

PPRP

The Potential for Biomass Cofiring in Maryland

MARYLAND POWER PLANT RESEARCH PROGRAM

March 2006



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THE POTENTIAL FOR BIOMASS COFIRING IN MARYLAND

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POWER PLANT RESEARCH PROGRAM

MARYLAND DEPARTMENT OF NATURAL RESOURCES

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Abstract

Cofiring biomass resources is a viable option for coal-fired power plants to allow the use of renewable resources with existing capital infrastructure. There are 16 coal-fired facilities in Maryland that can be considered candidates for biomass cofiring. This report provides information on Maryland's coal-fired power plants and identifies the best candidates for cofiring. The feasibility of cofiring at each of Maryland's facilities is based on the type of boiler, assessment of the technologies in use, the availability of biomass resources, the capital costs to retrofit coal facilities, and the environmental benefits from cofiring.

Executive Summary

Cofiring coal with biomass resources such as urban waste wood, agricultural residues, mill residues, forest residues, or energy crops is a promising, near term opportunity that allows power plant owners to use renewable resources while incurring relatively low capital costs. The rising costs of fossil fuels along with more stringent environmental regulations and incentives for clean, renewable energy are factors that should encourage power plant owners to consider the potential for cofiring with biomass. However, despite the years of experience in burning wood fuels to generate electricity, there are still a number of uncertainties regarding the efficiency, economics and environmental impacts of cofiring biomass with coal. To determine the potential for biomass cofiring in Maryland, it is necessary to understand the various types of boilers and technologies in use at Maryland facilities as well as the availability of biomass resources, the capital costs to retrofit coal facilities and the environmental benefits from cofiring.

There are 16 coal-fired boilers operating at Maryland's electric utility generators, 13 are pulverized coal boilers, two are cyclone boilers and one is a circulating fluidized bed combustion boiler. Pulverized coal boilers are able to cofire small amounts of biomass (less than 2 percent based on total heat input) without significant modifications to the boiler or fuel feed systems. However, combusting greater than two percent without making modifications to the fuel feed system causes problems in fuel processing that lead to unevenly sized fuel particles and lower efficiency of the boiler. With modifications to the fuel systems that provide separate processing, conveying and injection of biomass fuels, it is possible to cofire as much as 20 to 30 percent biomass with coal. Of the 13 pulverized coal boilers, nine are wall-fired and four are tangentially fired. Of the two technologies, tangentially fired pulverized coal boilers have responded better to cofiring with coal at higher amounts, successfully cofiring up to 30 percent biomass, based on fuel mass. The tangentially fired boilers have a single burn zone with lower temperatures than the wall-fired boilers that have multiple burn zones at higher temperatures. These lower temperatures allow time for more uniform and complete combustion of different fuels. A review of recently published research findings and industry experience indicates that of those boilers found in Maryland, tangentially fired pulverized coal boilers are likely to experience the best results. In Maryland, the three coal-fired units of Dickerson and R.P. Smith, unit 4 are tangentially fired pulverized coal boilers. However, there have been successful test burns and commercial operations with wall-fired pulverized coal boilers and cyclone boilers making biomass cofiring technically possible for all Maryland's coal-fired power plants.

A significant finding from the numerous research efforts and test burns is the interaction between the biomass fuels and emissions control equipment. Most biomass fuels have higher alkali levels than coal. The test results indicate that the high alkali content of biomass fuels may interfere with the effectiveness of catalytic reduction systems designed to control for nitrogen oxides. Facilities that have made an investment in selective or non-selective catalytic reduction systems will not want to risk the effectiveness of this expensive emissions control technology and are therefore unlikely to consider cofiring biomass. Based on this finding, H.A. Wagner 3, Brandon Shores 1 and 2, and Morgantown 1 and 2 are not suitable candidates for biomass cofiring.

A second important consideration when contemplating cofiring biomass is the availability of biomass resources in the local area. Resources located outside of a 50-mile radius will be too expensive to transport. Therefore, only those counties within 50 miles of a Maryland coal-fired facility are considered viable suppliers of biomass resources. Eligible resources for cofiring include urban waste wood, mill residue, forest residue, agricultural residue and energy crops. The region has approximately 440 thousand tons of forest residues; 590 thousand tons of mill residues; 665 thousand tons of urban waste wood and 1.1 million tons of agricultural residues for a total amount of 2.7 million dry tons of biomass resources. In addition to those sources currently available, there is the potential to cultivate energy crops for an additional estimated 1 million tons of biomass resources.

The quantity of biomass resources available in the area is sufficient to support the development of more than one biomass cofiring project. However, the cost of biomass resources is such that only the lower cost fuels can be considered economically viable. Lacking a more sophisticated market for biomass fuels, all of the resources are more expensive than coal, which is approximately \$1.41 per million Btu. The most cost-competitive fuels are urban waste wood, \$1.70 per million Btu, and mill residues, \$1.93 per million Btu. Agricultural residues, forest residues, and energy crops are far more expensive than coal at \$4.95 per million Btu, \$3.65 per million Btu, and \$3.20 per million Btu, respectively. Based on the high costs of biomass resources in the region, it is probable that an economically viable cofiring project would use only urban waste wood and mill residues. Looking at the amount of urban waste wood and mill residue in the region, Fairfax County, Virginia has the largest amount of biomass with more than 245 thousand tons and Baltimore City is second with nearly 100 thousand tons. Lancaster and Franklin Counties in Pennsylvania have the largest supply of mill residue, with 54 thousand and 35 thousand tons of biomass, respectively. The large amount of biomass available from urban waste wood in Fairfax County and Baltimore City indicates that a good candidate for biomass cofiring should be located near Washington or Baltimore. However, if urban waste wood were unavailable from the local waste management facilities, the results of the assessment would favor more rural areas close to Pennsylvania and West Virginia.

The initial capital investment for cofiring retrofits is the third consideration when assessing the potential for use of biomass fuels in coal-fired facilities. Cofiring only a small amount of biomass will require very little capital investment. However, cofiring greater than 2 percent of total heat input will require the development of a separate fuel system than increases costs. The experience acquired through a series of test burns and pilot projects provides a range of costs for the engineering and construction of retrofits, including the development of a separate fuel feeding system for the biomass fuels. Costs range from \$150/kW to \$400/kW of biomass capacity and are largely dependent on the design and size of fuel handling and feeder systems. The boiler size, technology, and configuration drive the specifications for the fuel processing and injection systems. Therefore, each boiler unit would require a detailed engineering analysis to determine the true capital costs for that specific system.

The high cost of biomass fuels and the capital investments required for fuel processing, conveying and injection will make biomass cofiring uneconomic in all instances. However, the environmental benefits from replacing some coal with biomass fuels may make cofiring attractive to Maryland facilities. Biomass fuels have little to no sulfur content and thus

substituting biomass for coal reduces the amount of sulfur dioxide emitted. Cofiring biomass may also reduce ozone-creating nitrogen dioxide, although this environmental benefit is less certain than with sulfur dioxide. Facilities facing environmental compliance issues based on sulfur dioxide emissions may want to consider cofiring as an alternative to investing in emissions controls or switching to natural gas. Additionally, the economic incentives from the sale of renewable energy credits available in Maryland and some of the surrounding states will help to make these projects more economic. Thus, the economic valuation of environmental benefits is the fourth and final consideration analyzed within this report.

It is possible to identify the most attractive candidates for biomass cofiring by ranking each of the facilities according to the four assessment criteria described above. A facility with the best potential for cofiring has compatible technology, reasonable capital costs, local access to the lower cost biomass resources, and an opportunity to reduce criteria pollutants. Based on this assessment, there is one facility that stands out as the best candidate for biomass cofiring, Mirant Power's Dickerson facility, Units 1, 2 and 3. However, this assessment does not take into consideration any conditions or system configurations specific to Dickerson or any other facilities. Variations in plant design and operations that affect the capital costs or environmental performance of the facility may alter the findings of this assessment.

THE POTENTIAL FOR BIOMASS COFIRING IN MARYLAND

I. Introduction

Of the 13,470 megawatts (MW) of electric generating capacity in Maryland, coal-fired generating units make up 56 percent. Coal usage by Maryland electric generators has increased by 4.5 million tons, or 23 percent, over the past ten years despite increasing coal costs and changes in environmental regulations. With costs of all fossil fuels on the rise, and further revisions and tightening of environmental regulations expected, owners of facilities may find greater incentives to explore the potential for biomass resources as an alternative or supplement to coal. This report, commissioned by the Maryland Department of Natural Resources' Power Plant Research Program, provides an introduction to biomass cofiring; the technologies, efficiencies, and environmental impacts; and analyzes the potential for biomass cofiring in Maryland coal facilities.

Cofiring refers to supplementing coal use in coal-fired boilers with non-coal fuels, in this case biomass. Cofiring is usually conducted on a limited basis, making up between 5 and 15 percent of the total heat input to the boiler. Biomass cofiring is not the same as using biomass in boilers designed to handle multiple fuels, as is common in the pulp and paper industry. While multiple fuel boilers are designed to burn a wide range of fuels, cofiring biomass with coal is done in a boiler designed to burn only (or primarily) coal.¹

According to the U.S. Department of Energy (DOE), biomass energy is derived from three distinct energy sources: wood, waste, and alcohol fuels. Biomass resources include all plant or plant-derived materials such as trees, grasses, wood, residues from the agriculture and forest industries, agricultural crops, and aquatic plants. Additionally, biomass can include

¹ Jeffrey E. Fehrs, Christine Donovan, *Co-firing Wood in Coal-Fired Industrial Stoker Boilers: Strategies for Increasing Co-Firing in New York and the Northeast*, Northeast Regional Biomass Program, April 1999, p. 1.

animal wastes and wastes produced by cities and factories.² Wood, the largest source of biomass energy, includes both harvested wood and waste from wood-based products. Black liquor, a by-product from processes of the pulp, paper and paperboard industry, is a common form of wood-based fuel. Waste is the second-largest source of biomass energy. The main contributors of waste for energy production are municipal solid waste (MSW), manufacturing waste, and landfill gas. Alcohol fuels such as ethanol are derived from plant matter such as corn, beets, or barley. Its principal use is as an oxygenate in gasoline.

In 2003, biomass supplied 2.9 quadrillion Btu of energy, nearly three percent of total energy consumption in the United States.³ The industrial and electric power sectors account for over three fourths of total biomass consumption, consuming 1.7 quadrillion Btu and 0.5 quadrillion Btu respectively.⁴ The pulp and paper industry is the largest consumer of biomass energy, where wood residues, black liquor and other by-products are combusted to produce process heat, steam and electricity.

The U.S. has an estimated 11 gigawatts (GW) of capacity from biopower facilities in the commercial, industrial and electric power sectors. This 11 GW includes an estimated 7.5 GW from forest product and agricultural industry residues, about 3 GW from municipal solid waste, and another 0.5 GW from landfill gas facilities. The 7.5 GW of wood and agricultural biomass capacity represents about 1 percent of electricity generating capacity and 8 percent of all non-utility generating capacity. Of the more than 500 facilities that use wood or waste wood to generate electricity, fewer than 20 are owned and operated by investor-owned or municipal electric utilities. Cogeneration facilities in the pulp and paper industry make up the majority of the capacity.⁵

² *Bioenergy: An Overview*, U.S. Department of Energy, Information Resources, <http://www.eere.energy.gov/consumerinfo/factsheets/nb2.html> accessed March 22, 2005.

³ *Renewable Energy Trends 2003*; Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy; July 2004, p. 5. Available via <http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/trends.pdf>, accessed March 23, 2005.

⁴ *Ibid.* p. 1.

⁵ W.A. Amos, R.L. Bain, M. Downing, and R.L. Perlack, *Biopower Technical Assessment: State of Industry and Technology*, National Renewable Energy Laboratory, March 2003, pp. 1-2.

There are several benefits to cofiring with biomass, including fuel price risk mitigation, emissions reductions, and waste management. In the case of the pulp and paper industry, cofiring with biomass reuses the black liquor that would otherwise have to be disposed of in a landfill or other long-term storage. Biomass cofiring also leads to reductions in SO_x, NO_x and CO₂ emissions. Biomass is considered to be CO₂ neutral since the CO₂ released during combustion is taken up during the course of new plant growth. Biomass also has lower sulfur content than coal so cofiring results in a reduction of SO_x emissions because of the displacement of sulfur in the fuel blend. Eastern bituminous coal contains between 4-7 percent ash, while wood fuels generally contain 1 percent or less of ash. Thus cofiring with wood biomass will reduce the amount of ash required for disposal. Moreover, since biomass has a lower ash content, limited biomass cofiring would not have a negative impact on the ability of the plants to market their ash. In addition to the environmental benefits, reducing SO₂ emissions may have important financial benefits for a coal-fired facility. Cofiring coal with biomass can allow power producers to earn SO₂ emissions allowances under section 404(f) of the Clean Air Act (U.S. House of Representatives, 1990). An allowance is earned, or freed-up from the facility's compliance requirements, when one ton of SO₂ is reduced.

Cofiring with biomass can also provide reductions in NO_x emissions because the nitrogen content of the cofired biomass fuel is generally lower than the nitrogen content of coal. Cofiring with biomass reduces flame temperatures, which may lead to lower levels of thermal NO_x.⁶ However, the NO_x (and SO_x) emissions reductions vary according to biomass resource and facility design. Biofuels such as alfalfa stalks, rice hulls, and urban waste wood can contain nitrogen concentrations higher than that found in coal.⁷

There is one significant, non-economic negative impact associated with the cofiring of biomass: the possibility of increased slagging and fouling on boiler surfaces. Slagging refers to the deposition of solid material on the boiler tubes which obstructs the flow of heat-energy from

⁶ Biomass has a significantly lower heating value than most coal. This is in part due to the generally higher moisture content and in part due to the high oxygen content.

⁷ S. Laux, J. Grusha, D. Tillman, *Co-Firing of Biomass and Opportunity Fuels in Low NO_x Boilers*, Foster Wheeler Technical Papers, p. 3, http://www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.

the fire to the steam in the watertubes. Slagging is a greater risk when firing high alkali biomass fuels, such as switchgrass.⁸

A. Maryland Experience with Biomass Cofiring

Currently, there is one biomass cofiring facility operating in Maryland. MeadWestvaco operates a 60 MW facility for self-generation as part of their Luke Mill facility located in Luke, Maryland. The plant is fully integrated, producing all of its own power. The company purchases 4,000 tons of wood per day (75 percent is local hardwood, 25 percent is pine) and manufactures an average of 15,600 tons of coated paper products per day.⁹ Luke Mill's two generator units have a combination of three pressure boilers and two recovery boilers that use a mixture of coal, fuel oil, natural gas, and black liquor. According to data collected through EIA Form 767, "Steam Electric Plant Operation and Design Report," and EIA Form 860, "Annual Electric Generator Report," three percent of the total amount of energy resources consumed by the Luke Mill's two electric generators came from biomass (black liquor), in 2003. The recovery boilers are the boilers designed to combust black liquor. Generator 1, with a summer capacity rating of 32 MW, used mostly fuel oil with a small amount of coal in 2003. Generator 2 (28 MW) consumed 10 percent of its energy resources from biomass, 22 percent from coal, 63 percent from fuel oil and 5 percent from natural gas.¹⁰

B. Barriers to Biomass Cofiring

There are a number of technological, institutional, and financial barriers that have restricted the development of biomass cofiring in Maryland and throughout the U.S. These barriers can result in biomass resources having higher associated costs than coal. Technology barriers are due, in part, to the fact that biomass resources vary considerably in energy content and physical characteristics from region to region, more so than other fossil-fuel resources.

⁸ W.A. Amos, R.L. Bain, M. Downing, and R.L. Perlack, *Biopower Technical Assessment: State of Industry and Technology*, National Renewable Energy Laboratory, March 2003, pp. 5-22.

⁹ MeadWestvaco, Maryland Department of Business and Economic Development, <http://www.choosemaryland.org/pressroom/events/mead.asp>, accessed March 20, 2005.

¹⁰ Annual Steam-Electric Plant Operation and Design Data, EIA-Form 767, 2003, <http://www.eia.doe.gov/cneaf/electricity/page/eia767.html>, accessed March 18, 2005.

Additionally, biomass resources contain varying amounts of alkali metals that cause mechanical problems such as deposition when combusted. The tendency to form unmanageable ash deposits on boiler surfaces, which can cause poor operating performances or boiler shutdown, is perhaps the largest technological impediment to the widespread use of biomass. Other technological barriers are related to the compatibility of biomass with power plant emissions control technologies.¹¹

The DOE and the Electric Power Research Institute (EPRI) have spent millions of dollars demonstrating the technical viability of cofiring biomass with coal in an effort to break down technological barriers. According to the final report of a 5-year Cooperative Agreement between DOE and EPRI, the tests conducted by the DOE-EPRI project document that biomass cofiring can be employed to achieve environmental benefits without sacrificing the economics of plant operations.¹² The technical feasibility of biomass cofiring has gained credibility from the experience and testing of cofiring demonstration projects. However, the general public is largely unaware of the low emissions, high efficiency opportunities provided from biomass resources. Instead, developers must confront public fears of clear cutting and unsustainable harvesting practices. Furthermore, a lack of familiarity with biomass cofiring among facility operators may require additional documentation and training prior to retrofitting a facility. Utility management can also be an obstacle to cofiring. Cofiring biomass with coal in large-scale electricity generators will require management to change operating practices that have been in effect for many years.

Finally, the high cost of biomass fuels and supply uncertainty add to the project risk. Even if the capital costs for retrofitting a facility to cofire biomass are nominal, they come at the expense of other investments that may be a higher priority for basic operations. Barring those investments required to maintain operations or environmental compliance, facility owners and operators are likely to resist investments in aging facilities. The economics of cofiring may improve with the added benefits of emissions reductions and renewable energy credits, but

¹¹ Ibid., p. 2-1.

¹² David Tillman, *Final Report: EPRI-USDOE Cooperative Agreement: Cofiring Biomass with Coal*, Foster Wheeler Corporation, DOE Contract No. DE-FC22-96PC96252, September 2001, p. 4.

whether or not these added incentives are sufficient to encourage investment in new equipment for an aging facility is questionable.

The barriers to cofiring, the extent of utility experience, and the availability of biomass resources in Maryland are addressed within this report. Chapter II, *Coal-Fired Plant and Technology Characterization*, describes the type and configuration of boilers used by Maryland's coal-fired power plants and the potential opportunities for cofiring biomass in each boiler type. Chapter II also discusses the environmental implications of cofiring biomass with coal. Chapter III, *Biomass Resource Assessment*, identifies the various categories of biomass applicable to cofiring and assesses the quantity available in Maryland and select counties located in neighboring states. Chapter IV, *The Economics of Cofiring*, provides details regarding the estimated capital costs of retrofits, fuel costs, and the savings resulting from environmental benefits. The estimated costs and benefits for each Maryland coal-fired facility, and the availability of biomass are discussed in Chapter V, *Potential for Cofiring Biomass with Coal*. Finally, the conclusions of the assessment are presented in Chapter 6, *Conclusions*.

II. Coal-Fired Plant and Technology Characterization

A. Introduction

More than 30 power plants (142 units) are currently operating in Maryland, generating a maximum capacity of 13,470 MW. They use several different fuel types including coal, natural gas, fuel oil, diesel, hydro, landfill gas, municipal solid waste, nuclear, and wood to produce electricity. A total of 16 coal-fired units, with a generating capacity of 4,930 MW, are responsible for 56 percent of the annual electricity generation in Maryland.¹³ Coal-fired boilers can be classified by type, fuel and construction. Boilers are identified by the method of heat transfer (water tube, fire tube or cast iron), the arrangement of the heat transfer surfaces (horizontal, vertical, straight or bent) and the firing configurations (suspension, stoker or fluidized bed). Maryland's coal-fired power plants are water tube boilers; water and steam are contained within tubes while hot combustion gases contact the outside of the tubes for heat transfer. Coal-fired water tube boilers include pulverized coal, cyclone, stoker, fluidized bed and hand fed units. There are 13 Pulverized Coal (PC) dry bottom boilers with a generating capacity of 4,370 MW in Maryland. Additionally, there are two cyclone or wet bottom boilers with 380 MW of generating capacity and one circulating fluidized bed combustion unit (CFBC), with 180 MW of generating capacity.¹⁴ This chapter describes the technologies in use at Maryland's coal-fired power plants, and assesses of the suitability of a technology to cofire biomass. Table 2.1 describes Maryland's coal-fired units by owners, location, plant and boiler type.

