6. ENVIRONMENTAL PERFORMANCE

Two primary issues that could create a tremendous opportunity for biomass are global warming and the implementation of Phase II of Title IV of the Clean Air Act Amendments of 1990 (CAAA). Biomass offers the benefit of reducing NO_x, SO_2, and CO_2 emissions. The environmental benefits of biomass technologies are among its greatest assets. Global warming is gaining greater salience in the scientific community. There now appears to be a consensus among the world's leading environmental scientists and informed individuals in the energy and environmental communities that there is a discernable human influence on the climate, and that there is a link between the concentration of carbon dioxide (i.e., greenhouse gases) and the increase in global temperatures. Biomass use can play an essential role in reducing greenhouse gases, thus reducing the impact on the atmosphere. Cofiring biomass and fossil fuels and using integrated biomass gasification combined cycle systems can be an effective strategy for electric utilities to reduce their emissions of greenhouse gases.

The use of biomass crops also has the potential to mitigate water pollution. Since many dedicated crops under consideration are perennial, soil disturbance, and thus erosion can be substantially reduced. The need for agricultural chemicals is often lower for dedicated energy crops as well leading to lower stream and river pollution by agrichemical run-off.

Air Pollution

Biomass power has long been a source of heat and power in the United States and throughout the world. and is unique among renewables because it is a combustion technology that releases air pollutants. This environmental overview reviews air emissions from traditional biomass (wood and agriculture residues) and landfill methane biomass projects, and compares those emissions with conventional fossil-fuel generating plants. Greenhouse gas emissions will be discussed in the life cycle analysis section.

Major emissions of concern from traditional biomass power plants are particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_x). Biomass releases very little sulfur dioxide because of the low amount of sulfur typically found in biomass. Actual amounts and the type of air emissions depend on several factors, including the type of biomass combusted, the furnace design, and operating conditions.

For larger biomass projects, two types of boilers are commonly used. One boiler type is the spreader stoker. Biomass enters the furnace through a fuel chute and is distributed either pneumatically or mechanically across the furnace, where the biomass burns in suspension. At the same time, larger pieces of biomass are spread on a stationary or moving grate and combusted. A second boiler type used is the fluidized bed combustion (FBC) boiler. The fluidized bed is comprised of inert particles through which air is blown so that the fluidized bed behaves as a fluid. The biomass is combusted faster and more completely because of the immediate contact with the hot bed material, and uncontrolled air emissions are correspondingly lower.

Table 6.1 compares air emissions from biomass facilities, using different feedstocks and boilers, with representative coal and natural gas systems. The table illustrates that biomass FBC boilers, as presently permitted, have lower emissions than biomass systems with stoker boilers. Biomass systems using stoker

boilers emit less SO_2 than coal and natural gas units (except for natural gas combined cycle units, which are characterized by extremely low SO_2 emissions), and less NO_x than stoker boilers combusting coal and reciprocating engines burning natural gas. Biomass systems with FBC boilers are even cleaner, with lower SO_2 and NO_x emissions than coal and natural gas combustion turbines and lower PM-10 emissions than coal systems. When comparing emissions, it is very important to understand that all the power systems reported–both fossil and biomass–meet the air emission standards governing permitting and operation that were in effect when the facilities were constructed, and represent not only differences in fuel, but also differences in emission control systems. Future systems will meet the emissions standards in place at the time of permitting, and choices of system and fuel will largely be governed by costs associated with meeting those standards.

Table 6.1 Direct Air Emissions from Wood Residue Facilities by Boiler Type

	SO_X	NO_X	CO	PM-10[1]	Comments
Biomass Technology					
Stoker Boiler, Wood Residues (1,4)	0.08	2.1 (biomass type not specified)	12.2 (biomass type not specified)	0.50 (total particulates) (biomass type not specified)	Based on 23 California grate boilers, except for SO_2 (uncontrolled)
Fluidized Bed, Biomass (4)	0.08 (biomass type not specified)	0.9 (biomass type not specified)	0.17 (biomass type not specified)	0.3 (total particulates) (biomass type not specified)	11 FBC boilers in California
Energy Crops (Poplar) Gasification (a,b)	0.05 (**suggested** value based on SOx numbers for Stoker and FBC, adjusted by a factor of 9,180/13,800 to account for heat rate improvement)	1.10 to 2.2 (0.66 to 1.32 w/SNCR; 0.22 to 0.44 with SCR)	0.23	0.01 (total particulates)	Combustor flue gas goes through cyclone and baghouse. Syngas goes through scrubber and baghouse before gas turbine. No controls on gas turbine.
Coal Technology					
Bituminous Coal, Stoker Boiler (f)	20.2 1 wt% S coal	5.8	2.7	0.62	PM Control only (baghouse)
Pulverized Coal Boiler (d)	14.3	6.89	0.35	0.32 (total particulates)	Average US PC boiler (typically:baghouse, limestone FGC)
Cofiring 15% Biomass (d2)	12.2	6.17	0.35	0.32 (total particulates)	?
Fluidized Bed, Coal (f)	3.7 (1 wt% S coal Ca/S = 2.5)	2.7	9.6	0.30	Baghouse for PM Control, Ca sorbents used for SO_x
Natural Gas Technology					
4-Stroke NG Reciprocating Engine (g)	0.006	7.96-38.3 (depends on load and air:fuel ratio)	2.98-35.0 (depends on load and air:fuel ratio)	0.09-0.18 (depends on load and air:fuel ratio)	No control except PCC at high-end of PM-10 range
Natural Gas Turbine (e)	0.009 (0.0007 wt% S)	1.72	0.4	.09 (total particulates)	Water-steam injection only
Natural Gas Combined Cycle (c,e)	0.004	0.91 (0.21 w/ SCR)	0.06	0.14 (total particulates)	Water-steam injection only

