THE ENVIRONMENTAL BENEFITS OF COFIRING BIOMASS AND COAL

Margaret K. Mann, Pamela L. Spath
National Renewable Energy Laboratory
1617 Cole Blvd., Golden, CO 80401 USA

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ABSTRACT

The generation of electricity, and the consumption of energy in general, often result in adverse effects on the environment. Coal-fired power plants generate over half of the electricity used in the U.S., and therefore play a significant role in any discussion of energy and the environment. By cofiring biomass, currently-operating coal plants have an opportunity to reduce the impact they have, but to what degree, and with what trade-offs? A life cycle assessment (LCA) has been conducted on a coal-fired power system that cofires wood residue. The assessment was conducted in a cradle-to-grave manner to cover all processes necessary for the operation of the power plant, including raw material extraction, feed preparation, transportation, and waste disposal and recycling. Cofiring was found to significantly reduce the environmental footprint of the average coal-fired power plant. At rates of 5% and 15% by heat input, cofiring reduces greenhouse gas emissions on a CO_2-equivalent basis by 5.4% and 18.2%, respectively. Emissions of SO_2, NO_x, non-methane hydrocarbons, particulates, and carbon monoxide are also reduced with cofiring. Additionally, total system energy consumption is lowered by 3.5% and 12.4% for the 5% and 15% cofiring cases, respectively. Finally, resource consumption and solid waste generation were found to be much less for systems that cofire.

INTRODUCTION

There is no question that coal contributes enormously to the high standard of living made possible by easy access to electricity. However, along with its benefits, the chemical make-up of coal and the older technologies used at most operating coal-fired power plants create significant environmental impacts. In an effort to reduce the environmental impacts associated with electricity production, owners and operators of coal-fired power plants have considered adding biomass to their fuel mix. Biomass, either grown specifically to produce energy or that which is recovered from a residue stream, reduces the net greenhouse gases produced per unit of electricity generated. Additionally, because of its low sulfur content relative to coal, biomass can reduce power plant SO_2 emissions. Biomass also contains less ash than coal, thus decreasing the amount of solid waste generated. Likewise, because biomass is more volatile than coal and usually contains lower amounts of fuel-bound nitrogen, cofiring may result in lower NO_x emissions. Other impacts associated with producing and using coal, such as mining emissions and particulates generated during limestone production for flue gas scrubbing, will also be reduced.

In order to quantify the magnitude of the benefits offered by cofiring, a LCA was used to evaluate systems that cofire wood residue at 5% and 15% by heat input, compared to a baseline system firing only coal. More detail on this study can be found in Mann and Spath (2001). The methodology used in this study is consistent with that described by the ISO 14000 series of standards, particularly that which covers inventory analysis. In conducting a life cycle inventory, energy and raw material requirements, emissions, effluents, and solid waste are quantified for each process, from resource extraction to final product use and disposal. The system boundaries for this life cycle assessment include all operations required for the power plant to cofire biomass and coal. These include surface coal mining, construction material production, manufacturing of cofiring-related equipment, coal and biomass transportation, grid electricity production used in upstream processes, and the avoided operations of biomass mulching and landfilling. Avoided operations are those processes that would have taken place if the biomass had not been cofired with coal at the power plant. The emissions, resource consumption, and energy use that would have occurred if these operations had taken place are subtracted from the total inventory of the cofiring system.

SYSTEM DESCRIPTION

Table 1 lists the major specifications for the plant operation with and without cofiring. The no cofiring case represents a plant with the average emissions and efficiency of coal-fired power plants currently operating in the U.S. (Spath and Mann, 1999). Plant capacity is diminished slightly in the cofiring cases because of the efficiency losses that result from the biomass having a lower energy density and higher moisture content than coal. Based on data from various cofiring tests (EPRI, 1997a; Gold and Tillman, 1993; Hughes, 1997; Tillman and Prinzing, 1994; Tillman *et al*, 1997; Tillman *et al*, 1998; EPRI/DOE, 1997; NRBP, 1996) efficiency losses of 0.5 and 0.9 percentage points were assumed for the 5% and 15% cofiring cases, respectively.

