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Article

A Path Forward for Low Carbon Power from Biomass

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Abstract: The two major pathways for energy utilization from biomass are conversion to a liquid fuel (*i.e.*, biofuels) or conversion to electricity (*i.e.*, biopower). In the United States (US), biomass policy has focused on biofuels. However, this paper will investigate three options for biopower: low co-firing (co-firing scenarios refer to combusting a given percentage of biomass with coal) (5%–10% biomass), medium co-firing (15%–20% biomass), and dedicated biomass firing (100% biomass). We analyze the economic and greenhouse gas (GHG) emissions impact of each of these options, with and without CO_2 capture and storage (CCS). Our analysis shows that in the absence of land use change emissions, all biomass co-combustion scenarios result in a decrease in GHG emissions over coal generation alone. The two biggest barriers to biopower are concerns about carbon neutrality of biomass fuels and the high cost compared to today's electricity prices. This paper recommends two policy actions. First, the need to define sustainability criteria and initiate a certification process so that biomass providers have a fixed set of guidelines to determine whether their feedstocks qualify as renewable energy sources. Second, the need for a consistent, predictable policy that provides the economic incentives to make biopower economically attractive.

Keywords: biomass; CCS; renewable energy; bioenergy with carbon capture and sequestration (BECCS); negative emissions; co-firing

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1. Introduction

Energy can be produced from biomass by one of two routes: conversion to a liquid fuel generally for use in vehicles or through thermochemical processes that generate electricity. In the United States (US), renewable energy from biomass has long consisted of biofuels. Nonetheless, biomass is also being converted to power worldwide via thermochemical processes. Despite the potential for decreased carbon emissions from biomass to power, biomass only made up 1.4% of US power generation in 2012 [1].

Biofuel generation has benefited significantly from a national push for energy independence meant to limit the nation's dependence on imported fuels that support regimes hostile to the US. The Renewable Fuel Standard (RFS), created under the Energy Policy Act of 2005, mandated the volume of renewable fuel production in the US on an annual basis. In 2007, the Energy Independence and Security Act (EISA) expanded the RFS and mandated the current biofuel target of 36 billion gallons of renewable fuel to be produced in 2022. Although the EISA also mandated that new renewable fuels have lower GHG emissions than their petroleum counterparts, the law is still focused on a pathway towards energy independence [2]. Because biomass generated electric power would displace domestic energy sources (such as coal and natural gas), there is no energy security motivation for promoting its adoption.

Although legislation promoting the use and generation of renewable, low carbon power has mostly existed at the state level, the Environmental Protection Agency (EPA) recently proposed rules that would limit CO_2 emissions from both new and existing power plants. In 2007, the US Supreme Court ruled that GHGs met the definition of a pollutant as defined in the Clean Air Act (CAA) in the case Massachusetts *v*. EPA. This case eventually led to a rule proposed on 13 April 2012 and updated on 20 September 2013, entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units". The rule limits CO_2 emissions from new fossil fuel power plants to 1100 lb CO_2 per MWh gross for plants larger than 25 MW. This limit is slightly above the emissions of a natural gas fired plant and a little more than half the emissions from coal-fired power generation [3]. Because this rule applies only to fossil fuel plants, it does not apply to a plant firing biomass alone or one that co-fires biomass with less than 250 million BTU per hour of fossil fuels (amounting to about 22 MW of fossil fueled power) [4].

On 2 June 2014, the EPA proposed a rule governing CO_2 emissions from existing power plants, entitled "Carbon Pollution Emission Guidelines for Stationary Sources: Electric Utility Generating Units" [5]. The rule calls for reducing CO_2 emissions from existing power plants by 30% from 2005 levels by 2030. It is up to each state (or group of states) to develop their own implementation plan. While neither "the use of biomass-derived fuels at affected Electric Generating Units (EGUs)", nor the "retrofitting affected EGUs with partial CCS (CO_2 capture and storage)" were used to set the proposed goals, "the agency anticipates that some states may be interested in using these approaches in their state plans" [5]. This rule has been the focus of intense controversy, so it is unclear exactly what the final rule will look like. However, if the rule is implemented, it appears it will provide modest incentives for biomass use.

Despite the low penetration and few policy incentives for biomass conversion to power in the US electric mix, there are numerous benefits to using biomass to generate renewable energy. Unlike biofuels, electricity can readily be generated from a variety of non-food biomass sources including waste streams and cellulosic feedstocks that can avoid the food *versus* fuel problem. Biomass conversion to power can also be undertaken in existing power plants with retrofits, meaning that the generating capacity exists to produce dispatchable, renewable power from biomass. In addition, if biomass is properly sourced it can be a carbon neutral feedstock. Prior work concluded that in the absence of land use change emissions, converting three biomass feedstocks (farmed trees, switchgrass, and forest residue) to power in the US results in a decrease in Greenhouse Gas (GHG—including CO_2) emissions at co-firing ratios ranging from 5% to 20% biomass with coal [3]. If CCS is added to a plant burning biomass (termed BECCS), there is also the potential for negative carbon emissions, *i.e.*, the biomass removes CO_2 from the air, which can then be captured during combustion at a power plant and stored in geologic formations [6–9]. The recently released Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (AR5) on mitigation (Working Group III) highlighted BECCS as a critical technology for stabilization of CO_2 atmospheric concentrations at acceptable levels [10].