B. Pulverized Coal

1. Technology Description

Pulverized Coal (PC) boilers are the most commonly used technology in cofiring operations, and in electricity production in general.¹⁵ The PC boiler takes its name from the fact that it burns finely ground particles of coal in a suspension boiler within the combustion area. PC boilers use pulverizers to grind up coal to specific size, so that approximately 70 percent of

¹³ Energy Information Administration, EIA906/920, 2004.

http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

¹⁴ Power Plant Research Program, *Electricity in Maryland Factbook*, January 2003.

¹⁵ National Renewable Energy Laboratory, *Biopower Technical Assessment: State of the Industry and Technology*, pp. 5-20. <http://www.nrel.gov/docs/fy03osti/33502.pdf>

the particles will pass through a 200-mesh screen (i.e., 200 openings per inch). Primary air is used to transport the fuel into the combustion area and to dry the coal on its way to the boiler. This primary air makes up a small portion (15-20 percent) of the total air used in the combustion process, with the remaining air, the secondary and possibly tertiary air, introduced in the boiler's combustion zone. Once the fuel enters the combustion area it burns in suspension, with any unburned fuel or char returning to the combustion area for completed combustion.¹⁶

Some of the advantages of PC boilers when compared to other boiler types are that they can burn almost any type of coal from anthracite to lignite. PC boilers also have the ability to respond rapidly to load changes. They have increased efficiency due to reduced excess air, low labor related operations costs and the ability to cofire with oil, gas and other fuels.

PC boilers are generally classified as dry-bottom or wet-bottom, depending on the physical state (solid or molten) of the ash removed from the bottom of the boiler. Dry bottom, which are more common, are further classified as wall fired, tangentially fired (T-fired), and vertically fired, depending on the fuel firing direction. In dry bottom boilers, the intent is for the combustion to take place fully within the area inside the furnace, at temperatures below the ash melting point. Combustion at or above the ash melting point causes slagging, which can cake on the walls of the furnace and convection banks and decreases overall boiler efficiency. However, improvements in post combustion flue gas clean up technologies, coupled with the dry bottom boiler's simpler, more reliable design and greater flexibility in load and fuel properties has led to the dominance of dry bottom PC boilers in the U.S.¹⁷

Wall-fired boilers are the most common type of PC coal-fired boilers, and thus became one of the main subjects of the EPRI-DOE test burns and analysis. Cofiring biomass in wall-fired boiler units was tested and demonstrated at three locations: Colbert Fossil Plant, Tennessee Valley Authority (TVA); Seward Generating Station, GPU Genco; and Blount St. Station, Madison Gas & Electric (MG&E).

¹⁶ Babcock & Wilcox, 1978, Steam: Its Generation and Use, The Babcock and Wilcox Company, New York, NY.

¹⁷ Elliot, M.A., 1981, Chemistry of Coal Utilization: Second Supplementary Volume, Prepared under the Guidance of the Committee on Chemistry of Coal Utilization, John Wiley & Sons, New York, NY.

Table 2.1 Maryland Utility Coal-fired Units

Coal-fired Generating Capacity in Maryland (> 2 MW)					Boiler Characteristics				
Owner	Plant Name	No. of Units	Total Coal Capacity (MW)	Location	Unit No.	Boiler Type	Unit Capacity (MW)	Boiler Type	Boiler Age (Years)
AES Corp.	Warrior Run	1	180	Allegany County	2	CFBC	180	Circulating	2
Allegheny Energy Supply	R.P. Smith	2	117	Washington County	3	PC	29	Dry Bottom, Wall-fired	55
					4	PC	88	Dry Bottom, Tangential	37
Constellation Power Source	Brandon Shores	2	1,380	Anne Arundel County	1	PC	690	Dry Bottom, Wall-fired	18
					2	PC	690	Dry Bottom, Wall-fired	11
Constellation Power Source	C.P. Crane	2	380	Baltimore County	1	Cyclone	190	Wet Bottom	41
					2	Cyclone	190	Wet Bottom	39
Constellation Power Source	H.A. Wagner	2	453	Anne Arundel County	2	PC	134	Dry Bottom, Wall-fired	43
					3	PC	319	Dry Bottom, Cell burner	36
Mirant Energy Corporation	Chalk Point	2	683	Prince George's County	1	PC	341	Dry Bottom, Wall-fired	38
					2	PC	342	Dry Bottom, Wall-fired	37
Mirant Energy Corporation	Dickerson	3	573	Montgomery County	1	PC	191	Dry Bottom, Tangential	43
					2	PC	191	Dry Bottom, Tangential	42
					3	PC	191	Dry Bottom, Tangential	40
Mirant Energy Corporation	Morgantown	2	1,164	Charles County	1	PC	582	Dry Bottom, Wall-fired	32
					2	PC	582	Dry Bottom, Wall-fired	31
Total Maryland Coal Capacity			4,930			4,930			

Tangentially fired (T-fired) boilers are fundamentally different from wall-fired boilers in that they employ a single central fireball in the middle of the furnace for combustion, as opposed to discrete burners, with sets of burners employing distinct flames and combustion zones. T-fired boilers have multiple fuel and air injections points that feed in a direction tangent to the combustion zone and generally have lower heat release rates and lower NO_x emissions than wall-fired PC boilers. Due to the single fireball combustion zone, the T-fired boiler is seen as an appealing technology for cofiring with considerable flexibility. The EPRI-DOE cooperative program included cofiring tests, demonstrations and commercialization at four sites with T-fired boilers: Kingston Fossil Plant, TVA; Greenridge Station, New York State Electric and Gas (now AES); the Albright Generating Station, Allegheny Energy Supply Company, LLC (Allegheny); and Plant Gadsden, Southern Company.¹⁸

2. Efficiency with Biomass Cofiring in PC Boilers

The PC Boiler design comprises the largest share of boilers covered by Title IV of Clean Air Act Amendments (CAAA), and would therefore seem to indicate a potential target for biomass cofiring as an emissions reductions strategy. However, requirements for retrofitting are substantially higher for PC boilers than most other designs. There are limitations on the amount of biomass that can be blended with coal in the feed system, about 2-4 percent by heat input. A separate feed system is required to cofire biomass in greater amounts. Separate feed systems, however, require significantly higher capital costs for retrofitting, as there is a need for the addition of biomass injection ports and a biomass combustion air system; or require using existing ports and tuning combustion air flows. Biomass cofiring generally requires increased excess air in PCs and increased fan capacity may be needed.¹⁹

¹⁸ Tillman, D.A., 2001, *Final Report: EPRI-DOE Cooperative Agreement: Cofiring Biomass with Coal*, DOE Contract No. DE-FC22-96PC96252.

¹⁹ Antares Group, Inc. and Parsons Power, 1996, *Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments, Prepared for the Northeast Regional Biomass Program and the United States Department of Energy*, Final Report, December 13, 1996.

3. Maryland Power Plants with PC Boilers

The R. P. Smith plant is located in Williamsport, Washington County, Maryland. The plant currently has two active coal-fired units. Unit 3, brought on line in 1947, utilizes dry bottom, wall-fired boiler technology and has a maximum capacity of 29 MW. Unit 4, brought on line in 1965, utilizes dry bottom, tangentially fired boiler technology and has a maximum capacity of 88 MW.²⁰

Constellation Energy operates Brandon Shores and H.A. Wagner in Maryland. The Brandon Shores plant, located in Anne Arundel County, has two coal-fired units. Units 1 and 2, respectively brought on line in 1984 and 1991, have each a maximum capacity of 690 MW to produce electricity. Both units utilize dry bottom, opposed-firing boiler technology.

The H.A. Wagner plant is also located in Anne Arundel County. Two of the five Wagner units, units 2 and 3, are coal-fired. They both utilize dry bottom boiler technology, and have a maximum capacity of 134 and 319 MW, respectively. The units were brought on line in 1959 and 1966. Units 1 and 2 of Brandon Shores, and unit 3 of H.A. Wagner have selective catalytic reduction emissions controls installed.

Mirant Energy Corporation operates the Chalk Point, Dickerson, and Morgantown generating plants in Maryland. The Chalk Point plant is located in Prince George's County and operates two coal-fired units. Unit 1, brought on line in 1964, has a maximum capacity of 341 MW, and Unit 2, brought on-line in 1965, has a maximum capacity of 342 MW. Both units utilize dry bottom, opposed-firing, super critical boiler technology. The Dickerson plant, located in Montgomery County, operates seven power generation units. Three of the seven units at this plant are coal-fired. Unit 1, brought on line in 1959, Unit 2, brought on line in 1960, and Unit 3, brought on line in 1962, each have a maximum capacity of 191 MW. All three units utilize dry bottom, tangentially fired boiler technology. The Morgantown Generating plant, located in Charles County, includes eight power generation units, of which two are coal-fired. Units 1 and

²⁰ Energy Information Administration, EIA906/920, 2004.
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

2 are dry bottom, tangentially fired boilers, each with a maximum capacity of 582 MW. The units were brought on line in 1970 and 1971, respectively.²¹

C. Cyclone Boiler

1. Technology Description

The cyclone boiler was designed as an extension of the wet bottom boiler, in that they employ a two stage, wet bottom design. Wet bottom boilers, or “slag tap” units, were originally developed to deal with the particulate emission problems associated with early dry bottom PC boilers by getting the ash into heavier granular form and retaining more of it in the furnace where it could be more easily removed. Due to advances in confining and intensifying the ash melting process, cyclone boilers have a much smaller area for combustion and slag formation than wet bottom PC boilers. Additionally, cyclone boilers have certain advantages over PC boilers in that they: 1) allow for the use of larger particle sizes, up to ¼ inch, which reduces the need for pulverizers and, in turn, reduces the cost of fuel preparations; 2) have a reduction of fly ash content in the flue gas, as ~70 percent of ash exits as molten bottom ash as opposed to dry fly ash; and 3) have a reduction in furnace size.²² This type of boiler is generally most economic for use with lower rank or grade coals, as the economics of dry bottom PC boilers are still superior with higher-grade coals.

The fuel is generally reduced to a size so that 95 percent of the particles pass through a four-mesh screen. The fuel and primary air mixture is introduced into the furnace tangentially to the direction of the burner, which imparts a whirling motion to the fuel particles. Combined with the secondary air entering in the same direction tangentially at the roof of the main barrel at 300 ft/sec, the cyclonic action within the furnace pushes the particles to the walls where combustion takes place. The whirling air also forces the CO₂ product of combustion away from the surface

²¹ Energy Information Administration, EIA906/920, 2004.
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

²² Elliot, M.A., 1981, *Chemistry of Coal Utilization: Second Supplementary Volume*, Prepared under the Guidance of the Committee on Chemistry of Coal Utilization, John Wiley & Sons, New York, NY.

of the particle allowing for more complete combustion and a lower residence time even with larger particles than in PC boilers.²³

2. Efficiency with Biomass Co-firing

Due to the acceptance of larger particles, the absence of a pulverizer, and relatively high amounts of NO_x formation, cyclone boilers can implement biomass cofiring. Cofiring in cyclone boilers is significantly different than cofiring in other boiler types, and manipulating the combustion process in a cyclone furnace is a much different process than that of a PC boiler.²⁴ The cyclone boiler's design of injecting air tangentially creates a swirling motion that traps large particles against the sidewall in slag layer and allows them to burn completely. This gives the ability to burn larger particles, which reduces biomass fuel processing equipment needs and costs. The higher temperatures provide a better carbon burn, which actually increases boiler efficiency despite higher biomass moisture content. The higher moisture content and volatility levels in biomass have been shown to lower NO_x.²⁵

3. Maryland Power Plants

Constellation Energy operates the C.P. Crane plant located in Baltimore County. Two of the three units at this plant are coal-fired with wet bottom, cyclone boilers. Each of the coal-fired units has a maximum capacity of 190 MW. The units were brought on line in 1961 and 1963.²⁶

²³ Babcock & Wilcox, 1978, *Steam: Its Generation and Use*, The Babcock and Wilcox Company, New York, NY.

²⁴ Tillman, D.A., 2001, *Final Report: EPRI-DOE Cooperative Agreement: Cofiring Biomass with Coal*, DOE Contract No. DE-FC22-96PC96252.

²⁵ Antares Group, Inc. and Parsons Power, 1996, *Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments, Prepared for the Northeast Regional Biomass Program and the United States Department of Energy*, Final Report, December 13, 1996.

²⁶ Energy Information Administration, EIA906/920, 2004.
http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

D. Fluidized Bed Combustors

1. Technology Description

Fluidized bed combustion (FBC) involves the combustion of a fuel in a bed of inert material (i.e., sand, ash, or sorbent) at temperatures ranging from 1400-1700°F. Air injected from underneath the bed at high velocities, from 2 to 10 m/s, causes the individual particles to be forced upwards until they reach a point where they remain suspended in the air stream. The suspended particles take on the hydrodynamic properties of fluid, and are therefore termed “fluidized.” The fluidized movement within the combustion chamber translates into increased heat transfer efficiency, and therefore lower combustion temperatures are needed, which avoids problems of NO_x formation, slagging and fouling associated with high temperature combustion processes.²⁷

The wide range of fuels acceptable for FBC combustion (e.g., all grades of coals, natural gas, fossil fuel wastes, wood wastes and chips, agricultural and forestry wastes, municipal solid waste, peat, etc.) gives this technique a distinct economic advantage over control of variable fuel costs. Additionally, the size of fuel fed into an FBC is much larger than for a comparable PC boiler system, up to ¼ inch in size. The increased size of particles fed into the boiler means that less energy must be spent in pulverizing the coal, and a longer residence time of the fuel in the combustion bed will result.

The FBC technology can be broken down into both atmospheric and pressurized FBCs. The Atmospheric Fluidized Bed Combustor (AFBC) operates at normal pressures (1 atm), and basically performs the same work as a conventional boiler in driving a steam turbine. Pressurized Fluidized Bed Combustors (PFBC), because of the increased energy of gases exiting the boiler (>1.5 atm), can be used to drive both a gas turbine and a steam turbine, generally referred to as a combined cycle. Within both the AFBC and PFBC options, two predominant types of technologies exist: Bubbling Bed (or conventional bed), and Circulating technologies.²⁸

²⁷ U.S. Department of Energy, Office of Fossil Energy, 2002, *Electric Power R&D: Fluidized Bed Coal Combustion*, http://www.fossil.energy.gov/programs/powersystems/combustion/fluidizedbed_overview.html.

²⁸ Singer, J.G., 1981, Combustion: Fossil Power Systems- A Reference Book on Fuel Burning and Steam Generation, Combustion Engineering, Inc., Windsor, CT.

Advantages of the FBC design over other coal combustion technologies include: 1) the wide variety of fuels that can be used; 2) mixing of limestone/lime with the fuel or bed materials allows SO₂ reduction to occur in the combustion area, without needing expensive flue gas clean-up devices; and 3) low combustion temperatures reduce the levels of NO_x and slag formation produced from combustion processes.²⁹

2. Efficiency with Biomass Co-firing

FBCs are another attractive technology for cofiring, but for different reasons than other technologies. The fuel flexibility inherent in FBCs allows a wide range of fuels to be accepted for cofiring. Since FBCs can fire limestone (or lime) with fuel in the combustion chamber to reduce SO₂, cofiring is therefore not an SO₂ reduction strategy, but rather lowers the amount of reagent needed and thus lowers operating costs. FBCs are easily retrofitted, with only the fuel delivery system as a primary concern.³⁰

3. Maryland Power Plants

The Warrior Run plant located in Cumberland, Allegany County, Maryland operates a CFBC boiler plant with a maximum capacity of 180 MW. The plant was brought on line in 2000.³¹

E. Environmental Considerations of Coal-Fired Power Plants

The major pollutants produced by the combustion of coal include particulate matter, sulfur oxides and nitrogen oxides. As a fossil fuel, coal combustion technologies are also a significant source of carbon dioxide (CO₂) emissions. In addition, some unburned combustibles such as carbon monoxide and numerous organic compounds are generally emitted as well. The

²⁹ U.S. Department of Energy, Office of Fossil Energy, 2002, *Electric Power R&D: Fluidized Bed Coal Combustion* http://www.fossil.energy.gov/programs/powersystems/combustion/fluidizedbed_overview.html

³⁰ Antares Group, Inc. and Parsons Power, 1996, *Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments, Prepared for the Northeast Regional Biomass Program and the United States Department of Energy*, Final Report, December 13, 1996.

³¹ Energy Information Administration, EIA906/920, 2004. http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

level of emissions varies a great deal and is dependent on a variety of factors including the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies and the level of equipment maintenance.³²

Particulate matter is primarily composed of inorganic ash residues. Coal either settles in the boiler as bottom ash or is entrained in the flue gas as fly ash. The ratio of bottom ash to fly ash directly affects the particulate emission rate and is primarily dependent on the boiler firing method and furnace type (wet or dry bottom). Boiler load can also affect particulate matter emissions as decreasing loads reduces emissions. Particulate matter emissions are categorized as either filterable or condensable. Filterable particles are those that can be trapped by a glass fiber filter while condensable particles pass through the filter and are generally emitted as vapor. Particulate matter emissions can be minimized through combustion modifications such as proper design and operation of air delivery system, operating within recommended load ranges, controlling the rate of load changes and ensuring steady fuel feed. The post combustion minimization of particulate matter emissions can be managed by using electrostatic precipitators (ESP), fabric filters, wet scrubbers, cyclone or multiclone collectors and side steam separators.³³

The combustion of coal generally produces sulfur dioxide with a much smaller quantity of sulfur trioxide and gaseous sulfates. About 95 percent of the sulfur present in bituminous coal will be emitted as gaseous sulfur oxide while the emissions from the combustion of subbituminous coal are slightly less. Sulfur emissions can be managed simply by using lower sulfur coals as available. In some cases, a coal cleaning process may also be employed. Post combustion minimization of sulfur oxides can be accomplished through the use of flue gas desulfurization techniques, which utilize an alkaline reagent to absorb sulfur dioxide. Flue gas desulfurization techniques are categorized into dry, wet and semi-dry techniques. Wet systems are the most commonly applied and generally use alkali slurries, which can remove 90 percent or more of the sulfur dioxide from flue gas.³⁴

³²EPA, AP 42 Fifth Edition Volume I, *External Combustion Sources: Bituminous and Subbituminous Coal Combustion*, September 1998, p. 3. <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>.

³³ *Ibid.* pp. 3, 6-7.

³⁴ *Ibid.* pp. 3, 7-8.

Nitrogen oxides emissions from the combustion of coal are generally composed of nitric oxide with a small percentage of nitrogen dioxide. Nitrogen oxides form as a result of the thermal fixation of atmospheric nitrogen in the combustion flame and from the oxidation of nitrogen bound in the coal. Experimentation has demonstrated that the concentration of nitrogen oxides is exponentially related to the temperature. Cyclone boilers typically have high rates of conversion of nitrogen to nitrogen oxides. Combustion controls are primarily used to manage nitrogen oxides and include methods such as low excess air, burners out of service, biased burner firing, overfire air, low nitrogen oxide burners and reburn. Most of the combustion controls generally reduce the amount of oxygen available in the combustion zone, which reduces the amount of nitrogen that can be fixed to form nitrogen oxides. Other combustion methods manage temperatures within the combustion zone. Post combustion controls include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). SNCR and SCR are methods by which ammonia is either ejected into various temperature zones or into flue gas to reduce nitrogen oxides to water and nitrogen. SCR and SNCR techniques have demonstrated reductions of 75 to 86 percent.³⁵

F. Biomass Cofiring Retrofit Consideration

In general terms, retrofitting an existing coal-fired boiler to cofire with biomass will require careful consideration of several factors. These technical, economic, environmental, and regulatory factors are discussed below.