Table 1: Coal -fired Power Plant Data

Design Parameter	No cofiring	15% cofiring	5% cofiring
Plant capacity (MW)	360	350	354
Average operating capacity factor	60%	60%	60%
Coal feed rate @ 100% operating capacity (Mg/day) (as-received basis)	3,872	3,291	3,679
Biomass feed rate @ 100% operating capacity (Mg/day) (as-received basis - 50% moisture)	0	1,498	499
Power plant efficiency	32%	31.1%	31.5%

The power plant, particularly the fuel handling, storage, and feeding systems, will require modest modifications in order to cofire biomass. An automated feeding system to supply biomass to the boiler is needed to allow continuous cofiring over a period of 24 hours. Additionally, equipment to receive and process the biomass is needed, but a biomass dryer may or may not be necessary depending on the boiler configuration and the acceptable level of derating. The amount of biomass that is required for 5% cofiring is probably small enough to be added to the coal feed conveyor, mitigating the need for a separate feed conveyor and feed port. However, the volume of biomass required at the 15% cofiring level will necessitate a separate feeding system, including a biomass injection port into the boiler. Equipment production, including acquisition of raw materials, was included in this LCA.

Power Plant Feedstock

The power plant is assumed to use Illinois No. 6 coal, excavated using surface mining from mines located in central Illinois. This coal has a heat of combustion of 28,661 kJ/kg (LHV, bone-dry basis), and is fired at 15.4 wt% moisture. The biomass used in this study is assumed to be wood residue, the nature of which varies greatly. Generally however, sources of biomass considered to be feasible for the type of cofiring projects examined here include clean urban waste wood, mill residue, biomass generated during timber stand improvements, some construction and demolition (C/D) residues, and industrial wood residues. The availability of such materials for power generation depends heavily upon location and the price that the operator is willing to pay. Wiltsee (1998) describes the amount of biomass residue available, plus the primary use and disposal methods, in 30 U.S. metropolitan areas. The U.S. Environmental Protection Agency (EPA) reports that 9,834,000 Mg of wood, excluding C/D waste, and 25,400,000 Mg of yard trimmings, were generated in the municipal waste stream in 1996. This represents 5.2% and 13.4% of the total amount of waste generated annually in the United States. Approximately 4.5% of the wood and 38.6% of the yard trimmings are recovered for further processing and use (U.S. EPA, 1998a). Thus, it is felt that significant quantities are still available for energy generation. The biomass for this analysis has a lower heating value of 18,295 kJ/kg (bone-dry basis), based on data from various wood cofiring tests conducted by the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE).

Avoided Operations

Because the biomass used at the power plant is not grown for the purpose of cofiring, a credit is not taken for the absorption of CO_2 during the growing cycle (see Mann and Spath, 1997). Rather, the emissions, resource consumption, and energy use that would have occurred during the normal routes of biomass disposal are avoided, and credited in the life cycle inventory. Using data from Wiltsee (1998), it was assumed that 46% of the cofired biomass would have been landfilled and 54% would have been mulched or converted to other short-lived products. In the case of mulch, it is likely that most decomposition occurs under aerobic conditions, although decomposition at the interior and bottom of mulch piles will be anaerobic. Additionally, chipping and mulching wood increase the surface area subject to degradation both by microorganisms and air oxidation. Pier and Kelly (1997) found that 20% of the gas coming from sawdust piles was methane; therefore, of the total carbon in the biomass, 13.9% ends up as methane. For this assessment, all of the mulch disposed of through normal routes was assumed to decompose, with 10% of the carbon going to methane and 90% to CO_2. To take into account differences in pile heights and decomposition conditions, the sensitivity analysis tested additional cases of 0%, 5%, and 15% conversion of the carbon to methane.

Unlike mulch, decomposition in landfills occurs under mostly anaerobic conditions, resulting in a gas that can be approximated as a mixture of 50% CO_2 and 50% CH_4. Because lignin is resistant to microbial degradation under anaerobic conditions (Ham *et al*, 1993; Tong *et al*, 1990; Bingemer and Crutzen, 1987; Micales and Skog, 1997), only non-lignin compounds (e.g., cellulose, hemicellulose, acetate, etc.) were assumed to be subject to decomposition in the landfill. The question of the extent to which these compounds decompose is difficult to answer, however. Based on several literature sources (see Mann and Spath, 2001), approximately 34.7% of the carbon in the landfilled biomass is assumed to decompose, while the remainder is assumed to be indefinitely stored. Some of the CH_4 that is produced in the landfill is oxidized by surface soil microbes and combusted in collection and recovery systems. Figure 1 summarizes the assumptions regarding the fate of the carbon in the biomass if it is not used for cofiring. As shown in Figure 1, the total CO_2 and methane avoided per 100 kg of biomass are 111.7 kg and 6.5 kg, respectively.

