State-Level Infrastructure and Economic Effects of Switchgrass Cofiring with Coal in Existing Power Plants for Carbon Mitigation

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This paper presents a linear programming (LP) methodology for estimating the cost of reducing a state’s coal-fired power plant carbon dioxide emissions by cofiring switchgrass and coal. LP modeling allows interplay between regionally specific switchgrass production forecasts, coal plant locations, and individual coal plant historic performance data to determine an allocation of switchgrass minimizing cost or maximizing carbon reduction. The LP methodology is applied to two states, Pennsylvania (PA) and Iowa (IA), and results are presented with a discussion of modeling assumptions, techniques, and carbon mitigation policy implications. The LP methodology estimates that, in PA, 4.9 million tons of CO₂/year could be mitigated at an average cost of less than $34/ton of CO₂ and that, in IA, 7 million tons of CO₂/year could be mitigated at an average Cost of Mitigation of $27/ton of CO₂. Because the factors determining the cofiring costs vary so much between the two states, results suggest that cofiring costs will also vary considerably between different U.S. regions. A national level analysis could suggest a lowest-cost cofiring region. This paper presents techniques and assumptions that can simplify biomass energy policy analysis with little effect on analysis conclusions.

Introduction

A total of 1500 coal-fired power plants generated roughly 50% of the 4.1 trillion kWh of electricity used in the U.S. in 2005 (1). In 2004, these coal-fired power plants produced 81% of total U.S. electricity sector CO₂ emissions, representing 27% of the U.S.’s 7.7 billion short tons of greenhouse gas emissions (CO₂ equivalent) (2). A 4% increase in coal-fired capacity (13 GW) is scheduled to come online by 2009, increasing the total carbon dioxide (CO₂) emissions attributable to coal combustion (1). Concern for global climate change may engender the establishment of a U.S. carbon emission mitigation policy, which would require the electricity industry to identify strategies to reduce greenhouse gas (GHG) emissions. Such strategies might include fuel switching and repowering, plant replacement with a lower carbon electricity generation option, or retrofitting for CO₂ capture and sequestration technologies (3). This paper looks at the GHG-emission mitigation strategy of cofiring biomass, specifically grown as an energy crop, with coal.

Numerous studies have investigated the potential of biomass cofiring with coal as a low-cost, technologically simple method for reduction of fossil fuel use with a concomitant reduction in CO₂ emissions (4–7). Many researchers argue that switchgrass is a carbon-negative energy resource; carbon is sequestered by switchgrass roots, while a carbon-neutral cycle takes place as carbon is absorbed from the atmosphere during growth and readmitted during combustion (8–10). The degree to which switchgrass and other biomass fuels lower net GHG emissions depends on farming practices such as tilling and irrigation (11). National Renewable Energy Laboratory researchers estimate that lifecycle GHG emissions from cofiring wood with coal are reduced at a rate slightly greater than the ratio of biomass thermal energy (e.g., at a 5% cofire rate, GHG emissions are reduced by 5.4%; at a 15% cofire rate, GHG emissions are reduced by 18.2%), making our simple carbon-neutral estimation conservative by comparison (12).

Although cofiring biomass with coal may offer modest CO₂ emission reductions, legislation will likely be required to overcome the economic advantages of using coal versus biomass as an electricity-generation feedstock. Thus, the cost of carbon reduction is an important metric. Facilitating comparisons between potential CO₂-emission-reducing options. For example, Robinson et al. estimate that, at an average cost of $24/ton of CO₂, cofiring wood and agricultural wastes with coal could displace roughly 275 million short tons of CO₂ emissions annually (5). Gan and Smith estimate that a 25% reduction in carbon emissions will require a carbon price of $23/ton of CO₂, and coal prices will likely rise by 58% from a base price of $1.19/million British thermal units (MMBtu), allowing electricity generated from logging residues to be competitive with electricity generated from coal (4). CO₂ capture and sequestration technologies are estimated to not significantly penetrate the electricity sector below $100/ton of CO₂ prices (13).