Sources:
a. Spath and Mann (2000), "A Summary of Life Cycle Assessment Studies Conducted on Biomass, Coal, and Natural Gas Systems." NREL
b. Spath and Mann (1997), "Life Cycle Assessment of a Biomass Gasification Combined-Cycle System." NREL.
c. Spath and Mann (2000), "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System." NREL.
d. Spath, Mann, and Kerr (1999), "Life Cycle Assessment of Coal-Fired Power Production." NREL.
d2. Mann???!5% wood residue on a heat basis (on Exh3 cofire sheet)
e. AP-42 Chapter 3.1
f. AP-42 Chapter 1.1
g. AP-42 Chapter 3.2
1 & 4 from References
Notes: [1]PM10 emission factors are not always available. Total particulates are specified in some cases (includes PM larger than 10 microns). Condensible PM is included in the direct emissions factors for Bituminous Coal Stoker Boiler, Fluidized Bed Coal Boiler, NG Reciprocating Engine, and the NG Turbine. In general, all particulates from

Additional emissions data for wood combustion systems from the Environmental Protection Agency, 5th Edition of AP-42, Compilation of Air Pollution Emission Factors are given in Appendix 4.

Table 6.2 presents averaged permitted and actual emission levels from 34 operating wood-fired generating plants in California. Of these, 23 are spreader stoker facilities and 11 are FBCs . These facilities were built prior to the new emissions standards. New facilities are subject to the new and much stricter Clean Air Act emissions standards. Air emission standards for the most recently constructed stand-alone biomass plant in the New England region, Pine Tree Power in Westminster, Massachusetts, are included for comparison. This facility was permitted to burn clean construction/demolition wood and has the most restrictive permit conditions of any wood-fired power plant in New England. The facility can meet these requirements using a high-efficiency fluidized bed boiler (low CO and VOC emissions), an SNCR system for NOx reduction, and a mechanical collector and baghouse for particulate control. No SO_2 controls are required.

Table 6.2 Air Pollutant Emissions Limits for Biomass Power Plants (lb/MWh)

	Boiler Type	SO_2		NOx		CO		PM	
		Permitted	Measured	Permitted	Measured	Permitted	Measured	Permitted	Measured
Existing California Biomass Facilities[1]	All	1.0	0.08	2.2	1.7	9.6	8.6	0.7	0.4
	Stokers	0.8	0.08	2.6	2.1	13.6	12.2	0.8	0.5
	FBCs	1.4	0.08	1.3	0.8	1.7	0.2	0.5	0.3
New Massachussetts Biomass Facility[2]	FBC	0.78 (BACT)	N/A	0.74 (LAER)	N/A	0.88 (BACT)	N/A	0.20 (BACT)	N/A

[1][4air] Data averaged for 34 California biomass facilities (23 stokers and 11 FBCs). Based on a heating value for biomass of 8,293 BTU/lb, and an average heat rate of 13,800 BTU/kWh.

[2][2air]Permitted emissions levels for new Pine Tree Biomass Power Plant in Westminster, MA. BACT=Best Available Control Technology; LAER=Lowest Achievable Emissions Rate

A number of states–including Texas, California, and Connecticut–have enacted or are considering type certification standards for distributed generation units less than 50 MW_e to ensure that emissions from small electric generating units to do not exceed BACT standards for central generating stations, and to simplify and reduce the time and cost of permitting such units. The majority of existing biopower plants would be covered by such standards if permitted today.

The Texas air quality standard became effective in 2001 for distributed generation units less than 50 MW_e installed or permitted after June 1, 2001, to provide a streamlined permitting method to encourage the use of clean electric generating units. The standard provides a certification method for emissions based on test results from EPA reference methods, California Air Resources Board methods, or equivalent testing to verify certification, and requires re-certification of the unit after 16,000 hours, or three years, of operation. The standard only requires certification of NO_x under the decision that CO and VOC emissions will be controlled if the NO_x limits are reached. To control SO_x, only gases containing less than 10 grains total sulfur per 100 standard cubic feet are allowed. Systems are required to display the certification on the unit, much like an automobile emissions sticker. Certification permit costs are $450 for units larger than 1 MW_e, and $100 for units smaller than 1 MW_e. Units that use combined heat and power may take credit for heat at a rate of 1 MWh for each 3.4 million Btu if the heat recovered is greater than 20% of the total CHP output. Emissions have been established for ozone attainment (West Texas) and non-

attainment (East Texas) areas, for units larger and smaller than 10 MW_e, for units that operate less than 300 hours per year, and for certain gases that would otherwise be vented to the atmosphere. A summary of emission limits are given in Table 6.3.

Table 6.3: Texas Distributed Generation Certification Standards

Size	Area	> 300 hours per year	< 300 hours per year	Landfill gas, digester gas
> 10 MW	All	0.14 lb NO_x/MWh	0.38 lb NO_x/MWh	1.77 lb NO_x/MWh (a)
< 10 MW	East Texas	0.44 lb NO_x/MWh (b) 0.14 lb NO_x/MWh (c)		
< 10 MW	West Texas	1.6 lb NO_x/MWh	21 lb NO_x/MWh	

(a) must contain less than 1.5 grains of H_2S or 30 grains of total sulfur
(b) prior to December 31, 2004
(c) after January 1, 2005

California has issued a draft standard, to become effective January 1, 2003, for any distributed generation system sold, leased, or offered for sale or lease, for use or operation in the State of California. CHP units may take credit for heat recovery if the unit achieves a minimum efficiency of 60 percent (useful energy out/fuel in). Unit emissions must be certified by California Air Resources Board reference methods; and the certification fee is $500 (60 day processing period). Units must meet the emission standards for 15,000 hours of operation when operated and maintained according to the manufacturer's instructions; and must be re-certified every 4 years. A summary of the proposed standard is given in Table 6.4.

Table 6.4: Proposed California Distributed Generation Certification Standards.