This paper will cover three options for biomass combustion for power generation (low co-firing (5%–10% biomass), medium co-firing (15%–20% biomass), and dedicated biomass firing (100% biomass) defined on a percent heating value basis), the effect on GHG emissions of each of these options, and their economics with and without CCS. The results will quantify the potential benefits of using biomass for power generation and will provide the basis for the suggested policy actions.

2. Methodology

For this analysis, we reference previous work [3] that developed a model quantifying the fuel cycle GHG emissions of power generation from both dedicated biomass power plants and coal power plants with biomass co-firing. The model is a modification of the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. The GREET model is a lifecycle analysis tool for conventional and renewable transportation fuels. The GREET model has the capability to analyze energy requirements and emissions from cellulosic biomass sourced fuels and others. This model provides useful information in terms of the energy consumption, greenhouse gas emissions, and criteria emissions for the lifecycle of these biomass sources from cultivation to conversion to a biofuel or electricity. Fuel characteristics such as emissions from combustion and heating value (a function of moisture content) were given in the GREET model [11]. Another important characteristic, ash content, was obtained from literature sources [12–14].

The GREET model was modified to calculate the lifecycle GHG emissions from firing and co-firing various ratios of three kinds of biomass (farmed trees, switchgrass, and forest residues) with coal and to simulate the addition of carbon capture and sequestration (CCS). Lifecycle emissions calculated by the model include those from cultivation/mining, transportation and handling of biomass and coal fuels as well as combustion. Net emissions refer to the combination of lifecycle emissions with carbon dioxide taken up by biomass plants when they are regrown after harvest. Emissions from land use change are not included in the model [3]. The net GHG emission rate of our reference coal-fired power plant is 893 g CO_2 equivalent/kWh.

The addition of CCS decreases the carbon dioxide emitted after combustion of the biomass and also affects the conversion efficiency of the power plant. These effects of CCS on the function of a biomass fired and co-fired power plant are included in the model. We assume that CCS captures 90% of carbon dioxide emissions from the power plant. The amount of CO_2 in the flue gas before CCS is adjusted depending on the emissions rate from each coal firing and biomass co-firing scenario. Other than the change in flue gas composition, we consider CCS for a co-firing plant or biomass plant to be similar in cost and function to that of a coal power plant. See [3] for more details on the model construction and function.

Converting biomass to power in existing power plants can affect the operation of the plant. Moisture and impurities in biomass can result in corrosion, fouling, and decreased plant efficiency when biomass is fired at high ratios with coal. To avoid severe operational effects on the boiler and to properly store the biomass feedstock, an existing coal plant will need retrofits [12,13]. The level of retrofits needed depends on the amount of biomass the plant is to fire, state of the plant, and the quality of the biomass feedstock. For this study, we assume that a coal plant is 40% efficient [15] and that with the addition of biomass co-firing plant efficiency decreases to the values given in Table 1. More information on how the change of efficiency for biomass co-firing was determined is given in [3].

Table 1. Power plant efficiency at the different co-firing ratios used in this study [3].

% Co-Fire (Heat Input Basis)	Plant Efficiency
0%	40.0%
5%	39.5%
10%	39.2%
15%	39.1%
20%	39.0%
100%	30.0%

Plants that have converted to dedicated biomass combustion note a decrease in efficiency to 25%–30% [12,16,17]. In this analysis, it was assumed that the converted plant would have an efficiency of 30% on a higher heating value basis which is a drop of about 10 percentage points from the coal only efficiency. For a coal power plant, the additional drop in efficiency due to the addition of CCS is 10.75 percentage points over the original efficiency. We assume that a co-firing plant with CCS will also experience a 10.75 percentage point drop in efficiency over the values given in Table 1.

Using the results of the biomass to power model and other literature sourced data, the levelized cost of electricity for all biomass firing and co-firing permutations modeled was calculated. For this analysis, the levelized cost of electricity (LCOE) for a coal power plant retrofitted to co-fire biomass is compared to the levelized cost of electricity from an existing coal plant. This comparison is used to evaluate how the price of electricity will compare between a coal plant that does not retrofit to co-fire biomass and one that does undergo retrofits. The LCOE calculated excludes the sunk capital costs of the coal plant being retrofitted to fire biomass [3]. The LCOE equation is shown as Equation (1):

$$\mathrm{LCOE} = \frac{\mathrm{CCF(TOC)} + \mathrm{FOM}}{8760\mathrm{(CF)(MW)}} + \mathrm{VOM} \quad (1)$$

The variables in Equation (1) are:

CCF = Capital charge factor, which annualizes capital costs over the project lifetime. The value used here for the CCF is 0.15/yr.

TOC = Total overnight capital, which consists of the capital costs outlined in Table 2. For this analysis, an additional 10% of the total capital costs are added to account for contingencies.

FOM = Fixed operating costs for the plant (values used for calculating this term are given in Table 2).

CF = Capacity factor of the plant, here 0.8 is used.
VOM = Variable O&M costs, values used to calculate this term are given in Table 2; fuel costs are also included in VOM.
MW = Net output of the power plant.

In this analysis, the price of carbon is included as a variable operating cost. To understand how carbon price legislation would affect the economics of a coal and biomass plant, the LCOE including a price on carbon ranging from \$0/tonne CO_2 equivalent to \$165/tonne CO_2 equivalent is used.

