Technical Support Document for the
Revisions to Definition of Cogeneration Unit in Clean Air Interstate Rule (CAIR), CAIR Federal Implementation Plan, Clean Air Mercury Rule (CAMR), and CAMR Proposed Federal Plan; Revision to National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters; and Technical Corrections to CAIR and Acid Rain Program Rules

Methodology for Thermal Efficiency and Energy Input Calculations and Analysis of Biomass Cogeneration Unit Characteristics

EPA Docket number: EPA-HQ-OAR-2007-0012
April 2007

U.S. Environmental Protection Agency
Office of Air and Radiation

Technical Support Document for Proposed Revisions to Cogeneration Definition in CAIR, CAIR FIP, CAMR, and Proposed CAMR Federal Plan

This Technical Support Document (TSD) has several purposes. One purpose of the TSD is to set forth the methodology for determining the thermal efficiency of a unit for purposes of applying the definition of the term "cogeneration unit" under the existing CAIR, the CAIR model trading rules, the CAIR FIP, CAMR, the CAMR Hg model trading rule, and the proposed CAMR Federal Plan. Another purpose of the TSD is to present information relevant to the proposed revisions, and other potential revisions for which EPA is requesting comment, concerning the thermal efficiency standard. One of the critical values used in the determination of thermal efficiency is the "total energy input" of the unit. Consequently, in connection with setting forth the methodology for determining thermal efficiency, the TSD specifically addresses what formula is to be used in calculating a unit's total energy input under the existing rules.

There are two major issues concerning the calculation of total energy input. The first issue is whether, under the existing rules, total energy input is determined based on the higher or lower heating value of the fuel or fuels combusted in the unit and how to calculate heating value. As discussed below, EPA maintains that, under the existing rules, total energy input constitutes the lower heating value of the fuel or fuels combusted by the unit, and EPA is requesting comment on whether the existing rules should be revised to state explicitly the formula for calculating total energy input using lower heating value. The second issue is whether and to what extent the existing rules should be revised to exclude non-fossil fuel (such as biomass) from the calculation of total energy input. As discussed below, EPA is requesting comment on the proposed revision, and other potential revisions, concerning such exclusion. EPA is not requesting comment on any other aspects of the thermal efficiency standard such as, for example, the adoption of a standard as part of the definition of the term "cogeneration unit," the specific percentages of total energy output that must be met, or the treatment of useful thermal energy in the thermal efficiency standard.

Another purpose of the TSD is to address the information that EPA has developed concerning the units potentially affected by the proposed change to the existing rules concerning the extent to which non-fossil fuel should be excluded from the calculation of a unit's total energy input. As discussed in the preamble of the proposed rule for which this TSD is provided, EPA has taken a number of steps to gather the most complete information we could about the number, size, location, industry, fuel use, electricity sales, and environmental impacts of the units potentially affected by the proposed change concerning the exclusion of non-fossil fuel from the calculation of total energy input. The TSD provides more detailed information about the biomass cogeneration unit inventory, data sources, and emissions calculations that EPA used in its analysis for the proposed rule.

I. Thermal Efficiency and Total Energy Input

In this section of the TSD, EPA describes the methodology for calculating thermal efficiency of a unit in order to help determine whether the unit qualifies for the cogeneration unit exemption. In addition, EPA addresses the definition and calculation of "total energy input," which is used in calculating thermal efficiency in order to determine whether the unit qualifies for the cogeneration unit exemption.

A. Determining Thermal Efficiency

In CAIR, the CAIR model trading rules, the CAIR FIP, CAMR, the CAMR Hg model trading rule, and the proposed CAMR Federal Plan, EPA included, as one criterion that a unit must meet in order to potentially qualify for the cogeneration unit exemption, the requirement that the unit meet a thermal efficiency standard. In adopting a thermal efficiency standard, EPA decided to use the thermal efficiency standard adopted by the Federal Energy Regulatory Commission (FERC) in determining whether a unit is a qualifying cogeneration unit under section (3)(18)(B) of the Federal Power Act (as amended by the Public Utility Regulatory Policy Act (PURPA)). However, EPA decided to make the thermal efficiency standard applicable to all fuels combusted by a unit, while the FERC limited application of the standard to natural gas and oil. (See 18 CFR 292.205(a)(2) and (b)(1). See 70 FR 25277).

The methodology for determining thermal efficiency adopted by EPA in the existing rules can be represented as the following:

Thermal Efficiency = (Net Electric Output + Net Thermal Output/2)/Fuel Heat Input (LHV)

More background on the decision to use a thermal efficiency standard and how to perform the thermal efficiency calculation can be found in the "Cogeneration Unit Efficiencies Calculation" TSD for CAIR.[1]

B. Calculating Total Energy Input

1. Higher Heating Value vs. Lower Heating Value

A critical value used in applying the thermal efficiency standard is the "total energy input" for the year for which thermal efficiency is being calculated. One of the first steps in determining the total energy input for a unit is identifying the unit's fuel mix and the heat content or heating value of the fuel or fuels combusted by the unit. Heating value, commonly expressed in Btu, can be measured in several ways, but the most common are to use gross heat content (referred to as "higher heating value" or "HHV") or to use net heat content (referred to as "lower heating value" or "LHV"). According to the Energy Information Administration (EIA) of U.S. Department of Energy, higher heating value includes, while low heating value excludes, "the energy used to vaporize water (contained in the original energy form or created during the combustion process)."[2]

As discussed above, EPA adopted in the existing rules the same thermal efficiency standard as that adopted by FERC in determining whether a unit is a qualifying cogeneration unit, except that EPA applied the thermal efficiency standard to all fuels and the FERC limited application of the standard to natural gas and oil. FERC's regulations that included the thermal efficiency standard stated that "energy input" in the form of natural gas and oil "is to be measured by the lower heating value of the natural gas or oil." See 18 CFR 292.202(m). As explained by FERC when it adopted these regulations in 1980 (45 FR 17959, 17962 (1980)):

> Lower heating values were specified in the proposed rules in recognition of the fact that practical cogeneration systems cannot recover and use the latent heat of water vapor formed in the combustion of hydrocarbon fuels. By specifying that energy input to a

[1] Cogeneration Unit Efficiencies Calculation, March 2005. OAR-2003-0053-2087 http://epa.gov/cair/pdfs/tsd_cogen.pdf

[2] http://www.eia.doe.gov/glossary/glossary_h.htm

> facility excludes energy that could not be recovered, the commission hoped that the proposed energy efficiency standards would be easier to understand and apply.

Because the thermal efficiency standard on which EPA's thermal efficiency standard was based is premised on using LHV to determine total energy input, EPA believes that the thermal efficiency standard in the existing CAIR, CAIR model trading rules, CAIR FIP, CAMR, CAMR Hg model trading program, and the proposed CAMR Federal Plan should be interpreted as similarly requiring the use of LHV of all fuels combusted at the unit in calculating a unit's total energy input. EPA notes that, if a unit uses HHV for the calculations and meets the thermal efficiency standard on that basis, the unit would necessarily meet the standard using LHV. See 45 FR 17962.

2. Definition of Lower Heating Value (LHV)

Although FERC regulations use lower heating value to measure a unit's energy input from natural gas and oil, the regulations do not specify a formula for calculating lower heating value. While there may be alternative definitions of, or formulas for calculating, LHV, EPA maintains that the following formula is consistent with the FERC approach for calculating LHV of fuels by excluding from the higher heating value of such fuels "the latent heat of water vapor formed in the combustion of hydrocarbon fuels." See 45 FR 17962. Under this formula, the relationship between the lower heating value of a fuel and the higher heating value of that fuel is:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of fuel in Btu/lb,

HHV = higher heating value of fuel in Btu/lb,

W = Weight % of moisture in fuel, and

H = Weight % of hydrogen in fuel.

EPA believes that the existing CAIR, CAIR model trading rules, CAIR FIP, CAMR, CAMR Hg model trading rule, and the proposed CAMR Federal Plan should be interpreted to require use of this formula for calculating lower heating value for purposes of determining total energy input.

This formula is consistent not only with the description of "lower heating value" by FERC, but also with EIA's description of the term. Moreover, the formula reflects a standard approach to calculating lower heating value. See the International Flame Research Foundation Combustion Handbook, http://www.handbook.ifrf.net (IFRF 1999-2000) (discussing relationship between higher and lower calorific value of a fuel).