First, the plant will need a biomass fuel handling system. The extent to which retrofits will be needed depends on whether the fuel will be blended with coal or injected via a separate feeding system. The fuel handling system may require additional processing equipment such as spike rolls, disc screens, and hammer mills to properly size the biomass. The facility will also need storage, reclaim and fuel metering systems.

Additionally, cofiring biomass with coal may cause problems with ESPs or other exhaust gas treatment systems due to increased flue gas volumes, and fly ash resistivity of the

³⁵ EPA, AP 42 Fifth Edition Volume I, *External Combustion Sources: Bituminous and Subbituminous Coal Combustion*, September 1998, pp. 3, 9-11. <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf>.

coal/biomass particulate mixture, which may decrease ESP efficiency. Also, excess air requirements and higher fuel moisture associated with cofiring biomass will increase the plant heat rate and flue gas flow rates, which may decrease plant capacity and/or boiler efficiency. The plant may need to add additional fan capacity due to increased pressure (draft) losses in the combustion air and flue gas path equipment.

Efficiency losses and capacity deratings must be addressed when considering biomass cofiring. Increased moisture of biomass fuels impedes the transfer of heat to the working fluid and generally leads to lower efficiencies (i.e., higher heat rates). Efficiency losses may also stem from the higher hydrogen to oxygen ratio of fuel, which is converted to water during combustion, absorbs heat and creates steam losses from the boiler. These losses tend to increase with higher percentages of biomass fuel. Additionally, dry gas losses, the mass flow of the dry gases, which normally transfer heat to the working fluid, are increased and therefore efficiency is lost.³⁶

If the total air requirements exceed the induced draft fan capacity or if the gas velocities exceed the allowable limits, then the unit capacity will be derated. Biomass cofiring may increase excess air requirements and feed rates leading to increased combustion air and flue gas flow rates and thus increased gas velocities.³⁷

³⁶ Antares Group, Inc. and Parsons Power, 1996, Utility Coal-Biomass Co-firing Plant Opportunities and Conceptual Assessments, Prepared for the Northeast Regional Biomass Program and the United States Olsen, A., 2001, Co-Burning Biomass Opportunities in Wisconsin: A Strategic Assessment, Prepared for the Division of Energy, Wisconsin Department of Administration, DE-FG45-99R530438, June 2001.

III. Biomass Resource Assessment

Local availability and cost of biomass are principal factors in determining feasibility of cofiring. The coexistence of multiple raw materials is vastly preferred to a single local resource. A single fuel stream can be overburdened by competition, a bad economy, weather, or low production yields. For the purpose of this analysis, biomass resources are categorized according to five groups: urban waste woods, mill residues, forest residues, agricultural residues, and dedicated energy crops. In addition to biomass resources from Maryland, resources from some counties in Pennsylvania, Virginia, and West Virginia are considered to be available for use by some of the Maryland coal plants, depending on location. This section presents the data and methodology used to estimate biomass resources for counties within a 50-mile radius of each plant. A 50-mile radius was chosen as the maximum distance that biomass resources could be transported economically.³⁸ The assessment of biomass resource availability described in this chapter includes the viable resources for those counties in Maryland, Pennsylvania, Virginia, and West Virginia that have more than 25 percent of their land area within a 50-mile radius of a Maryland coal-fired power plant (Figure 3.1).

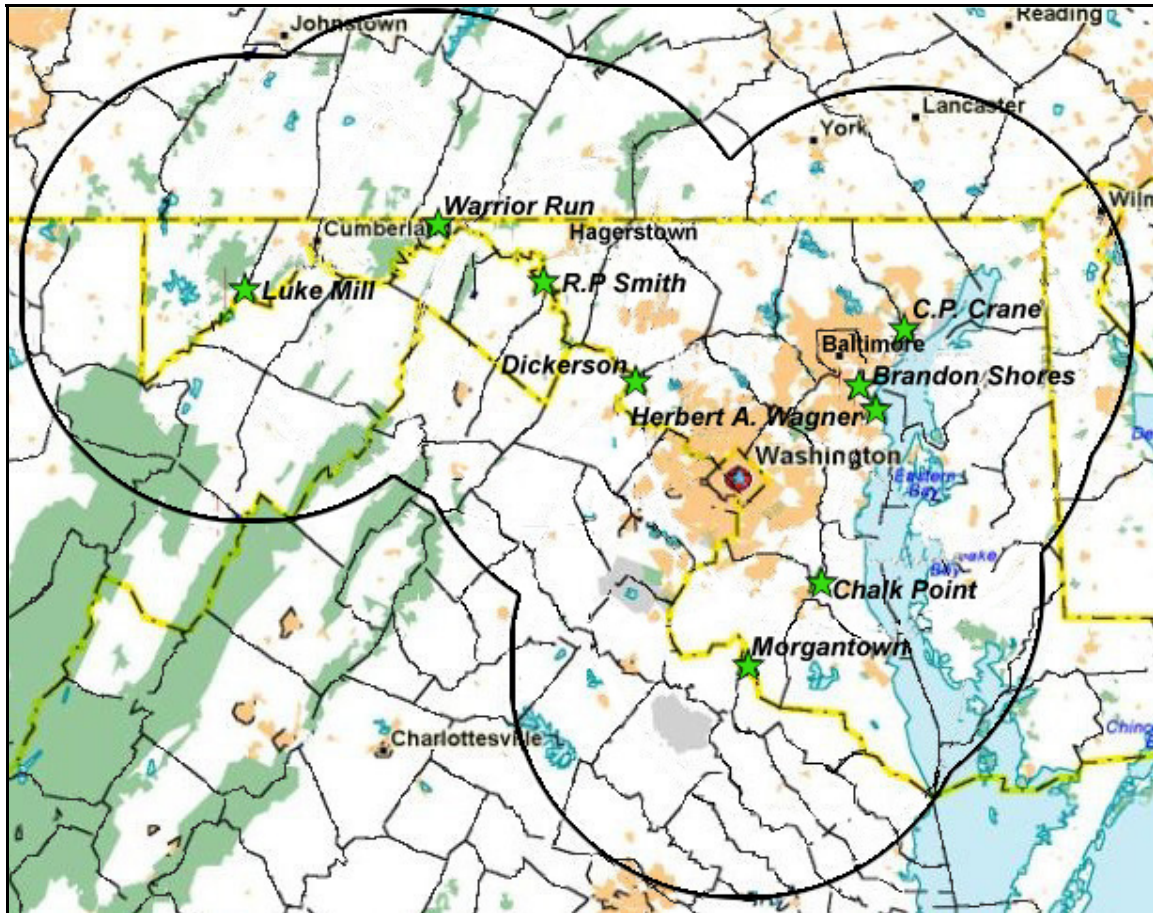
A. Urban Waste Woods

Urban waste woods that are not composted or otherwise recycled could be diverted from various landfills, separated and processed as fuel and ultimately cofired with coal. Not all of the waste generated within a specific geographic region would be applicable to cofiring. The demographics of an area, including geography, population, economic base, income and land use determine not only the amount and type of waste that is generated in an area but the waste management collection practices and alternatives. An area with a low-density population and little industry will have a waste stream comprised primarily of residential waste with various products commingled in a central facility or landfill. A high-density population area is likely to have multiple repositories for waste, often separated by industry or source-sector. This section

³⁸ *Renewable Energy Technology Characterizations, Topical Report – 109496*, Electric Power Research Institute, December 1997, pp. 2-40.

describes the amount and availability of various wastes streams as well as the potential for utilizing urban wastes as a biomass fuel.

Figure 3.1 Geographic Region for Biomass Resource Assessment



The physical characteristics of urban waste wood vary greatly. There are three main categories of waste: municipal solid waste, construction and demolition waste, and industrial waste. For purposes of this analysis, industrial waste is considered to be non-woody material not applicable to biomass cofiring. Municipal solid waste (MSW) contains a wide variety of wood products and residues, including: wood furniture, fencing, poles, toys, cabinets, yard wastes and tree trimmings. While not classified as MSW, construction and demolition debris, non-hazardous industrial wastes, and wastewater treatment sludge are often disposed of in the same landfill as MSW.³⁹ As the name indicates, construction and demolition (C&D) waste is produced

³⁹ *Municipal Solid Waste in the United States: 2001 Facts and Figures*, U.S. Environmental Protection Agency, p. 4.

in the process of building, renovating or demolishing buildings or structures. Components of C&D typically include concrete, asphalt, pallets, wood, metals, gypsum wallboard, and roofing material. Land clearing debris is often commingled with C&D waste.⁴⁰

Local economic conditions, along with local regulations, the weather and major disasters all impact the amount and type of waste received.⁴¹ For example in the months following Hurricane Isabelle, which struck the mid-Atlantic region on September 8, 2003, the State of Virginia reported a significant amount of woody waste attributed to downed trees and C&D. According to the data collected in Virginia, the hurricane created more than 3,280,000 tons of woody waste as reported by 97 waste management facilities provided with emergency permits to handle the waste.⁴²

A national study analyzing the composition of MSW by material type indicates that wood products make up six percent of the materials generated in the municipal waste stream (Figure 3.2).⁴³ State-specific waste composition data is unavailable for Maryland, but Pennsylvania's *Statewide Waste Composition Study* found that wood materials make up 8.3 percent of the landfilled MSW.⁴⁴ Due to the similarity of demographics and product availability between Maryland and Pennsylvania, the Pennsylvania waste composition data is assumed to be a better indication for the waste composition of Maryland than the information provided in the EPA study. Maryland's MSW landfills accepted 1,561,024 tons of MSW in 2003. Assuming 8.3 percent of the waste is waste wood, an estimated 129,565 tons of waste wood was landfilled in 2003.⁴⁵

⁴⁰ *Characterization of Building-Related Construction and Demolition Debris in the United States*, Prepared by Franklin Associates for the U.S. Environmental Protection Agency Municipal and Industrial Solid Waste Division, Office of Solid Waste, June 1998, p. ES-2.

⁴¹ *Characterization of Building-Related Construction and Demolition Debris in the United States*, p. 1-4.

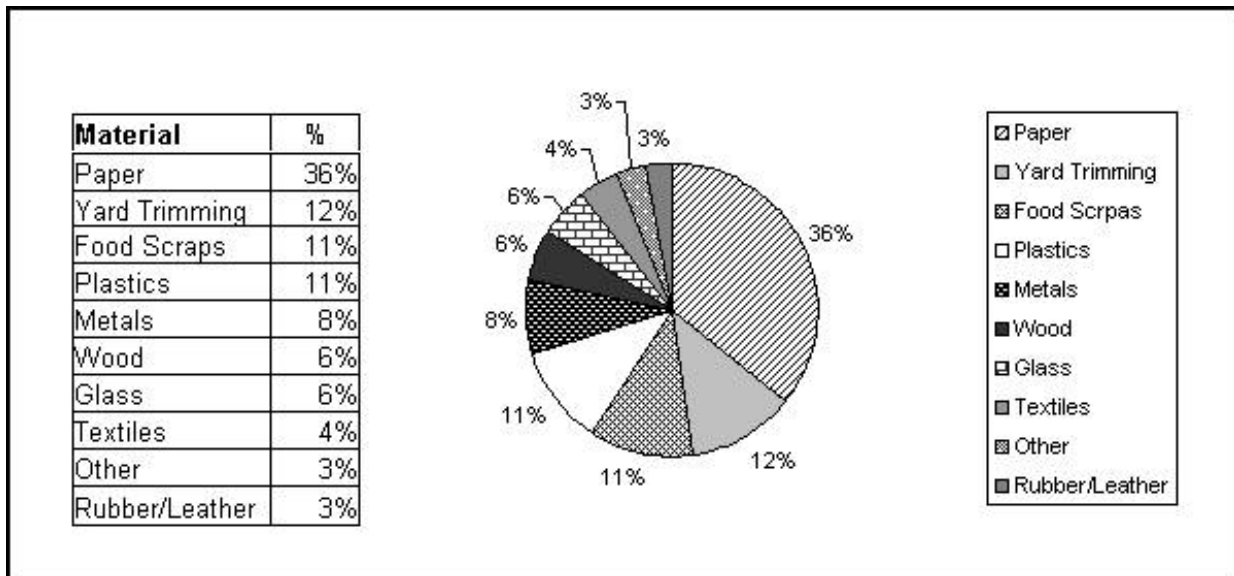
⁴² *Solid Waste Managed in Virginia During Calendar Year 2003*, Department of Environmental Quality, Commonwealth of Virginia, June 2004, p. 5.

⁴³ *Municipal Solid Waste in the United States: 2001 Facts and Figures*, p. 34.

⁴⁴ *Statewide Waste Composition Study*, Pennsylvania Department of Environmental Protection, April 2003, p. 4-10.

⁴⁵ Landfill Tonnage data for 2003 provided by A.Hussain Alhija, Engineer Chief, Design & Certification Division Solid Waste Program, Maryland Department of the Environment via electronic mail on April 8, 2005.

Figure 3.2 Materials Generated in MSW in the U.S., 2001



Sources of C&D waste include homebuilders, homeowners, commercial developers, building contractors, highway contractors, pavement contractors, remodelers, grading contractors, demolition specialists, and excavation contractors. The amount of waste generated depends on the type of construction or demolition. A residential construction project provides approximately 4.38 pounds of waste per square foot constructed.⁴⁶ With 29,300 new construction-housing permits issued in 2004 and an average size of 2,100 square feet per house, an estimated 134,750 tons of waste was generated by new home construction in Maryland in 2004.⁴⁷ The National Association of Home Builders estimates that 42 percent of the total amount of waste generated in residential new construction is wood.⁴⁸ Therefore, an estimated 57,000 tons of waste wood was generated in Maryland from residential new construction in 2004.

A large amount of the C&D waste generated in the United States is landfilled. Inert materials (those with little to no “active” properties), such as sand, lumber, cement, and appliances, are often sent to special C&D landfills that have fewer environmental protections

⁴⁶ *Characterization of Building-Related Construction and Demolition Debris in the United States*, p. 2-3.

⁴⁷ *Annual State and Metro Building Permits*, National Association of Home Builders, Construction Statistics, <http://www.nahb.org/page.aspx/category/sectionID=130>.

⁴⁸ *Characterization of Building-Related Construction and Demolition Debris in the United States*, p. 2-15.

(liners, leachate collection) and thus cost less to operate. These C&D landfills usually have lower tipping fees and more stringent acceptance controls. Despite the lower tipping fees, C&D wastes are often sent to MSW landfills because they are closer or because of contractual agreements among waste management companies. Once commingled in an MSW landfill, C&D waste wood is difficult to separate and recover for use in biomass cofiring facilities. Approximately 41 percent of C&D waste is sent to C&D landfills.⁴⁹ On average, waste wood from construction and demolition has moisture content of 12 to 15 percent.⁵⁰

Whether deposited in an MSW landfill or C&D landfill, waste wood from commercial tree trimming operations or recovery of wood pallets are another viable resource for cofiring. Waste woods collected from commercial tree trimming operations provide a biomass fuel that has relatively consistent physical properties with moisture content of 35 to 60 percent. Commercial tree trimmers often use drum chippers, which produces wood chips that are 25 mm by 6 mm by 75-100 mm blown directly from the chipper into a transport van. Additionally, the waste wood is usually transported as a mono-load making it a good, separated waste wood and a viable resource for biomass cofiring.⁵¹ Pallets and wooden packaging materials are typically constructed of hardwood, have moisture content between 12 to 15 percent, and are largely free of non-wood materials except nails. For use as a fuel, pallets and packaging material must be broken up into smaller pieces with all non-wood materials, such as nails removed. This is easily done with the use of a hammer mill to break apart pieces and a magnet to remove metal.⁵²

While economic activity, demographics and population density are good indicators for the amount and type of urban waste that is available in a given geographic area, collection of urban wastes from individual homes and businesses is typically managed via an existing waste management system made up of local government and private businesses. Therefore, when analyzing the availability of urban waste woods as a biomass resource it is necessary to consider the collection and disposal of various waste streams. For purposes of this analysis, it is assumed

⁴⁹ *Characterization of Building-Related Construction and Demolition Debris in the United States*, p. 3-1.

⁵⁰ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 6.

⁵¹ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 7.

⁵² Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 7.

that any viable supplies of waste wood would be a from a waste management facility such as a landfill or transfer station located within a 50-mile radius of a power plant. Material recovery facilities are facilities at which wastes are separated, either mechanically or physically for the purpose of reuse. Most material recovery facilities accept and sort paper, plastic, glass and aluminum products and do not process wood products. Without a change in the collection and business practices of material recovery facilities so that wood products are collected and separated, it is unlikely that material recovery facilities would provide a viable resources for urban waste wood biomass fuels.

Transfer stations provide a temporary storage, less than five days, for urban waste. The purpose of a transfer station is to offload the waste from small collection vehicles (usually less than 10 tons per vehicle) and prepare the waste for transport to a disposal facility via larger transportation vehicles. These large trucks can hold four or five times the amount of waste as the smaller collection vehicle and is designed to more efficiently transport the waste to its final destination.⁵³ Separating and collecting urban waste woods from a transfer facility may be possible, particularly if waste collection is done in a manner that provides a segregated waste source. For example, commercial tree trimming or construction and demolition wastes arrive separately from mixed municipal solid waste and are able to be segregated and separated on site.

From the transfer station the urban waste is transported to a final disposal area, typically an incinerator or landfill. Once the wastes have been commingled in a landfill the opportunity to recover useable waste wood products is very low. Only those landfills that provide facilities to physically separate waste wood products from non-wood or inorganic waste products are a viable resource. A “mono-load,” or a load of solid waste comprised only of one source, for example tree trimmings or pallets, is the best opportunity to recover waste woods. According to the analysis conducted by Phillip Badger of Oak Ridge National Laboratories, “usually, only the wood that is brought to the landfill in the form of mono-loads of waste wood is recovered.”⁵⁴

⁵³ *West Virginia Solid Waste Management Plan*, West Virginia Solid Waste Management Board, January 2005, p. 3-24. Available www.state.wv.us/swmb/ accessed April 1, 2005.

⁵⁴ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 8.

A review of the waste management facilities in Maryland and neighboring states provide an estimate of the potential biomass resources available from urban waste woods. The amount of biomass material available from urban waste streams as fuel is estimated to be the total amount of urban waste, excluding those materials already combusted, recycled or composted and adjusted for moisture content and the amount of waste wood that can be separated.

Data and reports available from the Maryland Department of the Environment, and the Department of Environments of Pennsylvania, Virginia and West Virginia were examined to calculate the amount of waste wood contained in municipal solid waste. The Maryland Department of the Environment collects data from Maryland landfills on the amount and type of solid waste managed in the State (Table 3.1). In 2003, 26.6 percent of the 13,599,235 tons of solid waste was placed in landfills within the State.⁵⁵

Table 3.1 Solid Waste Managed in Maryland, Calendar Year 2003

Solid Waste Category	Tons Accepted for Disposal^a	Tons Recycled or Composted^b	Total Tons Managed
Construction & Demolition	1,913,774	307,489	2,221,263
Industrial Waste	161,377	164,437	325,814
Land Clearing Debris	94,389	41,474	135,863
Municipal Solid Waste	4,772,651	2,171,131	6,943,782
Other Wastes	145,244	3,374,132	3,519,376
Subtotal	7,087,435	6,058,663	13,146,098
Incinerator Ash^c	195,182	257,955	453,137
TOTAL	7,282,617	6,316,618	13,599,235

^a Includes waste accepted at landfills (3,623,799 tons) and incinerators (1,444,325 tons) for disposal and wastes transported out of state (2,214,493 tons).

^b Other wastes includes scrap metal, asphalt and concrete recycled into roadways, which is not included in the 36.8 percent annual "Maryland Recycling Act" average.

^c Total Tons Managed indicates the tons of incinerator ash accepted at MSW landfills for disposal and the "Tons Recycled or Composted" section indicates that portion of ash that was utilized at the facility for "Landfill Construction."

