MEMORANDUM

TO: Robert Wayland, Group Leader, Energy Strategies Group, Office of Air Quality Planning and Standards, EPA (D243-01)

FROM: William H. Maxwell, Energy Strategies Group, Office of Air Quality Planning and Standards, EPA (D243-01)

DATE: May 31, 2006

SUBJECT: Revised new source performance standard (NSPS) statistical analysis for mercury emissions

BACKGROUND

Under section 111 of the Clean Air Act (CAA), new source performance standards (NSPS) are to be established based on best demonstrated technology (BDT) considering cost, non-air quality health and environmental impacts, and energy requirements. This memorandum revises and supersedes the October 21, 2005, memorandum entitled "Revised New Source Performance Standard (NSPS) Statistical Analysis for Mercury Emissions" (EPA-HQ-OAR-2002-0056-6305) to you based on issues raised in the public comments on the Petition to Reconsider the May 18, 2005 Clean Air Mercury Rule (CAMR). This memorandum presents an updated approach to determining an appropriate, achievable mercury (Hg) emission level for new, modified, and reconstructed utility boilers fired with bituminous coal, subbituminous coal, lignite coal, and coal refuse that reflects BDT using the 1999 information collection request (ICR) data and data subsequently provided through the public comment period for the reconsideration process (70 FR 62213; October 28, 2005).

As explained in the final rule,[1] after considering the available information, EPA "determined that the technical basis (i.e., ... BDT) selected for establishing Hg emission limits for new sources is the use of effective PM controls (e.g., fabric filter or ESP) and wet or dry FGD systems on subbituminous-, lignite-, and coal-refuse-fired units; effective PM controls, wet or dry FGD systems, and SCR or SNCR on bituminous units."[2] These controls are generally the same type of controls that EPA identified to control sulfur dioxide (SO_2), nitrogen oxides (NO_x),

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[1] See 70 FR 28606; May 18, 2005.
[2] See 70 FR 28614/1-2.

and particulate matter (PM) under 40 CFR part 60, subpart Da. The controls are also generally the same type of controls that EPA anticipates that utility boilers will install in response to the Clean Air Interstate Rule (CAIR).[3] Having identified BDT, EPA then undertook the analysis detailed in this memorandum to determine the level at which to set the NSPS considering the range of units and operating conditions that are reasonably anticipated to occur.

As explained in the final rule, Hg removal is a co-benefit of the SO_2, NO_x, and PM controls. There is no identified additional cost, beyond that associated with compliance with other aspects of subpart Da, with complying with the NSPS for Hg. There are, however, some additional costs associated with the Hg monitoring requirements contained in the NSPS, and EPA has determined that these costs are reasonable. Similarly, EPA has not identified any non-air quality health or environmental impacts attributable exclusively to compliance with the Hg NSPS apart from the potential impact on water availability identified in conjunction with the NSPS for subbituminous-fired units. Nor does EPA believe that compliance with the Hg NSPS will exacerbate any non-air quality health or environmental impacts which may be associated with compliance with other aspects of subpart Da. Finally, because the Hg standards are based on co-control, there are no additional energy requirements associated with compliance with the standards.

For each coal rank, ICR emission test data (ICR-3) were reviewed to identify the units that were using technologies which were most effective at capturing Hg from coal-fired power plants. The technologies that appeared most effective in reducing Hg emissions were those that were installed, or likely would be installed, to comply with the current NSPS standards for PM and sulfur dioxide SO_2. This combination of controls was most effective in reducing Hg emissions and, thus, is considered BDT.

For bituminous coal-fired boilers, BDT is considered to be the combination of a fabric filter (FF) and a flue gas desulfurization (FGD) system. The FGD may be either a wet scrubber system or a spray dryer absorber (SDA). Of the 27 bituminous units listed in ICR-3, 6 units had a combination of a FF and a FGD. These units are listed in Table 1, along with the control efficiency, test results, and the BDT statistical analysis results.

For subbituminous coal-fired units, BDT was determined to be dependent on water availability. For new subbituminous units that are located where an adequate water supply is not available (i.e., in areas receiving less than or equal to 25 inches per year [in/yr] mean annual precipitation, based on the most currently publicly available U.S. Department of Agriculture 30-year data), BDT is considered to be a dry FGD system (i.e., a combination of a FF with a SDA). For new subbituminous units that are located where an adequate water supply is available (i.e., in areas receiving greater than 25 in/yr mean annual precipitation, based on the most currently publicly available U.S. Department of Agriculture 30-year data), BDT is considered to be a wet FGD system. Of the 27 subbituminous units listed in ICR-3, 2 units have controls representing BDT for the "wet" subbituminous subcategory and 4 units have controls representing BDT for the "dry" subbituminous subcategory. These units are listed in Table 2, along with the control efficiency, test results, and the BDT statistical analysis results.

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[3] See 70 FR 25162; May 12, 2005.

For lignite coal-fired units, BDT is considered to be either a FF/SDA system, a fluidized bed combustor (FBC) with an ESP, or an ESP with a wet FGD system. Of the 12 lignite coal units listed in ICR-3, 7 units have controls representing BDT. These units are listed in Table 3 along with the control efficiency, test result, and the BDT statistical analysis results.