In this paper, we estimate cost curves associated with large-scale conversion of switchgrass to electricity by cofiring in existing U.S. coal-fired power plants to reduce existing power-plant CO₂ emissions. This analysis contributes a means for comparing switchgrass cofiring, as an electricity sector carbon mitigation option, to other options of carbon mitigation for existing coal-fired power plants. We use switchgrass because it can be readily grown throughout areas of the U.S. where coal is used for electricity generation (14). We chose an LP methodology as a means of estimating the cofiring costs because of its ability to consider tradeoffs between cofiring cost components such as capital equipment, labor, and transportation distances. To explore the bounding conditions associated with switchgrass and coal cofiring, we analyze three scenarios using our LP methodology.

We apply our analysis to Pennsylvania (PA) and Iowa (IA), two states that have large and small numbers of coal-fired plants and low and high potential to produce switchgrass, respectively. We explain the costs of switchgrass and coal cofiring with respect to each state’s existing coal-fired capacity.

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and its geographical attributes, which, taken together, represent unique cofiring costs.

Methods

Linear Programming (LP) is used here to balance multiple factors affecting total cofiring economics, including switchgrass availability, switchgrass transportation costs, power-plant capital equipment investments, added operation and maintenance costs, NOx and SO2 emission reduction credits, and individual power-plant performance. See Supporting Information, eqs 10–35 for technoeconomic equations and related discussion. All coal-fired power plants located within each state are candidate cofiring plants, although existing cofiring plants are excluded. Switchgrass data, categorized by Agricultural Statistical Districts (ASD) and market prices, were kindly provided by Lynn Wright of Oak Ridge National Laboratory (ORNL) and were generated using University of Tennessee’s POLYSYS agriculture sector economic model (15). POLYSYS is used to create an economic estimation of domestic biomass resource production. The resulting database comprises supply forecasts at discrete prices for each ASD (e.g., X tons at $30/dry short ton, X + λX tons at $40/dry short ton, etc.) (16). The switchgrass data are disaggregated from ASDs (comprising multiple counties) into individual counties where, for simplification, it is assumed that all switchgrass resides in the center of each county (see Supporting Information for disaggregation methodology and equations; see Figures S-7 and S-9 for disaggregated county maps). All biomass is assumed to be transported from farms directly to power plants. Because farms typically do not have rail loading infrastructure on location, trucking is the only transportation mode considered, and CO2 emissions resulting from switchgrass transportation are subtracted from the CO2 emission reductions at power plants. Individual power-plant characteristics, including environmental performance, are taken from the eGRID database (year 2000) (17). Individual power-plant attributes, performance characteristics, retrofitting capital costs, and power-plant proximity to switchgrass affect optimal switchgrass allocation.

Some U.S. regions are able to grow enough switchgrass to allow cofiring ratios larger than the typical 10–15% cofiring limitation assumed in most cofiring analysis. Instead of limiting our LP to cofire below this range, we estimate switchgrass and coal cofiring costs over the full range of switchgrass growth potential. Our LP methodology assumes that capital costs increase in proportion to cofiring rates up to 20% on an energy basis. Above 20%, we assume that the entire power-plant boiler must be replaced and a much larger retrofitting capital cost rate of $2,000/kW is applied. Although we recognize that biomass gasification technologies could be deployed with lower capital costs and greater carbon reduction benefits (18), we seek to estimate an upper-bound cost associated with switchgrass and coal cocombustion at existing power-plants and therefore do not consider gasification technology retrofitting options. Instead, we assume the existing steam turbines and remainder of the plant will remain intact and only the boiler will be replaced. When boilers are replaced in our LP, we continue to estimate carbon emission reductions based on the existing plant’s carbon-emission performance.

The total incremental costs of cofiring switchgrass are calculated for three bounding scenarios which are used to analyze the implications of cofiring switchgrass with coal. The LP objective functions and constraints for these three scenarios are defined mathematically in the Supporting Information in eqs 1–9. In the first scenario, “Minimal-Capital-Cost”, all coal-fired power plants are constrained by the LP to cofire switchgrass at their maximum rate before requiring the installation of a separate biomass feed system (2% for pulverized coal (PC) boilers, 10% for non-PC boilers). In the second scenario, “Minimize-Incremental-Cost”, the LP minimizes the total incremental costs associated with switchgrass consumption at existing power plants and constrains the cofire rates to be less than or equal to a boiler replacement threshold of 20% cofiring. The third scenario, “Minimize-CO2-Emissions”, the LP minimizes total CO2 emissions given the maximum quantity of switchgrass allowed by the data and allows boiler replacement.