Pollutant	Emission Standard (lb/MWh)		
	Power Only Jan 2003 - Dec 2006	CHP Jan 2003 - Dec 2006	All Units After Jan 1, 2007
NO_x	0.5	0.7	0.05
CO	6.0	6.0	0.08
VOCs	1.0	1.0	0.02

To evaluate the potential of biopower systems, a simple analysis has been performed to compare existing and potential biopower system performance relative to the proposed standards. NO_x emissions for existing systems are given in Figure 6.1[1] on both a life cycle and point-source plant emission basis. A national average coal station has NO_x emissions of about 6.75 lb NO_x/MWh, a NSPS coal plant emits

[1]Mann, M.K.; Spath, P.L. (2001). Comparison of Environmental Consequences of Power from Biomass, Coal and Natural Gas. Kyritsis, S., et al., eds. 1st World Conference on Biomass for Energy and Industry: Proceedings of the Conference held 5-9 June 2000, Sevilla, Spain. London, UK: James & James Ltd.; Vol. I: pp. 65-68; NREL NICH Report No. 31172.

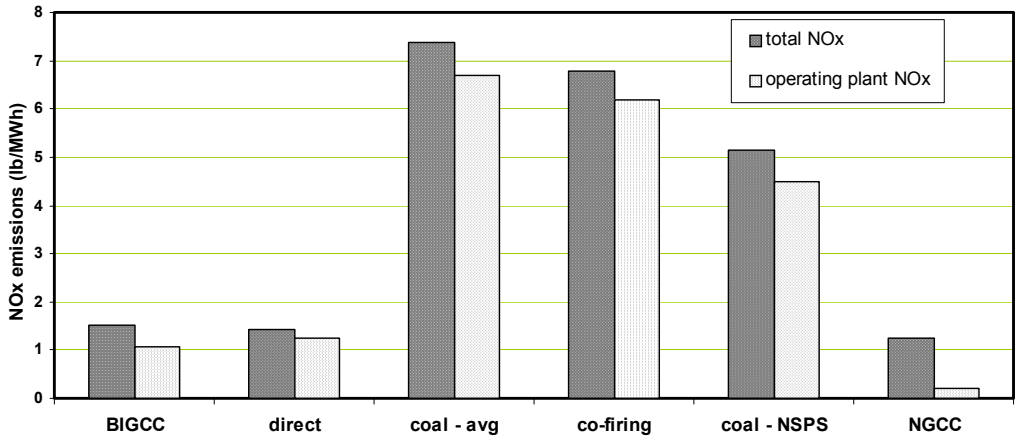


Figure 6.1: NO_x Emissions-Life Cycle Total and Plant Operating Emissions

about 4.5 lb NO_x/MWh, a natural gas combined cycle plant emits about 0. 2 lb NO_x/MWh, and a biopower direct combustion system emits about 1.2 lb NO_x/MWh.

Figure 6.2 gives a comparison of four existing biopower direct combustion plant emissions relative to the proposed standards for East and West Texas. CHP emissions have also been estimated, assuming that the existing systems could be modified to give a 60% CHP efficiency. Two out of the four operating biopower plants meet the West Texas standard. All CHP systems meet the West Texas standard, but additional NO_x control would be required for the systems to meet the East Texas standard.