⁵⁵ *Solid Waste Managed in Maryland Calendar Year 2003*, Report to the House Environmental Matters Committee and Senate Education, Health, and Environmental Affairs Committee, September 2004, p. 8.

Most Maryland counties and Baltimore City have a solid waste landfill facility within their jurisdiction. Only Montgomery, Caroline, Kent and Queen Anne's Counties do not have a local MSW landfill. Allegany County is the only county that has a privately owned landfill. Four counties have C&D landfills located within their jurisdictions: Baltimore, Harford, Prince George's and Queen Anne's Counties. All five of the construction and demolition landfills (Baltimore County has two facilities) are owned and operated by private companies.⁵⁶ Landfill tonnage data for Maryland and neighboring counties in Pennsylvania, Virginia, and West Virginia is provided below (Table 3.2).

The data presented in Table 3.2 include only the waste that is placed in landfills in Maryland and neighboring counties in Virginia, West Virginia, and Pennsylvania. The table includes both private and public landfill facilities. Counties without a landfill are not listed in the table, even if they are within 50-miles from a Maryland coal-fired power plant. Data specific to land clearing debris was only available for Maryland. For purposes of this report, the analysis of urban waste wood includes only waste that is placed in landfills. Waste that is otherwise recycled, composted, or combusted in waste-to-energy facilities is not considered an available resource for use in a biomass cofiring facility.

More than nine million tons of waste is landfilled in Maryland and the surrounding counties. However, the large majority of the waste is not suitable for cofiring. Only the wood that can be physically separated from other waste products can be used in cofiring. Additionally, only a fraction of the waste is wood suitable for cofiring with coal. Table 3.3, below, identifies the various assumptions used to estimate the tons of wood biomass available from urban waste woods. Adjustments based on moisture content, wood content and the ease of physically separating the waste wood from other waste products, are made to estimate the total amount of urban waste wood. Based on these assumptions, for every ton of MSW collected at a landfill, approximately 46.6 pounds of urban waste wood may be recovered for cofiring with coal. Likewise, for every ton of construction and demolition waste, and land clearing waste collected at a landfill, 357 pounds and 654.5 pounds of useable waste wood are recovered, respectively.

⁵⁶ *Solid Waste Managed in Maryland, Calendar Year 2003*, p. 10.

Table 3.2 Landfill Tonnage Data by State and County, 2003 (Wet Tons)⁵⁷

County	MSW Landfilled (Residential & Commercial)	C&D Landfilled	Land Clearing Debris Landfilled	Total Landfilled
MARYLAND^a				
Allegany	106,829	17,110	-	123,939
Anne Arundel	96,905	19,118	23,162	139,186
Baltimore	184,049	470,055	772	654,876
Calvert	2,049	5,447	2,100	9,596
Carroll	-	12,850	-	12,850
Cecil	69,098	8,531	184	77,813
Charles	35,973	-	-	35,973
Dorchester	-	11,115	-	11,115
Frederick	155,355	65,230	843	221,428
Garrett	22,971	8,675	1,996	33,642
Harford	50,657	124,667	-	175,324
Howard	30,303	8,879	-	39,183
Prince George's	419,676	350,907	15,785	786,368
Queen Anne's	-	33,709	2,989	36,698
St. Mary's	-	6,067	-	6,067
Somerset	19,027	5,683	-	24,710
Talbot	104,396	10,892	894	116,182
Washington	95,322	26,694	-	122,016
Wicomico	87,210	3,585	-	90,795
Worcester	81,204	4,286	32,212	117,702
PENNSYLVANIA^b				
Chester	79,527	32,595	-	112,122
York	1,307,854	156,221	-	1,464,074
Lancaster	336,225	-	-	336,225
Bedford	84,431	8,017	-	92,448
Franklin	524,977	49,371	-	574,349
Somerset	878,740	35,267	-	914,007
WEST VIRGINIA^c				
Tucker	73,332	-	-	73,332
Berkeley	118,956	-	-	118,956
VIRGINIA^d				
Fairfax	656,082	1,243,871	-	1,899,953
Fauquier	229,417	-	-	229,417
Frederick	143,242	42,097	-	185,339
Loudoun	38,196	-	-	38,196
Shenandoah	37,182	-	-	37,182
Stafford	165,596	-	-	165,596
TOTAL	6,234,780	2,760,939	80,937	9,076,656

^a Maryland Landfill Tonnage data for 2003 provided by A. Hussain Alhija, Engineer Chief, Design & Certification Division, Solid Waste Program, Maryland Department of the Environment via electronic mail on April 8, 2005.

^b Commonwealth of Pennsylvania, Department of Environmental Protection Bureau of Land Recycling and Waste Management Division of Reporting and Fee Collection: Landfill Waste Receipts for 2003, available from, <http://www.dep.state.pa.us/dep/deputate/airwaste/wm/drfc/reports/repinfo.htm>.

^c West Virginia Solid Waste Management Plan, West Virginia Solid Waste Management Board, January 2005.

^d Solid Waste Managed in Virginia During Calendar Year 2003, Commonwealth of Virginia, Department of Environmental Quality, available from <http://www.deq.state.va.us/waste/aswrs.html>.

⁵⁷Wet tons refers to the weight of a biomass resource as collected and prior to any drying process to remove moisture.

Table 3.3 Data Assumptions for Urban Waste Wood

Municipal Solid Waste	
amount of wood contained in MSW ^a	8.3%
amount of waste wood that is recoverable - separated from other MSW ^b	33%
moisture content of waste wood in MSW ^b	15%
Pounds of Useable Waste wood in 1 Ton of MSW	46.6
Construction and Demolition Waste	
amount of wood contained in C&D ^c	42%
amount of waste wood that is recoverable - separated from other C&D ^c	50%
moisture content of waste wood in C&D ^c	15%
Pounds of Useable Waste wood in 1 Ton of C&D	357.0
Land Clearing Waste wood	
amount of wood contained in land clearing waste ^b	70%
amount of waste wood that is recoverable (separated from non-wood land clearing waste) ^b	85%
moisture content of waste wood from land clearing ^b	45%
Pounds of Useable Waste wood in 1 Ton of Land Clearing Waste	654.5
Source:	
^a <i>Statewide Waste Composition Study</i> , Pennsylvania Department of Environmental Protection, April 2003.	
^b Badger, Phillip T., <i>Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory</i> , Oak Ridge, TN, April 2002.	
^c <i>Characterization of Building-Related Construction and Demolition Debris in the United States</i> , Prepared by Franklin Associates for the U.S. Environmental Protection Agency Municipal and Industrial Solid Waste Division, Office of Solid Waste, June 1998.	

To estimate the available amount of urban waste wood that may be used for cofiring with coal, the tonnage data available by county (Table 3.4) was adjusted according to the assumptions outlined above in Table 3.3. There is an estimated 665,000 tons of urban waste wood available in the region.

B. Mill Residues

Wood is removed from Maryland's forests for a variety of products: building lumber, shipping crates, veneer for shelving and furniture, chips for fuel and particleboard, and pulp for paper. Milling the wood is the first stage of processing after wood is extracted. For the typical log processed by the non-paper hardwood forest products industry, about one-third becomes

Table 3.4 Urban Waste Wood Available by County, 2003 (Dry Tons)⁵⁸

County	Waste wood from MSW	Waste wood from C&D Waste	Waste wood from Land Clearing Waste	Total Urban Waste Wood Available
MARYLAND				
Allegany	2,487	3,054	-	5,541
Anne Arundel	2,256	3,413	7,580	13,249
Baltimore	4,285	83,905	253	88,442
Calvert	48	972	687	1,707
Carroll	-	2,294	-	2,294
Cecil	1,609	1,523	60	3,192
Charles	838	-	-	838
Dorchester	-	1,984	-	1,984
Frederick	3,617	11,644	276	15,536
Garrett	535	1,548	653	2,736
Harford	1,179	22,253	-	23,432
Howard	706	1,585	-	2,290
Prince George's	9,771	62,637	5,166	77,573
Queen Anne's	-	6,017	978	6,995
St. Mary's	-	1,083	-	1,083
Somerset	443	1,014	-	1,457
Talbot	2,431	1,944	292	4,667
Washington	2,219	4,765	-	6,984
Wicomico	2,030	640	-	2,670
Worcester	1,891	765	10,541	13,197
PENNSYLVANIA				
Bedford	1,966	1,431	-	3,397
Chester	1,851	5,818	-	7,670
Franklin	12,222	8,813	-	21,035
Lancaster	7,828	-	-	7,828
Sommerset	20,458	6,295	-	26,754
York	30,449	27,885	-	58,334
WEST VIRGINIA				
Berkeley	2,769	-	-	2,769
Tucker	1,707	-	-	1,707
VIRGINIA				
Fairfax	15,275	222,031	-	237,306
Fauquier	5,341	-	-	5,341
Frederick	3,335	7,514	-	10,849
Loudon	889	-	-	889
Shenandoah	866	-	-	866
Stafford	3,855	-	-	3,855
TOTAL	145,155	492,828	26,487	664,469

residue usually taking the form of bark or chips. Another third ends up as low value lumber, which often is used in the manufacturing of trusses, pallets or rail ties. Finally, the other third of the log, and the mill's primary product, is used as dimension stock for furniture, flooring and

⁵⁸ A dry ton is the weight of a resource after having the moisture removed, as would be required for cofiring.

other wood products. Sources of mill residues include sawmills, paper mills, wood working companies, firewood companies, pallet recycling companies, and lumberyards.

Much of the mill residue produced from wood manufacturing industries is utilized on site as fuel for boilers or kilns in the drying process or sold as mulch.⁵⁹ With two-thirds of their manufacturing process resulting in a “residue” or byproduct, there is already a mature “non-captive” market established for mill residues. Non-captive markets are markets that utilize primary or secondary mill residues as a resource because they are less expensive than other resources. For example, compost or mulch markets are non-captive and utilize mill residue only if the residue is very inexpensive. A power plant seeking to obtain mill residues for fuel may compete with existing non-captive markets for mill residue products.

Lumber mill residues or lumber processing residues consist of the slabs, shavings, trimmings, sawdust, bark, end pieces of wood, and log cores. For fuel use, waste wood is classified into two categories primary mill residues and secondary mill residues. Primary mill residues, also called green mill residue, includes bark, sawdust or fine wood, and slabs and end cuts, also known as coarse wood.⁶⁰ Table 3.5 provides an estimate of the amount of primary mill residue available in Maryland and the surrounding counties in Pennsylvania, Virginia, and West Virginia.

Approximately 20 percent of primary mill residue is comprised of bark, which is typically processed and sold as mulch or other byproducts. Bark is dirty and wet with a moisture content ranging between 35 and 55 percent depending on the climate and species.⁶¹ Bark generally has a high alkali content and is not considered a good biomass fuel for cofiring, despite its use in systems and boilers designed to burn wood fuels. For purposes of this analysis, bark

⁵⁹ According to ORNL, 44 percent of primary mill residues are used for energy.

⁶⁰ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 4.

⁶¹ *The Moisture Content and Specific Gravity of the Bark and Wood of Northern Pulpwood Species*, Research Note NC – 141, North Central Forest Station, Forest Service, U.S. Department of Agriculture, November 1972, p. 3. Available at http://ncrs.fs.fed.us/pubs/rn/rn_nc141.pdf accessed on April 14, 2005.

Table 3.5 Primary Mill Residue by Type and County (Wet Tons)*

County	Bark	Coarse Wood	Fine Wood	Total
MARYLAND				
Allegany	547	911	1,039	2,497
Anne Arundel	1,677	2,805	3,183	7,665
Baltimore	1,678	2,804	3,182	7,664
Calvert	2,624	4,357	4,991	11,971
Caroline	4,136	7,213	7,969	19,319
Carroll	974	1,669	1,865	4,508
Cecil	1,718	2,869	3,263	7,850
Charles	3,150	5,229	5,992	14,371
Dorchester	4,279	7,551	8,990	20,820
Frederick	300	501	569	1,371
Harford	1,635	2,740	3,106	7,481
Montgomery	1,609	2,669	3,061	7,339
St. Mary's	2,569	4,255	4,890	11,714
Somerset	3,113	5,186	5,914	14,212
Worcester	5,794	9,400	11,615	26,809
PENNSYLVANIA				
Adams	1,797	5,373	3,129	10,298
Bedford	10,707	32,035	18,629	61,370
Chester	127	377	221	725
Fayette	9,264	27,948	16,144	53,355
Franklin	11,872	36,949	19,952	68,773
Fulton	2,673	7,991	4,656	15,320
Lancaster	4,541	13,607	7,898	26,046
Somerset	5,974	17,972	10,362	34,308
York	3,370	8,181	6,955	18,506
VIRGINIA				
Caroline	11,357	37,811	29,685	78,853
Clarke	437	1,237	747	2,420
Culpepper	2,521	7,951	4,968	15,440
Essex	2,431	6,379	6,814	15,624
Fauquier	1,559	4,928	3,036	9,523
Frederick	5,636	14,544	12,001	32,180
Loudoun	386	1,231	760	2,377
North-Umberland	1,320	4,495	3,359	9,174
Richmond	8,490	9,853	6,293	24,636
Shenandoah	203	656	406	1,266
Stafford	2,247	7,686	4,823	14,756
Westmoreland	6,807	22,468	18,303	47,577
WEST VIRGINIA				
Berkeley	1,029	1,916	1,813	4,758
Grant	2,067	3,411	2,932	8,410
Hampshire	2,053	3,811	3,610	9,474
Hardy	504	939	889	2,332
Mineral	8,461	15,713	14,880	39,054
Preston	20,951	38,663	36,695	96,310
TOTAL	164,583	394,283	309,593	868,459

*The USDA Forest Service Timber Product Output (TPO) Database Retrieval System provided county-by-county information for forest and mill residues. TPO data consists of 11 data variables which describe the round-wood products harvested, the logging residues left behind, the timber otherwise removed, and the wood and bark residues generated by primary wood-using mills for each county. Residue data, presented in dry tons, were compiled for the 2002 calendar year from the latest TPO studies available for each State. Timber Products Output Database, available at http://ncrs2.fs.fed.us/4801/fiadb/rpa_tpo/wc_rpa_tpo.ASP.

residue is not included as a viable cofiring resource. Additionally, approximately 25 percent of all mill residue is already used for fuel, with an estimated 12 percent used on site in drying kilns or boilers.⁶² The mill residue used as fuel on site is not considered as a potential resource for cofiring with coal. After subtracting the bark and fuel wood, only 68 percent of the 868,459 tons of primary mill residue is available for cofiring with coal, approximately 591,000 wet tons.⁶³

The 591,000 wet tons of mill residue available as biomass fuel for the power facilities in the region must be adjusted according to the moisture content of the wood. Moisture levels in range from 10 to 40 percent depending on the source and storage of the waste wood. In this assessment, an average moisture content of 30 percent is assumed for sawdust and 20 percent for coarse mill residue. The estimated amount of mill residues available for cofiring with coal is 360,000 dry tons (Table 3.6). With relatively high moisture rates (greater than 20 percent) fine and coarse residues can be stored outside in piles, which is the cheapest possible method of storage. However, drying and further processing to make the fuel uniform in size may be required for primary mill residues to be used as fuel. Oversized chunks of wood cause mechanical problems in handling and combustion and lower overall efficiencies.⁶⁴

Secondary mill residues, also called dry mill residue, is low moisture wood (normally 5-6 percent) that includes sawdust, trimmings and wood from wood-products companies. Secondary mill residues are the byproducts of wood products industries that utilize kiln dried materials for making cabinets, flooring, furniture, and other finished products. These waste woods are generally free of bark, low in moisture, and have a high-energy value. Indoor storage is necessary to prevent added moisture.⁶⁵

⁶² For purposes of this analysis, it is assumed that 50 percent of fuel wood is used on site.

⁶³ Of the 68 percent “available” for use as a biomass resource for cofiring, much of that is already consumed in existing markets for waste wood.

⁶⁴ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 5.

⁶⁵ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, pp. 5-6.

Table 3.6 Primary Mill Residue Available as Biomass Cofiring Fuel (Wet Tons)

County	Coarse Wood	Fine Wood	Total Biomass Fuel
MARYLAND			
Allegany	729	615	1,344
Anne Arundel	2,244	1,463	2,943
Baltimore	2,243	2,108	4,232
Calvert	3,486	3,490	6,972
Caroline	5,770	5,236	10,664
Carroll	1,335	1,097	2,224
Cecil	2,295	2,239	4,489
Charles	4,183	3,210	6,408
Dorchester	6,041	6,292	12,332
Frederick	401	78	158
Harford	2,192	1,583	3,184
Montgomery	2,135	1,041	2,076
St. Mary's	3,404	2,854	5,689
Somerset	4,149	4,137	8,284
Worcester	7,520	8,032	15,454
PENNSYLVANIA			
Adams	4,298	864	3,836
Bedford	25,628	10,099	32,786
Chester	302	58	262
Fayette	22,358	8,381	27,819
Franklin	29,559	7,774	31,141
Fulton	6,393	2,116	7,366
Lancaster	10,886	3,491	12,340
Somerset	14,378	2,467	12,058
York	6,545	2,972	7,621
VIRGINIA			
Caroline	30,249	5,243	19,955
Clarke	990	433	1,333
Culpepper	6,361	1,134	5,150
Essex	5,103	2,665	5,664
Fauquier	3,942	1,945	5,708
Frederick	11,635	4,636	12,506
Loudoun	985	307	1,067
North-Umberland	3,596	1,223	3,691
Richmond	7,882	1,352	6,180
Shenandoah	525	205	651
Stafford	6,149	3,242	9,256
Westmoreland	17,974	7,388	19,939
WEST VIRGINIA			
Berkeley	1,533	1,242	2,748
Grant	2,729	358	1,392
Hampshire	3,049	1,057	2,635
Hardy	751	249	626
Morgan	12,570	4,662	11,479
Tucker	30,930	11,525	28,293
TOTAL	315,427	130,564	359,955

*The USDA Forest Service Timber Product Output (TPO) Database Retrieval System provided county-by-county information for forest and mill residues. TPO data consists of 11 data variables which describe the round-wood products harvested, the logging residues left behind, the timber otherwise removed, and the wood and bark residues generated by primary wood-using mills for each county. Residue data, presented in dry tons, were compiled for the 2002 calendar year from the latest TPO studies available for each State. Timber Products Output Database, available at http://ncrs2.fs.fed.us/4801/fiadb/rpa_tpo/wc_rpa_tpo.ASP.

Data on secondary mill residue generation and availability is not readily available through agencies that track wood products industries such as the Forest Service, state agencies and the U.S. Department of Agriculture (USDA). However, the availability of mill residues is a direct result of the size and economic strength of the forest products industry and thus it is possible to estimate the amount of secondary wood residue based on economic census data. The methodology for estimating secondary mill residue quantities is based on *Minnesota Waste wood Studies: One Man's Waste is Another Man's Gold*, published in 1994 by the Minnesota Department of Natural Resources. The study establishes an average amount of residue generated according to the number of employees (Table 3.7).⁶⁶

**Table 3.7 Secondary Mill Residue
By Company Size (Tons/Year)**

Number of Employees	Waste Wood per Company
1-3	58
4-9	71
10-19	280
20-49	691
50-99	1,694
100-199	1,966
200-499	2,384
500-999	8,537
1000+	36,153
<i>Minnesota Waste Wood Studies, p. 24.</i>	

According to the Economic Census of 1997, there are 197 wood product manufacturers operating in the state of Maryland, excluding primary sawmills but including manufacturers of veneer, building lumber, flooring, shipping crates and pallets, veneer for shelving and furniture, wood cabinets and particle board (NAICS Codes 3212, 3219, and 33711).⁶⁷ The *Maryland Manufacturers Directory* provides a list of manufacturers by county, including employment data. Table 3.8 provides information on the number and employment size of secondary mills in Maryland. The table only includes companies with greater than 25 employees based on an assumption that recovery of waste woods from smaller companies is managed under traditional

⁶⁶*Minnesota Waste wood Studies: One Man's Waste is Another Man's Gold*, Minnesota Department of Natural Resources, 1994, p. 24, available at <http://files.dnr.state.mn.us/forestry/um/woodwaste.pdf>.

