MEMORANDUM

TO: Docket

FROM: EPA, Clean Air Markets Division

SUBJECT: Allocation Adjustment Factors for the Proposed Mercury Trading Rulemaking

DATE: March 10, 2004

Background

As discussed in the January 30, 2004 Notice of Proposed Rulemaking (NPR), the trading program establishes, for affected utility units, a Phase I Hg cap at a level that reflects the maximum Hg reductions expected as co-benefits accompanying the SO_2 and NO_x caps in the IAQR in 2010 and a Phase II cap of 15 tons starting in 2018.

The NPR proposed a formula for determining the total amount of emissions for the Budget Trading Program for each State for 2018, and, using that mechanism, proposed the amount of emissions for the Program for each State for 2018. EPA also proposed that formula be used to develop budgets for each state for 2010. That formula is, in essence, the sum of the hypothetical allocations to each affected Utility Unit in the State, and that allocation, in turn, is based on the proportionate share of their baseline heat input to total heat input of all affected units. For purposes of this hypothetical allocation of the allowances, each unit's baseline heat input is adjusted to reflect the ranks of coal combusted by the unit during the baseline period. While the formula determines the States' allocation budgets, each State is given discretion on how to distribute the allocations within a State.

Adjustment factors of 1 for bituminous, 1.25 for subbituminous, and 3 for lignite coals were proposed in the NPR. Alternatively, for purposes of this hypothetical allocation of allowances to Utility Units which where used to calculate the state budgets, EPA proposed using the MACT emission rates proposed in the NPR as the basis for the adjustment factors.

This memorandum describes the rationale for these adjustment factors and the methodology for determining the state budgets.

Proposed Adjustment Factors

As discussed above, adjustment factors of 1.0 for bituminous, 1.25 for subbituminous, and 3.0 for lignite coals were proposed in the NPR. The allocation methodology takes into account the different levels of mercury control that lignite, bituminous, and subbituminous coals can achieve.

Specifically, the adjustment factors are based on the expectation that mercury in the coal types reacts differently to NOx and SO_2 control equipment and that the mercury content of the different coal types varies.

The conclusion that mercury in each of the coals reacts differently to NOx and SO_2 control equipment was based on information collected in EPA's 1999 Mercury Information Collection Request. According to the 1999 ICR data, the existing air pollution control technologies used on coal-fired utility boilers exhibit average levels of mercury control that range from 0 to 98 percent. The amount of mercury capture varied by given control technology configuration (e.g. cold-side ESP or cold-side ESP and wet scrubber) and by coal grade. Bituminous coal achieved the best capture, subbituminous the next best capture, and lignite the lowest capture. Examining the single best performing control configurations by coal type in the ICR data[1], the following average mercury removals are seen:

< Bituminous - 98 percent
< Subbituminous - 72 percent
< Lignite - 44 percent

The ICR also collected coal property data for the year 1999, including quarterly analysis of the mercury content of coal from all electric power generating plants. Table 1 shows the mercury content of coal by type[2].

Table 1
Mercury Content (lb/TBtu) by Type

Coal Type	Range	Mean	Standard Deviation
Bituminous	0.04-103.81	8.59	6.69
Subbituminous	0.39-71.08	5.74	3.59
Lignite	0.93-75.06	10.54	9.05

To develop allocation ratios, EPA balanced these two factors: (1) data on mercury capture by control figuration and coal type, and (2) data on mercury content of coal. EPA believes the proposed allocation ratios recognize that subbituminous and lignite coals have the lowest mercury capture with existing technologies and in the case of lignite also have higher mercury coal content. These adjustment factors are considered to be directionally correct based on the test data currently available.

[1] Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report, U.S. EPA, EPA-600/R-01-109, April 2002, Table 6-5.

[2] Id., Tables A-2, A-4, A-6.

Proposed Alternative Adjustment Factors

As an alternative, allocation adjustment factors using the proposed MACT emission rates were proposed in the NPR. The allocation of allowances using these adjustment factors could than be used to derive hypothetical unit allocations which in turn would be used the calculate the state budgets.

The proposed MACT emissions limits in the NPR appear in Table 2. For further discussion of the basis of these MACT emission rates, please see the proposed Hg MACT rule, published January 30, 2004.