EPA is requesting comment on the methodology described above for determining a unit's thermal efficiency (i.e., on the use of lower heating value in the denominator of the equation for thermal efficiency) and on the above-described formula for calculating LHV to determine a unit's total energy input, under the existing regulations. In addition, EPA is considering adding language to the existing regulations specifying this formula for calculating total energy input for purposes of applying the thermal efficiency standard. In particular, EPA is considering revising the definition of "total energy input" in the existing CAIR, CAIR model trading rules, CAIR FIP, CAMR, CAMR Hg model trading rule, and proposed CAMR Federal Plan by adding the following language to that definition:

> The energy input of any form of energy shall be measured by the lower heating value of that form of energy calculated as follows:
>
> $$LHV = HHV - 10.55(W + 9H)$$
>
> Where:
>
> LHV = lower heating value of fuel in Btu/lb,
>
> HHV = higher heating value of fuel in Btu/lb,
>
> W = Weight % of moisture in fuel, and
>
> H = Weight % of hydrogen in fuel.

As discussed in the preamble of the proposed rule for which this TSD is provided, EPA requests comment on whether the formula for calculating lower heating value shown above should be added to the existing regulations or whether some alternative formula for calculating total energy input or lower heating value is appropriate and should be added to the existing regulations.

3. Fuels to Include in Total Energy Input

In the rulemaking for which this TSD is provided, EPA is proposing to revise the thermal efficiency standard, as applied to certain existing units, to include in "total energy input" only the energy input from fossil fuel combusted by the units, rather than energy input from all fuels combusted. This change would make it more likely that those existing units that burn biomass and cogenerate electricity and useful thermal energy (referred to herein as "biomass cogeneration units") could meet the thermal efficiency standard and qualify as exempt cogeneration units under these rules. As discussed in the preamble of the rulemaking for which the TSD is provided, EPA is requesting comment on the proposed revision and on an alternative under which "total energy input" would instead be defined to include energy input from all fuels combusted, except biomass.

II. Units Affected by the Proposed Rule Change

This section of the TSD discusses the approach EPA used to estimate the universe of cogeneration units potentially affected by the proposed rule. As explained in more detail below, we used several data sources and selection criteria to develop a list of units, estimate which units would possibly be affected by a rule change, and what the environmental impacts might be. These inventory lists of identified biomass cogeneration units represent EPA's best effort to identify biomass cogeneration units that meet the specified criteria, but should not be assumed to be all inclusive or a determination of rule applicability.

A. Inventory Criteria and Information

To start, EPA wanted to know more about the population of biomass cogeneration units currently in use and their characteristics. We defined the appropriate criteria for the cogeneration units and then applied the criteria to help identify units that would potentially be included in CAIR and/or CAMR. The final inventory list of existing biomass cogeneration units was developed by applying the following criteria:

- Produced both electricity and useful thermal energy;
- Associated with a cogeneration generator with capacity greater than 25MW;

- Reported some type of biomass fuel use (biomass and coal use for CAMR units) in the 2001-2004 period; and
- Located in the CAIR or CAMR regions.

This exercise resulted in an inventory of 181 units in the CAIR region and 55 units in the CAMR region. The list of CAIR units includes all known units in states that participate in the NOx and/or SO2 trading programs. These inventories are not to be used to determine applicability for any biomass cogeneration units. Rather, they represent EPA's best attempt to identify units potentially affected by the proposed rule. See Appendix A for List of Identified Biomass Cogeneration Units in CAIR and CAMR Regions.

Once the units were identified, EPA collected more detailed information about the characteristics of each unit. The inventory was populated with the following types of data from 2004, the most recent baseline period year:

- Plant location;
- Industry category;
- Unit size (generator nameplate);
- Utilization
- Unit fuel type(s) and amounts; and
- Unit sales to the grid.

In addition, we had limited information about the emission controls installed on some units. The information available was sufficient to allow EPA to estimate which units were most likely to be affected by the proposed change to the CAIR and CAMR applicability provisions and cogeneration unit definition to limit total energy input for some units to fossil fuels. Other units were expected to either already be exempt from CAIR and CAMR or to remain covered by the cap-and-trade programs regardless of the proposed change.

Emissions data at the unit level was not available and had to be estimated. The approach for estimating emissions is covered later in this document.

B. Data Sources

After researching several sources of data, EPA decided to use data reported by owners to the Energy Information Administration (EIA). The EIA data is based on Electricity Survey Forms 860 and 767. We also considered data from EPA databases, the National Emission Inventory (NEI), and Energy and Environmental Analysis, Inc (EEA) Industrial Boiler database, but found that EIA had the most complete data for our needs at the individual unit level. The EIA database contains the associated generator nameplate data that is an important applicability factor for CAIR and CAMR. The associated generator nameplate is not available in the other databases. EIA also identifies whether each generator is a cogenerator, and whether it meets FERC qualifying facility requirements for cogeneration. In addition, there is an EIA data field that identifies whether the generator delivers electricity to the grid (EGU/Non-EGU status). However, the field only indicates those units that may deliver some amount of electricity to the grid, but not how much they actually sold.

For the inventory, we used the EIA-860 and EIA-767 databases to identify all boilers associated with a cogenerator with generator nameplate greater than 25 MW. The EIA-767 database has fuel use and heat content by specific fuel type. This data can be used to identify units that burn both biomass and any fossil fuel or any coal. We used this data for the inventory and identified any unit burning any amount of a biomass fuel, and biomass fuel and coal, in the 2001 to 2004 period.

EIA, and the other databases, do not provide the data necessary to determine if an EGU cogeneration unit is exempt -- percent of unit generating capacity or total amounts of electricity sold to the grid, and overall thermal efficiency. Prior to 2001, EIA provided facility electricity sales data and total facility nameplate in the non-utility version of EIA-860. This data can be used to make an estimate of the percentage of plant capacity sold, but not unit capacity. In addition, EIA does not collect unit emissions data from these sources, leaving a gap in the inventory analysis.

C. Developing Emissions Estimates

EIA does not collect measured emissions from the units of interest, but it does collect information such as fuels burned, fuel heat and sulfur content, New Source Performance Standards (NSPS) applicability, and control equipment information that can be used in conjunction with emission factors to estimate annual NO_x, SO_2, and Hg emissions. The emission calculations are based on 2004 fuel data and other emission-related information provided in the EIA-767 boiler database, combined with emission factor information from other sources. Estimation methods for each pollutant are outlined below.

1. NO_x Emissions

Whenever possible, EIA annual controlled NO_x rates (lb/mmBtu) and annual fuel heat input from EIA-767 were used to calculate annual NO_x emissions. The EIA annual controlled NOx rates are in lbs/mmBtu and were found in the boiler table of the EIA-767 database. The EIA-767 instructions request that these rates be based on data from continuous emission monitors (CEMs), if possible. If CEMS data are not available, these rates should be based on the method used to report emissions data to environmental authorities. The controlled NO_x rates are not fuel-specific, so the same annual NO_x rate was multiplied by each fuel's annual heat input in the calculations.

However, not all units reported emission rate information on EIA-767, so we had to look to additional sources for average emission factors. U.S. EPA AP-42 emission factors and National Renewable Energy Lab (NREL) emission factors were used when EIA factors were not available. AP-42 and NREL tables contain average emission factors for most unit type, NO_x control, and fuel type combinations. The NSPS status was the main driver used in determining the most appropriate NOx emission factor since we did not have consistent boiler type information from EIA-767. These emission factors were used in conjunction with the annual fuel quantities and heat input for each boiler to calculate the annual NO_x emission estimate for each fuel burned by the unit. The NO_x emission factors are reported in Table 1 below.