Because the switchgrass price forecasts are higher than current coal prices, an economic LP model minimizing costs would not allocate any switchgrass. Therefore, a constraint forces allocation as follows: switchgrass must be consumed up to the point that either switchgrass is fully used, or boiler restriction on cofire rates is reached at all power-plants (20% in non-boiler replacement scenarios and 100% in boiler replacement scenarios).

In all three scenarios, only the appropriate amount of switchgrass is considered available. For example, the Minimal-Capital-Cost scenario requires less switchgrass to satisfy its constraints, and consequently, switchgrass prices can be lower than in the other two scenarios. By contrast, the Minimize-CO2-Emissions scenario seeks to estimate greatest potential for CO2 emission reductions when cofiring switchgrass in existing power-plants, therefore uses the maximum amount of switchgrass (at the maximum switchgrass price). In all scenarios, CO2 emission reductions and the total incremental cost estimations are calculated for each power plant and are presented as costs per reduction in CO2 emissions ($/ton of CO2), also referred to in this paper as cost of carbon mitigation (COM).

Model sensitivity to switchgrass location, disaggregation resolution, feedstock prices, shadow prices for the switchgrass allocation decision variables, and eGRID data (capacity factors and data year) are discussed in the sensitivity analysis section.

Pennsylvania was chosen because of its relatively large quantity of coal-fired electricity capacity versus its relatively small forecast of switchgrass growth: 41% of PA’s 45 GW of summertime capacity is coal capacity, which in 2004 generated 55% of the state’s 214 TWh of electricity (19). At $50/dry short ton of switchgrass, PA’s switchgrass growth forecast is 3 million tons per year.

Iowa was chosen for comparison to PA because it represents essentially an opposite set of cofiring circumstances. Iowa’s switchgrass growth potential is approximately 20 million tons per year at $50/dry short ton switchgrass, which is 6–7 times that of PA, while IA’s coal-fired capacity is one-third of PA’s 57% of IA’s 10.9 GW of summertime capacity is coal capacity, which generated 43 TWh of electricity (19).

Results

Pennsylvania Carbon Reduction and Cost Estimation. Figure 1 presents COM curves for the three cofiring scenarios performed for PA. The Minimal-Capital-Cost scenario results in the lowest costs, as well as the lowest CO2 reductions: 2 million tons of CO2/year mitigated at an average COM of $22/ton of CO2. Despite larger overall costs, no additional CO2 reduction benefits are forecasted for the Minimize-CO2-Emissions scenario over the Minimize-Incremental-Cost scenario. The Minimize-Incremental-Cost scenario results in 4.9 million tons of CO2/year mitigated at an average COM of less than $34/ton of CO2.