For coal refuse, the ICR-3 contains data on only two units. Both were FBC units equipped with FF. Both have reported Hg control efficiency of greater than 99 percent. Therefore, BDT for coal refuse units is considered to be a FBC/FF combination. One unit fired waste anthracite, the other fired waste bituminous. As a result of the October 28, 2005 notice of reconsideration, ARIPPA (the trade association representing a number of coal refuse-fired units in Pennsylvania) provided additional emission test data in support of their position that the NSPS established by EPA was too stringent and did not adequately represent the variability in Hg content in the coal refuse. These data were reviewed and incorporated, where appropriate, into the analysis. Appendix A contains a discussion of these data.

STATISTICAL ANALYSIS

To determine the appropriate achievable Hg emission level for each coal rank that reflects BDT, a statistical analysis was conducted to determine the appropriate control efficiency achieved by BDT. That is, the 90^{th} percentile Hg reduction efficiency achievable for a source using BDT (i.e., the control efficiency which BDT is estimated to achieve 90 percent of the time) was determined using the one-sided t-statistics test.

For all coal ranks except coal refuse, the control efficiency used was the greater of that achieved either from the coal-to-the-stack or across the control device as shown through the ICR-3 3-run averages. The data provided by ARIPPA for coal refuse did not include testing prior to the final control device so only coal-to-stack data were available for this coal rank. This approach was used to minimize the impact of “negative” control removals indicated by some of the test results. It is recognized that Hg cannot be generated within a utility boiler/control system and that any negative removals merely indicate that no control is being shown. However, it is also believed that most of the Hg control achieved is being effected by the last control device (the one tested during the ICR program) and that little Hg is removed in the boiler. Therefore, it is believed that use of the highest control adequately reflects performance of the entire system. Further, as negative reductions are not realistic, any negative reductions found were equated to zero.

The statistical approach used was the one-sided t-statistics test using the general equation:

confidence interval = point estimate $\pm$ test statistic * standard error[4,5]

Stated another way, the equation becomes:

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[4] Voelker, D.H. and P.Z. Orton. “Statistics.” Cliffs Notes. Lincoln, NE. 1993. p.84. EPA-HQ-OAR-2002-0056-6716.

[5] Moore, D.S. and G.P. McCabe. “Introduction to the Practice of Statistics.” W.H. Freeman and Company. New York. Third Edition. 1999. p. 441. EPA-HQ-OAR-2002-0056-6712.

confidence limit = average - t * standard deviation,

where the value of t is a function of the degrees of freedom and obtained from the statistical table listing *t* distribution critical values. The number of degrees of freedom for sample size *n* is simply *n*-1 for a one-sample mean problem. The t values used in determining the 90^{th} percentile confidence limit are:

Degrees of Freedom	t value
1	3.078
3	1.638
5	1.476
6	1.440
7	1.415

The calculated control efficiency for BDT was then applied to the maximum annual average uncontrolled Hg emission rate for that coal rank to determine the appropriate NSPS Hg emission limits. The analysis was based on a reasonable maximum Hg content in coal (represented by the 90^{th} percentile of measured Hg concentrations in coal) as listed in the ICR coal data (ICR-2). This was considered reasonable since compliance with the NSPS will be based on a 12-month rolling average. Also, this reasonable maximum annual average Hg fuel content was used for any unit in the subcategory because the NSPS is applicable nationwide. Using the highest Hg fuel content ensures that the developed NSPS limits are achievable by a unit located anywhere in the United States under conditions that are reasonably expected to recur.

<u>Bituminous Coal</u>

For bituminous coal-fired units, the data used consisted of Hg control efficiency for the 6 units and the annual average fuel Hg content for all bituminous units. The control efficiency of the 6 units using BDT range from 83.8 percent (Intermountain) to 98.8 percent (Mecklenburg Cogeneration Facility). The 90^{th} percentile annual average Hg content for any bituminous coal was 0.2 ppm and the 90^{th} percentile annual average Btu content for any bituminous coal was 14,018 Btu/lb, which results in an Hg value of 14.27 lb Hg/TBtu.

The average (mean) of the control efficiencies is 94.96 percent, and the standard deviation is 5.6 percent. Therefore, using the above equation:

confidence limit = average - t * standard deviation
90^{th} percentile confidence limit = 94.96 - 1.476 * 5.6

the achievable control efficiency for Hg emissions reflecting BDT for bituminous coal-fired units is 86.72 (rounded to 86.7) percent.

Because the Hg emissions from any control system is a linear function of the inlet Hg fuel, assuming a constant control efficiency, the achievable Hg emission limit reflecting BDT for bituminous coal units was calculated by applying the 86.7 percent reduction to the 90th percentile annual average uncontrolled Hg emission rate. Therefore, the achievable Hg emission limit reflecting BDT for bituminous coal units is 1.90 lb Hg/TBtu. The analysis results are reported in Table 1.

Subbituminous Coal

For subbituminous coal-fired units, the same approach was performed as for bituminous coal units, except that the analysis was performed for the two subcategories of subbituminous units ("wet" and "dry").