RESULTS

Air Emissions

The air emissions that combine to account for 99.9 wt% of those tracked in this analysis are shown in Table 2. Although the amount of N_2O being emitted from this system is very low, it has been included in this table because it is a powerful greenhouse gas. The vast majority of air emissions from the power plant are reduced through the practice of cofiring. The rates of reduction of some emissions are lower than the rate of cofiring because of the loss in power plant efficiency and because some emissions occur in producing and using the biomass. It is important to recognize that an average reduction in air emissions does not by itself, imply a similar reduction in the associated health and environmental impacts. As shown below, however, the typical power plant pollutants that are believed to have the most serious environmental and health consequences are substantially reduced.

Figure 1: Avoided fate of biomass

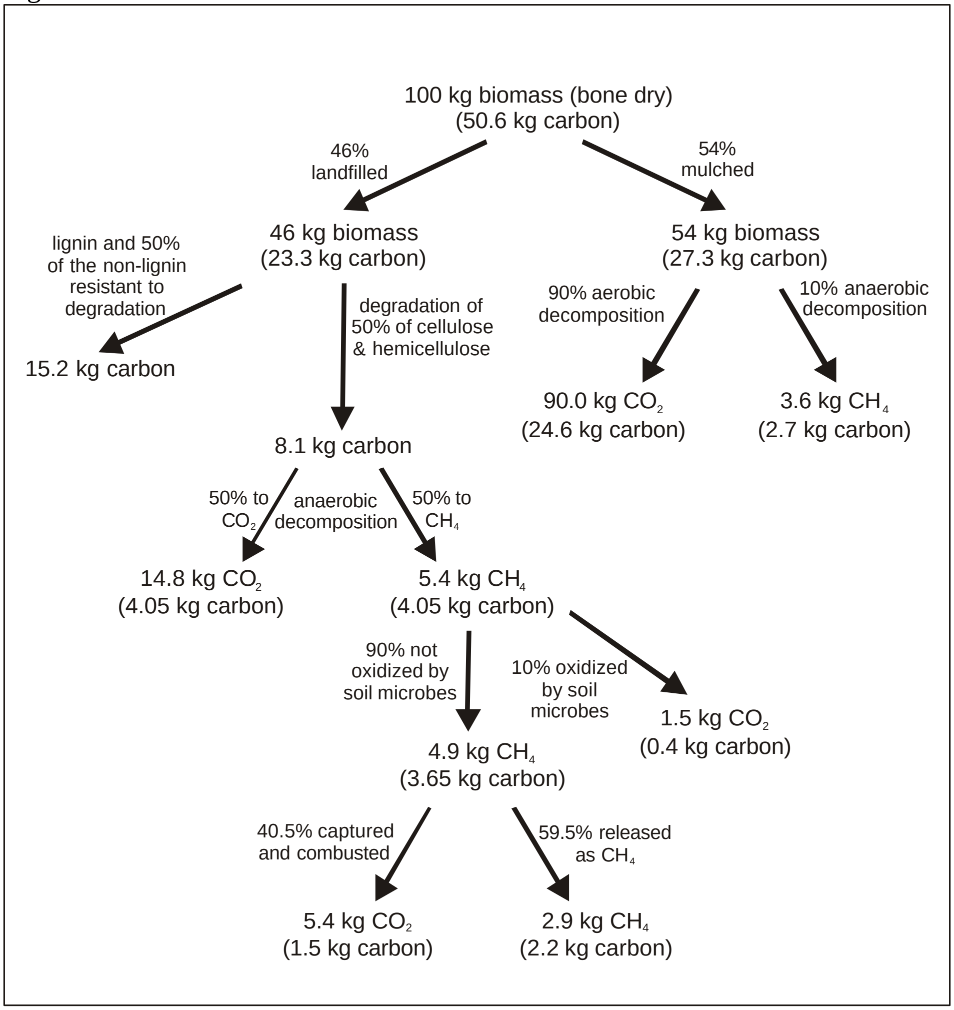


Table 2: Air Emissions

	15% Cofiring		5% Cofiring		No Cofiring
	Emissions (g/kWh)	% change from no cofiring	Emissions (g/kWh)	% change from no cofiring	Emissions (g/kWh)
Carbon dioxide	954	-6%	1,003	-2%	1,018
Carbon monoxide	0.2	-5%	0.3	-1%	0.3
Non-methane hydrocarbons	0.2	-11%	0.2	-4%	0.2
Methane	-5.0	-652%	-1.0	-214%	0.9
Nitrogen oxides (NO_x)	3.1	-8%	3.3	-2%	3.3
Nitrous oxide (N_2O)	0.0	-19%	0.0	-6%	0.0
Particulates	8.1	-12%	8.9	-3%	9.2
Sulfur oxides (as SO_2)	5.9	-12%	6.5	-3%	6.7

The amount of SO_2 produced decreases because of the lower sulfur content of the biomass feed compared to coal. Smaller quantities of sulfur in the feed also result in a reduction in the amount of lime and limestone required for flue gas cleanup. Because the majority of the system particulates are due to the production of these absorbants, overall system particulate emissions are reduced with cofiring. Actual reductions in both SO2 and particulates will depend on the quantity of sulfur in the coal being used and the amount of scrubbing that is practiced. Particulate emissions from the plant stack are not expected to be greatly affected with cofiring (NRBP, 1996). In this analysis, reductions in NO_x were assumed to be due solely to the lower amount of fuel-bound nitrogen in the biomass. This assumption was made to reflect the fact that site-specific details on boiler configuration and downstream NO_x reduction technology are not known. It is likely, however, that in real cofiring situations, higher fuel volatility will cause NO_x emissions to be even lower than assumed here (Tillman, 2000). During many of the cofiring tests conducted by EPRI, a measurable reduction in NO_x beyond a dilution effect was observed (EPRI, 1997a; EPRI, 1997b; Hughes, 1997). Using the equation presented in Tillman (2000), power plant NO_x may be reduced by as much as 26.4% and 9.8% for 15% and 5% cofiring rates, respectively.