In our LP model, switchgrass displaces coal on an energy basis, one Btu of switchgrass displaces almost one Btu of coal, regardless of which power plant consumes the switchgrass. The replacement is actually slightly less than one-to-one because of lower boiler efficiency for biomass fuels compared to coal. The LP model calculates CO2 reductions by multiplying the Btus of switchgrass consumed at a power
plant by the power plant’s eGRID CO₂ emission rate (CO₂/ MMBtu). CO₂ emission rates are relatively consistent between coal-fired power plants. In the year 2000, the average of all PA coal-fired power plants was 205 lb of CO₂/ MMBtu with a standard deviation of only 5 lb of CO₂/ MMBtu. When measured by tons of CO₂ emissions per ton of switchgrass consumed, transportation-related CO₂ emissions represent, on average, 1.6% of the power-plant smoke-stack CO₂ emission reductions estimated in our Minimize-Incremental-Cost scenario. Therefore, under the Minimize-CO₂-Emissions scenario, if an individual power plant exhibits above average CO₂ emissions, the LP model will allocate more switchgrass to this plant and away from plants that are below average CO₂ emissions. For example, two large power plants in PA have lower than average CO₂ emission rates, 192 lb of CO₂/ MMBtu (420 MW of capacity) and 194 lb of CO₂/ MMBtu (1569 MW), and two have higher than average CO₂ emission rates, 219 lb of CO₂/ MMBtu (34 MW of capacity) and 210 lb of CO₂/ MMBtu (498 MW). Allocating switchgrass to the larger emissions plants first results in larger overall capital costs. In the Minimize-CO₂-Emissions scenario, the one high-CO₂ emission rate plant replaces its boiler and becomes a dedicated switchgrass-fired plant. This plant’s larger capital cost explains the sharp slope increase at the end of the Minimize-CO₂-Emissions curve. The shift of switchgrass toward the next largest CO₂ emission rate plants accounts for the larger overall costs associated with the Minimize-CO₂-Emissions scenario cost curve in Figure 1. Although unnoticeable in Figure 1, there is a marginal CO₂ reduction benefit of 14 600 ton/year or an additional 0.3% reduction as compared to the Minimize-Incremental-Cost scenario.

The Minimal-Capital-Cost scenario’s lower demand for switchgrass allows for both lower switchgrass prices and cofiring costs in general. That being said, lower switchgrass prices require larger transportation costs, resulting in a steeper sloped cost curve. Enough switchgrass is available in all of PA to satisfy the scenario’s cofire ratio constraints beginning at a switchgrass price of $35/dry short ton. At this price, however, not all counties can support their closest coal-fired power plant. With the assumption that biomass is transported by truck exclusively, transportation costs increase by 26 cents per ton mile, translating into a $5/dry short ton transportation cost increase for every additional 19 miles of transportation. Stepping to the next switchgrass price point ($40/dry short ton) results in lowered transportation costs but a larger cost solution overall and is therefore not presented.

Cost Components. Figure 2 presents cost estimates for equipment, labor and maintenance, transportation, and emissions credits, expressed in $/ton of switchgrass for cofiring power plants in the three scenario solutions. The wide bars present average costs experienced by individual power plants, and the error bars present one standard deviation of these values. The narrow bars on the right side present the average costs for all switchgrass and represents PA’s switchgrass weighted average cost component.

When the total optimization solution is at a global minimum, costs for equipment, labor and maintenance, and transportation required for cofiring vary widely between individual power plants, as illustrated by the error bars in Figure 2. The variations depend on individual plant attributes, as much as proximity to switchgrass resources. For example, a plant’s cofire rate determines the amount of capital equipment and plant modifications required to handle biomass feedstocks. The cofire rate is the ratio of switchgrass to coal energy consumption, but the amount of coal consumed is dependent on a plant’s annual operating hours (or capacity factor). If a plant has a lower capacity factor in the eGRID database, a unit of switchgrass consumption will correspond to a larger cofire rate than if consumed by a plant with a larger capacity factor. Larger cofire rates result in larger capital costs even if a relatively small amount of biomass is actually fired. If capacity factors differ considerably between two otherwise similar power plants, equal quantities of switchgrass consumption will result in a wide variance in capital costs. The maintenance cost is modeled as a percentage of capital equipment costs and, therefore, experiences a similar dependence on capacity factors. Labor cost, however, is modeled using an economy of scale variable: as switchgrass consumption increases, operation costs decrease. Transportation is a tradeoff to capital costs. If a plant is located relatively close to biomass feedstock supplies, then the lowered transportation cost will be substituted with increased capital costs as more biomass is consumed. An LP solution represents the equilibrium of all factors resulting in the optimal goal, either lowest-cost or lowest-CO₂ emissions.
In addition to the engineering relationships modeled, scenario constraints also cause cost-component variances. In the Minimize-Incremental-Cost scenario, 4 of the 21 PA power plants do not cofire at all; four reach the highest capital cost bracket with three of those bound by the 20% cofire boiler replacement constraint. For the Minimize-CO₂-Emissions scenario, five plants do not cofire; six plants reach the top capital cost bracket with three of those bound by the 20% cofire boiler replacement constraint, and one replaces its boiler. As a result, PA’s average capital costs of $8.00/dry ton of switchgrass estimate in the Minimize-Incremental-Cost scenario increases to $11.60/dry ton of switchgrass consumed in the Minimize-CO₂-Emissions scenario. Allowing switchgrass to the larger CO₂ emission rate plants means that other plants are not able to reduce their labor cost through larger switchgrass consumption rates, and therefore, labor costs estimates have larger variance for this scenario. Transportation expenses remain consistent between these two scenarios, although transportation is much larger in the Minimal-Capital-Cost scenario for reasons previously discussed.

