Assessment of Potential Carbon Dioxide Reductions Due to Biomass–Coal Cofiring in the United States

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Cofiring biomass with coal in existing power plants offers a relatively inexpensive and efficient option for increasing near-term biomass energy utilization. Potential benefits include reduced emissions of carbon dioxide, sulfur, and nitrogen oxides and development of biomass energy markets. To understand the economics of this strategy, we develop a model to calculate electricity and pollutant mitigation costs with explicit characterization of uncertainty in fuel and technology costs and variability in fuel properties. The model is first used to evaluate the plant-level economics of cofiring as a function of biomass cost. It is then integrated with state-specific coal consumption and biomass supply estimates to develop national supply curves for cofire electricity and carbon mitigation. A delivered cost of biomass below $15 per ton is required for cofire to be competitive with existing coal-based generation. Except at low biomass prices (less than $15 per ton), cofiring is unlikely to be competitive for NO_x or SO_x control, but it can provide comparatively inexpensive control of CO_2 emissions: we estimate that emissions reductions of 100 Mt-CO_2/year (a 5% reduction in electric-sector emissions) can be achieved at 25 ± 20 $/tC. The 2–3 year time horizon for deployment—compared with 10–20 years for other CO_2 mitigation options—makes cofiring particularly attractive.

Introduction

The increased use of biomass energy has been variously proposed as a means to abate CO_2 emissions, to reduce our dependence on imported petroleum, to enhance rural development, to improve energy security, or more generally to advance sustainability by increasing the use of renewable resources. Biomass energy is the stored solar energy in unfossilized organic material such as energy crops or wood and agricultural residues. While biomass burning emits CO_2, use of biomass is considered carbon-neutral in the context of climate change if the fuel is sustainably harvested because the carbon in biomass is part of the active carbon cycle. Biomass currently supplies only about 3% of the U.S. primary energy but has the potential for meeting a significantly larger fraction of our energy needs (*1*, *2*).

Biomass is not economically competitive for electricity production in the current energy market except in niche applications where fuel costs are low or negative such as in integrated pulp and paper facilities. Biomass is generally more expensive than coal; the delivered cost of biomass typically ranges from $1 to $4 per GJ, whereas coal costs around $1 per GJ. In addition, existing biomass power plants, which are based on well-proven, low-technology, direct-combustion steam generation, are inefficient, with typical overall plant conversion efficiencies ranging from 16 to 25% on a higher heating value (HHV) basis (*3*, *4*) versus the 33–38% efficiency on a HHV basis of a typical coal-fired power plant (*5*). The lower conversion efficiencies of dedicated biomass power plants are due to the often high moisture content of biomass fuels, relatively small plant sizes, and lower steam temperatures. Much recent analysis of biomass energy has focused on the use of new technologies and purpose grown energy crops to produce electricity, hydrogen, or liquid fuels from biomass; while it is conceivable that such applications may eventually be important, their cost-effectiveness depends on dramatic improvements in the economics of biomass production and processing or dramatic changes in the economic value of the environmental, energy security, or rural-development attributes of biomass energy.

This paper analyzes cofiring of biomass fuels in existing coal-fired electric generating facilities using currently available agriculture and forest products residues. Cofiring replaces a fraction of the coal used in an existing power plant with biomass—typically 2–20% on an energy basis. Since power production from coal exceeds that from dedicated biomass facilities by almost 2 orders of magnitude (*6*), even relatively minor incorporation of biomass as a cofiring fuel will notably increase electricity production from biomass. Numerous commercial-scale demonstrations indicate that biomass–coal cofiring is technically feasible (*7*–*18*). By taking advantage of existing coal-fired power plants, cofiring can be implemented with low capital costs over a time frame of 1–2 years if sufficient biomass residues such as urban wood waste, mill, and agricultural residues are available. Cofiring uses biomass resources efficiently because large-scale coal-based power plants do not have the efficiency penalties associated with lower steam temperatures and small plant sizes of dedicated biomass systems, and cofiring has been shown to have minimal impact on the overall power plant conversion efficiency (*7*, *10*–*12*, *18*). Cofiring does not overcome the higher heating value efficiency penalty associated with fuel moisture, which is unavoidable unless the fuel is dried before firing. Cofiring can also address the often limited and cyclical nature of biomass fuel availability by appropriately adjusting the coal–biomass blend ratio.

Costs, however, are still a major barrier to increased biomass–coal cofiring. Cofiring significantly increases the efficiency of biomass utilization compared to existing dedicated biomass electricity production and does not have high capital costs and uncertainty of new advanced technologies. However, the high cost of biomass remains a problem; cofiring is only cost-competitive in niche applications where low-cost locally available biomass displaces high-cost coal (*3*, *8*, *19*, *20*).

Cofiring offers the possibility to reduce the net CO_2 emissions on an electrical output basis, to generate green energy with existing infrastructure, to provide a useful service to local industries that generate biomass residue, and to achieve modest reductions in SO_2 and potentially NO_x

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emissions. Therefore, policies that, for example, constrain carbon emissions or promote renewable energy may lead to more substantial levels of cofiring. A number of analyses have considered the effects of policies to promote renewable energy or to constrain carbon emissions on the economics of cofiring. Many of these only consider an individual plant and therefore provide little insight into national cofiring potential, which depends on both plant level economics and national fuel supply (*3*, *8*, *19*, *20*). Estimates of nationwide cofiring potential span a wide range from a 1.1 TWh (*21*) to 88 TWh (*22*) of electricity from biomass in the year 2010 (0.4−40% of projected coal-based power generation). The lower estimate is based on existing energy markets and current policies; the upper estimate assumes a national policy to reduce carbon emissions and relatively inexpensive energy crops. The wide array of assumptions combined with the relative lack of cost information makes it difficult to compare the different estimates and to make comparisons with other technologies.