Methane emissions become negative for the systems employing cofiring because of the avoided decomposition emissions. The methane released during surface mining operations is also reduced, but at a rate slightly lower than the rate of cofiring because of efficiency losses. In the 15% cofiring case, a 13% reduction in coal mine methane is realized. However, relative to the amount of mulch and landfill methane avoided, the impact of this reduction is small, equating to less than 2% of the methane that would have been released had the biomass been allowed to decompose.

Greenhouse Gas Emissions

Coal-fired power plants essentially have three opportunities to reduce their greenhouse gas emissions: efficiency improvements, CO_2 removal and sequestration, and biomass cofiring. Because existing plants cannot easily take advantage of new technologies that offer higher conversion efficiencies, and installation of CO_2 capture equipment is costly and impractical, biomass cofiring offers the most economical means of reducing the net amount of greenhouse gases they produce. Quantifying CO_2 emissions from the power plant itself is not as much of a concern as looking at the net emissions of the greenhouse gases produced by the entire system. Although CO_2 receives the most attention for its potential contribution to climate change, two other greenhouse gases, methane and N_2O, are also produced by these systems. The capacity of methane to contribute to the warming of the atmosphere, a measure known as the global warming potential (GWP), is 21 times that of CO_2, while the capacity of N_2O is 310 times that of CO_2. Thus, the GWP of a system can be normalized to CO_2-equivalence to describe its overall effect on global climate change.

The GWP of the 15%, 5%, and no cofiring cases is 849.3 g CO_2-eq/kWh, 1,002.9 g CO_2-eq/kWh, and 1,038.9 g CO_2-eq/kWh, respectively. Cofiring biomass at 15% thus reduces the GWP of the coal-fired power plant by 18.2%. A 5.4% reduction is obtained by cofiring at 5%. The reduction in the GWP of the cofiring systems is higher than the rate of cofiring because the GWP of the methane and CO_2 that would have been produced during decomposition is greater than the greenhouse gases produced in supplying and combusting the biomass plus the value of the carbon sequestered in the landfill. For all systems, the majority (>89%) of the CO_2 emissions, which make up greater than 98% of all air emissions, come from combustion of the coal. In the 15% cofiring case, operations related to flue-gas cleanup (the production, transportation, and use of limestone and lime), coal transportation, and coal mining account for 20%, 15%, and 8% of the non-coal CO_2 (i.e., the CO_2 not produced during coal combustion at the power plant), respectively.