Table 1
NO_x Emission Factors (AP42 and NREL)

Unit Type	EIA Fuel	Emission Factor	Factor Source
Non-NSPS Boiler Non-NSPS Recovery Furnace	Wood/Woodwaste Liquids Other Biomass Liquids	1.66 lbs/1000 gals	NREL Table 12.6b
Non-NSPS Boiler Non-NSPS Recovery Furnace	Distillate Fuel Oil	24 lbs/1000 gals	AP42 Table 1.3-1
D Boiler D Recovery Furnace	Residual Fuel Oil Waste Oil (petroleum based liquid waste)	40 lbs/1000 gals	AP42 Table 1.3-1
Non-NSPS Boiler Non-NSPS Recovery Furnace	Residual Fuel Oil Waste Oil (petroleum based liquid waste)	47 lbs/1000 gals	AP42 Table 1.3-1
Da Boiler Db Boiler	Natural Gas	0.14 lb/mmBtu	AP42 Table 1.4-1
D Recovery Boiler	Natural Gas	0.19 lb/mmBtu	AP42 Table 1.4-1
Non-NSPS Boiler Non-NSPS Recovery Boiler	Natural Gas	0.27 lb/mmBtu	AP42 Table 1.4-1
Non-NSPS Recovery Boiler	Propane Gas	0.27 lb/mmBtu	AP42 Table 1.5-1
Da Boiler Db Boiler Non-NSPS Boiler	Wood Waste Solids	0.22 lb/mmBtu	AP42 Table 1.6-2
D Recovery Furnace Da Recovery Furnace Non-NSPS Recovery Furnace	Black Liquor	1.5 lbs/ton	NREL Table 12.6a
Non-NSPS Boiler	Other Biomass Solids	1.2 lbs/ton	NREL Table 12.6a
Non-NSPS Boiler	Sludge Waste	5 lbs/ton	NREL Table 12.6a
Non-NSPS Boiler	Tire Derived Fuel	22 lbs/ton	NREL Table 12.6a
D Boiler	Bituminous Coal	10 lbs/ton	AP42 Table 1.1-3
Non-NSPS Boiler	Bituminous Coal Petroleum Coke Waste Coal	15 lbs/ton	AP42 Table 1.1-3
Non-NSPS Boiler	Agricultural By-Products	1.2 lbs/ton	NREL Table 12.6a

2. SO_2 Emissions

The SO_2 emissions were similarly calculated based on EIA fuel quantity, heat content, and fossil fuel sulfur content from EIA-767, combined with SO_2 emission factors from AP-42, NREL, 40 CFR Part 75, and NESCAUM. EIA fuel sulfur content was used in all of the fossil fuel emission estimates except for natural gas, propane gas, and petroleum coke. The Part 75 default SO_2 emission rate of 0.0006 lb/mmBtu was used for natural gas and propane gas. We assumed a petroleum coke sulfur content of 4.5% since none of the facilities that burned petroleum coke had reported the sulfur content to EIA.

SO_2 emission factors for all of the non-fossil fuels, except for wood waste solids and black liquor, were taken from the same NREL document used for the non-fossil fuel NO_x emission factors. The wood waste solids emission factor was taken from AP-42. The black liquor emission factor was based on information from a NESCAUM document. The SO_2 emission factors are shown in Table 2 below.

Table 2
SO_2 Emission Factors (AP42, Part 75, NREL, NESCAUM)

EIA Fuel	Emission Factor	Factor Source
Wood/Wood Waste Liquids Other Biomass Liquids	1.42 lbs/1000 gals	NREL Table 12.6a
Wood Waste Solids	0.025 lb/mmBtu	AP42 Table 1.6-2
Sludge Waste	2.8 lbs/ton	NREL Table 12.6a
Agricultural By-Products Other Biomass Solids	0.08 lb/ton	NREL Table 12.6a
Black Liquor	1.5 lb/ton -- 3 to 5% S, with less than 1% of sulfur emitted.	NESCAUM BART
Distillate Fuel Oil Residual Fuel Oil Waste Oil	157 (%S) lbs/1000 gals	AP42 Table 1.3-1
Natural Gas	0.0006 lb/mmBtu	Part 75 Default Rate
Propane Gas	0.0006 lb/mmBtu	Part 75 Default Rate
Tire Derived Fuel	38 lbs/ton	NREL Table 12.6a
Bituminous Coal (CFB Boiler)	31 (%S) lbs/ton	AP42 Table 1.1-3
Bituminous Coal	38 (%S) lbs/ton	AP42 Table 1.1-3

EIA Fuel	Emission Factor	Factor Source
Subbituminous Coal	38 (%S) lbs/ton	AP42 Table 1.1-3
Waste Coal (CFB Boiler)[1]	31 (%S) lbs/ton	AP42 Table 1.1-3
Petroleum Coke (CFB Boiler)[1]	31 (%S) lbs/ton -- assumed S content of 4.5%	AP42 Table 1.1-3
Petroleum Coke	38 (%S) lbs/ton -- assumed S content of 4.5%	AP42 Table 1.1-3

[1] The EIA reported standard of 0.129 lb/mmBtu was used for one waste coal/petroleum coke fired CFB unit in place of the petroleum coke sulfur content assumption used for other petroleum coke units.

EIA flue gas desulfurization (FGD) unit SO_2 removal efficiencies for different types have been included in the calculation. We are unsure how complete the FGD data are, so we also capped NSPS unit SO_2 emission rates at the emission limit in the applicable subpart. EIA-767 information on FGD units was used to identify units with SO_2 control devices, and the FGD control efficiency.

3. Hg Emissions

Although fuel Hg content is not reported by EIA, the annual Hg emissions had to be calculated for coal burning units in CAMR. We decided to use the uncontrolled emission factors and emission modification factors (from the Integrated Planning Model (IPM)) for the coal type and control equipment that was reported to EIA. For the biomass cogeneration Hg estimate, we calculated a median emission factor for bituminous coal and sub-bituminous coal from the EPA emission factor clusters. The median emission factor for bituminous coal was 12.07 lbs/TBtu, and 5.02 lbs/TBtu for sub-bituminous coal. The emission modification factors are based on boiler type, coal type, and control equipment. The EIA data did not consistently identify boiler type, so our assignment of emission modification factors was limited to coal type and control equipment. The emission modification factors that we used for the biomass cogeneration inventory are listed below in Table 3.

Table 3
Emission Modification Factors Used in Biomass Unit Hg Estimates

Hg Emission Modification Factor	Unit Type[1]	Coal Type[2]	NO_x PostCombustion Control	Particulate Matter Control	SO_2 Post Combustion Control
0.05	Fluidized Bed	BIT	SNCR	Fabric Filter	Yes, Not Identified
0.05	Fluidized Bed	BIT	None	Fabric Filter	None
0.64	Fluidized Bed	BIT	None	Cold Side ESP	None
0.1	-	BIT	None	Fabric Filter	Dry FGD
0.11	-	BIT	None	Fabric Filter	None
0.34	-	BIT	None	Cold Side ESP	Wet FGD
0.64	-	BIT	None	Cold Side ESP	None
0.64	-	BIT	None	Cold Side ESP	Dry FGD
0.9	-	BIT	None	Wet Scrubber	None
0.97	-	SUB	None	Cold Side ESP	None
1.0	-	BIT	None	Hot Side ESP	None

[1] Unit type was only identified for fluidized bed units.
[2] Waste coal and synthetic coal were treated as bituminous.

D. Determining Affected Units

With an estimated universe of biomass cogeneration units and their attributes, the next step was to try to estimate which ones were most likely to be affected by a change to the CAIR and CAMR applicability provisions and cogeneration unit definition to limit total energy input to fossil fuels for some units. This subset consists of units that are (1) below the threshold for electricity sales and also (2) operating below the thermal efficiency standard. Because EPA does not have either of these important pieces of information from EIA or the American Forest and Paper Association (AF&PA), we had to use the information we did have to make a reasonable assessment.

Any units that reported to EIA that they did not have the ability to sell power to the grid were eliminated first. There are 79 units in the inventory that reported they do not sell power to the grid. Units at plants that sold more than the threshold (i.e., more than 1/3 potential electric output capacity or 219,000 MWh) in 1999 or 2000 (the most recent years for which such data exists) were also eliminated because they would still not qualify as exempt cogeneration units from CAIR and CAMR, even with the proposed revisions to the applicability provisions and cogeneration unit definition to limit total energy input to fossil fuels for some units. Using data that EPA analyzed in developing the NO_x NODA Allocations, we identified 15 more units above the electricity sales threshold.[3] Since EPA did not have any evidence that any other units had surpassed the threshold, it assumed that the rest had electricity sales below the threshold level to be conservative in its estimates. EPA recognizes that some of these remaining units may have sales above the threshold in unreported years and therefore also not qualify for the cogeneration unit exemption. In addition, one unit in the inventory was found to have irreconcilable data problems and not included in the results.