The goal of this paper is to evaluate the potential and costs of biomass−coal cofiring in the United States. Section 2 reviews the technical feasibility of cofiring. In Section 3, a plant-level economic model is developed to estimate the cost of producing electricity from biomass−coal cofiring, and in Section 4, this model is combined with state-by-state estimates of biomass availability (*23*) to develop a supply curve for biomass−coal cofiring for the United States. This analysis accounts for uncertainties in a wide range of parameters such as biomass fuel costs, fuel variability, and capital costs. Section 5 assesses the cost-effectiveness of cofiring as a means to reduce emissions of CO_2, SO_x, and NO_x and to increase renewable energy utilization when compared to alternative means to achieve these benefits.

Technical Feasibility

Over the past decade numerous demonstrations have been performed using commercial coal-fired utility boilers in both the United States and Europe to evaluate the technical feasibility of biomass−coal cofiring (*7*−*18*). These demonstrations provide a wealth of information that spans the range of major coal combustion technologies (stoker-, pulverized-, and cyclone-fired systems), important fuel types (wood, straw, switchgrass, and a variety of coals), feeding configurations (biomass premixed with coal and separate feed), and cofiring levels (1−40% biomass on an energy basis). The results indicate that there are no major technical obstacles to implementing cofiring: cofiring can either benefit or hinder power plant operations, but the problems appear manageable with judicious choices of fuels and operating conditions. Here we briefly review state-of-knowledge of the impacts of biomass−coal cofiring on power plant operations; for more information see recent reviews (*7*, *24*, *25*).

The impacts of cofiring on plant operations arise from differences in fuel properties between biomass and coal. Coal-fired power plants are designed to operate on a fuel with a given set of properties; fuel properties outside of the design range can adversely impact boiler performance. Jenkins et al. (*26*) compares biomass and coal properties; critical differences include the inorganic composition, the fibrous nature of biomass, moisture content, energy density, and volatile content.

Cofiring can create fuel-feeding challenges because coal processing and delivery systems are not designed to handle fibrous biomass fuels with their low energy density and high moisture content. For low levels of cofiring the biomass can often be premixed with the coal and delivered to the boiler using the existing coal feeding system (*3*, *7*, *24*). The exact level of cofiring that can be achieved by this approach depends on the excess feeding capacity at a particular power plant and is typically a few percent biomass by energy at full load. Once this limit is reached, higher levels of cofiring cannot be achieved without reducing the capacity of the power plant (*12*). To achieve higher levels of cofiring a dedicated biomass preparation and feeding system is required; cofiring levels as high as 40% biomass by energy with no loss in capacity have been demonstrated using separate feeding systems (*17*).

Cofiring can reduce boiler efficiency and therefore overall plant fuel-to-electricity conversion efficiencies. Reported reductions are roughly a 0.5% loss in boiler efficiency for every 10% biomass input on a mass basis (*7*, *10*, *11*, *18*). However, several studies report no change in boiler efficiency at low levels of cofiring (*9*, *12*). The reductions in boiler efficiency while cofiring appears largely due to the often higher moisture levels of the biomass fuel compared to the coal and not due to a changes in boiler operations or the conversion efficiency of the coal. In fact, higher efficiencies have been reported for situations when cofiring a dry biomass with a wet coal (*9*, *10*). The efficiency penalty associated with fuel moisture cannot be avoided unless the biomass fuel is dried before firing.

Unburned carbon is a concern when cofiring because biomass fuels cannot be economically processed to the same sizes as pulverized coal particles; for example, commercial-scale cofiring demonstrations typically prepare biomass fuels such that the particles pass through a 6.4 mm mesh—approximately 200 times larger than pulverized coal particles. Modeling and pilot-scale testing indicate that these large particles are unlikely to burnout completely in a utility boiler (*27*) but that the very high volatile matter content of biomass results in high conversion efficiencies for even large biomass particles. Many demonstrations report no significant increases in unburned carbon levels (*7*, *9*, *10*, *13*, *28*), and that reductions in boiler efficiency due to unburned carbon appear to be manageable with proper fuel preparation and firing conditions (*18*).

Ash deposition (slagging and fouling) frequently plays a dominant role in the operation of power generation systems that operate on coal, biomass, and other ash-forming fuels. Ash deposits form from fly ash, inorganic vapors, and some gas species that deposit or react on boiler surfaces through a variety of mechanisms. Commercial scale cofiring demonstrations indicate that cofiring coal with clean wood wastes does not create ash deposition problems (*7*); clean wood residues are excellent fuels with low ash and alkali levels (*26*). Agricultural residues such as straw and other herbaceous materials are important biomass resources that often have high alkali and chlorine levels creating deposition concerns; for example, straw-fired boilers often experience severe slagging, fouling, and corrosion problems (*29*, *30*). Long-term commercial scale tests indicate that although coal-straw cofiring can cause some ash related problems including increased deposition and corrosion, the problems appeared to be manageable for up to a 20% straw share (by energy) (*13*, *15*, *16*, *28*). Cofiring straw with coal may also reduce some of the problems associated with corrosion and deposition compared to combustion of straw alone (*16*, *31*).

Cofiring reduces SO_x emissions because biomass fuels contain little or no sulfur (*26*); in fact, reductions in SO_x emissions are often greater than simple dilution because of reactions between the sulfur from the coal and alkali and alkaline species from the biomass which form sulfates that are collected in the particulate control system (*14*, *28*). The majority of demonstrations report modest reductions in NO_x emissions (*7*, *11*, *14*, *17*), but a few report no change (*18*, *28*). It is generally believed that cofiring reduces NO_x, but the underlying mechanism is not completely understood. NO_x reductions due to cofiring are often attributed to the low fuel-nitrogen levels of biomass fuels and to changes of the stoichiometry in the near-burner region of the boiler caused