The costs used for economic calculations throughout this document are summarized in Table 2 including capital, fixed operating, and variable operating costs for different co-firing methods.

Table 2. Costs used for levelized cost of electricity (LCOE) and other economic calculations throughout this work [3].

Feedstock	Price in \$/dry tonne
Short Rotation Woody Crops	\$98
Forest Residues	\$86
Switchgrass	\$87
Uinta Basin coal	\$45
Ash	in \$/tonne ash
Coal Ash credit	\$2.2
Biomass/coal ash cost	\$11
CO_2 handling	in \$/tonne CO_2
CO_2 transport	\$6.5
CO_2 storage	\$6.5
CCS material	in \$/kWh net
MEA costs	\$0.0003
Fixed O&M	Price in \$/kW yr
Fixed O&M for coal plant	\$104
Additional O&M for biomass firing	\$12
Additional O&M for CCS	\$52
Capital Costs	Price in \$/kW_e *
Low co-firing	\$150
Medium co-firing (in \$/kWth)	\$139
Retrofitting for 100% biomass	\$640
Additional CCS cost	\$888

* Capital costs are given per kW_e biomass capacity of the plant (unless otherwise noted) before loss of generation due to CCS or biomass co-firing. Additional CCS cost is per kW_e total plant capacity.

3. Results

This paper will divide the biomass firing options into three categories depending on the ratio of biomass that is co-fired with coal: low co-firing (5%–10% biomass), medium co-firing (15%–20% biomass), and dedicated biomass firing (100% biomass).

3.1. Low Co-Firing

For low co-firing ratios of 5%–10%, minimal retrofits to the plant are needed and the biomass can be burned via direct co-firing [16,18]. Direct co-firing refers to the burning of biomass with coal in the same boiler. The exact co-firing ratio for which direct co-firing can be used may vary, depending on the quality of the biomass feedstock. Co-firing biomass with coal at low ratios also results in minor negative effects on the efficiency and therefore output of the plant. Nonetheless, combusting biomass at lower ratios means that the effect on GHG emissions will also be relatively low.

Figure 1 summarizes the expected change in emissions for a plant operating with low co-firing of biomass (that is, GHG emissions from fuel combustion in the power plant and the lifecycle of the biomass and coal fuel before combustion as well as CO_2 uptake from biomass growth). Emissions for low co-firing decrease 3.5%–8% as compared to coal only.