That left a total of 86 units that were selling power to the grid and assumed to be below the sales threshold. EPA then analyzed the heat input of the remaining units to determine which ones were likely to meet the thermal efficiency standard in the existing rules and therefore, already qualify for the exemption from CAIR and CAMR for cogeneration units. The best indicator to make this determination was the ratio of fossil heat input to total heat input. In general, the higher the percentage of heat input from fossil fuels, the more likely a biomass cogeneration unit is to meet the existing efficiency standard because there is less moisture in the fuel (moisture lowers the thermal efficiency). To estimate which units were likely to meet the existing efficiency standard in the cogeneration unit definition, EPA calculated the percentage of heat input from biomass and the percentage of heat input from fossil fuel. We also performed calculations on what percentage of fossil fuel was generally needed for a unit to be likely to meet the existing efficiency standard based on the type of biomass and type of fossil fuel or fuels burned. To do this, a number of assumptions about unit characteristics and performance

[3] EPA published a Notice of Data Availability (NODA) with initial unit NOx allocations for the CAIR Federal Implementation Plan trading programs, " Notice of Data Availability for EGU NOx Annual and NOx Ozone Season Allocations for the Clean Air Interstate Rule Federal Implementation Plan Trading Programs," 71 FR 44283.

attributes were required. These assumptions and calculations are EPA's best estimate, but are not definitive measures of unit efficiency.

For units burning bituminous coal, EPA calculated that at least 40% of the heat input would have to come from coal and the remainder from biomass. For other fossil fuels, the heat input percentages were found to be at least 30% for heating oil and 10% for natural gas and the remaining heat input from biomass. These are assumptions based on model unit characteristics and may not apply to all units. Not all units with fossil fuel input above these levels are guaranteed to meet the existing efficiency standard and not all units below these levels are guaranteed not to meet the existing efficiency standard due to their particular boiler and turbine characteristics. More information about the fuel and heat input assumptions and the thermal efficiency calculation is available in the following sections.

Units with fossil heat input above the minimum are assumed to already meet the existing efficiency standard and be eligible for the cogeneration unit exemption. We have assumed that those units below the minimum are unlikely to meet the existing efficiency standard and will not be eligible for the exemption, as currently written. These are the units that would be affected by the proposed change in the efficiency standard to limit total energy input for some units to fossil fuels. After calculating the heat input ratios for each unit, there were 55 units in this subset for NO_x emissions, 46 units for SO_2 emissions, and 6 units for Hg emissions. The other units who would not be affected by the change consist of 31 units for NO_x emissions, 28 units for SO_2 emissions, and 30 units for Hg emissions. The number of units for NO_x and SO_2 are not identical because the state of Arkansas is only required to make NO_x emissions reductions under CAIR, not SO_2 reductions. See Appendix B for the List of Biomass Cogeneration Units Potentially Affected by the Proposal in CAIR and CAMR Regions.

E. Thermal Efficiency Estimates for Fossil Fuels

As discussed earlier in this TSD, the thermal efficiency standard is based on the ratio of energy output to energy input determined by using the fuel's lower heating value (LHV). EPA estimated the amounts of fossil fuels required to be co-fired with biomass to allow cogeneration units to meet the existing thermal efficiency standard of 42.5%. Units already meeting the existing thermal efficiency standard would not be affected by the proposed action. The following assumptions and methodologies were used to develop the estimates used to determine which units were likely to be affected by the proposed rule:

1. Heat balance for a typical cogeneration unit firing biomass that does not meet the existing EPA-specified thermal efficiency standard is shown in Table 4.[4] This heat balance was used as a basis for estimating the amounts of various fossil fuels required for co-firing with biomass to improve the unit thermal efficiency to reach the 42.5% standard. The cogeneration unit represented in Table 4 uses a backpressure turbine and provides process steam at two different pressures. The boiler efficiency for this unit is only 69% and the overall unit thermal efficiency based on the lower heating value of biomass is 39.6% -- below the thermal efficiency standard.

TABLE 4
Biomass-Fired Cogeneration Unit Heat Balance

Parameter	Unit	Value
Unit gross output	MW	6.6
Unit net output	MW	4.1
Unit net output	Btu/hr	13,993,300
Turbine inlet steam flow	lb/hr	200,000
Turbine inlet steam pressure	psig	900
Turbine inlet steam temperature	^oF	800
Turbine inlet steam enthalpy	Btu/lb	1,411
Process steam #1 flow	lb/hr	65,000
Process steam #1 pressure	Psig	175
Process steam #1 temperature	^oF	420
Process steam #1 enthalpy	Btu/lb	1,225
Process steam #2 flow	Lb/hr	135,000
Process steam #2 pressure	psig	50

[4] AF&PA's Policy, Practical, and Legal Concerns about Inclusion of Biomass Fired Cogeneration Units in the Clean Air Interstate Rule, Report Submitted by American Forest & Paper Association to EPA, September 18, 2006

Parameter	Unit	Value
Process steam #2 temperature	^oF	320
Process steam #2 enthalpy	Btu/lb	1,190
Makeup water enthalpy	Btu/lb	41
Process thermal output	Btu/hr	232,075,000
Power to heat ratio		0.06
Boiler efficiency	%	69
Boiler feedwater temperature	^oF	250
Boiler feedwater enthalpy	Btu/lb	218
Fuel heat input (higher heating value)	Btu/hr	345,797,101
Fuel heat input (lower heating value)	Btu/hr	328,507,246
Thermal efficiency	%	71.2
Thermal efficiency (based on EPA efficiency standard)	**%**	**39.6**

2. Table 5 shows typical biomass and fossil fuel ultimate analyses used in the estimates. The fossil fuels include bituminous coal, sub-bituminous coal, lignite, natural gas, and residual oil. The analysis for biomass was selected to match the 69% boiler efficiency shown in Table 4.

TABLE 5
Fuel Ultimate Analyses

Fuel Property	Biomass(1)	Bituminous Coal(2)	Sub-Bituminous Coal(2)	Lignite(2)	Natural Gas(1)	Residual Oil(3)
Carbon, wt. %	28.49	63.74	50.25	36.27	69.26	85.70
Hydrogen, wt. %	3.14	4.5	3.41	2.42	22.68	10.50
Nitrogen, wt. %	0.11	1.25	0.65	0.71	8.06	0.40

Oxygen, wt. %	21.12	6.89	13.55	10.76	-	0.52
Sulfur, wt. %	0.06	2.51	0.22	0.64	-	2.50
Moisture, wt. %	45.00	11.12	27.40	31.24	-	0.30
Ash, wt. %	2.08	9.70	4.50	17.92	-	0.08
Higher heating value, Btu/lb	4,807	11,667	8,800	6,312	21,824	18,660

NOTES:
1. Source: Steam, Babcock & Wilcox, 40th Edition. The analysis of natural gas is based on the following volumetric analysis: CH_4: 90.0%; C_2H_6: 5.0%; and N_2: 5.0%.
2. Source: Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, EPA-430/R-06/006, July 2006.
3. Source: Combustion, Combustion Engineering, 3rd Edition

3. Compared to biomass, the analyses of all fossil fuels in Table 5 show lower moisture contents, greater carbon contents, and greater heating values. If these fossil fuels are co-fired with biomass, the boiler efficiency would improve, with the amount of improvement depending on the amount of each fossil fuel in the fuel mix. A certain increase in the boiler efficiency would be anticipated with the co-firing of each fossil fuel to improve the overall thermal efficiency of the cogeneration plant to the required 42.5%. Therefore, the main objective of these estimates was to determine the amount of each fossil fuel in the fuel mix that would provide sufficient increase in the boiler efficiency to meet the existing thermal efficiency standard.
4. Boiler efficiencies and the lower and higher heating value ratios were estimated using different proportions of biomass and fossil fuels in the fuel mix. These estimates were based on well-established industry practices.[5] The estimates were used in the cogeneration unit heat balance (Table 4) to determine the boiler efficiency and the amount of co-fired fossil fuel that would result in an overall unit thermal efficiency of 42.5%. Since the heating values of residual and distillate oils are close, the results of this analysis for residual oil would also apply to distillate oil.

[5] Steam, Babcock & Wilcox, 40th Edition.

