomass produced for cellulosic ethanol refining. The biomass for cellulosic ethanol price is the market price of biomass, it accounts for the fact that biomass used for ethanol refining yields both cellulosic biofuel and electricity generated from a renewable source. The biomass for cellulosic ethanol price net of co-product only considers the price of biomass in terms of its value for biofuel. Both of these prices are greater in the RFS & RPS scenario than in the RFS scenario, as there is a greater demand for biomass and the value of renewable electricity is greater due to the RPSs.

The price of electricity and the price of natural gas in the electricity sector is also shown in Table 8. The electricity price reported is a generation-weighted average of the electricity prices of the twenty electricity market regions considered in the model. The electricity price is $123/Mwh under the BAU scenario, while the other three considered scenarios have lower prices. The relative price decrease from the RFS scenario is due to the addition of co-product electricity generated as a function of the RFS mandate, increasing the quantity of electricity produced at a given price. The electricity price also decreases in both the RPS and RFS & RPS scenarios, for the reason described by Fischer (2010). The decrease in the electricity price is in part a function in the decrease of the natural gas price seen across the RFS, RPS, and RFS & RPS scenarios relative to the BAU scenario.

6. Conclusion

Renewable energy policies have been enacted in the electricity sector to increase the amount of electricity generated from renewable sources. A set of these policies are state level RPSs that require a specific percentage of a state's electricity to be generated from renewable sources. Biomass is a potential feedstock for electricity generation that qualifies as a renewable source under state RPS. Electricity can be generated from biomass in dedicated bio-power plants, a coal plant with co-firing capability, or as net co-product generation from a cellulosic ethanol refinery.

A multi-market, price endogenous sector modeling framework is used to analyze the effects of RPSs with and without the RFS. The multi-market sector model is used consists of agricultural and transportation fuels sectors that have been previously developed and an electricity sector that has been developed for this study. The model examines how electricity is generated from existing and new, renewable and non-renewable energy sources to meet specific energy policies in the agricultural, electricity, and transportation sectors.

The economic sectors modeled are simulated under four different policy scenarios that consider different electricity and agricultural sector energy policies implemented alone, and combined together. The results from these policy scenarios allow for an examination of questions about how these policies affect the mix of renewables used to generate electricity in the future and what part biomass has in it. The use of biomass for co-firing is analyzed over time.

In general the results indicate that the effect on electricity generation from the state-level RPSs is to increase generation from all renewables considered while decreasing generation from natural gas and coal sources, relative to the baseline. The increase in renewables is greater than the decrease in non-renewables, hence overall generation is greater under a RPS. Expansion of wind capacity is used to satisfy a greater proportion of the RPS than is the expansion of the bioenergy based generation.

Co-product electricity generation plays an interesting role in satisfying the RPSs by leading to an increase in biomass based generation for the RFS & RPS scenario over the RPS even though there is an increase in the biomass price, due to the fact that it is generated as byproduct of the RFS mandate.

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8. Tables & Figures

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
MROE	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 3: Definitions of sets, variables, and parameters

Sets & Indices	
$r \in R$	Crop Reporting District (CRD). These are a disaggregation of states (R maps to S)
$s \in S$	The 48 contiguous United States. These are a disaggregation of the electricity market regions (S maps to ER)
$er \in ER$	Electricity market region. There are 20 regions included in the model.
$t \in T$	Years.
$et \in ET$	Type of generation technology at existing plant. Contains: coal, natural gas, oil, and all others.
$nt \in NT$	Type of generation technology at new power plant
$at \in AT$	All types of generation technology from new and existing plants ($AT = ET \cup NT$)
$rt \in AT$	All types of generation from renewable sources that can be applied to RPSs

Variables	
$QE_{er,t,at}$	Quantity of all electricity consumed in region er at time t
$QR_{r,t,ot}$	Quantity of generation in CRD r at time t from technology ot
$QS_{s,t,nt}$	Quantity of generation in state s at time t from technology nt
$QW_{er,t}$	Quantity of wind generation in region er at time t.
$FF_{r,t,f,age}$	Quantity of fossil fuels used in CRD r, at time t, of type f, and plant age, age
$BE_{r,t}$	Quantity of biomass produced in CRD r a time t for the electricity sector
$BT_{r_1,r_2,t}$	Quantity of biomass transported from region $r_1$to r_2 at time t
$BD_{r(s),t}$	Quantity of biomass used as an input for a dedicated bio-power plant in state s, at time t.
$BC_{r,t}$	Quantity of biomass co-fired at a coal plant in CRD r, at time t.
$IT_{er_1,er_2,at,t}$	Transmission of electricity from region $er_1$to er_2 of type at at time t

Parameters	
$hr_{ot,r}$	Heatrate for plant type ot in region r
$cf_{ot,r}$	Capacity factor for plant type ot in region r
$nr_{nt,s}$	Heatrate for new plant type nt in state s
$cap_{et,r}$	Capacity of an existing plant of type et in CRD r.
lc_{nt}	Levelized cost of generation from technology nt.
ec_{et}	All cost of generating at an existing power plant of type et.
$tcap_{er_1,er_2}$	Inter-regional transmission capacity between two adjacent electricity market regions.
mw	A constant that converts megawatts to megawatt hours.