TABLE 1. Parameters Used in Cost Model[g]

parameter	min	mode	max	ref
Economic				
utilization (%)		65		
interest rate (%)		10		
economic life (yrs)		10		
capital cost for cofeeding (\$/kW biomass)[a]	40	60	100	(*3*, *8*)
capital cost for separate feed (\$/kW biomass)[a]	150	200	300	(*3*, *8*)
nonfuel O&M for coal (c/kWhe)		0.4		(*5*)
biomass nonfuel O&M multiplier[b]	1.05	variable	1.15	(*3*, *8*)
sulfur emissions cost (\$/tSO_2)		175		
NO_x emissions cost (\$/tNO_x)	750	1500	3000	
Biomass				
oxygen content (wt %, dry)		41		(*36*)
carbon content (wt %, dry)		48		(*36*)
hydrogen content (wt %, dry)	5.4	6	7.3	(*36*)
sulfur content (wt %, dry)	0.02	0.07	0.15	(*36*)
moisture content (wt %)	10	30	50	(*36*)
heating value (HHV, MJ/kg, dry)	16.7	19.3	20.9	(*36*)
Coal				
plant efficiency (net, HHV, %)		34		(*5*)
cost (\$/GJ)		1.15		(*39*)
heating value (HHV, MJ/kg, dry)		23.5		(*39*)
sulfur content (wt %, dry)	0.5	0.9	3	(*39*)
NO_x emissions rate (lbs NO_x/$MBTU_{th}$)[c]	0.15		0.42	(*35*)
National Supply Curves				
coal cost, sulfur, carbon, and heating value		state specific		(*39*)
urban waste HHV (MJ/kg, dry basis)[d]		19.9		(*36*)
mill waste HHV (MJ/kg, dry basis)[d]		19.2		(*36*)
forest residue HHV (MJ/kg, dry basis)[d]		19.6		(*36*)
agricultural residue HHV (MJ/kg, dry basis)[d]		17.7		(*36*)
biomass cost[e]	−50%	variable	50%	(*23*)
capital cost for cofire (\$/kW biomass)[f]	variable	variable	300	(*3*, *8*)

[a] Model assumes that biomass can be cofed with coal at cofiring rates lower than 2% biomass on an energy basis. Higher biomass cofiring require a separate feed. [b] The factor by which nonfuel O&M costs for biomass exceed those for coal. The mode of the premium multiplier varies linearly with biomass thermal input between the minimum and maximum values, which correspond to a 2% and 20% cofiring rate, respectively. [c] No mode value given because a uniform probability distribution was used. [d] Averages of a large number of samples reported in EPRI biomass fuels database (*36*). [e] The modal values are taken from state-specific biomass supply curves developed by Walsh et al. (*23*). The min/max values are ±50% of the mode. [f] The modal value is linearly dependent on the state-specific cofire rate, eq 4, across the range of \$50/kW to \$150/kW. The minimum value is linearly dependent on the state-specific cofire rate across the range of \$60/kW to \$200/kW. [g] Except as noted, the columns min, mode, and max define a triangular distribution used for the Monte Carlo simulations. Parameters for which only a mode value is listed are treated deterministically by the model.

by the rapid release of the large volatile content of the biomass fuel. A critical issue is how the biomass and coal are introduced into the boiler (*32, 33*); for example, use of biomass as a reburn fuel can reduce NO_x emissions by 60% or more (*33*). Reburning is a combustion modification that reduces NO_x by injecting a fuel such as biomass downstream of the primary coal combustion zone (*33*). The reburn fuel (biomass in the case of cofiring) acts as a reducing agent for the NO_x formed in the primary combustion zone.

Cofiring biomass with coal may impact a power plant's ability to sell fly ash for concrete manufacture. The current ASTM standard (ASTM C 618) specifies that only coal ash meeting certain composition specifications can be used cement manufacture. However, there is no technical basis for limiting fly ash reuse to only coal ash; fly ash from cofiring is suitable for cement manufacture as long as it meets the meets the necessary composition specifications. Efforts are underway to make the ASTM standard more technically based which will allow suitable fly ash from coal−biomass cofiring to be used in cement manufacture.

Plant-Level Economics

The economics of cofiring depend largely on biomass fuel costs, which vary from near zero or even negative cost for biomass waste streams, to projections above 100 dollars per ton (\$/t) for dedicated energy crops. We describe a simple model of the economics of cofiring that predicts electricity and pollutant mitigation costs and explicitly accounts for uncertainty and variability in a wide range of parameters such as fuel costs, fuel properties, and capital costs. In the following section the model is combined with national biomass availability and coal consumption data to assess nationwide economics of pollutant mitigation using cofiring.

The cost of electricity (COE) is calculated as the energy-weighted average of the costs of electricity from biomass and from coal

$$\mathrm{COE}(f) = f(C_B + \mathrm{VOM}_B + F_B/\eta_B) + (1 - f)(\mathrm{VOM}_C + F_C/\eta_C) \quad (1)$$

where *f* is the fraction of electricity output from biomass and the subscripts "B" and "C" refer to biomass and coal, respectively. The model considers three cost components, each evaluated on a per unit electricity output basis: *C* is the capital charge; VOM is nonfuel variable operations and maintenance costs; and F/η is the fuel cost (*F* is cost of fuel in energy units and η is the net plant conversion efficiency). As indicated by the subscripts, different values for these parameters are used for coal and biomass. Although cofire fraction is often defined on an energy input basis, we compute costs using the biomass cofire fraction, *f*, on an electricity output basis to avoid the confounding effects of differential fuel conversion efficiencies on mitigation cost calculations.

Table 1 summarizes the input parameters used for the calculations. The baseline coal-fired power plant is assumed to have no outstanding capital costs. The model defines two levels of capital costs for cofiring biomass depending on the cofire rate (Table 1). The model assumes that low levels of cofire (up to 2% biomass by energy) can be achieved by cofeeding the biomass through the existing coal handling system; higher levels of cofire (greater than 2% biomass by energy) require a separate feeding system.

Nonfuel operation and maintenance (O&M) costs for coal combustion (Table 1) are based on U.S. averages (*5*). The fixed costs are incorporated into the calculations by assuming an annual plant utilization of 0.65, approximately the national average for coal-fired power plants (*5*). The specific O&M costs for biomass (VOM_B) are somewhat higher than those for coal (*3, 8*) and are estimated by adding a premium to coal O&M on a thermal energy basis. This premium ranges between 5% and 15% of the coal nonfuel O&M depending on cofire rate, with higher premiums associated with higher cofire rates (Table 1).