5. Table 6 presents the results of the analysis, showing the estimated percentage of each fossil fuel (on a heat input basis) required to be co-fired with biomass in order to meet the existing thermal efficiency standard. The corresponding ratio of lower to higher heating value and boiler efficiency for each fossil fuel is also shown. The estimated amounts of fossil fuels required to be co-fired with biomass on a heat input basis to meet the existing thermal efficiency standard are as follows (rounded):
   - Lignite: 60%
   - Sub-bituminous coal: 50%
   - Bituminous coal: 40%
   - Residual oil: 30%
   - Natural gas: 10%

TABLE 6
Amounts of Fossil Fuels Required for Co-firing

Co-fired Fuel	Amount of Fuel Co-fired, % of heat input	Lower to Higher Heating Value Ratio	Boiler Efficiency, %
Lignite	60	0.96	74.4
Sub-Bituminous Coal	50	0.95	74
Bituminous Coal	40	0.95	74
Residual Oil	30	0.94	73.4
Natural Gas	10	0.94	73.3

6. The results of this analysis presented in Table 6 may vary due to differences in the assumed fuel or cogeneration unit characteristics. For example, the boiler efficiency may vary with a different biomass analysis, especially if the moisture content is significantly different from what has been assumed and shown in Table 5. The overall thermal efficiency of the cogeneration unit may also be different as a result of different design parameters. However, it is expected that the results from different cogeneration unit and fuel characteristics would not be significantly different from what is presented in the estimates for this document.

APPENDIX A

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION

PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
Abitibi Consolidated Sheldon	TX	Harris	50253	1PB	322122	0					
Alabama Pine Pulp	AL	Monroe	54429	RB2	322	8,621	13,734,572	13,541,792	192,780	944	824
Alabama Pine Pulp	AL	Monroe	54429	PB2	322	8,354	1,874,440	1,705,600	168,840	35	22
Alabama River Pulp	AL	Monroe	10216	PB1	322	8,473	3,495,210	3,264,000	231,210	60	122
Alabama River Pulp	AL	Monroe	10216	RB1	322	8,263	10,848,070	10,348,480	499,590	751	108
Ashdown	AR	Little River	54104	PB2	322122	8,532	7,117,398	2,174,400	4,942,998	1,253	1,174
Ashdown	AR	Little River	54104	RB3	322122	8,452	10,257,299	10,175,520	81,779	702	669
Ashdown	AR	Little River	54104	RB2	322122	8,441	6,672,803	6,573,720	99,083	453	438
Ashdown	AR	Little River	54104	PB3	322122	8,436	7,376,715	6,795,000	581,715	85	332
Ashdown	AR	Little River	54104	PB1	322122	8,543	3,816,794	3,468,600	348,194	192	115
Brunswick Cellulose	GA	Glynn	10605	6RB	322122	8,445	11,867,833	11,840,000	27,833	748	696
Brunswick Cellulose	GA	Glynn	10605	4PB	322122	8,356	5,341,232	3,996,125	1,317,207	1,980	656
Brunswick Cellulose	GA	Glynn	10605	5RB	322122	8,356	7,446,729	7,361,280	85,449	579	445
Cedar Bay Generating LP	FL	Duval	10672	CBC	22	7,560	7,549,458		7,549,458	468	642
Chester Operations	PA	Delaware	50410	10	322122	7,381	5,304,331	52,430	5,251,901	9,921	2,395
Cogentrix Roxboro	NC	Person	10379	1B	22	6,213	942,177	39,096	738,106	499	193
Cogentrix Roxboro	NC	Person	10379	1A	22	4,631	845,747	27,023	659,978	453	173
Cogentrix Roxboro	NC	Person	10379	1C	22	5,148	826,070	33,311	633,326	399	169
Covington Facility	VA	Covington	50900	7PB	32213	8,528	2,152,560	498,960	1,653,600	73	472
Covington Facility	VA	Covington	50900	8PB	32213	8,404	3,205,000	862,400	2,342,600	103	697
Covington Facility	VA	Covington	50900	2RB	32213	8,400	8,819,082	8,517,312	301,770	777	691
Covington Facility	VA	Covington	50900	1RB	32213	8,486	5,719,188	5,246,688	472,500	564	471

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION

PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
DeRidder Mill	LA	Beauregard	10488	PB1	322122	8,605	6,796,955	4,839,024	1,647,931	63	865
DeRidder Mill	LA	Beauregard	10488	PB2	322122	8,398	2,767,967	2,191,752	576,215	8	319
DeRidder Mill	LA	Beauregard	10488	REC	322122	8,171	7,754,583	7,139,571	615,013	522	572
Escanaba Paper Company	MI	Delta	10208	11	322122	8,497	7,654,422	3,147,145	4,507,277	3,446	1,914
Escanaba Paper Company	MI	Delta	10208	10	322122	8,486	7,842,134	7,521,423	320,711	531	500
Escanaba Paper Company	MI	Delta	10208	9	322122	8,310	2,502,776	2,317,500	185,276	29	280
Finch Pruyn	NY	Warren	10511	9	322122	8,077	1,497,730	1,047,280	450,450	367	186
Finch Pruyn	NY	Warren	10511	8	322122	7,901	1,385,790	1,385,790		20	23
Finch Pruyn	NY	Warren	10511	10	322122	8,118	1,337,700	1,337,700		19	22
Flint River Operations	GA	Macon	50465	RB	322	8,254	8,770,620	8,727,108	43,512	689	965
Flint River Operations	GA	Macon	50465	PB	322	8,484	2,693,406	2,473,360	220,046	72	673
Gadsden	AL	Etowah	7	2	22	5,542	3,649,559	8,124	3,641,435	5,398	1,077
Gadsden	AL	Etowah	7	1	22	7,582	2,811,935	10,000	2,801,935	4,306	943
Gaylord Container Bogalusa	LA	Washington	54427	12	322122	8,568	6,360,750	6,017,400	343,350	345	716
Gaylord Container Bogalusa	LA	Washington	54427	10C	322122	8,568	3,611,452	3,449,700	161,752	43	401
Gaylord Container Bogalusa	LA	Washington	54427	21	322122	8,568	5,820,780	5,678,400	142,380	490	377
Gaylord Container Bogalusa	LA	Washington	54427	20	322122	8,568	3,719,610	3,639,600	80,010	305	240
Georgia Pacific Cedar Springs	GA	Early	54101	PB1	32213	8,280	5,552,354	1,909,200	3,643,154	7,799	1,284
Georgia Pacific Cedar Springs	GA	Early	54101	PB2	32213	8,240	5,552,354	1,909,200	3,643,154	7,799	1,284
Georgia Pacific Crossett	AR	Ashley	10606	10A	322122	8,479	5,228,500	4,360,458	868,042	55	1,281
Georgia Pacific Crossett	AR	Ashley	10606	9A	322122	8,040	3,804,691	3,193,502	611,189	40	304
Georgia Pacific Crossett	AR	Ashley	10606	8R	322122	8,437	11,061,260	10,980,900	80,360	757	719
Georgia Pacific Naheola Mill	AL	Choctaw	10699	4	322122	8,387	11,085,696	10,881,530	204,166	730	694
Georgia Pacific Palatka Operations	FL	Putnam	10611	4 COMB	322122	8,462	3,494,440	2,840,500	653,940	768	415
Georgia Pacific Palatka Operations	FL	Putnam	10611	4RB	322122	8,094	6,364,690	2,456,800	3,907,890	4,634	758
Georgia Pacific Port Hudson	LA	East Baton Rouge	10612	PB1	322122	8,590	2,814,008	2,340,000	474,008	29	281