Comparison of IA and PA. Figure 3 presents COM curves for IA, using the same three cofiring optimization scenarios performed for PA. In IA, the Minimal-Capital-Cost and Minimize-Incremental-Cost scenario costs and carbon reductions are lower than PA’s (1.3 million tons of CO₂/year mitigated at an average COM of $19/ton of CO₂ and 7 million tons of CO₂/year mitigated at an average COM of $27/ton of CO₂, respectively), although IA’s Minimize-CO₂-Emissions scenario costs and carbon reductions are much larger than PA’s (26 million tons of CO₂/year mitigated at an average COM of $82/ton of CO₂). Differences between the two states can be explained by each state’s endowment of coal power plants. In general, a state with a smaller coal-power capacity necessarily cannot fire as much biomass as a state with a larger capacity. Iowa has only one power plant larger than 1000 MW, while PA has eight plants larger than 1500 MW. Thus, IA displaces less CO₂ in the Minimal-Capital-Cost scenario but can do so with lower switchgrass prices. To grow enough switchgrass to reach the Minimal-Capital-Cost scenario’s cofire threshold constraint, IA’s smaller switchgrass demand can be satisfied at a $30/dry short ton switchgrass price, while PA requires a $35/dry short ton switchgrass price. Moreover, smaller power plants demand less biomass which reduces the distance required to satisfy demand and allows IA’s transportation costs to be less than half those in PA. Capital costs are virtually identical, although IA’s power plants are too small to enjoy economies of scale for labor, resulting in higher labor costs.

Differences between IA and PA COM curves for the Minimize-CO₂-Emissions scenarios are explained by each state’s endowment of coal power capacity and ability to grow switchgrass. IA can grow a maximum of 20 million tons of switchgrass/year at $50/dry short ton (the maximum price in the ORNL switchgrass supply curve dataset), while PA can only grow a little more than 3 million tons/year maximum. When IA’s ability to grow switchgrass is compared to its existing coal power capacity, IA can grow 75% of its year 2000 coal-based thermal energy consumption in the form of switchgrass; PA can only grow 6% of its year 2000 coal-based thermal energy consumption. Given IA’s comparatively smaller coal-power capacity and abundant switchgrass growth potential, cofiring all of IA’s switchgrass would result in large cofire ratios at most of its power plants. For the Minimize-CO₂-Emissions scenario, four of IA’s 19 plants fire up to the boiler replacement threshold of 20%, eleven replace their boilers, with ten switching to switchgrass fuel only. These large switchgrass consumption estimations require very large capital investments, leading to IA’s higher scenario costs. Transportation costs are also higher than for PA’s Minimize-CO₂-Emissions scenario. Most U.S. coal power plants are located along rivers because rivers offer process cooling water and a secondary coal-shipping mode. Iowa’s two major rivers, the Mississippi and Missouri, are located along its borders, while IA’s switchgrass is located relatively uniformly across the state (see Figure S-12 in the Supporting Information for the spatial arrangement of switchgrass quantities available at $50/dry short ton in Iowa). In PA, rivers and, consequently, power-plants tend to be located throughout the state’s interior. When the larger switchgrass quantities are consumed in the Minimize-CO₂-Emissions scenario, IA’s shipping costs are much greater than PA’s because large quantities of switchgrass are shipped from IA’s interior toward its borders. The average shipping distance for IA is 65 miles, versus PA’s 43 miles.