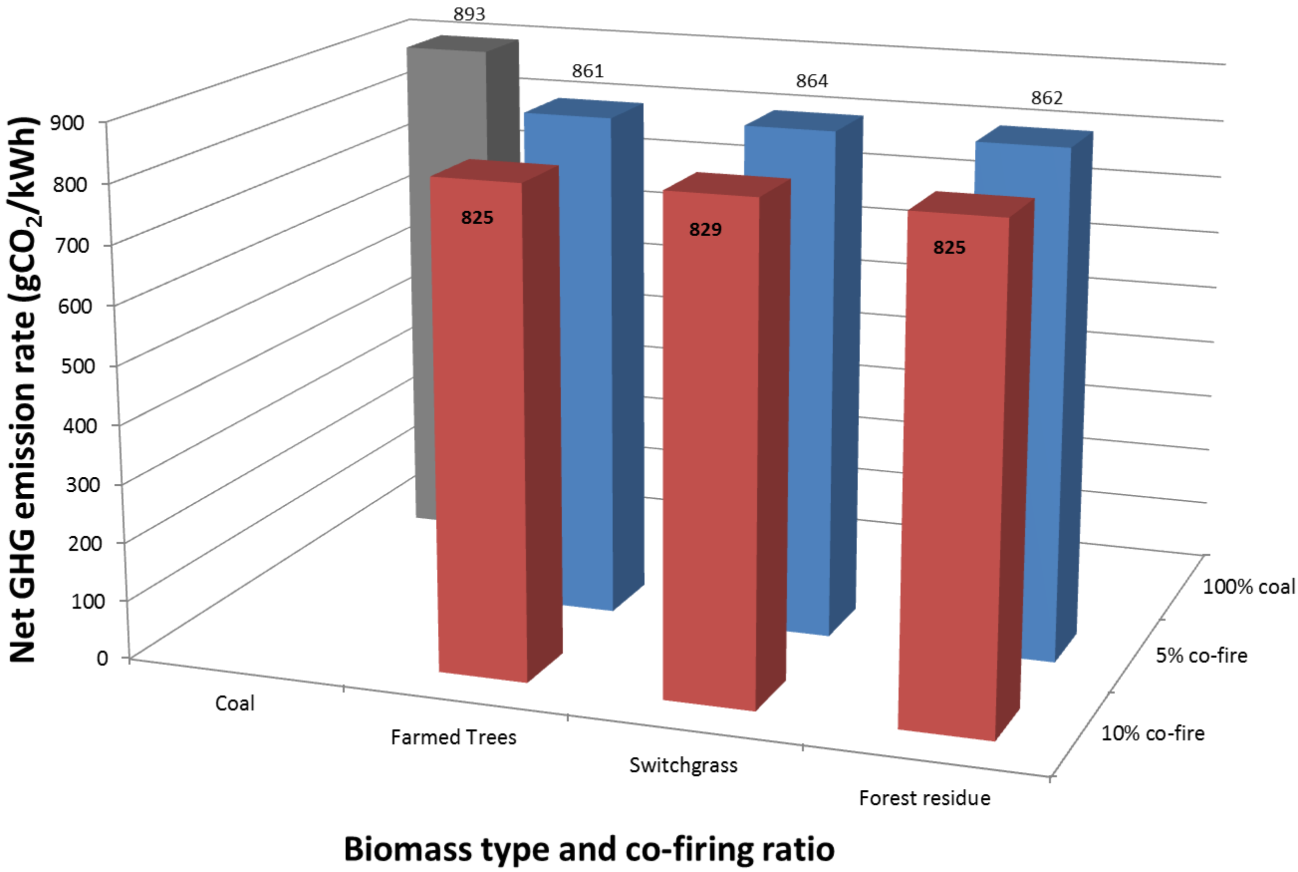

Figure 1. Net lifecycle emissions from low co-firing in an existing coal-fired power plant.

As a measure of the cost of implementing low rates of co-firing at existing coal plants, the LCOE was calculated for all scenarios modeled as described in the methodology section. The LCOE of co-firing was then compared with the LCOE of firing coal alone including the variable price for carbon emissions. When the LCOE of co-firing equaled the LCOE for coal alone, then the co-firing option becomes economically favorable compared to coal alone. These intersection points are summarized in Table 3.

Table 3. Cost of carbon at which co-firing low rates of biomass becomes economical compared to coal alone firing.

Co-firing ratio	Price of Carbon in $/tonne CO_2 Equivalent		
	Farmed Trees	Switchgrass	Forest Residue
5%	$76	$84	$84
10%	$63	$68	$69

The values in Table 3 indicate that for co-firing biomass at 5%–10% to be economical the cost of carbon must be approximately $63–$84 per tonne CO_2 equivalent. The price of carbon at which 10% biomass co-firing becomes economical is less than that for 5% biomass because both scenarios incur a capital cost, but the 10% biomass case results in lower GHG emissions and efficiency loss than the 5% scenario. In this analysis, the same capital cost per kW_e was used for the 5% and 10% co-firing scenario. It is assumed that for 5%–10% co-firing the capital cost of retrofits is $150 per kW_e of biomass capacity [19]. Nonetheless, it is possible that a power plant may be able to burn biomass without any retrofits at co-firing ratios of 5%.

Because co-firing low ratios of biomass requires minimal to no retrofits, this scenario works well for opportunistic biomass co-firing when cheap feedstock is available. Co-firing at low biomass ratios is the most common way biomass is utilized at US power plants [20].

3.2. Medium Co-Firing

Medium co-firing refers to co-firing at ratios of 15%–20% biomass with coal. Co-firing higher ratios of biomass requires more extensive retrofits and may require the construction of a second, smaller boiler that combusts biomass separately from coal. The use of a dedicated biomass boiler avoids the negative effects that higher co-firing ratios can have on the plant's boiler such as slagging and corrosion.

When co-firing at medium ratios the drop in efficiency and capacity of the power plant will be more than for low co-firing ratios as indicated in Table 1. Likewise, the decrease in GHG emissions will also be greater. As compared to coal firing alone, medium co-firing ratios result in a decrease in emissions of 11.5%–17%. Emission values for medium co-firing are summarized in Figure 2.

Table 4 summarizes the cost of carbon at which co-firing would become economically advantageous compared to coal alone.

In order for co-firing medium quantities of biomass with coal to be economical compared to firing coal alone, the price of carbon emissions must be in the range of $57–$67 per tonne. The carbon price required to make a medium level of co-firing economically competitive with coal alone is less than for the low co-firing option because higher retrofit costs are offset by greater decreases in emissions compared to coal alone. Retrofitting a plant to co-fire medium amounts of biomass costs approximately $355 per kW electric of biomass capacity.

Medium co-firing ratios are economical at a lower price of carbon than the low co-firing scenario. Nonetheless, there is very little experience with co-firing 15%–20% biomass in existing coal plants in the US. Therefore, many of the operating and retrofit assumptions used in this analysis have a large uncertainty range and must be evaluated more thoroughly before implementation.