"Wet" units

The control efficiency of the 2 units using BDT is 86 percent (Clay Boswell 2) and 66 percent (Comanche). Both of these units are controlled only with a FF, but are considered to reflect BDT since the addition of a wet FGD system would only enhance the Hg removal achieved by the FF. There are no subbituminous coal units listed in ICR-3 that utilize a FF/wet FGD combination. The 90th percentile annual average Hg content for any subbituminous coal was 0.114 ppm and the 90th percentile annual average Btu content for any subbituminous coal was 12,522 Btu/lb, which results in an Hg value of 9.10 lb Hg/TBtu.

The average (mean) of the control efficiencies is 75.9 percent, and the standard deviation is 14.3 percent. Therefore, using the above equation:

confidence limit = average - t * standard deviation
90% confidence limit = 75.9 – 3.078 * 14.3

the achievable control efficiency for Hg emissions reflecting BDT for wet subbituminous coal units is 31.80 percent. Therefore, the achievable Hg emission limit reflecting BDT for wet FGD subbituminous coal units is 6.21 lb Hg/TBtu. The analysis results are reported in Table 2.

"Dry" units

The control efficiency of the 4 units using BDT ranges from 8.2 percent (Sherburne County Generation Plant) to 78.8 percent (AES Hawaii). The 90th percentile annual average Hg content for any subbituminous coal was 0.114 ppm and the 90th percentile annual average Btu content for any subbituminous coal was 12,522 Btu/lb, which results in an Hg value of 9.10 lb Hg/TBtu.

The average (mean) of the control efficiencies is 38.1 percent, and the standard deviation is 29.5 percent. Therefore, using the above equation:

confidence limit = average - t * standard deviation

90% confidence limit = 38.1 - 1.638 * 29.5

the achievable control efficiency for Hg emissions reflecting BDT for dry subbituminous coal units, because of the high standard deviation, was calculated to be a negative removal; this value has been set to 0 percent. Therefore, the achievable Hg emission limit reflecting BDT for dry FGD subbituminous coal units is 9.10 lb Hg/TBtu. The analysis results are reported in Table 3.

Lignite Coal

For lignite coal units, the control efficiency of the 6 units using BDT ranges from 5.9 percent (Stanton 10) to 65.7 percent (Antelope Valley). Two units (R.M. Heskett and TNP-One) are FBC units which serve as a dry SO_2 control. The 90th percentile annual average Hg content for any lignite coal was 0.217 ppm and the 90th percentile annual average Btu content for any lignite coal was 10,820 Btu/lb, which results in an Hg value of 20.06 lb Hg/TBtu.

The average (mean) of the control efficiencies is 48.8 percent, and the standard deviation is 21.1 percent. Therefore, using the above equation:

confidence limit = average - t * standard deviation
90% confidence limit = 48.8 - 1.440 * 21.1

the achievable control efficiency for Hg emissions reflecting BDT for lignite coal units is 18.36 percent. Therefore, the achievable Hg emission limit reflecting BDT for lignite coal units is 16.39 lb Hg/TBtu. The analysis results are reported in Table 4.

Coal Refuse

For coal refuse units, the control efficiency of the 2 units (having 99.95 and 99.92 percent reductions, respectively) was 99.9 percent. Both units are FBC boilers with FF. One unit combusts waste anthracite, the other combusts waste bituminous. The 90th percentile annual average Hg content for any coal refuse was 0.781 ppm and the 90th percentile annual average Btu content for any coal refuse was 11,376 Btu/lb, which results in an Hg value of 68.65 lb Hg/TBtu.

The average (mean) of the control efficiencies is 99.24 percent, and the standard deviation is 1.02 percent. Therefore, using the above equation:

confidence limit = average - t * standard deviation
90% confidence limit = 99.24 – 1.415 * 1.02

the achievable control efficiency for Hg emissions reflecting BDT for coal refuse units is 98 percent. Therefore, the achievable Hg emission limit reflecting BDT for coal refuse units is 1.51 lb Hg/TBtu. The analysis results are reported in Table 5.

Conversion to Output-Based Units

The output-based equivalent Hg emission limits of the BDT emission limits (lb Hg/TBtu heat input) calculated above can be computed by using the following equation:

Eo (lb/MWh) = Ei (lb/million) x n (heat rate) x 1000 kWh/MWh
For bituminous coal-fired units the output-based BDT limit would be:
Eo (lb/MWh) = 1.90 lb/trillion x 10,667 Btu/kWh x 1000 kWh/MWh x 0.0000001
where 0.0000001 is the conversion factor from trillion Btu to million Btu
OR
Eo (lb/MWh) = 1.90 lb/trillion x 1.056
where 1.056 is the conversion factor from lb/TBtu to lb x 10^{-5} lb/MWh

Therefore, for bituminous coal Eo (lb/MWh) = 0.000020 lb/MWh or 2.0 x 10^{-5} lb/MWh

The output-based Hg limits for each coal rank would be:

Bituminous coal =	2.0 x 10^{-5} lb/MWh
Subbituminous coal (wet units) =	6.6 x 10^{-5} lb/MWh
Subbituminous coal (dry units) =	9.7 x 10^{-5} lb/MWh
Lignite coal =	17.5 x 10^{-5} lb/MWh
Coal refuse =	1.6 x 10^{-5} lb/MWh

Permit Information

Recent, available permit (available in March 2005) Hg levels were evaluated for comparison with the limits presented above. The available permit information is presented in Appendix B. Comparison of the available permit limits with those developed above is a valid "reality check" on the appropriateness of NSPS limits determined above that reflect BDT. Available permits on bituminous-fired units have Hg emission limits ranging from approximately 2.0 x 10^{-5} lb/MWh to 3.9 x 10^{-5} lb/MWh; those for subbituminous-fired units range from 1.1 x 10^{-5} lb/MWh to 12.6 x 10^{-5} lb/MWh. Considering the limited number of permits and the limited experience in developing appropriate Hg limits for those permits, the NSPS Hg emission limits developed above are in reasonable agreement with these permits. Insufficient permit information is available to do a similar comparison for lignite- and coal refuse-fired units but we have used the same analytic procedure for these subcategories.

TABLE 1
MERCURY DATA FOR BITUMINOUS COAL-FIRED UTILITY BOILERS USED FOR DETERMINING BDT

BDT: FF and SDA; FF and wet FGD
Units using BDT:

Plant name	Unit name	Controls	Highest control efficiency (%)
Mecklenburg Cogeneration Facility	GEN 1	FF/SDA	98.8
SEI – Birchwood Power Facility	1	FF/SDA/SCR	97.3
Logan Generating Plant	GEN 1	FF/SDA/SCR	97.8
Clover Power Station	2	FF/WS	96.7
Intermountain	2SGA	FF/WS	83.8
Collier	2B	FF/SDA	95.2

Average percent reduction of BDT units: 94.96 %
Standard deviation: 5.6 %
Percent reduction of BDT: 86.7 %
90th percentile annual average Hg content used: 0.20 ppm
90th percentile annual average Btu content used: 14,018 Btu/lb
Achievable Hg emission limit: 1.9 lb/TBtu

TABLE 2
MERCURY DATA FOR SUBBITUMINOUS COAL-FIRED (WET) UTILITY BOILERS USED FOR DETERMINING BDT

BDT: FF and wet FGD
Units using BDT:

Plant name	Unit name	Controls	Highest control efficiency (%)
Clay Boswell	2	FF	86.0
Comanche	2	FF	65.7

Average percent reduction of BDT units: 75.90 %
Standard deviation: 14.3 %
Percent reduction of BDT: 31.8 %
90th percentile annual average Hg content used: 0.114 ppm
90th percentile annual average Btu content used: 12,522 Btu/lb
Achievable Hg emission limit: 6.2 lb/TBtu

TABLE 3
MERCURY DATA FOR SUBBITUMINOUS COAL-FIRED (DRY) UTILITY BOILERS USED FOR DETERMINING BDT

BDT: FF and SDA; FBC and FF
Units using BDT:

Plant name	Unit name	Controls	Highest control efficiency (%)
AES Hawaii	A	FBC/FF	78.8
Craig	3	FF/SDA	33.6
Sherburne County	3	FF/SDA	8.2
Rawhide	101	FF/SDA	31.8

Average percent reduction of BDT units: 38.10 %
Standard deviation: 29.5 %
Percent reduction of BDT: 0.0 %
90^{th} percentile annual average Hg content used: 0.114 ppm
90^{th} percentile annual average Btu content used: 12,522 Btu/lb
Achievable Hg emission limit: 9.1 lb/TBtu

TABLE 4
MERCURY DATA FOR LIGNITE COAL-FIRED UTILITY BOILERS USED FOR DETERMINING BDT

BDT: FF and SDA; FBC and ESP or FF; ESP and wet FGD
Units using BDT:

Plant name	Unit name	Controls	Highest control efficiency (%)
R.M. Heskett	B2	FBC/ESP	56.1
Coyote	1	FF/SDA	38.2
Limestone	1	ESP/WS	51.0
Monticello	3	ESP/WS	65.1
Antelope Valley Station	B1	FF/SDA	65.7
TNP-One	U2	FF	59.2
Stanton	10	FF/SDA	5.9

* ICR-3 value doubled based on later data received

Average percent reduction of BDT units: 48.76 %
Standard deviation: 21.1 %
Percent reduction of BDT: 18.3 %
90^{th} percentile annual average Hg content used: 0.217 ppm
90^{th} percentile annual average Btu content used: 10,820
Achievable Hg emission limit: 16.4 lb/TBtu

TABLE 5
MERCURY DATA FOR COAL REFUSE-FIRED UTILITY BOILERS USED FOR DETERMINING BDT

BDT: FBC and FF
Units using BDT:

Plant name	Unit name	Fuel	Controls	Control efficiency (%)
Kline Township Cogen Facility	GEN 1	Waste Anthracite	FBC/FF	99.95
Scrubgrass Generating Company	GEN 1	Waste Bituminous	FBC/FF	99.92
Cambria Cogen Facility	GEN 1	Waste Bituminous	FBC/FF	99.41
Colver Power Plant	COLV	Waste Bituminous	FBC/FF	99.10
Ebensburg Power Company (2004)	GEN 1	Waste Bituminous	FBC/FF	99.91
Ebensburg Power Company (2005)	GEN 1	Waste Bituminous	FBC/FF	99.55
Scrubgrass Generating Company (2005)	GEN 1	Waste Bituminous	FBC/FF	99.24
Wheelabrator Frackville	GEN 1	Waste Anthracite	FBC/FF	96.85

Average percent reduction of BDT units: 99.24 %
Standard deviation: 1.02 %
Percent reduction of BDT: 97.8 %
90^{th} percentile annual average Hg content used: 0.781 ppm
90^{th} percentile annual average Btu content used: 11,376 Btu/lb
Achievable Hg emission limit: 1.5 lb/TBtu

APPENDIX A

ARIPPA indicated in their comments submitted in response to the October 28, 2005 CAMR reconsideration notice (EPA-HQ-OAR-2002-0056-6529.1) that they had identified 16 test runs for which Hg emission results and contemporaneous fuel data were available. Six of these test runs were from the EPA ICR-3 emission test program. ARIPPA identified 15 additional test runs for which contemporaneous fuel data were NOT available but for which fuel data were available at or near the time of the stack test. EPA obtained these data from ARIPPA on April 12 based on a follow-up request from ARIPPA (EPA-HQ-OAR-2002-0056-6698 through -6698.12).

EPA has evaluated the submitted data (comparing them to the two ICR-3 test reports). The 31 test runs that ARIPPA provided are as follows:

Kline Township; October 1999, Runs 1 – 3 (1999 ICR-3 data)
Scrubgrass; 1999; Runs 1 – 3 (1999 ICR-3 data)
Scrubgrass; March 2005; Runs 1 – 3
Wheelabrator; February 2004; Runs 1 – 2 (Method 29)
Wheelabrator; February 2004; Runs 3 – 4 (Ontario Hydro method)
Ebensburg; October 2003; Runs 1 – 3
Ebensburg; November 2004; Runs 1 – 3
Ebensburg; July 2005; Runs 1 – 3
Cambria; April 2005; Runs 1 – 3
Colver; April 2004; Runs 1 – 3
Panther Creek; May 2004; Unit 1; Run 1
Panther Creek; May 2004; Unit 2; Run 2
Piney Creek; February 1999; Composite average

Of these, the following eight runs have been excluded from the EPA analysis for the noted reason:

Wheelabrator; February 2004; Runs 3 – 4 (Ontario Hydro method): The test report gives the indication that there was, or may have been, a contamination problem with the Ontario Hydro runs ("…cannot find a source or reason for contamination…"). Given that there is no definitive answer that there was NO contamination, EPA has excluded the runs.

Ebensburg; October 2003; Runs 1 – 3: The test report indicates that there was some concern that "…a portion of the boiler emissions were still bypassing the baghouse…" during the Hg tests. This "…may have been affirmed by the heavy loading of particulate captured on the filter of each multiple metals test train." The test firm and the company elected to leave the data in; EPA believes that there is an unresolved question as to the representativeness of the data and has excluded the runs.

Panther Creek; May 2004; Unit 1; Run 1: This is only a single test run and, thus, EPA has excluded it from the analysis.

Panther Creek; May 2004; Unit 2; Run 2: This is only a single test run and, thus, EPA has excluded it from the analysis.

Piney Creek; February 1999; Composite average: These data are only on a single sheet containing the test data. There is insufficient information to assess much about the test or the data. Even ARIPPA indicated that “the Piney Creek data did not include individual lbs/MMBtu output for each run so the entire test was used as a single data point.” EPA has excluded the data from the analysis.

The remaining run data have been included in the reanalysis of the coal refuse Hg NSPS emission limit.

APPENDIX B

Table A-1. Summary of Approved State Air Permits with Mercury Emission Limitations for Coal-Fired Electric Utility Steam Generating Units