In determining the net greenhouse gas emissions balance for this system, it is important to recognize that not all of the emissions and avoided emissions will occur at the same time. While CO_2 will be emitted at the power plant as soon as biomass is fired, the release of CO_2 and methane from mulch, and particularly from landfills, will be delayed. Because it is exposed to the elements, the time frame for complete decomposition of mulch would likely be on the order of just a few years, and is reported to occur at a rate of 10% per year (Harmon *et al*, 1996). In landfills, non-lignin species of wood are estimated to have half-lives on the order of 20-40 years, although faster rates have also been reported (Micales and Skog, 1997).

System Energy Balance

The energy use within each process block was calculated so that the net energy consumption of the system could be determined. Energy is used either in consuming a material that has a fuel value or by consuming a material for which energy was used in its manufacture. When a fuel is consumed, either for energy generation or because it is the feedstock to a process, the heating value of that fuel (LHV basis) is subtracted from the net energy balance of the system. This reflects the fact that the fuel had a potential energy that was consumed by the system. In the case of a renewable energy resource such as biomass grown for energy uses, its heating value is not subtracted from the net energy of the system because it is both consumed and produced by the system. For the current case, the net energy is reduced by the heating value of the coal and the energy consumed in upstream processes (e.g., transportation, mining, etc.). Regarding the biomass residue, though, it cannot be considered a traditional renewable fuel since it is not grown within the boundaries of the system. However, landfilling or mulching wood that has an energy value would result in a loss of potential energy from the system. By using this fuel, therefore, loss of this energy is avoided. Thus, the only energy that is consumed when biomass residue is used at the power plant is the fossil energy required to deliver it and prepare it for combustion. Additionally, the energy that might be generated from landfill gas is considered to be lost if the biomass is cofired.

In addition to power plant efficiency, two other measures can be defined:

$$\text{Net energy ratio} = \frac{E_g}{E_{ff}}$$

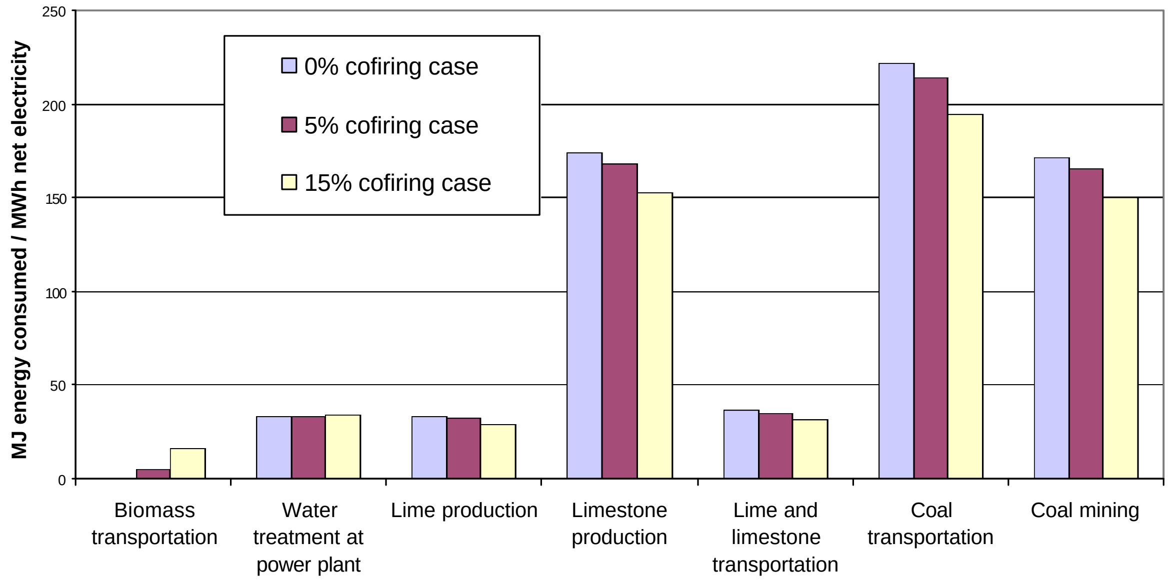
$$\text{External energy ratio} = \frac{E_g}{E_{ff} - E_c}$$

where: E_g = electric energy delivered to the utility grid
E_{ff} = fossil fuel energy consumed within the system, including that in the coal fed to the power plant
Ec = energy contained in the coal fed to the power plant