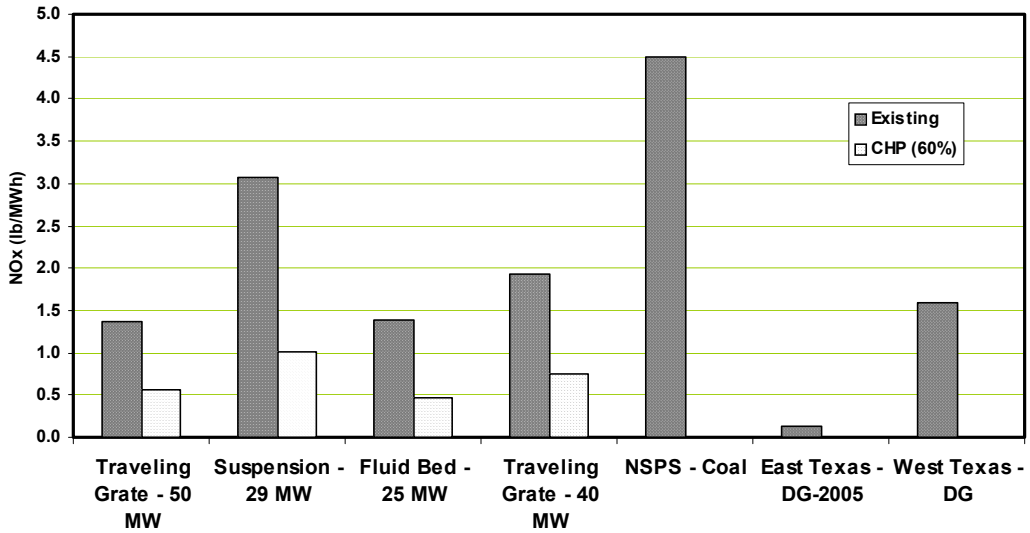
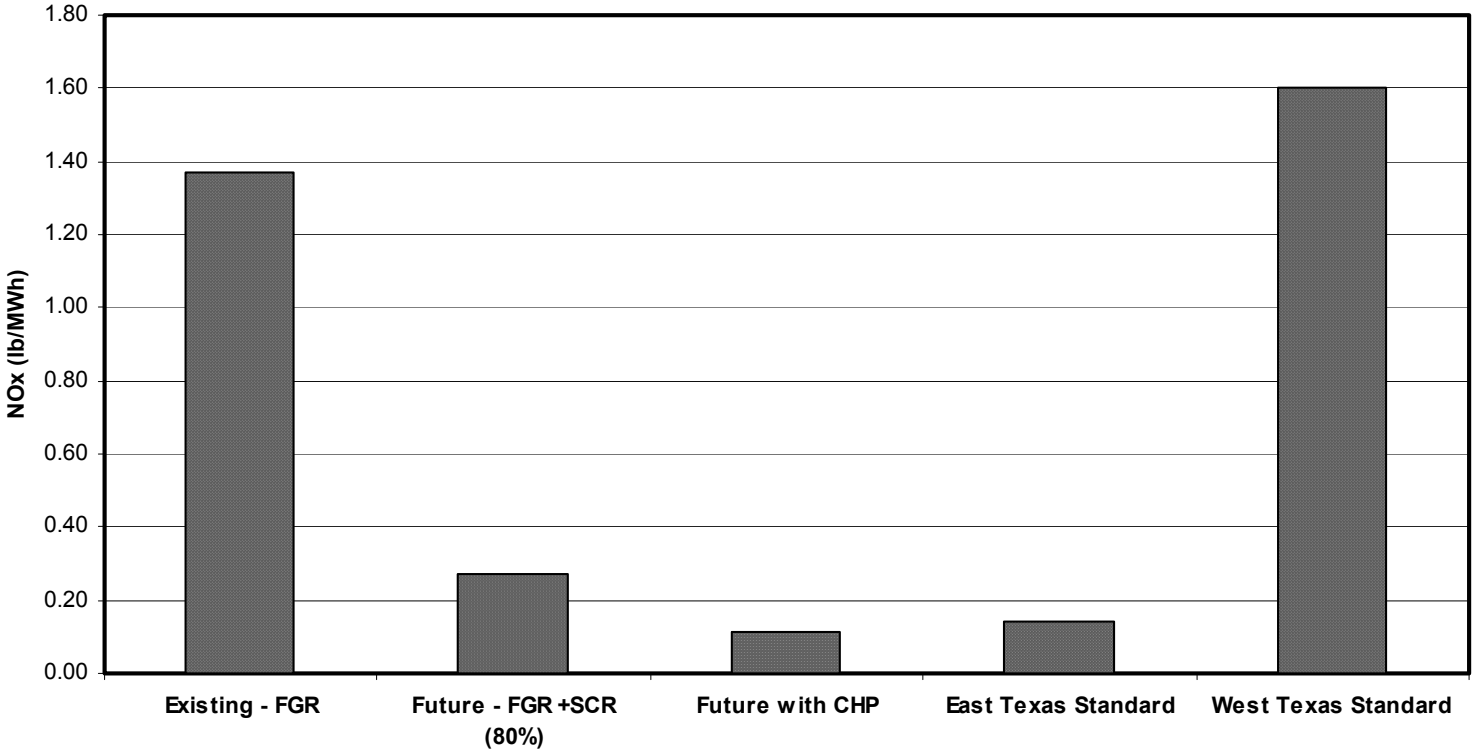


Figure 6.2: Biomass Combustion -Comparison of NO_x Emissions to 2001 Texas DG Standard

The potential for a CHP system to meet standards is shown in Figure 6.3. A existing system with flue gas recycle (FGR) has emissions of about 1.4 lb NO_x/MWh. Since FGR and selective catalytic reduction (SCR) are additive, SCR is also used, assuming an additional 80% reduction. This lowers the NO_x to about 0.25 lb NO_x/MWh. CHP is then assumed (60% total efficiency), bringing the level down to 0.12 lb NO_x/MWh. The existing system meets the West Texas standard, and the CHP system with both FGR and SCR meets the East Texas standard. The system with FGR and SCR meets the 2003 California standard, but additional optimization would be required for the CHP system to meet the 2007 California standard.

Figure 6.3: Biomass Combustion - Potential for NO_x Reduction



There are about 2,500 active landfills in the United States that receive over 200 million tons of municipal solid waste every year, with 55 to 60 percent from household waste, and 35 to 45 percent as commercial waste. Landfill gas is produced during the bacterial decomposition of this waste. The amount of landfill gas that is generated depends on the composition of waste in the landfill, the age of the landfill, the moisture content in the waste, pH levels, oxygen availability, and the temperature in the landfill.

Air emissions from landfills consist of roughly 50 percent methane, 48 percent carbon dioxide, small amounts of hydrogen, oxygen and nitrogen, and trace amounts of more than 100 non-methane organic compounds (NMOCs) like ethane, toluene, and benzene. The NMOC emissions include VOCs, hazardous air pollutants (HAPs), and odorous compounds. The VOCs present in NMOC emissions from landfills contribute to the formation of ozone that can reduce or damage growth in vegetables as well as exacerbate respiratory problems in humans. The health effects of HAPs include cancerous and non-cancerous illnesses like respiratory irritation and damage of the central nervous system. In 1996, the EPA issued New Source Performance Standards (NSPS) under the Clean Air Act for landfills with a capacity

of greater than 2.75 million tons that emit more than 50 Mg/year of NMOC emissions. These landfills have to install gas collection and combustion systems capable of controlling 98 percent or more of the NMOC emissions. The landfill gas can either be flared or converted to direct energy use or electrical energy.

Nationwide, there are over 325 landfill gas projects, with about two-thirds generating electricity for sale. The other one-third is for direct use, particularly for heating. Air emissions from landfill gas electric generating projects include CO, NO_x, SO_2, hydrogen chloride (HCI), PM, and other combustion products. Representative emissions are given in Table 6.5. PM emissions may also result from fugitive dust created by garbage trucks traveling along paved and unpaved roads. Gas collection systems are typically 60 to 85 percent efficient, so emissions of methane and NMOCs still occur. SO_2 emissions are site-specific and depend on the sulfur content of the waste in the landfill, and so are not included in the table.