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION											
PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
Georgia Pacific Port Hudson	LA	East Baton Rouge	10612	RB2	322122	8,520	8,183,330	8,004,000	179,330	552	622
Georgia Pacific Port Hudson	LA	East Baton Rouge	10612	RB1	322122	8,520	5,293,371	5,185,200	108,171	358	384
Green Power Kenansville	NC	Duplin	10381	1B	22	2,266	273,702	96,000	165,502	94	45
Green Power Kenansville	NC	Duplin	10381	1A	22	2,980	344,871	165,000	155,471	98	57
Inland Paperboard Packaging Rome	GA	Floyd	10426	RF3	32213	1,599	316,052	10,880	305,172	67	48
Inland Paperboard Packaging Rome	GA	Floyd	10426	RF4	32213	788	151,164	32,640	118,524	28	21
Inland Paperboard Packaging Rome	GA	Floyd	10426	PB3	32213	8,599	2,997,150	2,482,004	485,116	445	427
Inland Paperboard Packaging Rome	GA	Floyd	10426	PB1	32213	6,916	3,190,642	2,724,776	465,866	394	436
Inland Paperboard Packaging Rome	GA	Floyd	10426	RF5	32213	8,175	8,130,490	8,087,272	43,218	624	583
International Paper Augusta Mill	GA	Richmond	54358	PB1	32213	8,347	5,126,835	2,860,011	2,266,824	1,287	935
International Paper Augusta Mill	GA	Richmond	54358	RB3	32213	8,438	11,453,163	11,406,957	46,206	735	688
International Paper Augusta Mill	GA	Richmond	54358	PB3	32213	8,426	4,973,896	4,821,606	152,290	60	551
International Paper Augusta Mill	GA	Richmond	54358	RB2	32213	8,359	2,974,331	2,716,595	257,736	471	216
International Paper Courtland Mill	AL	Lawrence	50245	PB3	322122	8,241	9,549,151	8,997,300	242,851	442	726
International Paper Courtland Mill	AL	Lawrence	50245	RB3	322122	8,363	8,054,211	8,041,050	13,161	611	1,301
International Paper Eastover Facility	SC	Richland	52151	PB2	322122	8,664	3,022,823	2,502,600	45,923	331	451
International Paper Eastover Facility	SC	Richland	52151	RF1	322122	8,480	4,629,895	4,569,600	60,295	372	295
International Paper Eastover Facility	SC	Richland	52151	RF2	322122	8,458	10,593,852	10,534,800	59,052	768	53
International Paper Franklin Mill	VA	Isle of Wight	52152	7PB	322122	8,507	4,650,553	1,289,330	3,361,223	2,098	1,098
International Paper Franklin Mill	VA	Isle of Wight	52152	6PB	322122	8,364	3,194,246	1,437,660	1,756,586	819	482
International Paper Franklin Mill	VA	Isle of Wight	52152	6RB	322122	8,477	6,631,494	6,612,340	19,154	537	488
International Paper Franklin Mill	VA	Isle of Wight	52152	5RB	322122	8,324	2,723,140	2,340,380	382,760	555	231

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION											
PLANT NAME	**STATE**	**COUNTY**	**PLANT CODE**	**BOILER ID**	**NAICS CODE**	**Hours Under Load**	**Total HI (mmBtu)**	**Biomass HI (mmBtu)**	**Fossil HI (mmBtu)**	**Est. Annual SO2 Emissions (tons)**	**Est. Annual NOx Emissions (tons)**
International Paper Franklin Mill	VA	Isle of Wight	52152	4RB	322122	7,626	2,483,460	2,483,460		194	182
International Paper Georgetown Mill	SC	Georgetown	54087	PB01	322122	8,587	4,257,583	2,419,217	1,119,166	1,249	766
International Paper Georgetown Mill	SC	Georgetown	54087	PB02	322122	8,609	4,173,126	2,509,147	954,079	1,105	751
International Paper Georgetown Mill	SC	Georgetown	54087	RB01	322122	8,308	5,673,035	5,505,938	167,097	556	387
International Paper Georgetown Mill	SC	Georgetown	54087	RB02	322122	8,487	7,031,535	6,864,382	167,153	651	475
International Paper Louisiana Mill	LA	Morehouse	54090	3PB	322122	8,564	5,661,928	3,264,525	1,020,403	1,481	48
International Paper Louisiana Mill	LA	Morehouse	54090	5REC	322122	8,405	4,741,380	4,469,760	271,620	310	326
International Paper Louisiana Mill	LA	Morehouse	54090	6REC	322122	8,522	5,158,971	5,040,120	118,851	346	341
International Paper Pensacola	FL	Escambia	50250	4PB	322122	8,249	4,444,719	3,492,873	951,846	96	756
International Paper Pensacola	FL	Escambia	50250	2RB	322122	8,320	5,575,360	5,443,200	132,160	363	114
International Paper Pensacola	FL	Escambia	50250	1RB	322122	8,267	5,468,656	5,400,000	68,656	360	104
International Paper Pine Bluff Mill	AR	Jefferson	10627	RB4	32213	7,770	8,079,931	7,977,980	101,951	541	521
International Paper Pine Bluff Mill	AR	Jefferson	10627	BB1	32213	8,012	2,677,907	2,589,830	88,076	38	303
International Paper Pine Bluff Mill	AR	Jefferson	10627	RB2	32213	8,316	2,565,437	2,460,300	105,137	167	171
International Paper Pine Bluff Mill	AR	Jefferson	10627	RB3	32213	7,971	2,484,848	2,396,580	88,268	163	164
International Paper Prattville Mill	AL	Autauga	52140	PB1	32213	8,527	2,839,307	1,328,718	1,510,589	67	356
International Paper Prattville Mill	AL	Autauga	52140	PB2	32213	8,567	4,407,171	2,161,412	2,245,759	1,491	838
International Paper Prattville Mill	AL	Autauga	52140	RF1	32213	8,421	4,865,477	4,604,890	260,586	115	355
International Paper Prattville Mill	AL	Autauga	52140	RF2	32213	8,561	6,728,681	6,513,894	214,787	509	467
International Paper Quinnesec Mich Mill	MI	Dickinson	50251	WTB	322	8,468	2,980,069	2,812,320	167,749	123	447
International Paper Quinnesec Mich Mill	MI	Dickinson	50251	RB	322	8,490	7,406,214	7,367,160	39,054	508	704
International Paper Riegelwood Mill	NC	Columbus	54656	PB2	32213	8,232	4,662,061	3,434,065	1,227,996	154	555
International Paper Riegelwood Mill	NC	Columbus	54656	PB5	32213	8,304	5,206,612	4,265,518	941,094	121	606

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION											
PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
International Paper Riegelwood Mill	NC	Columbus	54656	RB3	32213	5,568	1,516,419	1,403,460	112,959	204	109
International Paper Riegelwood Mill	NC	Columbus	54656	RB4	32213	8,215	4,452,702	4,345,980	106,722	407	304
International Paper Riegelwood Mill	NC	Columbus	54656	RB5	32213	7,879	10,969,433	10,767,770	201,663	949	743
International Paper Riverdale Mill	AL	Dallas	54096	BLRB2	322122	8,532	4,257,388	3,936,072	321,316	80	639
International Paper Riverdale Mill	AL	Dallas	54096	BLRR2	322122	8,532	5,383,661	5,347,132	36,529	350	333
International Paper Savanna Mill	GA	Chatham	50398	13PB	32213	8,592	8,695,526	1,095,726	7,599,800	3,552	2,043
International Paper Savanna Mill	GA	Chatham	50398	15RB	32213	8,592	10,719,437	10,251,000	468,437	820	802
International Paper Texarkana Mill	TX	Cass	54097	PB2	32213	8,376	6,465,027	2,904,700	3,560,327	2,070	842
International Paper Vicksburg Mill	MS	Warren	54100	N1BABO	322122	8,480	1,482,201	127,750	1,354,451	508	234
International Paper Vicksburg Mill	MS	Warren	54100	N1REBO	322122	8,480	6,029,106	5,932,500	96,606	420	407
Jefferson Smurfit Fernandina Beach	FL	Nassau	10202	5PWR	32213	8,520	4,337,240	2,849,180	1,488,060	1,982	547
Jefferson Smurfit Fernandina Beach	FL	Nassau	10202	4REC	32213	8,605	5,044,840	5,044,840		348	326
Jefferson Smurfit Fernandina Beach	FL	Nassau	10202	5REC	32213	8,452	5,034,400	5,034,400		347	326
Johnsonburg Mill	PA	Elk	54638	RB01	322122	8,426	5,133,165	5,051,402	81,762	361	357
Luke Mill	MD	Allegany	50282	2RB	322122	655	56,650		56,650	16	5
Luke Mill	MD	Allegany	50282	3RB	322122	8,592	7,661,949	7,566,803	95,146	609	516
M L Hibbard	MN	St Louis	1897	3	22	6,611	659,934	143,232	516,702	157	313
M L Hibbard	MN	St Louis	1897	4	22	6,616	641,438	143,232	498,206	158	316
Mansfield Mill	LA	De Soto	54091	PB2	32213	8,471	5,399,254	3,421,440	1,030,691	1,242	548
Mansfield Mill	LA	De Soto	54091	PB1	32213	8,508	6,101,037	4,263,600	893,175	1,362	397
Mansfield Mill	LA	De Soto	54091	RB1	32213	8,478	4,757,903	4,620,946	136,957	324	304
Mansfield Mill	LA	De Soto	54091	RB2	32213	8,516	4,912,941	4,812,786	100,155	329	312
Mead Coated Board	AL	Russell	54802	BB1	32213	7,717	2,253,982	2,001,650	252,332	29	254
Mead Coated Board	AL	Russell	54802	BB3	32213	7,765	5,002,328	4,897,991	104,337	61	546