The net energy ratio measures the total amount of energy produced by the system for every unit of energy consumed by the system. The external energy ratio differs from the net energy ratio in that the energy contained in the coal fed to the power plant is not subtracted from the net energy of the system. This provides a better means of measuring the amount of energy that is consumed in upstream operations. The net energy ratios of the 15%, 5%, and no cofiring cases are 0.35, 0.32, and 0.31, respectively. The respective external energy ratios are 5.60, 5.21, and 5.06. An increase in either of these ratios reflects an increase in overall system efficiency.

While power plant efficiency decreases with increasing cofiring levels, the total system energy efficiency increases. Two factors are responsible for this. First, as less coal is burned at the power plant because of cofiring, less energy is consumed by the system overall. Secondly, less upstream energy is required to produce and deliver biomass fuel to the power plant than to produce and deliver coal. While both feedstocks must be transported, coal must also be mined and cleaned. Additionally, a very significant amount of energy is consumed in producing limestone and lime for SO_2 emissions control. Because of the lower sulfur content of biomass, lower quantities of the absorbants are required in the cofiring scenario than when firing coal alone. Figure 2 shows the activities that consume the majority of each system's total energy, excluding the coal used by the power plant. The total amount of energy consumed in the no cofiring case is 11.5 MJ/kWh; cofiring reduces total system energy consumption by 3.5% and 12.4% for the 5% and 15% cofiring cases, respectively.

Figure 2: Non-coal system energy consumption



Resource Consumption

Fossil fuels, metals, and minerals are all used in the process steps required to convert coal or biomass to electricity. Table 3 shows the resources used in the most significant quantities for each case. Coal is consumed at the highest rate, accounting for nearly 80% of all non-renewable resources.

Table 3: Non-Renewable Natural Resource Consumption

	15% cofiring			5% cofiring			No cofiring	
	% by wt[(a)]	g/kWh	% change[(b)]	% by wt[(a)]	g/kWh	% change[(b)]	% by wt[(a)]	g/kWh
Coal	80	395	-13	80	436	-4	80	452
Limestone	18	90	-12	18	99	-3	18	103
Oil	2	10	-10	2	11	-3	2	11
Natural gas	0.2	1.1	-12	0.2	1.2	-4	0.2	1.2

(a) Percent of total resource consumption. Not all resources consumed by the system are shown; therefore the numbers do not add up to 100%.
(b) % of reduction due to cofiring, based on the amount consumed in each case per kWh produced.

Solid Waste

The waste resulting from operation of the various systems needed to cofire biomass with coal can be grouped into three main categories: 1) flue gas cleanup waste, 2) boiler ash, and 3) miscellaneous non-hazardous process waste. Additionally, due to cofiring, there is an avoided waste in the form of the biomass that was not disposed of in the landfill; this waste is measured as a credit in the cofiring cases. In the no cofiring case, the biomass not used at the power plant was not counted as a penalty, since biomass disposal is outside of the legitimate boundary of current coal-fired power plants. The amounts of both flue gas cleanup waste and boiler ash are reduced through cofiring. Boiler ash is reduced because of the lower ash content of biomass (0.1 g/kJ) compared to coal (0.3 g/kJ). The lower lime and limestone requirements result in less flue gas cleanup waste. The production of limestone and lime used in flue gas cleanup is responsible for 90% of the miscellaneous non-hazardous waste, with the remaining 10% from surface mining operations. Including the biomass as an avoided solid waste, the 15% and 5% cofiring cases reduce the amount of system waste landfilled by 85.6% and 27.6%, respectively.

Trace Metals

The amount of trace metals in biomass will be dependent upon its source. Clean, untreated wood, such as that assumed in this study, will likely have lower concentrations of trace metals than those that are typical of coal (EPRI, 1997a). Among others, these include arsenic, beryllium, cadmium, mercury, and lead. The amount released will be in direct proportion to the difference in the concentrations between the coal and the wood, although differences in wood and coal ash concentrations may affect the partitioning of some metals between gaseous emissions and solid waste. Case-specific studies will be required for actual cofiring operations once the source of the biomass has been identified.