Category	State Permitting Authority	Electric Utility Source			Permit Information			Project Status	Comments
		Name	Boiler Type	Unit Capacity	Type	Approval Date	Hg Emissions Limitation		
Bituminous	Illinois EPA	Prairie State Generating Co. Prairie State Generating Station Units 1 and 2	PC	750 MW (each unit)	Construction	1-14-2005	Federal NESHAP limit		
	Illinois EPA	Corn Belt Energy Corporation Prairie Energy Power Plant	PC	91 MW	Construction	12-17-2002	4×10^{-6} lb/MMBtu heat input		
	Illinois EPA	Indeck-Elwood LLC (Indeck)	CFB	660 MW	Construction	10-10-2003	2×10^{-6} lb/MMBtu heat input		
	South Carolina DHEC	Santee Cooper Power Cross Generating Station Units 3 and 4	PC	660 MW (each unit)	Construction	2-5-2004	3.6×10^{-6} lb/MMBtu heat input	Under construction	Facility subject to consent decree with EPA
	Kentucky DEP	Thoroughbred Generating Station Units 1 and 2	PC	750 MW (each unit)	Construction	10-11-2002	3.21×10^{-6} lb/MMBtu heat input		
	Kentucky DEP	Hugh L. Spurlock Power Station	CFB	270 MW	Air Quality Permit	8-4-2002	2.65×10^{-6} lb/MMBtu heat input		
	West Virginia DEP	Longview Power	PC	600 MW	Construction	3-2-2004	1.46×10^{-2} lb/hr based on a 3-hour average and 6.38×10^{-2} TPY based on 12 month rolling average.		
Subbituminous	Iowa DNR	MidAmerican Energy Co. Council Bluffs Energy Center Unit 4	PC	790 MW	Construction	6-17-2003	1.7×10^{-6} lb/MMBtu heat input		PRB coal Supercritical boiler Sorbent injection
	Utah DEQ	Sevier Power Company’s NEVCO Energy	CFB	270 MW	Air Quality Permit	10-12-2004	4×10^{-7} lb/MMBtu heat input		Burns a mixture of western bituminous / western (non SRB) subbituminous coal
	Arkansas ADEQ	Plum Point Energy Associates	PC	550-800 MW	Operating	8-20-2003	12.8×10^{-6} lb/MMBtu heat input		
	Montana DEQ	Bull Mountain Energy Roundup Power Plant Units 1 and 2	PC	390 MW (each unit)	MACT	7-25-2003	3.23×10^{-6} lb/MMBtu heat input		

Category	State Permitting Authority	Electric Utility Source			Permit Information			Project Status	Comments
		Name	Boiler Type	Unit Capacity	Type	Approval Date	Hg Emissions Limitation		
	Montana DEQ	Rocky Mountain Power Hardin Generation Project	PC	113 MW	Air Quality Permit	12-22-2004	5.8 lb/TBtu heat input based on 1-hour average	Permit decision under appeal	Existing unit permit revision triggered by reconstruction
	Missouri DNR	City Utilities of Springfield Southwest Power Station Unit 2	PC	275 MW	Construction	12-15-2004	7.5 x 10^{-6} lb/MMBtu heat input		
	Arizona DEQ	Tucson Electric Power Company Springerville Units 3 and 4	PC	400 MW (each unit)	Air Quality Permit	2-14-2002	6.9 x 10^{-6} lb/MMBtu heat input		
	Wisconsin DER	WE Energies Elm Road Generating Station	PC	615 MW (each unit)	Construction	1-14-2004	1.12 lb/TBtu heat input in any 12-consecutive months		PRB coal Supercritical boiler
	Wisconsin DER	Wisconsin Public Service Corp. Weston Plant	PC	500 MW	Construction	10-19-2004	1.7 lb/TBtu heat input in any 12-consecutive months	Permit decision under appeal	PRB coal Supercritical boiler Sorbent injection
Lignite	Texas TCEQ	Texas-New Mexico Power Company TNP One Units 1 and 2	CFB	175 MW (each unit)	Air Quality Permit	5-12-1987	Maximum Allowable Emission Rates 0.3 lb/hr, 1.3 TPY		Permit to construct and operate Issued 5/12/87
Lignite	Texas TCEQ	Alcoa's Rockdale Power Plant CFB 1and CFB 2	CFB	216.5 MW Net (each unit)	Air Quality Permit	10-25-2003	Maximum Allowable Emission Rates 0.033 lb/hr, 0.048 TPY		While these units will be industrial boilers at a primary aluminum plant they are fed by a mine-mouth facility and by permit must meet 40 CFR Part 60 Subparts A and Da.
IGCC	No units of this design have been permitted								
Coal refuse	Kentucky DEP	Kentucky Mountain Power	CFB	250 MW	Construction	6-15-2000	81 x 10^{-6} lb/MMBtu heat input		
Coal refuse/coal	Illinois EPA	EnviroPower of Illinois, LLC	CFB	250 MW (each unit)	Construction	7-3-2001	4 x 10^{-6} lb/MMBtu heat input		Burns a mixture of bituminous coal refuse (culm) and bituminous coal

Note: Data current as of March 2005.

Table A-2. Summary of Air Pollution Control Configurations for Coal-Fired Electric Utility Steam Generating Units With Approved State Air Permits with Mercury Emission Limitations