Table 2
Proposed Mercury MACT Emission Limits for Existing Coal-Fired Electric Utility Steam Generating Units

Subcategories Based on Coal Rank	Rates *(lb/TBtu)*
Bituminous	2.0
Subbituminous	5.8
Lignite	9.2
Coal refuse / Waste coal	0.4
IGCC units	19.0
Note: TBtu - trillion BTUs of heat input	

Source: Proposal of Mercury MACT, published on January 30, 2004, available on the web at http://www.epa.gov/mercury/actions.htm

Using the proposed MACT emission rates, the alternative adjustment factors would be the following: 1 for bituminous, 2.9 for subbituminous, 4.6 for lignite coals, 0.2 for waste coals, and 9.5 for IGCC units.

Methodology for Unit Level Allocations

The NPR established the total number of tons for the Budget Trading Program within a specific state for Phase II of the program beginning in 2018. Hypothetical unit level allocations for 2018 were derived and those unit allocations at the state level were added to develop a State level budget.

Hypothetical unit allocations were determined by adjusting a baseline heat input. That baseline heat input was determined using the average of the three highest heat inputs for each unit of the period 1998 to 2002. In order to adjust the heat input based on coal type, coal usage patterns were determined from the 1999 ICR data. The attached memorandum describes in detail the databases and other information EPA used to derive the heat input and coal use data to derive

hypothetical unit allocations for 2018 (see attachment: Calculation of Unit and State Mercury Allocations, dated February 13, 2004).

To calculate hypothetical units allocations, EPA first multiplied the baseline heat input for each unit by the adjustment factor and then added this number to develop a total adjusted baseline heat input. Next, the hypothetical unit allocation was determined by multiplying the Hg cap (in the case of the NPR this was the 2018 cap of 15 tons) by the ratio of the unit's adjusted baseline heat input to the total adjusted baseline heat input. State budgets were calculated by summing the hypothetical allocations to each unit in the State. While the formula determines the States' allocation budgets, each State is given discretion on how to distribute the allocations within a State.

February 13, 2004

Calculations of Unit and State Mercury Allocations

1. Summary

This document describes mercury (Hg) allocation calculations at the unit and State level performed by Perrin Quarles Associates, Inc. (PQA) for the U.S. EPA's Clean Air Markets Division (CAMD). The calculations are provided in two electronic spreadsheet files: 1) State Hg Allocations 2018.xls, which contains a summary of allocations at the State level, and 2) Unit Hg Allocations 2018.xls, which contains the unit level allocations.

2. Methodology

a. Affected Units

The affected unit population for the allocation calculations was based on the 1999 Hg ICR inventory, supplemented by CAMD's monitoring plan database. The Hg ICR surveyed coal-fired electric generating units (EGUs). The survey defined an EGU as a coal-fired unit serving a generator with a nameplate capacity greater than 25 MW that produces electricity for sale, except for a cogeneration unit that produces electricity for sale equal to less than one-third of the potential electrical output of the generator. The EGU definition is similar to the Acid Rain definition in 40 CFR Part 72, except that there are additional exemptions from the Acid Rain Program for certain small independent power producers. The Hg ICR inventory includes both Acid Rain and non-Acid Rain units.

Acid Rain Program units that burned coal based on monitoring plan information, and that were not in the Hg ICR inventory, were added to the affected unit population for the allocation calculations. This included units that were in existence when the Hg ICR was conducted, and new coal-fired Acid Rain units that have come online since the 1999 Hg ICR.

b. Baseline Heat Input

There were three approaches used to first calculate the baseline heat input, depending on the availability of heat input data:

1. **Acid Rain Units.** Annual heat input information is reported by Acid Rain units and is available in the CAMD database. The highest three annual heat input years in the 1998 - 2002 period were identified and heat inputs averaged to first calculate an "unadjusted baseline."

   In some cases, units that had become subject to the Acid Rain Program later in the period had less than three years of data. In those cases either a two year average of annual Acid Rain heat input was used, or one year of Acid Rain heat input was used. Table 1

identifies these units, and documents how the unadjusted baselines were calculated for these special situations.