Table 6.5: Air Emission Rates from Landfill Gas Combustion and Electric Generation (lb/MWh)

	NO_x	CO	PM-10
Flare (Btu Equivalent)	0.38	7.13	0.16
Internal Combustion Engine	2.37-4.73	4.45-8.9	0.45-0.91
Gas Turbine	0.98-1.93	2.55-5.10	0.24-0.49
Gas Boiler with low-NOx burners	0.33-0.66	0.06-0.11	0.08-0.16

Landfill gas systems with internal combustion (IC) engines generally have lower emissions than coal with stoker boilers, but higher emissions than most natural gas systems (except with reciprocating engines) and coal with FBC boilers. Landfill systems with gas turbines tend to have lower NO_x and CO emissions than coal systems with stoker boilers and natural gas combustion turbines, but higher NO_x and CO emissions than natural gas combined cycle systems. Landfill gas systems using gas turbines with low-NO_x burners have lower NO_x emissions than most of the generating technologies except natural gas combined cycle plants. All three landfill gas systems have relatively low levels of PM-10 emissions that are comparable to natural gas systems and lower than most coal systems.

Air emissions for landfill gas tend to be higher from facilities using IC engines, which are used at about 75 percent of the landfill gas electric facilities in the country. Because of tighter air emission standards, future landfill gas systems may need to use low-NO_x engines or gas turbines and may need CO and NO_x removal systems as well. Air emissions from landfill gas can be reduced through selective catalytic reduction to reduce NO_x emissions by injecting ammonia into the exhaust stream. Significant fuel pretreatment must be done at landfill gas generators to remove trace contaminants that can ruin the catalyst.

Some concern has been raised about possible dioxin production from landfill gas facilities. However, the EPA believes the potential is small for dioxin emissions from the combustion of landfill gas. Previous EPA analysis found that dioxin emissions from the combustion of landfill gas are comparable to dioxin emissions from oil or coal combustion, and significantly less than dioxin emissions from municipal waste combustion.

LIFE CYCLE ANALYSES[2]

The generation of electricity, and the consumption of energy in general, result in consequences to the environment. Using renewable resources and incorporating advanced technologies such as integrated gasification combined cycle (IGCC) may result in less environmental damage, but to what degree, and with what trade-offs? Life cycle assessment studies have been conducted on various power generating options in order to better understand the environmental benefits and drawbacks of each technology. Material and energy balances were used to quantify the emissions, energy use, and resource consumption of each process required for the power plant to operate. These include feedstock procurement (mining coal, extracting natural gas, growing dedicated biomass, collecting residue biomass), transportation, manufacture of equipment and intermediate materials (e.g., fertilizers, limestone), construction of the power plant, decommissioning, and any necessary waste disposal.

The systems chosen are:

- a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop (hybrid poplar)
- a direct-fired biomass power plant using biomass residue (urban, primarily)
- a pulverized coal boiler with steam cycle, representing the average for coal-fired power plants in the U.S. today
- a system cofiring biomass residue with coal (15% by heat input will be presented here)
- a natural gas combined cycle power plant.

Each study was conducted independently and can therefore stand alone, giving a complete picture of each power generation technology. However, the resulting emissions, resource consumption, and energy requirements of each system can ultimately be compared, revealing the environmental benefits and drawbacks of the renewable and fossil based systems.

System Energy Balance

The total energy consumed by each system includes the fuel energy consumed plus the energy contained in raw and intermediate materials that are consumed by the systems. Examples of the first type of energy use are the fuel spent in transportation, and fossil fuels consumed by the fossil-based power plants. The second type of energy is the sum of the energy that would be released during combustion of the material (if it is a fuel) and the total energy that is consumed in delivering the material to its point of use. Examples of this type of energy consumption are the use of natural gas in the manufacture of fertilizers and the use of limestone in flue-gas desulfurization. The combustion energy calculation is applied where non-renewable fuels are used, reflecting the fact that the fuel has a potential energy that is being consumed by the system. The combustion energy of renewable resources, those replenished at a rate equal to or greater than the rate of consumption, is not subtracted from the net energy of the system. This is because, on a life cycle basis, the resource is not being consumed. To determine the net energy balance of each system, the energy used in each process block is subtracted from the energy produced by the power plant. The total system energy consumption by each system is shown in Table 6.6.

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[2]Excerpted from Mann, M.K.; Spath, P.L. (2000). A Comparison of the Environmental Consequences of Power from Biomass, Coal, and Natural Gas. First World Conference and Exhibition on Biomass for Energy and Industry. June 5-9, Seville, Spain.

Table 6.6: Total System Energy Consumption

System	Total energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	12,575
Biomass / coal cofiring (15% by heat input)	10,118
Natural gas IGCC	8,377

To examine the process operations that consume the largest quantities of energy within each system, two energy measurement parameters were defined. First, the energy delivered to the grid divided by the total fossil-derived energy consumed by each system was calculated. This measure, known as the net energy ratio, is useful for assessing how much energy is generated for each unit of fossil fuel consumed. The other measure, the external energy ratio, is defined to be the energy delivered to the grid divided by the total non-feedstock energy to the power plant. That is, the energy contained in the coal and natural gas used at the fossil-based power plants is excluded. The external energy ratio assesses how much energy is generated for each unit of upstream energy consumed. Because the energy in the biomass is considered to be both generated and consumed within the boundaries of the system, the net energy ratio and external energy ratio will be the same for the biomass-only cases (biomass-fired IGCC and direct-fired biomass). In calculating the external energy ratio, we are essentially treating the coal and natural gas fed to the fossil power plants as renewable fuels, so that upstream energy consumption can be compared. Figure 6.4 shows the energy results for each case studied.

As expected, the biomass-only plants consume less energy overall, since the consumption of non-renewable coal and natural gas at the fossil plants results in net energy balances of less than one. The direct-fired biomass residue case delivers the most amount of electricity per unit of energy consumed. This is because the energy used to provide a usable residue biomass to the plant is fairly low. Despite its higher plant efficiency, the biomass IGCC plant has a lower net energy balance than the direct-fired plant because a significant amount of energy was required to grow the biomass as a dedicated crop. Resource limitations, however, may necessitate the use of energy crops in the future. Cofiring biomass with coal slightly increases the energy ratios over those for the coal-only case, even though the plant efficiency was derated by 0.9 percentage points.