Category	Electric Utility Source			Air Emission Control Configuration					Comments
	Name	Boiler Type	Unit Capacity	Combustion Controls	Post- Combustion Control Sequence				
Bituminous	Prairie State Generating Co. Prairie State Generating Station Units 1 and 2	PC	750 MW (each unit)	Low-NO_x burners	SCR	ESP	Wet FGD Scrubber	Wet ESP	
	Corn Belt Energy Corporation Prairie Energy Power Plant	PC	91 MW	Low-NO_x burners/staged combustion	SCR	ESP	Wet FGD Scrubber		
	Indeck-Elwood LLC (Indeck)	CFB	660 MW		SNCR	Lime Injection		Fabric Filter	
	Santee Cooper Power Cross Generating Station Units 3 and 4	PC	660 MW (each unit)		SCR	ESP	Wet FGD Scrubber		
	Thoroughbred Generating Station Units 1 and 2	PC	750 MW (each unit)	Low-NO_x burners	SCR	ESP	Wet FGD Scrubber	Wet ESP	
	Hugh L. Spurlock Power Station	CFB	270 MW		SNCR	Lime Injection		Fabric Filter	
	Longview Power	PC	600 MW	Low-NO_x burners	SCR		Wet FGD Scrubber	Fabric Filter	
Subbituminous	MidAmerican Energy Co. Council Bluffs Energy Center Unit 4	PC	790 MW	Low-NO_x burners	SCR	Activated Carbon Injection	Lime Spray Dryer	Fabric Filter	
	Sevier Power Company's NEVCO Energy	CFB	270 MW		SNCR	Lime Injection	Lime Spray Dryer	Fabric Filter	Burns a mixture of western bituminous/western (non SRB) subbituminous coal
	Plum Point Energy Associates	PC	550-800 MW		SCR		Wet FGD Scrubber	Fabric Filter	
	Bull Mountain Energy Roundup Power Plant Units 1 and 2	PC	390 MW (each unit)	Low-NO_x burners	SCR		Lime Spray Dryer	PJ Fabric Filter	
	Rocky Mountain Power Hardin Generation Project	PC	113 MW		SCR		Lime Spray Dryer	Fabric Filter	
	City Utilities of Springfield Southwest Power Station Unit 2	PC	275 MW	Low-NO_x burners	SCR	Activated Carbon Injection	Lime Spray Dryer	Fabric Filter	A

Category	Electric Utility Source			Air Emission Control Configuration					Comments
	Name	Boiler Type	Unit Capacity	Combustion Controls	Post- Combustion Control Sequence				
	Tucson Electric Power Company Springerville Units 3 and 4	PC	400 MW (each unit)	Low-NO_x burners	SCR		Lime Spray Dryer	Fabric Filter	
	WE Energies Elm Road Generating Station	PC	615 MW (each unit)	Low-NO_x burners	SCR	ESP	Wet FGD Scrubber	Wet ESP	
	Wisconsin Public Service Corp. Weston Plant	PC	500 MW	Low-NO_x burners	SCR	Activated Carbon Injection	Lime Spray Dryer	Fabric Filter	
Lignite	Texas-New Mexico Power Company TNP One Units 1and 2	CFB	175 MW (each unit)			Lime Injection		Fabric Filter	
	Alcoa's Rockdale Power Plant CFB 1and CFB 2	CFB	216.5 MW Net (each unit)		SNCR	Lime Injection		Fabric Filter	
IGCC	No units of this design have been permitted								
Coal refuse	Kentucky Mountain Power	CFB	250 MW		SCNR	Lime Injection		Fabric Filter	
	EnviroPower of Illinois, LLC	CFB	250 MW (each unit)		SNCR	Lime Injection		Fabric Filter	Burns a mixture of bituminous coal refuse (culm) and bituminous coal

Note: Data current as of March 2005.

A The entity building this plant decided to include as a part of this project the emissions associated with a potential Hg control system. The entity building this plant is anticipating controlling Hg emissions by means of injecting powdered activated carbon. However, a final decision as to the exact method of Hg control has not been made. The entity building this plant does plan on installing some type of Hg control, but is holding off making a final decision until a later date so that the most effective system of Hg control that has been shown to be compatible with the NO_X, PM, and SO_X pollution control technologies can be determined. If the Hg control is not powdered activated carbon, then it will be at least as effective.

Table A-3. Summary of Mercury Emission Limitations for Coal-Fired Electric Utility Steam Generating Units

Category	Electric Utility Source		Emission Limits		Comments
	Name	Permit Hg Emissions Limitation	Converted to input-based Emissions Limitation	Converted to output-based Emissions Limitation	
Bituminous	Prairie State Generating Co. Prairie State Generating Station Units 1 and 2	Federal NESHAP limit	NA	NA	No defined emission limit
	Corn Belt Energy Corporation Prairie Energy Power Plant	4×10^{-6} lb/MMBtu heat input	4 lb/TBtu	3.9×10^{-5} lb/MWh	A
	Indeck-Elwood LLC (Indeck)	2×10^{-6} lb/MMBtu heat input	2 lb/TBtu	2×10^{-5} lb/MWh	A
	Santee Cooper Power Cross Generating Station Units 3 and 4	3.6×10^{-6} lb/MMBtu heat input	3.6 lb/TBtu	3.5×10^{-5} lb/MWh	A
	Thoroughbred Generating Station Units 1 and 2	3.21×10^{-6} lb/MMBtu heat input	3.21 lb/TBtu	3.2×10^{-5} lb/MWh	A
	Hugh L. Spurlock Power Station	2.65×10^{-6} lb/MMBtu heat input	2.65 lb/TBtu	2.6×10^{-5} lb/MWh	A
	Longview Power	1.46×10^{-2} lb/hr based on a 3-hour average and 6.38×10^{-2} TPY based on 12 month rolling average.	2.4 lb/TBtu	2.3×10^{-5} lb/MWh	A, B
Subbituminous	MidAmerican Energy Co. Council Bluffs Energy Center Unit 4	1.7×10^{-6} lb/MM Btu heat input	1.7 lb/TBtu	1.7×10^{-5} lb/MWh	A
	Sevier Power Company's NEVCO Energy	4×10^{-7} lb/MM Btu heat input	0.4 lb/TBtu	0.39×10^{-5} lb/MWh	A
	Plum Point Energy Associates	12.8 lb/TBtu heat input	12.8 lb/TBtu	12.6×10^{-5} lb/MWh	A
	Bull Mountain Energy Roundup Power Plant Units 1 and 2	3.23×10^{-6} lb/MMBtu heat input	3.23 lb/TBtu	3.2×10^{-5} lb/MWh	A
	Rocky Mountain Power Hardin Generation Project	5.8 lb/TBtu heat input based on 1-hour average	5.8 lb/T Btu	5.7×10^{-5} lb/MWh	A
	City Utilities of Springfield Southwest Power Station Unit 2	7.5×10^{-6} lb/MMBtu heat input	7.5 lb/TBtu	7.4×10^{-5} lb/MWh	A