The model defines different net (fuel-to-electricity) conversion efficiencies for coal and biomass in order to accurately account for the impact of cofiring on power plant operations. We assume that the net conversion efficiency of coal to electricity is constant at 34% (HHV), which is the average value for plants built after 1950 (*5*). To estimate the conversion efficiency of the biomass to electricity, we calculate a higher heating value efficiency penalty due to the moisture content of the biomass fuel using the ASME Heat Loss method for calculating boiler efficiencies (*34*). This penalty is unavoidable unless the fuel is dried before firing. The method requires coal and biomass composition data; we also assume 20% excess air, 150 °C exhaust temperature, 1.5% losses due to unburned combustibles for both the biomass and the coal, and 1.5% minor losses (e.g., moisture in air) which are typical values for these parameters. This approach predicts the reductions in boiler efficiency observed in commercial cofiring demonstrations within ±0.5% (*9−11, 18*). The efficiency penalty due to fuel moisture is substantial for fuels with high moisture content; for example, the conversion efficiency of biomass that contains 50% moisture by mass to electricity is roughly 30% (HHV) versus the 34% (HHV) for coal. Note that even with the efficiency penalty due to high moisture content the overall conversion efficiency of biomass to electricity when cofiring is still significantly higher than the 16−25% efficiency (HHV) of existing dedicated biomass power plants (*3, 4*). The model does not account for changes in net plant efficiency due to changes in parasitic load when cofiring, which are expected to be small.

Biomass cofiring yields joint reductions in CO_2, SO_x, and NO_x emissions. Cofiring reduces SO_x emissions because of the lower sulfur levels in biomass compared to coal. If FS is the fuel energy specific sulfur content (e.g., kgS/GJ), then the emissions per unit output, ES(*f*), is computed as follows.

$$\mathrm{ES}(f) = f\frac{\mathrm{FS_B}}{\eta_\mathrm{B}} + (1 - f)\frac{\mathrm{FS_C}}{\eta_\mathrm{C}} \tag{2}$$

Reductions in SO_x emissions are based on coal and biomass sulfur content distributions that are representative of the U.S. supply (Table 1). We do not account for any reductions beyond dilution.

The CO_2 emissions per unit electrical output, EC(*f*), are computed using an identical formula to eq 2 except that the energy specific sulfur content (FS) is replaced with the energy specific carbon content. Displacement of coal with biomass results in a net reduction in carbon emissions from a climate change perspective because biomass carbon is in the active carbon cycle and therefore does not accumulate in the atmosphere if the biomass is used sustainably. Reductions in CO_2 emissions are based on the U.S. average coal carbon content and assume the carbon content for biomass is zero.

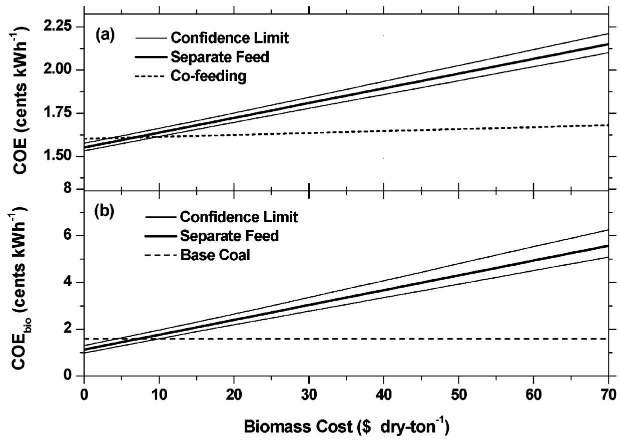

FIGURE 1. Cost of electricity as a function of biomass price: (a) overall plant level cost (coal and biomass) and (b) net cost of electricity from biomass, which equals $C_B + VOM_B + F/\eta_B$ from eq 1. The separate and cofeeding curves correspond to cofiring rates of 15% and 2%, respectively. The calculations are based on the U.S.-average coal and power plant characteristics defined by the mode values listed under the subheading "coal" in Table 1. The 5% and 95% confidence limits are shown for the separate feed case and are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The cost of electricity from the base coal plant is 1.6 cents/kWh.

In practice, fossil energy resources equivalent to less than 5% of the energy content of the biomass are typically consumed in its cultivation and processing (*3*).

The effects of cofiring on NO_x emissions are much more difficult to specify than its effects on SO_x or CO_2 emissions because of the complexity of NO_x formation in coal boilers. A large number of demonstrations report modest NO_x reductions when cofiring (*7, 11, 14, 17*); for this analysis NO_x emissions per unit electrical output, EN(*f*), are computed assuming a linear reduction in NO_x emissions with biomass energy input. This level of reduction is consistent with the findings of many cofiring demonstrations (*7*). A wide range is used for the baseline coal plant NO_x emission rate to account for variability in NO_x reductions when cofiring (Table 1). This range, 0.15−0.42 lbs $NO_x/MBTU_{th}$, spans the emission rate from a low-NO_x boiler to the current U.S.-fleet-average boiler (*35*).

The cost of mitigating emissions is computed by dividing the change in cost of electricity by the change in emission rates. For SO_x, the cost of mitigation (COM) is

$$\mathrm{COM} = \frac{\mathrm{COE}(f) - \mathrm{COE}(0)}{\mathrm{ES}(0) - \mathrm{ES}(f)} \tag{3}$$

Similar equations are used to calculate the cost of mitigation of CO_2 and NO_x emissions.