Table 1:
Existing Acid Rain Units with Less Than Three Years of Heat Input Data

State	Plant	ORIS Code	Unit ID	Heat Input Used in Calculation	Comment
MN	Taconite Harbor Energy Center	10075	1	2002	Acid Rain HI for 2002. No Hg ICR data.
MN	Taconite Harbor Energy Center	10075	2	2002	
MN	Taconite Harbor Energy Center	10075	3	2002	
NC	Elizabethtown Power	10380	Unit 1	2 Year Average (2001, 2002)	Acid Rain HI for 2001 and 2002. No Hg ICR data.
NC	Elizabethtown Power	10380	Unit 2	2 Year Average (2001, 2002)	
NC	Lumberton Power	10382	Unit 1	2 Year Average (2001, 2002)	Acid Rain HI for 2001 and 2002. No Hg ICR data.
NC	Lumberton Power	10382	Unit 2	2 Year Average (2001, 2002)	
PA	Foster Wheeler Mt Carmel	10343	SG-101	2002	Acid Rain HI for 2002. 2002 Acid Rain HI comparable to 1999 Hg ICR.
VA	Hopewell Power Station	10071	1	2 Year Average (2001, 2002)	Acid Rain HI for 2001 and 2002. 2002 Acid Rain HI significantly less than 2001. Two year average, however, is still higher than 1999 Hg ICR data.
VA	Hopewell Power Station	10071	2	2 Year Average (2001, 2002)	
VA	Altavista Power Station	10773	1	2 Year Average (2001, 2002)	Acid Rain HI for 2001 and 2002. Acid Rain HI significantly higher than 1999 Hg ICR data.
VA	Altavista Power Station	10773	2	2 Year Average (2001, 2002)	
VA	Southampton Power Station	10774	1	2 Year Average (2001, 2002)	Acid Rain HI for 2001 and 2002. Acid Rain HI significantly higher than 1999 Hg ICR data.
VA	Southampton Power Station	10774	2	2 Year Average (2001, 2002)	

2. **New Acid Rain Units.** There were five new coal fired Acid Rain units which came on line in 2001 and 2002. The 2002 heat input information was used for these units, prorated based on the first month of reported data. For four of the units the heat input was prorated for 8 months of operation, and for one unit a full year (see Table 2).

Table 2:
New (Operation after 1999) Acid Rain Coal Fired Units

State	Plant	ORIS Code	Unit ID	CAMD On-Line Date	Heat Input Used and Months of Operation
FL	Northside	667	0.04	2/19/2001	2002, 8 months
FL	Northside	667	0.08	8/1/2002	2002, 8 months
MO	Hawthorn	2079	0.208	5/11/2001	2002, 12 months
MS	Red Hills Generation Facility	55076	AA001	2/14/2001	2002, 8 months
MS	Red Hills Generation Facility	55076	AA002	2/14/2001	2002, 8 months

3. **Non-Acid Rain Units**. Non-Acid Rain units in the Hg ICR inventory do not uniformly report annual heat input to CAMD (some OTC NO_x Budget Program units may have reported ozone season heat input for 1999 - 2002). Baseline heat input information was collected by the Hg ICR for 1999. The fuel use and heat content data from the ICR were used to calculate 1999 annual heat input, and this single year was used as the baseline heat input. In some cases the Hg ICR fuel information was for multiple units. In those cases the total heat input was divided evenly between the units.

c. Adjusted Baseline Heat Input

Once a baseline heat input was calculated for the unit, it was adjusted for the specific coal type. Two separate allocation calculations were performed based on two separate sets of adjustment factors which are shown in Table 3 below. Based on directions from CAMD, the adjustment factors for all units were based on the type and amount of heat input from the different coal types each unit burned in one year, 1999. These data were taken from the Hg ICR information.

Table 3:
Coal Type Adjustment Factors

Adjustment Factors - Set 1		Adjustment Factors - Set 2	
Coal Type	**Factor**	**Coal/Unit Type**	**Factor**
Bituminous, Anthracite, Waste Coal (also Petroleum Coke and Tires)[1]	1	Bituminous, Anthracite, Waste Coal (also Petroleum Coke and Tires)[1]	2
Subbituminous	1.25	Subbituminous	5.8
Lignite	3	Lignite	9.2
		IGCC[2]	19

[1]Petroleum Coke and Tires are not coals, but were included in the Hg ICR data and the adjustment factor calculation.
[2]IGCC - Integrated Gasification Combined Cycle refers to a type of unit. The factor for IGCC was applied to an IGCC unit regardless of the type of coal used by the unit.