⁶⁷ 1997 Economic Census, U.S. Census Bureau, available at <http://www.census.gov>.

waste management practices.⁶⁸ Using the employee statistics available from the *Harris's Guide to Manufacturers 1999*, it is possible to estimate the amount of secondary mill residues generated in the region by county (Table 3.8). Smaller businesses, those with 25 or fewer employees, are not included in this assessment.

⁶⁸ An informal phone survey of three small wood products manufacturers, in Cumberland, Baltimore City and Mount Airy, Maryland indicate that no alternative waste management practices are used.

Table 3.8 Secondary Mill Residue by Company Size and County (Dry Tons)*

Company Size (# Employees)	251-500	101-250	51-100	26-50	Total Amount of Tons per County
Estimated Tons/Co/Year	2,300	2,000	1700	500	
Number of Companies per County According to Size					
MARYLAND					
Allegany	1	1			4,300
Anne Arundel				5	2,500
Baltimore			3	4	7,100
Calvert				1	500
Carroll		2	1	5	8,200
Charles			2	1	3,900
Dorchester				1	500
Frederick	2	1	1	4	10,300
Garrett			2	1	3,900
Harford				2	1,000
Howard			2	1	3,900
Kent				1	500
Montgomery			3	4	7,100
Queen Anne's				1	500
Somerset			1	1	2,200
Talbot			1	2	2,700
Washington			1	1	2,200
Wicomico				1	500
Worcester	1	1			4,300
PENNSYLVANIA					
Adams	1		5	1	11,300
Bedford				1	500
Chester	1		4	6	12,100
Fayette			1	1	2,200
Franklin			1	5	4,200
Lancaster	5	8	6	9	42,200
Somerset				2	1,000
York	2	2	9	6	26,900
VIRGINIA					
Caroline			1	2	2,700
Clarke	3				6,900
Culpepper				1	500
Essex				1	500
Fairfax		1	2	6	8,400
Fauquier				2	1,000
Frederick	2	2	1	2	11,300
Loudoun		1	2		5,400
Richmond			1	1	2,200
Shenandoah	1		1	1	4,500
Stafford				1	500
Westmoreland		1		1	2,500

Table 3.8 Secondary Mill Residue by Company Size and County (Dry Tons)* (Continued)

Company Size (# Employees)	251-500	101-250	51-100	26-50	Total Amount of Tons per County
Estimated Tons/Co/Year	2,300	2,000	1700	500	
Number of Companies per County According to Size					
WEST VIRGINIA					
Berkeley			1		1,700
Grant		2		2	5,000
Hardy	1	1	2		7,700
Mineral			1		1,700
Tucker			2		3,400
TOTAL	19	22	58	87	229,800

C. Forest Residue

Forest slash or logging residues are the portions of the trees that remain on the forest floor after logging operations have taken place, including imperfect commercial trees, dead wood, and other non-commercial trees generated mainly from logging companies. Logging tops are the upper portions of the stem. Culls are the saw timber harvest that is classified as defective, cut and left in the woods. Precommercial thinnings are a residue material that comes from timber stand improvement and is generally round, densely stocked stands. The moisture content of forest residue ranges from 40 to 60 percent, with a higher moisture content in actively growing trees.⁶⁹ Chipping is the primary method for harvesting forest residues. It is estimated that approximately 85 percent of the remaining tree cull and 45 percent of the treetops and limbs can be recovered for use as a biomass resource.⁷⁰ According to the data available through the USDA Timber Product Output Database there is approximately 441,000 tons of recoverable forest residue in Maryland and the relevant neighboring counties of Pennsylvania, Virginia, and West Virginia (Table 3.9).

⁶⁹ Badger, Phillip T., *Processing Cost Analysis for Biomass Feedstocks, Draft Report Prepared for Oak Ridge National Laboratory*, Oak Ridge, TN, April 2002, p. 3.

⁷⁰ *Minnesota Waste wood Studies: One Man's Waste is Another Man's Gold*, Minnesota Department of Natural Resources, 1994, p. 5, available at <http://files.dnr.state.mn.us/forestry/um/woodwaste.pdf>.

Table 3.9 Forest Residue Available as Biomass Cofiring Fuel (Dry Tons)

County	Culls and Saw Timber Residue	Tops and Thinning Residue	Total Forest Residue
MARYLAND			
Allegany	1,745	5,084	6,829
Anne Arundel	2,214	5,209	7,422
Baltimore	1,015	2,459	3,474
Calvert	1,776	3,023	4,800
Caroline	1,152	2,258	3,411
Carroll	1,056	2,034	3,089
Cecil	78	176	254
Charles	4,219	8,035	12,254
Dorchester	3,659	7,080	10,739
Frederick	594	1,083	1,677
Garrett	4,205	10,977	15,182
Harford	1,631	2,922	4,553
Howard	739	1,307	2,046
Kent	227	1,625	1,852
Montgomery	480	815	1,295
Prince George's	805	3,748	4,553
Queen Anne's	1,254	2,244	3,498
St. Mary's	2,414	4,949	7,363
Somerset	1,601	5,382	6,983
Talbot	1,127	3,154	4,281
Washington	533	1,011	1,544
Wicomico	4,359	11,952	16,311
Worcester	3,323	10,145	13,468
PENNSYLVANIA			
Adams	10,285	17,749	28,034
Bedford	8,226	16,427	24,653
Chester	2,440	4,289	6,729
Fayette	5,858	9,963	15,822
Franklin	9,273	17,236	26,509
Fulton	5,827	11,783	17,609
Lancaster	2,958	5,099	8,057
Somerset	9,246	17,394	26,640
York	3,657	7,259	10,917
VIRGINIA			
Caroline	6,039	2,734	8,773
Clarke	691	398	1,089
Culpepper	2,423	1,280	3,703
Essex	2,630	1,220	3,850
Fairfax	316	146	462
Fauquier	1,034	536	1,570
Frederick	1,094	602	1,696
King George	1,128	531	1,660
Loudoun	2,385	1,380	3,765
North-Umberland	1,198	556	1,754
Richmond	1,829	787	2,616
Shenandoah	1,132	636	1,768
Stafford	1,294	645	1,940
Westmoreland	3,380	1,538	4,918

County	Culls and Saw Timber Residue	Tops and Thinning Residue	Total Forest Residue
WEST VIRGINIA			
Berkeley	2,254	4,402	6,656
Grant	2,944	5,401	8,345
Hampshire	3,962	8,686	12,648
Hardy	4,199	8,431	12,630
Mineral	2,211	3,746	5,957
Morgan	3,515	7,441	10,956
Preston	2,402	4,558	6,960
Tucker	9,113	16,534	25,647
TOTAL	158,258	282,732	440,990
Source: The USDA Forest Service Timber Product Output (TPO) Database Forest residue data was converted from cubic feet to dry tons by using the National Renewable Energy Laboratory, Biomass and Biofuels conversion rate of 14 dry tons per 1,000 cubic feet of residue.			

D. Agricultural Residues

Agricultural residues are the biomass materials remaining after harvesting agricultural crops. Crop residues can be separated into two categories: field residues and process residues. Field residues are residues that are left in the field after harvesting. They are scattered over a wide area and are often used as fertilizer. Producers who participate in USDA programs are required to maintain 30 percent ground residue cover until after the succeeding crop has been planted the following spring. This plant residue helps reduce soil erosion during the winter and through to the establishment of the new crop. Therefore, 30 percent of crop residue is unavailable for use as a biomass resource in coal-fired power plants. The amount of crop residue that remains following a harvest depends on the operation of the combine during harvest, the type of crop, and crop yield. Table 3.10 provides an estimate of crop residues per unit of output for the major grain crops in Maryland and the surrounding counties: corn, wheat, winter wheat and barley. Soybeans were not included because residue production is small and tends to deteriorate quickly in the field.

Table 3.10 Estimated Crop Residue Production per Unit of Output

Crop	Unit	Lbs Residue/Unit
Corn or sorghum	bushel	50
Wheat	bushel	80
Winter Wheat	bushel	100
Barley	bushel	50
References:		
1. J.F. Shanahan, D.H. Smith, T.L. Stanton and B.E. Horn, <i>Crop Residues for Livestock Feed</i> , Colorado State University Cooperative Extension, available http://www.ext.colostate.edu/pubs/crops/00551.html .		
2. Wedlin, W.F. and T.J. Klopfenstein. 1985. "Cropland pastures and crop residues," pp. 496-506. In M.E. Heath, R.F. Barnes, and D.S. Metcalfe (eds.), <i>Forages - The Science of Grassland Agriculture</i> . Iowa State University Press, Ames, Iowa.		
3. M. Walsh, R. Perlack, A. Turhollowa, D. de la Torre Ugarte, D. Beckerc, R. Grahama, S. Slinskyb, and D. Rayb, <i>Biomass Feedstock Availability in the United States: 1999 State Level Analysis</i> , Oak Ridge National Laboratory, Oak Ridge, TN, available http://bioenergy.ornl.gov/resourcedata/index.html .		

For each county considered in this analysis, the amount of residue is estimated by adjusting the production data provided in the *2002 Census of Agriculture* for bushels of corn, wheat, winter wheat, and barley by the crop residue production per unit of output to determine the total amount of residues produced for each crop in each county.⁷¹ Residue is collected from the field by raking, stacking, and baling. However, in addition to the 30 percent that is left on the field for nutrient management and erosion, corn residue is collected and used in cattle feed and other agricultural feedstocks. For purposes of this analysis, we assume that only 50 percent of agricultural residues are available as an energy resource. Additionally, the crop residue has a moisture content of approximately 30 percent. Thus, an estimated 1.1 million tons of biomass fuel is available from crop residue (Table 3.11).

⁷¹ Data collected for relevant counties in Maryland, Pennsylvania, Virginia and West Virginia from Table 23. Selected Crops Harvested, 2002, *2002 Agriculture Census*, available <http://www.nass.usda.gov/census/census02/volume1/index2.htm>.

Table 3.11 Crop Residue by County and Crop (Dry Tons)

County	Corn	Wheat	Winter Wheat	Barley	Total
MARYLAND					
Allegany	287	-	-	-	287
Anne Arundel	4,488	1,567	1,959	338	8,351
Baltimore	10,118	1,425	1,781	417	13,740
Calvert	2,011	1,477	1,847	213	5,547
Caroline	18,902	16,623	20,779	4,736	61,039
Carroll	20,769	6,496	8,120	2,607	37,993
Cecil	11,556	6,222	7,777	1,195	26,749
Charles	1,918	2,284	2,856	165	7,223
Dorchester	17,270	13,188	16,485	1,906	48,849
Frederick	15,558	10,150	12,687	3,153	41,548
Garrett	3,599	-	-	258	3,857
Harford	12,561	1,945	2,431	457	17,394
Howard	5,494	1,805	2,256	489	10,044
Kent	20,181	14,105	17,631	2,224	54,140
Montgomery	9,134	4,383	5,479	207	19,203
Prince George's	2,346	1,092	1,364	-	4,802
Queen Anne's	30,226	27,473	34,341	2,113	94,154
St. Mary's	4,040	4,678	5,847	781	15,346
Somerset	7,704	4,399	5,499	270	17,873
Talbot	17,364	15,495	19,368	1,079	53,306
Washington	8,902	3,996	4,996	2,193	20,086
Wicomico	12,042	4,501	5,626	388	22,558
Worcester	26,396	5,419	6,774	201	38,791
PENNSYLVANIA					
Adams	9,508	10,733	13,417	834	34,491
Bedford	6,107	431	539	491	7,568
Chester	16,730	4,035	5,044	1,279	27,088
Fayette	4,648	202	253	150	5,253
Franklin	11,167	5,515	6,894	3,907	27,483
Fulton	2,045	854	1,068	502	4,469
Lancaster	41,076	8,916	11,145	5,796	66,933
Somerset	10,093	78	98	607	10,876
York	43,702	18,487	23,109	3,043	88,341
VIRGINIA					
Caroline	6,489	5,783	7,229	1,946	21,448
Clarke	2,692	546	683	186	4,107
Culpepper	5,091	1,135	1,419	452	8,098
Essex	8,183	6,491	8,113	2,769	25,556
Fairfax	93	-	-	-	93
Fauquier	8,026	1,040	1,300	971	11,337
Frederick	1,559	367	459	111	2,495
King George	1,923	1,011	1,264	1,213	5,411
Loudoun	4,306	1,958	2,447	165	8,877
North-Umberland	7,886	8,756	10,945	1,194	28,781
Richmond	6,891	5,130	6,412	1,610	20,043
Shenandoah	3,344	400	501	938	5,182
Stafford	709	135	169	193	1,207
Westmoreland	6,935	8,066	10,083	3,027	28,111

Table 3.11 Crop Residue by County and Crop (Dry Tons)
(Continued)

County	Corn	Wheat	Winter Wheat	Barley	Total
WEST VIRGINIA					
Berkeley	2,323	765	956	284	4,328
Grant	360	-	-	-	360
Hampshire	293	-	-	34	326
Hardy	3,145	-	-	145	3,290
Jefferson	9,673	2,629	3,286	198	15,786
Mineral	558	-	-	27	586
Morgan	78	143	179	28	428
Preston	1,759	-	-	32	1,791
Tucker	144	-	-	-	144
TOTAL	490,403	242,332	302,915	57,519	1,093,168

E. Energy Crops

Energy crops include fast-growing trees, shrubs, and grasses such as hybrid poplars, hybrid willows, and switchgrass grown specifically for energy use. Unlike the previous categories of biomass fuels, the viability of using energy crops as a resource for cofiring with coal are dependent on the development of a new agricultural product within the region. Energy crops are not widely produced in the United States largely because the sale price of energy crops is too low to justify switching crops from higher value products such as corn, wheat and barley. It is unlikely that a large percentage of local farmers will switch to bioenergy crops absent a subsidy or incentive to encourage the production of energy crops. However, approximately 14 percent of cropland in Maryland was idle according to the *2002 Agriculture Census*.⁷² Switchgrass, a low maintenance forage crop may be a low cost alternative crop for farmers with idle cropland. Switchgrass is a perennial warm-season grass with good burn qualities and is easily managed without high rates of nitrogen fertilizer. In the mid-Atlantic region, switchgrass produces an estimated 5.0-5.9 dry tons of biomass for every acre harvested, except on the

⁷² Data collected for relevant counties in Maryland, Pennsylvania, Virginia and West Virginia from Table 8. Farms, Land in Farms, Value of Land and Buildings, and Land Use 2002, *2002 Agriculture Census*, available <http://www.nass.usda.gov/census/census02/volume1/index2.htm>.

Eastern Shore where production is slightly less at 3.0-3.9 dry tons per acre.⁷³ For purposes of this analysis, we assume that switchgrass is the only energy crop produced in Maryland and the surrounding counties. To estimate the total amount of biomass available from energy crops, we assume that 25 percent of idle cropland, approximately 185,092 acres, is used to grow switchgrass (Table 3.12). This assessment shows that planting and harvesting crops on idle farmlands could produce an estimated 1 million tons of switchgrass fuel. However, the shift to switchgrass production is likely to take place as a gradual shift only if there is a growing demand for energy crops. Thus, in the short term, the biomass available from energy crops should not be considered in the assessment of available resources.

⁷³ L. Wright, J. Cushman, J. Tuskan, S. McLaughlin, and M. Walsh, Power Point Presentation: *Bioenergy Feedstock Development: Accomplishments and Needs*, Oak Ridge National Laboratory, February 7, 2002, p. 27, available, ftp://bioenergy.ornl.gov/pub/presentations/bfdp_accomp_needs.pdf.

Table 3.12 Energy Crop: Potential Switchgrass Production (Dry Tons), Idle Acreage

County	Idle Cropland (Acres)	Switchgrass (Dry Tons)
MARYLAND		
Allegany	2,145	11,798
Anne Arundel	1,262	6,940
Baltimore	2,508	13,791
Calvert	920	5,059
Caroline	1,404	4,915
Carroll	3,691	20,302
Cecil	2,020	7,068
Charles	1,903	10,465
Dorchester	2,736	9,576
Frederick	6,625	36,438
Garrett	3,435	18,893
Harford	2,382	13,101
Howard	1,253	6,890
Kent	1,948	6,816
Montgomery	2,262	12,441
Prince George's	1,635	8,991
Queen Anne's	1,872	6,552
St. Mary's	1,894	10,416
Somerset	982	3,437
Talbot	1,494	5,227
Washington	3,814	20,977
Wicomico	1,725	6,036
Worcester	1,397	4,890
PENNSYLVANIA		
Adams	4,739	26,066
Bedford	6,785	37,318
Chester	5,643	31,037
Fayette	4,706	25,882
Franklin	6,559	36,076
Fulton	3,193	17,559
Lancaster	8,688	47,785
Somerset	9,398	51,688
York	6,513	35,819
VIRGINIA		
Caroline	1,097	6,031
Clarke	5,674	31,206
Culpepper	5,397	29,681
Essex	836	4,598
Fairfax	524	2,881
Fauquier	11,759	64,676
Frederick	5,492	30,206
King George	874	4,804
Loudoun	9,997	54,981
North-Umberland	357	1,964
Richmond	716	3,935
Shenandoah	6,037	33,202
Stafford	1,224	6,733
Westmoreland	1,267	6,966

Table 3.12 Energy Crop: Potential Switchgrass Production (Dry Tons), Idle Acreage (Continued)

County	Idle Cropland (Acres)	Switchgrass (Dry Tons)
WEST VIRGINIA		
Berkeley	3,304	18,173
Grant	3,076	16,915
Hampshire	4,599	25,293
Hardy	4,532	24,925
Jefferson	2,055	11,301
Mineral	2,576	14,169
Morgan	913	5,023
Preston	4,259	23,422
Tucker	1,005	5,526
TOTAL	185,092	986,855

F. Available Biomass Resources

The combined impact of urban waste woods, mill residues, forest residues, and agricultural residues provides an estimated 3 million tons of biomass that could be available for cofiring in Maryland’s coal-fired power plants. An additional 1 million tons of switchgrass could be cultivated if the demand for biomass fuels increased. Table 3.13 summarizes the estimated total annual quantities of biomass resources available by county. It is estimated that a substantial amount of biomass could be available, however there is a great deal of uncertainty surrounding the estimates. The estimate of biomass resources may not adequately consider competing markets and existing contractual arrangements for the disposal of the waste products. With the exception of perhaps the forest residues, the majority of these biomass resources are already being used or disposed of in one manner or another. Given that much of the biomass feedstock is likely to be already in use, the price to acquire the biomass resources may increase with demand.