Figures 1 and 2 present the costs of electricity and pollutant mitigation from cofiring as a function of biomass price. Figure 1a shows the overall cost of electricity produced; Figure 1b shows the cost of the electricity produced from biomass, which equals $C_B + VOM_B + F/\eta_B$ from eq 1. The curves in Figures 1 and 2 are based on a typical U.S. coal-fired power plant burning average U.S. coal, as specified by the mode values listed under the subheading "coal" in Table 1. The confidence limits (5% and 95%) are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The distributions reflect the range of possible values for each parameter. For example, the distributions of biomass properties listed in Table 1 are calculated from the analyses of almost 300 different wood and agricultural residues samples

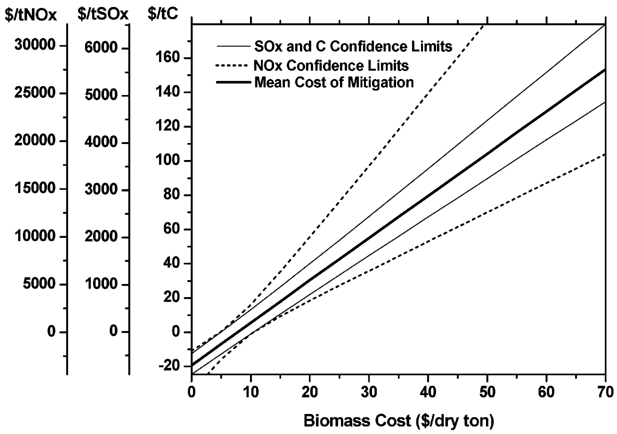

FIGURE 2. Cost of mitigation of carbon, sulfur dioxide, and oxides of nitrogen as a function of biomass price assuming cofiring using a separate feeding system and a cofiring rate of 15%. The curves are based on U.S.-average coal and power plant characteristics defined by the mode values listed under the subheading "coal" in Table 1. The 5% and 95% confidence limits are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1.

(*36*). The distributions in capital costs for cofiring reflect the range of reported costs in the literature.

The calculations of electricity and mitigation costs as a function of biomass price illustrate several important points. First, the variation in these costs across the range of reasonable biomass costs (0−70 $/t) is much greater than the range between the confidence limits, which underscores the critical importance of biomass fuel cost in cofiring economics. Second, biomass must be available at low cost for cofiring to produce electricity at the same price as the base coal plant. Figure 1b indicates that the cost of electricity from biomass is comparable to that from coal at a biomass price of around 7 $/t; the cost of biomass must be lower than this breakeven price in order for cofiring to produce electricity at a cost lower than a typical coal plant burning average U.S. coal.

The curves in Figures 1 and 2 do not account for any economic benefit for reductions in SO_2 and NO_x emissions due to cofiring. Including these credits by adding, for example, the cost of sulfur permits to the cost of electricity, COE, such that COE becomes COE + ES × Permit_Price, improves the economics of cofiring. A similar correction can made for NO_x. Accounting for these credits can change the breakeven price for biomass can be as high as 20 $/t depending on the power plant sulfur and NO_x emissions and the price of emission credits.

Pollutant mitigation costs as a function of biomass price are shown in Figure 2. Although cofiring reduces SO_2 and NO_x emissions, these reductions are not cost competitive with existing technologies except at low biomass prices. (Since the markets for these pollutants are reasonably well developed, permit prices are a plausible measure of the marginal cost of emissions control.) Figure 2 indicates that biomass must be available at a price of roughly 10 $/t for cofiring to provide reductions in SO_2 that are comparable to the current market price of roughly 175 $/tSO_2 for emissions credits. This value, 10 $/t, can also be viewed as the breakeven price at which biomass must be available in order for cofiring to produce electricity at the same cost as a typical coal power plant burning average U.S. coal and paying a price of 175 $/tSO_2 for sulfur emissions. For the case of NO_x emissions, biomass must be available at a price of 12−17 $/t to provide NO_x reductions that are comparable to the current market price for emissions credits of 2000−4000 $/tNO_2. In addition, cofiring at the modest levels considered here will likely only result in modest NO_x and SO_x emissions, which will likely not be large enough to avoid using other control strategies to meet recently required reductions in NO_x emissions (*37*) or the SO_x emission constraints imposed by Title IV of the Clean Air Act Amendments of 1990.

Figure 2 shows that cofiring can reduce carbon emissions by displacing coal for prices between −20 and 150 $/tC depending on the cost of biomass. While the cost of controlling CO_2 emissions is more uncertain than for criteria pollutants (because there is far less real-world experience), the cost of mitigating carbon emissions by cofiring are comparable with other technologies for abating CO_2 emissions from electricity generation and is discussed in detail in the section Policy Implications and Discussion.

The analysis shown in Figures 1 and 2 is based on an U.S.-average power plant burning U.S.-average coal in order to emphasize that the cost of cofiring in a specific plant operating with known coal quality is relatively certain, the confidence intervals are narrow, at a given cost of biomass. Varying coal properties such as coal cost, heating value, or sulfur content can alter the plant level economics by shifting the curves shown in Figures 1 and 2 and by changing the breakeven price for biomass to make cofiring cost competitive with the coal. This breakeven price is most sensitive to coal cost—plants burning higher priced coal have a higher price breakeven price for biomass. Coal sulfur has a more modest influence on the breakeven point. The economics of cofiring are most attractive for a power plant with high NO_x emissions operating on high cost, high sulfur coal—in this scenario the breakeven price of biomass approaches 20 $/t versus the 7 $/t for the average plant burning average coal shown in Figure 1. Alternatively, cofiring in a plant with inexpensive, low sulfur coal will result in a breakeven price much less than 7 $/ton. Other studies have examined in more detail the different combination of factors that influence the economics of cofiring at the plant level (*3*, *8*, *19*, *20*). In our calculation of the national supply curves, we account for the effects of variations in coal cost and coal quality on cofiring economics by using state-level averages for these parameters.

The range of breakeven prices for biomass discussed here (7−20 $/t) are consistent with previously published plant level economic analyses (*3*, *8*, *19*, *20*). The cost of biomass in existing markets or the expected price of energy crops provides a useful benchmark for evaluating the cost curves shown in Figures 1 and 2. For example, California produces a relatively large amount of biomass electricity and therefore has a reasonably well developed fuel market. During the 1990s biomass prices in California ranged between 35 and 55 $/t (*38*) much higher than the breakeven price for cofiring, which underscores the fact that cofiring is not generally cost competitive in existing energy markets.

National-Scale Economics

National supply curves for electricity generation and carbon mitigation are estimated by combining the cofiring cost model with biomass fuel availability and electric sector coal consumption data at the state level and then aggregating the results at the national level. This approach uses state-level averages to account for the effects of variations in parameters such as coal cost and coal quality on national cofiring economics.