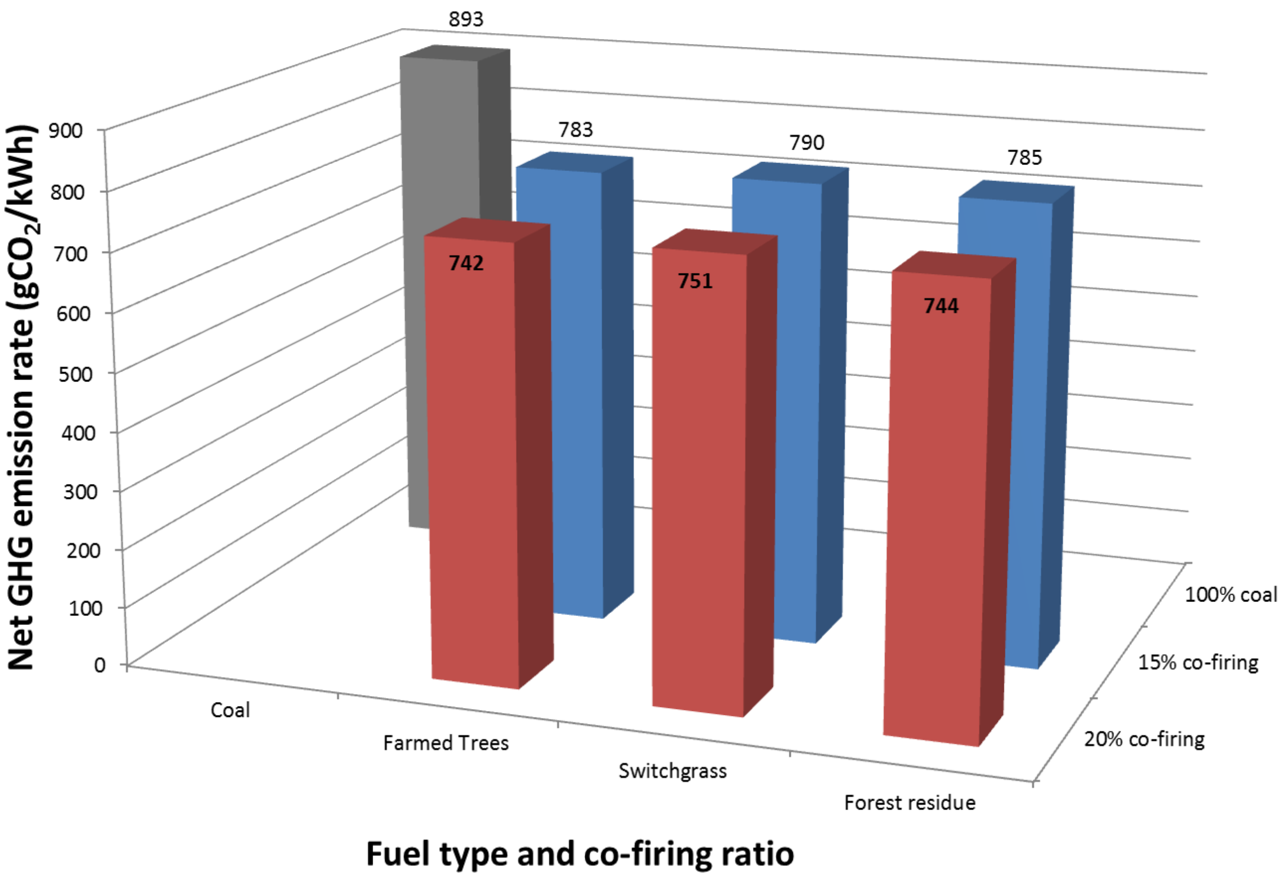

Figure 2. Net lifecycle emissions from medium co-firing in an existing coal-fired power plant.

Table 4. Cost of carbon at which co-firing medium rates of biomass becomes economical compared to coal alone firing.

Co-firing ratio	Price of Carbon in \$/tonne CO_2 Equivalent		
	Farmed Trees	Switchgrass	Forest Residue
15%	\$61	\$66	\$67
20%	\$57	\$62	\$63

3.3. Dedicated Biomass Firing

Dedicated biomass firing requires the existing coal plant to be retrofit to burn biomass alone. The extent of retrofits depends on the biomass quality and plant configuration. As noted in Table 1, we assume the efficiency of a dedicated biomass plant to be 30%. Nonetheless, substituting biomass for coal will result in a significant decrease in carbon emissions. Figure 3 summarizes the effect of dedicated biomass firing on the emission rate from power generation.

As expected, dedicated biomass firing results in the largest decrease in GHG emissions as compared to coal. Emissions decrease by 86%–93% as compared to coal firing alone, yet this scenario incurs a higher capital and operating cost than the other co-firing options. Table 5 summarizes the price of carbon required to make dedicated biomass firing economical compared to coal fired power.