Table 3.13 Potential Biomass Available by County and Category (Dry Tons)

County	Forest Residue	Mill Residue	Urban Residue	Agriculture Residue	Total	Additional Switchgrass
MARYLAND						
Allegany	6,829	5,644	5,541	287	18,302	11,798
Anne Arundel	7,422	5,443	13,249	8,351	34,465	6,940
Baltimore	3,474	11,332	88,442	13,740	116,989	13,791
Calvert	4,800	7,472	1,707	5,547	19,526	5,059
Caroline	3,411	10,664		61,039	75,114	4,915
Carroll	3,089	10,424	2,294	37,993	53,800	20,302
Cecil	254	4,489	3,192	26,749	34,684	7,068
Charles	12,254	10,308	838	7,223	30,622	10,465
Dorchester	10,739	12,832	1,984	48,849	74,404	9,576
Frederick	1,677	10,458	15,536	41,548	69,220	36,438
Garrett	15,182	3,900	2,736	3,857	25,675	18,893
Harford	4,553	4,185	23,432	17,394	49,564	13,101
Howard	2,046	3,900	2,290	10,044	18,280	6,890
Kent	1,852	500		54,140		6,816
Montgomery	1,295	2,576		19,203	23,074	12,441
Prince George's	4,553	7,100	77,573	4,802	94,029	8,991
Queen Anne's	3,498	0	6,995	94,154	104,647	6,552
St. Mary's	7,363	6,189	1,083	15,346	29,981	10,416
Somerset	6,983	8,284	1,457	17,873	34,596	3,437
Talbot	4,281	2,200	4,667	53,306	64,454	5,227
Washington	1,544	2,700	6,984	20,086	31,315	20,977
Wicomico	16,311	2,200	2,670	22,558	43,739	6,036
Worcester	13,468	15,954	13,197	38,791	81,410	4,890
PENNSYLVANIA						
Adams	28,034	15,136	0	34,491	77,661	26,066
Bedford	24,653	33,286	3,397	7,568	68,903	37,318
Chester	6,729	12,362	7,670	27,088	53,849	31,037
Fayette	15,822	30,019	0	5,253	51,094	25,882
Franklin	26,509	35,341	21,035	27,483	110,368	36,076
Fulton	17,609	7,366	0	4,469	29,445	17,559
Lancaster	8,057	54,540	7,828	66,933	137,358	47,785
Somerset	26,640	13,058	26,754	10,876	77,327	51,688
York	10,917	34,521	58,334	88,341	192,112	35,819
VIRGINIA						
Caroline	8,773	22,655	0	21,448	52,877	6,031
Clarke	1,089	8,233	0	4,107	13,430	31,206
Culpepper	3,703	5,650	0	8,098	17,451	29,681
Essex	3,850	6,164	0	25,556	35,570	4,598
Fairfax	462	8,400	237,306	93	246,260	2,881
Fauquier	1,570	6,708	5,341	11,337	24,956	64,676
Frederick	1,696	23,806	10,849	2,495	38,847	30,206
King George	1,660	0	0	5,411	7,070	4,804
Loudoun	3,765	6,467	889	8,877	19,998	54,981
North-Umberland	1,754	3,691	0	28,781	34,226	1,964
Richmond	2,616	8,380	0	20,043	31,040	3,935
Shenandoah	1,768	5,151	866	5,182	12,967	33,202
Stafford	1,940	9,756	3,855	1,207	16,758	6,733
Westmoreland	4,918	22,439	0	28,111	55,468	6,966

Table 3.13 Potential Biomass Available by County and Category (Dry Tons)
(Continued)

County	Forest Residue	Mill Residue	Urban Residue	Agriculture Residue	Total	Additional Switchgrass
WEST VIRGINIA						
Berkeley	6,656	4,448	2,769	4,328	18,202	18,173
Grant	8,345	6,392		360	15,097	16,915
Hampshire	12,648	2,635		326	15,610	25,293
Hardy	12,630	8,326		3,290	24,246	24,925
Jefferson	5,957	1,700		15,786	23,443	11,301
Mineral	10,956	11,479		586	23,020	14,169
Morgan	6,960	0		428	7,388	5,023
Preston	25,647	31,693		1,791	59,131	23,422
Tucker	9,777	1,700	1,707	144	13,329	5,526
TOTAL	440,990	590,255	664,469	1,093,168	2,732,390	986,855
Percent of Total	16.1%	21.6%	24.3%	40.0%	100%	+2,732,116
					TOTAL	3,712,429

G. Heat Content of Biomass Fuels

The value of a biomass resource as an energy source is directly related to the heat content of the specific resource. The Department of Energy, Energy Information Administration provides average heat contents of selected biomass fuels (Table 3.14).

Table 3.14 Average Heat Content of Selected Biomass Fuels

Fuel Type	Heat Content	Units
Agricultural Byproducts ^a	8.3	Million Btu/Short Ton
Urban waste wood ^a	10.0	Million Btu/Short Ton
Switchgrass ^b	14.7	Million Btu/Short Ton
Mill Residue (Dry)	14.0	Million Btu/Short Ton
Forest Residue ^a	9.6	Million Btu/Short Ton

^aEnergy Information Administration, Form EIA-860B (1999), *Annual Electric Generator Report*, available, http://www.eia.doe.gov/cneaf/solar_renewables/page/trends/tableb6.html
^bEnergy Information Administration, *Annual Energy Outlook 2005*, Table H1, February 2005.

The amount of biomass required by any one facility will depend on the type of biomass, the size of the facility, and portion of heat input to come from biomass resources. As an example, Table 3.15, below, assumes that a 300 MW coal-fired facility operates at 85 percent of total capacity with an average heat rate of 10.5 MmBtu/MWh. The table presents the amount of biomass required from any one source to cofire for 3, 5, or 10 percent of the total required heat input.

Table 3.15 Amount of Biomass Required for Cofiring in a 300 MW Facility

Biomass Resource	3% Heat Input		5% Heat Input		10% Heat Input	
	Tons Per Year	Mass (%)	Tons per Year	Mass (%)	Tons Per Year	Mass (%)
Agricultural Residue	84,777	8%	141,925	13%	282,589	24%
Urban Waste Wood	70,365	7%	117,275	11%	234,549	21%
Switchgrass	47,867	5%	79,779	8%	159,557	15%
Mill Residue	50,261	5%	83,768	8%	167,535	16%
Forest Residue	73,297	7%	122,161	12%	244,322	22%

Therefore, according to this analysis and the results of Table 3.13, a 300 MW facility cofiring 10 percent biomass would require nearly 26 percent of the region’s agricultural residue resources (i.e., 282,589/1,093,168 tons per year = 25.9 percent), 35 percent of the available urban waste wood, 28 percent of the estimated amount of mill residue, and more than 55 percent of the amount of forest residue available for cofiring. This indicates that a facility considering cofiring with biomass is likely to require flexibility within the system to allow combustion of various types of resources.

Chapter IV. The Economics of Biomass Cofiring

Along with the technical feasibility and environmental impacts, the economic considerations of cofiring coal with biomass will help determine the potential for biomass cofiring in Maryland. This section discusses three elements affecting the economic feasibility of biomass cofiring in Maryland: capital costs, fuel costs and environmental incentives.

A. Capital Costs

The costs to retrofit a coal-fired power plant to cofire biomass fuels will vary depending on the facility, the type of boiler, the type of fuel and the amount of biomass to be used. Since the majority of the coal-fired facilities in Maryland have wall-fired PC boilers, the system and costs described in this assessment have been tailored to address pulverized coal boilers. Unfortunately, while cofiring in PC boilers represents the largest opportunity in Maryland, it is also one of the most expensive co-firing arrangements.⁷⁴ Costs are largely dependent on the design of fuel handling and feeder systems. For pulverized coal boilers, biomass co-firing has been successful at small percentages (up to 2 percent on a heat basis, or about 5 percent by mass) for less than \$100/kW using existing fuel processing and handling equipment. However, blending biomass fuels with coal in the fuel pile can affect pulverizer performance and can reduce the overall capacity of the pulverizer.⁷⁵ Installing separate feed systems for biomass has allowed utilities to co-fire at higher percentages (up to about 15 percent on a heat basis, or about 30 percent by mass), but generally requires a higher capital investment (\$150 to \$400/kW of biomass power).⁷⁶ For continuous cofiring, an automated system capable of processing and storing a 24-hour supply of biomass is required. Biomass receiving equipment includes truck scales, hydraulic tippers or self-unloading trucks. Front-end loaders are used to manage and move biomass resources on site. Conveyors transport the fuel to the processing facility and if

⁷⁴ *Renewable Energy Technology Characterizations*, EPRI Topical Report No. TR-109496, December 1997, p. 2-46.

⁷⁵ S. Laux, J. Grusha, D. Tillman, *Co-Firing of Biomass and Opportunity Fuels in Low NO_x Burners*, Foster Wheeler Energy Corporation, 1999, p. 3, available at http://www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.

⁷⁶ *Co-Firing II: Co-firing Coal and Biomass in Utility Boilers*, Report of a One-Day Forum, Office of Utility Technologies, U.S. Department of Energy, Northeast Regional Biomass Program, Southeast Regional Biomass Program, Great Lakes Regional Biomass Program; January 1997, available at <http://www.nrbp.org/pdfs/pub13.pdf>.

waste wood is to be considered for fuel, magnetic separators need to be installed to remove spikes, nails and other metal components.⁷⁷

The cost and configuration of fuel processing equipment depend on the expected fuel choices. Equipment such as “hoggers,” hammer mills, and disc screens are required to properly size the feedstock. In a PC facility with suspension firing, test-burn results have shown that wood fuel must be double ground through a tub grinder or “hog” to a fine mesh size, approximately 6.4 mm or less, with moisture levels under 25 percent. The biomass fuels did not burn well when using larger mesh size biomass processed with only a single pass through the tub grinder or hog. The larger particles fell through the PC boiler's combustion zones and accumulated, uncombusted, on the grate. In wall-fired boilers, biomass particles that are too large cause efficiency problems. In wet bottom boilers (such as C.P. Crane), biomass particles sized too large cause operational problems. For PC units, controlling airflows with the pneumatic lifting of wood fuel to the boiler's fuel ports has also been shown to be important for optimizing efficiency and reducing slagging.⁷⁸

Once the biomass is processed to the appropriate particle size it will need to be stored. Biomass can be stored in a variety of configurations, for example silo, open pile, open shed, bunker and bin. The feeding system removes the biomass from the storage facility for injection to the boiler. Facilities that are planning to have a more than 2 percent of cofiring (on a heat input basis) will want to install a separate feed system to parallel the coal feed system. The coal injection points to the boiler need to be modified to allow biomass injection during cofiring. Finally, additional controls and boiler modifications are required to configure the boiler to biomass cofiring. The costs of fuel handling, storage and boiler retrofits are presented below, in 2005 dollars, for a 300 MW and 700 MW PC Boiler (Table 4.1). The investment per kilowatt refers only to the biomass portion of the facility. For example, for a 300 MW facility cofiring with 15 percent of biomass, the capital costs are applied only to the 45 MW of biomass capacity.

⁷⁷ W.A. Amos, R.L. Bain, M. Downing, and R.L. Perlack, *Biopower Technical Assessment: State of Industry and Technology*, National Renewable Energy Laboratory, March 2003, p. 5-20.

⁷⁸ *Biomass Co-Firing Efforts in Florida*, “Biomass Co-firing Power Plant Engineering,” available at <http://www.treepower.org/cofiring/main.html#lakeland>.

Table 4.1 Capital Costs for PC Retrofit to Cofire 15 Percent Biomass

	300 MW (\$1,000)	700 MW (\$1,000)	300 MW (\$/kW)	700 MW (\$/kW)
Hydraulic Dumping	\$331	\$331	\$7.34	\$5.08
Conveyor	\$538	\$973	\$11.92	\$9.27
Separation Equipment	\$146	\$265	\$3.20	\$2.54
Processing/Hogging Equipment	\$887	\$1,606	\$19.76	\$15.34
Conveyor Systems	\$465	\$841	\$10.38	\$7.95
Storage (Silo)	\$230	\$416	\$5.08	\$3.97
Feeder System Retrofit	\$736	\$1,332	\$16.34	\$12.69
Automated Controls	\$439	\$794	\$9.71	\$7.51
Burner Modification	\$125	\$227	\$2.76	\$2.21
Installation	\$3,670	\$6,641	\$81.57	\$63.25
Engineering	\$911	\$1,648	\$20.20	\$15.67
Electrical	\$684	\$1,238	\$15.23	\$11.81
Total Capital Costs	\$9,161	\$16,309	\$203.49	\$157.29
W.A. Amos, R.L. Bain, M. Downing, and R.L. Perlack, <i>Biopower Technical Assessment: State of Industry and Technology</i> , National Renewable Energy Laboratory, March 2003, p. 5-27. Badger, Phillip T., <i>Processing Cost Analysis for Biomass Feedstocks</i> , Draft Report Prepared for Oak Ridge National Laboratory, Oak Ridge, TN, April 2002, p. 17.				

Based on the retrofit costs described above, it is possible to estimate the capital costs for Maryland's coal-fired power plants. Smaller units (400 MW and less) are assumed to have a capital cost of \$200/kW of biomass capacity. Units larger than 400 MW are assumed to have a lower capital cost of \$150/kW. Since the majority of the costs are directly related to fuel handling and fuel feeding systems, the age and condition of the facility are expected to have little impact on the retrofit costs. Given the relatively modest size of the capital investment, it is assumed that the capital costs are owner-financed with an opportunity cost of no less than a 5 percent return on investment. To arrive at an annual cost of capital, each project is financed over a 30-year term with an interest rate of 5.5 percent (Table 4.2). The estimated costs are based on the assumption that the facility is cofiring 10 percent biomass, based on heat input.

Table 4.2 Estimated Capital Costs for Biomass Cofiring Retrofit

Plant Name	System and Retrofit Type	Capacity (MW)	Biomass Capacity (MW) ^a	Capital Costs for Retrofit		
				\$/kW	\$ millions	Annualized Costs ^b
Warrior Run-2	CFBC	180	18	200	\$3.60	\$230,000
R.P. Smith-3	PC - Wall-fired	29	2.9	200	\$0.58	\$40,000
R.P. Smith-4	PC - Tangential	88	8.8	200	\$1.76	\$110,000
Brandon Shores-1	PC - Wall-fired	690	69	150	\$10.35	\$680,000
Brandon Shores-2	PC - Wall-fired	690	69	150	\$10.35	\$680,000
C.P. Crane-1	PC - Cyclone	190	19	200	\$3.80	\$250,000
C.P. Crane-2	PC - Cyclone	190	19	200	\$3.80	\$250,000
H.A. Wagner-2	PC - Wall-fired	134	13.4	200	\$2.68	\$170,000
H.A. Wagner-3	PC - Cell burner	319	31.9	200	\$6.38	\$420,000
Chalk Point-1	PC - Wall-fired	341	34.1	200	\$6.82	\$440,000
Chalk Point-2	PC - Wall-fired	342	34.2	200	\$6.84	\$450,000
Dickerson-1	PC - Tangential	191	19.1	200	\$3.82	\$250,000
Dickerson-2	PC - Tangential	191	19.1	200	\$3.82	\$250,000
Dickerson-3	PC - Tangential	191	19.1	200	\$3.82	\$250,000
Morgantown-1	PC - Wall-fired	582	58.2	150	\$8.73	\$570,000
Morgantown-2	PC - Wall-fired	582	58.2	150	\$8.73	\$570,000

^a Cofiring biomass for 10 percent heat input.
^b Based on a 5.5 percent interest rate over 30 years.

B. Operating Costs

Non-fuel operating and maintenance (O&M) costs for biomass cofiring are not expected to deviate significantly from coal-only generation. For purposes of this analysis we assume that O&M costs and fly ash sales remain constant. Fly ash is a fine residue that results from the combustion of coal in power plants, which is disposed of as part of plant operations. Coal-fired units can sell the fly ash to concrete producers as a feedstock replacement for Portland cement.⁷⁹

⁷⁹Fly ash contains unburned carbon, which in too great an amount, can interfere with the chemical processes required for concrete manufacturing. However, the small amount of ash introduced from biomass cofiring would not significantly change the total amount of unburned carbon in the resulting ash -- known as the loss on ignition or "LOI" -- and may even lower the overall LOI. Moreover, biomass does not introduce any constituents into the ash that would cause it to be classified as hazardous. The boundaries of acceptable ash characteristics are typically determined by agreement between the power plant operator and the party taking the fly ash. The American Society of Testing and Materials (ASTM) standard for fly ash use in concrete manufacturing provides industry participants with guidelines, specifically ASTM C618.

C. Fuel Costs

According to two separate assessments, one conducted by the National Renewable Energy Laboratory, and a separate analysis provided by the Antares Group, the biomass resource has to be available for less than \$20/dry ton or less than \$1.18/MmBtu (2005 dollars) in order for a cofiring project to be economically feasible. An assessment of Maryland biomass resources and estimated prices indicate that there is very little available within this price range (Table 4.3). The average costs of biomass resources available in the state are higher than the cost of coal, which is approximately \$30-\$35 per ton delivered.⁸⁰ The best potential source for low cost biomass fuel is from urban waste wood that may be available for little or no cost from landfills and waste management facilities. According to a study conducted in California, actual average fuel cost in 2002 for combustion facilities in California, excluding municipal solid waste incinerators, was \$28 per dry ton delivered for urban waste woods. Tipping fees averaging \$40-\$60 per ton, available to landfills and mass-burn facilities receiving MSW have not been available to biomass generators.⁸¹ Changing this precedent through contract negotiations with waste management companies has the potential to provide a low cost biomass fuel to generators.

⁸⁰ EIA Electric Power Monthly, April 2005, available at http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

⁸¹ *An Assessment of Biomass Resources in California*, California Energy Commission, February 2004, p. 94.

Table 4.3 Average Cost of Selected Biomass Fuels (dry tons)

Fuel Type	Cost \$/ton delivered	Cost \$/MmBtu delivered
Agricultural Byproducts ^a	\$40.00	\$4.85
Urban waste wood ^b	\$17.00	\$1.70
SwitchGrass ^c	\$47.00	\$3.20
Mill Residue (Dry) ^d	\$27.00	\$1.93
Forest Residue ^e	\$35.00	\$3.65
Bituminous Coal	\$33.84	\$1.41

^a National Assessment of Promising Areas for Switchgrass, Hybrid Poplar, or Willow Energy Crop Production, Appalachian Region, Oak Ridge National Laboratory, available at <http://bioenergy.ornl.gov/reports/graham/appal.html>

^b Assumption of \$10/ton collection fee and \$7/ton transportation fee, an average of prices reported in various biomass studies.

^c English, D. Ugarte, R.J. Menard, C. Hellwinckel, and M. Walsh, *An Economic Analysis of Producing Switchgrass and Crop Residues for Use as a Bioenergy Feedstock*, Agricultural Experiment Station, University of Tennessee, November 2004, p. 22.

^d *Final Report of the Governor's Task Force on Co-Firing*, West Virginia University for National Research Center for Coal and Energy, p. 13.

^e Estimate based on average prices of wood chips and sawdust available in the region as determined through an informal phone survey.

The annual fuel costs of a 300 MW and 700 MW facility cofiring coal with biomass are provided below. The costs are based on an assumed capacity factor of 85 percent, generating 2.2 million MWh and 5.2 million MWh per year for a 300 MW and 700 MW plant, respectively. The cost of coal is specified according to four scenarios: 100 percent coal-fired, 3 percent biomass cofiring, 5 percent biomass cofiring and 10 percent biomass cofiring (Table 4.4).

Table 4.4 Plant Operating Assumptions

	300 MW	700 MW
Electricity Output/Year	2,233,800	5,212,200
Plant Heat Rate (MmBtu/MWh)	10.5	10.5
BTU Requirement/Year (MmBtu)	23,454,900	52,122,000
Cost of Coal (\$/MmBtu)	\$1.41	\$1.41
Cost of Coal for 100% coal (\$1,000)	\$33,071	\$73,492
Cost of Coal for 90% coal (\$1,000)	\$29,764	\$66,143
Cost of Coal for 95% coal (\$1,000)	\$31,418	\$69,817
Cost of Coal for 97% coal (\$1,000)	\$32,079	\$74,852

The costs for biomass resources vary according to the heat content and cost of each biomass type. Table 4.5 provides the biomass heat content under the three biomass cofiring scenarios: 3 percent, 5 percent, and 10 percent; and the corresponding cost for fuel under each biomass category. The range of total fuel costs, biomass and coal, for each scenario are then presented in Table 4.6.