CAMD directed that units which did not have Hg ICR coal type information should be assigned the bituminous factor. These included the five new units in Table 2, five existing Hg ICR units identified in Table 4, and Acid Rain units that were not in the Hg ICR inventory listed in Table 5.

An exception was also made for a number of units in the Hg ICR which are identified as gas-fired in the CAMD database. The Hg ICR had no coal data for these units, so an adjustment factor of zero was applied to the Acid Rain heat input (so that these units would receive no allocation). Also a coal fired Hg ICR unit which was destroyed in an explosion after1999, Hawthorn unit 5 in Missouri, received an adjustment factor of zero. These units are listed in Table 6.

d. Hg Allocations

While hypothetical unit allocations were used to determine the States' allocation budgets, each State is given discretion on how to distribute the allocations within a State. Hypothetical mercury allocations were calculated for each unit under a Hg cap of 15 tons per year. The unit allocation was determined by multiplying the Hg cap by the ratio of the unit's adjusted baseline heat input to total adjusted baseline heat input. The allocations in the State level spreadsheet are in tons per year, and the unit level allocations are in ounces. State allocations were calculated by summing the allocations to each unit in the State.

Table 4:
Hg ICR Existing Coal Fired Units
without Hg ICR Coal Type Information

State	Plant	ORIS Code	Unit
GA	Arkwright	699	1
KY	R D Green	6639	G1
KY	R D Green	6639	G2
MN	Black Dog	1904	1
NV	Reid Garner	2234	4

Table 5:
Acid Rain, Non-Hg ICR, Existing Coal Fired Units
without Hg ICR Coal Type Information

State	Plant	ORIS Code	Unit ID
IA	Dubuque	1046	6
IA	Lansing	1047	1
IA	Lansing	1047	2
IA	Pella	1175	6
IA	Pella	1175	7
IA	Sixth Street	1058	2
IA	Sixth Street	1058	3
IA	Sixth Street	1058	4
IA	Sixth Street	1058	5
KY	Green River	1357	1
KY	Green River	1357	2
KY	Green River	1357	3
MI	Presque Isle	1769	1
MI	Wyandotte	1866	7
MI	Wyandotte	1866	8
MN	High Bridge	1912	3
MN	High Bridge	1912	4
MN	Taconite Harbor Energy Center	10075	1
MN	Taconite Harbor Energy Center	10075	2

MN	Taconite Harbor Energy Center	10075	3
MO	Columbia	2123	6

MO	Columbia	2123	7
NC	Elizabethtown Power	10380	UNIT1
NC	Elizabethtown Power	10380	UNIT2
NC	Lumberton Power	10382	UNIT1
NC	Lumberton Power	10382	UNIT2
NY	S A Carlson	2682	10
NY	S A Carlson	2682	11
NY	S A Carlson	2682	12
NY	S A Carlson	2682	9
NY	WPS Empire State, Inc Niagara Falls	50202	1
WI	Alma	4140	B1
WI	Alma	4140	B2
WI	Alma	4140	B3
WI	Blunt Street	3992	7
WI	Manitowoc	4125	6
WI	Manitowoc	4125	7
WI	Manitowoc	4125	8
WI	Stoneman	4146	B1
WI	Stoneman	4146	B2

Table 6:
Hg ICR Units Not Included in the Allocation Calculation

State	Plant	ORIS Code	Unit ID	Comment
KS	Kaw	1294	1	Natural Gas Fired Unit
KS	Kaw	1294	3	Natural Gas Fired Unit
MI	Conners Creek	1726	15	Natural Gas Fired Unit
MI	Conners Creek	1726	16	Natural Gas Fired Unit
MI	Conners Creek	1726	17	Natural Gas Fired Unit
MI	Conners Creek	1726	18	Natural Gas Fired Unit
MO	Hawthorn	2079	5	Unit Destroyed in 1999

DBS/efh
Enclosures