In calculating the external energy ratios, the feedstocks to the power plants were excluded, essentially treating all feedstocks as renewable. Because of the perception that biomass fuels are of lower quality than fossil fuels, it was expected that the external energy ratios for the fossil-based systems would be substantially higher than those of the biomass-based systems. The opposite is true, however, due to the large amount of energy that is consumed in upstream operations in the fossil-based systems.

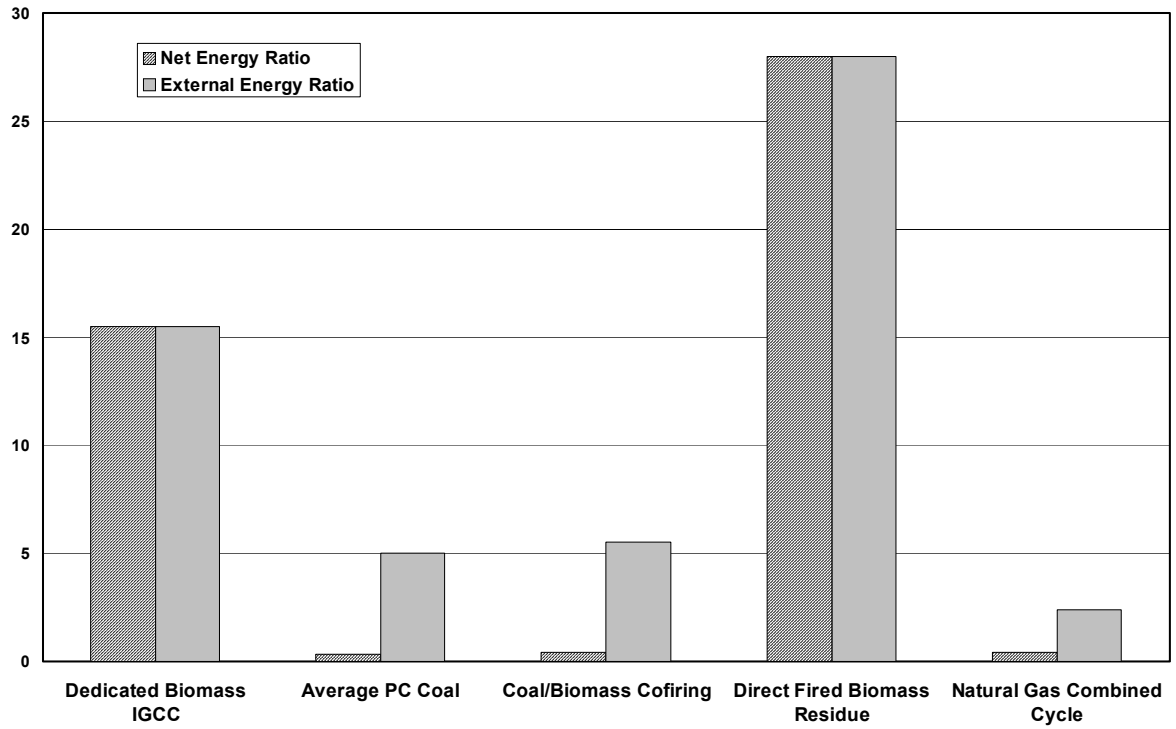


Figure 6.4: Life Cycle Energy Balance

The total non-feedstock energy consumed by the systems is shown in Table 6.7. In the coal case, 35% of this energy is consumed in operations relating to flue-gas cleanup, including limestone procurement. Mining the coal consumes 25% of this energy, while transporting the coal is responsible for 32%. Greater than 97% of the upstream energy consumption related to the natural gas IGCC system is due to natural gas extraction and pipeline transport steps, including fugitive losses. Although upstream processes in the biomass systems also consume energy, shorter transportation distances and the fact that flue-gas desulfurization is not required, reduce the total energy burden.

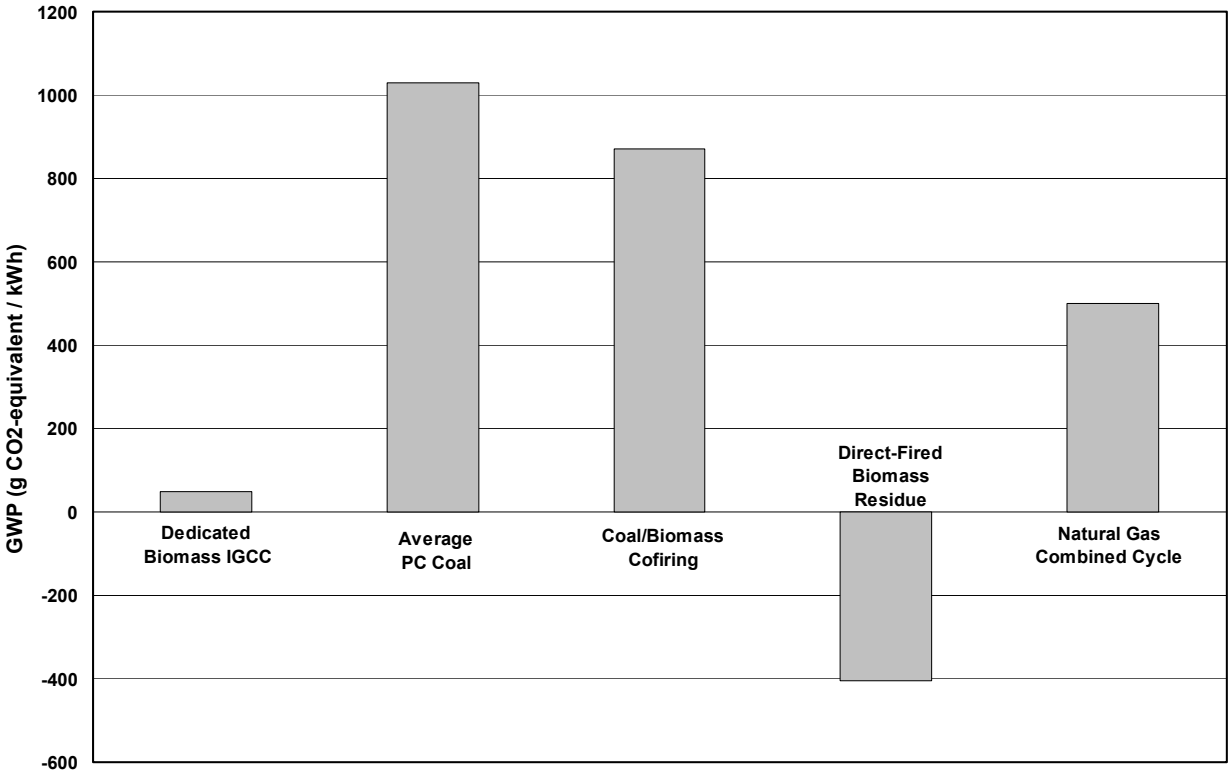
Table 6.7: Non-feedstock Energy Consumption