**Table 4.5 Estimated Annual Costs for Biomass Fuels
(Thousands of Dollars)**

	Biomass Heat Content (MmBtu)	Agricultural Byproducts	Urban Waste Wood	Switch Grass	Mill Residue	Forest Residue
300 MW Facility						
3% Biomass	703,647	\$3,391	\$1,196	\$2,250	\$1,357	\$2,565
5% Biomass	1,172,745	\$5,653	\$1,994	\$3,750	\$2,262	\$4,276
10% Biomass	2,345,490	\$11,304	\$3,987	\$7,499	\$4,523	\$8,551
700 MW Facility						
3% Biomass	1,641,843	\$7,912	\$2,791	\$5,249	\$3,166	\$5,986
5% Biomass	2,736,405	\$13,187	\$4,652	\$8,749	\$5,277	\$9,976
10% Biomass	5,472,810	\$26,375	\$9,304	\$17,498	\$10,555	\$19,953

Table 4.6 Estimated Range of Annual Fuel Costs (Thousands of Dollars)

Fuel	300 MW Facility		700 MW Facility	
Coal Only	\$33,071		\$73,492	
Coal and Biomass	Lo	Hi	Lo	Hi
3% Biomass	\$33,275	\$35,470	\$77,643	\$82,764
5% Biomass	\$33,412	\$37,070	\$77,960	\$86,496
10% Biomass	\$33,752	\$41,068	\$78,753	\$95,825

When estimating fuel costs specific to the cofiring opportunities in Maryland, it is assumed that the most competitive projects will make use of low cost biomass fuels, specifically mill residues and urban waste wood. Table 4.7, below, provides the estimated costs of biomass fuels, assuming that the facilities use primarily urban waste wood and mill residues at an average cost of \$2/MmBtu delivered, and cofire either 5 or 10 percent of heat input.

Table 4.7 Cost of Biomass Fuels for Maryland Coal Plants

Plant Name	Unit No.	Capacity (MW)	2003 Heat Input (MmBtu)	Biomass Fuel Costs			
				(5%)		(10%)	
				Tons/Yr.	\$1,000	Tons/Yr.	\$1,000
Warrior Run	2	180	15,954,434	66,477	\$1,595	132,954	\$3,191
R.P. Smith	3	29	4,118,772	17,162	\$412	34,323	\$824
	4	88	1,190,328	4,960	\$119	9,919	\$238
Brandon Shores	1	690	35,838,632	149,328	\$3,584	298,655	\$7,168
	2	690	43,585,261	181,605	\$4,359	363,211	\$8,717
C.P. Crane	1	190	12,088,151	50,367	\$1,209	100,735	\$2,418
	2	190	13,264,963	55,271	\$1,327	110,541	\$2,653
H.A. Wagner	2	134	9,731,782	40,549	\$973,00	81,098	\$1,946
	3	319	19,594,811	81,645	\$1,960	163,290	\$3,919
Chalk Point	1	341	17,750,242	73,959	\$1,775	147,919	\$3,550
	2	342	19,884,133	82,851	\$1,988	165,701	\$3,977
Dickerson	1	191	8,365,574	34,857	\$837	69,713	\$1,673
	2	191	7,656,066	31,900	\$766	63,801	\$1,531
	3	191	9,297,330	38,739	\$930	77,478	\$1,859
Morgantown	1	582	37,488,101	156,200	\$3,749	312,401	\$7,498
	2	582	38,205,354	159,189	\$3,821	318,378	\$7,641

Due to the higher cost of biomass fuels when compared to coal, cofiring with biomass will lead to an increase in fuel costs. Without consideration for any environmental benefits, it is unlikely that any Maryland coal-fired facility would make the investments required to cofire with a more expensive and less efficient fuel. A decrease in the cost of biomass fuels is necessary to generate interest in cofiring among investors and facility owners. However, with the development of a market for biomass fuels, the price of agricultural residues may decrease. Additionally, urban waste wood may be available at a lower cost from one of the region's waste management facilities.

D. Environmental Costs and Benefits

Absent environmental benefits and the additional economic incentives available for biomass cofiring, there would be very little opportunity for cofiring biomass. However, the market based incentives created through state and federal regulations are critical factors when considering the potential for biomass cofiring in Maryland.

The Clean Air Act (CAA), amended in 1990, requires EPA to set National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. Title IV of the CAA and the corresponding regulations of the Acid Rain Program call for reductions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) from power plants. To achieve the required reductions, EPA's Acid Rain Program created trading programs for SO₂ and NO_x emissions. The SO₂ trading program established a cap for the total amount of SO₂ emissions to be emitted by power plants in a given year. Each year, utility units are allocated allowances based on their historical fuel consumption and a specific emissions rate so that the total number of allowances allocated is less than the cap. An allowance corresponds to one ton per year of the relevant pollutant. Those utility units that require additional allowances may purchase, or trade, the allowances from other utilities. Under the EPA Acid Rain Program, NO_x emissions are not "capped" as with the SO₂ program, and there is no allowance trading system. Instead, NO_x emission limitations for boilers are based on the emission rate to be achieved, expressed in pounds of NO_x per million Btu of heat input. Power plants may meet emissions restrictions for an individual boiler, or they can average the emission rates over two or more units to meet an overall emission rate limitation.

Additionally, the recently published Clean Air Interstate Rule (CAIR) is likely to require further reductions of SO₂ and NO_x from coal-fired facilities. CAIR adopts an SO₂ and NO_x emissions budget for each state. States may comply with the allocated budgets either by participating in an EPA-administered cap and trade program or by proposing alternative measures including emissions reductions in other sectors. One effect of the rule is an acceleration of retiring SO₂ allowances. Vintage 2010 to 2014 allowances would be retired at a ratio of two allowances for every ton of SO₂ emitted. After 2015, allowances are retired at a ratio of 2.86 allowances for every ton emitted. This is likely to increase the price of an SO₂ allowance. The average price of an SO₂ allowance was \$702.51 in the March 2005 EPA allowance auction, more than 250 percent higher than the average price paid in 2004, \$279.⁸² Under the CAIR, the price of allowances is likely to increase.

⁸² Roy Belden, "Environmental Update," *Project Finance News Wire*, Chadbourne & Park, LLP, April 2005, p. 51.

Biomass fuels contain little or no sulfur, thus cofiring with biomass results in a reduction in SO₂ emissions. Similarly, the nitrogen content of biomass fuels is generally lower than that of coal, which corresponds to a decrease in the fuel nitrogen conversion to NO_x emissions. However, this characteristic is not universal for all biomass fuels. Alfalfa stalks, rice hulls, and urban waste wood can contain nitrogen levels higher than coal. Adding biomass also reduces NO_x emissions by reducing the overall flame temperatures, leading to lower levels of thermal NO_x emissions. The range of NO_x emissions reductions can vary greatly depending on the boiler type and efficiency, fuel, and emissions management practices.⁸³ The results of various utility demonstrations of biomass cofiring provide an indication of the NO_x emission reductions that might be expected from cofiring. Table 4.8 shows the potential reductions of NO_x and SO₂ emissions that may be attributed to cofiring biomass with coal at both a 5 percent and 10 percent biomass heat input. When cofiring approximately 5 percent biomass (heat content), a 6 percent reduction in NO_x emissions is provided on that 5 percent. At 10 percent biomass cofiring, a reduction of approximately 10 percent in NO_x can be expected.

⁸³ David Dayton, *A Summary of NO_x Emissions Reduction from Biomass Cofiring*, National Renewable Energy Laboratory, NREL/TP-510-32260, May 2002, p. 2.

Table 4.8 Potential Emissions Reductions from Cofiring Biomass with Coal

Plant Name	Unit No.	Capacity (MW)	2003 Heat Input ^a (MmBtu)	2003 Emissions from Coal-only Generation ^a (TPY)		Emission Reductions from Cofiring (TPY)			
				NO _x	SO ₂	(5%)		(10%)	
						NO _x ^b	SO ₂ ^c	NO _x ^d	SO ₂ ^c
Warrior Run	2	180	15,954,434	483	-	1	-	5	-
R.P. Smith	3	29	4,118,772	757	2,921	2	146	8	292
	4	88	1,190,328	230	829	1	41	2	83
Brandon Shores	1	690	35,838,632	5,419	18,153	16	908	54	1,815
	2	690	43,585,261	7,624	22,614	23	1,131	76	2,261
C.P. Crane	1	190	12,088,151	5,253	15,420	16	771	53	1,542
	2	190	13,264,963	5,597	16,841	17	842	56	1,684
H.A. Wagner	2	134	9,731,782	2,434	7,121	7	356	24	712
	3	319	19,594,811	2,488	13,783	7	689	25	1,378
Chalk Point	1	341	17,750,242	4,511	19,652	14	983	45	1,965
	2	342	19,884,133	5,054	22,014	15	1,101	51	2,201
Dickerson	1	191	8,365,574	1,839	9,947	6	497	18	995
	2	191	7,656,066	1,543	9,104	5	455	15	910
	3	191	9,297,330	1,981	11,056	6	553	20	1,106
Morgantown	1	582	37,488,101	9,066	43,039	27	2,152	91	4,304
	2	582	38,205,354	8,726	42,301	26	2,115	87	4,230
Maryland Total		4,930	294,013,934	63,004	254,793	189	12,740	630	25,479

^aEPA Clean Air Markets Data, available at from <http://cfpub.epa.gov/gdm/index.cfm?fuseaction=iss.isshome>.
^bNO_x Emissions are reduced 6 percent for the 5 percent of heat input attributed to biomass.
^cSO₂ Emissions are reduced 100 percent for the 5 percent and 10 percent of heat input attributed to biomass.
^dNO_x Emissions are reduced 10 percent for the 10 percent of heat input attributed to biomass.

As a facility reduces NO_x and SO₂ emissions, the environmental benefit translates into an economic benefit from either avoiding the purchase of allowances or freeing excess emissions allowances for sale. The price of an SO₂ allowance in 2005 is approximately \$700. The SO₂ allowance market is a 12-month market, thus the timing of emissions reductions does not impact the value of the allowance. The NO_x Sip Call Allowance market, the follow-on to the EPA NO_x Budget Program, completed its first Ozone season in 2004. Average prices in 2004 were \$2,400 and prices for 2005 are \$3,000.⁸⁴ The ozone season extends through only 5 months, May 1 – September 30, so that only a portion of the year-round emissions reductions holds an economic value. For purposes of this analysis, it is assumed that one-half of the NO_x emissions reductions achieved through biomass cofiring will take place within the ozone season reflecting the increase in electricity demand for the summer peak periods. Table 4.9 provides the estimated economic benefit from emissions reductions attributed to cofiring in Maryland’s coal-fired facilities based on actual 2003 data. The 2003 emissions data reflect the effectiveness of existing strategies and

⁸⁴ Cantor Fitzgerald Real Time Market Data, available at <http://www.emissionstrading.com/>.

environmental controls. Those facilities with higher emissions, in particular those with high SO₂ emissions, have a greater opportunity to reduce emissions and receive a significant economic benefit from excess emissions allowances.

Table 4.9 Potential Revenues from Emissions Reductions

Plant Name	Unit No.	Value of Emission Reductions from Cofiring (\$1,000)			
		(5%)		(10%)	
		NO _x	SO ₂	NO _x	SO ₂
Warrior Run	2	\$2	\$-	\$8	\$-
R.P. Smith	3	\$3	\$102	\$11	\$204
	4	\$1	\$29	\$3	\$58
Brandon Shores	1	\$24	\$635	\$81	\$1,271
	2	\$34	\$791	\$114	\$1,583
C.P. Crane	1	\$24	\$540	\$79	\$1,079
	2	\$25	\$589	\$84	\$1,179
H.A. Wagner	2	\$11	\$249	\$37	\$498
	3	\$11	\$482	\$37	\$965
Chalk Point	1	\$20	\$688	\$68	\$1,376
	2	\$2	\$770	\$76	\$1,541
Dickerson	1	\$8	\$348	\$28	\$696
	2	\$7	\$319	\$23	\$637
	3	\$9	\$387	\$30	\$774
Morgantown	1	\$41	\$1,506	\$131	\$3,013
	2	\$39	\$1,480	\$136	\$2,961
Maryland Total		\$284	\$8,918	\$945	\$17,836

In addition to the economic benefits captured by the emissions trading markets, facilities cofiring qualified biomass resources are eligible to participate in the Maryland Renewable Energy Portfolio Standard (RPS). The Maryland RPS includes biomass cofiring as a Tier 1 resource. Qualified biomass resources include: mill residue; precommercial soft wood thinning; urban waste wood; pallets, crates or dunnage; brush; and agricultural sources. Under the Maryland RPS, a Tier 1 resource is valued at up to \$20/MWh. Based on 2003 operating data as reported to the Energy Information Administration and assuming a minimum price of \$1.75/MWh for the renewable energy credits (RECs) created from the biomass cofiring, Maryland coal facilities could receive a combined total of \$5 million in additional revenues for cofiring 10 percent biomass resources to generate 2.8 million MWh of green power (Table

4.10).⁸⁵ The federal production tax credit allows a 1.9-cent/kWh tax credit for cofiring facilities than make use of closed loop biomass (dedicated energy crops such as switchgrass). The narrow definition of closed loop biomass makes it unlikely that any one Maryland facility would have access to a sufficient quantity of closed loop biomass resources to qualify under the federal production tax credit.

Table 4.10 Potential Value of RECs from Biomass Cofiring in Maryland

Plant Name	Unit No.	Capacity (MW)	2003 Generation ^a (MWh)	Renewable Energy Credits Generated			
				(5%)		(10%)	
				MWh	REC \$1,000	MWh	REC \$1,000
Warrior Run	2	180	1,519,470	75,973	\$133	151,947	\$266
R.P. Smith	3	29	392,264	19,613	\$34	39,226	\$69
	4	88	113,365	5,668	\$10	11,336	\$20
Brandon Shores	1	690	3,413,203	170,660	\$299	341,320	\$597
	2	690	4,150,977	207,549	\$363	415,098	\$726
C.P. Crane	1	190	1,151,252	57,563	\$101	115,125	\$201
	2	190	1,263,330	63,166	\$111	126,333	\$221
H.A. Wagner	2	134	926,836	46,342	\$81	92,684	\$162
	3	319	1,866,172	93,309	\$163	186,617	\$327
Chalk Point	1	341	1,690,499	84,525	\$148	169,050	\$296
	2	342	1,893,727	94,686	\$166	189,373	\$331
Dickerson	1	191	796,721	39,836	\$70	79,672	\$139
	2	191	729,149	36,457	\$64	72,915	\$128
	3	191	885,460	44,273	\$77	88,546	\$155
Morgantown	1	582	3,570,295	178,515	\$312	357,030	\$625
	2	582	3,638,605	181,930	\$318	363,861	\$637
Maryland Total		4,930	28,001,327	1,400,066	\$2,450	2,800,133	\$4,900

^aCalculated from 2003 heat input data, assuming a plant heat rate of 10.5 MmBtu/Mwh.

Biomass cofiring also produces positive environmental benefits with respect to reductions in greenhouse gases (GHGs), commonly associated with climate change. In particular, biomass cofiring provides net reductions in carbon dioxide (CO₂) by avoiding emissions through fossil fuel (i.e., coal) displacement. Currently, power plants in Maryland are not required to participate at the state or federal levels in mandatory GHG reduction strategies or market-based cap-and-trade systems.

⁸⁵ The \$1.75/MWh figure relied upon is based on market clearing prices for Maryland-eligible renewable energy credits in May 2005. Future market clearing prices may be significantly higher.

However, Maryland is an observer to the Regional Greenhouse Gas Initiative (RGGI) -- a cooperative effort by Northeastern and Mid-Atlantic states to establish a market-based cap and trade system to reduce power plant CO₂ emissions. Moreover, many states have introduced or enacted legislation to address climate change through GHG and CO₂ reductions, and legislation at the federal level continues to be considered. Additionally, the owners of coal-fired generating capacity can also explore membership in the Chicago Climate Exchange (CCX) – a broad, voluntary, legally binding private sector effort that employs a GHG cap and trade system to help selected business sectors understand the monetary costs associated with undertaking GHG mitigation efforts. In early 2006, prices were \$2 per metric ton prices of CO₂ in the voluntary CCX market.⁸⁶ In the European markets, CO₂ prices average nearly 27 euros per metric ton – or nearly \$32.50 per metric ton.⁸⁷ To the extent coal-fired power plants participate in voluntary or mandatory CO₂ market trading activities and achieve net reductions in CO₂ through biomass cofiring, these emission offsets can be sold to U.S. business operations (through the CCX or through bilateral arrangements) that have not met their voluntary or mandatory CO₂ quotas, and defray costs associate with biomass retrofitting.

E. Economic Assessment of Cofiring Biomass in Maryland Power Plants

The cost assessments described above provide a first look at the economic considerations of biomass cofiring. Based on the estimated incremental capital and fuel costs, and the economic and environmental benefits associated with biomass fuels, it is possible to identify those facilities that may economically benefit from cofiring. A summary of the economic costs and benefits attributed to cofiring is provided below. These assessments do not take into consideration any limitations stemming from technical and engineering configurations or unexpected problems with fuel availability. Tables 4.11 and 4.12 provide a summary of the incremental costs and revenues that may occur at a Maryland coal-fired power plant that retrofits its facility to cofire biomass with coal at 5 percent and 10 percent based on heat input, respectively.

⁸⁶CCX, CCX Market Activity, <http://www.chicagoclimatex.com/> (Available March 2, 2006).

⁸⁷Point Carbon, EUA price last 30 days, <http://www.pointcarbon.com> (Available March 2, 2006).

**Table 4.11 Economic Value of Environmental Benefits from
Cofiring 5 Percent Biomass in Maryland**

Plant Name	Biomass Capacity MW	Incremental Costs		Incremental Revenues			Net Costs (Savings) \$1,000/year
		\$/Year (\$1,000)		\$/Year (\$1,000)			
	Capital	Fuel	NO _x	SO ₂	RECS		
Warrior Run-2	9	\$117	\$471	\$2	\$-	\$133	\$453
R.P. Smith-3	1.45	\$19	\$122	\$3	\$102	\$34	\$0.5
R.P. Smith-4	4.4	\$57	\$35	\$1	\$29	\$10	\$53
Brandon Shores-1	34.5	\$338	\$1,057	\$24	\$635	\$299	\$436
Brandon Shores-2	34.5	\$338	\$1,286	\$34	\$791	\$363	\$434
C.P. Crane-1	9.5	\$124	\$357	\$23	\$540	\$101	\$(184)
C.P. Crane-2	9.5	\$124	\$391	\$25	\$589	\$111	\$(210)
H.A. Wagner-2	6.7	\$87	\$287	\$11	\$249	\$81	\$33
H.A. Wagner-3	15.95	\$208	\$578	\$11	\$482	\$164	\$129
Chalk Point-1	17.05	\$222	\$524	\$20	\$688	\$148	\$(110)
Chalk Point-2	17.1	\$223	\$587	\$23	\$770	\$166	\$(149)
Dickerson-1	9.55	\$125	\$247	\$8	\$348	\$70	\$(55)
Dickerson-2	9.55	\$125	\$226	\$7	\$319	\$64	\$(39)
Dickerson-3	9.55	\$125	\$274	\$9	\$387	\$77	\$(74)
Morgantown-1	29.1	\$285	\$1,106	\$41	\$1,506	\$312	\$(469)
Morgantown-2	29.1	\$285	\$1,127	\$39	\$1,481	\$318	\$(426)

**Table 4.12 Economic Value of Environmental Benefits from Cofiring
10 Percent Biomass in Maryland**

Plant Name	Biomass Capacity MW	Incremental Costs		Incremental Revenues			Net Costs \$1,000/Year
		\$/Year (\$1,000)		\$/Year (\$1,000)			
	Capital	Fuel	NO _x	SO ₂	RECS		
Warrior Run-2	18	\$235	\$941	\$7	\$0	\$266	\$903
R.P. Smith-3	2.9	\$38	\$243	\$11	\$204	\$69	\$(4)
R.P. Smith-4	8.8	\$115	\$70	\$3	\$58	\$20	\$104
Brandon Shores-1	69	\$675	\$2,114	\$81	\$1,271	\$597	\$840
Brandon Shores-2	69	\$675	\$2,572	\$114	\$1,583	\$726	\$823
C.P. Crane-1	19	\$248	\$713	\$79	\$1,079	\$201	\$(399)
C.P. Crane-2	19	\$248	\$783	\$84	\$1,179	\$221	\$(453)
H.A. Wagner-2	13.4	\$175	\$574	\$37	\$498	\$162	\$52
H.A. Wagner-3	31.9	\$416	\$1,156	\$37	\$965	\$327	\$243
Chalk Point-1	34.1	\$445	\$1,047	\$68	\$1,376	\$296	\$(247)
Chalk Point-2	34.2	\$446	\$1,173	\$76	\$1,541	\$331	\$(329)
Dickerson-1	19.1	\$249	\$494	\$28	\$696	\$139	\$(121)
Dickerson-2	19.1	\$249	\$452	\$23	\$637	\$128	\$(87)
Dickerson-3	19.1	\$249	\$549	\$30	\$774	\$155	\$(161)
Morgantown-1	58.2	\$569	\$2,212	\$136	\$3,013	\$625	\$(992)
Morgantown-2	58.2	\$569	\$2,254	\$131	\$2,961	\$637	\$(905)

Chapter V. Potential for Cofiring Biomass with Coal In Maryland

A. Technical Potential

Maryland has 16 coal-fired units within eight coal-fired power plants. It is feasible to cofire biomass in any of the 16 units, however some boiler technologies are more easily adaptable to biomass, providing fewer risks and efficiency losses than others. All but three of the Maryland facilities operate either wall-fired or tangential-fired pulverized coal boilers. Wall-fired, pulverized coal boilers are the most common type of coal-fired boiler and thus have been the subject of several test burns of biomass to analyze the opportunities for commercialization and the impacts on plant efficiency and emissions. The results of both research efforts and commercial demonstrations of cofiring in wall-fired PC boilers indicate that there are no technical barriers to cofiring up to 20 percent biomass, based on mass, as long as there is separate processing and fuel injection for the biomass fuels. Maryland's facilities include 9 wall-fired boilers.⁸⁸ Maryland also has four tangentially fired pulverized coal units. The process of cofiring in tangentially fired pulverized coal burners is fundamentally different from that of wall-fired boilers which have discrete and separate burn zones within the boiler. The tangentially fired boiler has a single burn zone with lower temperatures, which makes combustion more uniform regardless of fuel. Under both privately funded research efforts by New York State Electric and Gas Company and the EPRI-DOE Cooperative Agreement Program, there have been positive results from cofiring as much as 30 percent biomass, on a mass basis, with little efficiency loss. However, in some tests the NO_x reductions were not as high as were expected. Based on a review of various research efforts, technical papers, and commercially operating facilities, we assume that it is technically possible to cofire as much as 20 percent biomass in a wall-fired boiler and 30 percent biomass (mass basis) in a tangentially fired boiler, with separate fuel injection. Without separate fuel injection, studies indicate that no more than 5 percent biomass (mass basis) should be cofired, and that there are likely to be some mechanical and efficiency problems with blended fuels in the pulverizer.