Water Emissions

As with the coal cases studied in Spath and Mann (1999), water emissions were low compared to other emissions. The majority of the water emissions are from the mining and power plant subsystems. Cofiring results in a net reduction because of avoided mining operations and because less water contamination occurs in sections of the system related to biomass procurement. Additionally, it is likely that contamination of groundwater from landfill leachate will be reduced because of the reduction in disposal of organic material. The magnitude of this reduction, however, is difficult to quantify, as groundwater contamination from landfills is highly site-specific, and the allocation of the contamination to different materials in the landfill is unknown.

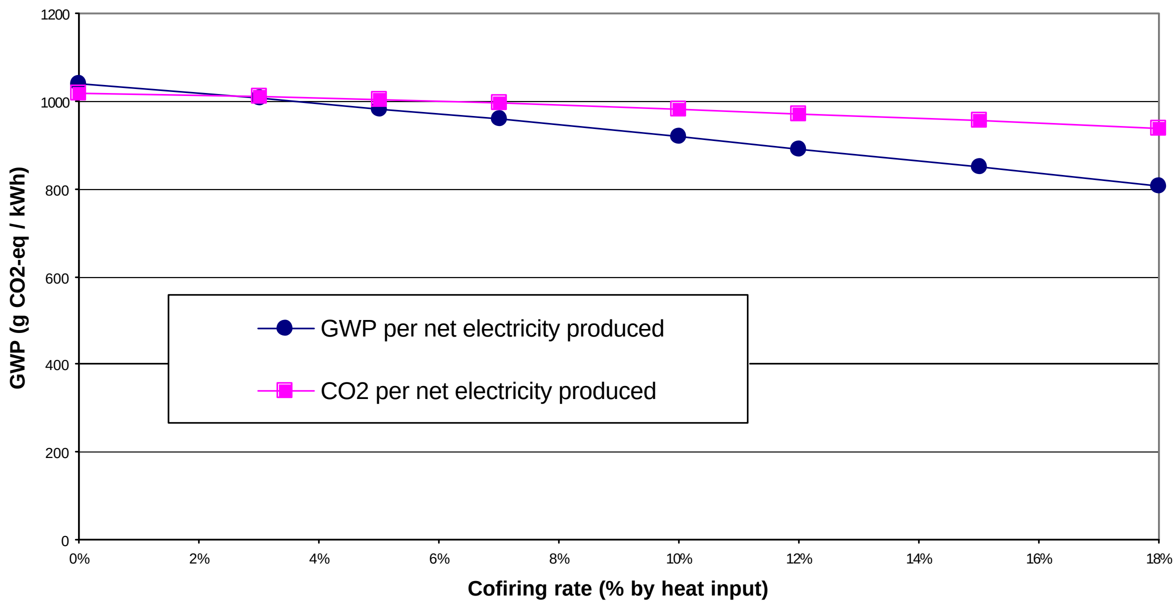
SENSITIVITY ANALYSIS

An important component of any LCA is the sensitivity analysis. The impact of different assumptions on the results can be measured by varying parameters and observing the subsequent changes. The extensive sensitivity analyses conducted for the coal LCA (Spath and Mann, 1999) make a study of many of the variables in the cofiring system redundant. For example, the conclusions drawn by varying feedstock transportation distance, operating capacity, power plant efficiency, and the amount of materials recycled will be the same for this and the previous study. Two important parameters, however, could be identified for the cofiring situation that were not applicable to the previous study: the rate of cofiring, and the fate of biomass in avoided operations.

Sensitivity of Results to Cofiring Rate

Figure 3 shows the net CO_2 emissions and GWP per kWh of electricity produced, for various rates of cofiring. The lines cross early as the rate of cofiring increases because the avoided landfill methane becomes more important than the CO_2 released by the power plant; as more biomass is used to cofire, less is allowed to decompose to methane and CO_2. Because these avoided emissions are subtracted from the net emissions of the system, and because the methane has higher capacity for holding heat than CO_2, the GWP of the system is actually less than the net CO_2 emissions at cofiring rates greater than about 3%. For every one-percent increase in cofiring rate (by energy input), there is approximately a 1.0% to 1.3% drop in the GWP of the system. Therefore, the reduction in system GWP is at least as great as the rate of cofiring, and increases with increasing cofiring rates. An interesting result is that the efficiency losses increase the magnitude of this positive impact because at higher cofiring rates, more biomass must be used per unit of coal avoided to produce the same amount of electricity.