Walsh et al. (*23*) provides state-specific biomass fuel supply curves at delivered costs of 20−50 $/t for several classes of materials including forest residues, mill residues, agricultural residues, and urban wood wastes. The cost estimates behind these supply curves include harvest, collection, and transportation to the power plant and account for a reasonable profit margin for suppliers. Transportation costs assume a haul distance of 50 miles to the power plant. For this analysis we only consider the cofiring potential using wood and agricultural residue data reported by Walsh et al. (*23*). Cofiring with wood is a natural first step toward implementing cofiring because it poses few technical challenges; agricultural residues are considered separately because they pose more significant technical challenges than wood but represent a significant fraction of the available biomass fuel. We do not consider the potential of cofiring with energy crops because their near-term economic viability is not clear.

State-average cofire rates on an electricity output basis are defined as a function of biomass price

$$f(F_B) = \frac{E_B(F_B)/\eta_B}{E_C/\eta_C} \tag{4}$$

where $f(F_B)$ is the state specific cofire rate at biomass price "F_B"; E_B (F_B) is the biomass energy (HHV) available within the state at biomass fuel price "F_B"; and E_C is the coal energy (HHV) consumed for power generation within the state (using year 2000 data). The biomass energy available in each state is calculated from the supply curves from Walsh et al. (*23*) and the higher heating values listed in Table 1. State-level coal consumption data are reported by the Department of Energy (*39*). Net coal-to-electricity conversion efficiencies (η_C) are assumed to be 34% HHV in all states. State-average biomass-to-electricity conversion efficiencies, η_B, are estimated by calculating a biomass fuel moisture efficiency penalty as described above using state-average coal property data (*39*) and the biomass fuel property distributions listed in Table 1. State-average cofire rates are limited to a maximum of 20%, which results in relatively low biomass prices in states with excess supply and limits the national cofire rate as regional imbalances in biomass supply and coal capacity result in stranded biomass resources. National-average cofire rates are estimated at each biomass fuel price as the average of the state-average rates weighted by the fraction of national coal consumption within each state.

State-average electricity and mitigation costs are computed for each price in the biomass supply curves using eqs 1−3 with the state-average cofire rates, conversion efficiencies, and coal properties. National-average electricity and mitigation costs are calculated for each price in the biomass supply curves as the average of the state-average costs weighted by the fraction of national cofiring within each state. For example, the national average cost of biomass electricity is

$$\mathrm{COE_B}(F_B) = \sum \frac{\mathrm{COE}_{B,i}(F_B) \times f_i(F_B) \times E_{C,i}}{f_N(F_B) \times E_{C,N}} \tag{5}$$

where $\mathrm{COE_B}$ (F_B) is the national-average cost of biomass electricity from cofire at biomass cost "F_B"; $f_i(F_B)$ and $f_N(F_B)$ are the *i*th state-average and national cofire rate at biomass cost "F_B", respectively; and $E_{C,i}$ and $E_{C,N}$ are the *i*th state and national coal consumption for power production, respectively. Monte Carlo simulation is used to evaluate the 90% confidence intervals of national-average electricity and mitigation costs for each biomass price in the biomass supply curves given uncertainty in fuel costs, capital costs, and O&M costs and the variability of biomass fuel properties represented by the distribution parameters in Table 1.

As illustrated by the results in Figure 1, fuel cost is a critical parameter for determining cofiring costs. A large uncertainty, ±50%, is assigned to the biomass prices because the absence of widespread biofuel markets makes estimates of biomass cost and availability, such as those by Walsh et al. (*23*), highly uncertain. The systematic methodology of the survey provides a level of consistency in the estimates but leads to a correlated price uncertainty across states (i.e. if the cost estimates for a specific resource subcategory are underestimated, then the fuel costs in all states will likely be higher than expected). In addition, biomass fuel prices are likely to be highly variable, dominated by local market conditions, as high transportation costs will require a substantial price differential to induce trade between local or regional markets.

The supply curves of Walsh et al. (*23*) were compared to other published fuel surveys (*19*, *40*−*42*) as a consistency check; however, such comparisons are difficult because many surveys report national estimates without spatial resolution and residue availability for a specific region and/or do not provide any cost information. The survey by Walsh et al. (*23*) is unique in that it provides biomass supply curves at the state level. In general, comparisons among different surveys indicates broad consistency in the estimates of the total available resources indicating that amount of available biomass residues estimated by Walsh et al. (*23*) is reasonable. There is inconsistency in the estimates of delivered costs among the surveys, with the costs from Walsh et al. (*23*) being generally higher and therefore more conservative. Reference lists were compared to ensure that the different surveys were based on different primary sources.

The spatial distribution of biomass resources is a critical issue for this analysis because transportation costs limit the range over which biomass resources can be economically utilized (*43*). A state-level analysis cannot account for problems created by the distribution of biomass residues and coal consumption within each state. Ideally, one would use surveys of residue availability around each power plant (*43*); however, data are not currently available for such a nationwide analysis of cofiring potential. Transportation costs for biomass range from 5 to 10 $/t per 50 miles (*23*, *43*). The survey by Walsh et al. (*23*) includes the cost of transportation up to 50 miles, the large uncertainty assigned to biomass price will likely account for any additional transportation costs.

Several interesting trends are apparent when comparing the state-level biomass residue and coal consumption data shown in Figure 3. Major coal consuming states fall into three general categories: states with substantial wood residues, states with substantial agricultural residues, and states with little biomass residues. The Southeast falls in the first category with substantial coal consumption and large amounts of wood residues. Midwestern states, such as Illinois, Indiana, and Ohio, have little wood residues but large amounts of agricultural residues. The final category include states such as Kentucky, West Virginia, and Pennsylvania which have high coal consumption but relatively little biomass residues available for cofiring. Although there are significant biomass residues located in the western United States, this material cannot be used for cofiring due to the lack of coal-fired power plants in the region and the prohibitively high cost of transporting biomass.