Iowa and Pennsylvania’s Minimize-Incremental-Cost components are much more alike. The primary difference between the scenario curves is switchgrass price. In IA, the Minimize-Incremental-Cost scenario constraints bind when switchgrass prices are at $30/dry short ton. In PA, the scenario constraints bind for only three power plants, even though the switchgrass price is at its maximum of $50/dry short ton.

Sensitivity Analysis. Feedstock costs represent the largest expense when cofiring (with the exception of IA’s Minimize-CO₂-Emissions scenario), and therefore, our results are most sensitive to changes in either switchgrass or coal feedstock prices. Assuming a $50/dry short ton feedstock price and a $1.24/MMBtu coal price, subtracting savings from displaced...
coal fuel from the switchgrass price, and correcting for the lowered efficiency when firing switchgrass, the cofiring cost can be estimated. An incremental switchgrass price of roughly $34/dry short ton of switchgrass. For every coal price increase of $0.75/MMBtu, approximately $10/dry short ton is subtracted from the incremental switchgrass price. For example, if coal prices rise to $2/MMBtu, the resulting incremental switchgrass price would be approximately $24/dry short ton. Including the NOx and SO2 co-benefit values, the fuel cost for PA’s Minimize-Incremental-Costs scenario is 67% of the average cofiring costs. Assuming that coal prices rise to $2/MMBtu, the average fuel cost drops to 59% of the average cofiring costs, resulting in roughly a $6.50/ton of CO2 price decrease for the whole curve presented in Figure 1. A further increase of coal prices to $2.75/MMBtu results in roughly another $8.50/ton of CO2 price decrease. For IA’s Minimize-Incremental-Costs scenario, the $30/dry short ton switchgrass price was used and the same $0.75/MMBtu coal price increase results in roughly a $7.50/ton of CO2 price decrease. The same effect happens if the switchgrass price is reduced, while the coal price remains constant.

Within each state model, two spatial resolutions are compared: one based on the switchgrass data disaggregated to a county level as described above and the other further disaggregating from the county level to a “farm” level, based on satellite land-use images. See Supporting Information for disaggregation methodology, equations, and discussion. Figures S-11 and S-12 show PA and IA’s disaggregated switchgrass and power-plant location maps, and Figures S-13 and S-14 show the results of solving the Minimize-Incremental-Costs scenario as compared to the county resolution results. Virtually no difference exists between the two resolutions. We concluded that no transportation estimation clarity is gained by further disaggregating biomass feedstocks supply below a county resolution basis. This observation is not trivial: modeling the finer resolution required approximately 4000 farm-representing nodes for each state. The LP models thus consisted of roughly 20 power plants by 4000 farm nodes requiring roughly 80 000 decision variables in the linear program. The coarser “county-level” resolution only required 100 county nodes in Iowa and 67 in PA, for approximately 2000 decision variables. Solution times for the two resolutions vary accordingly: the “farm-level” LP model takes roughly 60 times longer to solve compared to the “county-level” LP model.

The LP global solutions are not sensitive to unit changes in any individual county’s switchgrass growth potential. All of the individual LP variable values (quantities of tons shipped from a county to a power plant) have very small shadow prices when compared to the solution; on average, the shadow prices are 0.0004% of the solution. If switchgrass quantities (or mileage between a county and a power plant) are changed for one county and all else is held equal, the allocation might adjust, but the net result changes insignificantly. Considering the large number of counties in the model, an increase (or decrease) in any given county’s switchgrass production does not alter our conclusions. Changes would need to be applied to all counties simultaneously (such as market changes resulting in altered switchgrass prices) to produce drastic COM changes.

We explored allowing boiler replacements in the Minimize-Incremental-Cost scenario for IA, and costs were only marginally reduced below those presented by the Minimize-CO2-Emissions scenario in Figure 3. We also allowed capacity factors to relax for plants that replace boilers and observed an increase in overall costs as more switchgrass was allocated to the new boiler plants and away from plants with much lower cofiring costs (see Figure S-15 in the Supporting Information for graphical presentation of curve results). We also used eGRID data for 1999 and observed adjustments to the curves but found no changes in our results and conclusions (see Figure S-16 in the Supporting Information for graphical presentation of curve results).