Figure 3: The effect of cofiring rate on CO_2 emissions and GWP



Sensitivity of Results to Avoided Fate of Biomass

Because they are subtracted from the net emissions, higher or lower avoided methane and CO_2 emissions from landfill and mulch decomposition will affect the GWP of the entire cofiring system. While the assumptions in Figure 1 were chosen to be conservative and are based on published data, variance is likely. This will be the case for not only the average system represented here, but especially for plant-specific situations. The amounts of methane and CO_2 that are avoided by cofiring biomass are dependent on several factors:

1) the split between how much of the biomass goes to the landfill and how much goes to mulch,
2) the extent of degradation of biomass in landfills,
3) the amount of landfill gas that is captured and combusted, and
4) the conditions under which the mulch will decompose (anaerobic or aerobic).

Several combinations of reasonable but less likely values (from the base-case) of each of these factors were tested for the 15% cofiring case in order to quantify the range of possible GWP results. The largest increase in GWP from the base case represents the situation where all of the biomass carbon is permanently sequestered in the landfill (i.e., zero avoided decomposition emissions). While this is a highly improbable scenario, it is interesting to note that it results in a GWP that is only 3% higher than that of the no-cofiring case. In fact, if all of the biomass is landfilled, cofiring will result in a net reduction in greenhouse gases if just 8% of the carbon in the biomass decomposes, assuming all other parameters shown in Figure 1 remain the same. This value is well below that used in the base case (35%), and demonstrates that for almost all disposal scenarios, cofiring reduces the GWP of coal-fired power plants.

Where 70% of the non-lignin species in the wood decompose at the landfill and no landfill gas combustion occurs, a GWP reduction of 28% from the no-cofiring case can be realized. This scenario is improbable because in dry, modern landfills, wood is not likely to degrade to this extent. Other cases, however, are more probable and highlight realistic opportunities for significant reductions in GWP. The situation where the landfill is not required to collect and combust its gas results in 21% and 4% decreases from the no-cofiring case and 15% cofiring base case, respectively.

When all of the biomass is disposed of as mulch and degrades such that 10% of the carbon ends up as methane, a 24% reduction from the no cofiring case GWP is seen. Even allowing only 5% of the carbon to go to methane results in an 18% reduction. Cases that examine greater degrees of anaerobic decomposition of mulch because of larger piles and/or greater pile moisture, all result in larger reductions in GWP than those predicted in the 15% cofiring base case.

Situations where the reduction in GWP is not as great as in the base case include those where more of the landfill gas is combusted or less of the biomass carbon ends up as methane. For example, if all biomass is landfilled at a site that treats 75% of its gas, the GWP of the coal-only plant is reduced by only 6%, instead of the 18% predicted in the base case. Another example is the case where the portion of the biomass that ends up as mulch is decomposed under only aerobic conditions, resulting in a 12% reduction in GWP. Nevertheless, these reductions should be recognized as considerable, given the relatively low capital and operating costs of cofiring.

CONCLUSIONS

Cofiring can lead to significant reductions in the environmental impacts of coal-based electricity production. The amounts of nearly all air emissions are reduced by feeding even small amounts of biomass into the boiler. Additionally, because of avoided decomposition emissions, net greenhouse gas emissions are reduced at rates greater than the rate at which wood is added. The net energy balance of the system is improved because of a reduction in the amount of coal that is burned and because, on an energy-equivalent basis, procuring biomass residue for the power plant consumes less energy than mining and transporting coal. Consumption of non-renewable resources is cut substantially from those levels required when firing coal alone. Finally, solid waste emissions are reduced not only at the plant in the forms of boiler ash and flue gas cleanup waste, but also because landfilling of available biomass resources is avoided. While existing coal-fired power plants will incur some capital expenses to cofire biomass, the environmental benefits are significant and may be justified by emissions restrictions and consumer desire for clean power. At $50-250/kW, biomass cofiring is an attractive and inexpensive near-term option for incorporating renewables into a generating portfolio.

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