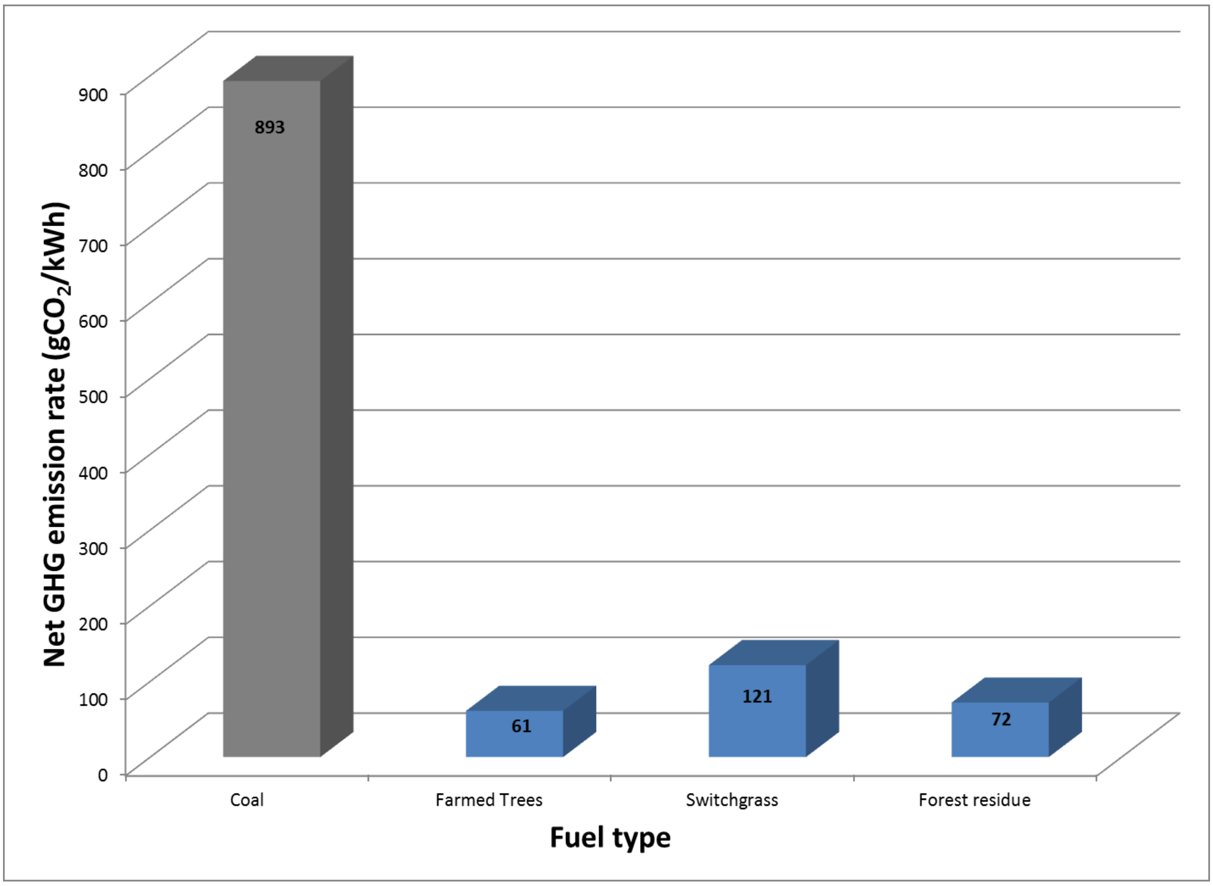

Figure 3. Net life-cycle emissions from dedicated biomass and coal firing.

Table 5. Price of carbon that would make dedicated biomass firing economical compared to coal alone firing.

Co-firing ratio	Price of Carbon in \$/tonne CO_2 Equivalent		
	Farmed Trees	Switchgrass	Forest Residue
100%	\$82	\$89	\$89

Table 5 shows that for dedicated biomass firing to be economically competitive with coal firing, the price of carbon must be between \$82 and \$89 per tonne. This is slightly higher than the co-firing cases, but the total GHG emissions reductions (see Figure 3) are much greater than the co-firing cases. Despite the emissions benefits, there is little experience with retrofits to enable a coal plant to fire biomass exclusively. A few dedicated biomass plant projects have been initiated in the US in response to state Renewable Portfolio Standards (RPS) [21–24], demonstrating that policies other than assigning a cost to carbon can be effective drivers of biomass to power technology.

3.4. Biomass Co-Firing with Carbon Capture

Another option analyzed was the addition of CCS to plants co-firing biomass in the three categories listed above. Because the carbon dioxide emitted from the burning of biomass was originally captured from the atmosphere during biomass growth, there is a potential for negative emissions if CO_2 in the flue gas from biomass combustion is captured and stored. Adding CCS to a power plant results in a drop in plant efficiency and capacity in addition to the drop described previously due to co-firing biomass.

Co-firing at high biomass ratios and dedicated biomass firing were the only scenarios that resulted in negative emissions of GHG's (a net capture of atmospheric CO_2). Table 6 shows a comparison of the GHG emission rate of co-firing with and without CCS.

Table 6. GHG life-cycle emission rate for biomass co-firing without CCS and with CCS.

Co-Firing Ratio	g CO_2 Equivalent Emissions/kWh					
	Farmed Trees	with CCS	Switchgrass	with CCS	Forest residue	with CCS
0%	893	143	893	143	893	143
5%	861	90	864	93	862	77
10%	825	34	829	41	826	9
15%	783	−22	790	−12	785	−60
20%	742	−79	751	−65	744	−130
100%	61	−1449	121	−1345	7.9	−1818