Discussion

Based on our results, any biomass and coal cofiring policy should focus on minimizing total costs rather than minimizing CO2 emissions. The ratio of CO2 emissions to thermal energy input for a power plant is a function of the carbon intensity of coal, is independent of power-plant efficiencies, and is relatively uniform across all power-plants. Moreover, far more CO2 emissions are displaced from power-plant smoke stacks than are emitted from truck tail pipes. Therefore, the marginal benefit of replacing the most carbon-intensive ton of coal will be small, although the marginal transportation cost for doing so will likely be larger than the transportation cost for replacing any other (less carbon intense) ton of coal. Thus, a disproportionate financial penalty for replacing the most carbon-intensive ton of coal will result in a larger overall cofiring cost.

We recognize that the high COM estimations for IA’s Minimize-CO2-Emissions presented above and the price estimations of other carbon-reducing retrofit options exceed the amount that would likely be available to existing coal plants if a carbon constraint were placed upon them. We believe, however, that our cost estimation provides a scale for understanding how much carbon mitigation could be expected if switchgrass cofiring were the only option available in IA. We also recognize that other technologies could use switchgrass as an electricity feedstock for lower prices than replacing boilers at existing power plants. Therefore, we present the results of this scenario as an upper-bound on the reduction of CO2 emissions at existing coal-fired power plants.

When optimizing for costs, an individual state’s cofiring economics will be determined by three items: its endowment of existing coal-fired power plants, its ability to grow biomass energy, and the spatial distribution of the two. Assuming no boiler replacements, a state’s ratio of biomass growth potential to existing coal energy consumption can crudely forecast its cofiring costs; states with a small ratio will more likely experience higher cofiring capital costs than a state with a larger ratio. Comparing PA and IA’s COM curve in Figures 1 and 3 supports this observation. Moreover, if the ratio of biomass to coal-energy consumption is low, then it is more likely that access to biomass resources will require large shipping distances and higher transportation costs. If the ratio is high, then access will more likely result in lower costs.

Approximating the transportation distances between biomass and power-plants using a coarse resolution (e.g., county center to power plants) provides a reasonable estimation of transportation costs. The use of our transportation estimation methodology can allow a relatively simple biomass allocation model. Our cofiring simulation LP can be applied to other states to estimate the role that biomass cofiring energy policies could contribute to electricity sector carbon mitigation. Moreover, a national cofiring model can be developed relatively easily using publically available distance data and county-level switchgrass data developed by the DOE’s biomass program (20).

Differences between PA and IA’s cost of carbon mitigation suggest several policy questions. From a state carbon mitigation policy perspective and given the differences between state cofiring cost estimations presented here, how might neighboring states’ environmental policies affect one another? If one state has much lower cofiring costs than a neighboring state, will each state’s policies affect each other’s costs as biomass flows freely across state borders? If so, by how much? From a national carbon mitigation policy
perspective, recognizing that states can experience different cofiring costs, a national cofiring policy incentive, such as the “closed loop” biomass tax credit, will most likely affect states differently. For this reason, how much cofiring incentive is required to reasonably expect a desired carbon mitigation outcome? Does the existing “closed loop” biomass tax credit provide any incentive to combust biomass for electricity generation and in the event of carbon mitigation legislation, should the tax credit remain as is, change, or be discarded?

From both a state and a federal environmental policy perspective, the estimation of multistate cost curves or a total U.S. cost curve can provide perspective to these questions. Moreover, the research presented here suggests that there could be regions within the United States where using biomass for electricity generation makes more sense than other areas. Our LP methodology can be applied to any state or multistate region to estimate cofiring costs and CO₂ reductions and to help set policy targets for cofiring biomass in coal plants. In the event of a carbon mitigation policy, obvious low-hanging-fruit opportunities could exist, and modeling national-level switchgrass and coal could indicate the regions that would benefit the most from biomass and coal cofiring.

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Supporting Information Available
Mathematical details for our technoeconomic model, LP objective functions, constraints, and substantiation of assumptions through a discussion of model structure and techniques. This material is available free of charge via the Internet at http://pubs.acs.org.

Literature Cited

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