System	Non-feedstock energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	702
Biomass / coal cofiring (15% by heat input)	614
Natural gas IGCC	1,718

Global Warming Potential

Figure 6.5 shows the net emissions of greenhouse gases, using the 100-year values from the Intergovernmental Panel on Climate Change. CO_2, CH_4, and N_2O were quantified for these studies. The biomass IGCC system has a much lower GWP than the fossil systems because of the absorption of CO_2 during the biomass growth cycle. The direct-fired biomass system has a highly negative rate of greenhouse gas emissions because of the avoided methane generation associated with biomass decomposition that would have occurred had the residue not been used at the power plant.

Figure 6.5: Net Life Cycle Greenhouse Gas Emissions



Based on current disposal practices, it was assumed that 46% of the residue biomass used in the direct-fired and cofiring cases would have been sent to a landfill and that the remainder would end up as mulch and other low-value products. Decomposition studies reported in the literature were used to determine that approximately 9% of the carbon in the biomass residue would end up as CH_4 were it not used at the power plant, while 61% would end up as CO_2. The remaining carbon is resistant to decomposition in the landfill, either due to inadequate growth conditions for the microbes or because of the protective nature of the lignin compounds.

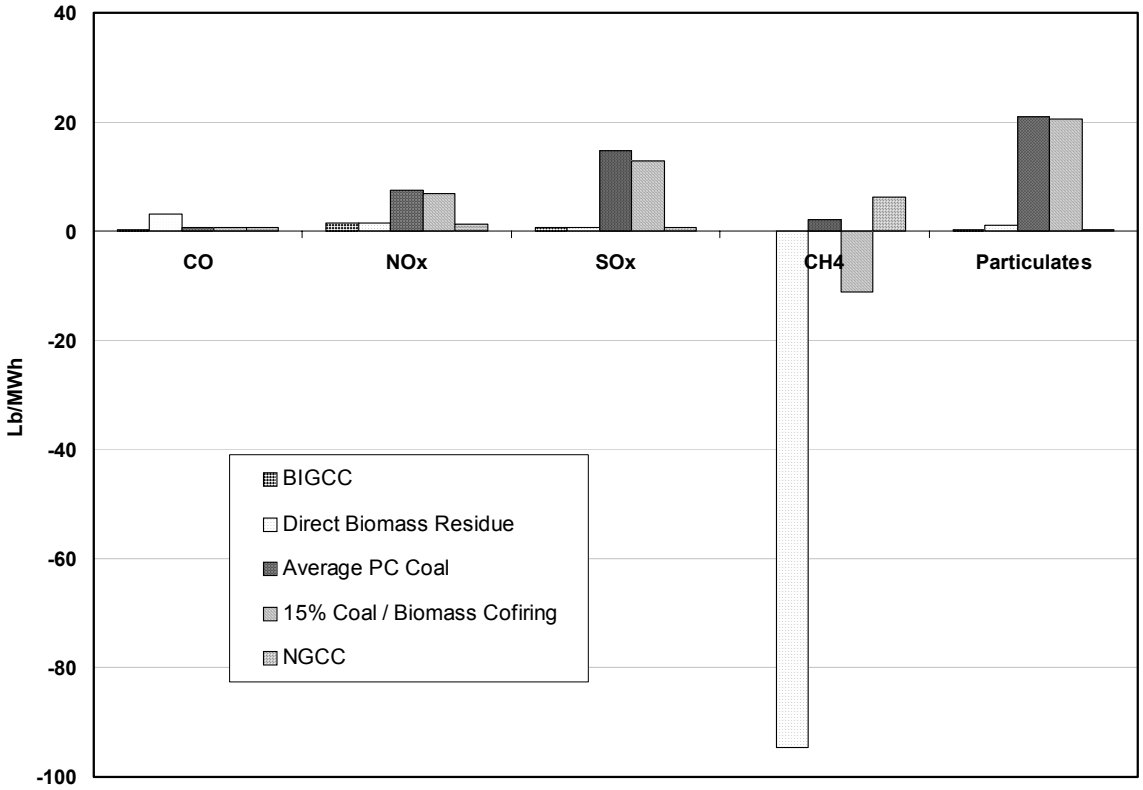
Sensitivity analyses demonstrated that even moderate amounts of soil carbon sequestration (1,900 kg/ha/seven-year rotation) would result in the biomass IGCC system having a zero-net greenhouse gas balance. Sequestration amounts greater than this would result in a negative release of greenhouse gases, and a system that removes carbon from the atmosphere overall. The base case presented here assumes that there will be no net change in soil carbon, as actual gains and losses will be very site specific.