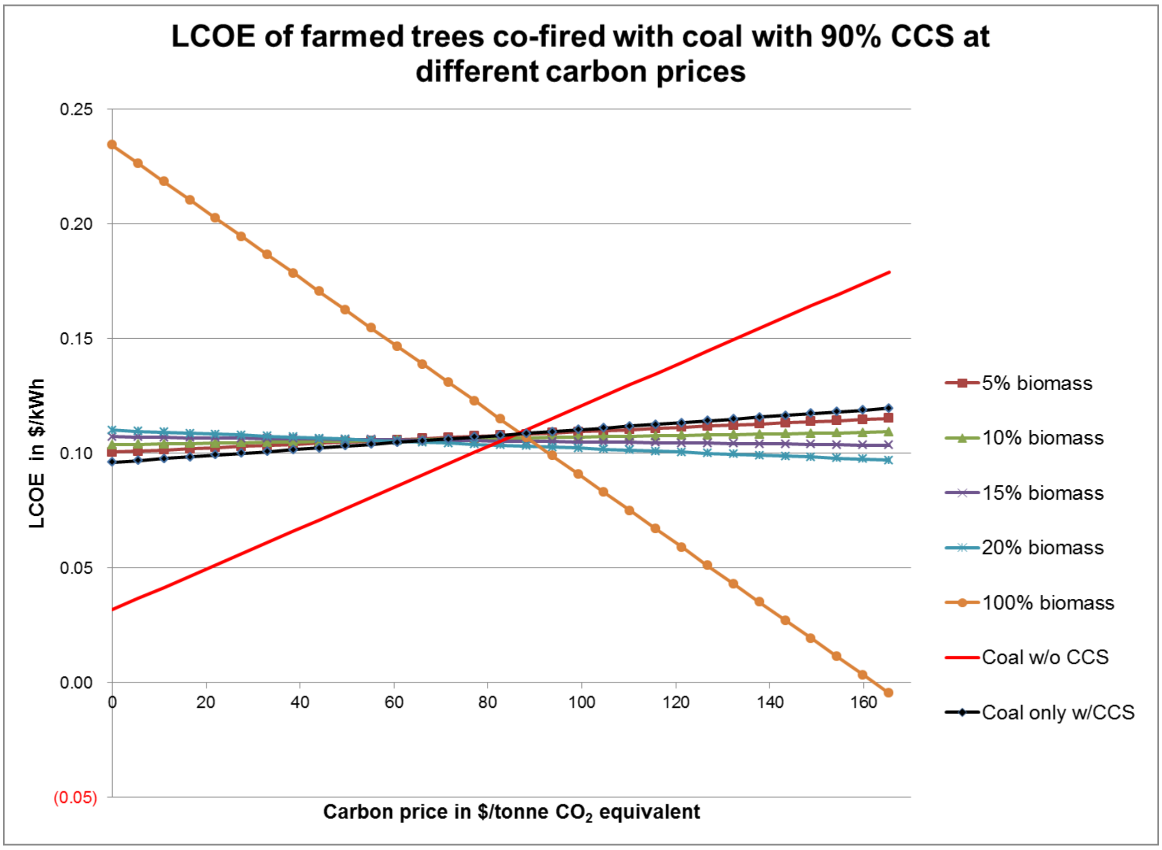

Figure 4. Plot of the LCOE for farmed tree co-firing with coal and dedicated co-firing with the addition of CCS.

The economic analysis of biomass co-firing with CCS shows that implementing these changes to an existing coal plant is far more expensive than implementing co-firing alone. The costs associated with adding CCS to the co-firing power plant are summarized in Table 2 and include CO_2 transport and storage. Figure 4 shows the LCOE as a function of carbon price for farmed tree co-firing with CCS and coal alone with and without CCS. For biomass co-firing with CCS to be economically favorable compared to coal without CCS, the price of carbon emissions must be greater than $78 per tonne CO_2 equivalent. The plots for switchgrass and forest residue show a similar trend as that in Figure 4.

Although biomass co-firing with CCS is much more expensive than co-firing alone, a high enough cost of carbon emissions would make such a scheme economically favorable, assuming a mechanism is in place to earn credits for negative emissions. Table 7 shows the price on carbon emissions at which biomass and coal power have the same LCOE.

As noted in Table 6, co-firing ratios equal to 15% and higher have negative emissions meaning that the LCOE of these co-firing ratios decreases as the cost of carbon increases. Therefore, these plants can make money in two ways, selling electricity and selling carbon credits. The higher the carbon price, the greater their profits will be.

Table 7. Price of carbon that would make biomass co-firing with CCS economic compared to coal without CCS.

Coal/Biomass Interception Points	Price of Carbon in \$/tonne CO_2 Equivalent		
Co-firing ratio	**Farmed Trees**	**Switchgrass**	**Forest Residue**
Coal only	$86	$86	$86
5%	$86	$86	$85
10%	$85	$85	$83
15%	$83	$84	$80
20%	$80	$83	$78
100%	$87	$92	$80

4. Discussion

The above sections show that co-firing biomass at low, medium, and dedicated biomass levels can lead to a decrease in GHG emissions. When CCS is added to the medium and dedicated biomass scenarios there is a potential for negative emissions. In this study, it was assumed that producing the biomass crops did not result in land use change emissions. The impact of land-use change is very dependent on the specific circumstances. In many cases, accounting for land-use changes can result in an increase of the carbon emissions associated with the biomass, but in some cases it can decrease. The potential for land use change emissions and their effect on the GHG balance of biomass fired power has raised concerns about whether biomass is a renewable power source [25]. Another concern is the difference in time scales over when emissions from biomass combustion are released (immediately) compared to when they are absorbed during plant regrowth (sometimes over decades) [25].

The main barrier for biomass to power facilities is the expense of adapting a power plant to co-fire biomass and purchasing fuel. Carbon prices required for biomass power to match the price of coal-fired power range from about \$60–90/tonne CO_2, depending on the level of biomass co-firing and the type of biomass feedstock [26].

Although the US does not assign a price to carbon on a national level, a few biomass to power plants are being encouraged through state level policies such as the Renewable Portfolio Standard (RPS) [21,22,24]. These standards require utilities to provide a certain percentage of electricity (generally in the range of 5%–20%) from renewable energy sources. Yet, the effectiveness of state level policies in promoting co-firing plants has been tempered by the concern over the environmental effects of continuing to fire some coal [27]. The acceptance of biomass firing and co-firing with coal as a renewable source of power varies from state to state, which makes biomass to power plants ineligible for the RPS standards in some states. Some states also have laws stipulating what biomass sources qualify as renewable [28]. These definitions also affect biomass power's acceptability in regional GHG trading schemes [29].