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION											
PLANT NAME	**STATE**	**COUNTY**	**PLANT CODE**	**BOILER ID**	**NAICS CODE**	**Hours Under Load**	**Total HI (mmBtu)**	**Biomass HI (mmBtu)**	**Fossil HI (mmBtu)**	**Est. Annual SO2 Emissions (tons)**	**Est. Annual NOx Emissions (tons)**
Mead Coated Board	AL	Russell	54802	BB2	32213	8,358	3,591,949	3,521,973	69,976	44	392
Mead Coated Board	AL	Russell	54802	REC1	32213	8,273	5,844,992	5,742,185	102,807	394	373
Mead Coated Board	AL	Russell	54802	REC2	32213	8,160	7,511,587	7,494,670	16,917	498	468
MeadWestvaco Evadale	TX	Jasper	50101	PB2	32213	8,442	4,979,311	2,766,400	2,212,911	35	603
MeadWestvaco Evadale	TX	Jasper	50101	PB6	32213	8,483	5,175,146	4,648,800	526,346	58	285
MeadWestvaco Evadale	TX	Jasper	50101	RB2	32213	8,167	2,887,374	2,842,000	45,374	196	190
MeadWestvaco Evadale	TX	Jasper	50101	RB3	32213	8,606	3,362,895	3,340,800	22,095	230	219
MeadWestvaco Evadale	TX	Jasper	50101	RB4	32213	8,712	6,055,062	6,043,600	11,462	417	392
Mobile Energy Services LLC	AL	Mobile	50407	7PB	22	8,472	5,924,678	3,223,894	2,700,784	1,788	908
MW Custom Papers	OH	Ross	10244	6	322122	8,443	2,323,216	2,293,569	29,648	34	255
MW Custom Papers	OH	Ross	10244	9	322122	8,756	4,643,845	4,586,326	57,519	445	413
Northhampton Generating LP	PA	Northampton	50888	BLR1	22	7,709	9,282,185	221,888	9,060,298	585	436
Okeelanta Cogeneration	FL	Palm Beach	54627	C	22	7,519	4,033,714	4,011,110	22,604	34	292
Okeelanta Cogeneration	FL	Palm Beach	54627	A	22	7,659	4,050,826	4,031,120	19,706	35	296
Okeelanta Cogeneration	FL	Palm Beach	54627	B	22	7,495	3,995,462	3,983,290	12,172	34	292
P H Glatfelter	PA	York	50397	5PB036	322122	8,496	4,795,518	1,230,394	3,565,124	3,950	647
P H Glatfelter	PA	York	50397	REC037	322122	8,280	7,129,373	7,111,380	17,993	429	356
Packaging Corp of America	TN	Hardin	50296	C1	32213	7,488	1,476,074	288,129	1,187,945	456	192
Packaging Corp of America	TN	Hardin	50296	C2	32213	8,585	6,566,343	4,425,874	2,140,469	1,093	1,083
Packaging Corp of America	TN	Hardin	50296	R3	32213	8,507	6,376,690	6,372,000	4,690	425	399
Packaging Corp of America	TN	Hardin	50296	R1	32213	8,210	2,868,389	2,868,000	389	191	179
Packaging Corp of America	TN	Hardin	50296	R2	32213	8,380	2,928,369	2,928,000	369	195	183
Port Wentworth Mill (Stone Savanah)	GA	Chatham	50804	4	322	8,560	3,788,955	3,604,500	184,455	53	432
Port Wentworth Mill (Stone Savanah)	GA	Chatham	50804	RE01	322	8,300	7,072,124	7,008,032	64,092	495	467
Rayonier Jesup Mill	GA	Wayne	10560	POWB	322	7,864	5,089,289	3,094,580	1,994,709	1,427	637
Rayonier Jesup Mill	GA	Wayne	10560	RB6	322	8,449	10,710,627	10,400,400	310,227	908	696

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION

PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
Rayonier Jesup Mill	GA	Wayne	10560	RB5	322	8,484	7,092,217	6,960,000	132,217	557	455
S D Warren Muskegon	MI	Muskegon	50438	4PB	322122	8,177	3,303,319	542,080	2,761,239	89	578
Sappi Cloquet Mill	MN	Carlton	50639	7PB	322122	7,950	1,486,311	1,097,220	389,091	16	102
Sappi Cloquet Mill	MN	Carlton	50639	9PB	322122	8,561	2,589,894	2,109,440	480,454	30	233
Sappi Cloquet Mill	MN	Carlton	50639	10RB	322122	8,525	8,682,091	8,569,288	112,803	620	451
Savannah River Mill	GA	Effingham	10361	5B	322122	8,454	3,462,113	21,980	3,440,133	9,623	927
Savannah River Mill	GA	Effingham	10361	3B	322122	8,533	3,196,370	21,980	3,174,390	8,601	863
SP Newsprint	GA	Laurens	54004	PB2	322122	8,520	3,742,462	780,494	1,527,746	2,377	150
Stone Container Florence Mill	SC	Florence	50806	PB4	322122	8,385	8,599,602	3,498,600	5,101,002	3,089	1,419
Stone Container Hodge	LA	Jackson	50810	CB	322122	8,516	7,108,390	2,961,000	4,147,390	38	886
Stone Container Hodge	LA	Jackson	50810	3RB	322122	8,459	3,521,448	3,192,000	329,448	224	254
Stone Container Hodge	LA	Jackson	50810	2RB	322122	8,309	6,458,318	6,372,600	85,718	447	431
Stone Container Hopewell Mill	VA	Hopewell City	50813	CB1	322122	8,568	4,316,175	2,556,000	1,760,175	1,031	1,081
Stone Container Hopewell Mill	VA	Hopewell City	50813	RB1	322122	8,401	5,010,480	4,976,050	34,430	359	330
TES Filer City Station	MI	Manistee	50835	2	22	8,658	3,347,713	145,195	3,135,318	226	993
TES Filer City Station	MI	Manistee	50835	1	22	8,098	3,154,695	145,195	2,942,299	212	934
Ticonderoga Mill	NY	Essex	54099	PB1	322122	8,400	4,688,267	949,381	3,738,886	428	488
Ticonderoga Mill	NY	Essex	54099	RB1	322122	8,400	3,062,078	2,906,400	155,678	395	283
West Point Mill (St Laurent Paper)	VA	King William	10017	RF04	322	8,263	5,542,140	5,142,720	399,420	695	355
West Point Mill (St Laurent Paper)	VA	King William	10017	PB10	322	8,424	4,615,480	4,320,640	294,840	337	521
West Point Mill (St Laurent Paper)	VA	King William	10017	RF05	322	8,068	5,456,026	5,322,550	133,476	381	439
Weyerhaeuser Columbus MS	MS	Lowndes	50184	COMB	322122	8,600	6,461,390	6,056,400	404,990	271	1,034
Weyerhaeuser Columbus MS	MS	Lowndes	50184	REC	322122	8,496	12,314,380	12,249,600	64,780	828	554
Weyerhaeuser Kentucky Mills	KY	Hancock	55429	BFB	322	8,439	3,290,933	2,950,500	340,433	75	247
Weyerhaeuser Kentucky Mills	KY	Hancock	55429	4REC	322	8,455	6,674,654	6,594,600	80,054	455	437
Weyerhaeuser Kentucky Mills	KY	Hancock	55429	3REC	322	8,228	4,261,330	4,247,920	13,410	293	276
Weyerhaeuser New Bern NC	NC	Craven	50188	RB	322	8,424	8,541,576	8,364,000	177,576	742	550