The natural gas combined cycle has the lowest GWP of all fossil systems because of its higher efficiency, despite natural gas losses that increase net CH_4 emissions. Cofiring biomass with coal at 15% by heat input reduces the GWP of the average coal-fired power plant by 18%.

Air Emissions

Emissions of particulates, SO_x, NO_x, CH_4, CO, and NMHCs are shown in Figure 6.6. Methane emissions are high for the natural gas case due to natural gas losses during extraction and delivery. The direct-fired biomass and coal/biomass cofiring cases have negative methane emissions, due to avoided decomposition processes (landfilling and mulching). CO and NMHCs are higher for the biomass case because of upstream diesel combustion during biomass growth and preparation. Cofiring reduces the coal system air emissions by approximately the rate of cofiring, with the exception of particulates, which are generated during biomass chipping.

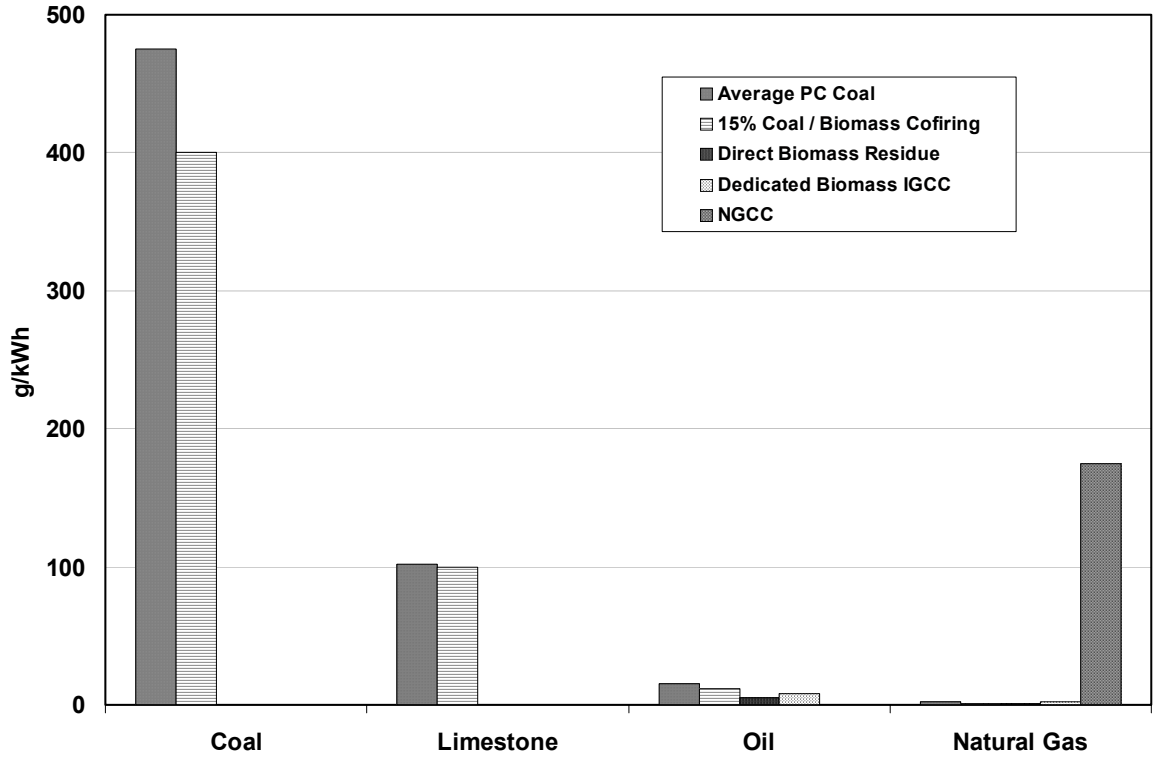
Figure 6.6: Other Air Emissions



Resource Consumption

Figure 6.7 shows the total amount of non-renewable resources consumed by the systems. Limestone is used in significant quantities by the coal-fired power plants for flue-gas desulfurization. The natural gas combined cycle plant consumes almost negligible quantities of resources, with the exception of the feedstock itself. The natural gas consumed in this case includes a 1.4% loss to the atmosphere during extraction and delivery.

Figure 6.7 Resource Consumption



Summary

Completing several life cycle assessment studies has allowed us to determine where biomass power systems reduce the environmental burden associated with power generation. The key comparative results can be summarized as follows:

- The GWP of generating electricity using a dedicated energy crop in an IGCC system is 4.7% of that of an average U.S. coal power system.
- Cofiring residue biomass at 15% by heat input reduces the greenhouse gas emissions and net energy consumption of the average coal system by 18% and 12%, respectively.
- The life cycle energy balances of the coal and natural gas systems are significantly lower than those of the biomass systems because of the consumption of non-renewable resources.
- Not counting the coal and natural gas consumed at the power plants in these systems, the net energy balance is still lower than that of the biomass systems because of the energy used in processes related to flue gas clean-up, transportation, and natural gas extraction and coal mining.
- The biomass systems produce very low levels of particulates, NO_x, and SO_x compared to the fossil systems.
- System methane emissions are negative when residue biomass is used because of avoided decomposition emissions.
- The biomass systems consume very small quantities of natural resources compared to the fossil systems.
- Other than natural gas, the natural gas IGCC consumes almost no resources.

These results demonstrate quite clearly that, overall, biomass power provides significant environmental benefits over conventional fossil-based power systems. In particular, biomass systems can significantly reduce the amount of greenhouse gases that are produced per kWh of electricity generated. Additionally, because the biomass systems use renewable energy instead of non-renewable fossil fuels, they consume very small quantities of natural resources and have a positive net energy balance. Cofiring biomass with coal offers us an opportunity to reduce the environmental burdens associated with the coal-fired power systems that currently generate over half of the electricity in the United States. Finally, by reducing NO_x, SO_x, and particulates, biomass power can improve local air quality.