Table 4: Validation

Electricity Market Region	Observed Generation	Simulated Generation	Percentage difference (%)	Observed Price	Simulated Price	Percentage difference (%)
	Total Generation (Million Mwhs)			Retail Price (2007$)		
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	-0.75	116.5	119.99	3
MROE	63.48	61.19	-3.6	115.1	131.67	14.4
MROW	209.68	197.1	-6	88.13	109.28	24
NEWE	127.09	134.72	6	172.49	131.09	-24
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	-2.93	107.5	120.12	11.74
RFCW	437.72	414.81	-5.23	93.48	113.06	20.94
RMPA	99.94	96.34	-3.6	91.36	104.51	14.4
SPNO	46.63	43.83	-6	88.8	110.11	24
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	-7.65	83.79	109.43	30.6
SRVC	298.97	300.68	0.57	96.67	94.46	-2.29

Table 5: Electricity Generation in 2030 by Energy Source by Scenario

Energy source	**BAU**	**RFS**	**RPS**	**RFS & RPS**
Coal based generation (M Mwhs)	1843.95	1844.00	1826.33	1836.14
Nat gas generation: total (M Mwhs)	1430.02	1416.98	1311.11	1290.95
Co-firing generation (M Mwhs)	0.05	0.00	17.67	7.86
Co-product biofuel generation (M Mwhs)	0.00	39.84	0.00	39.89
Dedicate biomass generation (M Mwhs)	16.26	0.00	37.22	14.91
Wind generation (M Mwhs)	34.21	34.21	224.40	236.78
Fuel oil generation (M Mwhs)	1.36	1.36	0.70	0.69
Hydroelectric generation (M Mwhs)	287.71	287.71	287.71	287.71
Other renewables (M Mwhs)	55.75	55.75	55.75	55.75
Nuclear generation (M Mwhs)	928.93	928.93	928.93	928.93
Other generation (M Mwhs)	7.90	7.90	7.90	7.90
Total electricity generated (M Mwhs)	4606.14	4616.67	4697.71	4707.51

Table 6: Electricity generation shares by energy source in 2030

Electricity generation shares	**BAU**	**RFS**	**RPS**	**RFS & RPS**
Renewable share of generation (%)	8.55	9.04	13.26	13.66
Wind generation share of production (%)	0.74	0.74	4.78	5.03
Coal generation share of production (%)	40.03	39.94	38.88	39.00
Natural gas generation share of production (%)	31.05	30.69	27.91	27.42
Biomass generation share of production (%)	0.35	0.00	0.79	0.32
Co-firing generation share of production (%)	0.00	0.00	0.38	0.17
Co-product biofuel generation share of production (%)	0.00	0.86	0.00	0.85
Hydro generation share of production (%)	6.25	6.23	6.12	6.11
Nuclear generation share of production (%)	20.17	20.12	19.77	19.73
Other sources generation share of production (%)	1.38	1.38	1.36	1.35

Table 7: Biomass production in 2030 by feedstock

Biomass feedstocks	BAU	RFS	RPS	RFS & RPS
Corn for ethanol (M MT)	36.2	140.8	36.2	140.8
Stover amount(M MT)	0.0	96.1	16.1	110.9
STRAW amount(M MT)	0.0	17.4	1.4	21.2
Miscanthus amount(M MT)	0.0	90.1	3.4	96.0
Switchgrass amount(M MT)	0.0	14.6	0.6	7.9
Soybean for biodiesel(M MT)	0.0	0.0	0.0	0.0
Total energy crops and crop residues (M MT)	0.0	218.3	21.4	236.0
Total Forest Residues (M MT)	28.0	44.3	34.8	44.3
Total Pulpwood (M MT)	0.0	0.1	0.0	0.3
Total biomass production (M MT)	28.0	262.7	56.2	280.6

Table 8: Commodity prices in 2030 across scenarios

	Price in 2030				% change from BAU (where ≠ 0)		
Commodity Prices	**BAU**	**RFS**	**RPS**	**RFS & RPS**	**RFS**	**RPS**	**RFS & RPS**
Corn ($/MT)	125.89	175.65	126.08	175.34	39.5%	0.1%	39.3%
Soybeans ($/MT)	335.66	446.16	335.13	447.44	32.9%	-0.2%	33.3%
Wheat ($/MT)	229.92	252.99	230.23	251.95	10.0%	0.1%	9.6%
Land Rent ($/Ha)	502.26	669.77	503.25	673.93	33.4%	0.2%	34.2%
Biomass for Cellulosic Ethanol Price ($/Mg)	0.00	68.47	0.00	71.84			
Biomass for Cellulosic Ethanol Net Price($/Mg)	0.00	47.57	0.00	50.12			
Cellulosic ethanol Producer Price($/Liter)	0.00	0.80	0.00	0.81			
Biomass Diesel producer price($/Liter)	0.00	0.00	0.00	0.00			
US Gasoline Producer Price($/Liter)	0.95	0.84	0.95	0.85	-11.9%	0.0%	-11.3%
Ethanol Consumer Price ($/Liter)	0.63	0.56	0.63	0.56	-11.8%	0.0%	-11.4%
Corn ethanol producer price($/Liter)	0.69	0.76	0.69	0.76	10.5%	0.0%	10.5%
Sugarcane ethanol producer Price($/Liter)	0.68	0.80	0.68	0.81	17.6%	0.0%	18.8%
US Diesel producer price($/Liter)	0.98	0.95	0.98	0.96	-2.4%	0.0%	-2.3%
Weighted average electricity price ($/Mwh)	123.18	122.40	115.40	114.53	-0.6%	-6.3%	-7.0%
Natural gas for electricity ($/MBtu)	9.42	9.32	8.54	8.39	-1.1%	-9.3%	-11.0%