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAIR REGION											
PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Hours Under Load	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual SO2 Emissions (tons)	Est. Annual NOx Emissions (tons)
Weyerhaeuser Pine Hill Operations	AL	Wilcox	54752	1PB	32213	8,549	4,118,160	2,304,050	1,814,110	48	499
Weyerhaeuser Pine Hill Operations	AL	Wilcox	54752	2PB	32213	8,506	5,372,115	3,681,550	1,690,565	576	772
Weyerhaeuser Pine Hill Operations	AL	Wilcox	54752	RECB	32213	8,270	7,303,421	6,916,617	386,804	765	553
Weyerhaeuser Plymouth NC	NC	Martin	50189	2HFB	322122	8,470	8,604,948	5,125,092	3,479,856	1,907	1,242
Weyerhaeuser Plymouth NC	NC	Martin	50189	5REC	322122	8,507	11,733,121	11,613,003	120,118	779	1,056
Weyerhaeuser Plymouth NC	NC	Martin	50189	1HFB	322122	8,262	6,751,997	6,242,418	509,579	468	770
Wisconsin Rapids Pulp Mill	WI	Wood	10477	P1	322122	8,599	2,541,915	994,875	1,547,040	363	674
Wisconsin Rapids Pulp Mill	WI	Wood	10477	P2	322122	8,538	2,541,915	994,875	1,547,040	363	686
Wisconsin Rapids Pulp Mill	WI	Wood	10477	R1	322122	7,876	2,023,040	2,023,040		140	131
Wisconsin Rapids Pulp Mill	WI	Wood	10477	R2	322122	8,234	2,023,040	2,023,040		140	131
Wisconsin Rapids Pulp Mill	WI	Wood	10477	R3	322122	8,421	2,023,040	2,023,040		140	131

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAMR REGION

PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual Hg Emissions (lbs)
Ashdown	AR	Little River	54104	PB2	322122	7,117,398	2,174,400	4,942,998	53.44
Bucksport Mill	ME	Hancock	50243	8	322122	2,768,668	1,601,490	829,228	
Cedar Bay Generating LP	FL	Duval	10672	CBC	22	7,549,458		7,549,458	4.54
Chester Operations	PA	Delaware	50410	10	322122	5,304,331	52,430	5,251,901	1.49
Cogentrix Roxboro	NC	Person	10379	1B	22	942,177	39,096	738,106	0.98
Cogentrix Roxboro	NC	Person	10379	1A	22	845,747	27,023	659,978	0.88
Cogentrix Roxboro	NC	Person	10379	1C	22	826,070	33,311	633,326	0.84
Covington Facility	VA	Covington	50900	7PB	32213	2,152,560	498,960	1,653,600	6.79
Covington Facility	VA	Covington	50900	8PB	32213	3,205,000	862,400	2,342,600	9.61
Escanaba Paper Company	MI	Delta	10208	11	322122	7,654,422	3,147,145	4,507,277	53.07
Gadsden	AL	Etowah	7	2	22	3,649,559	8,124	3,641,435	27.52
Gadsden	AL	Etowah	7	1	22	2,811,935	10,000	2,801,935	21.32
Georgia Pacific Cedar Springs	GA	Early	54101	PB1	32213	5,552,354	1,909,200	3,643,154	38.32
Georgia Pacific Cedar Springs	GA	Early	54101	PB2	32213	5,552,354	1,909,200	3,643,154	38.32
Green Power Kenansville	NC	Duplin	10381	1B	22	273,702	96,000	165,502	0.22
Green Power Kenansville	NC	Duplin	10381	1A	22	344,871	165,000	155,471	0.21
Inland Paperboard Packaging Rome	GA	Floyd	10426	PB3	32213	2,997,150	2,482,004	485,116	5.86
Inland Paperboard Packaging Rome	GA	Floyd	10426	PB1	32213	3,190,642	2,724,776	465,866	5.55
International Paper Augusta Mill	GA	Richmond	54358	PB1	32213	5,126,835	2,860,011	2,266,824	22.18
International Paper Franklin Mill	VA	Isle of Wight	52152	7PB	322122	4,650,553	1,289,330	3,361,223	25.03
International Paper Franklin Mill	VA	Isle of Wight	52152	6PB	322122	3,194,246	1,437,660	1,756,586	13.57
International Paper Georgetown Mill	SC	Georgetown	54087	PB01	322122	4,257,583	2,419,217	1,119,166	10.02
International Paper Georgetown Mill	SC	Georgetown	54087	PB02	322122	4,173,126	2,509,147	954,079	8.03
International Paper Louisiana Mill	LA	Morehouse	54090	3PB	322122	5,661,928	3,264,525	1,020,403	5.60
International Paper Pensacola	FL	Escambia	50250	4PB	322122	4,444,719	3,492,873	951,846	10.61
International Paper Prattville Mill	AL	Autauga	52140	PB2	32213	4,407,171	2,161,412	2,245,759	13.86
International Paper Quinnesec Mich Mill	MI	Dickinson	50251	WTB	322	2,980,069	2,812,320	167,749	1.33
International Paper Riegelwood Mill	NC	Columbus	54656	PB2	32213	4,662,061	3,434,065	1,227,996	
International Paper Riegelwood Mill	NC	Columbus	54656	PB5	32213	5,206,612	4,265,518	941,094	

LIST OF IDENTIFIED BIOMASS COGENERATION UNITS IN THE CAMR REGION

PLANT NAME	STATE	COUNTY	PLANT CODE	BOILER ID	NAICS CODE	Total HI (mmBtu)	Biomass HI (mmBtu)	Fossil HI (mmBtu)	Est. Annual Hg Emissions (lbs)
International Paper Savanna Mill	GA	Chatham	50398	13PB	32213	8,695,526	1,095,726	7,599,800	91.73
M L Hibbard	MN	St Louis	1897	3	22	659,934	143,232	516,702	2.51
M L Hibbard	MN	St Louis	1897	4	22	641,438	143,232	498,206	2.42
Mansfield Mill	LA	De Soto	54091	PB2	32213	5,399,254	3,421,440	1,030,691	5.76
Mansfield Mill	LA	De Soto	54091	PB1	32213	6,101,037	4,263,600	893,175	8.57
Mobile Energy Services LLC	AL	Mobile	50407	7PB	22	5,924,678	3,223,894	2,700,784	30.23
Northhampton Generating LP	PA	Northampton	50888	BLR1	22	9,282,185	221,888	9,060,298	3.23
P H Glatfelter	PA	York	50397	5PB036	322122	4,795,518	1,230,394	3,565,124	42.90
Packaging Corp of America	TN	Hardin	50296	C2	32213	6,566,343	4,425,874	2,140,469	24.85
Rumford Cogeneration	ME	Oxford	10495	6	22	4,486,241	1,358,300	2,340,541	28.25
Rumford Cogeneration	ME	Oxford	10495	7	22	3,796,003	1,156,000	1,964,203	23.71
S D Warren Muskegon	MI	Muskegon	50438	4PB	322122	3,303,319	542,080	2,761,239	20.63
Savannah River Mill	GA	Effingham	10361	5B	322122	3,462,113	21,980	3,440,133	0.50
Savannah River Mill	GA	Effingham	10361	3B	322122	3,196,370	21,980	3,174,390	0.66
SP Newsprint	GA	Laurens	54004	PB2	322122	3,742,462	780,494	1,527,746	11.80
Stone Container Florence Mill	SC	Florence	50806	PB4	322122	8,599,602	3,498,600	5,101,002	60.93
Stone Container Hopewell Mill	VA	Hopewell City	50813	CB1	322122	4,316,175	2,556,000	1,760,175	13.20
TES Filer City Station	MI	Manistee	50835	2	22	3,347,713	145,195	3,135,318	3.78
TES Filer City Station	MI	Manistee	50835	1	22	3,154,695	145,195	2,942,299	3.55
Weyerhaeuser Columbus MS	MS	Lowndes	50184	COMB	322122	6,461,390	6,056,400	404,990	2.84
Weyerhaeuser Longview WA	WA	Cowlitz	50187	11B	322122	5,529,500	4,192,700	1,336,800	16.14
Weyerhaeuser Pine Hill Operations	AL	Wilcox	54752	2PB	32213	5,372,115	3,681,550	1,690,565	11.29
Weyerhaeuser Plymouth NC	NC	Martin	50189	2HFB	322122	8,604,948	5,125,092	3,479,856	4.57
Weyerhaeuser Plymouth NC	NC	Martin	50189	1HFB	322122	6,751,997	6,242,418	509,579	0.33
Wisconsin Rapids Pulp Mill	WI	Wood	10477	P1	322122	2,541,915	994,875	1,547,040	7.53
Wisconsin Rapids Pulp Mill	WI	Wood	10477	P2	322122	2,541,915	994,875	1,547,040	7.53

APPENDIX B

The List of Identified Biomass Cogeneration Units Potentially Affected by the Proposal in CAIR and CAMR Regions is available on the CAIR and CAMR websites on the Technical Information pages:

http://www.epa.gov/CAIR/technical.html

http://www.epa.gov/ttn/atw/utility/utiltoxpg.html

The TSD and Appendix B are also available in the public docket for the proposed rule (EPA-HQ-OAR-2007-0012):

http://www.regulations.gov