⁸⁸ Including the cell burner at H.A. Wagner, a cell burner boiler is a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame.

In addition to the pulverized coal boilers, there are two cyclone boilers located at C.P Crane, Units 1 and 2. Cyclones are mixed in terms of their adaptability to biomass. Fuel processing and injection is easier and less costly because there is no pulverizer and cyclones accept larger particles of coal (and biomass). However, biomass cofiring may exacerbate slagging problems given the nature of the technology, in which coal is flung onto the sides of the boiler. The tests on cyclone boilers demonstrate that careful management of the fuel mix is critical to avoiding slagging and maintaining boiler efficiency. Additionally, cyclone boilers typically deliver relatively high NO_x emissions. A lack of experience and the potential for efficiency losses make cofiring with cyclone boilers less attractive than with wall-fired and tangentially fired pulverized coal boilers.

Fluidized bed technology is generally regarded as a flexible fuel system with a capacity to handle low grade and problematic fuels. This fuel flexibility makes FBC boilers good candidates for biomass cofiring. Fluidized-bed combustion has been applied successfully to a range of wood-waste and coal-burning boilers in California and is more widely used for biomass cofiring outside the United States, specifically in Canada and Finland. Additionally, fluidized-bed combustion temperatures are lower than in most other systems and thus provide lower NO_x emissions when compared with other methods of burning wood fuels.

Perhaps the greatest technical barrier to cofiring is an apparent incompatibility of NO_x control technologies with biomass cofiring. In particular, tests have demonstrated that high alkali fuels, such as biomass, may adversely affect the longevity and performance of selective catalytic reduction (SCR) technologies. This could be a significant technical barrier to cofiring. The existence of this problem has not yet been definitively confirmed, but if the problem is valid, careful monitoring of biomass feedstock compositions and further processing of biomass resources are likely to be required which would further increase fuel costs.⁸⁹ Based on the test results that biomass cofiring is problematic with SCR/SACR/SNCR technologies, Maryland facilities relying on these technologies face a greater risk to emissions control performance when cofiring with biomass.

⁸⁹ R.L. Bain, *et al.*, p. 2-2.

The technical potential for biomass cofiring is greatest for tangentially fired pulverized coal facilities that have not installed SCR technologies. Under this scenario, R.P. Smith Unit 4, and all three units of Dickerson have good technical potential for biomass cofiring. Likewise, Warrior Run, which has a circulating fluidized bed combustion boiler, may be a good candidate. Wagner Unit 3 and Brandon Shores Units 1 and 2 have installed SCR technologies, and thus the technical potential for these facilities is low. Additionally, as part of their settlement with EPA under the Clean Air Act, Mirant plans to install SCR technologies in their Morgantown Facilities, Units 1 and 2 in 2007 and 2008, respectively. While technically possible, the higher risk of slagging in cyclone boilers makes biomass cofiring in C.P. Crane's Unit 1 and 2 less attractive than in other facilities.

B. Economic Potential

Based on the economic assessment described in Chapter 4, there are several facilities that would benefit from cofiring with biomass. The degree of which each facility is able to achieve an annual cost savings from cofiring is directly related to the environmental benefits of cofiring and the value of emissions allowances and renewable energy credits. Those facilities with relatively high SO₂ emissions are able to generate a large number of allowances for sale under the EPA Acid Rain Program. As the Clean Air Interstate Rule and the NO_x SIP Call come into effect, one can expect that prices of allowances will increase. However, the total amount of emissions reduced is subject to fuel selection and boiler operations and efficiency. A careful analysis of the engineering and operating parameters for each facility will more accurately predict the amount and value of emissions reductions. Likewise, the value of renewable energy credits generated under the Maryland Renewable Energy Portfolio Standard is speculative and subject to market conditions once the RPS for Maryland, as well as the RPSs in neighboring states, comes into effect.

Those facilities that have the potential for cost savings under both a 5 percent and 10 percent biomass cofiring scenario can be considered good candidates for more detailed and site-specific analysis. This includes all of the units currently firing coal at C.P. Crane, Chalk Point, Dickerson and Morgantown. Those facilities that are likely to have increased costs as a result of

cofiring, even when considering the environmental benefits, are not considered good candidates. Therefore, Warrior Run, R.P. Smith Unit 4, Brandon Shores Units 1 and 2, and H.A. Wagner Units 2 and 3 appear not to be good candidates for any additional, more detailed analysis. In the case of R.P. Smith Unit 3, the results are mixed and therefore considered neutral, i.e., R.P. Smith Unit 3 cannot be unambiguously assessed as either a good candidate or a bad candidate for biomass cofiring based on the analysis conducted herein. Table 5.1 summarizes the results of the economic assessment described in Chapter 4.

Table 5.1 Economic Potential for Biomass Cofiring

Plant and Unit	Economic Costs (Savings) \$/year (\$1,000)	
	5% Biomass (heat input)	10% Biomass (heat input)
Warrior Run-2	\$453	\$903
R.P. Smith-3	\$0.5	\$(4)
R.P. Smith-4	\$53	\$109
Brandon Shores-1	\$336	\$840
Brandon Shores-2	\$434	\$823
C.P. Crane-1	\$(184)	\$(399)
C.P. Crane-2	\$(210)	\$(455)
H.A. Wagner-2	\$33	\$52
H.A. Wagner-3	\$129	\$243
Chalk Point-1	\$(110)	\$(247)
Chalk Point-2	\$(149)	\$(329)
Dickerson-1	\$(55)	\$(120)
Dickerson-2	\$(39)	\$(87)
Dickerson-3	\$(75)	\$(161)
Morgantown-1	\$(469)	\$(992)
Morgantown-2	\$(426)	\$(905)

C. Fuel Availability

Biomass power plants typically fire a blend of biomass fuels. Fuel choices are based on reliability of supply, cost, and availability. There are five categories of biomass suitable for cofiring with coal: urban waste woods, mill residues, forest residues, agricultural residues, and dedicated energy crops. The current market for biomass fuels in the region is limited to small users (i.e., pellet stoves) and industrial facilities using largely waste biomass fuels for on site generation. Without a large market for biomass fuels, suppliers within the region tend to be small and may have to develop additional capabilities to serve a large electricity generator. Prior

to the development of a biomass fuels market, the reliability of one source of fuel compared with another is largely unknown. When and if they become available, dedicated energy crops would be a very reliable source of fuels. Experience with on site generation and wood waste disposal may make suppliers sourcing biomass from mill residues more reliable than other currently available biomass sources. Likewise, urban waste woods are expected to provide a reliable source of biomass if contracts with waste management operators are structured to protect the supply of wood. Forest and agricultural residues appear to be the least reliable as they rely on weather, crop production, location, and the cooperation of multiple landowners.

The availability and cost of biomass fuels is described in Chapter 3, *Biomass Resource Assessment*, and Chapter 4, *The Economics of Biomass Cofiring*, respectively. Based solely on quantity available within the region, agricultural residues are most widely available, followed by mill residue, urban waste woods, and forest residues. As noted previously, dedicated energy crops are not presently available. When reviewing the costs of biomass fuels according to heat value (MmBtu), the least expensive fuel on an MmBtu basis is urban waste wood, closely followed by mill residues. Forest residue, agricultural residues, and dedicated energy crops are significantly more expensive. Additionally, the amount of alkali present in the fuels will affect the efficiency of the boiler with high alkali fuels lowering the overall efficiency and increasing the risk of slagging.⁹⁰ Agricultural residues and switchgrass have relatively high levels of alkali, making them the least attractive fuels for biomass cofiring. Urban waste wood and forest residue have slightly less alkali with mill residues having the least amount.⁹¹ Using four criteria, i.e., reliability, availability, cost and alkali content, and assuming an equal weight for each, it is possible to score and rank the five categories of biomass fuels for use in predominantly coal-fired power plants. Based on the results this ranking process shown in Table 5.2, mill residue and urban waste wood have the best potential for biomass cofiring.

⁹⁰ The term “alkali” is used to describe the sum of potassium and sodium compounds, generically expressed as the oxides K₂O and Na₂O. The alkali earths, MgO and CaO, are also important in slagging and deposit formation.

⁹¹ Thomas Miles, P.E., Larry L. Baxter, Richard W. Bryers, Bryan M. Jenkins, and Laurance L. Oden, *Alkali Deposits Found in Biomass Power Plants: A Preliminary Investigation of Their Extent and Nature*, National Renewable Energy Laboratory, February 1996, p. 21, available at <http://www.nrel.gov/docs/legosti/fy96/8142v1.pdf>.

Table 5.2 Ranking Biomass Fuels

Fuel	Reliability	Availability	Cost	Alkali	Score - (Rank)
Agricultural Residues	4	1	5	5	15 – (4)
Urban waste wood	2	3	1	3	9 – (2)
Switchgrass	5	5	3	4	17 – (5)
Mill Residue (Dry)	1	2	2	1	6 – (1)
Forest Residue	3	4	4	2	13 – (3)

Based on the assumption that the preferred fuels for a biomass cofiring facility in Maryland is urban waste wood, mill residue, or a combination thereof, it is possible to determine which Maryland facilities are located within range of sufficient resources. Table 5.3 lists the twenty leading counties for urban waste wood and mill residue biomass production and provides the estimated amount of biomass generated per year. The table then compares the biomass availability per county with the locations of Maryland’s coal-fired facilities, identifying those counties that are within a 50-mile radius of each facility. For each facility, the estimated amount of available biomass (urban waste wood and mill residue) is provided in order to determine which facility has the best access to low cost, preferable biomass resources.

Table 5.3 Biomass Availability by County and Facility: Urban Waste Wood and Mill Residue (Tons)

County	County Total	Chalk Point	Dickerson	Morgan-town	Brandon Shores	CP Crane	HA Wagner	RP Smith	Warrior Run
Fairfax, VA	245,706		245,706						
Baltimore, MD	99,775		99,775		99,775	99,775	99,775		
York, PA	92,855					92,855			
Prince George's, MD	84,673	84,673	84,673	84,673		84,673			
Lancaster, PA	62,368					62,368			
Franklin, PA	56,376							56,376	56,376
Somerset, PA	39,812								39,812
Bedford, PA	36,683							36,683	36,683
Frederick, VA	34,656		34,656						34,656
Harford, MD	27,617				27,617	27,617	27,617		
Frederick, MD	25,995		25,995					25,995	25,995
Caroline, VA	22,655	22,655		22,655					
Westmore., VA	22,439	22,439		22,439					
Chester, PA	20,032					20,032			
Anne Arundel, MD	18,691				18,691	18,691	18,691		
Adams, PA	15,136		15,136					15,136	
Stafford, VA	13,611	13,611		13,611					
Carroll, MD	12,718		12,718		12,718	12,718	12,718	12,718	
Fauquier, VA	12,049	12,049	12,049	12,049					
Mineral, WV	11,479								11,479
TOTAL	955,322	155,427	530,706	155,427	158,800	418,728	158,800	146,907	205,000

The quantity of biomass listed for each facility assumes that 100 percent of the estimated amount of biomass is available to that facility. Blank cells indicate that a county is outside of the 50-mile range of a particular facility.

According to this analysis, Dickerson, located northwest of Washington, D.C. in Montgomery County, has the best access to biomass resources, largely from one area: Fairfax County. Dickerson, along with C.P. Crane in Baltimore County, has access to enough biomass resources that even with some competition for urban waste wood and mill residue there is sufficient fuel available for cofiring. The remaining facilities have access to sufficient resources for cofiring, but may be limited to cofiring only a small amount due to competition for resources.

VI. Conclusions

Faced with an aging fleet of coal-fired facilities, the pressure of additional and more stringent environmental regulations, and the rising price of fossil fuels, Maryland power plants may wish to consider biomass cofiring as a strategy to extend the life of coal-fired generators. The assessment described in the preceding chapters provides a first look at the potential for cofiring biomass with coal.

A. Facilities with Potential for Cofiring Biomass

Based on the findings of the technical and economic potential as well as fuel availability, it is possible to identify those facilities that are likely candidates for biomass cofiring (Table 6.1). A facility with low technical or economic potential, designated by an empty circle, is considered unsuitable for biomass cofiring. Low potential arises from having incompatible emissions control or boiler systems, or a negative economic performance under the cofiring scenarios. While some facilities have better access to low cost biomass resources than others, all of the Maryland coal-fired power plants have access to sufficient resources for at least a small amount of cofiring. The full circle designates those facilities with high technical or economic potential and access to low cost biomass resources. Facilities that are not particularly strong, or weak, are designated by a half circle.

Table 6.1 Screening for Biomass Cofiring Potential

Plant Name	Unit	Technical Potential	Economic Potential	Fuel Availability	Overall Score
Warrior Run	2	◐	○	◐	○
R.P. Smith	3	◐	◐	◐	◐
	4	●	○	◐	○
Brandon Shores	1	○	○	◐	○
	2	○	○	◐	○
C.P. Crane	1	◐	●	●	◐
	2	◐	●	●	◐
H.A. Wagner	2	◐	○	◐	○
	3	○	○	◐	○
Chalk Point	1	◐	●	◐	◐
	2	◐	●	◐	◐
Dickerson	1	●	●	●	●
	2	●	●	●	●
	3	●	●	●	●
Morgantown	1	○	●	◐	○
	2	○	●	◐	○

● = good potential
 ◐ = neutral
 ○ = poor potential

There are five facilities that can be considered poor candidates for biomass cofiring: Warrior Run, R.P. Smith unit 4, Brandon Shores, H.A. Wagner, and Morgantown. The economic assessment for these facilities indicates that biomass cofiring is not financially viable. Additionally, the installation of SCR equipment at Brandon Shores, H.A. Wagner 3, and Morgantown suggests that these facilities are more likely to experience technical problems from cofiring. While not strong candidates, R.P. Smith-unit 3, C.P. Crane, and Chalk Point, are technically and economically suitable for biomass cofiring and have access to sufficient resources. The three units at Dickerson provide the best potential for biomass cofiring among the state's coal-fired facilities. Dickerson is located in close proximity to Fairfax County, which has a large amount of urban waste wood that may be made available for cofiring. Additionally, as a tangentially fired pulverized coal facility without SCR emissions control technology, it is a good technical fit for cofiring. Finally, Dickerson has a history of emitting significant amounts of SO₂ and NO_x, which provides an opportunity for cost recovery through the sale (or avoided purchase) of emissions allowances. Table 6.2 provides the estimated impacts from cofiring 5 and 10 percent biomass at Dickerson and the cumulative impact of cofiring with all three units.

Table 6.2 Results from Cofiring Biomass at Dickerson

	Biomass (TPY)	Savings (\$ (\$1,000))	Biomass Power (MWh)	NO_x Reduction (TPY)	SO₂ Reduction (TPY)
Cofiring 5 % (Heat Input)					
Unit 1	34,857	\$55	39,836	6	497
Unit 2	31,900	\$39	36,457	5	455
Unit 3	38,739	\$74	44,273	6	553
<i>Total</i>	<i>105,496</i>	<i>\$168</i>	<i>120,556</i>	<i>17</i>	<i>1,505</i>
Cofiring 10 % (Heat Input)					
Unit 1	69,713	\$121	79,672	18	995
Unit 2	63,801	\$87	72,915	15	910
Unit 3	77,478	161	88,546	20	1,106
<i>Total</i>	<i>210,992</i>	<i>\$369</i>	<i>241,133</i>	<i>53</i>	<i>3,011</i>

While further engineering and site-specific assessments would be required prior to any final recommendation, the initial screen identifies Dickerson as the most likely candidate for biomass cofiring. With three units of similar size, technology and age, Dickerson provides a good opportunity to first test the impacts of biomass cofiring in one unit with a potential for expanding to two other units.

B. Fuel Availability

By and large, fuel costs are the most prohibitive element to biomass cofiring. Biomass fuels are more expensive than coal, with the exception of very low cost sander dust or sawdust mixed at the coal pile and burned in very small quantities (less than 2 percent heat input) with coal. Without a significant decrease in fuel costs, it is unlikely that many power plants are going to make the necessary capital investment to cofire biomass in quantities greater than what can be accomplished with existing feed systems. Additionally, prior to any maturation of the biomass fuels industry, arranging supplies of low-cost biomass fuels, such as urban waste wood, may require multiple contracts with parties outside of the traditional energy sector. Thus, fuel supply contracts may become administratively burdensome and less reliable. The lack of an established market for biofuels is likely to hamper collection and delivery of fuels and may increase costs. While there is a potential for energy crop development, this is not an option in the near term because of the high opportunity costs to farmers and the lack of a local market.

C. Environmental Considerations

Emissions reductions and environmental compliance are likely to be driving forces behind any facility considering biomass cofiring. In reviewing Maryland facility data for 2003, it appears that the majority of the state's coal-fired boilers are also burning oil and natural gas in significant quantities. One reason for this fuel mixing and switching is likely to be environmental compliance. Switching from coal to natural gas in the summer months is a proven strategy to lower NO_x emissions during the ozone season while simultaneously providing SO₂ reductions. While biomass is not cost effective when compared with coal (\$1.40/ MmBtu), when compared to natural gas (\$6-7/MmBtu) biomass fuels are more attractive. However, there is still a great deal of uncertainty surrounding the actual environmental benefits of cofiring. While SO₂ emissions reductions are guaranteed as a result of low/no sulfur content in the fuel, the impact of cofiring on NO_x emissions is far less certain. A facility switching to natural gas in order to lower NO_x emissions is likely to need further testing and assurances regarding the environmental benefits of cofiring prior to making any capital investments required to facilitate cofiring.