National supply curves for biomass electricity and carbon mitigation from cofiring are shown in Figure 4. Results are shown for two scenarios: one that considers only wood residues (urban waste wood, mill waste, and forestry residues) and a second that considers both wood and agricultural residues. Figure 4a shows costs without accounting for credit from cofire NO_x and SO_x emissions reductions; Figure 4b includes this accounting by adding, for example, the cost of sulfur permits to the cost of electricity, COE, such that COE becomes COE + ES × Permit_Price. A similar correction is made for NO_x. A large range of conservative values is used for NO_x permit price and baseline (Table 1).

The results indicate that cofiring can substantially increase our supply of biomass electricity at a reasonable cost; for example, the mean estimate of the Monte Carlo simulation is that cofiring wood residues could supply 15 TWh annual of electricity at a cost of 4 cents/kWh, which increases to almost 25 TWh (0.7% of current electric generation) if

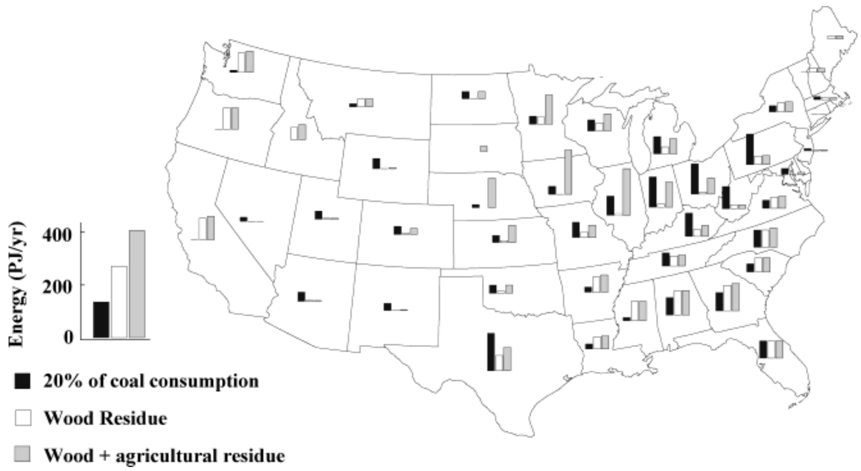

FIGURE 3. State-level coal consumption and biomass availability data. The height of the black bars indicates 20% of coal consumption; the height of the white bars indicate available wood residue at \$40/t; and the height of the gray bars indicate wood and agricultural residues available at \$40/t. All quantities are on an energy basis. Comparing the height of the bars within a state indicates the availability of biomass residues for cofiring. For example, if the white or gray bars are the same height as the black bar, then there is sufficient residues within that state to displace 20% of the coal on an energy input basis; if the white or gray bars are less than the black bar, then there is inadequate biomass residues to cofire at a level of 20%; if the height of the white or gray bars is greater than the black bar, then there are more than enough residues available to cofire at a level of 20%. Comparing the heights of white and gray bars provides an indication of the relative amounts of wood versus agricultural residues within a state. Coal consumption data are from ref *39*; biomass data are from ref *23*.

agricultural residues are included in the analysis. Including the value of NO_x and SO_x credits in the calculation (Figure 4b) reduces the carbon mitigation cost by roughly 10 \$/tC but has minimal effect on the relative cost of biomass electricity. Cofiring appears to be a cost-effective technology for providing modest reductions in carbon emissions from coal-fired power plants; for example, a 5% reduction in national coal-fired power plant CO_2 emission, ~100 million metric tons of CO_2 (Mt CO_2), could be achieved at a cost of less than 30 \$/tC (Figure 4b).

Only limited comparisons can be made between our assessment and previous analyses of national cofiring potential because of the relative lack of cost information provided by the previous analyses. The predictions shown in Figure 4a are very close to an EPRI estimate that 2.3% of coal generated electricity could be offset at a net cost of 22.60 \$/tC (*20*). The DOE predicts that a renewable portfolio standard requiring 10% of electricity production from renewable sources would result in almost 10 TWh of electricity generated annually by cofiring (*44*). No cost information is provided by the DOE analysis so it is difficult to compare results. Figure 4 indicates that this level of cofiring is feasible using available wood residues at a relatively low cost of approximately 2.7 cents/kWh for the electricity from biomass and that higher levels of cofiring are feasible at a reasonable cost compared to other renewables suggesting that the DOE analysis likely underestimates the potential for cofiring. The DOE analysis caps cofiring at 5% biomass share by energy at an individual coal-fired power plant and at a level of 4% of coal consumption on a national basis, which, as previously discussed, appear to be unnecessarily restrictive constraints. Conversely, our estimates of cofiring potential are substantially less than those of a DOE working group that consider the potential of cofiring under conditions of carbon constraints (*22*). They estimate that cofiring could generate 58−88 TWh of electricity in 2010 with dedicated energy crops produced at \$32/t providing a substantial fraction of the biomass feedstock. These costs may be optimistic given current projections of energy crop production costs; Walsh et al. (*23*) predicts that switchgrass becomes economically viable at a price of 40 \$/t with substantial production only feasible at prices around 55 \$/t (*45*).

Policy Implications and Discussion

Although biomass−coal cofiring is generally not cost competitive in the current energy market, cofiring offers benefits that could result in more widespread cofiring under certain policy scenarios. We judge that the most important application of cofiring is as a way to achieve significant near-term reductions in CO_2 emissions. Its potential as a CO_2 mitigation strategy depends on its competitiveness with other control strategies. If costs of NO_x and SO_x emissions are accounted for, cofiring could reduce CO_2 emissions from the coal-fired electricity generation sector by 10% (about 3% of U.S. emissions) at a carbon price of about 50 \$/tC (Figure 4b), significantly smaller than the near-term cost of roughly 100 \$/tC or larger for reducing emissions by replacing existing capacity with nonfossil sources such as wind or nuclear or by building new plants or retrofitting existing coal-fired plants to capture and store CO_2 (*46*−*48*). Moreover, cofiring can achieve significant reductions in CO_2 emissions in the very near term (less than 5 years).