Given these barriers to biomass to power—concerns about carbon neutrality of biomass fuels and the higher cost of biomass power compared to coal power—this paper recommends two policy actions. First, policymakers should work with experts and stakeholders to define sustainability criteria and initiate a certification process so that biomass providers have a fixed set of guidelines to determine whether their feedstocks qualify as renewable energy sources. In addition, policymakers should establish policies at either a state or national level that recognize the benefits of producing power from biomass—whether through co-firing or dedicated firing—that meets the certification criteria. Although policy makers may be concerned about the prospect of emissions from continuing to burn coal, setting the policy stage for development of biomass conversion systems and of a sustainable biomass market is an important first step in capturing the GHG emission benefits of biomass to power.

Given that biomass energy sources are not necessarily beneficial to the environment, establishing sustainability guidelines for biomass to qualify as a renewable energy source is important to gain the public's confidence and support for biomass. By defining sustainability criteria and instituting a certification process, policy makers can design a system such that excessive land use change emissions or environmentally harmful harvesting methods do not outweigh the benefits of displacing fossil fuels with biomass for power generation. In addition, biomass certification can be designed to address the public's concerns over the temporal difference of emissions released to the atmosphere by combustion *versus* uptake of CO_2 by biomass regrowth. These standards, though, should be accepted for all state renewable energy laws in order to establish a nationwide market for biomass feedstocks. A nationwide market would drive down biomass prices and limit risk for power plant operators. Biomass as it is available today, dried or pelletized, may not be an ideal fuel for all power generation technologies. Nonetheless, through the continued development of biomass pre-processing technologies, such as torrefaction, these fuels will become easier to convert and have improved performance, which will drive the widespread use of low carbon biomass fuels.

The second component of biomass to power policy has to be a consistent, predictable policy that monetizes the benefits of biomass to power. Specifically, the policy must reward the use of biomass to lower GHG emissions from power production. One possibility is to put a price on GHG emissions. The economic analysis summarized above concludes that a carbon price in the range of $60–90 per tonne of CO_2 equivalent is required. In the near future, a carbon price in the US is highly unlikely. More realistic near-term policy drivers for biomass power are either renewable portfolio standards (RPS) or EPA's power plant rulemaking under the Clean Air Act.

For a RPS or other renewable energy requirement, such as Green Certificates as in Europe or Renewable Energy Certificates as in Australia, biomass to power need only be more economical than other renewable energy sources. Given the very high cost of some of these projects (e.g., Cape Wind project in Massachusetts), it is reasonable to assume that biomass power projects would be incentivized if they are made eligible for an RPS. Determining the economic threshold at which biomass to power is cheaper than solar, wind, or other renewable power sources depends on many situation specific variables (for example: the location in question, whether infrastructure is available to facilitate decentralized power generation, *etc.*), and must be evaluated for each project. Note that electricity from biomass is dispatchable, which makes it more valuable than intermittent electricity from wind and solar.

EPA's proposed rule for lowering GHG emissions from existing power plants in the US leaves open the biomass to power option. If it goes into effect, it would be up to the states to decide whether and under what conditions to allow for biomass power in their implementation plans. One should expect a varied landscape, just as we see with the RPSs of today.

The interest in and importance of negative GHG emissions is growing, as witnessed by the recent IPCC AR5. BECCS appears to be the best option to realize negative emissions at a reasonable scale. By implementing the two policy recommendations above, it would move the US much closer to making BECCS a reality.

5. Conclusions

To date, most policy efforts regarding the use of biomass for energy in the US have focused on manufacturing liquid fuels. This trend has been driven primarily by the desire for energy security. However, biomass can also play a significant role in the power sector. The primary driver here will be mitigation of GHG emissions. Furthermore, biomass for power generation can be combined with CCS to actually remove CO_2 from the atmosphere.

Biomass power can take several forms. Co-firing with coal up to about 20% biomass is feasible. Another option is to have 100% biomass power plants. Finally, any of these plants can add CCS. Low levels of co-firing are economically feasible today if cheap biomass feedstocks are available. However, for larger-scale use of biomass, policy drivers would need to be put in place. Carbon pricing would require a price greater than \$60/tonne CO_2. More likely policies in the near term include Renewable Portfolio Standards, as well as GHG emission limits on the power sector. These later policies would be implemented on the state level and the treatment of biomass could vary widely between the states.

All biomass is not equal. It is critical to look at its entire life-cycle and to include both direct and indirect land-use changes in calculating its potential to reduce GHG emissions. Some sort of certification procedure is required to allow biomass to power conversion to qualify as a climate mitigation technology and achieve the emissions benefits desired.

Finally, the potential for negative GHG emissions by combining biomass power with CCS is an extremely important option. According to the IPCC, it is the best option available for negative emissions. The call for negative emissions will only increase over time. A critical step on this path is to establish biomass power as a viable renewable energy source.

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Author Contributions

Amanda Cuellar conducted data analysis with the guidance and input of Howard Herzog. Both authors contributed jointly to the writing of the manuscript.

Conflicts of Interest

The authors declare no conflict of interest.

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