Category	Electric Utility Source		Emission Limits		Comments
	Name	Permit Hg Emissions Limitation	Converted to input-based Emissions Limitation	Converted to output-based Emissions Limitation	
	Tucson Electric Power Company Springerville Units 3 and 4	6.9 x 10^{-6} lb/MMBtu heat input	6.9 lb/TBtu	6.8 x 10^{-5} lb/MWh	A
	WE Energies Elm Road Generating Station	1.12 lb/TBtu heat input in any 12-consecutive months	1.12 lb/TBtu	1.1 x 10^{-5} lb/MWh	A
	Wisconsin Public Service Corp. Weston Plant	1.7 lb/TBtu heat input in any 12-consecutive months	1.7 lb/TBtu	1.7 x 10^{-5} lb/MWh	A
Lignite	Texas-New Mexico Power Company TNP One Units 1 and 2	Maximum Allowable Emission Rates 0.3 lb/hr, 1.3 TPY	190 lb/TBtu	186 x 10^{-5} lb/MWh	A, C, D
	Alcoa's Rockdale Power Plant CFB 1and CFB 2	Maximum Allowable Emission Rates 0.033 lb/hr, 0.048 TPY	3.7 lb/TBtu	3.6 x 10^{-5} lb/MWh	A, E
IGCC	No units of this design have been permitted			2 x 10^{-5} lb/MWh	F
Coal refuse	Kentucky Mountain Power	81 x 10^{-6} lb/MMBtu heat input	81 lb/TBtu	80 x 10^{-5} lb/MWh	A
Coal refuse/coal	EnviroPower of Illinois, LLC	4 x 10^{-6} lb/MMBtu heat input	4 lb/TBtu	3.9 x 10^{-5} lb/MWh	A, G

Note: Data current as of March 2005.

A The emission limits were converted from input-based standard (lb/TBtu) to output-based standard (lb/MWh) by multiplying by 9.8 x 10^{-6}. This factor incorporates a 35 percent efficiency is 10 joules per watt hour (J/Wh) (9,833 Btu per kilowatt hour (kWh)).

B Based on a boiler capacity of 6,114 MMBtu/hr. A permitted emission limit of 6.38 x 10^{-2} TPY * 2,000 lb/T/8,760 hr/yr/6,114 MMBtu/hr = 2.4 x 10^{-6} lb/MMBtu or 2.4 lb/TBtu. 2.4 lb/TBtu * 9.8 x 10^{-6} = 2.3 x10^{-5} lb/MWh.

C Based on EPA ICR stack testing done on 10/6 - 10/8/99. While testing, the coal feed averaged 234,897 lb/hr. The heat content of the coal averaged 6,670 Btu/lb. 234,897 lb/hr * 6,670 Btu/lb/1,000,000 = 1,566.6 MMBtu/hr. A permitted emission limit of 1.3 TPY * 2,000 lb/T/8,760 hr/yr/1,566.6 MMBtu/hr = 1.90 x 10^{-4} lb/MMBtu or 190 lb/TBtu. 190 lb/TBtu * 9.8 x 10^{-6} = 186 x10^{-5} lb/MWh.

D This permit level predates the 1990 Amendments to the CAA so we would not give it much credence. There appear to be no other new or existing lignite-fired units with an Hg emission limit.

E Based on a boiler capacity of 2,960 MMBtu/hr. A permitted emission limit of 0.048 TPY * 2,000 lb/T/8,760 hr/yr/2,960 MMBtu/hr = 3.7 x 10^{-6} lb/MMBtu or 3.7 lb/TBtu. 3.7 lb/TBtu * 9.8 x 10^{-6} = 3.6 x10^{-5} lb/MWh.

F Currently no units of this design (IGCC) have been permitted. However, it is prudent to promulgate a new emissions limit. For this limit, we used the ICR emission limit data from the only two IGCC units in the country.

G This unit is permitted to fire a mixture of waste bituminous (culm) and bituminous coal; therefore, it is not strictly a coal refuse-fired unit.