One might assume that biomass cofiring would have limited utility in mitigating CO_2 emissions because coal-fired generation might be rapidly eliminated from the electric market as the stringency of constraints on CO_2 emissions increases (*44*). If the price of natural gas remains low and stable, then it seems likely that a CO_2 constraint would rapidly eliminate coal-fired capacity because substantial emissions abatement could be achieved by switching from coal to natural gas and "carbon-ordered dispatch" (*22*, *46*). However, if natural gas prices rise significantly, the future of coal under CO_2 constraints is less certain. First, with limited use of energy crops—as opposed to the residues considered in our analysis—biomass cofiring can plausibly achieve significantly larger decreases in electric sector CO_2 emissions. Second, as we describe in the Technical Feasibility Section, there is little doubt that biomass-to-coal cofire ratios could be increased beyond the maximum of 20% considered here; higher ratios might permit an economically efficient strategy in which some coal-fired generation is retired, while the remainder uses a gradually increasing fraction of biomass for generation. Finally, if CO_2 capture and sequestration (CCS) technologies are viable (*48*, *49*), then coal-based CCS may well become the base-load generating technology of choice,

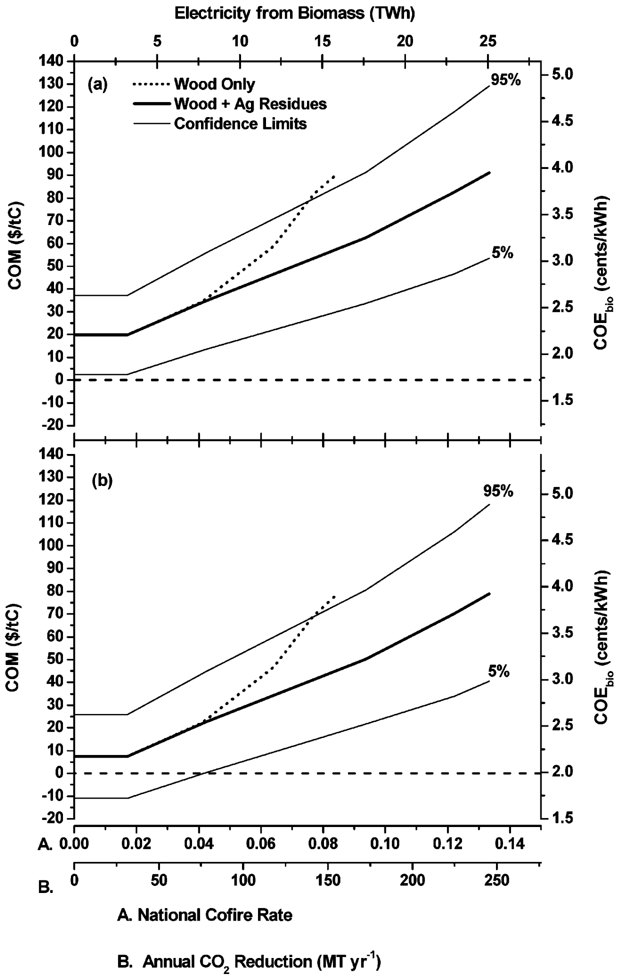

FIGURE 4. National supply curve for the cost of carbon mitigation (COM) and the cost of biomass electricity from cofire as a function of the national cofire rate. Part (a) does not include the credit for reduction of sulfur and nitrogen emissions due to cofiring; these credits are included in part (b). The confidence limits (5% and 95%) apply to the wood plus agricultural residues case and are from Monte Carlo simulation using the distributions for capital costs, O&M costs, and biomass fuel properties listed in Table 1. The dashed horizontal line indicates a cost of mitigation of 0 $/tC.

particularly if gas prices rise above about 3.5 $/GJ (*46*). Biomass is compatible with CCS; using these technologies on power plants firing biomass or biomass−coal mixtures can achieve electricity generation with negative net CO_2 emissions (*50*, *51*).

This analysis also suggests that cofiring is a very cost-effective use of biomass. The low capital costs and relatively high efficiency of cofiring make it more competitive than many proposed advanced biomass technologies. Another use of biomass is to produce liquid fuels such as ethanol that can be substituted for, or more practically blended with, gasoline to reduce CO_2 emissions. Most current ethanol production is from corn at very high cost (including subsidies) making it very uneconomic as a means of CO_2 mitigation. There is great interest in the possibility of producing ethanol from lignocellulosic biomass such as residues and energy crops, the same biomass sources that could be used for cofiring. It is therefore reasonable to compare the cost of reducing CO_2 emissions accomplished by cofiring and biomass ethanol production. Realistic projections of the cost of cellulosic ethanol suggest that the near-term costs will exceed 1 $/gallon which is equivalent of a carbon mitigation cost of order 200 $/tC (at a petroleum price of 25 $/bbl) (*52*, *53*). It therefore appears that cofiring is a far more cost-effective method of reducing CO_2 emissions than liquid fuel production from a given biomass supply. On the other hand, bioethanol offers energy-security benefits not considered here.

While there is yet no national commitment to reduce CO_2 emissions, policies such as federal tax credits or state-level initiatives exist to promote renewable energy production (*54*). Many of these programs, however, explicitly rule out biomass cofiring. This appears to be due, in part, to a desire to promote high technology solutions such as wind and solar energy and, perhaps, to a desire to prevent coal-fired generators from taking advantage of an environmental tax credit. Figure 4 indicates that cofiring could double U.S. current non-hydro renewable electricity production at a cost of less than 4 cents/kWh using wood residues; higher levels are achievable if one also considers agricultural residues. Four cents/kWh can be viewed as a best-case cost of new wind capacity, the fastest growing renewable technology (*55*, *56*). Therefore, unless specifically excluded, cofiring will likely be an important response to policy tools to encourage renewable energy production such as renewable portfolio standards or tax credits.

The most economically efficient methods for achieving carbon reductions are policies that set an even price on carbon emissions using either taxes or tradable permits. Such mechanisms are particularly appropriate in the electric sector where there already are successful trading systems for SO_2 and NO_x. Under an economically efficient emissions constraint, we expect that biomass cofiring would be one of the first technologies to be widely implemented because of its low cost of mitigation, low capital costs, and technological maturity. It is important that policies to reduce CO_2 emissions do not arbitrarily exclude cofiring from the solution mix.

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